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Enbridge Gas Inc.
P. O. Box 2001
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Chatham, ON N7M 5M1

February 12, 2026

VIA RESS AND EMAIL

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

Dear Ritchie Murray:

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

Further to the submission filed on October 30, 2025, enclosed please find the following updated exhibit:

Exhibit	Updates
E-1-1, Table 1	Correction to the Capacity Released and Actual UDC Cost Incurred for Union North West and Union South.
E-1-1, pars 5, 7-8	The amounts referenced in the paragraphs have been corrected to reflect the information provided in Table 2.

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

Sincerely,

Richard Wathy

Richard Wathy
Technical Manager, Regulatory Applications

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

EXHIBIT LIST

A – Overview and Introduction

B - Utility Results and Earning Sharing

E – Union Rate Zones Deferral and Variance Accounts

F – Rate Allocation

F – Rate Allocation

G – Additional Items Not Requiring OEB Approval

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 was focused on setting the IRM for 2025 to 2028. [2] 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

[1] EB-2022-0200.
[2] EB-2024-0111.

accounts relate to Enbridge Gas as a whole, while some apply to either the EGD or Union Rate Zones[3].

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 Utilities and ratepayers.

5. As set out in the 2024 Rebasing Phase 1 Decision[4], the ESM does not apply for 2024, as that is a cost of service year. Accordingly, there is no ESM amount proposed for 2024.

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)). These accounts are listed at Exhibit C, Tab 1, Schedule 1. Enbridge Gas requests approval to clear the final balances of certain Enbridge Gas deferral and variance accounts for 2024 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 2024 as set out at Exhibit C, Tab 1, Schedule 1.

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

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

4. Union Rate Zones

8. Enbridge Gas requests approval to clear the final balances of certain Union rate zones deferral and variance accounts for 2024 as set out at Exhibit C, Tab 1, Schedule 1.

5. Relief Requested

9. 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 2024 deferral and variance accounts requested in Exhibit C, Tab 1, Schedule 1. 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, as early as July 1, 2026.

10. 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.

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

12. 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.

13. 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.

14. 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.

15. 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: October 30, 2025, at Chatham, Ontario

ENBRIDGE GAS INC.

Richard Wathy

Richard Wathy
Technical Manager, Regulatory Applications

2024 DEFERRAL ACCOUNT DISPOSITION 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 2024 deferral and variance account final balances for Enbridge Gas, and the Enbridge Gas Distribution (EGD) and Union Gas (Union)[1] rate zones.

2. The evidence in this Application is organized as follows:
   Exhibit A: Overview and Introduction
   Exhibit B: 2024 Utility Results
   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 2024 deferral and variance account balances be implemented with the first available Quarterly Rate Adjustment Mechanism (QRAM) application following the OEB's approval, as early as July 1, 2026, 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 2024 deferral and variance accounts. The balances of the 2024 deferral and variance accounts are set out at Exhibit C, Tab 1,

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

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 2024 deferral and variance accounts as a one-time adjustment for all customers. However, Enbridge Gas proposes to dispose of the 2024 deferral and variance account balances for Rate M1 customers in the Union South rate zone evenly over three months in order to smooth bill impacts for customers. For all remaining general service, in-franchise contract and ex-franchise rate classes in the EGD and Union rate zones, Enbridge Gas proposes to dispose of the 2024 deferral and variance accounts as a one-time adjustment.

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 as part of the July 2026 bills that customers receive in August 2026. For Union South Rate M1 customers the disposition will occur evenly over three months commencing with the July 2026 bills that customers receive in August 2026.

Enbridge Gas Inc.
Deferral & Variance Account
Actual & Forecast Balances

Line No.	Account Description	OEB Account Number	Col. 1 Principal ($000s)	Col. 2 Interest ($000s)	Col. 3 Total ($000s)	Col.4 Reference to Evidence
			Forecast for clearance at July 1, 2026			
	EGI Commodity Related Accounts					
1	Upstream Transportation Optimization V/A	179-201	(33,371.7)	(2,566.0)	(35,937.7)	Exhibit C-2-1
2	UFG Volume V/A	179-203	6,359.3	282.3	6,641.6	Exhibit C-2-3
3	UFG Price V/A	179-204	(6,838.3)	(466.1)	(7,304.4)	Exhibit C-2-4
4	Total Commodity Related Accounts		(33,850.7)	(2,749.9)	(36,600.6)	
	EGI Non Commodity Related Accounts					
5	Transportation from Dawn Service D/A	179-202	73.3	5.0	78.3	Exhibit C-2-2
6	Deferral Clearance V/A	179-302	(6,184.1)	(5,040.7)	(11,224.8)	Exhibit C-2-5
7	Parkway Delivery Obligation V/A	179-303	3,245.6	231.8	3,477.4	Exhibit C-2-6
8	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-	
9	Pension & OPEB V/A	179-305	-	(6,562.5)	(6,562.5)	Exhibit C-2-7
10	Facility Carbon Charge V/A	179-307	(3,410.3)	(291.0)	(3,701.3)	Exhibit C-2-8
11	Customer Carbon Charge V/A	179-308	(10,979.3)	(1,793.1)	(12,772.4)	Exhibit C-2-9
12	Carbon Charges Bad Debt D/A	179-309	11,720.9	783.8	12,504.7	Exhibit C-2-10
13	Tax V/A	179-312	-	-	-	
14	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-	
15	IRP Operating Costs Deferral Account	179-318	429.9	30.7	460.6	Exhibit C-2-11
16	IRP Capital Costs Deferral Account	179-319	-	-	-	
17	Green Button Initiative D/A	179-320	-	-	-	
18	Dawn Parkway Surplus Capacity D/A	179-323	(902.5)	(21.2)	(923.7)	Exhibit C-2-12
19	Distribution Integrity Management Program D/A	179-326	(20.1)	(0.9)	(21.0)	Exhibit C-2-13
20	Post Retirement True-Up V/A	179-328	(1,359.3)	(85.6)	(1,444.9)	Exhibit C-2-14
21	Clean Fuel Regulation Credits D/A	179-330	(55.6)	(2.6)	(58.2)	Exhibit C-2-15
22	Indigenous Working Group D/A	179-331	119.3	7.0	126.3	Exhibit C-2-16
23	Cloud Computing Implementation Costs D/A	179-332	-	-	-	
24	Average Use Variance Account	179-333	15,698.4	1,145.1	16,843.5	Exhibit C-2-17
25	Getting Ontario Connected V/A	179-335	14,891.5	882.6	15,774.1	Exhibit C-2-18
26	Disposition of Property D/A	179-336	-	-	-	
27	LEAP Emergency Financial Assistance D/A	179-338	-	-	-	
28	Earnings Sharing D/A	179-339	-	-	-	
29	Enbridge Sustain Affiliate Recoveries V/A	179-344	(91.0)	(4.2)	(95.2)	Exhibit C-2-19
30	Total Non Commodity Related Accounts		23,176.7	(10,715.7)	12,460.9	
31	Total EGI Accounts (for clearance)		(10,674.0)	(13,465.6)	(24,139.7)	
	EGD Rate Zone Commodity Related Accounts					
32	Storage and Transportation D/A	179-88	6,433.4	461.7	6,895.1	Exhibit D-1-1
33	Total Commodity Related Accounts		6,433.4	461.7	6,895.1	
	EGD Rate Zone Non Commodity Related Accounts					
34	Open Bill Extension D/A	179-325	(3,066.4)	(212.7)	(3,279.1)	Exhibit D-1-2
35	Total Non Commodity Related Accounts		(3,066.4)	(212.7)	(3,279.1)	
36	Total EGD Rate Zone (for clearance)		3,367.0	249.0	3,616.0	
	Union Rate Zones Gas Supply Accounts					
37	Unabsorbed Demand Costs Variance Account	179-108	3,957.8	275.1	4,232.9	Exhibit E-1-1
38	Total Gas Supply Accounts		3,957.8	275.1	4,232.9	
	Union Rate Zones Storage Accounts					
39	Short-Term Storage and Other Balancing Services	179-70	(4,880.3)	(225.0)	(5,105.3)	Exhibit E-1-2
40	Total Storage Accounts		(4,880.3)	(225.0)	(5,105.3)	
41	Total Union Rate Zones (for clearance)		(922.5)	50.1	(872.4)	
42	Total Deferral and Variance Accounts (for clearance)		(8,229.5)	(13,166.6)	(21,396.1)	
	EGI Accounts Not Being Requested For Clearance					
43	Incremental Capital Module D/A	179-306	-	-	-	
44	Panhandle Region Expansion Project V/A	179-329	(14,231.3)	(654.0)	(14,885.3)	Exhibit C-2-20
45	Site Restoration Costs Tracking Account	179-337	(19,430.0)	-	(19,430.0)	Exhibit C-2-20
46	IRP System Pruning D/A	179-341	21.7	0.8	22.5	Exhibit C-2-20
47	Asset Life Extension Costs D/A	179-343	-	-	-	

2024 ENBRIDGE GAS INC. EARNINGS DETERMINATION PROCESS

1. In its 2024 Rebasing Phase 1 Decision,[1] the OEB found that an Earnings Sharing Mechanism for the 2024 Test Year is not required. The OEB stated that it had conducted a thorough review of all Phase 1 Issues in that Application which included extensive discovery and an Oral Hearing to test the evidence and that the OEB is confident that the rates resulting from its Decision are reasonable and appropriately reflect the costs to serve customers.

2. As such, for the year ended December 31, 2024, Enbridge Gas Inc. (Enbridge Gas, or the Company) is not subject to earnings sharing. The Company, however, has provided the Utility Results including Return on Rate Base and Equity in relation to the OEB-approved Return on Equity of 9.21% for 2024 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.

3. Within Exhibit B, Tab 1, Schedule 2, the Company has calculated achieved earnings and the resultant revenue deficiency in relation to the OEB-approved in two ways for confirmation purposes.

4. In part A), a return on rate base method is shown, while in part B), a return on equity from a deemed equity embedded within rate base perspective is shown. 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.

[1] EB-2022-0200, OEB Decision and Order, December 21, 2023, p.128.

<u>1. Part A) – Return on Rate Base</u>

5. The level of utility income, $859.9 million (line 4) divided by the level of utility rate base, $16,025.3 million (line 5) generates a utility return on rate base of 5.366% (line 6).

6. When compared to the OEB-approved return on rate base of 6.093% (line 7), as determined within the capital structure required in support of the determined rate base amount, there is a resulting deficiency of 0.727% (line 8) on total rate base.

7. As shown in lines 9 through 11, the deficiency of 0.727% multiplied by the rate base of $16,025.3 million, produces a net under earnings or deficiency of $116.6 million, which from a pre-tax perspective ($116.6 million divided by the reciprocal, 73.5%, of the corporate tax rate which is 26.5%), results in a $158.6 million gross amount of under earnings.

<u>2. Part B) – Return on Equity</u>

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

9. The $921.3 million (line 13) of utility income before income tax, less utility taxes of $61.4 million (line 18), produces the $859.9 million of utility income used in part A) above (at line 4).

10. In order to determine utility net income applicable to a deemed common equity percentage within rate base, all long term debt, short term debt and preference share costs must also be reduced against the part A) $859.9 million utility income.

11. These reductions are shown at lines 14, 15 and 16 which, along with the utility income tax reduction already mentioned and shown at line 18, results in a net income applicable to common equity of $444.3 million, shown at line 19.

12. The $444.3 million, divided by the deemed common equity level of $6,089.6 million (line 20, calculated as 38% of the $16,025.3 million rate base) produces a return on equity of 7.30% (line 22). When comparing the 7.30% achieved return on equity to the OEB-approved 2024 ROE percentage of 9.21% (line 21), there is a deficiency in ROE of 1.91% (line 23).

13. The 1.91% multiplied by the common equity level of $6,089.6 million (line 20) produces a net under earnings or deficiency of $116.6 million, which from a pre-tax perspective ($116.6 million divided by the reciprocal, 73.5%, of the corporate tax rate), results in a $158.6 million gross amount of under earnings.

3. Process Description

14. 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.

15. 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.

16. In addition, Enbridge Gas has made the appropriate adjustments in relation to non-standard legacy EGD and Union 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 Transactional Services, short-term storage, and net optimization incentives); and
- Elimination of Central Functions Corporate Cost Allocation Methodology (CFCAM) charges that did not pass the 3-prong test.

Summary
Return on Rate Base & Equity
Enbridge Gas Inc.

Ontario Utility
For the Year Ended December 31, 2024

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
			($ millions) & (%s)
2	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 2)	921.3
3	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	61.4
4	Utility Income		859.9
5	Utility Rate Base	(Ex. B, Tab 1, Sch. 4)	16,025.3
6	Indicated Return on Rate Base %	(line 4 / line 5)	5.366%
7	Less: Required Rate of Return %	(Ex. B, Tab 1, Sch. 5)	6.093%
8	(Deficiency) / Sufficiency %		-0.727%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(116.6)
10	Provision for Income Taxes		(42.0)
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	(158.6)
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
13	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 2)	921.3
14	Less: Long Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	420.5
15	Less: Short Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	-4.9
16	Less: Cost of Preferred Capital	(Ex. B, Tab 1, Sch. 5)	0
17	Net Income before Income Taxes		505.7
18	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	61.4
19	Net Income Applicable to Common Equity	(line 18 - line 19)	444.3
20	Common Equity	(Ex. B, Tab 1, Sch. 5)	6,089.60
21	Approved ROE %	(OEB-approved)	9.21%
22	Achieved Rate of Return on Equity %	(line 20 / line 21)	7.30%
23	Resulting (Deficiency) / Sufficiency in Return on Equity %		-1.91%
24	Net Earnings (Deficiency) / Sufficiency	(line 21 x line 24)	(116.6)
25	Provision for Income Taxes		(42.0)
26	Gross Earnings (Deficiency) / Sufficiency	(line 25 / 73.5%)	(158.6)

EGI Utility Income
2024 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)	4,704.5	-	(18.6)	(i)	4,686.0
2	Transportation	(Ex. B, Tab 2, Sch. 2)	157.5	(1.2)	(5.4)	(ii)	153.3
3	Storage	(Ex. B, Tab 2, Sch. 2)	253.2	252.8	(0.4)	(iii)	(0.0)
4	Other operating revenue	(Ex. B, Tab 2, Sch. 3)	81.0	5.7	(12.4)	(iv)	62.9
5	Other income	(Ex. B, Tab 2, Sch. 3)	5.1	(1.0)	(0.6)	(viii)	5.4
6	Total operating revenue		5,201.4	256.4	(37.4)		4,907.6
7	Gas costs		2,100.5	87.7	-		2,012.8
8	Operation and maintenance	(Ex. B, Tab 3, Sch. 1)	1,137.6	33.3	(11.5)	(v)	1,092.8
9	Depreciation and amortization expense		784.4	18.6	(22.5)	(vi)	743.3
10	Fixed financing costs		4.2	-	3.1	(vii)	7.2
11	Municipal and other taxes		132.1	1.9	-		130.2
12	Cost of service		4,158.8	141.5	(30.9)		3,986.3
13	Utility income before income taxes						921.3
14	Income tax expense	(Ex. B, Tab 1, Sch. 3)					61.4
15	Utility income						859.9

Notes on Adjustments:

(i)	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(18.6)
(ii)	Elimination of the shareholder portion of net optimization activity (before tax)	(0.7)
	Elimination of shareholder portion of transactional service revenues	(4.7)
		(5.4)
(iii)	Elimination of the shareholder portion of net short-term storage revenue (before tax)	(0.4)
(iv)	Elimination of demand-side management incentive	(12.4)
(v)	Elimination of donations	(2.9)
	Elimination of Central Functions Corporate Allocation Methodology (CFCAM) charges	(8.5)
		(11.5)
(vi)	Eliminate amortization of PPD (purchase price discrepancy)	(22.5)
(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.	3.1
(viii)	Elimination of interest income from investments not included in utility rate base	(0.6)

Calculation of EGI Utility Taxable Income and Income Tax Expense
2024 Actual

Line No.	Particulars ($ millions)	Col. 1 Federal	Col. 2 Provincial	Col. 3 Combined
1	Utility income before income taxes	921.3	921.3	
	Add			
2	Depreciation and amortization	743.3	743.3	
3	Accrual based pension and OPEB costs	(7.6)	(7.6)	
4	Other non-deductible items	1.9	1.9	
5	Total Add Back	737.6	737.6	
6	Sub-total	1,658.9	1,658.9	
	Deduct			
7	Capital cost allowance	790.9	790.9	
8	Items capitalized for regulatory purposes	199.9	199.9	
9	Amortization of share/debenture issue expense	0.8	0.8	
10	Amortization of C.D.E. and C.O.G.P.E	0.0	0.0	
11	Other	(0.5)	(0.5)	
12	Cash based pension and OPEB costs	20.5	20.5	
13	Total Deduction	1,011.6	1,011.6	
14	Taxable income	647.3	647.3	
15	Income tax rates	15.00%	11.50%	
16	Tax provision excluding interest shield	97.1	74.4	171.5
	Tax shield on interest expense			
17	Rate base	16,025.3		
18	Return component of debt	2.59%		
19	Interest expense	415.5		
20	Combined tax rate	26.50%		
21	Income tax credit			(110.1)
22	Total utility income taxes			61.4

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

Line No.	Class	Particulars ($000s)	Col. 1 UCC at Prior Year Filing EB-2023-0092 (a)	Col. 2 True-up from Filing to Tax Return (b)	Col. 3 UCC At Beginning of Year (c)	Col. 4 Total Additions (d)	Col. 5 Total Additions Qualifying for Accel. CCA (e)	Col. 6 Less: Lessor of Cost or Proceeds (f)	Col. 7 Eligible CCA Additions** (g)	Col 8 Depreciable UCC Balance (h)	Col. 9 Rate (%) (i)	Col. 10 CCA FY2023 (j)	Col. 11 Ending UCC (k)
1	1	Buildings, structures and improvements, services, meters, mains	2,118,476.9	-	2,118,476.9	-	-	-	-	2,118,476.9	4%	84,739.1	2,033,737.8
2	1	Non-residential building acquired after March 19, 2007	153,170.0	112.7	153,282.7	3,236.8	3,236.8	-	4,855.3	158,138.0	6%	9,488.3	147,031.3
3	2	Mains acquired before 1988	143,339.5	-	143,339.5	-	-	-	-	143,339.5	6%	8,600.4	134,739.2
4	3	Buildings acquired before 1988	2,704.7	-	2,704.7	-	-	-	-	2,704.7	5%	135.2	2,569.4
5	6	Other buildings	63.4	-	63.4	-	-	-	-	63.4	10%	6.3	57.1
6	7	Compression equipment acquired after February 22, 2005	371,124.6	-	371,124.6	4,446.1	4,446.1	-	6,669.2	377,793.8	15%	56,669.1	318,901.6
7	8	Compression assets, office furniture, equipment	200,767.9	(6,970.9)	193,797.0	125,909.3	125,909.3	-	188,864.0	382,661.0	20%	76,532.2	243,174.1
8	10	Transportation, computer equipment	30,593.4	(512.6)	30,080.7	3,253.9	3,253.9	-	4,880.9	34,961.7	30%	10,488.5	22,846.2
9	12	Computer software, small tools	780.1	(221.8)	558.4	33,766.4	33,766.4	-	33,766.4	34,324.7	100%	34,324.7	-
10	13	Leasehold improvements	139.6	-	139.6	-	-	-	-	139.6	0%	107.8	31.9
11	14.1	Intangibles	12,826.0	0.0	12,826.0	564.0	564.0	-	846.0	13,672.0	5%	683.6	12,706.4
12	14.1	Intangibles (pre 2017)	40,458.5	-	40,458.5	-	-	-	-	40,458.5	7%	2,832.1	37,626.4
13	17	Roads, sidewalk, parking lot or storage areas	425.4	-	425.4	-	-	-	-	425.4	8%	34.0	391.4
14	38	Heavy work equipment	11,178.4	(168.0)	11,010.4	2,462.7	2,462.7	-	3,694.1	14,704.5	30%	4,411.3	9,061.8
15	41	Storage assets	81,607.6	(653.0)	80,954.6	98,405.5	98,405.5	-	147,608.3	228,562.9	25%	57,140.7	122,219.4
16	45	Computers - Hardware acquired after March 22, 2004	1.9	-	1.9	-	-	-	-	1.9	45%	0.9	1.0
17	49	Transmission pipeline additions acquired after February 23, 2005	755,358.0	142.4	755,500.4	25,124.4	25,124.4	-	37,686.6	793,187.0	8%	63,455.0	717,169.9
18	50	Computers hardware acquired after March 18, 2007	6,966.8	(691.9)	6,274.9	17,057.2	17,057.2	-	25,585.7	31,860.6	55%	17,523.3	5,808.7
19	51	Distribution pipelines acquired after March 18, 2007	6,201,229.7	(31,916.7)	6,169,313.0	908,359.9	908,359.9	(4,738.9)	1,360,170.4	7,524,744.5	6%	451,484.7	6,621,449.3
20		Total	10,131,212.4	(40,879.7)	10,090,332.7	1,222,586.3	1,222,586.3	(4,738.9)	1,814,626.8	11,900,220.5		878,657.1	10,429,522.9

EGI Utility Rate Base
2024 Actual

Line No.	Particulars ($ millions)	Col. 1 2024 Actual	Col. 2 2024 OEB-Approved (1) (2)	Col. 3 Variance
	Property, Plant, and Equipment			
1	Gross property, plant, and equipment	24,298.0	24,241.8	56.2
2	Accumulated depreciation	(8,839.3)	(8,886.4)	47.1
3	Net property, plant, and equipment	15,458.7	15,355.4	103.3
	Allowance for Working Capital			
4	Materials and supplies	128.5	107.0	21.5
5	ABC receivable	(17.5)	(5.1)	(12.4)
6	Customer security deposits	(65.8)	(60.2)	(5.6)
7	Prepaid expenses	6.7	-	6.7
8	Gas in storage	609.6	648.4	(38.8)
9	Working cash allowance	(94.9)	(130.5)	35.6
10	Total Working Capital	566.6	559.6	7.0
11	Utility Rate Base	16,025.3	15,915.0	110.3

Notes:

(1) EB-2024-0111, Draft Rate Order, November 4, 2024, Working Papers, Schedule 1,p.2.

(2) Does not include Panhandle Regional Expansion Project (PREP) Rate Base of $30.811 (EB-2024-0111, Draft Rate Order, November 4, 2024, Working Papers, Schedule 13, p.1)

EGI Utility Property, Plant, and Equipment
Summary Statement - Average of Monthly Averages
2024 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	1,597.5	(551.8)	1,045.7
2	Transmission plant	5,000.3	(1,768.7)	3,231.6
3	Distribution plant	16,894.4	(6,091.2)	10,803.2
4	General plant	765.7	(403.9)	361.8
5	Local storage plant	36.7	(20.4)	16.3
6	Intangible plant	3.3	(3.2)	0.1
7	EGI Total	24,298.0	(8,839.3)	15,458.7

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

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

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

EGI Utility Plant
Continuity of Accumulated Depreciation
Year End Balances and Average of Monthly Averages
2024 Actual

Line No.	Particulars ($ millions)	Col. 1 Opening Balance Dec.2023	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.2024	Col. 8 Regulatory Adjustment	Col. 9 Utility Balance Dec.2024	Col. 10 Average of Monthly Averages
	Underground Storage Plant - EGI										
1	Land and gas storage rights (451)	(48.2)	(1.1)	-	-	-	-	(49.3)	-	(49.3)	(48.7)
2	Structures and improvements (452)	(76.0)	(3.8)	11.3	0.0	0.3	-	(68.2)	0.1	(68.1)	(69.7)
3	Wells (453)	(54.6)	(6.1)	0.2	0.0	1.4	-	(59.0)	-	(59.0)	(56.9)
4	Well equipment (454)	(10.2)	(0.2)	-	-	-	-	(10.4)	-	(10.4)	(10.3)
5	Field Lines (455)	(87.8)	(5.3)	-	0.0	0.5	0.0	(92.6)	-	(92.6)	(90.2)
6	Compressor equipment (456)	(243.4)	(18.8)	42.4	0.4	1.0	6.2	(212.3)	0.3	(212.0)	(214.9)
7	Measuring and regulating equipment (457)	(59.6)	(5.8)	1.0	0.7	0.2	-	(63.5)	-	(63.5)	(61.2)
8	Sub-Total	(579.8)	(41.0)	54.9	1.2	3.4		(555.2)	0.4	(554.8)	(551.8)
	Transmission Plant - EGI										
9	Land rights (461)	(21.7)	(1.1)	-	-	-	-	(22.8)	-	(22.8)	(22.2)
10	Structures and improvements (452)	(59.1)	(4.3)	-	-	0.3	-	(63.0)	-	(63.0)	(61.1)
11	Mains (465)	(1,064.0)	(43.0)	8.1	2.9	3.1	-	(1,092.8)	-	(1,092.8)	(1,078.7)
12	Compressor equipment (466)	(396.6)	(34.3)	-	(0.1)	1.6	-	(429.4)	-	(429.4)	(412.9)
13	Measuring and regulating equipment (467)	(187.3)	(14.8)	-	(0.0)	1.3	-	(200.8)	-	(200.8)	(193.9)
14	Sub-Total	(1,728.6)	(97.4)	8.1	2.8	6.3	-	(1,808.8)	-	(1,808.8)	(1,768.7)
	Distribution Plant - EGI										
15	Renewable Natural Gas (461)	(0.1)	(1.4)	-	-	-	-	(1.5)	-	(1.5)	(1.3)
16	Land rights intangibles (471)	(13.8)	(1.1)	-	-	-	-	(15.0)	-	(15.0)	(14.4)
17	Structures and improvements (472)	(105.9)	(12.1)	3.0	0.9	-	-	(114.2)	0.3	(113.9)	(110.5)
18	Services - metallic (473)	(408.6)	(21.7)	2.4	3.6	1.2	-	(423.1)	-	(423.1)	(415.7)
19	Services - plastic (473)	(1,487.0)	(146.0)	10.5	12.7	20.9	-	(1,588.9)	-	(1,588.9)	(1,537.4)
20	Regulators (474)	(202.4)	(49.0)	59.5	0.2	(0.2)	-	(191.9)	-	(191.9)	(204.4)
21	House regulators & meter installations (474)	(0.2)	(0.2)	-	-	-	-	(0.3)	-	(0.3)	(0.3)
22	Mains - metallic (475)	(1,347.9)	(95.8)	7.5	32.5	(9.0)	1.2	(1,411.3)	2.2	(1,409.1)	(1,375.1)
23	Mains - plastic (475)	(1,286.6)	(75.8)	8.2	12.8	1.3	0.0	(1,340.0)	-	(1,340.0)	(1,313.3)
24	Mans - envision (475)	(107.1)	(10.5)	-	-	-	-	(117.6)	-	(117.6)	(112.4)
25	NGV station compressors (476)	(6.2)	(0.4)	-	-	-	-	(6.6)	-	(6.6)	(6.4)
26	Measuring and regulating equip. (477)	(404.8)	(31.5)	7.3	8.9	(6.4)	0.2	(426.4)	1.1	(425.3)	(416.0)
27	Meters (478)	(546.3)	(100.4)	29.9	(0.5)	0.5	-	(616.8)	-	(616.8)	(584.1)
28	Sub-Total	(5,917.0)	(545.9)	128.3	71.3	8.2	1.4	(6,253.7)	3.6	(6,250.1)	(6,091.2)
	General Plant - EGI										
29	Investment in leased assets (101)	(0.9)	-	-	-	-	(0.5)	(1.4)	-	(1.4)	(1.2)
30	Structures & improvements (482)	(68.0)	(13.3)	8.4	0.0	-	-	(72.8)	0.2	(72.6)	(68.3)
31	Office furniture and equipment (483)	(24.2)	(1.4)	2.1	(0.2)	0.2	-	(23.5)	-	(23.5)	(23.5)
32	Transportation equipment (484)	(115.5)	(5.3)	2.9	(0.7)	0.7	-	(117.9)	0.1	(117.8)	(117.5)
33	NGV conversion kits (484)	(0.4)	(0.1)	-	-	-	-	(0.5)	-	(0.5)	(0.5)
34	Heavy work equipment (485)	(17.0)	(3.3)	(0.3)	(0.2)	0.2	-	(20.6)	-	(20.6)	(18.7)
35	Tools and work equipment (486)	(24.8)	(8.8)	20.9	-	-	-	(12.6)	-	(12.6)	(17.6)
36	Rental equipment (487)	(0.1)	(0.1)	-	-	-	-	(0.2)	-	(0.2)	(0.2)
37	NGV rental compressors (487)	(4.0)	(0.3)	-	-	-	-	(4.3)	-	(4.3)	(4.4)
38	NGV cylinders (484 and 487)	(0.6)	(0.0)	-	-	-	-	(0.6)	-	(0.6)	(0.6)
39	Communication structures & equip. (488)	(0.1)	(0.7)	3.1	-	-	-	2.4	-	2.4	1.0
40	Computer equipment (490)	(16.6)	(3.6)	3.2	-	-	0.2	(16.9)	-	(16.9)	(17.9)
41	Software Aquired/Developed (491)	(68.4)	(13.9)	7.2	-	-	(10.8)	(85.9)	-	(85.9)	(84.4)
42	WAMS (489)	(47.9)	(9.2)	-	-	-	-	(57.1)	-	(57.1)	(50.2)
43	Sub-Total	(388.5)	(59.9)	47.6	(1.1)	1.1	(11.2)	(412.0)	0.3	(411.8)	(403.9)
	Local Storage Plant - EGI										
44	Structures and improvements (442)	(3.0)	(0.1)	-	0.1	(0.1)	-	(3.2)	-	(3.2)	(3.1)
45	Gas holders - storage (443)	(4.3)	(0.1)	-	-	-	-	(4.4)	-	(4.4)	(4.4)
46	Gas holders - equipment (443)	(12.9)	(0.2)	-	-	-	-	(13.1)	-	(13.1)	(13.0)
47	Sub-Total	(20.2)	(0.4)	-	0.1	(0.1)	-	(20.6)	-	(20.6)	(20.4)
	Intangible Plant - EGI										
48	Inactive services (102)	(1.5)	(0.0)	-	-	-	-	(1.6)	-	(1.6)	(1.5)
49	Franchises and consents (401)	(1.1)	(0.1)	-	-	-	-	(1.2)	-	(1.2)	(1.1)
50	Other intangible plant (402)	(0.5)	(0.0)	-	-	-	-	(0.5)	-	(0.5)	(0.5)
51	Sub-Total	(3.1)	(0.1)	-	-	-	-	(3.3)	-	(3.3)	(3.2)
52	EGI Total	(8,637.3)	(744.7)	238.8	74.3	19.0	(9.8)	(9,053.5)	4.2	(9,049.3)	(8,839.3)

EGI Working Capital Components
Month End Balances and Average of Monthly Averages
2024 Actual

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Line No.	Particulars ($ millions)	Materials and Supplies	ABC Receivable	Customer Security Deposits	Prepaid Expenses	Gas in Storage	Working Cash Allowance	Total
1	January 1	119.5	(18.8)	(63.3)	(0.8)	850.5	(94.9)	792.2
2	January 31	122.2	(12.4)	(62.9)	(11.4)	701.3	(94.9)	641.9
3	February	123.3	(19.5)	(62.6)	(2.9)	632.4	(94.9)	575.6
4	March	123.5	(43.1)	(64.4)	3.0	528.7	(94.9)	452.8
5	April	125.3	(30.5)	(63.9)	6.5	376.2	(94.9)	318.7
6	May	125.2	(27.7)	(65.2)	5.8	423.5	(94.9)	366.7
7	June	126.0	(36.3)	(64.9)	9.8	479.0	(94.9)	418.7
8	July	125.5	(14.0)	(65.4)	10.1	588.3	(94.9)	549.5
9	August	128.0	(5.4)	(68.5)	14.1	652.2	(94.9)	625.5
10	September	127.8	(11.6)	(70.2)	19.5	731.4	(94.9)	702.0
11	October	139.1	3.5	(69.7)	16.0	742.1	(94.9)	736.2
12	November	144.9	4.5	(68.0)	10.8	712.7	(94.9)	710.0
13	December	143.4	(16.8)	(65.0)	(0.5)	644.0	(94.9)	610.2
14	Avg. of monthly avgs.	128.5	(17.5)	(65.8)	6.7	609.6	(94.9)	566.6

EGI Summary Of Capital Structure & Cost of Capital
2024 Actual

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5 (Col. 1x Col. 3)
Line No.	Particulars	Utility Capital Structure Principal	Component	Cost Rate	Return Component	Interest & Return
		($ millions)	%	%	%	($ millions)
1	Long and Medium-Term Debt	10,026.5	62.57	4.19	2.621	420.0
2	Short-Term Debt	(90.8)	(0.57)	4.75	(0.027)	(4.3)
3	Total Debt	9,935.7	62.00		2.594	415.7
4	Preference Shares	-	-	-	-	-
5	Common Equity	6,089.6	38.00	9.21	3.500	560.9
6	Total Rate Base	16,025.3	100.00		6.094	976.5

Calculation of Cost Rates
For EGI Capital Structure Components
2024 Actual

Line No.	Particulars ($ millions)		Col. 1 Average of Monthly Averages	Col. 2	Col. 3 Carrying Cost
	Long and Medium-Term Debt				
1	Debt Summary		10,310.9		435.9
2	Unamortized Finance Costs		95.1		-
3	(Profit)/Loss on Redemption		-		-
4			10,406.0		435.9
5	Percentage Allocation of Debt to Unregulated	3.65%	(379.5)		(15.9)
6	Net Regulated Long and Medium-Term Debt		10,026.5		420.0
7	Calculated Cost Rate			4.19%	
	Short-Term Debt				
8	Calculated Cost Rate			4.75%	
	Common Equity				
9	Board Formula ROE			9.21%	

EGI Summary Statement of Principal
and Carrying Cost of Term Debt
2024 Actual

Line No.	Coupon Rate	Maturity Date	Col. 1 Average of Monthly Averages Principal ($ millions)	Col. 2 Effective Cost Rate	Col. 3 Carrying Cost ($ 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	3.79%	July 10, 2023	-	3.87%	-
7	2.81%	June 1, 2026	250.0	2.87%	7.2
8	3.80%	June 1, 2046	250.0	3.84%	9.6
9	2.88%	November 22, 2027	250.0	2.95%	7.4
10	3.59%	November 22, 2047	250.0	3.64%	9.1
11	3.19%	September 17, 2025	200.0	3.26%	6.5
12	5.46%	September 11, 2036	165.0	5.49%	9.1
13	8.65%	November 10, 2025	125.0	8.77%	11.0
14	8.85%	October 2, 2025	20.0	8.97%	1.8
15	7.60%	October 29, 2026	100.0	8.09%	8.1
16	6.65%	November 3, 2027	100.0	6.71%	6.7
17	6.10%	May 19, 2028	100.0	6.16%	6.2
18	6.05%	July 5, 2023	-	6.38%	-
19	6.90%	November 15, 2032	150.0	6.95%	10.4
20	6.16%	December 16, 2033	150.0	6.18%	9.3
21	5.21%	February 25, 2036	300.0	5.18%	15.5
22	4.95%	November 22, 2050	200.0	4.99%	10.0
23	4.95%	November 22, 2050	100.0	4.73%	4.7
24	4.50%	November 23, 2043	200.0	4.20%	8.4
25	3.15%	August 22, 2024	134.4	3.24%	4.4
26	4.00%	August 22, 2044	215.0	3.89%	8.4
27	4.00%	August 22, 2044	170.0	4.44%	7.5
28	3.31%	September 11, 2025	400.0	3.62%	14.5
29	2.50%	August 5, 2026	300.0	3.42%	10.3
30	3.51%	November 29, 2047	300.0	3.53%	10.6
31	2.37%	August 9, 2029	400.0	3.23%	12.9
32	3.01%	August 9, 2049	300.0	3.03%	9.1
33	2.90%	April 1, 2030	600.0	3.41%	20.4
34	3.65%	April 1, 2050	600.0	3.67%	22.0
35	2.35%	September 1, 2031	475.0	2.94%	14.0
36	3.20%	September 1, 2051	425.0	3.22%	13.7
37	4.15%	August 17, 2032	325.0	3.15%	10.2
38	4.55%	August 17, 2052	325.0	4.52%	14.7
39	5.46%	October 6, 2028	250.0	5.54%	13.9
40	5.70%	October 6, 2033	400.0	3.70%	14.8
41	5.67%	October 6, 2053	350.0	5.08%	17.8
42			10,229.4		427.8
Long-Term Debentures					
43	9.85%	December 2, 2024	81.5	9.910%	8.1
44			81.5		8.1
45	Total Term Debt		10,310.9		435.9

EGI Unamortized Debt Discount and Expense
Average of Monthly Averages
2024 Actual

Line No.	Particulars	Col. 1 Unamortized Debt Discount and Expense ($ millions)
1	January 1	(94.6)
2	January 31	(95.1)
3	February	(95.1)
4	March	(95.1)
5	April	(95.1)
6	May	(95.1)
7	June	(95.1)
8	July	(95.1)
9	August	(95.1)
10	September	(95.1)
11	October	(95.1)
12	November	(95.1)
13	December	(95.1)
14	Average of Monthly Averages	(95.1)

Reconciliation of Audited EGI Income (Per Financial Statements)
To Corporate Income For Utility Income Determination Purposes
2024 Actual

Line No.	Particulars ($ 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	4,701.5	4,704.5		
2	Storage, transportation and other	494.8	-		
3	Transportation	-	157.5		
4	Storage	-	253.2		
5	Other operating revenue	-	81.0		
6	Other Income	61.0	5.1		
7	Total operating revenue	5,257.3	5,201.4	(55.9)	(a)
	Operating Expenses				
8	Gas Costs	2,100.5	2,100.5	-	
9	Operation and maintenance	1,327.4	1,137.6	(189.8)	(b)
10	Depreciation and amortization expense	784.4	784.4	-	
11	Impairment of long-lived assets	-	-	-	(b)
12	Fixed financing costs	-	4.2	4.2	(c)
13	Municipal and other taxes	-	132.1	132.1	(d)
14	Cost of service	4,212.3	4,158.8	(53.5)	
15	Income before interest and income taxes	1,045.0	1,042.6	(2.4)	
16	Interest and financing expenses	451.7	-	(451.7)	(e)
17	Income before income taxes	593.3	1,042.6	449.3	
18	Income taxes	91.2	-	(91.2)	(f)
19	Net Income	502.1	1,042.6	540.5	

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

a)	Audited Total Operating Revenue	5,257.3
	Reclassify pension related other revenue to O&M	(58.1)
	Reclassify bank charges from other income to interest & financing charges	1.8
	Reclassify other expenses out of other income to O&M	0.4
	Corporate Total Operating Revenue	5,201.4
b)	Audited Operation and Maintenance	1,327.4
	Reclassify pension related other revenue to O&M	(58.1)
	Reclassify Municipal & Property Taxes out of O&M	(132.1)
	Reclassify Impairment Charges to O&M	-
	Reclassify other expenses out of other income to O&M	0.4
	Corporate Operation and Maintenance	1,137.6
c)	Audited Fixed Financing Costs	-
	Reclassify fixed financing costs from interest and financing expenses	4.2
	Corporate Fixed Financing Costs	4.2
d)	Audited Municipal and Other Taxes	-
	Reclassify Municipal and other taxes included within O&M costs	132.1
	Corporate Municipal and Other Taxes	132.1
e)	Audited Interest and Financing expenses	451.7
	Reclassify fixed financing costs from interest and financing expenses	(4.2)
	Reclassify bank charges from other income to interest & financing charges	1.8
	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure	(449.3)
	Corporate Interest and Financing expenses	-
f)	Audited Income Taxes	91.2
	Elimination of corporate income taxes which will be calculated on a utility stand-alone basis	(91.2)
	Corporate Income Taxes	-

Average Customers by Rate Class

Line No.	Particulars	2024 OEB-Approved Sales Service	2024 OEB-Approved Direct Purchase	2024 OEB-Approved Total	2024 Actual Sales Service	2024 Actual Direct Purchase	2024 Actual Total	Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	2,137,812	25,277	2,163,088	2,135,254	25,993	2,161,247	(1,841)
2	Rate 6	154,960	18,015	172,974	147,679	23,796	171,475	(1,499)
3	Rate M1	1,173,201	30,976	1,204,177	1,175,355	27,897	1,203,251	(925)
4	Rate M2	4,625	3,452	8,077	5,294	3,854	9,148	1,071
5	Rate 01	358,904	10,690	369,594	360,504	10,043	370,547	953
6	Rate 10	1,251	953	2,204	1,550	1,001	2,551	347
7	Total General Service	3,830,752	89,362	3,920,114	3,825,635	92,584	3,918,219	(1,895)
	Contract							
8	Rate 100 (1)	4	10	14	6	15	21	7
9	Rate 110	58	358	416	76	398	473	57
10	Rate 115	2	20	22	0	17	17	(6)
11	Rate 125	0	4	4	0	4	4	0
12	Rate 135	3	38	41	3	40	43	2
13	Rate 145	1	15	16	1	14	15	(1)
14	Rate 170	1	21	22	0	20	20	(2)
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	33	192	225	25	196	221	(4)
19	Rate M5	4	34	38	11	30	42	4
20	Rate M7	4	57	61	2	68	70	9
21	Rate M9	1	3	4	1	3	4	0
22	Rate M10	0	0	0	1	0	1	1
23	Rate T1	0	39	39	0	37	37	(2)
24	Rate T2	0	26	26	0	27	27	1
25	Rate T3	0	1	1	0	1	1	0
26	Rate 20	5	58	63	5	60	65	2
27	Rate 25	2	70	72	27	17	43	(28)
28	Rate 30	0	0	0	0	0	0	0
29	Rate 100 (2)	0	12	12	0	11	11	(1)
30	Total Contract	119	957	1,076	159	957	1,117	40
31	Total Customers	3,830,871	90,320	3,921,191	3,825,794	93,542	3,919,336	(1,855)

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

Throughput Volumes by Rate Class - Unnormalized

Line No.	Particulars (10^3m^3)	2024 OEB-Approved Sales Service	2024 OEB-Approved Direct Purchase	2024 OEB-Approved Total	2024 Actual Sales Service	2024 Actual Direct Purchase	2024 Actual Total	Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	4,926,335	85,253	5,011,588	4,477,473	55,056	4,532,530	(479,058)
2	Rate 6	2,974,410	1,824,830	4,799,240	2,718,250	1,572,775	4,291,025	(508,215)
3	Rate M1	3,057,017	181,848	3,238,864	2,627,154	170,856	2,798,010	(440,855)
4	Rate M2	712,317	630,997	1,343,314	513,278	647,292	1,160,571	(182,744)
5	Rate 01	919,088	57,792	976,880	815,213	65,762	880,975	(95,905)
6	Rate 10	178,280	163,384	341,664	143,178	155,935	299,113	(42,551)
7	Total General Service	12,767,448	2,944,102	15,711,550	11,294,546	2,667,676	13,962,223	(1,749,327)
	Contract							
8	Rate 100 (1)	14,757	12,673	27,429	12,559	30,885	43,443	16,014
9	Rate 110	102,197	966,084	1,068,281	122,632	1,155,035	1,277,667	209,386
10	Rate 115	1,651	380,222	381,873	-	341,507	341,507	(40,366)
11	Rate 125	-	824,971	824,971	-	1,377,941	1,377,941	552,971
12	Rate 135	4,392	48,255	52,646	2,442	67,048	69,489	16,843
13	Rate 145	574	15,140	15,714	513	59,957	60,470	44,756
14	Rate 170	5,360	317,894	323,254	-	241,282	241,282	(81,972)
15	Rate 200	140,306	48,547	188,852	119,874	62,669	182,543	(6,309)
16	Rate 300	-	-	-	-	-	-	-
17	Rate 315	-	-	-	-	-	-	-
18	Rate M4	59,362	534,538	593,899	44,275	519,084	563,359	(30,541)
19	Rate M5	2,164	57,329	59,493	1,684	50,373	52,057	(7,436)
20	Rate M7	35,619	754,118	789,737	7,460	764,336	771,796	(17,940)
21	Rate M9	15,795	74,278	90,073	15,819	80,879	96,697	6,624
22	Rate M10	-	-	-	247	-	247	247
23	Rate T1	-	431,289	431,289	-	403,660	403,660	(27,629)
24	Rate T2	-	5,005,643	5,005,643	-	5,491,895	5,491,895	486,252
25	Rate T3	-	249,200	249,200	-	249,479	249,479	279
26	Rate 20	15,631	913,470	929,101	6,816	1,230,189	1,237,005	307,904
27	Rate 25	5,703	121,128	126,831	70,214	222,815	293,029	166,198
28	Rate 30	-	-	-	-	-	-	-
29	Rate 100 (2)	-	1,076,378	1,076,378	-	944,814	944,814	(131,564)
30	Total Contract	403,509	11,831,156	12,234,665	404,534	13,293,848	13,698,382	1,463,717
31	Total Throughput Volume	13,170,957	14,775,259	27,946,215	11,699,080	15,961,525	27,660,605	(285,610)

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

Throughput Volumes by Rate Class - Normalized

Line No.	Particulars (10^3m^3)	2024 OEB-Approved Sales Service	2024 OEB-Approved Direct Purchase	2024 OEB-Approved Total	2024 Actual Sales Service	2024 Actual Direct Purchase	2024 Actual Total	Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	4,926,335	85,253	5,011,588	5,010,075	61,795	5,071,871	60,283
2	Rate 6	2,974,410	1,824,830	4,799,240	2,989,982	1,743,179	4,733,161	(66,079)
3	Rate M1	3,057,017	181,848	3,238,864	2,956,058	194,443	3,150,501	(88,364)
4	Rate M2	712,317	630,997	1,343,314	571,616	726,100	1,297,716	(45,598)
5	Rate 01	919,088	57,792	976,880	919,537	73,391	992,927	16,047
6	Rate 10	178,280	163,384	341,664	159,083	172,926	332,009	(9,655)
7	Total General Service	12,767,448	2,944,102	15,711,550	12,606,350	2,971,834	15,578,184	(133,366)
	Contract							
8	Rate 100 (1)	14,757	12,673	27,429	12,559	30,885	43,443	16,014
9	Rate 110	102,197	966,084	1,068,281	122,632	1,155,035	1,277,667	209,386
10	Rate 115	1,651	380,222	381,873	-	341,507	341,507	(40,366)
11	Rate 125	-	824,971	824,971	-	1,377,941	1,377,941	552,971
12	Rate 135	4,392	48,255	52,646	2,442	67,048	69,489	16,843
13	Rate 145	574	15,140	15,714	513	59,957	60,470	44,756
14	Rate 170	5,360	317,894	323,254	-	241,282	241,282	(81,972)
15	Rate 200	140,306	48,547	188,852	119,874	62,669	182,543	(6,309)
16	Rate 300	-	-	-	-	-	-	-
17	Rate 315	-	-	-	-	-	-	-
18	Rate M4	59,362	534,538	593,899	44,275	519,084	563,359	(30,541)
19	Rate M5	2,164	57,329	59,493	1,684	50,373	52,057	(7,436)
20	Rate M7	35,619	754,118	789,737	7,460	764,336	771,796	(17,940)
21	Rate M9	15,795	74,278	90,073	15,819	80,879	96,697	6,624
22	Rate M10	-	-	-	247	-	247	247
23	Rate T1	-	431,289	431,289	-	403,660	403,660	(27,629)
24	Rate T2	-	5,005,643	5,005,643	-	5,491,895	5,491,895	486,252
25	Rate T3	-	249,200	249,200	-	249,479	249,479	279
26	Rate 20	15,631	913,470	929,101	6,816	1,230,189	1,237,005	307,904
27	Rate 25	5,703	121,128	126,831	70,214	222,815	293,029	166,198
28	Rate 30	-	-	-	-	-	-	-
29	Rate 100 (2)	-	1,076,378	1,076,378	-	944,814	944,814	(131,564)
30	Total Contract	403,509	11,831,156	12,234,665	404,534	13,293,848	13,698,382	1,463,717
31	Total Throughput Volume	13,170,957	14,775,259	27,946,215	13,010,884	16,265,683	29,276,566	1,330,351

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

Revenue by Rate Class - Unnormalized

Line No.	Particulars ($ millions)	2024 OEB-Approved Total (1)	2024 Actual Sales Service	2024 Actual Direct Purchase	2024 Actual Total	Variance
		(a)	(b)	(c)	(d)	(e) = (d-a)
	General Service					
1	Rate 1	2,210.0	1,803.4	14.3	1,817.6	(392.4)
2	Rate 6	1,191.0	783.0	152.5	935.5	(255.5)
3	Rate M1	1,183.7	904.2	19.3	923.5	(260.2)
4	Rate M2	242.5	109.6	44.4	154.0	(88.5)
5	Rate 01	469.5	365.9	14.7	380.6	(89.0)
6	Rate 10	85.1	39.7	20.9	60.7	(24.4)
7	Total General Service	5,381.9	4,005.8	266.0	4,271.9	(1,110.0)
	Contract					
8	Rate 100 (2)	5.6	3.4	3.1	6.5	0.9
9	Rate 110	68.1	23.9	50.3	74.2	6.2
10	Rate 115	9.5	0.0	8.3	8.3	(1.2)
11	Rate 125	12.5	-	13.4	13.4	0.9
12	Rate 135	2.3	0.5	2.9	3.4	1.0
13	Rate 145	1.8	0.1	2.2	2.3	0.5
14	Rate 170	2.3	(0.4)	2.0	1.6	(0.6)
15	Rate 200	38.6	23.2	3.1	26.3	(12.3)
16	Rate 300	-	-	-	-	-
17	Rate 315	-	-	-	-	-
18	Rate M4	48.6	9.5	32.8	42.3	(6.3)
19	Rate M5	3.2	0.5	2.1	2.6	(0.6)
20	Rate M7	37.2	1.8	31.1	32.9	(4.2)
21	Rate M9	5.2	2.9	1.3	4.2	(1.0)
22	Rate M10	-	0.1	-	0.1	0.1
23	Rate T1	14.4	-	13.3	13.3	(1.1)
24	Rate T2	79.8	-	87.7	87.7	7.9
25	Rate T3	7.8	-	7.8	7.8	(0.0)
26	Rate 20	40.5	2.7	38.8	41.5	1.0
27	Rate 25	6.2	12.6	8.3	21.0	14.8
28	Rate 30	-	-	-	-	-
29	Rate 100 (3)	11.8	-	11.3	11.3	(0.5)
30	Total Contract	395.3	80.9	319.9	400.8	5.5
31	Subtotal	5,777.2	4,086.7	585.9	4,672.7	(1,104.5)
32	Other Adjustments (4)				31.9	31.9
33	Total Gas Sales and Distribution Revenue	5,777.2			4,704.5	(1,072.6)
	Utility Adjustments					
34	Elimination of the Union rate zones' unregulated storage cost from the EGD rate zone revenues				(18.6)	(18.6)
35	Total Utility Revenue	5,777.2			4,686.0	(1,091.2)

Notes:
(1) 2024 Rebasing Phase 2 (EB-2024-0111) Revenue Deficiency was not allocated between System and DP customers.
(2) EGD rate zone.
(3) Union North rate zone.
(4) 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 OEB-Approved Total (1)	2024 Actual Sales Service	2024 Actual Direct Purchase	2024 Actual Total	Variance
		(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service					
1	Rate 1	2,210.0	1,947.2	15.0	1,962.2	(247.8)
2	Rate 6	1,191.0	849.4	166.3	1,015.7	(175.3)
3	Rate M1	1,183.7	975.7	20.7	996.4	(187.3)
4	Rate M2	242.5	122.2	49.4	171.7	(70.8)
5	Rate 01	469.5	399.6	16.0	415.6	(54.0)
6	Rate 10	85.1	44.1	23.1	67.2	(17.9)
7	Total General Service	5,381.9	4,338.2	290.6	4,628.8	(753.1)
	Contract					
8	Rate 100 (1)	5.6	3.4	3.1	6.5	0.9
9	Rate 110	68.1	23.9	50.3	74.2	6.2
10	Rate 115	9.5	0.0	8.3	8.3	(1.2)
11	Rate 125	12.5	-	13.4	13.4	0.9
12	Rate 135	2.3	0.5	2.9	3.4	1.0
13	Rate 145	1.8	0.1	2.2	2.3	0.5
14	Rate 170	2.3	(0.4)	2.0	1.6	(0.6)
15	Rate 200	38.6	23.2	3.1	26.3	(12.3)
16	Rate 300	-	-	-	-	-
17	Rate 315	-	-	-	-	-
18	Rate M4	48.6	9.5	32.8	42.3	(6.3)
19	Rate M5	3.2	0.5	2.1	2.6	(0.6)
20	Rate M7	37.2	1.8	31.1	32.9	(4.2)
21	Rate M9	5.2	2.9	1.3	4.2	(1.0)
22	Rate M10	-	0.1	-	0.1	0.1
23	Rate T1	14.4	-	13.3	13.3	(1.1)
24	Rate T2	79.8	-	87.7	87.7	7.9
25	Rate T3	7.8	-	7.8	7.8	(0.0)
26	Rate 20	40.5	2.7	38.8	41.5	1.0
27	Rate 25	6.2	12.6	8.3	21.0	14.8
28	Rate 30	-	-	-	-	-
29	Rate 100 (2)	11.8	-	11.3	11.3	(0.5)
30	Total Contract	395.3	80.9	319.9	400.8	5.5
31	Subtotal	5,777.2	4,419.1	610.5	5,029.6	(747.6)
32	Other Adjustments (4)	-			31.9	31.9
33	Total Gas Sales and Distribution Revenue	5,777.2			5,061.5	(715.7)
	Utility Adjustments					
34	Elimination of the Union rate zones' unregulated storage cost from the EGD rate zone revenues				(18.6)	(18.6)
35	Total Utility Revenue	5,777.2			5,042.9	(734.3)

Notes:
(1) 2024 Rebasing Phase 2 (EB-2024-0111) Revenue Deficiency was not allocated between System and DP customers.
(2) EGD rate zone.
(3) Union North rate zone.
(4) 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 OEB-Approved	2024 Actual	Variance
		(a)	(b)	(c) = (b-a)
	Storage			
1	Peak Storage	0.0	0.9	0.9
2	Off-peak Storage	0.0	2.4	2.4
3	Loans	0.0	(0.0)	(0.0)
4	Short-term Balancing	0.0	2.0	2.0
5	Short-term Deferral	0.0	(4.9)	(4.9)
6	Total Storage	0.0	0.4	0.4
	Utility Adjustment			
7	Elimination of the shareholder portion of net Short-term Storage Revenue	0.0	(0.4)	(0.4)
8	Total Storage - Utility Revenue	0.0	(0.0)	(0.0)
	Transportation			
9	Rate M12	87.3	94.0	6.7
10	Rate M12X	3.0	3.2	0.2
11	Rate F24T	0.6	0.6	0.0
12	Rate C1	15.9	18.7	2.9
13	Rate M13	0.4	0.5	0.1
14	Rate M16	0.5	0.6	0.1
15	Rate M17	0.5	0.5	0.0
16	Rate 331	0.2	0.2	0.0
17	Rate 332	19.2	20.0	0.9
18	Rate 401	3.6	1.5	(2.1)
19	Short-term Transportation	14.5	11.7	(2.8)
20	Upstream Transportation Optimization	0.0	5.9	5.9
21	Other	1.3	1.2	(0.0)
22	Total Transportation	146.8	158.7	11.9
	Utility Adjustment			
23	Elimination of the shareholder portion of net Upstream Optimization	0.0	(5.4)	(5.4)
24	Total Transportation - Utility Revenue	146.8	153.3	6.5
25	Total Storage & Transportation - Utility Revenue	146.8	153.3	6.5

Other Revenue and Other Income

Line No.	Particulars ($ millions)	2024 OEB-Approved (a)	2024 Actual (b)	Variance (c) = (b-a)
	Other Revenue			
1	Late Payment Penalties	26.9	21.9	(5.0)
2	Account Opening Charges	13.9	9.0	(5.0)
3	Other Billing Revenue	11.0	11.8	0.8
4	Customer Billing Revenue	51.8	42.7	(9.1)
5	Direct Purchase Administration Charges and Distributor Consolidated Billing	5.4	4.5	(0.8)
6	Open Bill Access Revenue (1)	-	9.6	9.6
7	Rental Revenue - NGV Program	1.9	1.8	(0.1)
8	Other Operating Revenue	1.7	16.7	15.1
9	Subtotal	60.8	75.3	14.6
	Utility Adjustments			
10	Elimination of demand-side management incentive	-	(12.4)	(12.4)
11	Total Other Revenue	60.8	62.9	2.2
	Other Income			
12	Other Income (2)	2.4	6.1	3.7
	Utility Adjustments			
13	Elimination of interest income from investments not included in rate base	-	(0.6)	(0.6)
14	Total Other Income	2.4	5.4	3.1

Notes:

(1) Represents net OBA revenue that is offset by costs. Please see Exhibit D, Tab 1, Schedule 2 for details of total revenue, deemed costs and amount deferred in Open Bill Extension Deferral Account.

(2) Includes gains/losses on FX, and sales-type lease lease income related to the NGV Program.

UTILITY OPERATING AND MAINTENANCE

1. This evidence explains the main drivers in the Utility Operating and Maintenance (O&M) expense between 2024 OEB-approved and 2024 actual results.

2. The Utility O&M schedule for 2024 preserves the presentation from the 2023 ESM Proceeding[1] to provide transparency to all expense categories and in particular, segregating Central Functions (CF) and Demand Side Management (DSM). Table 1 presents 2024 O&M expenses relative to the 2024 OEB-approved.

3. Overall, the variances between the OEB-approved and actual figures for Utility O&M expenses in 2024 show a notable increase of $39.9 million. This rise is mainly attributed to higher severance costs, an increase in rebasing intervenor costs, and higher OEB assessment costs not able to be deferred in 2024. Despite these increases, Enbridge Gas was able to achieve savings in several areas, including Compensation and Benefits, Outside Services, and Central Functions. These savings, alongside incremental recoveries from affiliates in Allocations and Recoveries allowed Enbridge Gas to address the overall O&M envelope reduction agreed to in the 2024 Rebasing Phase 1 Settlement Agreement[2]. After removing 2024 severance from actual O&M, Enbridge Gas was relatively flat to 2024 OEB-approved O&M.

[1] EB-2024-0125.
[2] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.10, subpart c) O&M.

Table 1

Utility O&M
2024 OEB-Approved versus Actual

Line No.	Expense Categories	2024 OEB-Approved ($ millions)	2024 Actuals ($ millions)	$ change	% change
1	Compensation & Benefits	416.5	446.3	(29.8)	-7.2%
2	Outside Services	262.4	246.6	15.8	6.0%
3	Materials and Supplies	31.2	29.5	1.7	5.3%
4	Professional and Regulatory Services	18.0	26.3	(8.3)	-46.3%
5	Other	59.0	55.8	3.2	5.4%
6	Employee Related Services	4.8	1.2	3.7	76.0%
7	Repairs & Maintenance	4.4	5.6	(1.2)	-26.0%
8	Rents & Leases	13.1	13.2	(0.1)	-1.0%
9	Travel & Accommodation	9.1	8.7	0.5	5.0%
10	Donations & Memberships	5.1	6.2	(1.1)	-20.5%
11	Internal Allocation & Recoveries	(20.7)	(24.5)	3.8	-18.1%
12	Energy Conservation	183.1	183.1	(0.0)	0.0%
13	Central Functions	377.1	348.2	28.9	7.7%
14	Overhead Capitalization	(242.0)	(242.0)	0.0	0.0%
15	O&M settlement reduction - ($50 million net, $68 million gross) (2)	(68.4)	-	(68.4)	100.0%
16	O&M Subtotal before adjustments	1,052.8	1,104.2	(51.4)	-4.9%
17	Donations	-	(2.9)		
18	Elimination of Central Functions Corporate Allocation Methodology (CFCAM) charges (1)	-	(8.5)		
19	Total Unregulated/Non-Utility Eliminations	-	(11.4)		
20	Total Net Utility O&M Expense	1,052.8	1,092.8	(40)	-3.8%

Notes:
(1) Utility CF Adjustment pertains to CF costs determined to not pass OEB Three-prong test and therefore eliminated from Utility results.
(2) EB-2022-0200, Settlement Agreement, August 17, 2023, Exhibit O1, Tab 1, Schedule 1, p.10, subpart c) O&M.

4. The variance in key areas noted in Table 1 above is explained in more detail below.

5. Compensation and Benefits (line 1) increased by $29.8 million mainly due to $48.3 million severance cost, $20.3 million increase in short term incentive benefits (STIP) and legislative benefits offset by $38.8 million efficiency achieved through workforce reduction.

6. Professional and Regulatory Services (line 4) increased $8.3 million mainly due to increased costs of $5.9 million related to a higher level of intervenor costs for rebasing plus increases in OEB assessment costs not deferrable in 2024 and $2.4 million in Operations consulting work booked to Professional and Regulatory Services, however, budgeted in the Outside Services cost category.

7. Outside Services (line 2) decreased $15.8 million mainly due to a $10 million decrease in spending resulting from the transition of Customer Care outsourcing to an in-house model, an $8 million decrease mainly due to lower spending in integrity work supported by risk-based analyses and a $2.4 million decrease in Operations consulting costs, where actuals were booked under Professional and Regulatory Services but budgeted in the Outside Services cost category.

8. Central Functions costs (line 15) include functional groups such as Legal, Finance, Human Resources and Technology Information Services (TIS) that serve business units across the Enbridge enterprise. Costs are charged to the individual business units based on appropriate cost allocation in relation to the services received. Central Functions decreased by $28.9 million mainly from efficiencies achieved in TIS, Finance, REWS and reductions in depreciation.

9. Internal Allocation & Recoveries (line 11) increased by $3.8 million mainly due to an increase in work completed related to affiliates.

10. Overhead Capitalization (line 16) is $242 million and is unchanged. In the 2024 Rebasing Phase 1 Decision, issued by the OEB[3], the OEB approved an overhead capitalization amount of $242 million for 2024, with an annual reduction of $50 million in each subsequent year. A review was performed by Enbridge Gas based on the harmonized overhead capitalization methodology as filed in Phase 1 of the 2024 Rebasing Application[4]. It was determined from the review that the total overhead capitalization amount for 2024 under the harmonized overhead capitalization methodology would have been higher than $242 million. As such Enbridge Gas capitalized the allowed $242 million and the overage in excess of the $242 million was recorded in O&M expense.

[3] EB-2022-0200, OEB Decision and Order, December 21, 2023, p.98.
[4] EB-2022-0200, Exhibit 2, Tab 4, Schedule 2.

UTILITY CAPITAL EXPENDITURES

1. The purpose of this evidence is to provide information on Enbridge Gas's 2024 utility capital expenditures.

Table 1
Summary of Capital Expenditures 2024 Actual

Line No.	Particulars ($ millions)	Col 1 Total EGI
1	Distribution Plant	789.0
2	Transmission Plant (1)	233.6
3	General & Other Plant	129.2
4	Underground Storage Plant	47.9
5	Total	1,199.8

Note:
(1) Includes PREP amounts of $147.3 million.

The dollars presented are annual capital expenditures and are comparable to the presentation in the Asset Management Plan.

2. On December 21, 2023, the OEB issued the 2024 Rebasing Phase 1 Decision[1]. In its Decision, the OEB found that Enbridge Gas's 2024 capital budget should be reduced by $250 million. In Phase 3[2], Enbridge Gas described how it addressed the reduction and how it adjusted its approach to capital spending to increase asset life extension through inspection and repair and prioritize its capital spending to implement the reduction. In addition, several investments were deferred to future years after a review of whether asset life extension activities would be sufficient to support the system in the near term.

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

3. Further to the Phase 3 Report on Capital Reduction[3], Enbridge Gas presents Table 2, which shows the year-over-year 2023/2024 variances for the expenditures by Asset Class. Further commentary regarding the year-over-year changes in capital expenditures are described by Asset Class in the narrative following Table 2.

Table 2
Asset Class

Line No.	Asset Class ($ millions)	2023	2024	Variance
1	Compression Stations	330.5	41.5	(289.0)
2	Customer Connections	341.9	282.7	(59.2)
3	Distribution Pipe	248.9	215.4	(33.5)
4	Distribution Stations	50.4	25.9	(24.5)
5	Fleet & Equipment	11.0	19.2	8.2
6	Growth - Distribution System Reinforcement	37.4	18.8	(18.7)
7	Real Estate & Workplace Services	73.0	69.4	(3.6)
8	Technology Information Services (TIS)	47.4	43.4	(4.0)
9	Transmission Pipe and Underground Storage	85.2	228.8	143.6
10	Utilization	171.8	189.6	17.8
11	EA Fixed Overhead	22.5	39.8	17.3
12	Integration Capital	8.6	-	(8.6)
13	Community Expansion	10.0	8.3	(1.6)
14	Other	4.4	17.0	12.6
15	Total	1,442.9	1,199.8	(243.1)

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.

[3] EB-2025-0064, Exhibit 2, Tab 5, Schedule 5.

- 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.
- The decrease in this category is primarily related to the $280.2 million higher Dawn to Corunna project expenditures that were incurred in 2023 with only trailing costs incurred in 2024.
- The remaining decrease is attributed to fewer significant projects being executed in 2024 than in 2023 (compressor foundation block replacements ($3.0 million) and conversion of high bleed devices to low/no bleed devices at Dawn ($2.0 million)).

b) <u>Customer Connections</u>

- 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.
- There was a significant reduction in Customer Connections costs from 2023 to 2024 ($59.2 million). The number of customers added in 2024 was 22% lower than that of 2023, which was largely driven by reduced housing starts because of the new construction housing market slowing.

c) Distribution Pipe

- This asset class includes the 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 decreased in 2024 due to the absence of significant capital spend on the NPS 20 Lake Shore Replacement Cherry to Bathurst project, which occurred in 2023, and the remaining restoration work pushed out from 2024 to 2026. In addition, there was less Integrity spend in 2024 compared to 2023 due to construction related deferrals in the Retrofit Program and cost efficiencies found in the Integrity Digs Program.

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.
- The decrease in 2024 compared to 2023 is due to pacing of station replacements and focusing on component level risk reduction of station replacements and rebuilds such as St. John's Sideroad ($5.7 million) and Dryden ($3.2 million) to accommodate the 2024 Rebasing Phase 1 Decision[4] capital reductions and offset inflationary pressures for labor and materials in other asset classes.

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

e) <u>Fleet & Equipment</u>

- The Fleet, Equipment and Tools asset class includes the vehicles, trailers, heavy equipment and tools owned by Enbridge Gas to support its business needs.
- Increases in the Fleet, Equipment and Tools asset class are due to an increase in purchases to decrease the number of assets which are well beyond optimal replacement age. The existing assets are ~30% outside optimal replacement and therefore have increased O&M expenses compared to new assets. Timing of replacements drove the increased variance between 2023 and 2024. Specifically for 2024, Fleet Vehicles increased by $8.3 million, equipment increased by $1 million, and tools had a reduction of capital of $1.3 million.

f) <u>Growth – Distribution System Reinforcement</u>

- The Growth asset class includes broad-based reinforcement projects designed to maintain system capacity when constraints are breached primarily due to growth in system wide demand.
- As a result of the 2024 Rebasing Phase 1 Decision[5], there was an overall reduction to the Growth asset class for two reasons. First is the reprioritization of investments based on funding the most urgent, near-term requirements of the system, and reducing scope of projects to focus on component and partial replacements. The second reason is the completion or re-pacing of several large customer-driven projects.

g) <u>Real Estate and Workplace Services</u>

- The Real Estate and Workplace Services (REWS) asset class includes properties (buildings and land) and furnishings.

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

- 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 market availability and are aligned with the long-term strategies described in the Asset Management Plan.
- The decrease is primarily due to completion or substantial completion of the 2023 projects - Ottawa New Building ($12.3 million) and Dryden facility ($2.5 million), offset by costs for 2024 projects - Station B facility ($7 million), VPC Improvements ($4.1 million).

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).
- The increase is largely due to the continuation of the Contract Market Modernization ($4 million) project as planned in 2024.

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.

- The increase in capital spend in 2024 over 2023 is primarily due to the Panhandle Regional Expansion Project ($135.1 million) that went into service in December 2024, combined with higher integrity spend in 2024 ($8.1 million).

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[6].
- Meter costs increased in 2024 ($8.9 million) due to delayed deliveries from 2023, and an increase in meter purchases at the end of 2024. These incremental meters are for additional exchanges in 2025 at premises with access issues that require Encoder Receiver Transmitter (ERT) meters to ensure more regular accurate automated meter readings. There were cost increases in labour and materials for Meter Exchange work of ($9.8 million). These increases were partially offset by a reduction in the AMI Pilot Project of ($1.3 million) as the project moved into the monitoring phase.

k) EA Fixed Overheads

- The EA fixed overhead asset class includes cost for Alliance partner overheads. The increase in 2024 is due to cost increases as part of renegotiated contracts.

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[6] 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.

l) Integration Capital

- Following the end of the deferred rebasing term, there are no 2024 expenditures in this category.

m) 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 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.
- The decrease is primarily due to higher contributions in aid of construction received in 2024 compared to 2023.

n) Other

- Other capital includes RNG, CNG and Hydrogen Blending Projects.
- The increase primarily driven by spend related to Watford (Twin Creeks) pipeline project offset by the RNG Disco Road project construction that was completed in 2023.

Enbridge Gas Inc.
Deferral & Variance Account
Actual & Forecast Balances

Line No.	Account Description	OEB Account Number	Col. 1 Principal ($000s)	Col. 2 Forecast for clearance at July 1, 2026 Interest ($000s)	Col. 3 Total ($000s)	Col.4 Reference to Evidence
	EGI Commodity Related Accounts					
1	Upstream Transportation Optimization V/A	179-201	(33,371.7)	(2,566.0)	(35,937.7)	Exhibit C-2-1
2	UFG Volume V/A	179-203	6,359.3	282.3	6,641.6	Exhibit C-2-3
3	UFG Price V/A	179-204	(6,838.3)	(466.1)	(7,304.4)	Exhibit C-2-4
4	Total Commodity Related Accounts		(33,850.7)	(2,749.9)	(36,600.6)	
	EGI Non Commodity Related Accounts					
5	Transportation from Dawn Service D/A	179-202	73.3	5.0	78.3	Exhibit C-2-2
6	Deferral Clearance V/A	179-302	(6,184.1)	(5,040.7)	(11,224.8)	Exhibit C-2-5
7	Parkway Delivery Obligation V/A	179-303	3,245.6	231.8	3,477.4	Exhibit C-2-6
8	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-	
9	Pension & OPEB V/A	179-305	-	(6,562.5)	(6,562.5)	Exhibit C-2-7
10	Facility Carbon Charge V/A	179-307	(3,410.3)	(291.0)	(3,701.3)	Exhibit C-2-8
11	Customer Carbon Charge V/A	179-308	(10,979.3)	(1,793.1)	(12,772.4)	Exhibit C-2-9
12	Carbon Charges Bad Debt D/A	179-309	11,720.9	783.8	12,504.7	Exhibit C-2-10
13	Tax V/A	179-312	-	-	-	
14	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-	
15	IRP Operating Costs Deferral Account	179-318	429.9	30.7	460.6	Exhibit C-2-11
16	IRP Capital Costs Deferral Account	179-319	-	-	-	
17	Green Button Initiative D/A	179-320	-	-	-	
18	Dawn Parkway Surplus Capacity D/A	179-323	(902.5)	(21.2)	(923.7)	Exhibit C-2-12
19	Distribution Integrity Management Program D/A	179-326	(20.1)	(0.9)	(21.0)	Exhibit C-2-13
20	Post Retirement True-Up V/A	179-328	(1,359.3)	(85.6)	(1,444.9)	Exhibit C-2-14
21	Clean Fuel Regulation Credits D/A	179-330	(55.6)	(2.6)	(58.2)	Exhibit C-2-15
22	Indigenous Working Group D/A	179-331	119.3	7.0	126.3	Exhibit C-2-16
23	Cloud Computing Implementation Costs D/A	179-332	-	-	-	
24	Average Use Variance Account	179-333	15,698.4	1,145.1	16,843.5	Exhibit C-2-17
25	Getting Ontario Connected V/A	179-335	14,891.5	882.6	15,774.1	Exhibit C-2-18
26	Disposition of Property D/A	179-336	-	-	-	
27	LEAP Emergency Financial Assistance D/A	179-338	-	-	-	
28	Earnings Sharing D/A	179-339	-	-	-	
29	Enbridge Sustain Affiliate Recoveries V/A	179-344	(91.0)	(4.2)	(95.2)	Exhibit C-2-19
30	Total Non Commodity Related Accounts		23,176.7	(10,715.7)	12,460.9	
31	Total EGI Accounts (for clearance)		(10,674.0)	(13,465.6)	(24,139.7)	
	EGD Rate Zone Commodity Related Accounts					
32	Storage and Transportation D/A	179-88	6,433.4	461.7	6,895.1	Exhibit D-1-1
33	Total Commodity Related Accounts		6,433.4	461.7	6,895.1	
	EGD Rate Zone Non Commodity Related Accounts					
34	Open Bill Extension D/A	179-325	(3,066.4)	(212.7)	(3,279.1)	Exhibit D-1-2
35	Total Non Commodity Related Accounts		(3,066.4)	(212.7)	(3,279.1)	
36	Total EGD Rate Zone (for clearance)		3,367.0	249.0	3,616.0	
	Union Rate Zones Gas Supply Accounts					
37	Unabsorbed Demand Costs Variance Account	179-108	3,957.8	275.1	4,232.9	Exhibit E-1-1
38	Total Gas Supply Accounts		3,957.8	275.1	4,232.9	
	Union Rate Zones Storage Accounts					
39	Short-Term Storage and Other Balancing Services	179-70	(4,880.3)	(225.0)	(5,105.3)	Exhibit E-1-2
40	Total Storage Accounts		(4,880.3)	(225.0)	(5,105.3)	
41	Total Union Rate Zones (for clearance)		(922.5)	50.1	(872.4)	
42	Total Deferral and Variance Accounts (for clearance)		(8,229.5)	(13,166.6)	(21,396.1)	
	EGI Accounts Not Being Requested For Clearance					
43	Incremental Capital Module D/A	179-306	-	-	-	
44	Panhandle Region Expansion Project V/A	179-329	(14,231.3)	(654.0)	(14,885.3)	Exhibit C-2-20
45	Site Restoration Costs Tracking Account	179-337	(19,430.0)	-	(19,430.0)	Exhibit C-2-20
46	IRP System Pruning D/A	179-341	21.7	0.8	22.5	Exhibit C-2-20
47	Asset Life Extension Costs D/A	179-343	-	-	-	

ACCOUNT NO. 179-201 UPSTREAM TRANSPORTATION OPTIMIZATION

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 2024 balance in this deferral account is a credit to ratepayers of $33.372 million.

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 $54.120 million in net revenues from upstream transportation optimization during 2024. In accordance with the OEB-approved sharing methodology, 90% of this net revenue, or $48.708 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 $33.372 million ($48.708 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)	Variance (c)
1	Upstream Transportation Optimization Revenue	17.0	54.1	(37.1)
2	Shareholder Incentive (10%)	1.7	5.4	(3.7)
3	Ratepayer portion (90%)	15.3	48.7	(33.4)
4	Less: Gas Optimization Margin included in Rates	15.3	15.3	-
5	Variance Account Balance (line 3 - line 4)	-	33.4	(33.4)

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 $0.073 million, plus interest of $0.005 million, for a total debit of $0.078 million. The balance of $0.073 million represents the difference between the TransCanada capacity costs incurred by Enbridge Gas of $2.006 million and the revenues collected from customers of $1.933 million. The net variance is driven by a reduction of 480 GJ per day of contracted quantity by Union North T-service customers.

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 2024 balances recorded in the UFGVVA.

2. Actual UFG volumes for 2024 for Enbridge Gas were determined to be 334,888 10^3m^3. The variance between actual and forecasted UFG volumes of 91,206 10^3m^3 resulted in a debit balance of $6.4 million in the UFGVVA, plus interest. Attachment 1 provides the detailed calculations of the UFGVVA balance.

3. The higher UFG volumes in 2024 are partially attributed to the harmonization of methodology for recording differences between estimated and actual UFG. Historically, in the LEGD rate zone, an adjustment to the variance account balance to reflect the variance between the unbilled and no-bill estimated consumption and the actual consumption was recorded in December of a given year[3]. In the Union rate zones, the variance between the unbilled and no-bill estimated and actual consumption was recorded in the following year.

[1] EB-2022-0200.
[2] EB-2022-0200, Settlement Agreement, August 17, 2023, Exhibit O1, Tab 1, Schedule 2, Accounting Orders. p.22.
[3] Please see EB-2024-0125, Exhibit D, Tab 1, p. 26, para. 43 for the true-up process description.

4. 2024 marks the first year the Union Rates Zones adopted the harmonized methodology consistent with the LEGD Rate Zone. Consequently, 2024 Union Rate Zones UFG volumes were affected by the adjustments for both December 2023 and December 2024 unbilled and no-bill estimates. The impact of the December 2023 unbilled and no-bill estimates (as was the previous practice) on 2024's UFGVVA was an increase in UFG recorded in the variance account of approximately 21,049 10^3m^3. The impact of the December 2024 unbilled and no-bill estimates was an increase of 63,948 10^3m^3. In the absence of the harmonized methodology, the adjustment of 63,948 10^3m^3 relating to December 2024 estimates would have rolled over into 2025 and would not have impacted the 2024 UFGVVA balance.

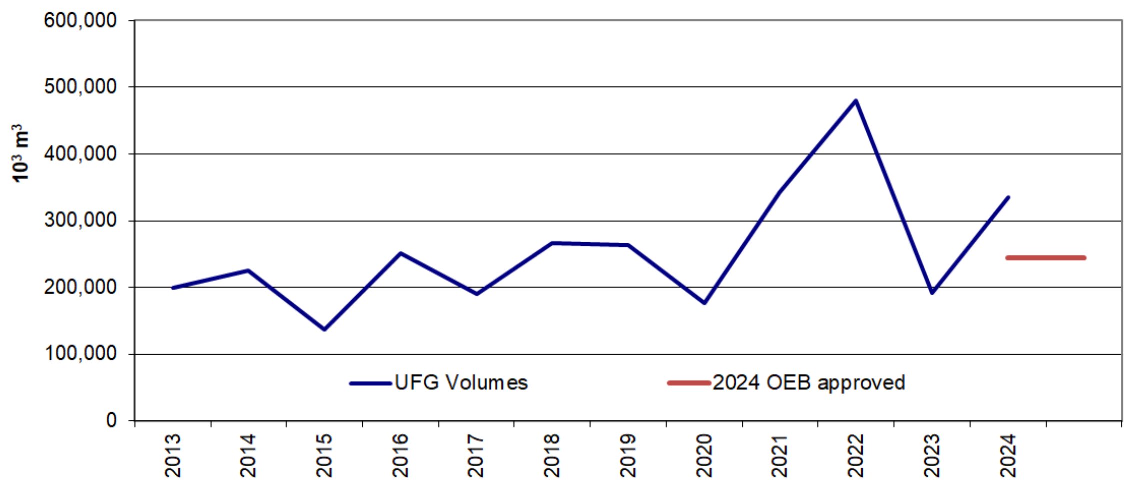
5. Table 1 provides historical UFG volumes for Enbridge Gas from 2013 to 2024.

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

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

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



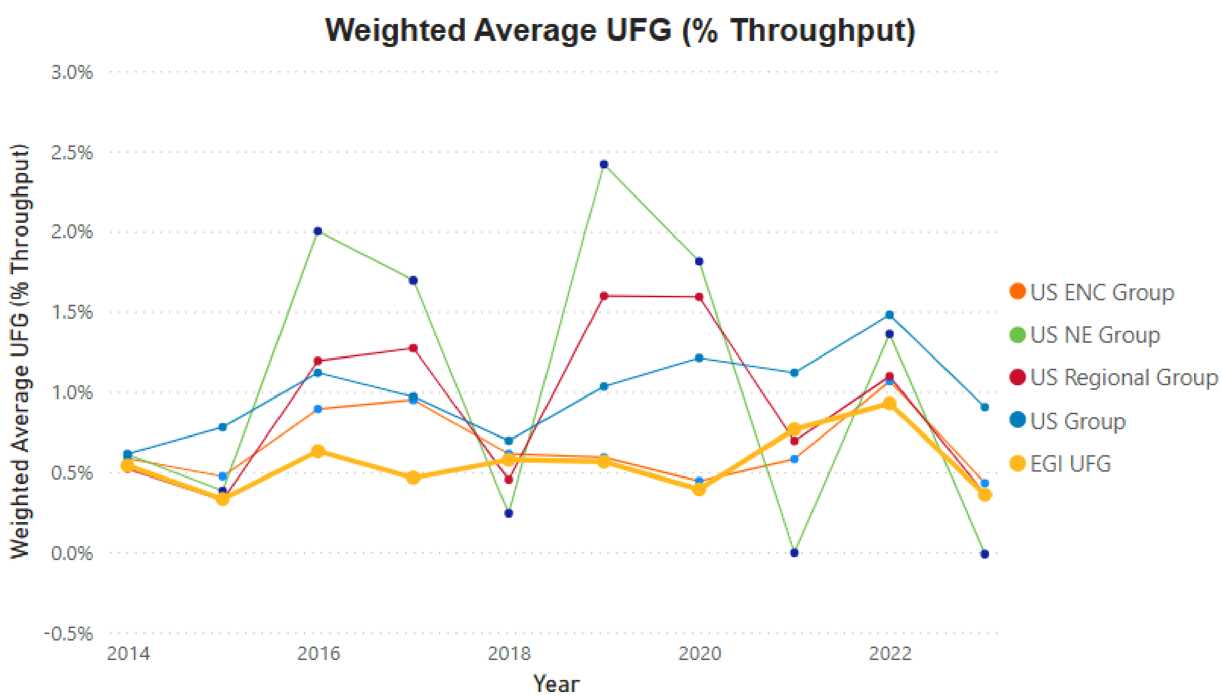
7. The 2019 Report on Unaccounted for Gas prepared by ScottMadden Management consultants filed in the Company's 2020 Rates Application[4] (the 2019 UFG Report) included a UFG Benchmark Analysis for the period of 2008 to 2017. Based on the results of the analysis completed, ScottMadden noted that from 2008 to 2017 Enbridge Gas had demonstrated lower average UFG volumes than comparative gas utilities[5].

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 2023 for comparative utilities and 2024 for the Company) and updated the benchmark analysis set out in the 2019 UFG Report to include utilities in the relevant comparator groups to the largest 15 utilities with throughput greater than 10 million Mcf. Figure 2 reflects the best available data regarding UFG volumes for each of the comparative utilities.

9. Historically, the benchmarking methodology afforded each utility, large or small, equal weighting within its comparator group. The new 2024 Benchmark Analysis, represented in Figure 2, recognizes the relative size of each utility within a comparator group by determining the groups weighted average UFG by volume of throughput.

[4] EB-2019-0194.
[5] EB 2019-0194, Report on Unaccounted for Gas, December 19, 2019, pp.3-4.

Figure 2: 2024 UFG Benchmark Analysis[6]



10. Enbridge Gas's total system (utility and non-utility) UFG in 2024 amounted to approximately 372,339 10^3m^3 compared to total system throughput for that same year of approximately 51,891,259 10^3m^3 (0.72%).

11. Figure 2 demonstrates that all utilities included in the benchmark analysis experienced similar volatility in UFG over the period from 2014 to 2023, with material increases recorded in any one year generally reversing in subsequent years. As noted in its most recent Decisions regarding UFG costs and related rate riders for

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[6] 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.

AltaGas and ATCO, the Alberta Utilities Commission stated: [7]

> 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.

12. Figure 2 reflects certain industry-wide trends across comparative utilities, such as a suppression of UFG volumes recorded in each of 2014, 2015, 2018, 2021, and 2023, followed by increases in UFG volumes recorded in subsequent years. It is reasonable to assume that such trends in UFG volumes or related trends in UFG costs may be reflective of common factors including macro-economic, and/or national/continental weather trends, which have the potential to impact UFG volumes or costs broadly across the industry. Figure 2 shows that Enbridge Gas's UFG volumes and annual fluctuations are generally consistent with other gas utilities.

[7] 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 2024 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 ($\$/10^3m^3$)	154.848	154.848	154.848	128.198	128.198	128.198	142.614	142.614	142.614	137.471	137.471	137.471	
3	Budget UFG ($ millions) (1)	5.5	5.2	4.6	2.7	1.7	1.3	1.4	1.6	1.5	2.0	3.3	4.2	35.0
4	Total Actual UFG (10^3m^3)	43,695	41,887	37,123	26,190	19,817	17,002	16,792	17,479	16,789	22,440	34,230	41,443	334,888
5	Weighted Average Reference Price ($\$/10^3m^3$)	154.848	154.848	154.848	128.198	128.198	128.198	142.614	142.614	142.614	137.471	137.471	137.471	
6	Actual UFG ($ millions) (2)	6.8	6.5	5.7	3.4	2.5	2.2	2.4	2.5	2.4	3.1	4.7	5.7	47.8
7	UFG Volume Variance (10^3m^3) (3)	8,086	8,498	7,622	5,464	6,567	6,522	6,778	6,517	6,543	7,604	10,444	10,563	91,206
8	UFG Volume Variance ($ millions) (4)	1.3	1.3	1.2	0.7	0.8	0.8	1.0	0.9	0.9	1.0	1.4	1.5	12.9
9	50/50 Cost Sharing (5)													6.4
10	Damages Recovery ($ millions)													(0.1)
11	UFG Volume Variance ($ millions) (6)													6.4

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 $6.84 million, plus interest.

1. EGD Rate Zone

3. During 2024, the Company purchased 163,569 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 2024 is $35.75/$10^3m^3$ lower than the OEB-approved reference prices included in rates based on the EGD rate zone gas portfolio cost of $165.27/$10^3m^3$. The result is a $5.85 million balance payable to ratepayers, as shown in Table 1. Attachment 1, page 1, provides the detailed calculation supporting the price variance of $35.75/$10^3m^3$.

[1] EB-2022-0200.

Table 1
Calculation of 2024 EGD Rate Zone UFG Price Variance

Line No.	Particulars	Deferral Calculation
1	UFG Volumes (10^3m^3) – Company Supplied (1)	163,569
2	Price Variance (\$/10^3m^3) (2)	(\$35.75)
3	Variance Account Balance (\$ millions)	(\$5.85)

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 2024, the Company purchased 85,826 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 2024 is \$11.54/10^3m^3 lower than the OEB-approved reference prices included in rates based on the Union South rate zone gas portfolio cost of \$138.50/10^3m^3. The result is a \$0.99 million balance payable to ratepayers, as shown in Table 2. Attachment 1, page 2, provides the detailed calculation supporting the price variance of \$11.54/10^3m^3.

Table 2
Calculation of 2024 Union Rate Zone UFG Price Variance

Line No.	Particulars	UFG Volumes (10^3m^3)
1	Experienced Regulated UFG	171,319
2	UFG Collected through CSF	85,493
3	UFG Volumes – Company Supplied (1)	85,826
		Deferral Calculation
4	UFG Volumes (10^3m^3) – Company Supplied (1)	85,826
5	Price Variance ($\$/10^3m^3$) (2)	($11.54)
6	Variance Account Balance ($ millions)	($0.99)

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 2024 EGD 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)	$178.27	$178.27	$178.27	$154.37	$154.37	$154.37	$167.60	$167.60	$167.60	$160.83	$160.83	$160.83	$165.27
2	Actual Purchase ($)	$161,732,069	$118,718,804	$63,725,704	$58,514,052	$52,008,502	$58,630,737	$60,184,687	$49,955,766	$50,249,750	$67,783,221	$79,287,897	$192,752,795	
3	Purchase Volumes (10^3m^3)	1,091,627	870,506	528,819	450,340	468,631	452,348	465,815	470,250	455,513	547,646	591,281	1,101,522	
4	Average Purchase Cost ($ / 103m3) (1)	$148.16	$136.38	$120.51	$129.93	$110.98	$129.61	$129.20	$106.23	$110.31	$123.77	$134.10	$174.99	$129.51
5	EGD Rate Zone Price Variance ($ / 10^3m^3) (2)	($30.11)	($41.89)	($57.77)	($24.44)	($43.39)	($24.76)	($38.40)	($61.37)	($57.28)	($37.05)	($26.73)	$14.16	($35.75)

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

Calculation of 2024 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)	$154.76	$154.76	$154.76	$123.78	$123.78	$123.78	$140.72	$140.72	$140.72	$134.74	$134.74	$134.74	$138.50
2	Actual Purchase ($)	$48,994,407	$47,892,760	$34,598,198	$20,346,734	$23,784,146	$24,063,358	$28,061,318	$22,641,130	$32,735,639	$36,815,211	$39,313,432	$57,568,787	
3	Purchase Volumes (10^3m^3)	338,442	316,631	277,087	209,839	199,590	242,829	217,537	208,983	317,136	301,876	292,341	302,299	
4	Average Purchase Cost ($ / 10^3m^3) (1)	$144.76	$151.26	$124.86	$96.96	$119.16	$99.10	$129.00	$108.34	$103.22	$121.95	$134.48	$190.44	$126.96
5	Union Rate Zone Price Variance ($ / 10^3m^3) (2)	($10.00)	($3.50)	($29.90)	($26.81)	($4.61)	($24.68)	($11.73)	($32.38)	($37.50)	($12.79)	($0.27)	$55.69	($11.54)

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 credit of $6.184 million, plus interest to June 30, 2026, of $5.041 million, for a total credit of $11.225 million. The balance includes the residual amounts not disposed of from the following deferral dispositions: 2021 DSM[2] cleared effective October 2024, 2022 Earnings Sharing and Deferral Disposition[3] cleared effective April 2024, 2022 Federal Carbon Pricing Program [4] cleared effective April 2024, and finally the 2024 Rebasing Phase 1 Decision[5] approved deferral balance for disposition cleared between April 1, 2024 to December 31, 2024. The total forecast disposition balance of these proceedings combined was a credit of $179.506 million, total recoveries were a debit of $173.322 million, resulting in a net residual credit balance of $6.184 million. A summary is provided in Table 1.

[1] EB-2022-0200, Decision on Interim Rate Order, April 11, 2024.
[2] EB-2023-0062.
[3] EB-2023-0092.
[4] EB-2023-0196.
[5] EB-2022-0200, OEB Decision and Order, December 21, 2023.

Table 1
Deferral Summary: Deferral Clearing Variance

Line No.	Proceeding	Amount ($ millions)
1	2021 DSM Deferral Disposition (1)	(3.295)
2	2022 ESM Deferral Disposition (2)	74.959
3	2022 Federal Carbon Pricing Program (3)	1.930
4	Phase 1 2024 Rebasing (4)	(253.100)
5	Subtotal – Approved for Disposition in 2024	(179.506)
6	Amounts disposed of in 2024 through rider and one-time billing adjustments	173.322
7	Residual balance to Deferral Clearing Variance Account	(6.184)

Notes:
(1) EB-2023-0062.
(2) EB-2023-0092.
(3) EB-2023-0196.
(4) EB-2022-0200.

3. The residual balance reflects the outstanding amount resulting from the clearance of deferral and variance accounts which occurred during 2024 and the inability to locate and dispose of the approved amounts to all intended customers. The accrued interest of $5.041 million is almost entirely related to the large 2024 Rebasing Phase 1 Decision[6] approval and draw down of the balance over the April to December timeframe.

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

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. 2024 PDOVA
    2. Annual PDO Reporting

1. 2024 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.

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[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 $3.246 million, plus forecast interest of $0.232 million, for a total debit of $3.477 million. The balance of $3.246 million represents the difference between the OEB-approved PDCI cost of $14.150 million recovered in rates and the actual PDCI cost of $17.395 million. 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 2024. 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 capacity expected to become available to reduce the PDO over the next two years.

2.2 Potential Market-based Solution Alternatives

7. Enbridge Gas did not identify practical market-based solution alternatives to reduce the PDO in 2024. In 2025, Enbridge Gas will continue to consider practical market-based solution alternatives to PDO, and as part of that consideration Enbridge Gas will be issuing an RFP for an exchange from Parkway to Dawn or Kirkwall to Dawn.

[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, 2025, is 264 TJ/d, which excludes the addition of approximately 46 TJ/D for DP customers in the EGD rate zone with a PDO, as proposed 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, 2025, is 310 TJ/d.

9. The DP customer PDO forecast on November 1, 2026, is 262 TJ/d, which excludes the addition of approximately 46 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, 2026, is 308 TJ/d.

2.4 Measures Taken in the Current Year

10. Enbridge Gas was not able to shift any PDO in 2024.

[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 Forecast Accrual vs Actual Cash Payment Differential 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 Other Post Employment Benefits (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

[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.

Enbridge Gas as of January 1, 2024. Interest will continue to be calculated monthly on the balance when the cumulative forecasted accrual amount recovered in rates exceeds the cumulative actual cash payments, as a payable to ratepayers. As of January 1, 2024, Enbridge Gas combined the December 31, 2023 cumulative ending Union Gas credit of ($142.7) million and the EGD debit of $4.4 million, for a net cumulative opening credit of ($138.3) million.

5. In 2024 Rebasing Phase 1[3], 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 $15.5 million debit variance. As such the variance carried forward from 2023 is a $138.3 million credit variance, plus the 2024 debit of $15.5 million result in a cumulative ending credit balance at the end of 2024 of $122.8 million credit variance through the end 2024.

6. In accordance with the OEB's Report[4], 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 2024 is an interest credit to ratepayers of $6.6 million to December 31, 2024. Table 1 sets out the detailed calculation of the forecast accrual versus actual cash payments, and associated interest.

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[3] EB-2022-0200.
[4] EB-2015-0040, *Regulatory Treatment of Pension and Other Post-employment Benefits (OPEB) Costs*, September 14, 2017.

Table 1
Details Of 2024 Interest Calculated on Forecast Accruals vs Actual Cash Payments
In Pension and OPEB Variance Account (No. 179-305)

Line No.	Particulars ($000s)	23-Dec	24-Jan	24-Feb	24-Mar	24-Apr	24-May	24-Jun	24-Jul	24-Aug	24-Sep	24-Oct	24-Nov	24-Dec	Total
1	Forecast accrual amounts		-136	-136	-136	-136	-136	-136	-136	-136	-136	-136	-136	-136	-1,633
2	Actual cash payments		1,429	1,247	1,687	749	948	1,455	671	896	1,380	677	811	1,888	13,839
3	Monthly variance		1,565	1,383	1,824	885	1,084	1,591	807	1,032	1,516	813	947	2,025	15,472
4	Cumulative variance	-138,305	-136,740	-135,357	-133,533	-132,648	-131,564	-129,973	-129,166	-128,134	-126,618	-125,805	-124,858	-122,833	
5	OEB prescribed CWIP rate		5.48%	5.48%	5.48%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.55%	4.55%	4.55%	
6	Asymmetrical interest		-0.632	-0.624	-0.618	-0.554	-0.550	-0.546	-0.539	-0.536	-0.532	-0.480	-0.477	-0.473	-6.563

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

1. Enbridge Gas is requesting a credit to ratepayers of $3.41 million, plus $0.29 million in 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. 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.

5. In 2024, 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.

[1] The Federal Carbon Charge rate for marketable natural gas from January 1, 2024, to March 31, 2024 was 12.39 cents per cubic metre and from April 1, 2024 to December 31, 2024 was 15.25 cents per cubic metre.

6. Enbridge Gas's facility-related volumes and associated costs are composed of Company Use Volumes (facilities which are not covered under the EPS) and EPS Volumes (facilities which are covered under the EPS).

7. Enbridge Gas's Company Use Volumes are subject to the Federal Carbon Charge. This charge applies 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.

8. Enbridge Gas's EPS Volumes are related to the fuel used in the Company's natural gas transmission and storage compressor facilities. These operations fall under the Ontario EPS Regulation, requiring the Company to register as an "EPS facility" and remit payment annually to the provincial government for any emissions that exceed the 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.

9. 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 2023 FCPP Application, the Facility Carbon Charge rate from January 1 to March 31, 2024, was 0.0157 cents per cubic metre (cents/m^3)[3]. From April 1 to December 31, 2024, the Facility Carbon Charge rate was 0.0143 cents/m^3 as approved by the OEB through Enbridge Gas's 2024 FCPP

[2] Excess emissions charge is the price per unit in $/tCO2e. For the 2024 compliance period, the excess emissions charge is $80/tCO2e. https://www.ontario.ca/laws/regulation/190241.
[3] EB-2022-0194, Decision and Order, February 9, 2023, pp.5-8.

Application[4]. Based on actual customer volumes, $8.0 million in revenue was billed through the Facility Carbon Charge from January 1 to December 31, 2024.

10. Enbridge Gas's 2024 facility-related obligation was $5.14 million ($1.75 million related to Company Use Volumes and $3.39 million related to EPS Volumes), of which $4.59 million is attributable to Enbridge Gas's regulated utility operations[5].

11. Enbridge Gas has recorded a 2024 facility-related variance of ($3.41 million), in the FCCVA[6]. 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
2024 FCCVA Balance

Line No.	Particulars ($ millions)	2024 Actual Costs
1	Facility Carbon Charge Revenue	$8.00
2	Company Use Costs	$(1.75)
3	EPS Costs	$(2.85)
4	Variance	$3.41

12. The main driver of the variance is due to the actual Company Use and EPS costs being lower than what was forecast. Regulated EPS compressor fuel volumes and the associated emissions were lower than forecast due to a warm winter. The mild

[4] EB-2023-0196, OEB Decision and Order, February 8, 2024, pp.5-6.
[5] 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.
[6] This variance reflects consideration of: (i) applying the Federal Carbon Charge Rate for Marketable Natural Gas of 12.39 ¢/m^3 from January 1, 2024 – March 31, 2024 and 15.25 ¢/m^3 from April 1, 2024 to December 31, 2024 to actual Company Use Volumes of natural gas consumed in the operation of Enbridge Gas's facilities from January 1, 2024 to December 31, 2024; (ii) Enbridge Gas's 2024 EPS obligation of $2.85 million related to regulated utility operations for the January 1, 2024 to December 31, 2024 period; and (iii) actual billed amounts for the January 1, 2024 to December 31, 2024 period.

winter months in turn reduced transmission and storage demand, resulting in lower EPS emissions and associated costs. The warmer than normal winter also contributed to the decrease in actual Company Use Volumes and the associated actual costs from what was forecast.

1. EPS Compliance Costs

13. The $3.39 million[7] related to EPS Volumes is based on Enbridge Gas satisfying its entire 2024 EPS compliance obligation by paying the excess emissions charge of $80/t$CO_2$e. As the deadline to pay the 2024 EPS obligation is not until December 1, 2025, Enbridge Gas still has the option to satisfy its 2024 EPS obligation by purchasing EPUs from other EPS participants. EPUs typically sell at a discount to the excess emissions charge, which would reduce Enbridge Gas's 2024 EPS compliance obligation.

14. 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[8].

15. EPP funding is equal to a facility's compliance payment made to the provincial government in the previous year. If an EPS participant purchases EPUs from another EPS participant and then retires the EPUs for use towards their compliance obligation, the corresponding compliance payment to the provincial government could be eliminated or decreased. Therefore, by utilizing EPUs for an EPS compliance obligation, an EPS facility forfeits or reduces the available EPP funding that the provincial government would offer the following year.

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[7] Includes costs related to both regulated and unregulated operations.
[8] 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

16. 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 2024 EPS compliance obligation or paying the excess emissions charge to secure EPP funding[9]. The ability to use EPUs to reduce the 2024 EPS compliance obligation is also based on the availability of EPUs in the market, which to date have been limited.

17. Should Enbridge Gas's 2024 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, any variances will be recorded in the 2025 FCCVA.

<u>2. Federal Carbon Charge Removal</u>

18. 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[10]. Accordingly, Enbridge Gas removed the Federal Carbon Charge from customer bills effective April 1, 2025.

19. The Ontario EPS program remains in place despite the removal of the Federal Carbon Charge. Enbridge Gas must continue to comply with the EPS Regulations, thus incurring facility related costs associated with the Company's annual EPS compliance obligations. As a result, Enbridge Gas will keep the FCCVA open to capture the variances between actual facility related costs and facility related costs recovered in rates.

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[9] EB-2024-0251, Exhibit I.STAFF.2.a).
[10] 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

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

1. Enbridge Gas is requesting disposition of ($10.98 million), plus ($1.79 million) in 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. 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.

5. In 2024, 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

[1] The Federal Carbon Charge rate for marketable natural gas from January 1, 2024 to March 31, 2024 was 12.39 cents per cubic metre and from April 1, 2024 to December 31, 2024 was 15.25 cents per cubic metre.

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 2023 FCPP Application[2] and the 2024 FCPP Application[3].

6. 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.

7. 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].

8. The CCCVA balance of ($0.04 million), plus ($0.01 million) in interest, is a credit to ratepayers who are subject to the Federal Carbon Charge. This includes the 2024 CCCVA balance of ($0.02 million) and the cumulative balance of the 2022 and 2023 CCCVAs of ($0.03 million).

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[2] EB-2022-0194.
[3] EB-2023-0196.
[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.

9. In Enbridge Gas's 2024 FCPP Application[7] and 2025 FCPP Application[8], the Company proposed to defer disposition of the balances within the 2022 and 2023 CCCVAs due to the inability to generate a unit rate from the minor balances[9]. The cumulative balance of ($0.03 million), plus interest, in the 2022 and 2023 CCCVAs includes ($0.022 million) for the EGD rate zone and ($0.003 million) for the Union rate zones.

10. The total CCCVA balance of ($0.04 million), plus ($0.01 million) in interest, that Enbridge Gas is seeking disposition of, reflects a variance between the amount of revenue billed through the Federal Carbon Charge and the subsequent amount Enbridge Gas remitted to the Government of Canada.

11. The variances recorded are due to deliveries of renewable natural gas (RNG) and hydrogen to customers from 2022 to 2024, through the Company's OptUp program and Low Carbon Energy Project (LCEP), respectively. Under the GGPPA and associated Fuel Charge Regulations, RNG and hydrogen are not subject to the Federal Carbon Charge[10].

12. 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

[7] EB-2023-0196, Exhibit C, Tab 1, Schedule 1, pp.9-10.
[8] EB-2024-0251, Exhibit C, Tab 1, Schedule 1, pp.9-11.
[9] Ibid.
[10] 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.

benefit to customers. Thus, Enbridge Gas applied the Federal Carbon Charge to all volumes of gas delivered to customers, including on the 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[11].

13. The cumulative variances in the CCCVA from 2022 to 2024 are minor due to lower-than-expected participation in the OptUp program, leading to Enbridge Gas only procuring a small amount of RNG once a year, each year, since 2022. Additionally, as hydrogen is only being distributed through the LCEP pilot project to a limited number of customers, the hydrogen volumes eligible for exemption are also small.

1. Federal Carbon Charge Removal

14. 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[12]. Accordingly, Enbridge Gas removed the Federal Carbon Charge from customer bills effective April 1, 2025.

15. In the federal government's announcement removing the Federal Carbon Charge, it was noted that the government "will also be considering broader amendments to the GGPPA, including proposed amendments to complete the orderly wind-down of the

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[11] EB-2020-0066, OEB Decision and Order, September 24, 2020, pp.16-17.
[12] 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.

fuel charge”[13].

16. Although the Federal Carbon Charge has been set to $0 in the GGPPA and removed from customer bills as of April 1, 2025, Enbridge Gas’s reporting obligation under the GGPPA remains in effect for periods in which the Federal Carbon Charge was in place. On May 26, 2025, the *Notice of Ways and Means Motion to introduce a bill respecting certain affordability measures for Canadians and another measure*[14] 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.

17. 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.

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[13] Government of Canada. (2025 March 22). Removing the consumer carbon price, effective April 1, 2025. https://www.canada.ca/en/department-finance/news/2025/03/removing-the-consumer-carbon-price-effective-april-1-2025.html

[14] 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

2. 2026 Rates – Settlement Proposal

18. As part of the 2026 Rates Application[15], Enbridge Gas and parties reached a settlement on the Company's request for a Z-factor and base rate adjustment for the working cash impacts of setting the Federal Carbon Charge to zero. As set out in the Settlement Proposal[16], part of the resolution of Z-factor request is that Enbridge Gas agreed to certain credits to be provided to ratepayers related to working cash impacts from Federal Carbon Charge collections during 2022 and 2023.

19. Enbridge Gas agreed that it will credit ratepayers $10.94 million plus interest of $1.78 million. The parties agreed that this credit would be reflected within the Customer Carbon Charge Variance Account, to be cleared as part of this 2024 Deferral and Variance Account Disposition Application.

20. Enbridge Gas has recorded the agreed amounts in the Customer Carbon Charge Variance Account, pending OEB approval of the 2026 Rates Settlement Proposal.

[15] EB-2025-0163.
[16] EB-2025-0163, Exhibit N1, Tab 1, Schedule 1, October 23, 2025, p.11.

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

1. Enbridge Gas is requesting disposition of $11.72 million, plus $0.78 million in 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 2024, Enbridge Gas's operations as a natural gas utility in Ontario fell under the purview of the GGPPA and EPS Regulation, which resulted in $11.72 million in incremental carbon related bad debt being incurred.

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

[1] The Federal Carbon Charge rate for marketable natural gas from January 1, 2024, to March 31, 2024, was 12.39 cents per cubic metre and from April 1, 2024, to December 31, 2024, was 15.25 cents per cubic metre.

within the two OEB-approved FCPP-related Greenhouse Gas Emissions Administration Deferral Accounts (GGEADAs)[2].

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[3]. The OEB approved these account modifications, effective January 1, 2024, in its Decision on the Settlement Agreement[4].

7. In 2024, Enbridge Gas incurred $11.72 million bad debt costs associated with carbon charges, which was recorded in the CCBDDA. In its 2024 FCPP Application, Enbridge Gas forecast it would incur $8.80 million in incremental carbon related bad debt expenses in 2024 based on forecasted costs recoverable from customers as a result of the GGPPA and EPS Regulation[5].

8. As outlined in the 2022 Federal Carbon Pricing Program Application in 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[6].The contributing factor to the 2024 forecast variance was an increase in total Company bad debt actuals compared to what was forecasted in the 2024 FCPP Application[7].

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[2] EB-2024-0251, Exhibit C, Tab 1, Schedule 1, pp.1-9.
[3] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, pp.53-55.
[4] EB-2022-0200, Settlement Agreement, August 17, 2023, p.1.
[5] EB-2023-0196, Exhibit C, Tab 1, Schedule 1, pp.12-13.
[6] EB-2021-0209, Exhibit I.VECC.7.
[7] EB-2023-0196, Exhibit C, Tab 1, Schedule 1, p.8.

1. Federal Carbon Charge Removal

9. 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[8]. Accordingly, Enbridge Gas removed the FCC from customer bills effective April 1, 2025.

10. 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 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] 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
[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. 179-318 – INTEGRATED RESOURCE PLANNING OPERATING COSTS DEFERRAL ACCOUNT

1. On July 22, 2021, the OEB released its Decision and Order for Enbridge Gas's Integrated Resource Planning (IRP) Proposal[1]. In this Decision, the OEB approved the establishment of an IRP Operating Costs Deferral Account for all IRP operations, maintenance, and administrations costs, and a separate IRP Capital Costs Deferral Account for IRP project plan costs.

2. On August 12, 2021, Enbridge Gas filed its draft accounting orders for the IRP Operating Costs Deferral Account and IRP Capital Cost Deferral Account. On September 2, 2021, the OEB found that the draft accounting orders were consistent with the Decision and Order and approved the accounts as filed.

3. The purpose of the IRP Operating Costs Deferral Account, as established in the OEB's IRP Proposal Decision, is to record incremental IRP general administrative costs, as well as incremental operating and maintenance costs and ongoing evaluation costs for approved IRP Plans. Operating costs associated with approved IRP Plans would also include all enabling payments to service providers, made as part of the IRP Plans. For clarity, as of 2024, base IRP O&M costs associated with supporting implementation of IRP broadly are included in the base O&M budget and rates, and only incremental activities and associated costs from IRP Plans (inclusive of pilot projects) are recorded in the deferral account.

4. The balance in the 2024 IRP Operating Costs Deferral Account that is being requested for clearance within this proceeding for 2024 is a debit of $ $0.430 million, which includes a debit of $0.060 for 2023 activity plus forecast interest of $0.031 million for a total debit of $0.461 million. This amount is attributable to the

[1] EB-2020-0091, OEB Decision and Order, July 22, 2021.

implementation of the IRP alternative to defer a project in Kingston, and costs associated with the IRP Pilot Project.

5. Table 1 provides details, and a breakdown of the expenditures included in the 2024 IRP Operating Costs Deferral Account.

Table 1

Details of Expenditures – IRP Operating Costs

Line No.	Item	Description	($ millions)
1	East Kingston Creekford Rd Project	IRP alternative costs	$0.271
2	IRP Pilot Project – 2023 Costs	Application and project costs	$0.060
3	IRP Pilot Project – 2024 Costs	Application and project costs	$0.099
4	Total Requested for Clearance		$0.430

1. East Kingston Creekford Rd Project

6. Enbridge Gas is proposing to recover $0.271 million in the IRP Operating Costs Deferral Account related to the IRP alternative that was implemented to defer a pipeline reinforcement project in the Kingston, Ontario area.

7. The East Kingston Creekford Rd Reinforcement project was a planned $24.3 million capital reinforcement. Enbridge Gas determined that this project could be deferred by implementing a supply side IRP alternative in the form of CNG beginning in 2022[2].Without the CNG injection, the Kingston system was anticipated to fall below its minimum pressure requirements as early as the Winter of 2022/2023. An agreement for CNG in 2022 ensured Enbridge Gas maintained a safe and reliable system for customers in the Kingston project service area. The CNG agreement was executed July 1, 2022, for the winters of 2022/2023 and 2023/2024 to ensure an in-service date of December 1, 2022. The contracted CNG service is an enabling

[2] For a detailed description of the pipeline project and IRP alternatives, please see EB-2023-0092, Exhibit C, Tab 1, pp.20 to 24.

payment to a competitive service provider, where Enbridge Gas does not own the asset, per the IRP Proposal Decision[3]. The costs incurred in 2024 are related to the final year of the CNG agreement. Enbridge Gas is requesting recovery of these costs consistent with approved recovery of the contract previously.

2. IRP Pilot Project (EB-2022-0335)

8. In the IRP Pilot Application, Enbridge Gas proposed that the operating costs related to the Southern Lake Huron (SLH) Pilot Project and Parry Sound (PS) Pilot Project would be recorded in the IRP Operating Cost Deferral Account because the project costs are incremental to the costs that support Enbridge Gas's 2024 current approved interim rates[4]. The Pilot Projects operating costs were outlined in the Pilot Project Application[5].

9. As noted in the 2023 Operating Cost Deferral Account Application[6] recovery of the 2023 amounts would be requested after the OEB Decision on the Pilot Project Application. The OEB Decision on the Pilot Project Application was issued on March 27, 2025. The OEB approved the scope, contents, costs, and proposed accounting treatment of costs as filed by Enbridge Gas in its updated application and evidence filed on June 28, 2024, subject to the various changes as detailed in the OEB's Decision and Order[7].

2.1 2023 Costs

10. Enbridge Gas is proposing to recover $0.060 million in the IRP Operating Costs Deferral Account related to activities and costs incurred in 2023 in support of the filing of the IRP Pilot Projects Application and proactive efforts to ensure timely

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[3] EB-2020-0091.
[4] EB-2022-0335, IRP Pilot Projects Application, Exhibit E, Tab 1, Schedule 2, updated June 28, 2024, p.1.
[5] EB-2022-0335, IRP Pilot Project Application, Exhibit E, Tab 1, Schedule 1, Attachment 1, updated June 28, 2024, version for SLH, and updated December 21, 2023 version for Parry Sound.
[6] EB-2024-0125.
[7] EB-2022-0335, OEB Decision and Order, March 27, 2025.

implementation of the pilots is possible upon receiving an OEB decision. For clarity, this amount is inclusive of costs for both the Parry Sound Pilot Project, which was ultimately withdrawn from the updated Pilot Project Application, and Southern Lake Huron Pilot Project.

11. The costs incurred include the following activities related to the Pilot Projects. Additional details are outlined in the IRP Pilot Project Application:[8]
    a. Stakeholdering – Costs associated with community engagement and open house events to support the Pilot Projects application.
    b. External Consultant – Costs associated with third-party/external consultant in support of the Pilot Projects application. Enbridge Gas engaged Posterity Group to provide a high-level analysis on Enhanced Targeted Energy Efficiency and Demand Response peak hour savings potential.
    c. Administrative/Legal – Costs associated with third-party/external legal support of the Pilot Projects and filing of the application.
    d. Data Collection and analysis – Costs associated with the on-going collection of hourly metering data for PS and SLH.
    e. CNG - Costs associated with identifying potential CNG injection locations for Parry Sound during Q4 2023.

2.2 2024 Costs

12. Enbridge Gas is proposing to recover $0.099 million in the IRP Operating Costs Deferral Account related to activities and costs incurred in 2024 in support of the filing of the IRP Pilot Project Application and proactive efforts to ensure timely implementation of the pilots is possible upon receiving an OEB decision. For clarity, this amount is inclusive of costs for both the Parry Sound Pilot Project, which was

[8] EB-2022-0335, IRP Pilot Project Application, Exhibit E, Tab 1, Schedule 1, updated June 28, 2024 version for SLH, and updated December 21, 2023, version for Parry Sound.

ultimately withdrawn from the updated Pilot Project application, and SLH Pilot Project.

13. The costs incurred include the following activities related to the pilot project. Additional details are outlined in the IRP Pilot Project Application[9].
    a. Administrative/Legal – Costs associated with third-party/external legal support of the Pilot Projects and filing of the application.
    b. CNG – Costs associated with a land lease agreement for a CNG injection site in Parry Sound signed Q1 2024.
    c. Data Collection and analysis – Costs associated with the on-going collection of hourly metering data for PS and SLH.
    d. External Consultant – Costs associated with large commercial and industrial sector outreach for the SLH pilot in Q4 2024. Enbridge Gas contracted Summerhill to support outbound calling services to larger commercial customers in the Southern Lake Huron pilot area in a targeted effort to identify potential participants and expedite the timelines and logistics associated with installing hourly measurement.

3. IRP Reporting Metrics

14. As part of the Settlement Proposal for the 2023 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding, parties agreed that Enbridge Gas will include in any future IRP Deferral Account clearance requests, details on the outcomes and ratepayer benefits related to each category of costs proposed to be cleared as part of the resolution of the IRP Operating Costs Deferral Account[10]. This will include metrics on the:

[9] EB-2022-0335, Exhibit E, Tab 1, Schedule 1, IRP Pilot Project Application, updated June 28, 2024 version for SLH, and updated December 21, 2023 version for Parry Sound.
[10] EB-2024-0125, Settlement Proposal, Exhibit N1, Tab 1, Schedule 1, p.10.

a. Percent of Asset Management Plan (AMP) Projects that have been screened for IRP.
b. Percent of Asset Management Plan (AMP) Projects that have passed the screen and been assessed.
c. Average length of time for Enbridge Gas to screen and assess projects.

15. The outcome for the costs incurred for the East Kingston Creekford Rd project, was the delay and subsequent removal of the project from the 10-year AMP. This enabled avoided planned capital costs of $24.3 million for this capital reinforcement. The O&M Costs for the supply side CNG alternative, inclusive of 2022 to 2024, are $0.63 million.[11] The system demands will continue to be reviewed as part of normal annual updates and forecasting processes.

16. The outcome of the costs incurred for the Pilot Project was the OEB's Decision and Order issued on March 27, 2025, for the Pilot Project Application, as well as enabling data collection to support Pilot Project objectives.[12] Enbridge Gas expects that the learnings obtained from the Pilot Project will be transferable to the assessment and implementation of future IRP Plans for investments in the Asset Management Plan. The primary objectives of the Pilot Project are to develop an understanding of how Enhanced Targeted Energy Efficiency (ETEE) and residential Demand Response (DR) programs impact peak hour flow/demand and to develop an understanding of how to design, deploy, and evaluate ETEE and residential DR programs.

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[11] The total CNG O&M costs of $0.63 million was incurred across 2022 to 2024, where the cost per year is $0.08 million, $0.28 million, and $0.27 million for each respective year. For clarity, costs in 2022 and 2023 have been included in previous Deferral Clearance applications request for disposition, and 2024 costs are included in the 2024 Deferral Clearance Application.
[12] EB-2022-0335, OEB Decision and Order, March 27, 2025.

17. A summary of the metrics is provided in Table 2.

Table 2

IRP Reporting Metrics

Line No.	Metric	Result
1	% of AMP Investments have been screened for IRP[13]	100%
2	% of AMP investments that have passed the screen and have been assessed[14]	87%
3	Average length of time for EGI to screen and assess projects	-

18. Enbridge Gas has conducted IRP screening on 100% of investments in the 2025 to 2034 AMP and subsequently 87% of the investments that passed Binary Screening have been fully assessed. As outlined in the IRP Framework[15] screening refers to the Binary Screening stage of the process, and assessment refers to the two-stage Technical and Economic Evaluation. Appendix C of the 2024 IRP Annual Report provides a breakdown of the investments screened or evaluated out of the 2025 to 2034 AMP and status in the evaluation process[16].

19. Between the months of January 1, 2025, to April 30, 2025, no new investments have been added to the 2025 to 2034 AMP. Therefore, there are no results to report for the average length of time for Enbridge Gas to screen and assess projects. The first full year of tracking will be filed in the 2025 IRP Deferral Account evidence in 2026[17].

[13] This metric reflects the percentage of AMP investments that have received initial and/or binary screening.
[14] This metric reflects the percentage of AMP investments that have passed binary screening, received technical evaluation, and where applicable, received economic evaluation by April 30, 2025.
[15] EB-2020-0091.
[16] Exhibit G, Tab 2, Schedule 1.
[17] EB-2024-0125, Settlement Proposal, Exhibit N1, Tab 1, Schedule 1, p.10, footnote 1.

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 2024, Enbridge Gas recognized $0.9 million of revenue from the sale of surplus capacity. Details of the sale of surplus capacity are provided in Table 1.

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

Table 1
2024 Dawn Parkway Surplus Capacity

Line No.	Particulars	Volume (GJ/d)	Unit Rate ($/GJ)	Revenue ($000s)
		(a)	(b)	(c) = (a x b)
1	January	16,964	3.864	65.5
2	February	16,964	3.864	65.5
3	March	16,964	3.864	65.5
4	April	16,964	3.864	65.5
5	May	16,964	3.864	65.5
6	June	16,964	3.864	65.5
7	July	16,964	3.864	65.5
8	August	16,964	3.864	65.5
9	September	16,964	3.864	65.5
10	October	16,964	3.864	65.5
11	November	28,236	3.864	109.1
12	December	35,696	3.864	137.9
13				902.5

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. 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).

2. The purpose of the DIMPVA is to track Enbridge Gas's spending each year on the DIMP and EDIMP programs. Parties agreed that $12.5 million is included in the 2024 O&M budget for these programs, and that variances will be recovered from or credited to ratepayers on an annual basis from 2024 until Enbridge Gas's next rebasing[1].

3. The balance of the 2024 DIMPVA that is being requested for clearance within this proceeding is a credit of $0.020 million, plus interest.

4. Enbridge Gas also agreed to provide annual reporting on DIMP/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/EDIMP work done during the past year[2]. This Report has been included at Exhibit G, Tab 4, Schedule 1 (DIMP/EDIMP Annual Reporting).

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[1] EB-2022-0200, Settlement Agreement, August 17, 2023, Exhibit O1, Tab 1, Schedule 1, p.31.
[2] Ibid, p.56.

5. Table 1 provides a breakdown of the expenditures included in the 2024 DIMPVA.

Table 1
2024 DIMPVA Breakdown

Line No.	Description	2024 Workplan ($ millions)	2024 Actuals ($ millions)	Variance ($ millions)
	DIMP Admin			
1	Labour, Training, Travel & Accommodations (T&A), Professional Dues, Other Materials/Supplies	0.699	1.596	0.897
	DIMP Projects			
2	Investigations & Assessments	0.307	0.670	0.363
3	Pipe Inspections	0.525	0.459	(0.065)
4	Station Inspections	0.120	0.236	0.116
5	Regulator Set Inspections	0.746	0.862	0.116
6	2023 DIMP Carryover Costs	0.056	0	(0.056)
7	Total DIMP	2.452	3.823	1.372
	EDIMP Admin			
8	Labour, Training, T&A, Professional Dues	1.053	0.887	(0.166)
	EDIMP Projects			
9	ILI & Digs	8.400	7.267	(1.133)
10	CP Surveys and Geohazard Assessments	0.555	0.493	(0.062)
11	Assessments	0.040	0.005	(0.035)
12	2023 EDIMP Carryover Costs	0	0.005	0.005
13	Total EDIMP	10.048	8.656	(1.392)
14	Total DIMP and EDIMP	12.500	12.480	(0.020)

6. The total DIMP costs and EDIMP costs were each divided into two main items: Admin and Projects. Descriptions of the work types and significant contributing factors to the variances within each work type are described below.

7. The 2024 actuals for DIMP amounted to $3.823 million, which is a variance of $1.372 million as compared to the 2024 workplan of $2.452 million. This variance was offset by the EDIMP portfolio, which had total actuals amounting to $8.656 million as compared to the 2024 workplan of $10.048 million, resulting in a variance of ($1.392 million). The overall combined variance for DIMP and EDIMP is ($0.020 million).

1. DIMP

8. DIMP Admin costs cover the costs related to the administration of the DIMP portfolio of work. These include Full Time Equivalent (FTE) positions, contractor positions, and employee expenses such as T&A, training and professional dues and any other materials or supplies required to support the DIMP portfolio. The variance of $0.897 million is largely attributed to an increase in employee and contract worker support needed for the DIMP portfolio that was not in the original workplan.

9. DIMP Projects consists of five distinct work categories: Investigations & Assessments; Pipe Inspections; Station Inspections; Regulator Set Inspections; and 2023 DIMP Carryover Costs. The 2024 Workplan for DIMP Projects was estimated at $1.753 million and actual spend was $2.228 million for a variance of $0.475 million.

10. Investigations and assessments accounted for $0.363 million of the variance, which was driven primarily by the incremental work required for an Aldyl “A” polyethylene (PE) pipe survey, as a result of some recent industry events. The survey was initiated on approximately 200 gas mains to verify the field installation of Aldyl “A” PE pipeline that was not recorded during installation in the 1970’s. The survey provided Enbridge Gas with more certainty on the inventory of Aldyl “A” PE pipelines within the network and was pursued following recent safety-related incidents in the U.S. involving Aldyl “A” PE pipelines.

11. Pipe inspections resulted in a variance of ($0.065 million). This work focused on isolated steel services and steel riser inspections and casing inspections. Isolated steel service lines and steel risers that have the potential to be isolated from a cathodically protected steel pipeline system have a higher likelihood of leaks from corrosion. The casing inspections were performed to identify indications where there may have been deterioration of the casing. There were 11,831 isolated steel services and riser inspections and 444 casing inspections completed in 2024.

12. Station inspections accounted for a variance of $0.116 million. This inspection plan focused on identifying potential hazards at distribution stations, with a focus on the cathodic protection of below ground piping at the station. The variance is primarily attributed to an increase in the number of inspections completed on distribution stations.

13. Regulator set inspections resulted in a variance of $0.116 million to the 2024 workplan. This variance is due to increased regulator inspections on local and remote first cut regulator sets and to increased bulk meter inspections. Other inspection plans focused on service extensions, greater than 400 series regulator sets, and 200 & 400 series regulator sets.

14. Forecast 2023 DIMP carryover costs reflected estimated work performed but not accrued in 2023. No further DIMP costs materialized in 2024, resulting in a variance of ($0.056 million) to the 2024 workplan.

<u>2. EDIMP</u>

15. EDIMP Admin costs cover the costs related to the administration of the EDIMP portfolio of work. These include Full Time Equivalent (FTE) positions, contractor positions, and employee expenses such as T&A, training and professional dues and any other materials or supplies required to support the EDIMP portfolio. The variance

of ($0.166 million) is primarily due to two contract roles that were budgeted but remained vacant for the majority of the year.

16. EDIMP Projects consists of four distinct work categories: In-line Inspection (ILI) & Digs; Cathodic Protection (CP) Surveys and Geohazard Assessments; Assessments; and 2023 EDIMP Carryover Costs. The 2024 Workplan for EDIMP Projects was estimated at $8.995 million and actual spend was $7.770 million for a variance of ($1.226 million).

17. The 2024 ILI workplan mainly consisted of in-line inspecting five pipelines and mitigating/repairing any Phase 1 anomalies that were discovered. The five pipelines in-line inspected were: the NPS 12 Wilson Ave; NPS 12 Martin Grove; NPS 8 Port Stanley; NPS 8 St. Thomas; and NPS 10 Sarnia South pipelines. The work category had a variance of ($1.133 million), which was primarily driven by cost efficiencies gained on the Wilson Ave, Martin Grove and Sarnia South ILIs. The efficiencies were partially offset by the inclusion of a second set of ILI runs for the Port Stanley pipeline.

18. The CP surveys and geohazard assessments work category had a variance of ($0.062 million). The main contributing factors to the variance include costs for the CP surveys and geohazards assessment consultant coming in below the forecast.

19. The assessments work category is used to fund any assessments or surveys carried out on EDIMP pipelines. Risk-informed reprioritization resulted in the majority of these funds instead being allocated to focus on risk assessments associated with DIMP. As a result, only $0.005 million of the planned $0.040 million was spent in 2024, resulting in a variance of ($0.035 million).

20. Forecast 2023 EDIMP carryover costs would generally include expected residual costs for EDIMP projects commenced in 2023 but not concluded until 2024. It was not anticipated that any residual costs for EDIMP projects commenced in 2023 would carryover to 2024, however, actuals in this category amounted to $0.005 million, resulting in a variance of $0.005 million to the 2024 workplan.

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[1] the establishment of the Post-Retirement True-Up Variance Account (PTUVA). 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 2024 is a credit of $8.3 million. As of December 31, 2024, the actual revenue requirement impact that resulted from pension and OPEB costs (accrual and cash-based amounts) was a credit of $19.7 million. The 2024 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 $1.4 million, plus interest of $0.086 million. A breakdown of the forecast and actual revenue requirement as well as the derivation of the $1.4 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 return on plan assets on an actual versus forecast basis in 2024.

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2024, p.56.

2024 Pension True-Up Variance Account (PTUVA)

Line No.	Particulars ($ millions)	Actual 2024	OEB-Approved 2024	Variance
		(a)	(b)	(a) - (b)
	Incremental Rate Base Investment			
1	Capital Expenditures	-	-	-
2	Average Rate Base	-	-	-
	Incremental Revenue Requirement Calculation:			
	Return on Incremental Rate Base:			
3	Long-term Debt Interest	-	-	-
4	Short-term Debt Interest	-	-	-
5	Preference Shares	-	-	-
6	Equity	-	-	-
7	Total Return on Incremental Rate Base			
	Incremental Operating Expenses:			
8	Operating and Maintenance Expenses	(11.0)	(1.6)	(9.3)
9	Depreciation Expense	-	-	-
10	Property Taxes	-	-	-
11	Total Incremental Operating Expenses	(11.0)	(1.6)	(9.3)
	Incremental Income Taxes:			
12	Return on Equity and Preference Shares	-	-	-
	Utility/Tax Timing Differences			
13	Add: Pension and OPEB Accrual Cost	(11.0)	(1.6)	(9.3)
14	Less: Pension and OPEB Cash Contributions	(13.2)	(16.9)	3.7
15	Taxable Income (line 12 + line 13 + line 14)	(24.1)	(18.5)	(5.6)
16	Income Taxes Before Gross Up (line 15 x 26.5% Tax Rate)	(6.4)	(4.9)	(1.5)
17	Total Incremental Income Taxes After Gross Up (line 16 / (1-26.5%))	(8.7)	(6.7)	(2.0)
18	Total Incremental Revenue Requirement (line 7 + line 11 + line 17)	(19.7)	(8.3)	(11.4)
19	Deferral Deadband +/- $10 million			(10.0)
20	Total PTUVA Deferral Debit (Credit) (line 18 - line 19)			(1.4)

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 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)[1]. 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. 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.

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

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

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 2024, the IWG met in person at the Enbridge Gas Toronto office on April 30, July 30, and December 10. The IWG also met virtually on October 17, 2024. Resilient LLP took the lead, with input from the IWG members, to interview and work with Brattle Group, who was hired as an expert witness to review the Enbridge Gas expert reports from the rebasing application and determine what is important information that may have been missed in those reports that would help mitigate energy-related risks and identify energy-related opportunities of First Nation groups in Ontario. The IWG Annual Report found at Exhibit G, Tab 3, Schedule 1, sets out more details on the activities of the IWG for 2024.

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

Table 1
IWG Incremental Capacity Funding

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

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

ACCOUNT NO. 179-333 AVERAGE USE VARIANCE ACCOUNT

1. The purpose of this evidence is to provide information in support of the 2024 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 2024 actual average use is weather normalized using 2024 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 2024 actual weather-normalized average use came higher than the 2024 forecasted average use, resulting in a total credit[3] to ratepayers of $6.1 million, including interest.

5. For Rate 6, the 2024 actual weather-normalized average use came lower than the 2024 forecasted average use, resulting in a total debit from ratepayers of $2.1 million, including 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, Settlement Agreement, 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 2024 actual weather-normalized average use came lower than the 2024 forecasted average use, resulting in a total debit from ratepayers of $5.4 million, including interest.

7. For Rate M2, the 2024 actual weather-normalized average use came lower than the 2024 forecasted average use, resulting in a total debit from ratepayers of $12.7 million, including interest.

8. For Rate 01, the 2024 actual weather-normalized average use came higher than the 2024 forecasted average use, resulting in a total credit to ratepayers of $2.0 million, including interest.

9. For Rate 10, the 2024 actual weather-normalized average use came lower than the 2024 forecasted average use, resulting in a total debit from ratepayers of $4.7 million, including interest.

10. Attachment 1 details the calculation of the 2024 AUVA by rate class that results in a net debit from ratepayers of $16.8 million, including 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	Budget Average Use	(m^3)	2,317	27,726	2,689	166,281	2,642	154,954	
2	Actual Normalized Average Use	(m^3)	2,347	27,543	2,621	142,421	2,681	131,411	
3	Average Use Variance (line 1 - line 2)	(m^3)	(30)	183	68	23,861	(40)	23,543	
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 3 x line 4)	(10^6m^3)	(65.1)	31.6	82.5	192.7	(14.7)	51.9	
6	Net Annual Weighted Average Unit Rate (3)	($/$m^3$)	$0.087609	$0.061892	$0.061026	$0.061629	$0.123576	$0.083964	
7	Annual AUVA Balance Amount (line 5 x line 6)	($ millions)	($5.7)	$2.0	$5.0	$11.9	($1.8)	$4.4	$15.7
8	Interest (4)	($ millions)	($0.4)	$0.1	$0.4	$0.9	($0.1)	$0.3	$1.1
9	Total Deferral Account Amount (5)	($ millions)	($6.1)	$2.1	$5.4	$12.7	($2.0)	$4.7	$16.8

Notes:
(1) Harmonized Average Use Variance Account (AUVA) as per the 2024 Rebasing Phase 1 Decision, Section 5.5.1. Reference to 'normalized' in Table 1 implies weather normalization based on 2024 Forecast Heating Degree Days (HDD).
(2) Refers to 2024 OEB-approved annual average number of customers including adjustment for customer numbers agreed to in the 2024 Rebasing Phase 1 Settlement Agreement.
(3) Represents the volume-weighted average of OEB-approved monthly unit rates in effect.
(4) Interest is calculated on the monthly opening balance in the deferral account using the OEB-approved EB-2006-0117 interest rate methodology. Interest is calculated to July 1, 2026.
(5) (+) value reflects a debit (collection) from ratepayers and refund to Enbridge Gas which results when forecasted average use is higher than the actual normalized average.
(-) value reflects a credit (refund) to ratepayers and collectable from Enbridge Gas which results when the forecasted average use is lower than the actual normalized average use.

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 EB-2023-0143[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 its EB-2023-0143 Decision, 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[4]. 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 2024 locating costs, in excess of the 2024 budget amount included in approved rates, that are directly attributable to the impacts of Bill 93.

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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] Ibid, Schedule B, p. 17.

3. The balance of the 2024 GOCA Variance Account that is being requested for clearance is a debit/receivable of $14.892 million plus interest. The background and methodology employed on arriving at this amount are outlined in detail below.

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%, resulting in costs incremental to 2024 base rates (please see Table 1). 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 base rates. This evidence outlines the drivers behind Bill 93 cost increases as well as the incremental cost calculations for 2024.

Table 1
2019-2024 External Locate Costs

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

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

[6] EB-2022-0200. Exhibit I.4.4-STAFF-122.

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 impacts. The resulting 2024 budget reflected a 28% increase over 2022 actual locating costs, a notable escalation considering the historically flat trend in annual locating spend from 2019 to 2021 (please see Table 1). With two full years of post-Bill 93 data now available, Enbridge Gas has observed the average external locating unit costs rise by approximately 108%. The approved 2024 base budget appropriately captured all foreseeable and controllable financial pressures. The $14.892 million recorded in excess of the approved budget is not due to inflationary or volume-related factors but is directly and solely attributable to structural changes in the locate industry driven by Bill 93.

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. Consider a car manufacturing assembly line. If the volume of cars to be built remains constant and you want to speed up the assembly time without impacting quality, then more skilled workers are required to speed up production. 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

[7] EB-2022-0200. Exhibit 9, Tab 1, Schedule 3, pp.8-11.

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 108% increase in average external locating unit costs in 2023 and 2024. Enbridge Gas has included only incremental external locating costs in the variance account.

7. Enbridge Gas has cost reducing mechanisms in place aimed at reducing the ongoing external costs related to locating. Alternative Locate Agreements (ALAs), generating $11.9 million in locating cost avoidance in 2024, 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. This program has grown significantly since 2020 and continues to drive reduced locating spend (please see Table 2). 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 $991K in locate savings in 2024. 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 2023 and 2024 (~$6.5 million) reduced what otherwise would have been included in the deferral account balance.

Table 2
2020-2024 Estimated Locating Cost Avoidance

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

8. Table 3 outlines the 2024 GOCA balance calculation.

Table 3
2024 Base Rate Budget vs. Actuals

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

9. It should be noted that Enbridge Gas has not included any Vital Main Standby (VMS) costs in the 2024 GOCA balance. This is in keeping with the OEB's Decision for the 2023 GOCA balance[8].

10. Notwithstanding the OEB's determination, 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. While Enbridge Gas is not requesting recovery of incremental VMS related costs in the 2024 GOCA, these costs are nonetheless relevant to any fairness or quantum arguments that might be advanced by other parties in relation to the amounts recorded in the 2024 GOCA. Should parties advance such arguments, then Enbridge Gas will point to the fact that it is having to absorb substantial VMS cost increases arising from Bill 93, without any recovery, and this is relevant to considering the recoverability of the full GOCA balance.

11. In Enbridge Gas's view, Bill 93 has resulted in increased VMS locating costs as this activity is performed by external Locate Service Providers (LSPs) for all locate requests on high-risk assets. The legislation's mandated reduction in locate delivery

[8] EB-2024-0125, Decision and Order, September 23, 2025.

timelines has placed substantial pressure on the labour market, resulting in higher LSP wages and directly increasing the cost of VMS for critical infrastructure locates.

12. In 2021 and 2022, Enbridge Gas averaged $3.2 million in actual spend on VMS for high risk locates. Following the implementation of Bill 93, annual expenditures have risen to $8.3 million in 2023 and $9.3 million in 2024. This represents an average cost increase of approximately 175% over pre-legislation levels, underscoring the ongoing and material financial impact of Bill 93 on this essential safety-related function. Enbridge Gas has not included VMS costs in the deferral account and will have to manage this cost pressure over the remaining rate term.

ACCOUNT NO. 179-344 ENBRIDGE SUSTAIN AFFILIATE RECOVERIES VARIANCE ACCOUNT

1. 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 to 2028 IRM term.

2. In the 2024 Rebasing Phase 2 Settlement Agreement, 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 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 to 2028 IRM term[1].

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

[1] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p.36.
[2] EB-2024-0111, Exhibit 1, Tab 18, Schedule 1.

4. Table 1 sets out the gross eligible costs paid or payable by Enbridge Sustain to Enbridge Gas for goods or services received in 2024. During 2024, Enbridge Sustain received services at a total cost of $1.1 million. As such, when compared to the base $1.0 million noted above, Enbridge Gas recorded in the Enbridge Sustain Affiliate Recoveries Variance Account a credit to customers (or payable) of $0.091 million, plus interest. Enbridge Sustain did not provide any services to Enbridge Gas during 2024.

Table 1
Amounts paid by Enbridge Sustain to Enbridge Gas for services received in 2024

Line No.	Cost Types	2024 Actual ($ millions)	Comments
1	Indirect Costs	$0.9	EGI Full Time Employees (FTE) providing services to Enbridge Sustain at a Fully Allocated Cost (FAC).
2	Direct Allocation: Real Estate	0.1	Real Estate costs for Ontario occupancy of Enbridge Sustain employees.
3	Direct Allocation: TIS	0.1	Shared IT support costs.
4	Total	$1.1	

5. 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[3].

[3] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, pp.36-37.

6. Table 2 presents the 2024 financial information for Sustain on an actuals basis.

Table 2
2024 Financial Information – Enbridge Sustain

Line No.	Cost Types	2024 Actual ($ millions)	Comments
1	Direct Costs	$13.2	Paid directly; does not flow through Utility
2	HR Burden and Benefits	1.9	Paid directly or charged to Enbridge Sustain as a flow through from Regulated Utility at weighted average burden rates (1)
3	Indirect Costs (2)	0.9	Charged to Enbridge Sustain from Regulated Utility at Fully Allocated Cost Rate (FAC)
4	Corporate Cost Allocations	0.3	Paid directly: does not flow through Utility
5	Direct Allocations (3)	0.2	Direct charge to Enbridge Sustain on actual cost incurred
6	Total	$16.5	

Notes:
(1) During 2024 prior to being established as an affiliate, Enbridge Sustain's portion of HR Burden and Benefits were charged through CFCAM to EGI regulated Line of Business (LOB) and then passed through to the Enbridge Sustain LOB.
(2) Please see Table 1 'Indirect Costs', as well as Table 3 for further details.
(3) Please see Table 1 'Direct Allocation: Real Estate' and 'Direct Allocation: TIS'.

7. Table 3 provides a further breakdown of the Indirect Labour Costs noted in Table 2, charged at a Fully Allocated Cost Rate (FAC), broken down by department.

Table 3
2024 Details of Indirect Labour Charges – Enbridge Gas to Enbridge Sustain

Line No.	Department	Total Hours	Cost ($ millions)
1	Business Development	747	$ 0.08
2	Public Affairs	97	0.01
3	Finance	2,972	0.53
4	Human Resources	211	0.04
5	Legal	451	0.09
6	Regulatory	84	0.01
7	Supply Chain	70	0.01
8	TIS	855	0.15
9	Total	5,486	$0.93

8. 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 LOB to remove these costs from Enbridge Gas regulated OM&A.

ACCOUNTS NOT BEING REQUESTED FOR CLEARANCE

1. The following 2024 accounts have no balance, and are therefore not requested for clearance to customers:

    - Incremental Capital Module Deferral Account
    - Asset Life Extension Costs Deferral Account
    - LEAP Emergency Financial Assistance Deferral Account
    - Unauthorized Overrun Non-Compliance Deferral Account
    - IRP Capital Costs Deferral Account
    - Tax Variance Account
    - Expansion of Natural Gas Distribution Systems Variance Account
    - Green Button Initiative Deferral Account
    - Cloud Computing Implementation Costs Deferral Account
    - Disposition of Property 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.

3. With regard to the Low-Income Energy Assistance Program Emergency Financial Assistance (LEAP EFA) Deferral Account, as established in the LEAP EFA Review,[1] the OEB announced changes to the LEAP EFA effective March 1, 2024. This included confirmation of the generic funding mechanism, in place since 2011, requiring each distributor provide the greater of 0.12% of their total OEB-approved

[1] EB-2023-0135.

distribution revenue requirement or $2,000 each year for LEAP EFA. Further, this change included the establishment of 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. This decision stipulated that the OEB expects only prudently incurred and material costs recorded in the accounts will be sought for disposition[2]. As part of the 2024 Rebasing Phase 1 Interim Rate Order[3], the OEB approved the establishment of the Enbridge Gas LEAP EFA 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. In 2024, Enbridge Gas was required to add incremental funding of $843,373 above the generic 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. This amount was below the materiality threshold of $1 million that applied to Enbridge Gas at the time that the OEB approved the new LEAP EFA Deferral Account, first on a generic basis in February 2024 and then specifically for Enbridge Gas in April 2024. As a result, Enbridge Gas did not record the incremental $843,373 in the LEAP EFA Deferral Account as the amount did not meet or exceed the $1 million materiality threshold required for clearance of this account.

3. With regard to the Unauthorized Overrun Non-Compliance Deferral Account, in its 2024 Rebasing Phase 1 Decision[4], 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

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[2] EB-2023-0135, Changes to the Low-income Energy Assistance Program Emergency Financial Assistance and Accounting Orders, February 12, 2024, p.4
[3] EB-2022-0200, Decision on Interim Rate Order, April 11, 2024.
[4] EB-2022-0200, OEB Decision and Order, December 21, 2023.

account is to record any unforecasted penalty revenue received from interruptible distribution customers who do not comply with a distribution interruption. In 2024, there were 6 interruption events called in the Union North rate zone for a total of 38.4 days, and 1 interruption event called in the Union South rate zone for a total of 2 days. All Customers were able to comply with each interruption event, therefore incurring no non-compliance charges in 2024.

4. With regard to the IRP Capital Costs Deferral Account (179-319), Enbridge Gas is not bringing forward a balance for disposition. In the IRP Pilot Application[5], Enbridge Gas proposed that the actual annual revenue requirement for the capital costs related to the Parry Sound IRP Pilot Project would be recorded in the IRP Capital Cost Deferral Account because the project costs were incremental to the costs that support Enbridge Gas's 2024 current approved interim rates[6]. The Parry Sound capital costs are associated with the installation of hourly metering, as outlined in the Pilot Project Application[7]. As noted in the 2023 Operating Cost Deferral Account Application[8], recovery of the 2023 amounts would be requested after the OEB Decision on the Pilot Project Application. The OEB Decision on the Pilot Project Application was issued on March 27, 2025[9]. The Parry Sound Pilot Project was ultimately withdrawn from the updated Pilot Project Application filed June 28, 2024. However, installation of meters in Parry Sound occurred in 2023 through 2024, and the associated capital costs incurred during this time were recorded. Given the meters are still being utilized, the Company will consider the expenditures as part of typical meter exchange/replacement activity.

[5] EB-2022-0335.
[6] EB-2022-0335, Exhibit E, Tab 1, Schedule 2, (updated June 28, 2024) p.1. Also see EB-2022-0335, JT1.1.
[7] EB-2022-0335, Exhibit E, Tab 1, Schedule 1, Attachment 1, (Updated December 21, 2023).
[8] EB-2024-0125.
[9] EB-2022-0335, IRP Pilot Project Decision and Order, March 27, 2025.

5. The following 2024 accounts have balances but are not requested for clearance, however information supporting each balance is provided for information purposes:

    - Panhandle Regional Expansion Project Variance Account
    - Site Restoration Costs Variance Account
    - IRP System Pruning Account

1. Panhandle Regional Expansion Project Variance Account (PREPVA) (179-329)

6. In its 2024 Rebasing Phase 1 Decision[10], 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.

7. In the 2024 Rebasing Phase 2 Settlement Agreement[11] the OEB approved unit rates reflecting levelized rate treatment for the PREP starting in 2025.

8. 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

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

amount will be brought forward in Enbridge Gas's next rebasing application for disposal.

9. 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 $14.231 million for 2024. The balance in the PREPVA as of December 31, 2024, reflects the revenue sufficiency credit of $14.231 million, which will be carried forward and accumulated with each year's net amount through the IR term as noted above. No revenue was collected during 2024 since the levelized rate was not implemented until 2025. The sufficiency in 2024 results primarily from the favourable income tax implications attributable to the accelerated capital cost allowance deduction in the year of in-service. The variances between the actual and approved Required Return and the Income Tax impacts essentially offset each other and relate to the decrease in 2024 average investment. The decrease in average investment of $21.061 million was mainly due to the lower cumulative capital expenditures of $16.855 million. The lower capital expenditures were partly as a result of a shift in some spending from 2024 to 2025 as well as a lower amount of expenditures required for the project. This resulted in a lower required return, which was partially offset by the timing of tax impacts as well as lower incremental project revenues to date. Please see Table 1 for details.

Table 1
Panhandle Regional Expansion Project
Revenue Requirement Summary

Line No.	Particulars ($000s)	2024 Actual	2024 OEB-Approved	Variance
		(a)	(b)	(c)
	Rate Base Investment			
1	Capital Expenditures	233,975	196,506	37,469
2	Cumulative Capital Expenditures	233,975	250,830	(16,855)
3	Average Investment	9,750	30,811	(21,061)
	Revenue Requirement Calculation			
4	Operating & Maintenance Expenses	21	21	0
5	Depreciation Expense	0	307	(307)
6	Property Taxes	310	143	167
7	Total Operating Expenses	331	470	(139)
8	Required Return	593	1,874	(1,281)
9	Total Operating Expenses and Return	924	2,344	(1,420)
	Income Taxes			
10	Income Taxes - Equity Return	123	389	(266)
11	Income Taxes - Utility Timing Differences	(14,982)	(16,426)	1,444
12	Total Income Taxes	(14,859)	(16,037)	1,178
13	Total Revenue Requirement	(13,935)	(13,693)	(242)
14	Incremental Project Revenue	296	595	(299)
15	Net Revenue Requirement	(14,231)	(14,288)	57

2. Site Restoration Costs Variance Account (SRCVA) (179-337)

10. In its 2024 Rebasing Phase 1 Interim Rate Order[12], 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.

11. 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 approximately $1.6 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.

12. 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

[12] 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.

13. As at December 31, 2024, the cumulative balance in the SRCVA is a credit of $19.430 million. During 2024, Enbridge Gas recovered $92.360 million of site restoration in depreciation rates, and incurred $73.370 million of decommissioning, abandonment, and site restoration costs (net of any proceeds), resulting in a net credit balance of $18.990 million. The total after-tax interest generated during 2024 (net of bank fees) on the net credit balance totaled $0.440 million. A summary of the SRCVA balance is provided in Table 2.

Table 2
2024 Site Restoration Cost Variance Account (SRCVA)

Line No.	Particulars ($ millions)	Col. 1 2024 Actuals
1	Site Restoration Recovered in Depreciation Rates	(92.360)
2	Decommissioning, Abandonment, and Site Restoration Costs	73.370
3	Interest Income (After-Tax)	(0.440)
4	Net SRCVA Balance as of Dec 31, 2024	(19.430)

3. IRP System Pruning Deferral Account (179-341)

14. On November 4, 2024, Enbridge Gas filed the 2024 Rebasing Phase 2 Settlement Agreement, where parties agreed that a new Integrated Resource Planning (IRP) System Pruning Deferral Account with a $5 million dollar cap would be created for recording incremental costs incurred to develop and implement one or two IRP system pruning pilot projects for later recovery[13]. In the Settlement Agreement, Enbridge Gas filed its draft accounting order for the IRP System Pruning Deferral Account. The Settlement Agreement was approved by the OEB on November 29, 2024.

15. The balance in the IRP System Pruning Deferral Account for 2024 is $0.022 million plus forecast interest of $0.001 million, for a total debit of $0.023 million related to activities and costs incurred in support of the System Pruning pilot. Enbridge Gas is reporting these amounts for 2024, and recovery of these amounts will be requested in a future application. Table 3 provides the details of System Pruning costs incurred in 2024.

[13] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, p.20.

16. Enbridge Gas, in consultation with the IRP Technical Working Group (TWG), engaged Det Norske Veritas (DNV) Canada Ltd. to conduct a jurisdictional scan on system pruning activities. The study is being 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.

Table 3
Details of Expenditures – System Pruning Costs

Line No.	Item	Description	($ millions)
1	System Pruning Pilot	Jurisdictional Scan	$0.022

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

1. This evidence will support the balance in the 2024 Storage & Transportation Deferral Account (S&TDA) and the commitment to report annually, effective for 2024, on market-based storage and load balancing costs pursuant to the 2024 Rebasing Phase 2 Settlement Agreement[1].

1. 2024 S&TDA

2. The purpose of the 2024 S&TDA is to record the difference between the forecast cost of market-based storage included in the Company's approved rates and the actual cost of market-based storage 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.

3. The balance in the 2024 S&TDA that the Company is proposing to collect from customers is $6.4 million, plus interest. A detailed breakdown of the S&TDA is provided at Table 1.

[1] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p.26.

Table 1
Breakdown of the 2024 S&TDA - EGD rate zone

Line No.	Particulars ($ millions)	Forecasted Costs	Actual Costs	Variance
		(a)	(b)	(c)
1	Market-Based Storage	20.0	28.4	8.4
2	2022 ESM/DVA Disposition (1)	-	11.5	11.5
3	2024 Rebasing DVA Disposition (2)	-	(13.5)	(13.5)
4	Total	20.0	26.4	6.4

Notes:
(1) Disposition of 2022 Deferral and Variance Account Balances proceeding (EB-2023-0092) collection for the EGD rate zone: M12 transportation of $11.9 million, M16 transportation of $0.2 million; plus, 2022 Federal Carbon proceeding (EB-2023-0196) refund for the EGD rate zone of ($0.6) million.

(2) Disposition of Deferral and Variance Account Balances from the 2024 Rebasing Application (EB-2022-0200) refund for the EGD rate zone: M12 transportation of ($13.4) million, and M16 transportation of ($0.02) million.

4. The primary driver for the balance in the 2024 S&TDA is higher than forecasted market-based storage costs in 2024 (line 1, column (c)), partially offset by a $2.0 million refund from the Union rate zones as part of Enbridge Gas's Deferral and Variance dispositions previously approved by the OEB (sum of line 2, column (c), and line 3, column (c))[2].

5. The market-based storage costs in 2024 were $28.4 million, which is $8.4 million higher than the OEB-approved 2024 market-based storage costs of $20.0 million. The increase in 2024 market-based storage costs is primarily driven by the higher average storage cost in 2024 of $1.09 CAD/GJ compared to the average storage cost in the OEB-approved 2024 market-based storage costs of $0.78 CAD/GJ.

[2] Transportation prices are determined by the OEB-approved rate schedules: https://www.enbridgegas.com/storage-transportation/rates-tariffs

6. As discussed recently in the Company's Annual Update to the 5-Year Gas Supply Plan,[3] Enbridge Gas purchases market-based storage services on behalf of customers in the EGD rate zone through a competitive blind RFP process. On September 25, 2023, Enbridge Gas initiated an RFP for market-based storage capacity with deliveries to Dawn. The RFP was conducted by the Company's designated RFP manager, EY LLP. The RFP requested offers for storage services with terms of up to 5 years commencing April 1, 2024, with firm injections from May to September and firm withdrawals from December to March. The RFP letter is provided at Exhibit D, Tab 2, Schedule 1.

7. Recognizing its reliability and cost-effectiveness, and consistent with the Company's 2024 gas supply plan, Enbridge Gas renewed sufficient market-based storage services to maintain total storage capacity and related late winter season deliverability. The RFP responses were received by the RFP manager on behalf of Enbridge Gas on October 16, 2023. Following its assessment of all offers received, the RFP manager made a procurement recommendation and Enbridge Gas transacted for market-based storage services based on that recommendation. Bids received and those that were selected are outlined at Confidential Exhibit D, Tab 2, Schedule 2.

<u>2. Load Balancing Reporting</u>

8. As part of the 2024 Rebasing Phase 2 Settlement Agreement approved by the OEB on November 29, 2024, Enbridge Gas committed to report annually on its market-based storage and load balancing costs going forward, starting in 2024[4]. 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:

[3] EB-2024-0067, 2024 Annual Gas Supply Plan Update, p.71.
[4] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p.26.

> …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]

9. 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 and purchases of gas supply.

10. The Union rate zones have sufficient cost-based storage to meet load balancing requirements. 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.

11. The EGD rate zone does not have sufficient cost-based storage to meet load balancing requirements. Accordingly, Enbridge Gas uses a combination of storage deliverability (from cost-based and market-based storage), winter supply purchases, and peaking services, to meet load balancing requirements for the EGD rate zone.

12. Enbridge Gas has made proposals to harmonize rate zones, including certain rate design methodologies for the determination and recovery of storage and load balancing costs, as part of Phase 3 of the 2024 Rebasing Application[7]. Until harmonized methodologies are approved and implemented, Enbridge Gas continues to apply the rate design methodologies and practices for the determination of

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[5] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p.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.
[7] EB-2025-0064. Specifically, the proposed harmonized methodology for the derivation of load balancing costs is provided at Phase 3 Exhibit 4, Tab 2, Schedule 2, Attachment 3.

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.

2.1 Storage

13. In 2024, Enbridge Gas held 199.7 PJ of cost-based storage reserved for in-franchise customers to meet 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 market-based storage, including 270 TJ/d of deliverability, for EGD rate zone customers.

14. 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 market-based storage is forecast in a cost of service rate application with cost variances recorded in the S&TDA. In 2024, the forecast cost in rates and actual cost of the 26 PJ of market-based storage held for the EGD rate zone was $20.0 million and $28.4 million, respectively, as shown in Table 1.

15. In the 2024 Rebasing Phase 2 Settlement Agreement, Enbridge Gas agreed to include 199.7 PJ of cost-based storage and 18 PJ of market-based storage (total 217.7 PJ) in the Company's consolidated gas supply plan[8], and to manage load balancing requirements above the 217.7 PJ in a manner the Company deems appropriate. The reduction of market-based storage from 26 PJ to 18 PJ was achieved by not-renewing a portion of expiring market-based storage service contracts in 2025.

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[8] Enbridge Gas prepared a consolidated 2024 Gas Supply Plan for the EGD and Union rate zones as part of it's 2024 Rebasing Application that uses the 199.7 PJ of cost-based storage for both the EGD and Union rate zones. Parties agreed to implement the cost consequences of the 2024 Gas Supply Plan as part of Phase 3 of the Rebasing Application. EB-2024-0111, Settlement Agreement, p.6 & Exhibit N, Tab 1, Schedule 1, November 29, 2024, pp.23-24.

<u>2.2 Load Balancing Supply Purchases</u>

16. In addition to storage, Enbridge Gas also relies on the flexibility inherent in its procurement processes and policy related to Dawn supply purchases[9] as well as peaking services to meet load balancing requirements for the EGD rate zone. 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 assists with load balancing needs due to seasonal changes in bundled in-franchise customer's demand.

17. 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, unplanned load balancing requirements are largely met using the flexibility provided by Dawn supply.

18. On a planned basis as needed, Enbridge Gas may also plan for the purchase of peaking services[11] to manage load balancing requirements needed during near-peak and peak day conditions. Peaking services typically have low fixed demand costs, however, they can be extremely expensive in the event supply is called upon. Enbridge Gas prefers to limit peaking services to a maximum limit of 2% of design day demand for each delivery area.

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[9] Dawn purchases include the ability to adjust the timing of planned purchases and to make unplanned short-term purchases to adjust for variation to forecast or market volatility.
[10] With the exception of planned unutilized capacity.
[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.

19. 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.

20. As provided in Table 2, 2024 planned Dawn supply purchases for the EGD rate zone were 81.3 PJ[12], whereas actual Dawn supply purchases were 59.3 PJ[13].

Table 2
2024 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	14,527	14,527
3	March	-	-
4	April	-	-
5	May	4,030	-
6	June	3,900	-
7	July	4,030	-
8	August	3,681	-
9	September	3,900	-
10	October	4,030	2,996
11	November	6,000	2,267
12	December	15,500	17,804
13	Total	81,298	59,296

21. Actual Dawn supply purchases were less than planned in 2024 due to a warmer than normal weather during the winter of 2023/24 resulting in excess inventory in storage at the end of winter. Enbridge Gas mitigated the excess inventory in storage during the summer of 2024 by reducing planned supply purchases at Dawn to

[12] Planned Dawn supply purchases for 2024 are from the 2023/24 gas supply plan.
[13] Enbridge Gas did not call on supply under contracted peaking services in 2024.

ensure it was able to meet, but not exceed, the storage inventory target for November 1, 2024.

22. The total cost associated with the Dawn supply purchases of 59.3 PJ was $201.6 million. Actual peaking service demand costs were $0.1 million.

2.3 Load Balancing Costs

23. 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

24. 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. For 2024, as part of Enbridge Gas's 2024 Rebasing Application, base rates were updated to reflect updated forecast volumes. However, parties agreed to implement the cost consequences of the 2024 gas supply plan as part of Phase 3 of the 2024 Rebasing Application[14]. Phase 3 is an active application, and a decision is not expected until sometime in 2026[15]. As a result, 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[16].

[14] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p.9.
[15] EB-2025-0064.
[16] EB-2018-0305.

25. The classification of costs as Load Balancing in the cost study for the EGD rate zone[17] includes peaking services, Dawn supplies and upstream transportation costs to meet the load balancing needs of sales service and bundled DP customers. For purposes of this evidence, Enbridge Gas will focus on the commodity costs included in base rates (peaking and Dawn supplies).

26. 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 2024 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[18].

27. For 2024, 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[19] (20% deemed transportation, 71% load balancing - seasonal, and 9% load balancing - peak). 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.

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[17] EB-2017-0086, Exhibit G2, Tab 6, Schedule 2, p.1.
[18] EB-2018-0305, Exhibit E, Tab 4, Schedule 3, pp.1-2.
[19] Per the approved cost allocation methodology underpinning the 2024 QRAM applications.

The allocation of load balancing costs to each customer class reflects cost causality and is based on load balancing needs of each customer class based on the gas supply plan in base rates[20].

28. Table 3 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.

[20] Per the approved cost allocation methodology underpinning the 2024 QRAM applications.

Table 3
2024 Load Balancing Costs in Rates – EGD Rate Zone

Line No.	Particulars ($000s)	2024 (1) Jan QRAM (a)	April QRAM (b)	July QRAM (c)	Oct QRAM (d)
1	Forecast Dawn supply purchases (10^3m^3)	2,649,848	2,649,848	2,649,848	2,649,848
2	Forecast peaking supply purchases (10^3m^3)	6,902	6,902	6,902	6,902
3	Empress reference price ($/10^3m^3$)	115.792	95.817	103.139	99.324
4	Dawn forecast price ($/10^3m^3$)	158.857	137.553	148.583	139.053
	Dawn Supply Purchases Classification				
5	System commodity supply (line 1 x line 3)	306,831	253,900	273,302	263,193
6	Transportation (2)	22,828	22,123	24,089	21,059
7	Load balancing - seasonal (2)	81,145	78,642	85,628	74,858
8	Load balancing - peak (2)	10,143	9,830	10,704	9,357
9	Total (line 1 x line 4)	420,947	364,495	393,722	368,468
	Peaking Services Classification				
10	Load balancing - peak (3)	3,005	3,077	3,071	3,092
	Load Balancing Costs in Rates				
11	Total load balancing commodity costs (lines 7 + 8 + 10)	94,293	91,549	99,402	87,307
12	Other load balancing costs (4)	67,181	64,603	66,025	65,355
13	Total load balancing costs in rates (5)	161,474	156,152	165,427	152,662

Notes:

(1) January 2024 QRAM (EB-2023-0330), April 2024 QRAM (EB-2024-0093), July 2024 QRAM (EB-2024-0166), and October 2024 QRAM (EB-2024-0245).

(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, and Exhibit C, Tab 4, Schedule 4, p. 5 (beginning with the July 2024 QRAM). See Note 1 for the docket numbers of each QRAM application.

29. 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

30. 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.

31. 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.

32. 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 2024 was a credit to ratepayers of $3.5 million as provided at Attachment 1[21]. Load balancing variance costs are allocated to each customer class in the same manner as the allocation of load balancing costs in rates.

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[21] The calculation of monthly variances can be found in QRAM evidence in Exhibit C, Tab 1, Schedule 2, pp.3- 4.

Derivation of Load Balancing Costs Variance for 2024 - EGD Rate Zone

Line No.	Particulars	2024 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 ($000s)
		(a)	(b)	(c)	(d) = (c)-(b)	(e) = (d)*(a)	(f)	(g)	(h) = (g)-(f)	(i) = (h)*(a)	(j) = (i)-(e)	(k)	(l) = (j)+(k)	(m)	(n)	(o) = (n)-(m)	(p) = (l)+(o)
1	Jan	563,209.5	118.735	107.364	(11.371)	($6,404.0)	151.478	120.117	(31.361)	($17,662.8)	($11,258.8)	$177.0	($11,081.8)	$291.4	$13.6	($277.8)	($11,359.6)
2	Feb	377,038.9	125.081	110.822	(14.259)	($5,376.4)	152.483	116.221	(36.262)	($13,672.4)	($8,296.0)	($64.5)	($8,360.5)	$291.4	$13.6	($277.8)	($8,638.3)
3	Mar	0.0	112.252	84.265	(27.987)	$0.0	150.590	0.000	(150.590)	$0.0	$0.0	$8.7	$8.7	$291.2	$13.7	($277.5)	($268.8)
4	Apr	0.3	76.381	80.542	4.162	$0.0	0.000	0.000	0.000	$0.0	($0.0)	$95.6	$95.6	$0.0	$13.7	$13.7	$109.4
5	May	0.0	71.259	67.451	(3.808)	($0.0)	92.303	0.000	(92.303)	($0.0)	($0.0)	($0.5)	($0.5)	$0.0	$0.0	$0.0	($0.5)
6	Jun	0.0	72.786	61.782	(11.004)	($0.0)	95.503	0.000	(95.503)	($0.0)	($0.0)	$44.6	$44.6	$0.0	$0.0	$0.0	$44.6
7	Jul	0.5	57.602	50.163	(7.439)	($0.0)	105.456	0.000	(105.456)	($0.0)	($0.0)	($3.2)	($3.2)	$0.0	$0.0	$0.0	($3.2)
8	Aug	0.3	60.083	47.433	(12.649)	($0.0)	106.177	0.000	(106.177)	($0.0)	($0.0)	$4.7	$4.7	$0.0	$0.0	$0.0	$4.7
9	Sep	0.0	64.611	45.402	(19.209)	($0.0)	102.189	0.000	(102.189)	($0.0)	($0.0)	$32.8	$32.8	$0.0	$0.0	$0.0	$32.8
10	Oct	76,662.5	46.677	47.250	0.573	$43.9	81.796	102.794	20.998	$1,609.7	$1,565.8	$113.0	$1,678.8	$0.0	$0.0	$0.0	$1,678.8
11	Nov	58,018.3	92.939	85.887	(7.052)	($409.1)	110.818	97.705	(13.113)	($760.8)	($351.6)	($2.8)	($354.4)	$0.0	$0.0	$0.0	($354.4)
12	Dec	455,582.7	111.239	99.100	(12.139)	($5,530.4)	137.819	159.812	21.993	$10,019.8	$15,550.3	$13.1	$15,563.4	$289.5	$0.0	($289.5)	$15,273.9
		1,530,512.9				($17,676.1)				($20,466.5)	($2,790.4)	$418.6	($2,371.8)	$1,163.6	$54.6	($1,109.0)	($3,480.8)

Notes:

(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 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 is the load balancing components that are disposed of in the PGVA.
Amounts for January to March 2024 - refer to the EGD QRAM EB-2024-0326, Exhibit C, Tab 1, Schedule 2, page 2. Amounts for April to December 2024, refer to the EGD QRAM EB-2025-0078, Exhibit C, Tab 1, Schedule 2, page 2.

(9) Peaking demand costs.

(10) Peaking costs variance is the load balancing components that are disposed of in the PGVA. Refer to the EGD QRAM schedule, Exhibit C, Tab 1, Schedule 2, page 2.
Amounts for January to March 2024, refer to the EGD QRAM EB-2024-0326, Exhibit C, Tab 1, Schedule 2, page 2. Amounts for April to December 2024 - refer to the EGD QRAM EB-2025-0078, 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.

ACCOUNT NO. 179-325 OPEN BILL EXTENSION DEFERRAL ACCOUNT

1. As part of the 2024 Rebasing Phase 1 Settlement Agreement[1], parties agreed to an Open Bill Extension Deferral Account (OBEDA). This account records all the net revenues for Open Bill services over a 10-month extension period from January 1, 2024, to October 31, 2024. The net revenue amounts were determined in accordance with the OEB-approved Open Bill Access Settlement Proposal,[2] with updated fees and costs as determined in the 2013 Open Bill proceeding[3] and adjusted each year thereafter.

2. Total revenues over the 10-month extension period were $12.622 million and total costs over the same period were $9.556 million. As a result, net revenues of $3.066 million associated with Open Bill services accrued to the benefit of ratepayers and has been credited to this account along with $0.213 million in accrued interest. A detailed breakdown of the $3.066 million OBEDA balance is shown in Table 1.

Table 1
Open Bill Extension – 2024 Net Revenues

Line No.	Particulars	Amount ($000s)
1	Revenue	
2	Shared	$ 10,093.0
3	Standalone	578.1
4	Bad Debt Recovery	1,950.9
5	Total Revenues (1) (A)	$ 12,622.0
6	Deemed Costs	
7	Shared	$7,151.3
8	Standalone	452.0
9	Bad Debt Expense	1,952.3
10	Total Costs (B)	$ 9,555.6
11	Net Revenues Deferred to Ratepayers (A-B=C)	$ 3,066.4

Note:
(1) Net revenues after deferral of $9,555.6 million equals Total Revenues (A) less Net Revenues Deferred (C) which are offset by Total Costs (B) – see Exhibit B, Tab 1, Schedule 3 and Exhibit B, Tab 2, Schedule 3.

[1] EB-2022-0200, Settlement Agreement, August 17, 2023.
[2] EB-2009-0043, October 15, 2009.
[3] EB-2013-0099.

Enbridge Gas Inc.
50 Keil Drive N
Chatham, Ontario N7M 5M1
Canada

September 25, 2023

Dear Recipient,

Subject: Storage at Dawn, injections commencing April 1, 2024

Enbridge Gas Inc. operating as Enbridge Gas Distribution (Enbridge Gas) requires firm natural gas storage services with injections commencing April 1, 2024.

This storage service request is being administered by Ernst & Young LLP on behalf of Enbridge Gas Inc.

Enbridge Gas is seeking a diverse portfolio of storage services that both meet and exceed the minimum requirements below. This includes those that allow higher deliverability and access to multiple nomination windows for each gas day.

Enbridge Gas requires that these storage services meet the following specifications:

Term: Up to five (5) years commencing April 1, 2024. To encourage storage contracts term diversity, Enbridge Gas is seeking service offerings of various term lengths. The amount placed will be at Enbridge Gas' discretion.

Term	Potential to be contracted
1 - year	2 PJ's
2 - year	4 PJ's
3 - year	3 PJ's
4 – year	2 PJ's
5 - year	1 PJ's

Location: Enbridge Gas will deliver gas to Storage Provider at Union Dawn for injection, and Storage Provider will re-deliver gas to Enbridge Gas at Union Dawn for withdrawal. If any transportation capacity is included as part of the storage offering to facilitate Dawn injections and withdrawals, please provide details.

Firm Injection Requirements: Must include the months from May 1 through Sept. 30

Firm Withdrawal Schedule: Must include the months from Dec. 1 through March 31

Services that require Enbridge Gas to inject into storage during months of November and December or withdraw from storage during April will be considered non-conforming.

Responses: Should you be interested in supplying this storage service to Enbridge Gas, please complete the attached Excel form, stating the delivery points, term, MSB and service attributes with the relevant pricing, including demand, commodity charges and other items indicated.[1] Enbridge Gas also requires sample invoices.

Credit*:* Prior to deal execution, service providers must have sufficient open credit with EGI. Counterparties are welcome to contact EGI Credit to discuss their credit position.

The deadline to submit your proposal(s) is **9 a.m. Eastern Time (ET) on Oct. 16, 2023,** after which time Enbridge Gas will contact the parties which submitted proposals that have been selected[2]. Please submit your proposal(s) to the attention of Chester Mercier at the e-mail address provided below:

Chester.Mercier@EY.com

All questions and responses are to be directed to Chester.Mercier@EY.com. Do not contact Enbridge Gas directly regarding this process.

*The deadline for any **queries** is 12 p.m.(noon) Eastern Time (ET) on September 29, 2023. All queries and responses will be provided to all parties on Oct. 9, 2023.*

Additional Information: Enbridge Gas invites all potential participants to review a presentation that has been posted to its website, in the Storage and Transportation section of its website, within News and Presentations.

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

Sincerely,

Chester Mercier

Ernst & Young LLP

[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 suppliers must meet all of Enbridge's credit criteria. Enbridge, in its sole discretion and for whatever reason, may accept or reject any and all proposals. Enbridge reserves the right at any time after the deadline to conduct negotiations with one or more of the bidders to the exclusion of others, and such negotiations may include changes to the storage service described in this letter.

2023 Storage RFP - Issued on 9/25/2023; Responses on 10/16/2023 ; Bid Refreshed on 10/17/2023- 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 $3.958 million plus interest as of December 31, 2024, of $0.275 million, for a total of $4.233 million. The $3.958 million balance is the difference between the actual UDC incurred by the Union rate zones and the amount of UDC collected in rates, partially offset by a credit to ratepayers related to a refund of Panhandle Pipeline tolls that were applicable to UDC costs between 2020 and 2023.

1. UDC Recovery in Rates

2. To meet customer demands across the Union rate zones and to meet the planned storage inventory levels at October 31, approved rates for the Union rate zones in 2024 included planned unutilized pipeline capacity of 3.1 PJ in Union North East, 11.3 PJ in Union North West, and 0 PJ in Union South. The UDC volumes included in 2024 rates are based on the gas supply plan filed in Union's Dawn Reference Price proceeding[1].

3. As discussed in Enbridge Gas's 5-Year Gas Supply Plan[2], in Union North, the upstream transportation capacity (long-haul, short-haul and STS) is first sized to meet the design day requirements. The amount of transportation capacity needed to meet average annual demand requirements is less than the capacity required to meet design day requirements. Therefore, a portion of contracted capacity for the Union North rate zone is planned to be unutilized. On an actual basis 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. The Union North and Union South transportation portfolios are managed on an integrated basis and the pipeline to leave unutilized, if necessary, is determined based on the least cost

[1] EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 1.
[2] EB-2025-0065, p.44.

option. In the OEB-approved Settlement Proposal for the disposition of the 2020 UDC Variance account, Enbridge Gas agreed:

> In future deferral and variance account clearance applications related to the deferred rebasing term, Enbridge Gas agrees that it will include evidence reporting on: UDC and transportation capacity released by rate zone, and the costs and revenues transferred between rate zones.[3]

4. Table 1 provides the capacity released by rate zone and the associated UDC costs and/or revenue. The path released does not determine where the UDC costs or associated revenue for the releases will be allocated. Instead, the costs and revenue are allocated based on the portion of the UDC variance driven by each respective rate zone, as can be seen in Table 2.

Table 1
Actual Capacity Released & UDC Costs/Revenue by Rate Zone

Line No.	Particulars	Union North East	Union North West	Union South	Total	
		(a)	(b)	(c)	(d)	
1	Capacity Released (TJ) (1)	12,959	7,849	30,894	51,703	/u
2	Actual UDC Costs Incurred ($000s)	4,616	3,735	6,257	14,608	/u
3	Actual Released Capacity Revenue ($000s)	0	(3,871)	(333)	(4,203)	

Note:
(1) The title “Capacity Released (TJ)” in Line No. 1 refers to total actual UDC volumes, a portion of which are capacity volumes released to market. /u

5. Enbridge Gas collected $5.870 million in rates for UDC for the Union rate zones during 2024 and recorded an associated interest debit of $0.275 million (please see Table 2). Actual UDC costs in 2024 were $14.608 million offset by $4.203 million in released capacity value, resulting in a net cost of $10.405 million (see Table 3). UDC costs/revenue are allocated to Union North East, Union North West, and Union /u

[3] EB-2021-0149, Settlement Proposal, Exhibit N1, Tab 1, Schedule 1, October 4, 2021, p.15.

South in proportion to the actual supply and demand variances which occurred in each respective area for account balance disposition.

6. In 2024, Enbridge Gas received a subsequent incremental refund from Panhandle Pipelines regarding over-recovery of costs of service of $0.577 million, including interest, pertaining to UDC between 2020 and 2023. This amount has been credited to the appropriate rate zones that bore the cost of the Panhandle tolls as outlined in line 6 of Table 2.

7. The variance between the amounts collected in rates and the actual UDC costs, including the interest debit of $0.275 million, and the Panhandle Pipelines refund of $0.577 million, results in a net debit from ratepayers in the UDC Variance Account of $4.233 million. /u

8. The balance applicable to sales service and bundled DP customers in Union North East is a debit of $1.279 million and in Union North West, a credit of $2.79 million. There is a debit of $5.744 million applicable to sales service customers in Union South. /u

9. Table 2 provides the derivation of the UDC variance account balances by rate zone.

Table 2

UDC Variance Account by Rate Zone

Line No.	Particulars ($000s)	Union North East	Union North West	Union South	Total
		(a)	(b)	(c)	(d)
1	UDC Collected in Rates	(1,220)	(4,650)	-	(5,870)
2	Net UDC Costs Incurred (per Table 3)	2,386	2,434	5,585	10,405
3	Variance (line 1 + line 2)	1,166	(2,217)	5,585	4,535
4	Interest	206	(290)	359	275
5	(Credit)/Debit to Operations Area	1,372	(2,507)	5,944	4,810
6	Panhandle Pipelines Refund Impact, including Interest	(93)	(284)	(200)	(577)
7	Total Debit/(Credit) to Rate Zone	1,279	(2,790)	5,744	4,233

The following is a description of each item in Table 2:

1.1 UDC Collected in Rates

10. The 2024 OEB-approved rates include $6.549 million of UDC associated with 14.4 PJ of planned unutilized pipeline capacity in Union North East and Union North West and no planned unutilized pipeline capacity in Union South. The total cost of UDC in rates assumes TransCanada Pipeline final tolls effective January 1, 2024. On an actual basis in 2024, Enbridge Gas recovered $5.870 million in Union North East and Union North West and $0.0 million in Union South.

1.2 UDC Costs Incurred

11. The actual unutilized capacity in 2024 was 51.7 PJ. The level of unutilized capacity experienced in 2024 was largely due to planned unutilized capacity (and resulting UDC), warmer than normal temperatures and lower customer use.

12. The costs reflected in the UDC Variance Account are the total demand charges for unutilized pipeline capacity totaling $14.608 million, partially offset by $4.203 million generated from releasing the pipeline transportation capacity to the market.

Unutilized upstream transportation capacity is released and sold on the secondary market to minimize UDC. The value generated from the transportation releases is credited to the UDC Variance Account mitigating the overall UDC impact as shown in Table 3.

Table 3

Net UDC Costs Allocated by Rate Zone Volumes

Line No.	Particulars ($000s)	Union North East	Union North West	Union South	Total
		(a)	(b)	(c)	(d)
1	UDC Costs Incurred (1)	3,350	3,417	7,841	14,608
2	Released Capacity Revenue (1)	(964)	(983)	(2,256)	(4,203)
3	Net UDC Costs Incurred	2,386	2,434	5,585	10,405

Note:

(1) Actual UDC Cost/Revenue from Table 1 allocated to Union North East, Union North West, and Union South in proportion to the actual supply and demand variances which occurred in each respective area.

1.3 Panhandle Pipelines Refund Impact, net of interest

13. As outlined above, Enbridge Gas received a subsequent incremental refund from Panhandle Pipelines regarding over-recovery of costs of service of which $0.577 million, including interest, pertained to UDC between 2020 and 2023. This amount has been credited to the appropriate rate zones in alignment with the historic allocation of UDC costs for each year.

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 $4.880 million, plus interest of $0.225 million, a total payable to ratepayers of $5.105 million.

5. As shown in Table 1, the balance is calculated by adding the ratepayer 90% share of the actual 2024 Short-Term Storage and Other Balancing Services revenue (line 2) plus the shareholder 10% portion of the actual 2024 Short-Term Storage and Other Balancing Services cost (line 4). 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. The details of the balance are found at Exhibit E, Tab 2, Schedule 1.

Table 1
Short-Term Storage and Other Storage Services

Line No.	Particulars ($ millions)	2024 Actual
		(a)
1	Short-term storage revenue	5.3
2	Ratepayer portion of revenue (90% of line 1)	4.8
3	Short-term storage costs	1.1
4	Ratepayer refund of costs (10% of line 3)	0.1
5	Amount approved in rates	-
6	Deferral balance (line 2 + line 4)	4.9

6. Year-over-year, actual utility storage requirements for 2024 were 1.5 PJ higher than the requirement in 2023, resulting in a decrease in the C1 Short-Term Peak Storage available for sale (from 1.9 PJ in 2023 to 0.4 PJ in 2024). This is a result of an increase in the storage requirement for utility customers. The storage requirement for the general service market was calculated using the OEB-approved aggregate excess methodology. The storage requirement for the contract market was calculated specifically for each customer using either the OEB-approved aggregate

excess methodology, the 15 times obligated Daily Contracted Quantity (DCQ) storage methodology, or the 10 times Firm Contract Demand (CD) storage methodology (for those customers who have elected the Customer Managed Service)[5]. As agreed, Enbridge Gas has included the calculation for utility storage space requirements and the deliverability by rate class[6] at Exhibit E, Tab 2, Schedule 1, Appendix A.

1. Non-Utility Storage Balances for 2024

7. In Union's 2013 Cost of Service Decision,[7] 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,[8] to monitor the inventory related to non-utility storage operations. Exhibit E, Tab 2, Schedule 2 shows the non-utility inventory balances for October and November of 2024 (for Union storage).

8. During the 2024 injection season, the non-utility storage balance peaked on October 13, 2024, at 97.2% full, with a balance of 126.4 PJ compared to available space of 130.0 PJ. On October 31, 2024, the date to which the Company manages its storage balance, the non-utility balance was 96.2% of available space. The balance stayed below the total non-utility available space of 100% for the rest of 2024.

2. Sale of Non-Utility Storage Space

9. Enbridge Gas prioritizes the sale of utility storage ahead of the sale of its short-term non-utility storage and allocates short-term peak storage margins between utility and non-utility as directed by the OEB in Union's 2013 Cost of Service Decision[9] Margins from short-term peak storage services are proportionately split between the utility and non-utility customers based on the utility and non-utility share of the total quantity of

[5] EB-2016-0245, OEB Decision and Rate Order, Schedule 1, Settlement Proposal, p.7.
[6] EB-2021-0149, OEB Decision on Settlement Proposal, Schedule 1, Settlement Proposal, p.16.
[7] EB-2011-0210, OEB Decision and Order, October 24, 2012.
[8] EB-2011-0038.
[9] EB-2011-0210, OEB Decision and Order, October 24, 2012, pp.116-117.

short-term peak storage sold each calendar year. Short-term peak sales include any sale of storage space for a term of less than two storage years.

10. In 2024, Enbridge Gas sold a total of 1.6 PJ of short-term peak storage[10]. Of this total, 0.4 PJ was excess utility space, calculated by deducting 99.6 PJ of in-franchise utility requirement (as per the Gas Supply Plan) from the total 100 PJ of in-franchise utility storage. Therefore, excess short term peak sales of 1.2 PJ was sold as non-utility space. Total revenue from the sale of C1 Short-Term Peak Storage for the utility in 2024 was $0.9 million. Details of the above sales are reflected in Exhibit E, Tab 2, Schedule 3.

[10] Total short-term peak storage sales of 3.2 PJ was derived from the sum of 1.36 PJ of non-utility short term peak storage and 1.86 PJ of utility short term peak storage.

Breakdown of Short-term Storage Deferral Account

Line No.	Particulars ($ millions)	Actual 2024 (a)
	Revenue	
1	Peak Storage	0.9
2	Off-Peak Storage	2.4
3	Loans	(0.0)
4	Short-term Balancing	2.0
5	Total Revenue	5.3
6	Ratepayer portion of revenue (90%)	4.8
	Costs	
7	O&M (1)	0.1
8	UFG (2)	0.6
9	Compressor Fuel (3)	0.4
10	Total Costs	1.1
11	Ratepayer refund of costs (10%)	0.1
12	Deferral Balance Payable to Ratepayers	4.9

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.

ENBRIDGE GAS INC.
2024 Storage Space & Deliverability

Line No.	Particulars	2024 (1) Storage Space (2) (PJ)	Storage Deliverability (2) (GJ/d)
		(a)	(b)
	Union North Rate Zone		
1	Rate 01	12.7	209,536
2	Rate 10	3.0	60,239
3	Rate 20	2.4	34,858
4	Rate 25	-	-
5	Rate 100	0.1	1,126
6	Total Union North Rate Zone	18.2	305,758
	Union South Rate Zone		
7	Rate M1	41.8	956,568
8	Rate M2	11.0	307,117
9	Rate M4	3.0	168,159
10	Rate M5	0.0	281
11	Rate M7	2.2	64,875
12	Rate M9	0.3	9,121
13	Rate T1	1.3	39,528
14	Rate T2	8.8	193,978
15	Rate T3	3.3	68,472
16	Total Union South Rate Zone	71.8	1,808,097
	Ex-Franchise		
17	Excess Utility Storage	0.4 (3)	5,312
18	Rate C1	-	-
19	Rate M12	-	-
20	Rate M13	-	-
21	Rate M16	-	-
22	Total Ex-Franchise	0.4	5,312
23	System Integrity Space	9.5	-
24	Total Union Rate Zone	100.0	2,119,167
	EGD Rate Zone		
25	Rate 1	61.2	1,204,130
26	Rate 6	58.7	959,515
27	Rate 9	-	-
28	Rate 100	-	-
29	Rate 110	2.2	5,059
30	Rate 115	0.5	2,006
31	Rate 125	-	-
32	Rate 135	-	-
33	Rate 145	0.3	-
34	Rate 170	0.8	-
35	Rate 200	2.0	20,287
36	Total EGD Rate Zone	125.7	2,190,998
37	Total Enbridge Gas (line 24 + line 36)	225.7	4,310,165

Notes:
(1) Allocation to rate classes using OEB-approved cost allocation methodologies.
(2) Union Rate Zone storage space based on actual W24/25 usage and storage deliverability based on forecast W24/25 requirements. EGD Rate Zone storage space and deliverability based on 2024 Gas Supply plan.
(3) Exhibit E, Tab 1, Schedule 2, p.4.

Enbridge Gas Inc.
Summary of Non-Utility Storage Balances

Date	Entitlement (PJ)	Balance (PJ)	% Full (%)	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
1-Oct-24	130.0	123.8	95.3%	1-Nov-24	130.0	125.2	96.3%
2-Oct-24	130.0	124.2	95.5%	2-Nov-24	130.0	125.4	96.5%
3-Oct-24	130.0	124.4	95.7%	3-Nov-24	130.0	125.7	96.7%
4-Oct-24	130.0	124.6	95.9%	4-Nov-24	130.0	125.9	96.8%
5-Oct-24	130.0	125.3	96.4%	5-Nov-24	130.0	126.0	96.9%
6-Oct-24	130.0	126.0	96.9%	6-Nov-24	130.0	125.8	96.7%
7-Oct-24	130.0	126.1	97.0%	7-Nov-24	130.0	125.7	96.7%
8-Oct-24	130.0	126.0	96.9%	8-Nov-24	130.0	125.7	96.7%
9-Oct-24	130.0	125.9	96.8%	9-Nov-24	130.0	125.6	96.6%
10-Oct-24	130.0	125.5	96.5%	10-Nov-24	130.0	125.7	96.7%
11-Oct-24	130.0	125.9	96.8%	11-Nov-24	130.0	125.7	96.7%
12-Oct-24	130.0	126.2	97.1%	12-Nov-24	130.0	125.4	96.5%
13-Oct-24	130.0	126.4	97.2%	13-Nov-24	130.0	125.0	96.2%
14-Oct-24	130.0	126.2	97.1%	14-Nov-24	130.0	124.7	95.9%
15-Oct-24	130.0	125.9	96.8%	15-Nov-24	130.0	124.7	96.0%
16-Oct-24	130.0	125.4	96.5%	16-Nov-24	130.0	125.0	96.2%
17-Oct-24	130.0	125.2	96.3%	17-Nov-24	130.0	125.2	96.3%
18-Oct-24	130.0	125.0	96.2%	18-Nov-24	130.0	125.2	96.3%
19-Oct-24	130.0	125.4	96.5%	19-Nov-24	130.0	125.3	96.4%
20-Oct-24	130.0	125.9	96.9%	20-Nov-24	130.0	125.4	96.5%
21-Oct-24	130.0	126.1	97.0%	21-Nov-24	130.0	125.3	96.4%
22-Oct-24	130.0	126.0	96.9%	22-Nov-24	130.0	125.3	96.4%
23-Oct-24	130.0	125.7	96.7%	23-Nov-24	130.0	125.5	96.6%
24-Oct-24	130.0	125.1	96.2%	24-Nov-24	130.0	125.7	96.7%
25-Oct-24	130.0	124.8	96.0%	25-Nov-24	130.0	125.9	96.8%
26-Oct-24	130.0	125.0	96.1%	26-Nov-24	130.0	126.0	96.9%
27-Oct-24	130.0	124.8	96.0%	27-Nov-24	130.0	126.0	96.9%
28-Oct-24	130.0	124.6	95.8%	28-Nov-24	130.0	126.0	97.0%
29-Oct-24	130.0	124.6	95.9%	29-Nov-24	130.0	126.0	96.9%
30-Oct-24	130.0	124.9	96.1%	30-Nov-24	130.0	125.8	96.8%
31-Oct-24	130.0	125.1	96.2%				

2024 Allocation of Short-Term Peak Storage Revenues Between Utility and Non-Utility

Line No.	Particulars	Utility Storage Space (PJ)	Space Sold (PJ)	Revenue ($ millions)
		(a)	(b)	(c)
1	Short-Term Peak Storage		1.6	3.3
2	Utility Storage Space	100.0		
3	Utility Space Requirement	99.6		
4	Excess Utility Storage Space	0.4		
5	Utility Short-Term Peak Storage Sales		0.4	0.9
6	Non-Utility Short-Term Peak Storage Sales		1.2	2.4

ALLOCATION AND DISPOSITION OF 2024 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The purpose of this evidence is to address the allocation and disposition of 2024 deferral and variance account balances identified at Exhibit C, Tab 1, Schedule 1.

2. Enbridge Gas proposes to dispose of the 2024 deferral and variance account balances with the first QRAM application following the OEB's approval, as early as July 1, 2026.

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

[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.

and Union rate zones will continue until harmonized rates are considered and determined in Phase 3 of the 2024 Rebasing Application[4].

5. Enbridge Gas has also included the Federal Carbon Pricing Program (FCPP) deferral and variance account balances as part of this Application. As of April 1, 2025, the Federal Carbon Charge is set to zero and Enbridge Gas will no longer file a separate application for the approval of rate changes and deferral account dispositions related to the FCPP.

1.1. EGI Accounts

6. The Enbridge Gas deferral and variance accounts consist of both new accounts and the harmonization of previously approved standalone accounts for the EGD and Union rate zones. As part of Phase 3 of the 2024 Rebasing Application, the Company has proposed a Rate Harmonization Plan, including a harmonized cost allocation study with implementation in 2027, pending OEB approval. Enbridge Gas will review and update the allocation of all deferral and variance accounts following the implementation of the OEB's Phase 3 decision, as early as 2027. 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. Exhibit F, Tab 1, Schedule 3 provides a summary of the split of account balances to the EGD and Union rate zones.

[4] EB-2025-0064.

7. Enbridge Gas is not requesting to dispose of the 2024 balances in the Panhandle Regional Expansion Project Variance Account, Site Restoration Costs Tracking Account, or IRP System Pruning Deferral Account as part of this Application. There is no balance in the Unauthorized Overrun Non-Compliance Deferral Account, Earnings Sharing Deferral Account, Tax Variance Account, Expansion of Natural Gas Distribution Systems Deferral Account, IRP Capital Costs Deferral Account, Green Button Initiative Deferral Account, Cloud Computing Implementation Costs Deferral Account, Disposition of Property Deferral Account, LEAP Emergency Financial Assistance Deferral Account, Incremental Capital Module Deferral Account and Asset Life Extension Costs Deferral Account as shown at Exhibit C, Tab 1, Schedule 1.

8. The 2024 UFG Price Variance Account balance, including interest, is a credit of $7.304 million, consisting of a credit of $6.247 million for the EGD rate zone and a credit of $1.058 million for the Union rate zones. While there is no proposed change to the previously approved allocation methodology for the Union rate zones, Enbridge Gas proposes to allocate the EGD rate zone credit in proportion to total delivery volumes, consistent with previous OEB-approved methodology for the allocation of the EGD Unaccounted for Gas Variance Account prior to harmonization of the deferral account.

9. The 2024 Pension and OPEB Variance Account balance is a credit of $6.563 million, which consists entirely of interest. Enbridge Gas proposes to split the balance between the EGD and Union rate zones in proportion to actual 2018 OEB-approved rate base[5]. Further, Enbridge Gas proposes to allocate the respective balances to rate classes in proportion to rate base from the last OEB-approved cost allocation

[5] 2018 actual rate base per EB-2019-0105, Exhibit B, Tab 2, Appendix B, Schedule 1 for the EGD rate zone and EB-2019-0105, Exhibit C, Tab 2, Appendix A, Schedule 4 for the Union rate zones.

study for each rate zone[6]. The proposed allocation factor is appropriate as the allocation factors for pension and benefit costs underpinning current approved rates are not common for the EGD and Union rate zones. The use of rate base to allocate the deferral balance is a comprehensive representation of how the costs of providing gas service are allocated and recovered from each customer class. Splitting the credit balance results in a credit of $3.464 million being allocated to the EGD rate zone and a credit of $3.098 million being allocated to the Union rate zones.

10. The 2024 IRP Operating Cost Deferral Account balance, including interest, is a debit of $0.461 million. Included in the balance is a $0.290 million[7] debit, including interest, for IRP project costs related to an IRP Plan that was implemented to defer a pipeline reinforcement project in the Kingston, Ontario area[8]. Consistent with the methodology approved in previous years, Enbridge Gas has directly assigned $0.290 million to the Union North rate zone. The remaining debit balance of $0.170 million, which includes costs to support the filing of the IRP Pilot Project Application, is allocated between the EGD and Union rate zones in proportion to the 2018 actual rate base for each rate zone, consistent with the IRP Pilot Project Decision[9]. Splitting the $0.170 million debit balance in proportion to 2018 actual rate base results in a debit of $0.090 million being allocated to the EGD rate zone and a debit of $0.080 million being allocated to the Union rate zones. The total debit balance to be allocated to the Union rate zones is $0.371 million[10].

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[6] EB-2017-0086, Exhibit G2, Tab 5, Schedule 1, line 8, columns (2-14) for the EGD rate zone and EB-2011-0210, Exhibit G3, Tab 2, Schedule 2, updated for the Union rate zones.
[7] $0.271 million of IRP project costs plus $0.019 million of interest.
[8] The balance of the IRP Operating Costs Deferral Account, including a description of the IRP project costs is described at Exhibit C, Tab 2, Schedule 11.
[9] EB-2022-0335 Decision and Order, March 27, 2025.
[10] $0.290 million direct assignment for IRP project costs plus $0.081 allocation of remaining balance.

11. The 2024 Dawn Parkway Surplus Capacity Deferral Account (DPSCDA) balance, including interest, is a credit of $0.924 million. Enbridge Gas proposes to allocate the credit balance of $0.924 million in proportion to the 2013 distance-weighted Dawn Parkway design day demands for the Union rate zones. The proposed allocation methodology is consistent with the recovery of Dawn Parkway system capacity related costs in current approved Union rate zones rates.

12. The 2024 Distribution Integrity Management Program Deferral Account balance, including interest, is a credit of $0.021 million. Enbridge Gas proposes to allocate the credit balance of $0.021 million in proportion to total O&M expense, excluding Cost of Gas, based on the last OEB-approved cost studies for the EGD and Union rate zones.[11] The proposed allocation factor is consistent with how O&M expenses are allocated in current approved rates. Splitting the credit balance results in a credit of $0.012 million being allocated to the EGD rate zone and a credit of $0.009 million being allocated to the Union rate zones.

13. The 2024 Post Retirement True-Up Variance Account balance, including interest, is a credit of $1.445 million. Similar to the Pension and OPEB Variance Account balance, Enbridge Gas proposes to split the credit balance of $1.445 million in proportion to the 2018 actual OEB-approved rate base for each rate zone[12] 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[13]. Splitting the

[11] EGD Rate Zone as per EB-2017-0086, Exhibit G2, Tab 5, Schedule 3, p. 1, updated. Union Rate Zone as per EB-2011-0210, Exhibit G3, Tab 5, Schedule 1, pp. 22-24, updated.
[12] 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.
[13] 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.

credit balance results in a credit of $0.763 million being allocated to the EGD rate zone and a credit of $0.682 million being allocated to the Union rate zones.

14. The 2024 Clean Fuel Regulation Credits Deferral Account balance, including interest, is a credit balance of $0.058 million. Enbridge Gas proposes to allocate the credit balance of $0.058 million in proportion to total O&M expense, excluding Cost of Gas, based on the last OEB-approved cost studies for the EGD and Union rate zones[14]. The proposed allocation factor is consistent with how O&M expenses are allocated in current approved rates. Splitting the credit balance results in a credit of $0.032 million being allocated to the EGD rate zone and a credit of $0.026 million being allocated to the Union rate zones.

15. The 2024 Indigenous Working Group Deferral Account balance, including interest, is a debit balance of $0.126 million. Enbridge Gas proposes to allocate the debit balance of $0.126 million in proportion to total O&M expense, excluding Cost of Gas, based on the last OEB-approved cost studies for the EGD and Union rate zones[15]. The proposed allocation factor is consistent with how O&M expenses are allocated in current approved rates. Splitting the debit balance results in a debit of $0.070 million being allocated to the EGD rate zone and a debit of $0.057 million being allocated to the Union rate zones.

16. The 2024 Enbridge Sustain Affiliate Recoveries Deferral Account balance, including interest, is a credit balance of $0.095 million. Enbridge Gas proposes to allocate the credit balance of $0.095 million in proportion to total O&M expense, excluding Cost of Gas, based on the last OEB-approved cost studies for the EGD and Union rate

[14] EGD Rate Zone as per EB-2017-0086, Exhibit G2, Tab 5, Schedule 3, p. 1, updated. Union Rate Zone as per EB-2011-0210, Exhibit G3, Tab 5, Schedule 1, pp. 22-24, updated.
[15] Ibid.

zones[16]. The proposed allocation factor is consistent with how O&M expenses are allocated in current approved rates. Splitting the credit balance results in a credit of $0.052 million being allocated to the EGD rate zone and a credit of $0.043 million being allocated to the Union rate zones.

1.2 EGD Rate Zone Accounts

17. The 2024 deferral and variance account balances to be cleared to the EGD rate zone are provided at Exhibit F, Tab 1, Schedule 3.

18. The 2024 Open Bill Extension Deferral Account balance, including interest, is a credit of $3.279 million. Enbridge Gas proposes to allocate the credit balance of $3.279 million to rate classes in proportion to the 2024 actual number of EGD rate zone customers, consistent with the previous OEB-approved methodology for the Open Bill deferral and variance account[17].

19. The remaining 2024 deferral and variance account balance specific to the EGD rate zone is the Storage and Transportation Deferral Account, which is allocated to rate classes using the same methodology as approved by the OEB in previous years.

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

1.3 Union Rate Zones' Accounts

21. The 2024 deferral and variance account balances to be cleared to the Union rate zones are provided at Exhibit F, Tab 1, Schedule 3.

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[16] EGD Rate Zone as per EB-2017-0086, Exhibit G2, Tab 5, Schedule 3, p. 1, updated. Union Rate Zone as per EB-2011-0210, Exhibit G3, Tab 5, Schedule 1, pp. 22-24, updated.
[17] EB-2009-0043, Exhibit N1, Tab 1, Schedule 1, p.13.

22. The 2024 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.

23. 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

24. Enbridge Gas proposes to dispose of the 2024 deferral and variance account balances with the first QRAM application following the OEB's approval, as early as July 1, 2026.

25. Enbridge Gas proposes to dispose of the 2024 deferral and variance account balances as a one-time billing adjustment, except for Rate M1 customers in Union South as noted below. 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, 2024, to December 31, 2024.

26. For Rate M1 general service customers in the Union South rate zone, Enbridge Gas proposes to dispose of the 2024 deferral and variance account balances as a billing adjustment spread evenly over three months in order to smooth bill impacts in a given month for Union South rate zone customers.

27. 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

28. 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 $13.38.

29. 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 $16.56. For a Rate M1 bundled direct purchase (DP) residential customer, the one-time billing adjustment charge is $8.69.

30. 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 $17.78.

31. 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 $10.21.

32. 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 (a)	Allocator to Rate Zone (b)	Allocator to Rate Class (c)
	EGI Commodity Related Accounts				
1	Upstream Transportation Optimization V/A	179-201	EB-2022-0200	Direct assigned in proportion to 2024 actual optimization activity	llocation of actual optimization activit 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 2024 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 2024 activity based on actual UFG gas supply purchases in 2024.
	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 2024 balance for disposition	No 2024 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	Tax V/A	179-312	EB-2022-0200	No 2024 balance for disposition	No 2024 balance for disposition
13	Expansion of Natural Gas Distribution Systems V/A	179-317	O. Reg. 24/19 s.4	No 2024 balance for disposition	No 2024 balance for disposition
14	IRP Operating Costs D/A	179-318	EB-2020-0091	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.
15	IRP Capital Costs D/A	179-319	EB-2020-0091	No 2024 balance for disposition	No 2024 balance for disposition
16	Green Button Initiative D/A	179-320	EB-2020-0183	No 2024 balance for disposition	No 2024 balance for disposition
17	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
18	Distribution Integrity Management Program D/A	179-326	EB-2022-0200		Total O&M expense excluding cost of gas
19	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.
20	Clean Fuel Regulation Credits D/A	179-330	EB-2022-0200		Total O&M expense excluding cost of gas
21	Indigenous Working Group D/A	179-331	EB-2022-0200		Total O&M expense excluding cost of gas
22	Cloud Computing Implementation Costs D/A	179-332	Accounting Order (003-2023)	No 2024 balance for disposition	No 2024 balance for disposition
23	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.
24	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.
25	Disposition of Property D/A	179-336	EB-2022-0200	No 2024 balance for disposition	No 2024 balance for disposition

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)
26	LEAP Emergency Financial Assistance D/A	179-338	EB-2023-0135	No 2024 balance for disposition	No 2024 balance for disposition
27	Earnings Sharing D/A	179-339	EB-2022-0200	No 2024 balance for disposition	No 2024 balance for disposition
28	Enbridge Sustain Affiliate Recoveries V/A	179-344	EB-2024-0111		Total O&M expense excluding cost of gas
	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	Direct assigned to the EGD rate zone	Actual number of customers
	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	Panhandle Region Expansion Project V/A	179-329	EB-2022-0200		
35	Site Restoration Costs Tracking Account	179-337	EB-2022-0200		
36	IRP System Pruning D/A	179-341	EB-2024-0111		
37	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 ($000s)	Union ($000s)	Total (1) ($000s)
			(a)	(b)	(c) = (a+b)
	EGI Commodity Related Accounts				
1	Upstream Transporation Optimization V/A	179-201	(38,588.9)	2,651.2	(35,937.7)
2	UFG Volume V/A	179-203	386.3	6,255.3	6,641.6
3	UFG Price V/A	179-204	(6,246.5)	(1,057.9)	(7,304.4)
4	Total Commodity Related Accounts		(44,449.1)	7,848.6	(36,600.6)
	EGI Non Commodity Related Accounts				
5	Transportation from Dawn Service D/A	179-202	-	78.3	78.3
6	Deferral Clearing V/A	179-302	(5,039.2)	(6,185.5)	(11,224.8)
7	Parkway Delivery Obligation V/A	179-303	-	3,477.4	3,477.4
8	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-
9	Pension & OPEB V/A	179-305	(3,464.2)	(3,098.3)	(6,562.5)
10	Facility Carbon Charge V/A	179-307	(1,300.0)	(2,401.3)	(3,701.3)
11	Customer Carbon Charge V/A	179-308	(8,055.1)	(4,717.3)	(12,772.4)
12	Carbon Charges Bad Debt D/A	179-309	5,118.3	7,386.4	12,504.7
13	Tax V/A	179-312	-	-	-
14	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-
15	IRP Operating Costs D/A	179-318	89.9	370.7	460.6
16	IRP Capital Costs D/A	179-319	-	-	-
17	Green Button Initiative D/A	179-320	-	-	-
18	Dawn Parkway Surplus Capacity D/A	179-323	-	(923.7)	(923.7)
19	Distribution Integrity Management Program D/A	179-326	(11.6)	(9.4)	(21.0)
20	Post Retirement True-Up V/A	179-328	(762.7)	(682.1)	(1,444.9)
21	Clean Fuel Regulation Credits D/A	179-330	(32.1)	(26.1)	(58.2)
22	Indigenous Working Group D/A	179-331	69.6	56.7	126.3
23	Cloud Computing Implementation Costs D/A	179-332	-	-	-
24	Average Use V/A	179-333	(4,022.1)	20,865.6	16,843.5
25	Getting Ontario Connected V/A	179-335	9,753.1	6,021.0	15,774.1
26	Disposition of Property D/A	179-336	-	-	-
27	LEAP Emergency Financial Assistance D/A	179-338	-	-	-
28	Earnings Sharing D/A	179-339	-	-	-
29	Enbridge Sustain Affiliate Recoveries V/A	179-344	(52.4)	(42.7)	(95.2)
30	Total Non Commodity Related Accounts		(7,708.6)	20,169.5	12,460.9
31	Total EGI Accounts (for clearance)		(52,157.8)	28,018.1	(24,139.7)
	EGD Rate Zone Commodity Related Accounts				
32	Storage and Transportation D/A	179-88	6,895.1	-	6,895.1
33	Total Commodity Related Accounts		6,895.1	-	6,895.1
34	EGD Rate Zone Non Commodity Related Accounts				
35	Open Bill Extension D/A	179-325	(3,279.1)	-	(3,279.1)
36	Total Non Commodity Related Accounts		(3,279.1)	-	(3,279.1)
37	Total EGD Rate Zone (for clearance)		3,616.0	-	3,616.0
38	Union Rate Zones Gas Supply Accounts				
39	Unabsorbed Demand Costs Variance Account	179-108	-	4,232.9	4,232.9
40	Total Gas Supply Accounts		-	4,232.9	4,232.9
41	Union Rate Zones Storage Accounts				
42	Short-Term Storage and Other Balancing Services	179-70		(5,105.3)	(5,105.3)
43	Total Storage Accounts		-	(5,105.3)	(5,105.3)
44	Total Union Rate Zones (for clearance)		-	(872.4)	(872.4)
45	Total Deferral and Variance Accounts (for clearance)		(48,541.8)	27,145.7	(21,396.1)

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

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

		Unit Rates Including Federal Carbon					Unit Rates Excluding Federal Carbon				
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)	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)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Bundled Services:										
1	Rate 1	(0.6425)	(0.1309)	(0.1309)	(0.6425)		(0.5575)	(0.0459)	(0.0459)	(0.5575)	
2	Rate 6	(0.5288)	(0.0172)	(0.0172)	(0.5288)		(0.4438)	0.0678	0.0678	(0.4438)	
3	Rate 100	(0.6523)	(0.1407)	(0.1407)	(0.6523)		(0.5673)	(0.0557)	(0.0557)	(0.5673)	
4	Rate 110	(0.6838)	(0.1722)	(0.1722)	(0.6838)		(0.5989)	(0.0873)	(0.0873)	(0.5989)	
5	Rate 115	(0.1683)	(0.1683)	(0.1683)	(0.1683)		(0.0833)	(0.0833)	(0.0833)	(0.0833)	
6	Rate 135	(0.7022)	(0.1905)	(0.1905)	(0.7022)		(0.6172)	(0.1056)	(0.1056)	(0.6172)	
7	Rate 145	(0.7027)	(0.1911)	(0.1911)	(0.7027)		(0.6178)	(0.1062)	(0.1062)	(0.6178)	
8	Rate 170	(0.1781)	(0.1781)	(0.1781)	(0.1781)		(0.0931)	(0.0931)	(0.0931)	(0.0931)	
9	Rate 200	(0.5617)	(0.0501)	(0.0501)	(0.5617)		(0.5617)	(0.0501)	(0.0501)	(0.5617)	
	Unbundled Services:										
10	Rate 125					(0.0060)					(0.0060)
11	Rate 300					-					-
12	Rate 332					(0.9495)					(0.9495)

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

Line No.	Particulars ($000s)	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	(22,932)	(14,255)	(64)	(709)	-	-	(12)	(3)	-	(613)	-	-	(38,589)
2	Total Gas Supply Related Deferrals		(22,932)	(14,255)	(64)	(709)	-	-	(12)	(3)	-	(613)	-	-	(38,589)
3	Storage and Transportation D/A	179-88	3,621	3,045	33	83	15	-	-	(5)	23	80	-	-	6,895
4	Total Storage Related Deferrals		3,621	3,045	33	83	15	-	-	(5)	23	80	-	-	6,895
5	Transportation from Dawn Service D/A	179-202	-	-	-	-	-	-	-	-	-	-	-	-	-
6	UFG Volume V/A	179-203	159	150	2	45	12	-	2	2	8	6	-	-	386
7	UFG Price V/A	179-204	(2,565)	(2,428)	(25)	(723)	(193)	-	(39)	(34)	(137)	(103)	-	-	(6,247)
8	Deferral Clearing V/A	179-302	(1,839)	(1,741)	(18)	(518)	(139)	(559)	(28)	(25)	(98)	(74)	-	-	(5,039)
9	Parkway Delivery Obligation V/A	179-303	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Pension & OPEB V/A	179-305	(2,272)	(960)	(11)	(42)	(15)	(33)	(2)	(3)	(5)	(9)	-	(112)	(3,464)
12	Facility Carbon Charge Variance Account	179-307	(416)	(393)	(4)	(117)	(31)	(126)	(6)	(6)	(22)	(17)	-	(162)	(1,300)
13	Carbon Charges Bad Debt Deferral Account	179-309	4,741	376	0	1	0	0	0	0	0	0	-	0	5,118
14	Tax V/A	179-312	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-	-	-	-	-	-	-	-	-	-	-
16	IRP Operating Costs Deferral Account	179-318	59	25	0	1	0	1	0	0	0	0	-	3	90
17	IRP Capital Costs Deferral Account	179-319	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Green Button Initiative D/A	179-320	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Dawn Parkway Surplus Capacity D/A	179-323	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Open Bill Extension D/A	179-325	(3,037)	(241)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	-	(0)	(3,279)
21	Distribution Integrity Management Program D/A	179-326	(8)	(3)	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	(0)	(12)
22	Post Retirement True-Up V/A	179-328	(500)	(211)	(2)	(9)	(3)	(7)	(0)	(1)	(1)	(2)	-	(25)	(763)
23	Clean Fuel Regulation Credits D/A	179-330	(22)	(9)	-	(1)	(0)	(0)	(0)	(0)	(0)	(0)	-	(0)	(32)
24	Indigenous Working Group D/A	179-331	47	19	-	1	1	1	0	0	1	0	-	0	70
25	Cloud Computing Implementation Costs D/A	179-332	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Average Use Variance Account	179-333	(6,122)	2,100	-	-	-	-	-	-	-	-	-	-	(4,022)
27	Getting Ontario Connected V/A	179-335	6,109	3,193	-	166	71	174	0	7	7	27	-	-	9,753
28	Disposition of Property D/A	179-336	-	-	-	-	-	-	-	-	-	-	-	-	-
29	LEAP Emergency Financial Assistance D/A	179-338	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Enbridge Sustain Affiliate Recoveries V/A	179-344	(35)	(14)	-	(1)	(0)	(1)	(0)	(0)	(0)	(0)	-	(0)	(52)
31	Total Delivery Related Deferrals (Lines 5 through 30)		(5,702)	(137)	(58)	(1,198)	(299)	(552)	(73)	(60)	(247)	(171)	-	(296)	(8,793)
32	Total Storage and Delivery Disposition (line 4 + line 31)		(2,081)	2,908	(24)	(1,115)	(284)	(552)	(73)	(64)	(225)	(91)	-	(296)	(1,898)
33	Customer Carbon Charge Variance Account	179-308	(3,781)	(3,547)	(27)	(607)	(2)	-	(51)	(7)	(33)	-	-	-	(8,055)
34	Earnings Sharing D/A	179-339	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Grand Total (line 2 + line 32 + line 33 + line 34)		(28,793)	(14,894)	(115)	(2,432)	(287)	(552)	(137)	(74)	(258)	(705)	-	(296)	(48,542)

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

Line No.	Particulars	2024 Deferral Balances ($000s)	2024 Earnings Sharing Mechanism ($000s)	Deferral Balance for Disposition ($000s)	2024 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	(2,081)	-	(2,081)	4,532,530	(0.0459)
2	Rate 6	2,908	-	2,908	4,291,025	0.0678
3	Rate 100	(24)	-	(24)	43,443	(0.0557)
4	Rate 110	(1,115)	-	(1,115)	1,277,667	(0.0873)
5	Rate 115	(284)	-	(284)	341,507	(0.0833)
6	Rate 135	(73)	-	(73)	69,489	(0.1056)
7	Rate 145	(64)	-	(64)	60,470	(0.1062)
8	Rate 170	(225)	-	(225)	241,282	(0.0931)
9	Rate 200	(91)	-	(91)	182,543	(0.0501)
	Unbundled Services:					
10	Rate 125	(552)	-	(552)	9,260,357	(0.0060)
11	Rate 300	-	-	-	-	-
12	Rate 332	(296)	-	(296)	31,145	(0.9495)

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

Line No.	Particulars	2024 Deferral Balances ($000s)	2024 Earnings Sharing Mechanism ($000s)	Deferral Balance for Disposition ($000s)	2024 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	(22,932)	-	(22,932)	4,482,274	(0.5116)
2	Rate 6	(14,255)	-	(14,255)	2,786,367	(0.5116)
3	Rate 100	(64)	-	(64)	12,559	(0.5116)
4	Rate 110	(709)	-	(709)	138,671	(0.5116)
5	Rate 115	-	-	-	-	-
6	Rate 135	(12)	-	(12)	2,442	(0.5116)
7	Rate 145	(3)	-	(3)	513	(0.5116)
8	Rate 170	-	-	-	-	-
9	Rate 200	(613)	-	(613)	119,874	(0.5116)

Enbridge Gas Inc.
EGD Rate Zone
Unit Rates for One-Time Adjustment - Customer-Related Federal Carbon

Line No.	Particulars	2024 Deferral Balances ($000s)	2024 Earnings Sharing Mechanism ($000s)	Deferral Balance for Disposition ($000s)	2024 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	(3,781)	-	(3,781)	4,449,604	(0.0850)
2	Rate 6	(3,547)	-	(3,547)	4,174,803	(0.0850)
3	Rate 100	(27)	-	(27)	31,216	(0.0850)
4	Rate 110	(607)	-	(607)	714,845	(0.0850)
5	Rate 115	(2)	-	(2)	2,917	(0.0850)
6	Rate 135	(51)	-	(51)	59,746	(0.0850)
7	Rate 145	(7)	-	(7)	8,339	(0.0850)
8	Rate 170	(33)	-	(33)	39,133	(0.0850)
9	Rate 200	-	-	-	-	-
	Unbundled Services:					
10	Rate 125	-	-	-	-	-
11	Rate 300	-	-	-	-	-
12	Rate 332	-	-	-	-	-

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 Including Federal Carbon ($)	Bill Impact Excluding Federal Carbon ($)
		(a)	(b)	(c)	(d)
	Rate 1 - Small Customer				
1	Delivery	(0.0459)	2,400	(1.10)	(1.10)
2	Federal Carbon	(0.0850)	2,400	(2.04)	
3	Sales & WBT	(0.5116)	2,400	(12.28)	(12.28)
4	Sales Service Impact			(15.42)	(13.38)
5	Bundled Direct Purchase Impact - OTS			(3.14)	(1.10)
6	Bundled Direct Purchase Impact - DTS			(3.14)	(1.10)
7	Bundled Direct Purchase Impact - WTS			(15.42)	(13.38)
	Rate 6 - Average Customer				
8	Delivery	0.0678	22,606	15.32	15.32
9	Federal Carbon	(0.0850)	22,606	(19.21)	
10	Sales & WBT	(0.5116)	22,606	(115.65)	(115.65)
11	Sales Service Impact			(119.54)	(100.33)
12	Bundled Direct Purchase Impact - OTS			(3.89)	15.32
13	Bundled Direct Purchase Impact - DTS			(3.89)	15.32
14	Bundled Direct Purchase Impact - WTS			(119.54)	(100.33)
	Rate 6 - Large Customer				
15	Delivery	0.0678	339,124	229.83	229.83
16	Federal Carbon	(0.0850)	339,124	(288.13)	
17	Sales & WBT	(0.5116)	339,124	(1,734.98)	(1,734.98)
18	Sales Service Impact			(1,793.28)	(1,505.15)
19	Bundled Direct Purchase Impact - OTS			(58.30)	229.83
20	Bundled Direct Purchase Impact - DTS			(58.30)	229.83
21	Bundled Direct Purchase Impact - WTS			(1,793.28)	(1,505.15)
22	Rate 100 - Small Customer				
23	Delivery	(0.0557)	339,188	(189)	(189)
24	Federal Carbon	(0.0850)	339,188	(288)	
25	Sales & WBT	(0.5116)	339,188	(1,735)	(1,735)
26	Sales Service Impact			(2,212)	(1,924)
27	Bundled Direct Purchase Impact - OTS			(477)	(189)
28	Bundled Direct Purchase Impact - DTS			(477)	(189)
29	Bundled Direct Purchase Impact - WTS			(2,212)	(1,924)

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 Including Federal Carbon ($)	Bill Impact Excluding Federal Carbon ($)
		(a)	(b)	(c)	(d)
	Rate 110 - Small Customer				
30	Delivery	(0.0873)	598,568	(522)	(522)
31	Federal Carbon	(0.0850)	598,568	(509)	
32	Sales & WBT	(0.5116)	598,568	(3,062)	(3,062)
33	Sales Service Impact			(4,093)	(3,585)
34	Bundled Direct Purchase Impact - OTS			(1,031)	(522)
35	Bundled Direct Purchase Impact - DTS			(1,031)	(522)
36	Bundled Direct Purchase Impact - WTS			(4,093)	(3,585)
	Rate 110 - Large Customer				
37	Delivery	(0.0873)	9,976,121	(8,705)	(8,705)
38	Federal Carbon	(0.0850)	9,976,121	(8,476)	
39	Sales & WBT	(0.5116)	9,976,121	(51,038)	(51,038)
40	Sales Service Impact			(68,220)	(59,744)
41	Bundled Direct Purchase Impact - OTS			(17,181)	(8,705)
42	Bundled Direct Purchase Impact - DTS			(17,181)	(8,705)
43	Bundled Direct Purchase Impact - WTS			(68,220)	(59,744)
	Rate 115 - Small Customer				
44	Delivery	(0.0833)	4,471,609	(3,724)	(3,724)
45	Federal Carbon	(0.0850)	4,471,609	(3,799)	
46	Sales & WBT	-	4,471,609	-	-
47	Sales Service Impact			(7,524)	(3,724)
48	Bundled Direct Purchase Impact - OTS			(7,524)	(3,724)
49	Bundled Direct Purchase Impact - DTS			(7,524)	(3,724)
50	Bundled Direct Purchase Impact - WTS			(7,524)	(3,724)
	Rate 125 - Average Customer				
51	Delivery Demand	(0.0060)	2,315,000	(138)	(138)
52	Federal Carbon	-	206,000,000	-	
53	Unbundled Impact			(138)	(138)
	Rate 135 - Average Customer				
54	Delivery	(0.1056)	598,567	(632)	(632)
55	Federal Carbon	(0.0850)	598,567	(509)	
56	Sales & WBT	(0.5116)	598,567	(3,062)	(3,062)
57	Sales Service Impact			(4,203)	(3,694)
58	Bundled Direct Purchase Impact - OTS			(1,141)	(632)
59	Bundled Direct Purchase Impact - DTS			(1,141)	(632)
60	Bundled Direct Purchase Impact - WTS			(4,203)	(3,694)

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 Including Federal Carbon ($)	Bill Impact Excluding Federal Carbon ($)
		(a)	(b)	(c)	(d)
	Rate 145 - Large Customer				
61	Delivery	(0.1062)	598,567	(635)	(635)
62	Federal Carbon	(0.0850)	598,567	(509)	
63	Sales & WBT	(0.5116)	598,567	(3,062)	(3,062)
64	Sales Service Impact			(4,206)	(3,698)
65	Bundled Direct Purchase Impact - OTS			(1,144)	(635)
66	Bundled Direct Purchase Impact - DTS			(1,144)	(635)
67	Bundled Direct Purchase Impact - WTS			(4,206)	(3,698)
	Rate 170 - Average Customer				
68	Delivery	(0.0931)	9,976,121	(9,290)	(9,290)
69	Federal Carbon	(0.0850)	9,976,121	(8,476)	
70	Sales & WBT	-	9,976,121	-	-
71	Sales Service Impact			(17,767)	(9,290)
72	Bundled Direct Purchase Impact - OTS			(17,767)	(9,290)
73	Bundled Direct Purchase Impact - DTS			(17,767)	(9,290)
74	Bundled Direct Purchase Impact - WTS			(17,767)	(9,290)
	Rate 200 - Average Customer				
75	Delivery	(0.0501)	69,832,850		(34,963)
76	Sales & WBT	(0.5116)	69,832,850		(357,269)
77	Sales Service Impact				(392,232)
78	Bundled Direct Purchase Impact - OTS				(34,963)
79	Bundled Direct Purchase Impact - DTS				(34,963)
80	Bundled Direct Purchase Impact - WTS				(392,232)

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

Line No.	Particulars	Unit Rates Including Federal Carbon: Sales Service (cents/m³)	Unit Rates Including Federal Carbon: Bundled DP (cents/m³)	Unit Rates Including Federal Carbon: T-Service (cents/m³)	Unit Rates Excluding Federal Carbon: Sales Service (cents/m³)	Unit Rates Excluding Federal Carbon: Bundled DP (cents/m³)	Unit Rates Excluding Federal Carbon: T-Service (cents/m³)
		(a)	(b)	(c)	(d)	(e)	(f)
	Union North West						
1	Rate 01	(0.8928)	(0.8928)	(0.2540)	(0.8082)	(0.8082)	(0.1694)
2	Rate 10	0.9904	0.9904	1.4046	1.0750	1.0750	1.4892
3	Rate 20 - Commodity	(0.1248)	(0.1248)	(0.1248)	(0.0401)	(0.0401)	(0.0401)
4	Rate 20 - Demand	(1.7082)	(1.7082)	-	(1.7082)	(1.7082)	-
5	Rate 25	(0.0935)	(0.0935)	(0.1119)	(0.0089)	(0.0089)	(0.0273)
6	Rate 100	(0.0295)	(0.0295)	(0.0295)	(0.0295)	(0.0295)	(0.0295)
7	Bundled-T Storage Service ($/GJ)	-	-	(0.023)	-	-	(0.023)
	Union North East						
8	Rate 01	(0.5486)	(0.5486)	(0.2540)	(0.4640)	(0.4640)	(0.1694)
9	Rate 10	1.0880	1.0880	1.4046	1.1726	1.1726	1.4892
10	Rate 20 - Commodity	(0.1248)	(0.1248)	(0.1248)	(0.0401)	(0.0401)	(0.0401)
11	Rate 20 - Demand	(4.6100)	(4.6100)	-	(4.6100)	(4.6100)	-
12	Rate 25	(0.1178)	(0.1178)	(0.1119)	(0.0331)	(0.0331)	(0.0273)
13	Rate 100	(0.0295)	(0.0295)	(0.0295)	(0.0295)	(0.0295)	(0.0295)
14	Bundled-T Storage Service ($/GJ)	-	-	(0.023)	-	-	(0.023)
15	North T-Service Transportation from Dawn Base Service ($/GJ)	-	-	0.042	-	-	0.042
	Union South						
16	Rate M1	0.6683	0.3103		0.7530	0.3949	
17	Rate M2	1.4091	1.0145		1.4937	1.0991	
18	Rate M4	0.2741	(0.1129)		0.3587	(0.0283)	
19	Rate M5	0.6911	0.3132		0.7757	0.3978	
20	Rate M7	0.8203	(0.1284)		0.9049	(0.0438)	
21	Rate M9	0.2920	(0.0391)		0.2920	(0.0391)	
22	Rate T1			(0.0906)			(0.0060)
23	Rate T2			(0.1225)			(0.0379)
24	Rate T3			0.0030			0.0030

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

Line No.	Particulars ($000s)	Acct No.	Union North					Union South														
			Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	M1	M2	M4	M5A	M7	M9	T1	T2	T3	M12	M13	C1	M16	M17	Total
		(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	(1,249)	(200)	(62)	-	-	4,701	919	79	3	13	28	-	-	-	-	-	-	-	-	4,233
2	Upstream Transportation Optimization V/A	179-201	(2,191)	(812)	(342)	-	6	4,706	1,108	92	3	57	24	-	-	-	-	-	-	-	-	2,651
3	Transportation from Dawn Service D/A	179-202	-	-	52	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78
4	Total Gas Supply Related Deferrals		(3,440)	(1,012)	(353)	26	6	9,407	2,026	171	6	71	52	-	-	-	-	-	-	-	-	6,962
5	Short-Term Storage and Other Balancing Services	179-70	(699)	(198)	(108)	-	-	(1,590)	(601)	(269)	(3)	(150)	(28)	(115)	(1,215)	(130)	-	-	-	-	-	(5,105)
6	Total Storage Related Deferrals		(699)	(198)	(108)	-	-	(1,590)	(601)	(269)	(3)	(150)	(28)	(115)	(1,215)	(130)	-	-	-	-	-	(5,105)
7	UFG Volume V/A	179-203	75	25	12	-	5	525	218	106	10	145	18	69	832	49	2,477	5	1,646	36	4	6,255
8	UFG Price V/A	179-204	(55)	(19)	(9)	-	(3)	(390)	(162)	(79)	(7)	(108)	(13)	-	-	-	-	(4)	(207)	(2)	-	(1,058)
9	Deferral Clearing V/A	179-302	(358)	(121)	(502)	(383)	(119)	(1,135)	(471)	(229)	(21)	(313)	(39)	(164)	(2,229)	(101)	-	-	-	-	-	(6,186)
10	Parkway Delivery Obligation V/A	179-303	-	-	-	-	-	1,764	594	172	2	79	28	85	552	200	-	-	-	-	-	3,477
11	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Pension & OPEB V/A	179-305	(554)	(85)	(60)	(47)	(17)	(1,210)	(183)	(46)	(39)	(16)	(3)	(32)	(140)	(18)	(643)	(0)	(6)	(1)	-	(3,098)
13	Facility Carbon Charge Variance Account	179-307	(42)	(14)	(59)	(45)	(14)	(134)	(56)	(27)	(2)	(37)	(5)	(19)	(263)	(12)	(993)	(2)	(660)	(14)	(1)	(2,401)
14	Carbon Charges Bad Debt Deferral Account	179-309	1,487	129	111	98	45	3,746	352	131	146	37	5	95	263	29	697	0	15	1	-	7,386
15	Tax V/A	179-312	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	IRP Operating Costs Deferral Account	179-318	123	37	61	74	16	31	5	1	1	0	0	1	4	0	17	0	0	0	-	371
18	IRP Capital Costs Deferral Account	179-319	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Green Button Initiative D/A	179-320	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Dawn Parkway Surplus Capacity D/A	179-323	(35)	(9)	(2)	(0)	-	(53)	(18)	(5)	(0)	(2)	(1)	(3)	(17)	(6)	(773)	-	-	-	-	(924)
21	Distribution Integrity Management Program D/A	179-326	(2)	(0)	(0)	(0)	(0)	(5)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(9)
22	Post Retirement True-Up V/A	179-328	(122)	(19)	(13)	(10)	(4)	(266)	(40)	(10)	(9)	(3)	(1)	(7)	(31)	(4)	(142)	(0)	(1)	(0)	-	(682)
23	Clean Fuel Regulation Credits D/A	179-330	(5)	(1)	(0)	(0)	(0)	(13)	(1)	(0)	(1)	(0)	(0)	(0)	(1)	(0)	(2)	(0)	(0)	(0)	(0)	(26)
24	Indigenous Working Group D/A	179-331	11	1	1	1	0	28	3	1	1	0	0	1	2	0	5	0	0	0	0	57
25	Cloud Computing Implementation Costs D/A	179-332	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Average Use Variance Account	179-333	(1,953)	4,675	-	-	-	5,400	12,744	-	-	-	-	-	-	-	-	-	-	-	-	20,866
27	Getting Ontario Connected V/A	179-335	646	55	41	36	12	4,372	378	95	130	30	-	65	161	-						6,021
28	Disposition of Property D/A	179-336	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	LEAP Emergency Financial Assistance D/A	179-338	-	-	-	-	-	-	-	-	-	-	-	-	-	-						-
30	Enbridge Sustain Affiliate Recoveries V/A	179-344	(8)	(1)	(1)	(1)	(0)	(21)	(2)	(1)	(1)	(0)	(0)	(1)	(2)	(0)	(4)	(0)	(0)	(0)	(0)	(43)
31	Total Delivery Related Deferrals		(793)	4,652	(422)	(279)	(80)	12,639	13,359	110	210	(188)	(10)	91	(868)	137	639	(1)	788	19	2	30,006
32	Total Storage and Delivery Disposition (line 6 + line 31)		(1,492)	4,454	(529)	(279)	(80)	11,049	12,759	(159)	207	(338)	(38)	(24)	(2,083)	8	639	(1)	788	19	2	24,901
33	Customer Carbon Charge Variance Account	179-308	(738)	(235)	(85)	-	(0)	(2,318)	(869)	(272)	(34)	(100)	-	(62)	(3)	-	-	-	-	-	-	(4,717)
34	Earnings Sharing D/A	179-339	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Grand Total (line 4 + line 32 + line 33 + line 34)		(5,671)	3,208	(967)	(252)	(74)	18,137	13,916	(260)	179	(367)	15	(86)	(2,086)	8	639	(1)	788	19	2	27,146

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

Line No.	Particulars ($000s)	Acct No. (a)	Rate 01 (b)	Rate 10 (c)	Rate 20 (d)	Rate 100 (e)	Rate 25 (f)	Total (g) = (sum b:f)
	Union North West							
	Gas Supply Related Deferrals:							
1	Unabsorbed Demand Costs Variance Account	179-108	(2,240)	(448)	(102)	-	-	(2,790)
2	Upstream Transportation Optimization V/A	179-201	673	173	72	-	8	925
3	Total Gas Supply Related Deferrals		(1,567)	(276)	(30)	-	8	(1,865)
	Storage Related Deferrals:							
4	Short-Term Storage and Other Balancing Services (1)	179-70	(199)	(50)	(10)	-	-	(259)
5	Total North West Deferral Account Disposition (Line 3 + Line 4)		(1,767)	(325)	(40)	-	8	(2,124)
	Union North East							
	Gas Supply Related Deferrals:							
6	Unabsorbed Demand Costs Variance Account	179-108	991	249	40	-	-	1,279
7	Upstream Transportation Optimization V/A	179-201	(2,864)	(985)	(414)	-	(2)	(4,264)
8	Total Gas Supply Related Deferrals		(1,873)	(736)	(375)	-	(2)	(2,985)
	Storage Related Deferrals:							
9	Short-Term Storage and Other Balancing Services (1)	179-70	(500)	(148)	(65)	-	-	(713)
10	Total North East Deferral Account Disposition (Line 8 + Line 9)		(2,373)	(885)	(439)	-	(2)	(3,699)
	Total North							
	Gas Supply Related Deferrals:							
11	Unabsorbed Demand Costs Variance Account	179-108	(1,249)	(200)	(62)	-	-	(1,511)
12	Upstream Transportation Optimization V/A	179-201	(2,191)	(812)	(342)	-	6	(3,339)
13	Total North Gas Supply Related Deferrals		(3,440)	(1,012)	(405)	-	6	(4,850)
	Storage Related Deferrals:							
14	Short-Term Storage and Other Balancing Services (1)	179-70	(699)	(198)	(75)	-	-	(972)
15	Total North Deferral Account Disposition (Line 13 + Line 14)		(4,140)	(1,210)	(479)	-	6	(5,822)

Note:
(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	2024 Deferral Balances ($000s)	2024 Earnings Sharing Mechanism ($000s)	Deferral Balance for Disposition ($000s)	2024 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	(1,492)	-	(1,492)	880,975	(0.1694)
2	Rate 10	4,454	-	4,454	299,113	1.4892
3	Rate 20	(497)	-	(497)	1,237,005	(0.0401)
4	Rate 100	(279)	-	(279)	944,814	(0.0295)
5	Rate 25	(80)	-	(80)	293,029	(0.0273)
	Union South					
6	Rate M1	11,049	-	11,049	2,798,010	0.3949
7	Rate M2	12,759	-	12,759	1,160,817	1.0991
8	Rate M4	(159)	-	(159)	563,359	(0.0283)
9	Rate M5	207	-	207	52,057	0.3978
10	Rate M7	(338)	-	(338)	771,796	(0.0438)
11	Rate M9	(38)	-	(38)	96,697	(0.0391)
12	Rate T1	(24)	-	(24)	403,660	(0.0060)
13	Rate T2	(2,083)	-	(2,083)	5,491,895	(0.0379)
14	Rate T3	8	-	8	249,479	0.0030

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

Line No.	Particulars	2024 Deferral Balances ($000s)	2024 Earnings Sharing Mechanism ($000s)	Deferral Balance for Disposition ($000s)	2024 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	9,407	-	9,407	2,627,154	0.3581
2	Rate M2	2,026	-	2,026	513,525	0.3946
3	Rate M4	171	-	171	44,275	0.3870
4	Rate M5	6	-	6	1,684	0.3780
5	Rate M7	71	-	71	7,460	0.9486
6	Rate M9	52	-	52	15,819	0.3311

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

Line No.	Particulars	2024 Deferral Balances ($000s) (a)	2024 Earnings Sharing Mechanism ($000s) (b)	Deferral Balance for Disposition ($000s) (c) = (a + b)	2024 Actual Volume/ Demand (d)	Billing Units	Unit Rate (cents/m^3) (e) = (c / d) * 100
	Gas Supply Transportation Charges						
	Union North West						
1	Rate 01	(1,567)	-	(1,567)	245,342	10^3m^3	(0.6388)
2	Rate 10	(276)	-	(276)	66,538	10^3m^3	(0.4142)
3	Rate 20	(30)	-	(30)	1,764	10^3m^3/	(1.7082)
4	Rate 25	8	-	d 8	43,698	10^3m^3	0.0184
	Union North East						
5	Rate 01	(1,873)	-	(1,873)	635,632	10^3m^3	(0.2947)
6	Rate 10	(736)	-	(736)	232,575	10^3m^3	(0.3166)
7	Rate 20	(375)	-	(375)	8,124	10^3m^3/	(4.6100)
8	Rate 25	(2)	-	d (2)	26,515	10^3m^3	(0.0059)
	North T-Service Transportation from Dawn						
9	Rate 20/100 Base Service ($/GJ)	78	-	78	186,720	GJ/d	0.042
	Storage Charges						
10	Rate 20/100 Storage Service ($/GJ)	(33)	-	(33)	141,504	GJ/d	(0.023)

Enbridge Gas Inc.
Union Rate Zones
Unit Rates for One-Time Adjustment - Customer-Related Federal Carbon

Line No.	Particulars	2024 Deferral Balances ($000s)	2024 Earnings Sharing Mechanism ($000s)	Deferral Balance for Disposition ($000s)	2024 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	(738)	-	(738)	872,583	(0.0846)
2	Rate 10	(235)	-	(235)	277,579	(0.0846)
3	Rate 20	(85)	-	(85)	100,799	(0.0846)
4	Rate 100	-	-	-	-	-
5	Rate 25	(0)	-	(0)	144	(0.0846)
	Union South					
6	Rate M1	(2,318)	-	(2,318)	2,739,994	(0.0846)
7	Rate M2	(869)	-	(869)	1,027,158	(0.0846)
8	Rate M4	(272)	-	(272)	321,993	(0.0846)
9	Rate M5	(34)	-	(34)	40,503	(0.0846)
10	Rate M7	(100)	-	(100)	118,068	(0.0846)
11	Rate M9	-	-	-	-	-
12	Rate T1	(62)	-	(62)	73,070	(0.0846)
13	Rate T2	(3)	-	(3)	3,322	(0.0846)
14	Rate T3	-	-	-	-	-

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

Line No.	Particulars ($000s) (1)	2024 Deferral Balances	2024 Earnings Sharing Mechanism	Deferral Balance for Disposition
		(a)	(b)	(c) = (a + b)
1	Rate M12	639	-	639
2	Rate M13	(1)	-	(1)
3	Rate C1	788	-	788
4	Rate M16	19	-	19
5	Rate M17	2	-	2

Note:
(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 Including Federal Carbon ($)	Bill Impact Excluding Federal Carbon ($)
		(a)	(b)	(c)	(d)
	Rate 01 - Small Customer				
1	Delivery	(0.1694)	2,200	(3.73)	(3.73)
2	Federal Carbon	(0.0846)	2,200	(1.86)	
3	Transportation - NW	(0.6388)	2,200	(14.05)	(14.05)
4	Sales Service Impact			(19.64)	(17.78)
5	Bundled Direct Purchase Impact			(19.64)	(17.78)
	Rate 10 - Average Customer				
6	Delivery	1.4892	93,000	1,384.94	1,384.94
7	Federal Carbon	(0.0846)	93,000	(78.69)	
8	Transportation - NW	(0.4142)	93,000	(385.21)	(385.21)
9	Sales Service Impact			921.04	999.73
10	Bundled Direct Purchase Impact			921.04	999.73
	Rate 20 - Small Customer				
11	Delivery	(0.0401)	3,000,000	(1,204)	(1,204)
12	Federal Carbon	(0.0846)	3,000,000	(2,538)	
13	Transportation Demand - NW	(1.7082)	14,000	(2,870)	(2,870)
14	Sales Service Impact			(6,613)	(4,074)
15	Bundled Direct Purchase Impact			(6,613)	(4,074)
	Rate 20 - Large Customer				
16	Delivery	(0.0283)	15,000,000	(4,244)	(4,244)
17	Federal Carbon	(0.0846)	15,000,000	(12,692)	
18	Transportation Demand - NW	(1.7082)	60,000	(12,299)	(12,299)
19	Sales Service Impact			(29,234)	(16,542)
20	Bundled Direct Purchase Impact			(29,234)	(16,542)
	Rate 25 - Average Customer				
21	Delivery	(0.0273)	2,275,000	(620)	(620)
22	Federal Carbon	(0.0846)	2,275,000	(1,925)	
23	Transportation - NW	0.0184	2,275,000	419	419
24	Sales Service Impact			(2,126)	(201)
25	Bundled Direct Purchase Impact			(2,126)	(201)
	Rate 100 - Small Customer				
26	Delivery	(0.0295)	27,000,000	(7,969)	(7,969)
27	Federal Carbon	-	27,000,000	-	
28	Unbundled Direct Purchase Impact			(7,969)	(7,969)
	Rate 100 - Large Customer				
29	Delivery	(0.0295)	240,000,000	(70,832)	(70,832)
30	Federal Carbon	-	240,000,000	-	
31	Unbundled Direct Purchase Impact			(70,832)	(70,832)

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 Including Federal Carbon ($)	Bill Impact Excluding Federal Carbon ($)
		(a)	(b)	(c)	(d)
	Rate 01 - Small Customer				
1	Delivery	(0.1694)	2,200	(3.73)	(3.73)
2	Federal Carbon	(0.0846)	2,200	(1.86)	
3	Transportation - NE	(0.2947)	2,200	(6.48)	(6.48)
4	Sales Service Impact			(12.07)	(10.21)
5	Bundled Direct Purchase Impact			(12.07)	(10.21)
	Rate 10 - Average Customer				
6	Delivery	1.4892	93,000	1,384.94	1,384.94
7	Federal Carbon	(0.0846)	93,000	(78.69)	
8	Transportation - NE	(0.3166)	93,000	(294.42)	(294.42)
9	Sales Service Impact			1,011.83	1,090.52
10	Bundled Direct Purchase Impact			1,011.83	1,090.52
	Rate 20 - Small Customer				
11	Delivery	(0.0401)	3,000,000	(1,204)	(1,204)
12	Federal Carbon	(0.0846)	3,000,000	(2,538)	
13	Transportation Demand - NE	(4.6100)	14,000	(7,745)	(7,745)
14	Sales Service Impact			(11,488)	(8,949)
15	Bundled Direct Purchase Impact			(11,488)	(8,949)
	Rate 20 - Large Customer				
16	Delivery	(0.0283)	15,000,000	(4,244)	(4,244)
17	Federal Carbon	(0.0846)	15,000,000	(12,692)	
18	Transportation Demand - NE	(4.6100)	60,000	(33,192)	(33,192)
19	Sales Service Impact			(50,127)	(37,436)
20	Bundled Direct Purchase Impact			(50,127)	(37,436)
	Rate 25 - Average Customer				
21	Delivery	(0.0273)	2,275,000	(620)	(620)
22	Federal Carbon	(0.0846)	2,275,000	(1,925)	
23	Transportation - NE	(0.0059)	2,275,000	(133)	(133)
24	Sales Service Impact			(2,679)	(754)
25	Bundled Direct Purchase Impact			(2,679)	(754)
	Rate 100 - Small Customer				
26	Delivery	(0.0295)	27,000,000	(7,969)	(7,969)
27	Federal Carbon	-	27,000,000	-	
28	Unbundled Direct Purchase Impact			(7,969)	(7,969)
	Rate 100 - Large Customer				
29	Delivery	(0.0295)	240,000,000	(70,832)	(70,832)
30	Federal Carbon	-	240,000,000	-	
31	Unbundled Direct Purchase Impact			(70,832)	(70,832)

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

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3)	Bill Impact Including Federal Carbon ($)	Bill Impact Excluding Federal Carbon ($)
		(a)	(b)	(c)	(d)
	Rate M1 - Small Customer				
1	Delivery	0.3949	2,200	8.69	8.69
2	Federal Carbon	(0.0846)	2,200	(1.86)	
3	Commodity	0.3581	2,200	7.88	7.88
4	Sales Service Impact			14.70	16.56
5	Bundled Direct Purchase Impact			6.83	8.69
	Rate M2 - Average Customer				
6	Delivery	1.0991	73,000	802.34	802.34
7	Federal Carbon	(0.0846)	73,000	(61.77)	
8	Commodity	0.3946	73,000	288.07	288.07
9	Sales Service Impact			1,028.65	1,090.42
10	Bundled Direct Purchase Impact			740.58	802.34
	Rate M4 - Small Customer				
11	Delivery	(0.0283)	875,000	(248)	(248)
12	Federal Carbon	(0.0846)	875,000	(740)	
13	Commodity	0.3870	875,000	3,387	3,387
14	Sales Service Impact			2,399	3,139
15	Bundled Direct Purchase Impact			(988)	(248)
	Rate M4 - Large Customer				
16	Delivery	(0.0283)	12,000,000	(3,395)	(3,395)
17	Federal Carbon	(0.0846)	12,000,000	(10,153)	
18	Commodity	0.3870	12,000,000	46,444	46,444
19	Sales Service Impact			32,896	43,049
20	Bundled Direct Purchase Impact			(13,548)	(3,395)
	Rate M5 - Small Customer				
21	Delivery	0.3978	825,000	3,282	3,282
22	Federal Carbon	(0.0846)	825,000	(698)	
23	Commodity	0.3780	825,000	3,118	3,118
24	Sales Service Impact			5,702	6,400
25	Direct Purchase Impact			2,584	3,282

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 Including Federal Carbon ($)	Bill Impact Excluding Federal Carbon ($)
		(a)	(b)	(c)	(d)
	Rate M5 - Large Customer				
26	Delivery	0.3978	6,500,000	25,855	25,855
27	Federal Carbon	(0.0846)	6,500,000	(5,500)	
28	Commodity	0.3780	6,500,000	24,567	24,567
29	Sales Service Impact			44,922	50,422
30	Direct Purchase Impact			20,355	25,855
	Rate M7 - Small Customer				
31	Delivery	(0.0438)	36,000,000	(15,755)	(15,755)
32	Federal Carbon	(0.0846)	36,000,000	(30,460)	
33	Commodity	0.9486	36,000,000	341,510	341,510
34	Sales Service Impact			295,295	325,755
35	Direct Purchase Impact			(46,215)	(15,755)
	Rate M7 - Large Customer				
36	Delivery	(0.0438)	52,000,000	(22,757)	(22,757)
37	Federal Carbon	(0.0846)	52,000,000	(43,998)	
38	Commodity	0.9486	52,000,000	493,292	493,292
39	Sales Service Impact			426,537	470,535
40	Direct Purchase Impact			(66,755)	(22,757)
	Rate M9 - Small Customer				
41	Delivery	(0.0391)	6,950,000		(2,717)
42	Commodity	0.3311	6,950,000		23,009
43	Sales Service Impact				20,291
44	Direct Purchase Impact				(2,717)
	Rate M9 - Large Customer				
45	Delivery	(0.0391)	20,178,000		(7,890)
46	Commodity	0.3311	20,178,000		66,802
47	Sales Service Impact				58,912
48	Direct Purchase Impact				(7,890)
	Rate T1 - Small Customer				
49	Delivery	(0.0060)	7,537,000	(454)	(454)
50	Federal Carbon	(0.0846)	7,537,000	(6,377)	
51	Direct Purchase Impact			(6,831)	(454)

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

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3)	Bill Impact Including Federal Carbon ($)	Bill Impact Excluding Federal Carbon ($)
		(a)	(b)	(c)	(d)
	Rate T1 - Average Customer				
52	Delivery	(0.0060)	11,565,938	(696)	(696)
53	Federal Carbon	(0.0846)	11,565,938	(9,786)	
54	Direct Purchase Impact			(10,482)	(696)
	Rate T1 - Large Customer				
55	Delivery	(0.0060)	25,624,080	(1,543)	(1,543)
56	Federal Carbon	(0.0846)	25,624,080	(21,681)	
57	Direct Purchase Impact			(23,224)	(1,543)
	Rate T2 - Small Customer				
58	Delivery	(0.0379)	59,256,000	(22,480)	(22,480)
59	Federal Carbon	(0.0846)	59,256,000	(50,138)	
60	Direct Purchase Impact			(72,617)	(22,480)
	Rate T2 - Average Customer				
61	Delivery	(0.0379)	197,789,850	(75,034)	(75,034)
62	Federal Carbon	(0.0846)	197,789,850	(167,354)	
63	Direct Purchase Impact			(242,388)	(75,034)
	Rate T2 - Large Customer				
64	Delivery	(0.0379)	370,089,000	(140,398)	(140,398)
65	Federal Carbon	(0.0846)	370,089,000	(313,139)	
66	Direct Purchase Impact			(453,537)	(140,398)
	Rate T3 - Large Customer				
67	Delivery	0.0030	272,712,000	8,262	8,262
68	Direct Purchase Impact			8,262	8,262

2024 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 (2020 to 2024), 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 2024, there were no IRP alternatives implemented, and as this is the first year of collecting pipeline condition data for ALE, there have been no capital costs avoided for either metric.

3. In 2024, Enbridge Gas met or exceeded all elements of the scorecard except for two Service Quality Requirements (SQR) measures: Customer Complaint Written Response (CCWR) and Meter Reading Performance Measurement (MRPM).

4. CCWR measures the percentage of customer complaints that require a substantive written response within 10 days of receiving the written complaint. As set out in the GDAR, the minimum performance standard for CCWR is 80%. Enbridge Gas's CCWR results for 2024 were 66.67%, based on missing the 10-day time frame on one of the three customer complaints received which required a substantive written response. As the number of customer complaints that require a substantive written response have declined over time, the Company has found that missing one

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

response is likely to result in Enbridge Gas not meeting the CCWR SQR metric. Therefore, in 2025, the Ombuds Office team conducted an internal review of the CCWR procedures to mitigate future occurrence.

5. MRPM 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 metric does not consider why Enbridge Gas has not read a meter.

6. In mid-2021, the OEB compliance staff commenced a review of Enbridge Gas's SQR results following an increased number of customer complaints to the OEB after the Company's July 2021 integration of customers to the CIS system. Following the OEB's compliance review, Enbridge Gas shared its 2022 MRPM Mitigation Plan[2] with the OEB and as part of an Assurance of Voluntary Compliance (AVC)[3], Enbridge Gas committed to aim for 4% for 2022 (3% when accounting for meters that Enbridge Gas cannot access). The action taken from mitigation planning in 2022 and 2023 have included additional hiring of meter readers, reduction in attrition, extended working hours, collaboration with meter reading vendors to conduct regular performance reviews, process improvements, improved meter reading technology, and marketing campaigns. Overall, the mitigation measures taken have resulted in a 74% improvement in MRPM results from 2021 to 2023. Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% in 2022, 1.3% in 2023 and 0.9% in 2024. Despite significantly improving this metric, there are persisting challenges beyond Enbridge Gas's control that limit the ability for meter readers to access and read a certain portion of gas meters, impairing the ability to achieve this target.

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[2] EB-2022-0200, Exhibit 1, Tab 7, Schedule 1, pp.18-21; and Attachment 4.
[3] EB-2022-0188, EGI-Assurance-of-Voluntary-Compliance-20220912.pdf (oeb.ca).

7. 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.[4] Customer behaviour impacting the number of inaccessible meters includes locked gates, inside meters with unresponsive tenants or landlords, customer sensitivity, and obstruction[5]. 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. Further details on the OEB's Decision and Enbridge Gas's proposal are available in Phase 2 of the 2024 Rebasing Application[6].

[4] EB-2024-0111, Exhibit 1, Tab 7, Schedule 1, pp.5-6.
[5] EB-2024-0111, Exhibit 1, Tab 7, Schedule 1, pp.10-13, and Attachment 3.
[6] EB-2024-0111, Exhibit 1, Tab 7, Schedule 1.

EGI OEB Scorecard 2020 - 2024

#	Performance Measure	Target	Actual 2024 EGI	Actual 2023 EGI	Actual 2022 EGI	Actual 2021 EGI	Actual 2020 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%	99.2%	99.3%	98.1%	96.9%	98.9%
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%	97.4%	96.3%	95.4%	94.5%	98.8%
3	**Telephone calls answered on time (call answering service level)** (# of calls answered within 30 seconds / # of calls received)	75.0%	85.2%	89.5%	75.9%	64.3%	75.2%
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%	66.7%	100.0%	90.0%	100.0%	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.'		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	427,524 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%	2.6%	1.4%	7.1%	16.0%	5.4%
7	**Time to Reschedule Missed Appointments** (% of rescheduled work within 2 hours of the end of the original appointment time)	98%[1]	98.5%	97.8%	93.8%	97.0%	97.3%
	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%	0.9%	1.3%	4.1%	5.0%	4.4%
9	**% of Emergency Calls Responded within One Hour** (# of emergency calls responded within 60 minutes / # of emergency calls)	90.0%	96.0%	95.3%	94.1%	95.2%	96.7%
10	**Compression Reliability** % reliable for transmission compression		100%	100.0%	100.0%	99.7%	99.7%
11	**Damages per 1000 locate requests**		1.91	2.10	2.31	1.95	2.22
12	**Total Cost per Customer** ($ / Customer)		756.5	745.7	683.2	643.9	658.2
13	**Total Cost per km of Distribution Pipe** ($ / km of Distribution Pipe)		19,492.6	19,079.6	17,480.7	16,639.6	16,928.5
	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)		2,607.5[2]	1,754.0[3]	1,385.9	1,654.9	1,632.2
	FINANCIAL PERFORMANCE (Avoided Capital Costs)						
15	**Intergrated Resource Plan (IRP)** (Capital Cost of Facility Alternative) - (Capital Cost of IRP Alternative)		$0[5]	NA[4]	NA[4]	NA[4]	NA[4]
16	**Asset Life Extension (ALE)** (Capital Cost for Total Repalacement) - (Capital Cost for Asset Life Extension)		$0[6]	NA[4]	NA[4]	NA[4]	NA[4]
	FINANCIAL PERFORMANCE (Financial Ratios)						
17	**Current Ratio** (Current Assets / Current Liabilities)		0.61	0.92	0.84	0.71	0.66
18	**Debt Ratio** (Total Debt / Total Assets)		0.37	0.39	0.42	0.41	0.40
19	**Debt to Equity Ratio** (Total Debt / Shareholders' Equity)		0.93	0.97	1.10	1.06	1.01
20	**Interest Coverage** (EBIT / Interest Charges)		2.28	1.75	2.54	2.55	2.34
21	**Financial Statement Return on Assets** (Net Income / Total Assets)		1.72%	1.20%	2.03%	2.07%	1.97%
22	**Financial Statement Return on Equity** (Net Income / Shareholders' Equity)		4.31%	3.00%	5.37%	5.32%	4.96%

[1] Time to Reschedule Missed Appointment target was 100% prior to the Phase 1 Decision
[2] 2024 is draft, unaudited, and subject to OEB approval
[3] 2023 is audited and subject to OEB approval
[4] Historical information is not avaialble
[5] There were no IRP alternatives implemented in 2024, therefore no capital costs have been avoided
[6] 2024 is the first year collecting pipeline condition data, therefore there were no capital costs avoided

Integrated Resource Planning (IRP)

2024 Annual Report

July 4, 2025

Table of Contents

Section 1 – Introduction

This Enbridge Gas Inc. ("Enbridge Gas" or the "Company") 2024 IRP Annual Report ("Report") encompasses the period from January 1, 2024, through to December 31, 2024. Incrementally, additional updates are provided for both the IRP Pilot Project and System Pruning Pilot. As per the OEB Decision on the IRP Pilot Project[1], updated pilot project plans and an update for the estimated unit rate and bill impact associated with forecast 2025 pilot costs for typical customers by rate class have been included within this Report, under Appendix H. As agreed in the Rebasing Phase 2 Settlement Agreement and accepted by the OEB, development of the System Pruning pilot approach is required by Q2 2025 and implementation initiated by Q1 2026.[2] Due to these immediate timelines, a comprehensive System Pruning update has been included within this Report (Section 10), as well as the System Pruning pilot approach, under Appendix G.

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:[3]

> "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 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 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."

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[1] EB-2022-0335, Decision and Order on IRP Pilot Project, March 27, 2025
[2] EB-2024-0111, Decision on Settlement Proposal and Interim Rate Order (Rebasing Phase 2), November 29, 2024.
[3] EB-2020-0091, OEB Decision and Order, Appendix A, p. 22.

Section 2 – Integration Update

Enbridge Gas has integrated IRP cross-functionally by embedding resources within its asset management ("AM"), distribution optimization engineering ("DOE"), demand side management ("DSM"), financial analysis, customer policy and strategy, regulatory, municipal energy solutions, community engagement departments, as well as within the IRP team. There are currently 15.5 IRP full-time equivalent ("FTE") roles, where 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.

In Q4 2024, Enbridge Gas began the resourcing process for the implementation of the IRP Pilot Project in Southern Lake Huron ("SLH").

Enbridge Gas built upon the progress made in 2023 by continuing to enhance cross-functional processes, including the following:

- **Integration of the IRP Binary Screening Process into the Asset Investment Planning Management ("AIPM") Process**
  Enbridge Gas has streamlined the Binary Screening process within the IRP evaluation to ensure that investments with IRP potential are reviewed during the Solution Planning and Value Assessment stage of the AIPM process. By establishing required protocols and process requirements in collaboration with key internal stakeholders, Enbridge Gas successfully integrated Binary Screening into the earliest stage of the AIPM process.

- **Refinement of Technical and Economic Evaluation Process for IRPAs**
  Enbridge Gas refined the technical evaluation process in 2024, by separating the technical screening and technical evaluation stages. This included developing templates to be used when evaluating an IRPA's technical 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 screening of 1,359 investments and supported the subsequent technical evaluation of a total of 79 investments in the EGI Asset Management Plan 2025-2034 filed on November 8, 2024.

  Enbridge Gas has also continued to develop its economic evaluation DCF+ model, including 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. The evaluation criteria at the economic evaluation stage are currently being developed in consultation with the IRP Technical Working Group ("TWG"). Further details on the IRP Evaluation are outlined in Section 3.

- **Expression of Interest/Reverse Open Season (EOI/ROS) Process**
  Enbridge Gas updated the EOI/ROS[4] process through inclusion of incremental questions on energy efficiency as it relates to reduction in contract bids or existing demand. This process ensures that the bid put

[4] Economic Development & Site Selection Services | Ontario | Enbridge Gas

forward by the customer is inclusive of consideration of all expected future natural gas conservation activities. Additionally, customers are asked whether they would be open to further engagement in discussing additional natural gas conservation activities to lower their bid amount and/or existing contract demand through potential incremental incentives as an IRP alternative, if applicable. An Enbridge Gas Energy Conservation Advisor will work with the customer on their specific opportunities.

Section 3 – IRPA Evaluation and AMP Update

The EGI Asset Management Plan ("AMP") from 2025 to 2034 was filed on November 8, 2024.[5]

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 AIPM process to initiate the IRP Evaluation process of the investments within the capital plan. The status of the IRP evaluation on investments are captured in Appendix B of the AMP.

The IRP Evaluation process is detailed below: DCF

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 with the Asset Class of Customer Connections are included in the list of Binary Screening requirements.

3. **Technical Screening & Evaluation**
   Investments undergo an initial technical screening to determine whether a detailed technical evaluation is required. Further details on this technical screening process can be found in Appendix F.

   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 demand reduction level required to meet system needs by determining the difference between the required and the current system capacity. Where IRPAs have a technical potential to reduce the design hour/day demand reduction without compromising the safety and reliability of the system, these investments pass the technical evaluation.

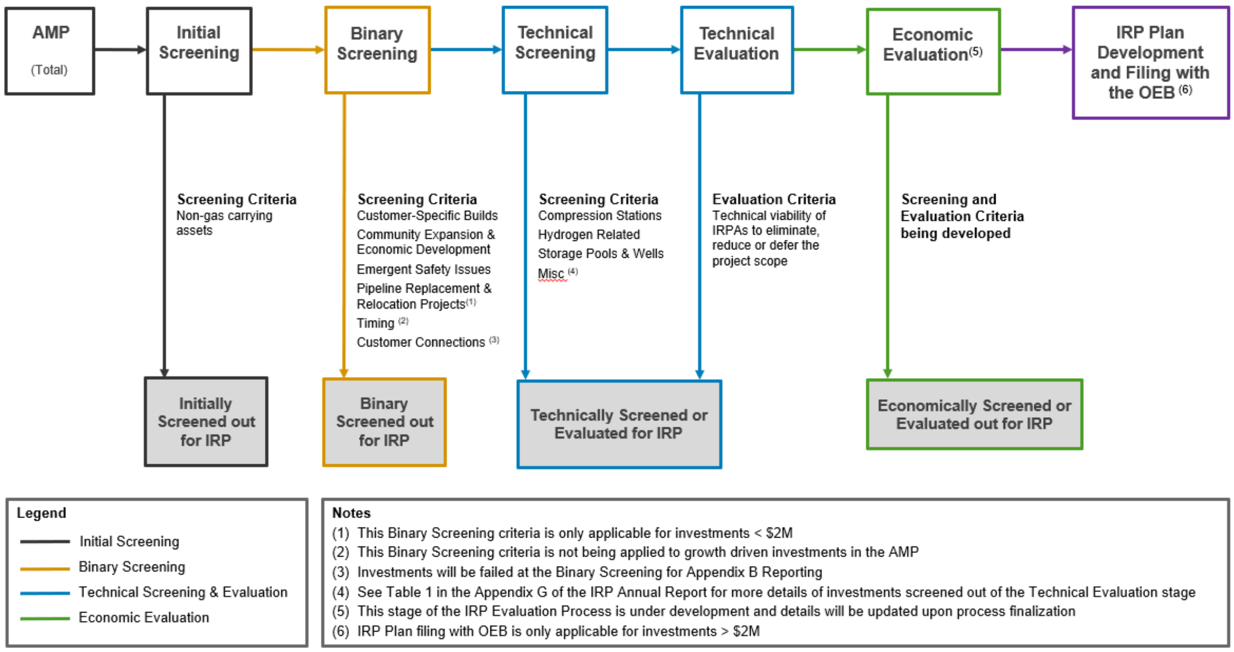
4. **Economic Evaluation**
   Investments that have passed technical evaluation will be economically evaluated using the DCF+ test. The DCF+ test compares each technically feasible IRPA and the identified baseline facility project to a 'do nothing' scenario. The DCF+ results for the IRPAs and the baseline 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.

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

The current IRP screening and evaluation process is outlined in Figure 3.1.

[5] EB-2020-0091, Enbridge Gas 2025-2034 AMP, November 8, 2024 (link)

Figure 3.1 – IRP Evaluation Process



2024 IRP Evaluation 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 of natural gas.

The 10-year forecast for the 2025-2034 Appendix B incorporates the following 3 key factors, directly or via sensitivities:

1. System Reinforcement Plan ("SRP") Update
   - A refresh to the SRP was completed in Q1 2024. 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.

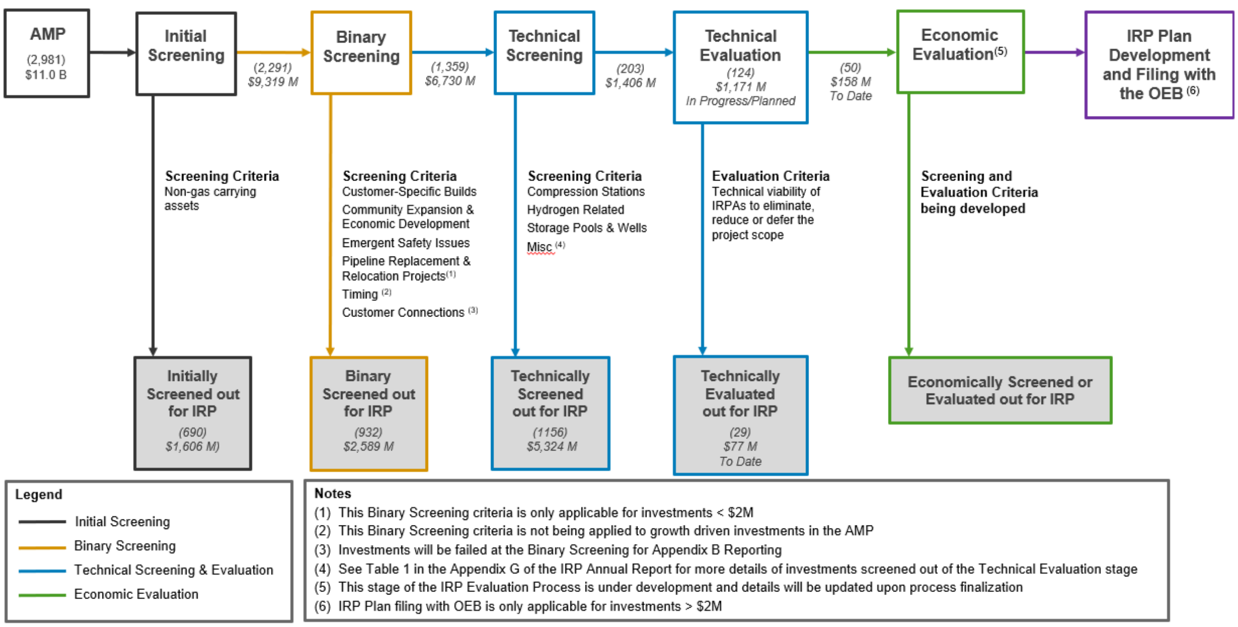
2. Energy Transition ("ET") Adjustments
   - As summarized in Enbridge Gas's 2024 Rates Application (EB-2022-0200), Enbridge Gas introduced ET Adjustments to its demand forecasts (for existing customers, customer additions and average annual use) and design elements (design hour and design day) to account 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 ET 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 ET Adjustments and account for new and/or updated external signals and/or development.[6]

[6] IRP TWG Meeting #37, May 10, 2024 - Meeting Materials (included 2024 ET Adjustments)

3. OEB Decision on Enbridge Gas's 2024 Rates Application – Phase 1 (EB-2022-0200) ("2024 Rebasing Phase 1 Decision")
    - Updates to the 10-year plan were required as the OEB's 2024 Rebasing Phase 1 Decision did not accept the AMP as filed and ordered a reduction in the capital budget. Reductions to the 2024 capital budget were reflected and filed in the Phase 1 Draft Rate Order.[7] Reporting on the reductions to the capital budget reflect the directions in the OEB's 2024 Rebasing Phase 1 Decision found in EB-2025-0064 Phase 3 filing at Phase 3 Exhibit 2, Tab 5, Schedule 5.

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



A summary of the IRP screening and evaluation process on the 2,981 investments in the 2025 to 2034 AMP at the time of the filing is provided below:

- 690 investments were screened out using initial screening.
- 932 investments were screened out using binary screening.
- 1156 investments were screened out using technical screening.
- 79 investments underwent a complete technical evaluation, including all investments under the Asset Class of Growth.
    - 29 investments did not pass technical evaluation.
    - 50 investments passed technical evaluation.
- 124 investments remain to undergo technical evaluation or had 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-

[7] EB-2022-0200, Rate Order, Working Papers, Schedule 5, p.1. (February 16, 2024)

side alternatives have a significant potential for technical feasibility but are inherently responsive to market conditions, and therefore, will be assessed closer to and prior 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 the LTC application or IRP Plan.

- 117 investments under the Asset Class of Distribution Pipe and Distribution Station have an IRP evaluation status of “Planned”. These are replacement type investments where project scope and timing are re-evaluated annually. These investments will proceed through to the IRP evaluation process once a detailed project scope is confirmed. The IRP evaluation process will determine whether an IRP alternative can technically and economically downsize the project. Enbridge Gas will prioritize investments with nearer-term in-service dates, ensuring that there is time to evaluate and implement the optimal alternative. The nearest in-service date for this category (Distribution Pipe investments) in the AMP is 2027 and Enbridge Gas plans to proceed with the economic evaluation of prioritized investments in 2025.
- 2 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 proceeding at the beginning of 2026.
- 50 investments have passed technical evaluation and are at the economic evaluation stage. This is comprised of 49 investments under the Asset Class of Growth, and 1 investment under the Asset Class of Distribution Pipe. Enbridge Gas is prioritizing the economic evaluation of investments with nearer term in-service dates, and higher IRP potential, which are growth investments with higher capital requirements. This ensures that there is time to evaluate and implement the optimal pipe and/or non-pipe alternative and that Enbridge Gas remains focused on those investments with a higher likelihood to be impacted by an IRPA. Enbridge Gas plans to proceed with priority economic evaluations in 2025 based on the enhanced DCF+ test in use at this time.

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

Section 4 – IRP Pilot Projects Update

The IRP Pilot Projects was first filed with the OEB on July 19, 2023[8], under EB-2022-0335 (link). The application sought approval of the cost consequences of the two IRP Pilot Projects, including approval to record the associated costs in the IRP costs deferral accounts. The application included details on the project area and need, baseline facility alternatives, design of IRPAs, associated budget and evaluation plans, an illustrative Stage 1 DCF test, and stakeholder engagement.

In response to Natural Resource Canada's ("NRCan") decision to close the application process for new entrants into the Greener Homes Grant program in Q1 2024, Enbridge Gas filed updated evidence on December 21, 2023.[9]

In response to the changes to the 10-year capital forecast resulting from the factors noted in Section 3, Enbridge Gas consulted with the TWG in April 2024 regarding whether there was a need to update the IRP Pilot Projects evidence. This process resulted in Enbridge Gas determining it was appropriate to move forward with the Southern Lake Huron Pilot Project focused solely on demand-side alternatives, and the Parry Sound Pilot Project focused solely on the supply-side alternative as outlined in the letter filed with the OEB April 30, 2024.[10] The TWG was generally supportive of this approach.

In May 2024, in response to energy transition and demand forecast adjustment updates, Enbridge Gas applied best available information to the Company's 10-year demand forecast and determined that the baseline facility projects for the Parry Sound Pilot Project have been pushed out of the Company's 10-year capital forecast. Without a justifiable need for localized CNG injection within the Parry Sound area, it was no longer reasonable to proceed with the Parry Sound Pilot Project. Enbridge Gas informed the TWG and subsequently notified the OEB in the letter filed June 7, 2024.[11] The updated Pilot Project application and evidence was filed with the OEB June 28, 2024.

As the IRP Pilot Project and the resulting learnings are a key focus for Enbridge Gas, proactive steps have been taken to initiate certain activities that are anticipated to require longer lead times in an effort to reduce delays in the implementation of the pilot project.

In Q4 2024, Enbridge Gas engaged with the larger commercial and industrial customers in the pilot area in a targeted effort to identify potential participants and expedite the timelines and logistics associated with installing hourly measurement. This proactive approach aimed to allow for the collection of baseline data prior to the rollout of the ETEE Program and implementation of energy efficiency measures. Based on this consultation, 61 customer premises in the pilot area expressed interest and were identified for hourly measurement. Enbridge Gas has secured Brightlync devices to allow for data collection and is initiating the implementation of hourly measurement for these customers starting in Q1 2025.

Additionally, in Q4 2024 Enbridge Gas initiated a competitive procurement process to retain an evaluation contractor to support the second IRP Pilot Project objective; to develop an understanding of how to effectively design, deploy, and evaluate ETEE and residential DR programs. The scope of the evaluation will include outcome evaluation regarding the financial spending and participation in the programs, as well as process evaluation to undertake a systematic assessment of the design and delivery approach of the offerings to provide insights and considerations for ongoing enhancements. The IRP TWG was engaged in the review of the scope of work for the evaluation contractor.

On March 27, 2025, the OEB issued its Decision and Order approving the Southern Lake Huron 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. Additionally, the OEB issued a Notice of Review (EB-2025-0124), initiating its own review of the Decision and Order for the IRP Pilot Project. As per the OEB Decision on the IRP Pilot Project,

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[8] EB-2022-0335, IRP Pilot Projects Application and Evidence, July 19, 2023.
[9] EB-2022-0335, IRP Pilot Projects Updated Evidence, December 21, 2023.
[10] EB-2022-0335, IRP Pilot Projects Application Status Update, April 30, 2024
[11] EB-2022-0335, IRP Pilot Projects Application Status Update, June 7, 2024

Enbridge Gas engaged with the IRP TWG to file an updated detailed project plan as part of this report and has provided an update for the estimated unit rate and bill impact associated with forecast 2025 pilot costs for typical customers by rate class within this Report (Appendix H).

The regulatory process to date for the IRP Pilot Projects (EB-2022-0335) includes:

- September 8, 2023 – OEB issued Procedural Order ("PO") No. 1 approving intervenor requests and detailing the timelines for subsequent procedural steps.
- September 14, 2023 – OEB staff filed a proposed issues list for the proceeding.
- September 21, 2023 – Intervenors and Enbridge Gas filed submissions on the proposed issues list for the proceeding.
- September 26, 2023 – Intervenors and Enbridge Gas filed reply submissions on the issues proposed. Additionally, Enbridge Gas also filed a request to defer interrogatory submissions and interrogatory response submissions by one week, to ensure that witnesses participating in the OEB's oral hearing for the Company's Panhandle Regional Expansion Project leave to construct application were available to contribute to the development of interrogatory responses.
- October 6, 2023 – OEB issued PO No. 2 which includes a Decision on the Issue List for the proceeding and approval of Enbridge Gas's request for a deferral of interrogatory submissions and responses by one week, thereby adjusting the procedural timelines set out in PO No. 1.
- October 20, 2023 – OEB staff and intervenors filed written interrogatories.
- November 3, 2023 – Enbridge Gas filed written responses to OEB staff and intervenor interrogatories.
- November 8, 2023 – OEB staff and intervenors filed comments regarding the need for a technical conference.
- November 10, 2023 – Enbridge Gas filed comments regarding the need for a technical conference. Additionally, Enbridge Gas advised the OEB that Natural Resources Canada ("NRCan") informed Enbridge Gas that it is halting intake into the Canada Greener Homes Grant program in Q1 2024, thereby impacting the Home Efficiency Rebate Plus ("HER+") program delivered by Enbridge Gas, and subsequently the design and budget of the IRP Pilot Projects. Enbridge Gas noted it planned to file all necessary evidence updates resulting from the NRCan announcement.
- November 17, 2023 – OEB issued PO No. 3 determining that the revised (updated) proposal for the IRP Pilot Projects should maintain the inclusion of electric heat pumps and should consider alternative approaches to address the loss of NRCan incentives. The OEB also determined a technical conference is warranted and placed the application in abeyance pending the filing of updated evidence and interrogatory responses by Enbridge Gas.
- November 30, 2023 – Enbridge Gas filed a letter stating that it expects to file all relevant evidence updates by the end of 2023.
- December 21, 2023 – Enbridge Gas filed updates to its pre-filed evidence and interrogatory responses. The updates primarily reflected Enbridge Gas's proposal to replace the incentives previously funded by NRCan with funding from the Pilot Projects budget to maintain the level of incentives the Company believes are required to drive the high levels of ETEE program uptake to achieve the necessary peak hour demand reductions.
- January 12, 2024 – Enbridge Gas filed a letter requesting the application remain in abeyance to allow time for Enbridge Gas to assess the impacts (if any) of the OEB's 2024 Rebasing Phase 1 Decision (EB-2022-0200). Enbridge Gas indicated that it would provide an update regarding the status of its assessment by the end of February.
- January 15, 2024 – OEB issued a letter confirming that the proceeding would continue to be held in abeyance pending a further update to be provided by Enbridge Gas by the end of February.
- February 29, 2024 – Enbridge Gas filed a letter requesting that the proceeding continue to be held in abeyance and stated that the Company expects it will be able to provide an update regarding the status of its application by April 30, 2024.

- March 12, 2024 – OEB issued a letter requesting that Enbridge Gas provide an explanation regarding the issues impacting the application and the Company's plan to move the proceeding forward by March 26, 2024.
- March 26, 2024 – Enbridge Gas filed a letter explaining that the Company is requesting that the OEB continue to hold the proceeding in abeyance as Enbridge Gas continues to assess impacts of changes to the Company's 10-year capital forecast resulting from the: (i) annual system reinforcement plan ("SRP") update, (ii) annual energy transition adjustments update, which are applied to the Company's 10-year demand forecast to reflect best available information in Ontario, and (iii) reduction in approved capital in the 2024 Rebasing Phase 1 (EB-2022-0200) Decision. Enbridge Gas went on to explain that these changes will impact the number of growth projects within the Company's 10-year forecast and may affect the baseline facility projects described within the application, as well as the number of projects to which the learnings from the pilot projects could be applied. Enbridge Gas stated that it expects to be able to provide a meaningful update regarding the status of the application by April 30, 2024 following consultation with the TWG.
- April 9, 2024 – OEB issued a letter stating that it is not opposed to Enbridge Gas's plan to consult with the TWG and accepts Enbridge Gas's request to continue holding the proceeding in abeyance until April 30, 2024. To avoid further delays to the proceeding, the OEB stated that it expects Enbridge Gas to provide a meaningful and detailed update by April 30, 2024, explaining any planned pilot project scope changes the Company proposes following its discussions with the TWG and, if necessary, the anticipated time it will take Enbridge Gas to update its application and evidence accordingly.
- April 30, 2024 – Enbridge Gas filed a letter with details regarding the planned changes it will be proposing for the application. Within the letter, Enbridge Gas explained that, as a result of the SRP update, the underlying system need and associated baseline facility projects for the Southern Lake Huron Pilot Project have been pushed out of the Company's 10-year capital forecast. Additionally, the baseline facility projects for the Parry Sound Pilot Project have been revised. Enbridge Gas went on to explain that it has determined, in consultation with the TWG, that it is appropriate, based on the best available information at the time, to move forward with the Southern Lake Huron Pilot Project focused solely on demand-side alternatives and with the Parry Sound Pilot Project focused solely on a supply-side alternative. Enbridge Gas indicated that it expects to file updates to the Company's application and evidence including interrogatory responses by June 28, 2024.
- June 7, 2024 – Enbridge Gas filed a letter explaining that, in the course of the May 2024 energy transition and demand forecast adjustment updates, Enbridge Gas applied best available information to the Company's 10-year demand forecast and determined that the baseline facility projects for the Parry Sound Pilot Project have also been pushed out of the Company's 10-year capital forecast. As a result, Enbridge Gas indicated that it plans to withdraw the Parry Sound Pilot Project from the application and proceed with the Southern Lake Huron Pilot Project focused on demand-side alternatives. Enbridge Gas stated that it informed the TWG of the planned removal of the Parry Sound Pilot Project from the application on June 5, 2024. Enbridge Gas stated that it continues to expect to file updates to the Company's application and evidence including interrogatory responses by June 28, 2024.
- June 28, 2024 - Enbridge Gas filed updates to its pre-filed evidence and interrogatory responses, reflecting the withdrawal of the Parry Sound Pilot Project from the application and the updated Southern Lake Huron Pilot Project.
- August 13, 2024 – OEB issued PO No. 4 determining that a virtual technical conference would be held on August 27, 2024 and provided an amended issues list.
- August 27, 2024 – OEB held a transcribed virtual technical conference.
- September 5, 2024 – OEB issued PO No. 5 determining that the application will proceed by way of a written hearing and established timelines for the subsequent procedural steps.
- September 10, 2024 – Enbridge Gas filed written undertakings from the technical conference.
- September 24, 2024 – Enbridge Gas filed its argument-in-chief.

- October 8, 2024 –OEB staff and intervenors filed final submissions.
- October 22, 2024 – Enbridge Gas filed its reply argument.
- November 5, 2024 – OEB issued PO No. 6 with additional questions from the OEB panel.
- November 12, 2024 – Enbridge Gas filed its written responses to the OEB panel's additional questions.
- March 27, 2025 – OEB issued its Decision and Order approving the Southern Lake Huron 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. Additionally, the OEB issued a Notice of Review (EB-2025-0124), initiating its own review of the Decision and Order for the IRP Pilot Project.

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".[12]

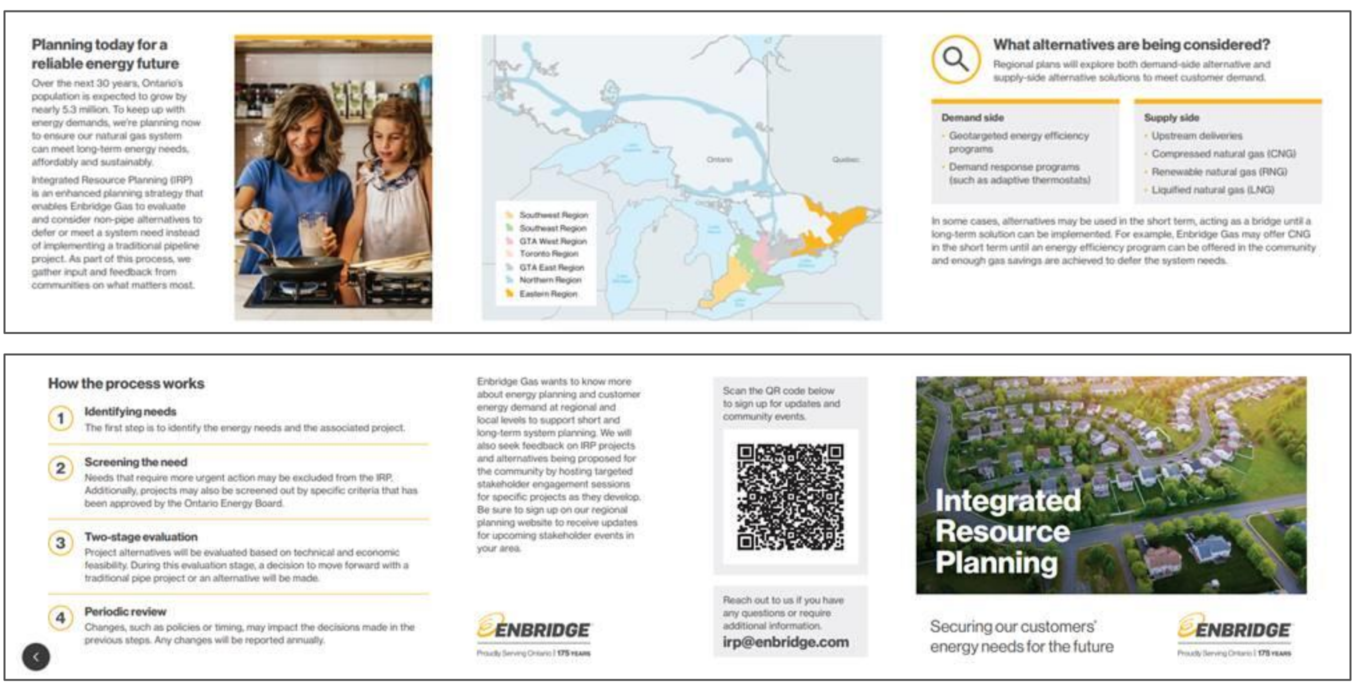
Municipal Outreach

Enbridge Gas engages with stakeholders within existing stakeholder engagement channels on an on-going basis. This includes outreach opportunities to reach wider audiences, such as through municipal conferences. Throughout 2024, Enbridge Gas participated in several conferences, including:

- ROMA (Rural Ontario Municipal Conference) in January 2024
- OSUM (Ontario Small Urban Municipalities) in May 2024
- AMO (Association of Municipalities of Ontario) in August 2024
- OEMC (Ontario East Municipal Conference) in September 2024
- WOMC (Western Ontario Municipal Conference) in October 2024

The conferences serve as an opportunity to raise awareness among municipalities about IRP and pilots, promote the regional webinars, and encourage municipalities to stay informed by signing up for the IRP mailing list. IRP postcards and trifold brochures were also available to provide additional information, as shown in Figure 5.1.

Figure 5.1 – Trifold used as promotion at tradeshow booth throughout 2024



[12] EB-2020-0091, IRP Proposal OEB Decision and Order, July 22, 2021, p. 66.

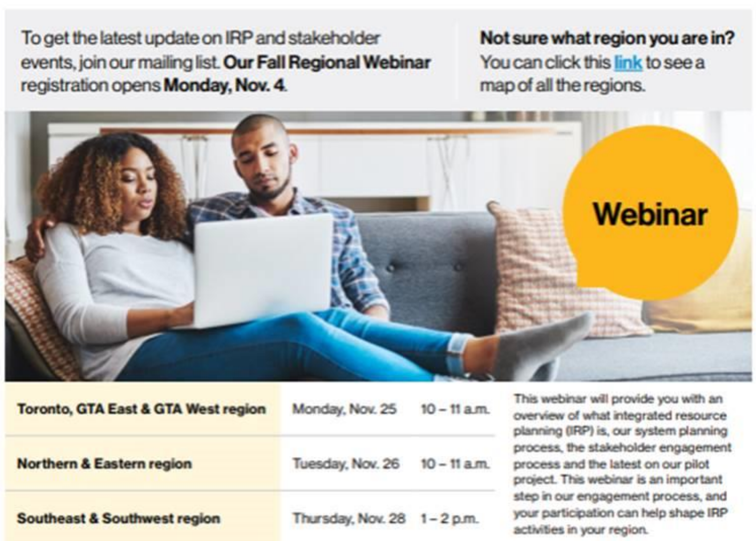
Regional Engagement

In Q1 2024, Enbridge Gas focused on raising general IRP awareness and encouraging email contact list sign-ups. The Company's enbridge.com landing page featured a tile that invited viewers to click on the link to learn more about IRP and sign up for updates.

Figure 5.2 – Example of the website tile for IRP promotion

In October 2024, Enbridge Gas put out a newsletter for all those who had signed up for updates to provide an update on IRP, including an introduction to the system pruning pilot and information on the upcoming regional webinars.

Figure 5.3 – Webinar promotion in newsletter

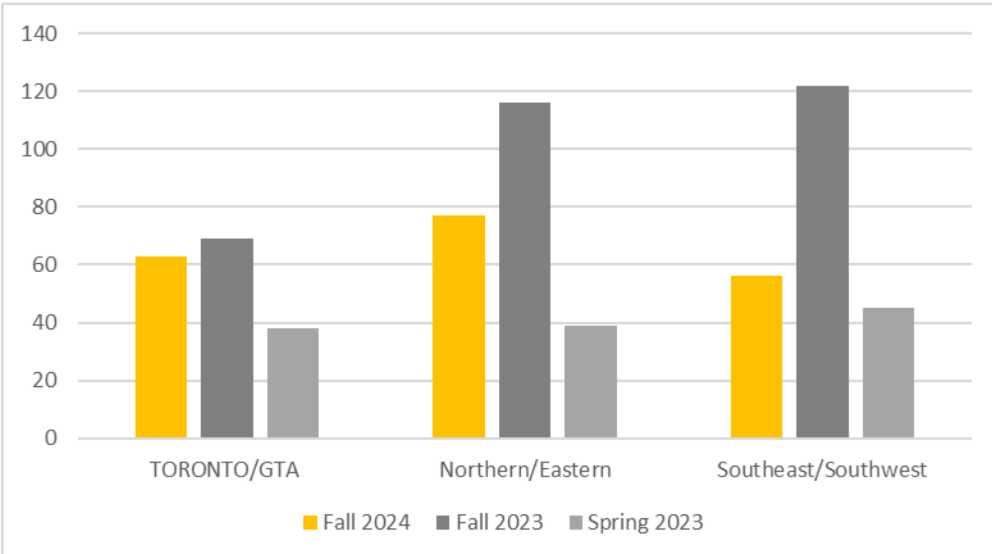


In addition to the newsletter and conference tactics noted above, Enbridge Gas encouraged registration for the regional webinars through leveraging the IRP stakeholder lists, which are lists of individuals who subscribed for updates via the website and through targeted Facebook ads directed at regions where the webinars were being held. Additionally, Enbridge Gas' Municipal teams supported outreach efforts by sharing their email contact lists and informing stakeholders about the upcoming webinars through routine engagement.

The regional webinars took place in November 2024. The Company hosted 1-hour webinars for its three operating regions. The webinar covered topics including a brief overview of IRP, the system planning process, IRP assessment and engagement process, key projects from the AMP located within each of the respective regions and an update on the IRP pilot and system pruning. The sessions concluded with a Question-and-Answer session and details on how to stay engaged and share feedback via the IRP webpage and IRP mailbox.

Through the promotion of the webinar through both municipal conferences and channels, as well as the fall newsletter, the webinars attendance rate is provided in Figure 5.4. While the webinar in Fall 2023 saw higher attendance levels in the Northern/Eastern and Southeast/Southwest regions, there was a significant increase in engagement with attendees with more questions asked during the Q&A portion and after through the IRP email.

Figure 5.4 – IRP regional webinar attendance



During each session, attendees were encouraged to view the IRP webpage for more information and were automatically registered to receive email updates on project information, page updates and upcoming newsletters. The feedback and responses shared during the webinars have been captured and shared on the IRP webpage, along with copies of the presentation decks.[13]

Targeted / Project-Specific Engagement

As part of Enbridge Gas' approach towards coordinated energy system planning, Enbridge Gas initiates targeted engagement efforts in areas where natural gas demand forecasting suggests a future need for a project that would trigger an LTC project. The purpose of the engagement is to determine if there is a need to adjust Enbridge Gas' demand forecasting and system design to account for potential future changes based on regional information. Outreach is extended to municipalities within a defined regional area, as well as the electric LDCs and IESO. During these meetings, Enbridge Gas shares the natural gas demand forecast that guides our system planning for the region, and requests additional information from attendees to inform energy system planning and design.

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 Leave to Construct 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. Enbridge Gas has enhanced the engagement process with contract

[13] Regional Planning & Engagement | Enbridge Gas

customers through this EOI/ROS process, where incremental questions on energy efficiency as it relates to reduction in contract bids or existing demand have been included. 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, 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, LDC, IESO and 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. In May 2024, Enbridge Gas notified all stakeholders who had signed up for updates through the Enbridge Gas Regional Planning and Engagement webpage, inclusive of the IESO and municipal staff from the City of Sarnia, the Town of Parry Sound, the County of Lambton, the Town of Plympton-Wyoming, and the Village of Point Edward, that the Pilot Projects were being revised to reflect recent updates to the Company's 10-year capital forecast. Enbridge Gas provided an overview of the planned Pilot Project updates at the time and had filed a letter with the OEB (dated April 30, 2024) regarding the updates and next steps.

In May 2024, Enbridge Gas notified municipal staff from the Town of Plympton-Wyoming that the Southern Lake Huron Pilot Project would no longer be targeted to their community in the updated IRP Pilot Project application and would instead be focused on the City of Sarnia and the Village of Point Edward, in order to leverage the advance meter reading technology already in place in those communities. In June 2024, Enbridge Gas notified the municipal staff from the Town of Parry Sound that the Company planned to withdraw the Parry Sound Pilot Project from the updated IRP Pilot Project application. Enbridge Gas also communicated with the municipal staff from the City of Sarnia and Village of Point Edward to advise them of the update to the Southern Lake Huron Pilot Project for their community. The City of Sarnia reconfirmed their support for the updated pilot, and the Village of Point Edward's council passed a resolution to send a letter of support.

Indigenous Engagement

IRP has continued to provide Enbridge Gas' 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.

Specific to the Pilot Project, in May 2024, pilot project updates were provided to Aamjiwnaang First Nation and Chippewas of Kettle and Stony Point First Nation. In June 2024, email notification was sent to Wasauksing First Nation advising that the Parry Sound Pilot Project would not be proceeding.[14]

In July 2024, the Three Fires Group on behalf of Chippewas of Kettle and Stony Point First Nation requested a meeting with their new board of directors. Enbridge Gas provided an overview of IRP and discussed the pilot project.

[14] EB-2022-0335, IRP Pilot Projects Application, Exhibit F, Tab 1, Schedule 3, June 28, 2024

Figure 5.5 – Example of the Indigenous newsletter IRP section

Summer 2024

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.

Updates:

As a part of its process, Enbridge Gas has developed the Southern Lake Huron Pilot Project to test IRP alternatives in the City of Sarnia and Village of Point Edward. Enbridge Gas has adjusted the original pilot plans based on changes to its 10-year capital forecast to better focus on achieving learnings in a manner that optimizes budget and timeline efficiencies. We submitted our evidence at the end of June.

What's new:

- In the Enbridge Gas 2024 Rebasing application, the OEB positioned system pruning as a potential IRP approach. System pruning involves the decommissioning of a portion of the natural gas system that is no longer required to serve the needs of energy users. For this to occur, all customers served by that pipeline system must fully convert off natural gas and be willing to disconnect from the pipeline system. System pruning can be supported by an IRP solution, including supporting existing customers in replacing their natural gas equipment with electric equipment.
- Enbridge Gas confirmed it is committed to working with the Ontario Energy Board-established IRP Technical Working Group and other relevant stakeholders to consult on system pruning processes and what role the Company could play in a system pruning pilot.

Contact us:

Stay informed about the Southern Lake Huron Pilot Project, system pruning, and everything else IRP by registering for updates here. We are always looking for feedback so please reach out to irp@enbridge.com with your questions and comments.

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 2024.

In 2024, Enbridge Gas did not file any non-Pilot IRP Plan applications with the OEB. However, Enbridge Gas concluded the implementation of an IRPA for the Kingston Reinforcement Project and focused on the assessment on key priority projects with IRP Plan potential.

Kingston Reinforcement Project

The East Kingston Creekford Rd Reinforcement project was a planned capital reinforcement, and Enbridge Gas determined that this project could be deferred by implementing a supply side IRPA in the form of CNG beginning in 2022. As CNG can be quickly injected into the natural gas system once the proper modifications have been made and a CNG trailer is secured, it ensured near-term system constraints could be addressed while other IRPAs were considered. Without the CNG injection, the Kingston system was anticipated to fall below its minimum pressure requirements as early as the Winter of 2022/2023. Given the urgency of the near-term constraint and need, Enbridge Gas did not wait to implement the CNG alternative and CNG was procured for the winters of 2022/2023 and 2023/2024. The CNG agreement provided time for Enbridge Gas to implement a Contract turnback to reduce contract demand avoiding the facilities project. The turnback provided 2,200 m^3/hour and 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.[15]

As part of the 2022 Utility Earnings and Disposition of Deferral & Variance Account Balances Settlement Proposal, parties agreed that it was appropriate for Enbridge Gas to clear the balances as requested for clearance[16] for the supply-side CNG IRPA for the East Kingston Creekford Rd reinforcement project.[17] OEB Staff submitted that enabling Enbridge Gas to record project costs of this nature in the IRP deferral accounts without an IRP Plan approval supports the OEB’s intent for Enbridge Gas to give greater consideration to IRP alternatives, and also promotes administration efficiency, enabling Enbridge Gas to pursue smaller IRP projects without seeking an IRP Plan approval.[18] The Settlement Proposal was approved as filed in February 2024.[19] Parties agreed on the clearance of the 2023 balances for the supply-side CNG IRPA requested for clearance as part of the 2023 Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism Settlement Agreement.[20] The OEB did not accept the Settlement Agreement, noting concerns on issues unrelated to IRP, and parties have asked for reconsideration of that decision. Enbridge Gas will be seeking recovery of the ongoing 2024 CNG IRPA costs in the 2024 Utility Earnings and Disposition of Deferral & Variance Account Balances Application. The system will be reviewed and monitored as part of normal annual updates and forecasting processes to understand if there are any changes to the system need.

Owen Sound Reinforcement Project

The Owen Sound County Rd 40 reinforcement was a 12km NPS 12 4,670 kPa project, continuation of the Phase 4 loop reinforcement along the existing Owen Sound lateral, with a project in-service date of 2025 in the 2023 – 2032

[15] EB-2023-0092, Exhibit C, Tab 1, June 14, 2023, p.20-25.
[16] EB-2023-0092, Exhibit N1, Tab 1, Schedule 1, November 28, 2023, p.7
[17] Also see EB-2023-0092, Exhibit N1, Tab 1, Schedule 1, November 28, 2023, p.10-11: “There was a small amount ($2,860) included in the 2022 IRP Operating Costs Deferral Account related to foregone revenue from a customer who turned back capacity as part of an IRP project in Kingston. Parties did not agree on the clearance of this part of the account balance. Instead, parties agreed that this amount will be carried forward to the 2023 account.” Also see EB-2024-0125, Exhibit C, Tab 1, p. 20: “Enbridge Gas is no longer seeking recovery of the lost revenue associated with the contract demand reduction for this project.”
[18] EB-2023-0092, OEB Staff Submission on Settlement Proposal, page 6.
[19] EB-2023-0092, Decision on Settlement Proposal and Rate Order, February 6, 2024, p 4.
[20] EB-2024-0125, Settlement Agreement, October 10, 2024.

AMP Addendum (Investment #30542). The primary driver of the project was growth. Enbridge Gas reviewed this project for IRPAs including:

- Supply-side alternatives: CNG
- Demand-side alternatives: ETEE, DR, and contract & interruptible rates review

In each municipality located downstream of the reinforcement project, Enbridge Gas initiated stakeholder engagement sessions in October and November 2023 with representatives of the municipalities, electric LDCs, Hydro One and the IESO to allow Enbridge Gas to provide a high-level overview of the project and seek input on the forecasted system growth and demands within their region. This included the Municipality of Grey County, City of Owen Sound, Municipality of Meaford, Town of the Blue Mountains, Township of Georgian Bluffs, Bruce County, Town of Saugeen Shores, Municipality of Arran Elderslie, and Town of South Bruce Peninsula.

Enbridge Gas implemented an In-Franchise Binding Reverse Open season, which offered contract customers within the proposed project service area an opportunity to “turnback” or reduce their existing contracted capacity. No responses were received.

The analysis of the IRPAs indicated that CNG was a viable option in deferring the project by a minimum of five years. A project team was assembled to begin the development of the IRP Plan and to review the scope of the CNG IRPA in greater detail.

As a result of the SRP updates described in Section 3, the timing of the Owen Sound project shifted from 2025 to 2031 and the development of the IRP Plan for this project was put on hold in Q1 2024. The project will be reassessed after the SRP update in 2025.

IRP Evaluation in Progress

As Enbridge Gas continues to work through the IRP economic evaluations of projects that have passed technical evaluation, targeted engagement is initiated in parallel to confirm the demand forecast and project scopes, as discussed in Section 5. This includes stakeholder engagement sessions with representatives from local municipalities located within the project area, local LDC, Hydro One and IESO, where Enbridge Gas provides a high-level overview of the system need and requests input on the forecasted system growth and demands within the region. Enbridge Gas also initiates an EOI/ROS process for contract customers, where applicable, to confirm contract customer demands and follow up with additional engagement to review energy efficiency opportunities in the context of both DSM and IRP potential. Table 6.1 summarizes the list of projects where targeted engagement occurred in 2024:

Table 6.1 – Summary of Stakeholder Engagement for Projects in Progress

Project (#)	Stakeholder Engagement	EOI/ROS	Status
L’Orignal Reinforcement (#7743)	**Date of Engagement:** Nov 19, 2024 **Stakeholders Engaged:** United Counties of Prescott & Russell, and the United Counties of Stormont, Dundas & Glengarry, Hydro 2000, Hydro One, IESO	**EOI/ROS Issued:** October 4, 2024	Currently rescoping based on EOI/ROS bids.
Listowel (#31019)	TBD pending rescoping.	**EOI/ROS Issued:** November 4, 2024	Currently rescoping based on EOI/ROS bids.

Area 20 (#30500, #30501,31018)	**Date of Engagement:** Oct 3, 2024 **Stakeholders Engaged:** Peel Region, Dufferin County, Wellington County, Grey County, Hydro One, IESO, Alectra, Orangeville Hydro	Initial engagement with contract customers in area occurred in November 2024. No customers expressed interest in change in contract.	Currently rescoping based on customer driven growth.

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.”[21]

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.

Traditional facility alternatives have routinely been considered when scoping out facility needs, where applicable, to ensure the most optimal facility alternative is included in the asset management plan. Enbridge Gas also routinely utilizes forecasted gas supply contracts when developing its 10-year asset management plan which can impact the timing of transmission projects and has the potential to avoid or reduce infrastructure projects, by providing firm supply at known transmission system locations. Enbridge Gas designs facility transmission requirements including these deliveries**.** Additionally, for distribution pipelines that fall under the Enhanced Distribution Integrity Management Program (EDIMP), Enbridge Gas applies the asset life extension (ALE) approach in evaluating and identifying ALE alternatives. The additional assessments will determine the appropriate mitigation approach, whether that results in a full replacement of gas infrastructure or targeted repairs to the assets to extend the useful life or a combination.

IRP alternatives are reviewed downstream and assessed against a project scope where traditional facility alternatives have already been considered. It should be noted that this process can be iterative due to the dynamic nature of facility planning and changes to the demand forecast. Therefore, project scopes for both traditional and IRP alternatives are 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, limited electrification measures were proposed as part of the Southern Lake Huron pilot project as a unique opportunity to evaluate potential applicability and feasibility of electrification measures in an isolated environment, where broader implementation in the future would require integrated energy planning across energy sources. As part of the IRP Pilot

[21] EB-2020-0091, IRP Planning OEB Decision and Order, July 22, 2021, p. 36

Decision and Order, the Commissioners indicated that electrification measures are now appropriate as part of IRP.[22] On the same day as the IRP Pilot Decision and Order was released, the OEB issued a motion to review its own Decision and Order, which sets out questions around whether it was appropriate for the IRP Pilot Decision and Order to broadly endorse electrification measures as part of IRP.[23]

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 also expects the IRP pilot projects to provide more information allowing for refinement and updating of the impacts of some of the IRP alternatives listed.

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[22] EB-2022-0335, IRP Pilot Project Decision and Order, March 27, 2025
[23] EB-2025-0124, Notice of Review on the OEB"s own Motion, March 27, 2025

Section 8 – Technical Working Group Summary

In the IRP Decision, the OEB directed that an IRP Technical Working Group 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 Technical working group can be found on the OEB website.[24]

Attached in Appendix E: Technical Working Group Report is a report prepared by the IRP Technical Working Group.

[24] Natural Gas Integrated Resource Planning (IRP) | Engage with Us (oeb.ca)

Section 9 – DCF+ Update

In the IRP Decision, the OEB concluded that the DCF+ test should be the economic evaluation test used under the IRP Framework. Further, the OEB recognizes 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 improvements to the DCF+ test for IRP and encouraged consultation with the TWG, which includes representatives from Enbridge Gas, OEB staff, and non-utility members.[25]

Consultation with the TWG commenced at the beginning of 2022, with dedicated subgroup meetings on DCF+ beginning in July 2022. Those meetings continued throughout 2022 and 2023. Discussions and considerations were captured in a report prepared by the TWG on May 30, 2023 as well as a draft of the DCF+ Supplemental Guide (the “Guide”) shared initially by Enbridge Gas on September 26, 2023 which is intended to accompany the enhanced DCF+ test that Enbridge Gas will file as part of the first non-pilot IRP Plan application. Comments on the Guide were shared and discussed in the October 3, 2023 meeting. On November 28, 2023, Enbridge Gas presented a walk-through of the DCF+ calculation using an illustrative example in Excel. The December 12, 2023 meeting continued with the review of the Excel calculations.

TWG engagement on DCF+ topics resumed in the second half of 2024. On July 25, 2024, discussions were focused on non-energy benefits (NEBs) from both participant and societal perspectives within phase 2 and phase 3 of the DCF+ test. Phase 2 consideration of NEBs was around whether there is value in pursuing other phase 2 NEBs besides the accentuating factor for energy efficiency benefits. Key areas of the discussion on phase 3 NEBs included consideration of indicators for economic impacts from other jurisdictions, the applicability and methodological derivation of GDP and jobs multiplier results to project costs and their associated considerations for additivity of phase 3 results, and any consideration of the social cost of carbon in the DCF+ calculation as well as any additivity in phase 3 results.[26] Following this meeting, TWG members provided material from other jurisdictions regarding NEBs for Enbridge Gas to review and consider. Additionally, Enbridge Gas had provided a summary of TWG comments received on the DCF+ Guide, accompanied by its response and clarifying comments. A request was made to provide a second draft version of the Guide to capture subsequent discussions from the first version shared in September 2023.

On August 21, 2024, the updated DCF+ Guide was shared, with further discussion on phase 3 NEBs. The discussions explored whether phase 1 was expressed in nominal or real terms, to what extent existing approaches from EBO 188 and EBO 134 should continue to be relied on for DCF+, and the appropriate forecasts of natural gas and electricity prices. TWG members provided written comments on the Guide subsequent to the meeting.

On September 25, 2024, Enbridge Gas provided a summary of TWG members’ comments on the second draft of the Guide along with its written responses to the comments received and also a summary on the NEBs documents shared. The discussion that followed focused on the appropriateness of adding the phases in light of concerns raised regarding inconsistent treatment of nominal and real discount rates and associated valuation streams within and across phases, of an “apples and oranges” valuation of project costs versus economic impacts using multipliers, and the reliance on EBO 134 as the basis for summing phases in DCF+.

On October 17, 2024, OEB Staff requested a written explanation on the potential resolution for the real versus nominal issue for the DCF+ test. Enbridge Gas provided an expanded response to the information request on January 16, 2025, which provided a resolution to the nominal and real concern by confirming that discount rates and

[25] EB-2020-0091, IRP Planning OEB Decision and Order, July 22, 2021, p. 56-57.
[26] Enbridge Gas continues to consider its position on the social cost of carbon, and the working group discussions are without prejudice to the position Enbridge Gas or other members of the group may take on this topic in future filings with the OEB on applications or other proceedings (including in respect of the mandate and jurisdiction of the OEB relating to this topic).

value streams would be nominal within and across phases 1 and 2, thereby making both phases additive. Additionally, it proposed to present results of phase 3 separately given the concerns around adding project costs and multiplier results.[27]

[27] Discussed at TWG Meeting #49, March 19, 2025 (link to meeting minutes)

Section 10 – System Pruning Update

In the Rebasing Phase 1 Decision, the OEB describes addressing stranded asset risks of 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."[28]

In the Company's submission for Phase 2 of its 2024 Rates 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 would be completed to identify how utilities in other jurisdictions are approaching natural gas system pruning to identify best practices, where applicable.[29]

In the Settlement Agreement for Phase 2 of the Company's 2024 Rates Application, Enbridge Gas and all parties agreed that it is appropriate for Enbridge Gas to develop and implement a system pruning pilot project. The Parties agreed that Enbridge Gas will develop its approach to system pruning in consultation with the IRP TWG by the end of Q2 of 2025 and begin implementation on one or two pilots by the end of Q1 of 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.[30] The OEB accepted the Settlement Proposal on November 29, 2024.[31]

Given the timelines for the development and implementation of the System Pruning Pilot, a comprehensive summary of the work completed to date since the Settlement Agreement has been included below.

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 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 were deferred until consultation and cost-award eligibility were reinstated by OEB Staff. Since the end of the writ period, Enbridge Gas has had regular meetings with the TWG Subgroup and full TWG to advance the approach and confirm support by the end of June 2025 for the System Pruning approach elements.[32]

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[28] EB-2022-0200, Phase 1 Decision and Order, December 21, 2023, p. 52
[29] EB-2024-0111. Phase 2, Exhibit 1, Tab 17, Schedule 1, April 26, 2024, p.17-27
[30] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1 Schedule 1, November 4, 2024, p.19-20.
[31] EB-2024-0111, Decision on Settlement Proposal and Interim Rate Order, November 29, 2024.
[32] Engage with Us, OEB (link) System Pruning Subgroup Meetings #2, 3, 4, 5 (January 12, 2025, March 20, 2025, April 17, 2025, May 15, 2025), TWG Meetings #50, 52, 53 (March 26, 2025, April 23, 2025, May 7,2025, May 21, 2025, Iune 4, 2025, June 25, 2025)

Appendix G provides the most current summary on the system pruning approach, developed in consultation with the TWG and with their feedback incorporated.

Section 11 – IRP Planning for 2025

This section provides a high-level summary of the work streams that Enbridge Gas expects to build upon and evolve further in 2025. These work streams are continuations of the work completed in 2024 as Enbridge Gas continues to make strides regarding IRP pilots, IRP evaluations, external rightsholder and stakeholder engagement initiatives, policy proposals and the evolution of economic evaluation.

External Stakeholder Outreach

Enbridge Gas will continue with its external stakeholder efforts including ongoing engagement with municipalities through conference attendance and existing stakeholder engagement relationships, as opportunities to engage on IRP and further develop stakeholder lists to promote online engagement and newsletter enrollment.

Enbridge Gas will schedule regional or general stakeholder engagement sessions to increase understanding of the IRP process, provide updates on on-going IRP initiatives, and highlight key projects within regions. Feedback received from these stakeholder engagement sessions will be reviewed and considered for subsequent stakeholder sessions.

For the IRP Pilot Project, a stakeholder plan has been included in Appendix H.

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. Enbridge Gas will explore engagement with the Indigenous Working Group to provide updates on the IRP. For Indigenous groups for pilot areas, separate geotargeted engagement will occur, although Indigenous groups are welcome to attend all public engagement initiatives.

As Enbridge Gas works through the 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 confirm 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, and Enbridge Gas will continue to seek opportunities for planning coordination with IESO and electricity LDCs.

Enhancements to the Regional Planning webpage will continue, inclusive of updates to the IRP Pilot Project and System Pruning pilot, noted in Section 4 and 10 respectively. It will also include opportunities to share feedback with Enbridge Gas' team that is responsible for IRP-related stakeholder communication and community engagement.

Continued IRP Evaluations

Enbridge Gas will continue to review and complete the technical and economic evaluation processes for projects from the 2025-2034 AMP. Enbridge Gas will continue to consult with the IRP TWG on the economic evaluation, including the interpretation and results of the DCF+.

For projects that pass both the technical and economic evaluation, Enbridge Gas expects to develop and subsequently file a stand-alone non-Pilot IRP Plan application and supporting evidence with the OEB for approval.

Enbridge Gas plans to consider the results of the economic evaluation to identify investment characteristics that could be used to determine whether an IRPA could be an economic approach to addressing a system constraint and, conversely, where an IRPA could not be an economic approach. Enbridge Gas expects this will inform opportunities to adjust or simplify the IRP evaluation criteria and overall approach, in consultation with the IRP TWG.

An update on the projects reviewed from the 2025-2034 AMP will be provided in the 2025 Asset Management Plan Addendum, anticipated to be filed in Fall 2025.

Enbridge Gas will continue to work with Posterity Group on updating the IRP model for assessing ETEE potential through refreshing data inputs and refining modelling approaches, assumptions, and methodologies to improve forecasting of peak hourly flow reduction potential and costs. Enbridge Gas will bring forward key assumptions and elements of the model to the TWG and will continue the work and consultation initiated in 2024 to summarize the information to allow for a more comprehensive understanding of the model to obtain technical input from the TWG. Additionally, Enbridge Gas will continue to refine the input assumptions for ETEE based on learnings and findings from the pilot as they become available.

DCF+ Test

Until an enhanced DCF+ test has been approved by the OEB, Enbridge Gas will continue to consult with the IRP TWG on the interpretation and results of the DCF+ for investments undergoing economic evaluation in 2025, the considerations and approach for sensitivity analysis, as well as other topics as needed. Enbridge Gas will file a submission on the DCF+ test as part of its first non-pilot IRP Plan

Pilot Projects

As noted in Section 4, the OEB issued a Decision on the Southern Lake Huron IRP Pilot Project on March 27, 2025. Enbridge Gas has engaged with the IRP TWG in the development of a detailed project plan, included in Appendix H. In 2025, Enbridge Gas will implement the multi-faceted pilot project, executing the project plan elements which 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 review over the term of the pilot.

System Pruning

As noted in Section 10, in the Settlement Agreement for Phase 2 of the Company's 2024 Rebasing Proceeding, parties agreed that it is appropriate for Enbridge Gas to develop and implement one or two system pruning pilot projects. Enbridge Gas has developed the approach for the pilot(s) in consultation with the TWG and informed by a jurisdictional scan. Additional details are provided in Appendix G. Enbridge Gas will determine pilot location(s) for implementation to begin by the end of Q1 2026.

Policy Proposals

Enbridge Gas and the TWG have held discussions on IRP-related policy proposals, with input informing considerations for Enbridge Gas when it brings forward its first non-pilot IRP Plan application. Policy elements included attribution of DSM versus IRP, the role of shareholder incentives and performance metrics, incrementality and the use of IRP Deferral Accounts, and consideration of how risk associated with facility projects and IRPAs could be considered. Enbridge Gas will continue to consult with the IRP TWG on policy issues with the goal of contributing to the development of proposals prior to filing. As per the Rebasing Phase 2 Settlement, 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). If there is no IRP Plan application in 2025, then Enbridge Gas will file a standalone application or request to the OEB for approval of an incentive mechanism within that same timeframe.[33]

As an input to inform IRP policy considerations and the IRP framework considerations more broadly, Enbridge Gas is planning to retain a consultant in 2025 to perform a jurisdictional scan to understand the current IRP framework and policy elements in place in other jurisdictions, how the approach is informed by the policy environment in the jurisdiction, outcomes and results for IRP, areas of commonality, divergence and associated implications for IRP outcomes. Enbridge Gas anticipates the landscape assessment conducted for the system pruning jurisdictional scan, and some elements of that scan will be leveraged as an input in the broader IRP jurisdictional scan for efficiency.

Framework Consultation

The OEB released a letter on March 27, 2025, outlining it is launching a consultation to support a review and evaluation of its IRP Framework for Enbridge Gas (EB-2025-0125). As outlined in the letter an OEB Staff report

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[33] EB-2024-0111, Phase 2, Exhibit N, Tab 1, Schedule 1, p.35.

assessing progress implementing the IRP Framework and proposed updates to the IRP Framework are targeted for release in September 2025. This will be followed by OEB staff hosting a stakeholder meeting in October 2025 to discuss the proposed updates and solicit verbal comments, followed by an opportunity to file written comments on the proposed updates.

As an input to the process, OEB Staff has communicated they will be engaging the TWG over the course of 2025 to provide an opportunity for in-depth discussion on specific themes and issues, as well as key developments and lessons learned to-date.

Appendix A: OEB IRP Directives and Progress Towards 2024 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 Rates 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 EB-2020-0091, Enbridge Gas 2025-2034 AMP

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.[34] 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 incremental costs related to these activities for later recovery.[35]

[34] EB-2022-0200, Exhibit O1, Tab 1, Schedule 2, September 12, 2023, p. 39 and 40,
[35] EB-2024-0111, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p.19-20,

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 and Appendix H.

The table below provides Enbridge Gas’s progress toward meeting the 2024 priorities as defined in the 2023 IRP Annual Report and 2023 IRP Technical Working Group report.

Priority	Activity	Status
External Stakeholder / Municipal Outreach	External stakeholder outreach (including broader discussions with municipalities and municipal organizations, collaboration with IESO on best practices, regional engagement sessions, and geotargeted engagement in pilot areas)	In progress – See Section 5
Planning/ Coordinating with the Electric Sector	Consultation with electric LDC and IESO to understand best practices for engagement and planning coordination.	In progress – See Section 5 and 10
IRP Evaluation / AMP Update	IRP binary screening, and technical and economic evaluations of system needs in the Asset Management Plan.	In progress – See Section 3
DCF+ Test	DCF+ Test (submission as part of first non-pilot IRP proceeding)	In progress – See Section 9
IRP Pilot Project	Pilot projects (pending regulatory approval and implementation)	In progress – See Section 4, Appendix H
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, and attribution between DSM and IRP	In progress – See Section 11
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 10, Appendix G

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, water heating equipment, and building envelope upgrades. Enbridge Gas will be 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.[36] 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.[37] Posterity Group's IRP model is run through Posterity's Navigator software, where the details in how the Navigator software works and how the model parameters interact with each other are available and documented.[38] Posterity Group and Enbridge Gas are working 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.

[36] 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
[37] 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
[38] 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

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.[39] Posterity Group and Enbridge Gas plan to continue to evolve this model 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 implementation of 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. - 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

[39] 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

Enbridge Gas has indicated 2023 learnings from natural gas IRP in other jurisdictions in Appendix A.

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.[40] 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.

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.

The OEB had determined that it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs as part of the first-generation IRP Framework; however, the Company is testing electric heat pumps as part of the IRP Pilot application to evaluate these measures on a limited basis and as a component of the broader DSM programming. As noted in Section 7, as part of the IRP Pilot Decision and Order, the Commissioners indicated that electrification measures are now appropriate as part of IRP. On the same day as the IRP Pilot Decision and Order was released, the OEB issued a motion to review its own Decision and Order, which sets out questions around whether it was appropriate for the IRP Pilot Decision and Order to broadly endorse electrification measures as part of IRP.

To better understand how non-pipeline electric alternatives could be offered more broadly in the future, Enbridge Gas has undertaken some jurisdictional research in-house including attending industry webinars.

High-level learnings to date include that the Colorado Public Utilities Commission includes beneficial electrification as a non-pipeline alternative to offset gas infrastructure investments in the long-term. 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.[41] Additionally, the California Energy Commission is funding two building electrification and gas infrastructure decommissioning pilots.[42]

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.

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[40] IRP ETEE-DR Pilot Review April 8, 2022. [Guidehouse (IRP ETEE-DR Pilot Review)]
[41] Strategen, Non-Pipeline Alternatives to Natural Gas Utility Infrastructure: An Examination of Existing Regulatory Approaches, November 2023.
[42] 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)]

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 will be 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[43] and adjusted for Ontario climate/buildings.[44] 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.
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 will engage 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

[43] https://www.calmac.org/publications/SoCalGas_2019_DR_Evaluation_Report_-_PUBLIC_FINAL.pdf
[44] Adjustment for Ontario climate/buildings provided on p.2 - Link

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 would provide insight on the time required to design a DR program and to deliver a DR program to reach participation levels required of the specific facility IRPA. 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 the implementation of 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 [45]. 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.

[45] 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 remotely 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 or points between Enbridge Gas's system and other pipelines such as the TC Energy Mainline and US based pipelines such as Panhandle Eastern Pipeline Company and Vector. 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 with incremental deliveries or pressure.
IRPA Peak Impacts
Incremental deliveries or increased pressure must be delivered in the project's 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.
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. However, for US pipelines, the Federal Energy Regulatory Commission rules dictate that US pipelines cannot sell capacity more than "90 days from the contract start date". Given that many of Enbridge Gas's interconnects are with US pipelines it may be difficult to utilize the market-based supply-side services for an IRP alternative.
IRPA Implementation Risks/Challenges
There are two primary operational risks with market-based supply-side alternatives: lack of renewal rights and failure to deliver. Most market-based supply-side alternatives are short-term (1-3 years) and lack renewal rights making it difficult to rely on long-term to reduce or mitigate a project need. In many instances, a market-based supply-side alternative will 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 [46]
- Investments that did not pass the technical evaluation stage are included in Table 4
- Investments that passed the technical evaluation stage and awaiting economic evaluation in Table 5
  Investments that are awaiting/pending Technical Evaluation are included in Table 6

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	$1,606.2 M	690
Grand Total	**$1,606.2 M**	**690**

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.	$1,889.7 M	59
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.	$219.5 M	3
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.	$469.9 M	865
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	$3.9 M	2
Emergent Safety - If an identified system constraint/need is determined to require a facility project for Enbridge Gas to offer	$6.1 M	3

[46] Appendix F, Table 1 outlines investment categories which did not pass the technical screening stage.

safe and reliable service or to meet an applicable law, an IRP evaluation is not required.		
Grand Total	**$2,589.2 M**	**932**

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	$5.7 M	3
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.	$460.1 M	606
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.	$148.3 M	97
Hydrogen related projects are required as no IRPAs can replace the hydrogen feasibility assessments and hydrogen blending initiatives.	$6.6 M	1
Distribution station condition related, IRPA not applicable	$485.2 M	53
Additional Screening for Investment descriptions where IRPAs are not applicable	$3,991.9 M	385
Project Status/Timing Related	$226.1 M	11
Grand Total	**$5,323.8 M**	**1156**

As Enbridge Gas progressed to the Technical Evaluation stage of the IRP framework for determining the technical viability of IRPAs to eliminate, reduce or defer the investment project scope, review of investment project scopes indicated that not all investments passing Binary Screening would require a detailed technical evaluation due to the nature of the project scope. A detailed technical evaluation involves network modelling of customer demands and demand reductions required to meet system needs. This rigorous and time intensive process would not be applicable to investment categories outlined in Table 3 as outlined in the detailed category descriptions provided in Appendix F, Table 1.

Thus, the "Technical Evaluation" stage of the IRP Evaluation process was updated to "Technical Screening and Evaluation" as shown in Figure 3-1. Enbridge Gas has discussed and reviewed the Technical Screening and Evaluation Process with the TWG to obtain feedback and will continue to engage with the TWG for further improvement and refinement of the IRP Evaluation Process.

The category in Table 3 with the highest capital costs is "Additional Screening for Investment descriptions where IRPAs are not applicable". This category is comprised of multiple different subcategories of investments where IRPAs would not be applicable, primarily due to the programmatic nature of the investments which are integrity related as opposed to individually distinct projects. While the Binary Screening stage includes a screening criterion for Pipeline and Relocation Projects that are below a $2 M threshold, programmatic spend on essential integrity related programs with annual spend greater than $2 M pass the Binary Screening stage however they do not have applicable IRPAs that could defer, reduce, or eliminate the investment scope due to the nature of the work.

Examples of these subcategories are listed below:

- AMP Fitting
- Class Location
- Corrosion
- Farm Taps
- Facilities Integrity Management Program
- Fire Suppression
- Geohazard
- Independent Asset Integrity Review (IAIR)
- Integrity Retrofit
- Inside Room Regulators
- Low Pressure Delivery Meter Sets (LPDMS)
- Meter Exchanges
- Maximum Operating Pressure (MOP verification)
- Pressure Factoring Metering (PFM Program)
- Remote Terminal Units

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. • Where applicable - It is recommended to maintain pipe size for trunk mains or system resiliency	$75.2 M	28
ETEE - Potentially could reduce project scope. Project has failed the technical evaluation as this is a trunk main which should not be downsized due to security of supply.	$2.2 M	1
Grand Total	**$77.4 M**	**29**

Table 5 – Breakdown of Investments passing Technical Evaluation in the 2025-2034 AMP for IRP

Category	2025-2034 Forecast (Includes overhead allocation)	# of Investments
Growth related projects	$151.5 M	26
Growth related projects - Low Cost, Low Value	$4.3 M	23
Distribution Pipe related projects	$1.8 M	1
Grand Total	**$157.6 M**	**50**

Table 6 – Breakdown of Investments awaiting/pending Technical Evaluation in the 2025-2034 AMP for IRP

Category	2025-2034 Forecast (Includes overhead allocation)	# of Investments
Distribution Pipe related projects • Future year replacement projects are in the queue for IRP Evaluation and will be assessed annually when the scope is confirmed	$363.1 M	117
Distribution Pipe related projects • Technical Evaluation awaiting further integrity assessment (through EDIMP) to confirm project scope and timing	$41.7 M	2
Transmission Pipe & Underground Storage related projects • Technical Evaluation will be conducted when the scope is confirmed.	$766.5 M	5
Grand Total	$1,171.3 M	124

Appendix D: IRP Screening Results for LTC Projects

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-2022-0203	Ridge Landfill RNG	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. The Project was driven solely by a specific customer's (Waste Connections) request for facilities to connect to Enbridge Gas's existing natural gas distribution system. Waste Connections has executed a long-term contract including a CIAC to fully fund the cost of the Project.	OEB Decision dated April 6, 2023: the proposed Project falls under the customer-specific build category in the OEB's IRP framework, which obviates the need for an IRP evaluation.
EB-2022-0155	Crowland well upgrade replacement project				Enbridge Gas stated that it is not aware of any comparable alternative facility or non-facility solution that would enable gathering information on the rock properties of these specific geological formations.	OEB Report of the Board September 13, 2022: found that there is a need for the Project. The OEB notes that any future conversion of EC 1 from a test well to an observation or injection/withdrawal well would be subject to Enbridge Gas receiving approvals from the MNRF.
EB-2022-0086	Dawn to Corunna Replacement Project		Fail		The Company applied the OEB-approved Binary Screening Criteria to the Project and determined that it is not possible to implement and resolve the identified system constraint within	OEB Decision dated November 3, 2022: found that the assessment of alternatives was

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					the timeframe required. As stated in the OEB's IRP Framework for Enbridge Gas: ii. 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. Although an IRP assessment was not required, Enbridge Gas did undertake an IRP review. This found that the cost of an ETEE program that could deliver 90 TJ/d of demand reduction in the most favorable market downstream (EGD rate zone – CDA) of the Project is estimated to be approximately $980 million. Further, this alternative would require additional expenditures of a similar magnitude every 10-15 years to maintain this reduction over the depreciable life of the proposed Project, which is currently anticipated to be approximately 40 years	sufficient for the purpose of selecting the Project as the preferred option. The OEB found that an Integrated Resource Planning assessment is not required in this case under the current Integrated Resource Planning Framework.
EB-2022-0003	NPS 20 Waterfront Relocation Project		Fail		Enbridge Gas applied the Binary Screening Criteria and determined that the need underpinning the Project does not warrant further IRP consideration, as the Project is driven by a need that must be met within 3 years: 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	OEB Decision dated July 7, 2022: found that an IRP assessment is not required in this case given that the proposed Project is a like-for-like with no growth component and has a tight timeline.

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.	
EB-2022-0088	Haldimand Shores Community Expansion Project			Fail	Enbridge Gas applied the Binary Screening Criteria and determined this Project meets the definition of a community expansion project 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 distribution services in the community of Haldimand Shores. Consequently, the need underpinning the Project does not warrant further IRP consideration. iv. 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.	OEB Decision dated August 18,2022: Enbridge Gas Inc. is granted leave, pursuant to section 90(1) of the OEB Act, to construct the Project in the Township of Alnwick/Haldimand as described in the Application. The OEB finds that the Project is the best alternative to meet the need. In EB-2020-0091 the OEB approved an integrated resource planning process for Enbridge Gas that required an evaluation and comparison of options to meet energy supply needs. To meet the Ontario Government's Natural Gas Expansion Program (NGEP) objective of bringing service to unserved communities the OEB provided that the consideration of such options or alternatives was not required for NGEP approved projects that have been designated in Ontario Regulation 24/19. The OEB's decision in this proceeding is in accordance with its approved integrated resource planning process
EB-2022-0247	Metrolinx Scarborough Extension – Kennedy Station	Fail	Fail		Enbridge Gas applied the Binary Screening Criteria and determined that the need underpinning the Project does not warrant further IRP consideration based on the timing criteria, as the need must be met in under three years (the proposed project has in-service dates of December 2023 for Phase 1,	OEB Decision dated May 9, 2023: Enbridge Gas Inc. is granted leave, pursuant to section 90(1) of the OEB Act, to construct the Project in the City of Toronto as described in its application.

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					and July 2025 for Phase 2). In addition, the Project is driven by a customer-specific build where Metrolinx will reimburse Enbridge Gas through a Contribution in Aid of Construction (“CIAC”) for the actual Project costs.	In the OEB’s Decision the OEB finds that the Project is the best alternative to meet the stated need. The Project is excluded from IRP considerations for the following reasons: the Project addresses a system need that must be met in under three years; Metrolinx will pay all project costs. The project is within the intent of the findings made by the OEB in the IRP Framework decision regarding customer specific builds where the customer fully pays for incremental infrastructure cost.
EB-2022-0248	Mohawks on the Bay of Quinte First Nation Community Expansion			Fail	Enbridge Gas applied the Binary Screening Criteria and determined that the proposed Project meets the definition of a community expansion project under 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 distribution services in MBQFN and the Township. Consequently, the need underpinning the Project does not warrant further IRP consideration.	OEB Decision dated September 21, 2023: Enbridge Gas Inc. is granted leave, pursuant to section 90(1) of the OEB Act, to construct the Project in Tyendinaga Mohawk Territory Reserve No. 38 and the community of Shannonville in the Township of Tyendinaga, Hastings County as described in its application. The OEB finds that the Project is the best alternative to meet the need. To meet the Ontario Government’s NGEP objective of bringing service to unserved communities, the OEB provided that the consideration of such IRP options or alternatives was not required for NGEP approved projects that have been designated in O. Reg. 24/19. The OEB’s decision in this

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
						proceeding is in accordance with its approved IRP process.
EB-2022-0249	Hidden Valley Community Expansion			Fail	As per the IRP Binary Screening Criteria (iv), the need underpinning the Project does not warrant further IRP consideration or assessment: iv. 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.	OEB Decision dated September 21, 2023: Enbridge Gas Inc. is granted leave, pursuant to section 90(1) of the OEB Act, to construct the Project in Township of Huntsville and District of Muskoka as described in its application. The OEB finds that the Project is the best alternative to meet the need. To meet the Ontario Government’s NGEP objective of bringing service to unserved communities, the OEB provided that the consideration of such IRP options or alternatives was not required for NGEP approved projects that have been designated in O. Reg. 24/19. The OEB’s decision in this proceeding is in accordance with its approved IRP process.
EB-2022-0156	Selwyn Community Expansion Project			Fail	As per the IRP Binary Screening Criteria (iv), the need underpinning the Project does not warrant further IRP consideration or assessment: iv. 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.	OEB Decision dated September 21, 2023: Enbridge Gas Inc. is granted leave, pursuant to section 90(1) of the OEB Act, to construct the Project in the Township of Selwyn as described in its application. The OEB finds that the Project is the best alternative to meet the need.

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
						To meet the Ontario Government's NGEP objective of bringing service to unserved communities, the OEB provided that the consideration of such IRP options or alternatives was not required for NGEP approved projects that have been designated in O. Reg. 24/19. The OEB's decision in this proceeding is in accordance with its approved IRP process.
EB-2022-0157	Panhandle Regional Expansion Project				Enbridge Gas reviewed potential IRPA such as firm exchange between Dawn and Ojibway, a hybrid alternative, trucked CNG, and an ETEE. These alternatives were found to not be technically feasible viable solutions.	OEB Decision dated May 14, 2024: Enbridge Gas Inc. is granted leave, pursuant to section 90(1) of the OEB Act, to construct the Project in the Municipality of Lakeshore. The OEB finds that the Project is the best alternative to meet the forecasted demand growth on the Panhandle system for the period November 1, 2024, to the winter of 2028/2029.
EB-2023-0260	Lawrence Ave East Station Relocation Project	Fail	Fail		Enbridge Gas has applied the Binary Screening Criteria and determined that the need underpinning the Project does not warrant further IRP consideration based on the timing criteria, as the need must be met in under three years (the proposed project has an in-service date of December 2024). In addition, the Project is driven by a customer-specific build where Metrolinx will reimburse Enbridge Gas through a	OEB Decision dated April 18, 2024: Enbridge Gas Inc. is granted leave, pursuant to section 90(1) of the OEB Act, to construct the Project in the City of Toronto as described in its application. The OEB finds that the Project is excluded from IRP considerations because Metrolinx will pay all Project costs. However states that

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					Contribution in Aid of Construction ("CIAC") for the actual Project costs.	in future similar application, Enbridge Gas has to provide clear evidence as to when it became aware of the project and how IRP considerations were taken into account in evaluating project alternatives. This evidence will enable the OEB to assess whether an identified system need or constraint must be met under three years.
EB-2023-0175	Watford Pipeline Project	Fail			Enbridge Gas has 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. The Project is driven solely by a specific customer's (WM's) request for facilities to connect to Enbridge Gas's existing natural gas system. WM has executed a long-term contract including a monthly service charge to be paid by the Customer.	OEB Decision dated March 7, 2024: Enbridge Gas Inc. is granted leave, pursuant to section 90(1) of the OEB Act, to construct the Project in the Municipality of Broke-Alvinston and Township of Warwick as described in its application. The OEB finds that Enbridge Gas has undertaken an appropriate review of alternatives and potential routes for the Project and finds that the proposed route is the preferred route from an environmental and socio-economic perspective.
EB-2022-0111	Bobcaygeon Community Expansion			Fail	Enbridge Gas applied the IRP 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 for funding as part of the Phase 2 NGEP. The IRP Framework 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	OEB Decision dated May 14, 2024: Enbridge Gas Inc. is granted leave, pursuant to section 90(1) of the OEB Act, to construct the Project in the City of Kawartha Lakes (including Bobcaygeon) as described in its application. To meet the Ontario Government's NGEP objective of bringing service to unserved

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					Gas to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need.	communities, the OEB provided that the consideration of such IRP options or alternatives was not required for NGEP approved projects that have been designated in O. Reg. 24/19. The OEB's decision in this proceeding is in accordance with its approved IRP process.
EB-2023-0200	Sandford Community Expansion			Fail	Enbridge Gas applied the IRP 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 for funding as part of the Phase 2 NGEP. The IRP Framework 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.	OEB Decision dated July 4, 2024: Enbridge Gas Inc. is granted leave, pursuant to section 90(1) of the OEB Act, to construct the Project in the City of Kawartha Lakes (including Bobcaygeon) as described in its application. To meet the Ontario Government's NGEP objective of bringing service to unserved communities, the OEB provided that the consideration of such IRP options or alternatives was not required for NGEP approved projects that have been designated in O. Reg. 24/19. The OEB's decision in this proceeding is in accordance with its approved IRP process.
EB-2023-0201	Eganville Community Expansion			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. The IRP Framework Decision explains that "Given the goal of the Ontario Government's Access to Natural Gas legislation to extend gas service to	OEB Decision dated May 30, 2024: Enbridge Gas Inc. is granted leave, pursuant to section 90(1) of the OEB Act, to construct the Project in the Community of Neustadt, in the Municipality of West Grey, as described in its application.

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					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.	To meet the Ontario Government's NGEP objective of bringing service to unserved communities, the OEB provided that the consideration of such IRP options or alternatives was not required for NGEP approved projects that have been designated in O. Reg. 24/19. The OEB's decision in this proceeding is in accordance with its approved IRP process.
EB-2023-0261	Neustadt Community Expansion			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 Neustadt in the Municipality of West Grey. 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	OEB Decision dated May 23, 2024: Enbridge Gas Inc. is granted leave, pursuant to section 90(1) of the OEB Act, to construct the Project in the Township of Admaston/Bromley, North Algona Wilberforce and Bonnechere Valley (including Eganville) as described in its application. To meet the Ontario Government's NGEP objective of bringing service to unserved communities, the OEB provided that the consideration of such IRP options or alternatives was not required for NGEP approved projects that have been designated in O. Reg. 24/19. The OEB's decision in this proceeding is in accordance with its approved IRP process.

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			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			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-2024-0200	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	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,

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					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.	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-2024-0322	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 not aware of any alternative to increase the capacity (volume) in the reef.	OEB Decision and Order dated May 13, 2025: the OEB granted Enbridge Gas approval to increase the MOP of the Kimball-Colinville and Bickford Storage Pools. The OEB found that Enbridge Gas established the need for the Project based on its existing regulated and unregulated storage being fully needed/contracted and expectation that there will be demand for the unregulated storage capacity created by the Project when offered to market. The OEB accepted Enbridge Gas's assessment that there are no alternatives to increase the storage capacity of its existing Storage Pools other than through an increase in the MOP.
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.	OEB issued its Report to the Minister of Natural Resources on May 8, 2025 recommending the issuance of a well drilling licence to Enbridge Gas.

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-2025-0073	Mississauga Reinforcement Project	Fail			Enbridge Gas applied the Binary Screening Criteria and determined that the Project met 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.

Appendix E: Technical Working Group Report

Review of Enbridge Gas Inc. 2024 Integrated Resource Planning (IRP) Annual Report and Update on IRP Working Group Activities

From: Integrated Resource Planning Technical Working Group

July 4, 2025

Contents

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 requires a Working Group report to be filed in the same proceeding in which Enbridge Gas's annual IRP report is filed. 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 2024 (as described in Enbridge Gas's 2024 Annual IRP Report), including individual member comments or concerns. (**Chapter 2**)
- A summary of activities undertaken by the Working Group over the previous year, from the time of the previous Working Group report (July 2, 2024) up until the Working Group subgroup meeting of June 13, 2025. (**Chapter 3**)
- The Working Group's views on priorities for implementation of the IRP Framework in 2025. (**Chapter 4**)

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.[1] 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 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

[1] The IRP Technical 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.

observers from the Independent Electricity System Operator (IESO) and EPCOR Natural Gas LP.

There were several Working Group member changes over the past year:

- IESO representative Steven Norrie was replaced by Stuti Rungee in October 2024 as an observer on the Working Group and System Pruning Subgroup.
- EPCOR Natural Gas LP representative Kenneth Poon, previously an observer on the Working Group, left the Working Group in October 2024 due to a change in position. EPCOR Natural Gas LP does not currently have a representative on the Working Group.
- Enbridge Gas is now represented on the IRP Working Group by Alison Moore (manager of IRP), Whitney Wong (IRP supervisor), and Helen Tong (IRP specialist). In addition, Catherine McCowan will be leading the system pruning work for Enbridge Gas on the System Pruning Subgroup. Other Enbridge Gas representatives also attend Working Group meetings as required, depending on the topics under discussion.

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.[2] These materials can be found at: https://engagewithus.oeb.ca/irp

[2] 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 to 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 2024 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 May 21 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

Working Group members (except observers) were asked the following questions:

> ***Having reviewed Enbridge Gas's description of its IRP activities in the previous year in its final 2024 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 the previous year? What do you think should be the top priorities for the OEB in its review of the IRP Framework? While recognizing that the IRP Framework may evolve, do you have any comments or concerns regarding the priority IRP work streams Enbridge Gas has identified for 2025 (section 11 of the Enbridge Gas annual IRP report) under the current IRP Framework?***

With regards to implementation of the IRP Framework, Working Group members generally agreed that the lack of concrete results from the current IRP Framework to date demonstrate that the current Framework is not working, and therefore supported the OEB's intent to review the Framework.

Several members expressed continued frustration with the slow pace of progress and implementation of IRP pilots. However, it was also noted that the approach to the system pruning pilot has proceeded at a faster pace, which was seen as a positive step forward.

Several members expressed concern with a perceived unwillingness of Enbridge Gas to meaningfully incorporate input from members, both generally, and specifically in the context of the Discounted Cash Flow-plus test and the now defunct Parry Sound pilot project.

Comments provided by individual members can be found below in **Table 2**.
Comments from Enbridge Gas Working Group members follow in **Table 3**.
Priorities for the coming year (including as part of the IRP Framework review) are further discussed in **Chapter 4** of this report, including a summary of member comments on this topic.

Table 2: Individual Comments of IRP Working Group Members

Working Group Member	Comments (optional)
John Dikeos (non-utility member)	Enbridge continues to make progress in operationalizing an approach to consider IRPAs as an alternative to gas infrastructure investments. From my perspective, there has been a noticeable improvement in the pace of progress over the past year, with more information being shared with the TWG, an uptick in the frequency of TWG meetings, and progress on new important initiatives such as system pruning pilots. However, 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 significant portion of gas infrastructure projects in the near future. In particular, the structure of the IRP framework has been shown to be hindering progress, so it is timely that the framework is set to be reviewed in the next few months, and I am hopeful that it will be meaningly restructured on an expedited basis to help enable success. 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. Considering the climate crisis, the potential speed of the energy transition, and the typical extended amortization period for natural gas infrastructure, the status quo approach of approving gas infrastructure projects needs to change so that IRPA projects can be considered on an even playing field to maximize long-term value for ratepayers. The current structure of the IRP Framework is not leading to this outcome. In my opinion, it

	was also inappropriate that Enbridge was not allowed to consider electrification strategies as part of the previous framework, and this decision should be reviewed. 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. The 21-month process for the review and approval of the proposed SLH pilot is woefully inadequate and this has significantly hampered progress in gaining experience with IRPAs and access to improved data on their cost and demand impacts, the effectiveness of marketing and engagement strategies, etc. The process that is being employed with the system pruning pilots seems to be moving more quickly and there are applicable learnings for broader pilots and IRPA projects in general. In addition, I strongly support Cameron's suggestion that traditional infrastructure projects need to be evaluated more thoroughly post-construction, with more thorough reviews of actual project costs and demand growth that feed into future project assessments. This will help improve ratepayer value and is also likely to improve the case for IRPA projects, further allowing them to be considered on an even playing field.
Tamara Kuiken (non-utility member)	I have reviewed and agree with the comments made by Cameron Leitch. In addition to his comments, I believe part of the collective failure of IRP is the lack of clear direction on its purpose. What problem is IRP trying to solve? In other jurisdictions, infrastructure alternatives are used to optimize fuel use in the face of infrastructure moratoria, avoid stranded assets as the system moves to known decommissioning, or meet clearly defined climate change mitigation goals within a given timeline. According to the Decision and Order, the Framework was developed in response to previous direction from the OEB that Enbridge Gas should improve its procedures for considering demand-side management as an alternative to pipelines and traditional facility infrastructure. Using that objective, the desired end product is a defined process, not implemented alternatives, and the objective has been met. Public Policy is one of the five guiding principles defined in the framework. Its inclusion is necessary because in the absence

	of policy direction, there is no clear reason to implement IRPAs. Current public policy includes an obligation to serve, financial incentives to install infrastructure, and a Natural Gas Expansion Program. It shouldn't be a surprise that IRPAs are not progressing; regulatory policy is that the process, not the alternative, is the goal.
Cameron Leitch (non-utility member)	In preparing these comments, I reviewed comments made by myself and other TWG members in IRP TWG reports from prior years, and there are themes: although the number and value of investments in the AMP has changed year-to-year, the conclusion that a fraction of a fraction of investments are identified as worthy of considering an IRPA (although none have yet succeeded) is consistent; an ongoing debate re. the application of (and modifications to) the proposed DCF+ test is unresolved. If, in 2021, one were contemplating what success might look like for gas IRP, and the individual had the benefit of foreseeing where we are in 2025 (no IRPAs proceeding, less than 2% of investments passing screening), I suspect they would conclude that something isn't working. I agree with Jay that the framework is inadequate. Per language in the Decision & Order, Enbridge recommended the DCF+ evaluation methodology as part of their Argument in Chief. The D&O suggested that modifications should be considered where appropriate, and despite exhaustive and contentious discussions with input from TWG members, Enbridge has hesitated to evolve the test based on input from several experienced members of the TWG. I don't recall a justification for not contemplating changes to the procedure (as has been detailed in comments by other TWG members in this report), other than Enbridge noting precedent in EBO 188 and 134. In my view there is adequate leeway in the D&O to develop and refine an appropriate economic test, and it remains unclear why there is such hesitation to explore improvements to the test. In any case, the TWG has spent a significant amount of time on the topic of DCF+, but the reality is that the fraction of investments that succeed through the various screening steps and eventually reach the economic evaluation step is insignificant; per Enbridge's 2024 Annual IRP Report, less than 2% of investments (both in terms of investment value and investment quantities) have reached the stage where DCF+ will be applied. Presumably of those 50/2981 investments

	($158M of nearly $11B in the AMP), most will fail during the DCF+ test. A reference point could be the 2023 IRP Report filed by Enbridge, where 63 out of nearly 4300 investments passed technical evaluation; the fate of IRPA for those 63 investments is unclear, but presumably few (if any) passed the DCF+ test. Perhaps the focus on refining the DCF+ test is unwarranted, and the TWG instead should be focusing on refinements to the various screening stages. As noted by other TWG members, the exploration of a system pruning pilot appears to be progressing. It shows that there is potential to be more agile, but whether that translates to implementation remains to be seen. Through the system pruning investigation, the jurisdictional scan offers valuable insights. In particular, likelihood of success appears greater where gas and electricity planning is truly integrated. Although separate entities are responsible for the gas and electricity utilities in Ontario, unless overall planning for both services is integrated, I don't believe that we will see best value for the rate base of either service. A very brief acknowledgement of Enbridge's intent to consult with the IESO was included in the 2023 IRP Report. The draft 2024 IRP Report includes various references to collaborating with LDCs and IESO, for example, "where Enbridge Gas provides a high-level overview of the system need and requests input on the forecasted system growth and demands within the region", but this is different than a fully integrated planning process, where the utilities work together from the ground up to build a common plan. This is obviously more complicated than it sounds, but if gas IRP as currently implemented is effectively resulting in business-as-usual facilities investments, we aren't losing anything by contemplating a significant overhaul. Regarding the plan for IRP noted in the 2025 Report, I would like to see the DCF+ Test discussion resolved. But in reaching this resolution, I would like to see Enbridge implementing input from the TWG (vs. "continuing to consult") or provide a clear justification where it chooses to ignore recommendations from the TWG. Since so few investments reach the economic evaluation stage, I do not think it would be a significant burden to compare the current DCF+ test results against a modified test that incorporates the TWG recommendations; it could highlight how the methodology

	influences the outcome. Further, and as noted by Chris, not contemplating costs associated with GHG emissions purely because the federal carbon charges were eliminated is flawed. I would like to see various methods and metrics for the cost of GHG emissions to be evaluated and a consensus reached as part of TWG efforts. I also think the various screening processes and criteria should be revisited, as hardly any investments reach the economic test. Lastly, and per comments from Jay and others, we should interrogate the assumptions that surround traditional facilities investments, as they are perceived to be the "certain" solution against which IRPAs compete. We should endeavour to apply a similar feedback loop to traditional facilities investments as we might for IRPAs: did the investment end up costing what was forecast? Did the growth that was forecast materialize in terms of timing and demand? How sensitive were the conclusions for facilities vs. IRPAs to capital costs and growth? Presumably this could be undertaken to retroactively evaluate investments in prior years to inform forward-looking plans. There is great potential to advance IRP, especially given the involvement of the highly experienced members of the TWG. It is my hope that the future TWG IRP Report for 2025 shows an inflection point occurred, where the ongoing and unresolved items from the past years of effort are resolved and true progress is realized.
Chris Neme (non-utility member)	While progress was made on a couple of issues, I am frustrated by our continued failure to work through other key DCF+ issues, particularly the failure to analyze and document the actual net job impacts of IRPAs relative to traditional supply side capital investments. I raised concern several years ago (and have re-raised the concern repeatedly since) that the current job/GDP “multipliers” used by Enbridge are poor indicators of such impacts, are highly likely to bias analytical results in the direction of options that produce the lowest such benefits/impacts, and could be corrected with a single new study. However, Enbridge has not committed to undertaking such work and the highly problematic status quo largely continues as a result. I don’t know how to read this other than as a tactic for allowing an existing process that advantages supply-side investments to continue as long as it can. This concern is exacerbated by Enbridge questioning

	whether GHG emission reduction benefits even belong in Phase 3, even though they are clearly a societal interest and concern (the elimination of the carbon tax does not mean that GHG reductions no longer have societal value). Notably the Company has suggested it is initiating a study of how other jurisdictions handle the issue – something it has not considered, let alone undertaken, on the jobs issue which was raised years earlier. I also remain frustrated that we went through the entire 2024 calendar year without launching the pilot programs. The process of planning (including plan revisions) and approvals – even for initial pilots – has been incredibly and unsustainably slow. Indeed, it appears the first pilot will be launched this year, more than three years after the OEB's deadline of mid-2022. The IRP process will never work if it cannot be made much more nimble. On a more positive note, I give credit to the Company for a more productive and much more timely effort to pull together a system pruning pilot (though much of this has occurred in 2025, it started with a workplan and initial stages of work in late 2024). Going forward, we need to do more to figure out how to address the likely multiple reasons the consideration of IRP alternatives has produced almost nothing after several years of work.
Dwayne Quinn (non-utility member)	While we have experienced the frustrations outlined by fellow members, Mr. Neme and Mr. Shepherd and concur with their comments, we want to emphasize a different aspect of frustration from the three plus years on the committee. The IRP Framework decision created the Technical Working Group (TWG) to provide input on IRP issues and called on the staff to lead the group and develop terms of reference. The call for nominations for the Working Group outlined the expectation that the Group would work collaboratively under the coordination of OEB staff. Unfortunately, that collaboration has not been our experience. Over my years of serving on the TWG, non-Enbridge members seem to be treated more as a sounding board for EGI's developed initiatives allowing the company to receive feedback to fortify their positions. While there have been

	many examples of this dynamic, the most significant was the now defunct pilot project in Parry Sound. From the outset of their identification of this project, we requested pipeline information along with flows and pressures to understand the need and to work with EGI on developing the pilot including supply-side alternatives. Over several months, requests for information were met with reasons why the information was not ready or not available. After receiving bits and pieces of data in the year of EGI preparing the project for submission as the pilot, I asked for the outstanding data on behalf of my ratepaying client in the interrogatory process once the evidence on the pilot came to the Board for review. EGI refused to answer the questions and through correspondence in the proceeding, my client was told that we would have to submit a formal motion to the Board for them to be directed to provide the desired information. As it happened, the application went into abeyance. Given the additional time afforded by the abeyance, I continued to pursue the data through communication in the IRP meetings and in communication directly with EGI while ensuring that OEB staff were included. After I answered a series of questions as to why I would need the information requested, some of the pertinent data was provided by Enbridge. In a subsequent meeting with EGI, through my analysis, I informed EGI that the $28M Baseline Facilities project that EGI had identified as required, absent IRPA's, could be eliminated with perhaps $1M of facilities work on EGI stations that feed Parry Sound. Very late in the period of abeyance, EGI informed the TWG that other changes resulted in the project being moved out of the 10-year forecast. We provide this detail to inform the reader of the facts so that EGI does not attribute our concerns as perception not reality. The inability to produce even pilot projects should provide evidence that the process is being inhibited. While it has been a frustrating process, I stand ready to serve and hope that the Board's review of the IRP framework will create conditions that enable a more effective TWG.
Jay Shepherd (non-utility member)	We are approaching the fourth anniversary of the IRP Decision, which itself followed more than a decade of debate about IRP in various other rate applications and policy discussions. We have also just had meeting #55 of the IRP

	Technical Working Group, and that number does not appear to include the many subgroup meetings that have also taken place. The end result of all this expenditure of time and resources is that no IRP projects have been implemented, and no facilities are currently targeted to being displaced or deferred by IRP initiatives, now or in the future. The primary reason for this is, of course, that Enbridge is highly incented to add to rate base (and their investors require it), and IRP is a method of limiting the growth of rate base. The secondary, and technical, reason for this is that the IRP Framework is structured so that there are five steps before an IRP project can proceed, and each step has as its sole purpose screening out IRP projects. The facilities alternative is always assumed to be cost effective, technically feasible, and appropriate. The IRP alternative has to successfully jump five hurdles before it is considered. This is counterintuitive, especially since IRP is "integrated resource planning", so by its nature it should be integrated. It is therefore timely that the OEB review the IRP Framework, and in that review ask fundamental questions. While the work of the TWG has not resulted in learnings about how to implement IRP successfully (because there has been no IRP), we have learned one key lesson. The current IRP Framework does not work. It does not need slight modifications. It needs to be re-thought. Part of that process should be re-thinking the role of the IRP TWG, and that new role should be driven by the nature of the changes to the IRP Framework. If meaningful changes are implemented, it may be that the IRP TWG can actually serve a useful advisory role. It the changes are less fundamental, then conversely the IRP TWG may have to be given more teeth to be effective.
Mike Parkes/ Stephanie Cheng (OEB staff representatives)	**Previous year comments and concerns; priorities for IRP Framework review:** The top-level concern with the implementation of the IRP Framework is the continued inability of IRP alternatives to pass the (current) IRP Assessment that is used to determine whether IRP alternatives are the preferred option to address a system need. The result is that no IRP alternatives have been

	deployed to defer or avoid investment in traditional pipe infrastructure and thereby reduce system costs. As part of the IRP Framework review, OEB staff will examine whether changes to improve the effectiveness and efficiency of the Framework might alter this outcome. Additionally, OEB staff is developing proposals to address the specific items identified for the Framework review: how the Framework can adapt and evolve; expectations and approach to oversight of innovation-related IRP proposals; and expectations regarding electrification as an IRP Alternative. For each of these items, OEB staff is engaging with the IRP Working Group to inform a Staff discussion paper, which will serve as the basis for broader stakeholder consultation. **Priority IRP workstreams for 2025:** OEB staff generally agrees with the priority work streams identified by Enbridge Gas (which include the IRP Framework review discussed above). In particular: • Progress on both pilots (the Southern Lake Huron pilot and the system pruning pilot) is important to gain learnings on IRP. • Continued work on completing the technical and economic evaluation processes for projects from the 2025-2034 Asset Management Plan (and the supporting work on updating the Posterity IRP model) is critical in understanding whether the IRP Assessment process puts IRP and facility solutions on an equal playing field as options to address system needs. With regards to work on enhancing the Discounted Cash Flow-plus test, OEB staff notes the lack of a specific time-bound milestone, and (as in last year's comments) encourages Enbridge Gas to bring this work to a conclusion.

Table 3: Comments of Enbridge Gas IRP Working Group Members

Working Group Member	Comments (optional)
Alison Moore/ Whitney Wong/ Helen Tong	Enbridge Gas believes the upcoming Framework Review is an opportunity to consider how the IRP Framework can evolve, informed by the learnings from implementing the IRP

(Enbridge Gas representatives)	assessment process and with a focus on ensuring the process is reflective of the system constraints with IRP potential. The recently issued Integrated Energy Plan and the Natural Gas Policy Statement will also be a consideration for the broader policy environment, where there was focus on maintaining customer choice while supporting a strong, resilient, and economically viable natural gas system. These policy expectations provide important context for evaluating the role of IRP and for guiding the future refinement of the IRP Framework within Ontario's broader energy policy environment. Enbridge Gas agrees that a key consideration will be ensuring regulatory clarity on the objectives of IRP, as well as ensuring regulatory policy takes account of and does not conflict with Ontario Government policy. Under the current Framework, IRP is defined as a planning strategy and process that considers facility alternatives and IRP Alternatives (including the interplay of these options) to address the system needs of Enbridge Gas's regulated operations, and identifies and implements the alternative (or combination of alternatives) that is in the best interest of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management. The outcome of this process, where an IRP alternative has not been selected as the preferred alternative, is a finding as opposed to a failure in its execution that warrants consideration. The goal of the IRP Framework is not to maximize the number of IRP alternatives implemented, but rather to ensure the most appropriate solution is identified based on the defined criteria and the policy context in Ontario. A member noted a re-thinking the role of the IRP TWG driven by the nature of the changes to the IRP Framework should be part of the process. The first priorities of the IRP TWG were to be consideration and implementation of IRP pilot projects and enhancements or additional guidance in applying the DCF+ evaluation methodology, which have both had substantive focus in the initial years of IRP. As IRP is considered beyond the first-generation IRP Framework, the role, scope and frequency of the TWG should be revaluated to ensure efficiency and value relative to other avenues such as adjudication.

	Beyond the IRP Framework consultation, the comments of the TWG members centered on progress that has been made on the pilot projects, the number of projects screened out and the screening process, information sharing with the TWG, and the finalization of the DCF+ test. Enbridge Gas has outlined in detail its IRP activities in the 2024 IRP Annual Report and has included comments below to further address the key concerns and comments noted above: <u>IRP Pilot Projects & System Pruning</u> Enbridge Gas was transparent and responsive throughout 2024 in updating the approach for the IRP Pilot Projects. The Company provided timely updates and actively engaged the TWG as new information became available, seeking input on how to proceed and incorporating the outcomes of the consultation into a revised application. This revised application received general support from the group, with the exception of differing views on the inclusion of advanced technologies, which is currently the subject of an OEB Motion to Review the Decision. Throughout the process, Enbridge Gas has valued the input from the TWG on the pilot and has viewed this as a collaborative effort. Enbridge Gas also shares concerns regarding the pace of the regulatory process that followed the updated application. In advance of a Decision, Enbridge Gas took proactive steps in 2024 and Q1 2025 to initiate activities that require longer lead times, in efforts to minimize any delays in implementation. The work with the TWG and system pruning TWG subgroup to establish the approach for the system pruning pilots will result in a shorter timeframe towards implementation than the application and adjudication process of the Southern Lake Huron pilot project. While the subgroup and TWG meeting arrangement led to a degree of overlap in exploring the same topics in both forums, particularly in initial conversations, this allowed for insights to be tabled at the TWG that were not explored in the subgroup. Despite a pause in consultation from January 31, 2025 to March 19, 2025 due to the election writ period, an approach was established within the originally

	committed timeframe that the TWG supports proceeding with as a reasonable initial approach, subject to ongoing review and further input as the pilot is implemented and lessons are learned. Enbridge Gas is committed to implementing the pilots in a timely and thoughtful manner, and to working with the TWG to ensure the pilots deliver practical learnings to inform future IRP efforts. <u>IRP Evaluation Process & Screening Results</u> TWG members have raised concerns that the inability of IRP alternatives to advance through the assessment process reflects that the screening is too inflexible or strict. Enbridge Gas has implemented the IRP evaluation process in accordance with the IRP Framework, with the binary screening and technical evaluation stages being applied consistently and transparently to ensure that investments where IRP is not applicable are filtered out early. The reality is that a large number of the projects in the AMP do not have potential IRP applicability or viability. The IRP Assessment Screening and Evaluation Guidelines (Appendix F in the Annual Report) has been reviewed with the TWG on multiple occasions with minimal substantive feedback or proposed changes. <u>Information Sharing with the TWG</u> Feedback from TWG member comments included both positive feedback in the pace of progress over the past year with more information being shared with the TWG, as well as a frustration expressed by another member focused on the Parry Sound pilot project and requested pipeline information along with flows and pressures. In 2024, Enbridge Gas worked to clarify with the TWG that the scope of the working group was on non-facility alternatives. While IRP as a planning strategy and process is intended to consider all cost-effective solutions to meet system needs, there was agreement expressed that the TWG's scope should generally be limited to non-facility alternatives as facility alternatives are already assessed through routine asset planning processes. Despite this alignment, one member expressed ongoing interest in additional information on facility alternatives within Enbridge

	Gas applications. This is not within the scope of the TWG. Enbridge Gas has included a section in the 2024 IRP Annual Report differentiating between traditional facility alternatives that have routinely been considered when assessing facility needs and non-facility IRP alternatives, assessed against a system constraint and scope. Notwithstanding this clarification, Enbridge Gas had sought to address questions related to traditional facility alternatives in 2024 without undue burden to the TWG when these discussions extend beyond the scope of the TWG, inclusive of a separate discussion on considerations relating to Parry Sound and traditional facility alternatives. Assertions about information in this respect have been addressed on multiple occasions, and Enbridge Gas would like to see enhanced focus moving forward to ensure we can optimize progress on non-facility considerations and focus on success of the pilot project in providing valuable learnings. <u>DCF+ Test</u> Enbridge Gas acknowledges the IRP Framework's directive in the Decision to refine the DCF+ test and appreciates the input received from TWG members on potential enhancements. Enbridge Gas has incorporated several suggested modifications where there has been general alignment, including adjustments to cost allocation between existing and new customers, aligned treatment of nominal values, inclusion of equipment costs in Phase 2, calculation of total bill impacts and recognition of the accentuating factor in Phase 2, and the recognition of the non-additivity of Phase 3. Although these are departures from EBO 188 and EBO 134 methodologies, they have been agreed to as they are seen to enhance the perspectives assigned to each of the phases in DCF+. Where Enbridge Gas has taken time to consider certain recommendations, this reflects the principled approach the Company took to factor in the currently approved methods and principles of the existing tests. Specifically, the Company continues to support the use of EBO 188 principles in Phase 1, consistent with its obligation to serve customers and to uniformly evaluate any ensuing rate impacts across both facility and non-facility alternatives. EBO 188 has been applied to hundreds of projects and remains foundational to

	facilitating rational distribution system planning. Where nominal adjustments have been made to the stream of benefits and costs in DCF+, the Company believes they remain reflective of general assumptions used in ratemaking. On specific areas where views diverge: • Phase 3 - additivity: Enbridge Gas has agreed with the non-additivity of Phase 3 in response to concerns raised on the use of GDP multipliers. This position is now being challenged by IRP TWG members who seek to reverse their position so as to include the social cost of carbon. Enbridge Gas continues to adhere to non-additivity. • Phase 3 – social cost of carbon: Members of the IRP TWG believe that it is appropriate to include a social carbon cost in Phase 3 - Enbridge Gas maintains that in the absence of provincial social cost of carbon legislation/regulation specifying that a social cost of carbon be considered within a regulated utility's benefit / cost tests that this should not be included in Phase 3. Including such a cost would be directly contrary to the government's Energy for Generations plan issued on June 11, 2025, that states, "Ontario's plan to meet growing energy demand while reducing emissions does not and will not include a carbon tax (p. 100)." If, however, the government should reinstate a carbon cost, it would be considered for inclusion. • Phase 3 – GDP Impacts: Enbridge Gas continues to see value in the use of GDP multipliers that measure direct, indirect, and induced economic impacts at the provincial and national level as has been used in other OEB-approved methodologies. It is consistent with government policy goals and appropriate within the societal perspective informed by Phase 3. As noted in the Ontario government's Energy for Generations, economic growth is being embedded into agency mandates to "ensure that energy planning and regulatory decisions recognize and support Ontario's growth objectives".[3] At this time, no clear support was reached among TWG members on the value of pursuing a study that would quantify the comparative

[3] Ontario Ministry of Energy and Mines. (June 2025, p. 125). Energy for Generations. Government of Ontario. *Energy for Generations

	impacts of facility alternatives and IRPAs. Enbridge Gas is applying a proxy that values the GDP impact of facility alternatives and IRPAs similarly. • Phase 3 - Job Impacts: While Enbridge Gas recognizes the IRP TWG's interest in quantifying job impacts, the Company has not committed to pursuing a study on this for either IRPAs or facility alternatives. To note, no clear support was reached among TWG members on the value of pursuing such a study. Additionally, Enbridge Gas recognizes that job impacts are reflected as job numbers not dollars and would not lend itself for inclusion in the DCF+'s phase 3 test itself, rather, shown separately. Enbridge Gas believes that it has been responsive to TWG input, adopted changes where appropriate, and transparently communicated the rationale behind its approach. Further refinements may be brought forward when the enhanced DCF+ methodology is filed for adjudication.

3. Description of Key Working Group Activities

IRP priorities for 2024 were identified in the 2023 IRP annual report of Enbridge Gas. These included:

- Stakeholder/Municipal/Electric Sector Outreach
- Continued IRP Evaluation
- DCF+ Test
- Pilot Projects
- Policy Proposals (for non-pilot IRP Plans)
- System Pruning

Of Enbridge Gas' identified priorities, multiple Working Group members identified the following as high priorities in the 2023 IRP Working Group report:

- Implementation and evaluation of the IRP pilots.
- Finalizing the Discounted Cash Flow-Plus (DCF+) economic evaluation test to assess and compare the costs and benefits of using either facility solutions or IRP alternatives to meet system needs.
- Understanding and refining various aspects of the IRP project evaluation process including dollar thresholds, timing considerations, the rationale for screening out projects, and the practical application of this process to the projects in Enbridge Gas's 2025-2034 Asset Management Plan update.
- System pruning in the context of discussing and developing a system pruning pilot

After further discussion with the Working Group, Enbridge Gas proposed a high-level work schedule for the remainder of 2024 that outlined meeting topics and was generally accepted by Working Group members.

Most of these topics have been subsequently discussed with the Working Group (one exception that was on the work schedule but has not been discussed this year is policy proposals for a non-pilot IRP Plan, including shareholder incentives). However, as the year progressed, there were changes to the schedule as significant new expectations for the IRP Working Group arose from OEB decisions in 2024 and 2025 and therefore became high priorities:

- (From November 2024 phase 2 rebasing decision): A requirement for Enbridge Gas to develop its approach to system pruning in consultation with the IRP Working Group by the end of Q2 of 2025 and begin implementation on one or two pilots by the end of Q1 of 2026.

- (From March 2025 IRP Pilot Project decision): A requirement for Enbridge Gas to engage with the IRP Working Group to develop and file a detailed project plan for the approved Southern Lake Huron Pilot Project.
- (From March 2025 IRP Framework review announcement): An announcement by the OEB that it is reviewing the IRP Framework. OEB staff have engaged with the IRP Working Group for input on this review.

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 (EwU) 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.

To advance the discussion and work required of the System Pruning Pilot, a System Pruning Subgroup was formed in September 2024 with some members of the broader Working Group. The members include Enbridge Gas representatives (with Catherine McCowan as the lead), DNV consultants (led by Ben Crosby), OEB staff representatives (led by Mike Parkes), several non-utility members, Cameron Leitch, Dwayne Quinn, Chris Neme, Tamara Kuiken, and observer Stuti Rungee. System Pruning Subgroup meeting dates and topics have been highlighted in yellow in Table 4 below.

Table 4: Summary of Meeting Dates and Key Topics Discussed

Meeting Date	Key Topics Discussed
July 3, 2024	• Proposed economic screening
July 25, 2024	• DCF+ (Phase 2 and Phase 3) • DCF+ supplemental guide
August 21, 2024	• DCF+ supplemental guide • 2024 workplan • Low-cost investment process update
September 4, 2024	• Cost threshold screening • System Pruning – Jurisdictional Scan • Stakeholder plan
September 9, 2024	• System pruning proposal

[4] https://engagewithus.oeb.ca/irp

September 25, 2024	• DCF+ consultation (informed by member feedback) and Phase 3 non-energy benefits (NEBs) • Pilot project – evaluation scope & update on larger C&I engagement • System Pruning – Jurisdictional Scan
October 9, 2024	• Stakeholder Plan • Classification of traditional facility vs. IRP alternatives
October 23, 2024	• System Pruning – Jurisdictional Scan • Posterity Group – IRP model (Overview of inputs and methodology)
November 20, 2024	• Overview of 2025-2034 AMP Appendix B & Summary of IRP evaluation • Overview of key projects • System Pruning – Jurisdictional Scan update • Stakeholder update
December 4, 2024	• 2025 Workplan – System Pruning, IRP Evaluation, and IRP Pilot • Limited Results of IRP Framework to Date – Discussion of Hypothesis and Remedies
December 11, 2024	• Introduction, selection of jurisdictions for jurisdictional scan
January 12, 2025	• DNV discussion on deliverables • Member feedback on DNV interview guides • Discussion on System Pruning Objectives and Key Elements
March 19, 2025	• Q1/Q2 2025 Workplan • DCF+ discussion (including member comments on draft supplemental guide)
March 20, 2025	• Update on jurisdictional scan progress • System Pruning Pilot – Discussion on objectives, selection criteria, customer research approach and findings, basis for the customer offer, contractor strategy, customer engagement, and implementation approach
March 26, 2025	• System Pruning – update to broader working group • IRP Evaluation Update – Review of projects and DCF+ results
April 9, 2025	• IRP Pilot Decision & Framework Review • DCF+ Interpretation (Review of initial DCF+ results & Review of DCF+ model) and Sensitivity Analysis

April 17, 2025	• Update on jurisdictional scan progress
	• Updates to elements of the approach, pilot objectives, and selection criteria for System Pruning
	  ○ Contractor strategy
	  ○ Evaluation strategy
	  ○ Workplan to develop approach

April 23, 2025	• IRP Pilot update and workplan timelines • IRP annual report timelines • System pruning – update to broader working group • IRP Framework Review
May 7, 2025	• IRP Pilot Update – Objective 1 (Peak hour) • System Pruning – update to broader working group • Annual Report Schedule
May 15, 2025	• Update on status of jurisdictional scan report • Update on Enbridge Gas customer research findings and proposed modifications to customer offer
May 21, 2025	• IRP Framework Review – purpose and form, evaluation process • System pruning proposal • Review of Enbridge IRP annual report
June 4, 2025	• IRP Framework Review – innovation • System pruning – review of draft approach • IRP Pilot Workplan, including customer offers and evaluation approach
June 13, 2025	• Presentation on findings of system pruning jurisdictional scan report • Discussion of member comments

3.1. IRP Pilot Implementation and Evaluation

Per the IRP Framework, Enbridge Gas was expected to develop and implement two IRP pilot projects by the end of 2022. The pilots were expected to be an effective approach for Enbridge Gas to understand and evaluate how IRP can be implemented to avoid, delay, or reduce facility projects. The IRP Pilot Projects application was filed by Enbridge Gas to the OEB on July 19, 2023, under EB-2022-0335. During the proceeding, the application was first put in abeyance on November 17, 2023, for Enbridge Gas to consider the impact of NRCan's announcement to close the application process for new entrants into the Greener Homes Grant program in Q1 2024. The abeyance period was then extended for Enbridge Gas to consider the impact of the changes to the 10-year capital forecast on the IRP Pilot Projects. After considering the Working Group's input on potential changes to the IRP Pilot Projects application, Enbridge Gas filed updated evidence on June 28, 2024, reflecting its ultimate decision to withdraw the Parry Sound Pilot Project since there is no longer a need for localized compressed natural gas (CNG) for supply-side IRP alternative learnings, and the refinement of the Southern Lake Huron (SLH)

Pilot Project to focus and optimize learnings on demand-side alternatives although this is no longer a system need to be deferred.

On March 27, 2025, the OEB issued its Decision and Order that approved the SLH Pilot scope, contents, costs, and proposed accounting treatment of costs as filed by Enbridge Gas, subject to various changes as detailed in the Decision.

The primary objectives of the SLH Pilot Project are to develop an understanding of how ETEE programs and DR programs impact peak hour flow/demand (Objective 1) and to develop an understanding of how to design, deploy, and evaluate enhanced targeted energy efficiency (ETEE) and residential demand response (DR) programs (Objective 2). Starting in Q4 2024, Enbridge Gas began consultation with the Working Group for feedback on aspects of pilot implementation, such as its planned approach to engage larger commercial and industrial customers, and in determining the scope and approach to EM&V (Objective 2). This included the Working Group's review of the planned scope of work for the external evaluation contractor, who will be engaged to consult on data analysis in developing an understanding of how to effectively design, deploy, and evaluate ETEE and DR programs. The scope of the evaluation is expected to include analysis of financial spending and program participation, as well as an assessment of the design and delivery approach of IRP offerings to provide insight and considerations for ongoing enhancements to the SLH Pilot.

As required by the IRP Pilot Projects Decision, Enbridge Gas subsequently engaged with the Working Group to develop and file an updated, detailed project plan (including marketing, stakeholdering, and evaluation, measurement, and verification (EM&V) efforts related to the SLH Pilot) as part of Enbridge Gas's 2024 IRP annual report. The Working Group had an opportunity to review the offer plans and provide input.

With regards to Objective 1, Enbridge Gas confirmed its plan to use in-house expertise to carry out some of the EM&V work and will leverage an external consultant to support analysis of customer regression and groupings of customer types. The Working Group emphasized the importance of leveraging the expertise of the external consultant for impact analysis. The Working Group suggested that the consultant work with Enbridge Gas up front on how the analysis will be conducted so any recommendations for modifications can be considered. Some Working Group members suggested that the impact evaluation be conducted entirely by an expert third party consultant, with data supplied by Enbridge and with an approach discussed with Enbridge and the Working Group, to both take advantage of expertise of organizations that regularly perform statistical analyses of ETEE and DR impacts in numerous jurisdictions and to enhance the credibility of the analytical results. If that was not going to happen, the Working Group also suggested that the consultant at least work with Enbridge Gas to review the results of Enbridge Gas's analysis to render its opinion on whether the results are reasonable, how to deal with errors, and any biases in data. Further, one Working Group member expressed concern that, in spite of the challenge of multiple feeds into the system, Enbridge Gas seems to have abandoned the opportunity to evaluate the effect of the various demand-side measures on the system pressures. The Working Group had an opportunity to review a Request for Quotation (RFQ) of the external consultant for Objective 1 and provide input.

With regards to Objective 2, the Working Group had an opportunity to review and comment on the draft evaluation plan.

It is expected that Enbridge Gas will continue to engage with the Working Group for its review and input on project plan elements over the term of the SLH Pilot.

3.2. DCF+ Test and Guide

The Report of the IRP Working Group on the Discounted Cash Flow-Plus Test (DCF+ report) was made public in May 2023, capturing differing perspectives and any items where consensus was reached between Enbridge Gas and Working Group members. Enbridge Gas is expected to leverage the Working Group's DCF+ report to develop a DCF+ test and supplemental handbook (DCF+ Guide) to be filed with the OEB for approval as part of its first non-pilot IRP Plan. In 2023, Enbridge Gas produced the first draft of its DCF+ guide, along with a sample DCF+ calculation, which was shared with the Working Group for their review and feedback.

The Working Group's engagement on DCF+ topics resumed in the second half of 2024, focusing discussions in areas of the DCF+ report where consensus was not reached or where further elaboration in the DCF+ guide was needed.

More specifically, in July 2024, discussions with the Working Group focused on non-energy benefits (NEBs) from both participant and societal perspectives within phases 2 and 3 of the DCF+ test. This included consideration of economic impact indicators in other jurisdictions, the applicability of GDP and job multipliers, the appropriateness and methods for consideration of social cost of carbon, and whether there is value in pursuing quantification of other phase 3 NEBs outside of an accentuating factor of energy efficiency benefits. Working Group members also provided materials from other jurisdictions for Enbridge Gas's review and consideration. In response, Enbridge Gas provided a summary of the Working Group's comments on its initial draft of the DCF+ guide, with Enbridge Gas’s response and clarifying comments. In August 2024, a second draft of the DCF+ guide was shared with the Working Group for review and feedback. Further discussions with the Working Group took place, which included matters like whether phase 1 was expressed in nominal or real dollars and the implications. In September 2024, Enbridge Gas provided a summary of the Working Group’s comments on the second draft of the DCF+ guide, with Enbridge Gas’s written responses to comments. The discussion that followed focused on the appropriateness of adding the phases in the DCF+ test considering the concerns raised by the Working Group regarding inconsistent treatment of nominal and real discount rates (and associated valuation streams within and across phases). In January 2025, Enbridge Gas provided an expanded written response that provided a resolution to the nominal and real concerns by confirming that discount rates and valuation streams would be nominal within and across phases 1 and 2, thereby making both phases additive. Enbridge Gas proposed that phase 3 be presented separately, given the concerns around additivity of this phase and the use of the economic multiplier. Some Working Group members expressed concern with this proposal (noting that some inputs to phase 3 such as social cost of carbon to may be additive but others such as GDP and job impacts are not), as well as with Enbridge Gas’s continued reluctance to directly address concerns about its approach to accurately quantifying economic benefits in Phase 3.

As per the IRP Framework, Enbridge Gas was expected to file its DCF+ test and supplemental guide for approval with the OEB as part of its first non-pilot IRP Plan application. This was initially planned for 2024 through the Owen Sound Reinforcement Project, but with the system reinforcement plan (SRP) updates following the rebasing decision, the timing of the Owen Sound project shifted out to later years in Enbridge Gas’s 10-year capital plan. At this time, there are no definitive timelines for when the first non-pilot IRP plan will be filed and the DCF+ test finalized and adjudicated. Enbridge Gas will continue to review and monitor changes to system needs.

3.3. Non-Pilot IRP Plan Policy Proposals

In 2023, the Working Group began IRP policy proposal discussions on the topics of Demand Side Management (DSM)/IRP Attribution, Shareholder Incentives and Performance Metrics, IRP Deferral Accounts, and Risk. Enbridge Gas had expected to consider the perspectives of the Working Group, and file proposals on these topics for the OEB’s consideration as part of

Enbridge Gas's first non-pilot IRP plan. Further discussion on these topics was anticipated, but policy discussions were put on hold in 2024 since Enbridge Gas did not have a viable non-pilot IRP plan application to file with the OEB in 2024 (since the Owen Sound Project shifted out to later years of Enbridge Gas's 10-year capital plan), and other topics took priority.

However, the phase 2 rebasing decision introduced a new commitment that by the end of November 2025, Enbridge Gas is expected to file an application that includes a proposal and request for approval of an IRP incentive mechanism. Therefore, this topic will be revisited in 2025.

3.4. IRP Evaluation Process and Applicability to Projects in Asset Management Plan

In 2024, Enbridge Gas continued discussions with the Working Group on refining aspects of its IRP evaluation process.

Key topics discussed where the Working Group provided input include:

- Review of the IRP Assessment process, including the process flow, technical screening and evaluation guideline document, and templates used by Enbridge Gas staff in completing the technical evaluation stage of the IRP evaluation.
- A proposal by Enbridge Gas to exclude "low-cost, low-value" projects from detailed IRP technical evaluations, based on analysis whereby Enbridge Gas concluded that such projects are unlikely to have viable IRP alternatives.
- A classification of which types of alternatives would be considered traditional facility alternatives and which would be considered IRP alternatives, and the sequencing and process by which these two types of alternatives are considered in Enbridge's evaluation process.
- Improving the methodology and documentation by which the technical potential of energy efficiency IRP alternatives is assessed through the Posterity Group IRP model.

The Working Group also suggested the incorporation of a sensitivity analysis to identify a potential range of energy transition adjustments and their impact on Enbridge Gas's AMP and resulting IRP opportunities.

Enbridge Gas also discussed with the Working Group the results of its IRP evaluation of projects in its 2025-2034 AMP (filed on November 8, 2024). The inclusion and timing of projects in the AMP were impacted by changes made earlier in 2024 by Enbridge Gas to its demand forecast methodology (discussed in last year's Working Group report). Documentation of the screening and evaluation results was shared with the Working Group for questions and comments.

Enbridge Gas discussed in more detail with the Working Group specific priority projects in the AMP with IRP Plan potential. Enbridge Gas shared two projects (L'Orignal and Listowel) in its current AMP, where there is a system need, but presented the difficulties and challenges associated with each project's respective IRP potential for the Working Group's comments and feedback.

In the first half of 2025, Enbridge Gas presented preliminary economic evaluations (using the current working version of the DCF+, see section 3.2) of some projects that passed the technical evaluation stage, including a proposed approach to conducting sensitivity analysis. This responded to an earlier suggestion from the Working Group to incorporate sensitivity analysis to identify a potential range of energy transition adjustments to Enbridge Gas's demand forecast and their impact on Enbridge Gas's AMP and resulting IRP opportunities. However, Enbridge Gas indicated that there are challenges with doing sensitivity analysis on the demand forecast and instead proposed conducting sensitivity analysis on key variables that might impact the results of the economic evaluation.

3.5. System Pruning – Jurisdictional Scan and Pilots

As part of the Settlement Agreement for Phase 2 of Enbridge Gas's rebasing application, Enbridge Gas agreed to develop an approach to a system pruning pilot (i.e., incenting customers to voluntarily exit the gas system in preference to replacing gas infrastructure), in consultation with the IRP Working Group by the end of Q2 of 2025 and begin implementation on one or two system pruning pilots by the end of Q1 of 2026. Enbridge Gas worked with the Working Group to develop the scope of a scan of system pruning in other jurisdictions, and engage a consultant to complete this work. This was intended to help Enbridge Gas, as well as the Working Group and OEB, understand how utilities in other jurisdictions are approaching natural gas system pruning to identify the best practices and to determine the applicability to Ontario.

In Q4 2024, Enbridge Gas began to develop a system pruning work plan, which includes a draft of the scope of work for the jurisdictional scan to be executed by the external contractor, DNV. Given the tight timelines for system pruning development and implementation, a subgroup was formed to focus on system pruning discussions, including members from the broader IRP Working Group. Enbridge Gas developed a work plan on the key elements required of the system pruning pilot approach to meet the Q2 2025 deliverable, which includes the timing of when elements would be brought forward to the subgroup for input and feedback, then shared with the broader Working Group to ensure alignment.

The subgroup was also consulted to determine the geographic locations DNV should focus its jurisdictional scan on to obtain the most relevant learnings.

However, in February 2025, consultation activities with DNV, the subgroup, and the broader Working Group were put on hold because of the writ period, which impacted the timing of consultation for some elements. Enbridge Gas continued to provide informational updates during the writ period, but discussions were deferred until consultation and cost award eligibility were reinstated.

Since the end of the writ period, Enbridge Gas and DNV resumed regular meetings with the subgroup.

DNV completed its jurisdictional scan research and provided a draft of the system pruning jurisdictional scan in June 2025 for member comment and discussion, which is expected to be finalized and published in the near future.

Enbridge Gas continued to provide updates to the subgroup and broader Working Group to advance the approach and confirm support by the end of June 2025 for the system pruning approach elements. Enbridge Gas consolidated its proposal for the system pruning pilot into a draft “approach” document for member comment, which summarizes key elements of the pilot (pilot objectives, selection criteria, customer engagement, customer offer, customer choice, stakeholder engagement, program delivery, implementation plan, and evaluation strategy). The approach was developed with input from the IRP Working Group (particularly the system pruning subgroup) and was informed by the jurisdictional scan, financial analysis and customer research. Enbridge Gas determined which suggestions it will implement in the pilot. The IRP Working Group has not formally approved the proposal but supports proceeding with it as a reasonable initial approach, subject to ongoing review and further input as the pilot is implemented and lessons are learned.

3.6. Stakeholder Plan

In October 2024, Enbridge Gas provided the Working Group with an overview of the various stakeholder conferences and webinars that took place and/or are planned for the near future. This included the sharing of stakeholder materials distributed/ presented at Enbridge Gas Conferences for Working Group feedback. Working Group members also provided advice on who should attend the conferences to steer marketing and communication approaches, inquired on the types of information presented (e.g. does it identify relevant regional specific projects in AMP versus general awareness? Are there visuals like maps with dollar values?), offering sessions with a strictly IRP focused agenda and discussion, and consideration of the best methods and channels to communicate information that is understandable to the targeted stakeholders. Enbridge Gas indicated it will continue to consider the Working Group's tips and feedback when refining its stakeholder approach and preparing for upcoming stakeholder engagements and materials.

3.7. IRP Framework Review

In March 2025, the OEB announced that it is initiating a consultation to review the IRP Framework. As part of the consultation, the OEB intends to 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,
- 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 will be developing a report to support this consultation and, beginning in April 2025, have held discussions with the IRP Working Group on these topics to inform the planned staff report. To date, the Working Group has discussed the purpose and form of the IRP Framework, technical evaluation, and how the Framework should address innovation.

4. IRP Priorities and Working Group Activities in 2025

Enbridge Gas identified the following IRP priorities for 2025 in its 2024 annual IRP report:

- External Stakeholder Outreach
- Continued IRP Evaluation
- DCF+ Test
- Pilot Projects
- System Pruning
- Policy Proposals (for Non-Pilot IRP Plans)
- Framework Consultation

Working Group members were asked if they have any comments or concerns regarding these priority IRP work streams, recognizing that there might be impacts from the IRP Framework review.

Working Group members generally agreed that making progress on the IRP pilots is a high priority, and there was general support for the Framework review to consider a nimbler process to allow for quicker implementation and learnings and reduced risks in implementing future IRP pilots or related projects.

Multiple Working Group members noted the continued failure of projects to pass the IRP assessment process, particularly the pre-economic stages, suggesting that this process needed to be reviewed and likely revised. There was also support for retroactively examining the assumptions and results underpinning past (facility) investments, to inform and improve the IRP assessment process going forward, and to ensure that IRP alternatives and facility projects are compared on a level playing field.

Multiple Working Group members noted frustration in the delay in updating the Discounted Cash Flow-Plus test. Several members noted that placing a value on the societal cost of greenhouse gas emissions was an important part of this test.

Several Working Group members commented that there were larger structural issues that would need to be addressed if an updated IRP Framework to deliver results. One member noted that current public policy, including an obligation to serve, financial incentives to install infrastructure, and a Natural Gas Expansion Program, does not provide a clear rationale for implementing IRP alternatives, while another member noted the structural disincentive for Enbridge Gas to pursue IRP as it limits their growth in rate base.

OEB staff will work with Enbridge Gas to develop an updated schedule/work plan for the Working Group based on 2025 priorities.

Appendix F: IRP Assessment Screening and Evaluation Guidelines

IRP Assessment Screening and Evaluation Guidelines

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Introduction

This document outlines the IRP Assessment Screening Criteria and rationale used in the IRP Evaluation process. A previous version of the content in this section was filed 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 (link). Appendix F is largely consistent with this filing, with enhancements to ensure clarity.

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 Evaluation 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 AIPM process for 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.[47]

The IRP Evaluation 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 AMP and are limited to regulated Enbridge Gas investments. This document will be updated on an annual basis to reflect process updates and learnings gained through the year. In future AMP investment evaluations, 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 Evaluation Process Overview

1. **Initial Screening**
   The evaluation process began with removing non-gas-carrying asset investments 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 with the Asset Class of Customer Connections will also be included in the list of Binary Screening requirements.

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 demand reduction level required to meet system needs by determining the difference between the required and the current system capacity. Where IRPAs have a technical potential to reduce the design hour/day demand reduction 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.

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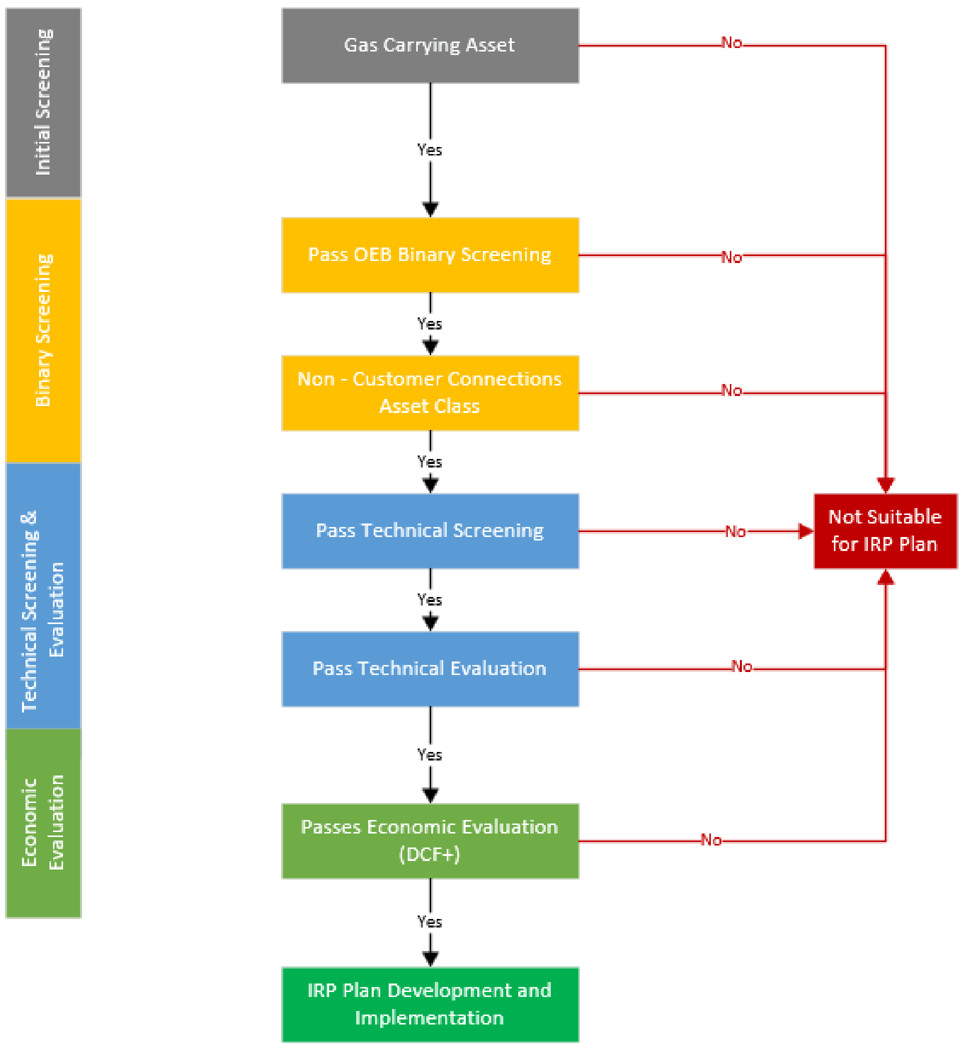
[47] IRP Annual Report, Section 7, Table 7.1 provides a "Summary of Facility and IRP Alternatives"

Figure 1 – IRP Evaluation 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."[48] Investments considered as emergent safety issues would include, but is not limited to, replacing mains and services after a leak requiring immediate attention has occurred.

- ***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".[49]

- ***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".[50] 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.[51] 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 it is not appropriate to conduct IRP analysis for those projects".[52]

- ***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."[53] As noted in the AMP[54], Community Expansion and Economic Development projects are not included in the AMP and therefore their associated IRP evaluation is not captured in the AMP.

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

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[48] EB-2020-0091 Decision and Order, Integrated Resource Planning Proposal, July 22, 2021, p. 47
[49] EB-2020-0091 Decision and Order, Integrated Resource Planning Proposal, July 22, 2021, p. 48
[50] EB-2020-0091 Decision and Order, Integrated Resource Planning Proposal, July 22, 2021, p. 49
[51] EB-2024-0233 Correspondence, OEB Filing Requirements LTC Exemption Applications
[52] EB-2020-0091 Integrated Resource Planning Proposal, Decision and Order July 21, 2021, p. 44.
[53] EB-2020-0091 Integrated Resource Planning Proposal, Decision and Order July 21, 2021, p. 48.
[54] EB-2022-0200 Exhibit 2, Tab 6, Schedule 2, p. 282

evaluations. It should be noted that any associated main reinforcement investments are still subject to the binary screening and technical evaluation process.

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 screening and evaluation stage is comprised of a technical screening and technical evaluation.

Enbridge Gas has undertaken detailed technical evaluation 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. In the future, these investments will be systematically screened out during the initial IRP technical evaluation process. It is expected that through continued technical evaluations, these categories would be refined and updated to reflect any changes.

Concurrently with the technical evaluation project review process 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 were subsequently removed from detailed technical evaluation. The categories of projects, their corresponding technical evaluation commentary and rationale are listed below.

Compressor Stations

- Technical Evaluation Comment: *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.*

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 evaluation. However, any investments driven by growth would be subject to the detailed technical evaluation process.

Hydrogen Blending

- Technical Evaluation 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 evaluation.

Storage Pools & Wells

- Technical Evaluation Comment: "*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."*

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 evaluation.

Distribution Stations

- Technical Evaluation 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 evaluation. However, any station investments that involve an element of growth would be subject to the detailed technical evaluation process.

CNG Facilities

- Technical Evaluation 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 evaluation.

Other

- Technical Evaluation 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. Where applicable, there are notes as to how these will be systematically removed prior to IRP Technical Evaluation in future.

Project Status/ Timing Related

Technical Evaluation 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 evaluation.

Table 1 – Description of Investments Screened out of the Technical Evaluation Project Review

	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 and the investment will be removed from further Technical Evaluation.
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. As such the investments should be excluded based on timing and the fact that individual service replacements cannot be offset by IRPA's.
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. Going forward this programmatic spend budget will be removed from IRP Technical Evaluation, but any specific pipeline replacements will be included for IRP 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. Once found, these problems must be addressed quickly to avoid degradation of the pipe and, as such, will be removed from IRP Evaluation based on timing.
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. Going forward this programmatic budget spend will be excluded from IRP Technical Evaluation, but any resultant pipeline replacements be included for IRP 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. These are repaired as they are found and should be eliminated based on timing.
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. Going forward, all such Station programmatic spend that is driven by condition, end-of-life, and compliance will be removed from 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. This spend will be excluded from IRP Technical Evaluation going forward but any resultant replacement projects will be included in 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. Although the programmatic spend budgeted here cannot be assessed for IRP Alternatives, any resultant 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. This programmatic budgeted spend will be excluded from future IRP Technical Evaluation but pipeline replacement projects found as a result of the integrity dig work will be included in the IRP 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. No technically feasible IRPA's exist for this type of work, and it will be removed from the Technical Evaluation going forward.

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. There is no technically feasible IRPA that could address this need and they will be removed from the Technical Evaluation going forward.
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 for which growth plays a role will be included in the IRP 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. Similar investments were excluded at binary screening based on the dollar threshold. Going forward, these investments will be removed from the Technical Evaluation.
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 budgeted spend will be removed from Technical Evaluation going forward but specific pipeline replacement projects will be included in IRP Evaluation when they are identified.
22	Odourant Program	Distribution Stations	DS-Gate, Feeder & A Stations	These investments are for the upgrade of odourant systems at stations. Similar investments failed at binary screening because of timing and because of the dollar threshold. Going forward all such Station programs that are driven by condition, end-of-life, and compliance will be removed from IRP Technical Evaluation.

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. There is no technically feasible IRPA to address this need and this programmatic budgeted spend will be removed from Technical Evaluation moving forward.
24	Re-class to CNG	Distribution Stations	DS-CNG	One investment relates to CNG and should have been allocated to the “See investment description – IRPA not applicable for CNG investments”.
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. This programmatic budgeted spend will be removed from Technical Evaluation moving forward but specific pipeline replacement projects will be included in IRP 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. Similar investments were eliminated at Binary Screening because of Timing. Going forward all such Station programs that are driven by condition, end-of-life, and compliance will be removed from IRP Technical Evaluation.
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. Similar investments failed at binary screening because of the dollar threshold. Going forward all such Station programs that are driven by condition, end-of-life, and compliance will be eliminated from IRP Technical Evaluation.
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. Although this programmatic spend will not- be put through Technical Evaluation projects, once identified, will go through IRP 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.

Technical Evaluation

Investments that are not screened out through the technical evaluation 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.

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 to 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.

Potential to be downsized to NPS 2, but need to avoid bottlenecks and maintain system resiliency

A portion of the project scope could potentially be replaced with NPS 2 prior to any IRP assessment. It is recommended that pipe size is maintained for segments of trunk main and for system resiliency. Thus, IRP is not applicable to the project scope; the scope will be confirmed when the project enters the detailed design phase. These projects may benefit from having a broader assessment of the needs in the area and the potential for reductions via a geographically focused IRP Plan. This type of analysis was beyond the capacity of the team for this first pass through the IRP Technical Evaluation process but is an area that will be explored in the future.

ETEE could reduce pipe size, but it is a trunk main

There are investments for which ETEE could potentially reduce the pipe size, but in doing so, would introduce a bottleneck in a trunk main which is not desirable from a network operations perspective.

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.

Appendix G: System Pruning Pilot Approach

System Pruning Pilot Approach

June 30, 2025

ENBRIDGE
Life Takes Energy

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Introduction & Background

System pruning involves the proactive decommissioning of a portion of the natural gas system that is no longer required to serve the needs of energy users. For this to occur, all customers served by that portion of the pipeline system must fully convert off natural gas and be willing (typically through incentives) to disconnect from the natural gas system. System pruning can be supported by the implementation of an electric or other non-gas solution to support existing customers in replacing their natural gas equipment.

The Settlement Agreement for Phase 2 of the Enbridge Gas Rebasing Application[1] contained the following commitments.

> *"The Parties agree that it is appropriate for Enbridge Gas to develop and implement a system pruning pilot project. The Parties have agreed that Enbridge Gas will develop its approach to system pruning in consultation with the IRP Technical Working Group by the end of Q2 of 2025 and begin implementation on one or two pilots by the end of Q1 of 2026.*
>
> *The Parties agree that for these one or two pilots OEB approval is not required if the combined costs of these pilots are $5 million or less and the pilot(s) are supported by the IRP Technical Working Group.*
>
> *The Parties agree that a new IRP System Pruning Deferral Account with a $5 million cap will be created for recording the incremental costs related to these activities for later recovery. Should Enbridge Gas forecast that the incremental costs of the IRP System Pruning pilot project(s) will exceed $5 million, then Enbridge Gas would be expected to seek OEB approval through an IRP Plan Application.*

The OEB's Decision and Order for Phase 1 of the Enbridge Gas Rebasing Application[2] provided the following commentary on IRP alternatives to address the stranded asset risk related to system renewal capital:

> *"The stranded asset risk for replacement assets is the same as for system access assets. For example, the replacement of the connection assets in an existing residential subdivision is the same as installing connection facilities in a new subdivision, in terms of the risk of stranded asset costs. If the cost of those assets is recovered over an average of 40 years, there is a risk that customers in each of those subdivisions will leave the gas system because of the energy transition, before the cost of those assets has been completely recovered.*

And later:

> *"System pruning…is another option. Under this option, existing gas customers would replace 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.*

This has informed the approach that Enbridge Gas has taken to developing the System Pruning Pilot ("Pilot").

This document contains a description of Enbridge Gas's approach to the Pilot ("Approach"). This Approach has been developed in consultation with the IRP Technical Working Group ("TWG"), and Enbridge Gas has determined which of their suggestions it will implement in the pilot. The TWG has not formally approved the proposal but supports proceeding with it as a reasonable initial approach, subject to ongoing review and further input as the pilot is implemented and lessons are learned. Consistent with the Settlement Agreement, costs for the System Pruning Pilot have been and will continue to be tracked in the IRP System Pruning Deferral Account for later recovery.

The Approach is also informed by a jurisdictional scan, financial comparison and customer research. The executive summary provides an overview of the elements of the Approach ("Elements"), and the body of the document goes into more detail about the alternatives considered and the supporting analyses undertaken, and feedback received from the TWG through the development process.

As the pilot progresses to implementation, Enbridge Gas anticipates further learnings and acknowledges that it may be necessary to adapt certain Elements that were not initially considered. Enbridge Gas, with the support of the TWG, considers this adaptive approach both reasonable and appropriate.

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[1] EB-2024-0111, Phase 2 Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 4, 2024. p.19-20
[2] EB-2022-0200, Phase 1 Decision and Order. December 21, 2023. p.51-52

Executive Summary

The Pilot Approach has been developed as a set of Elements which includes both inputs and analysis used to inform the Approach and describes how Enbridge Gas intends to implement the Pilot. These Elements include the following:

- Pilot Objectives
- Selection Criteria
- Customer Engagement
- Customer Offer
- Customer Choice
- Stakeholder Engagement
- Program Delivery
- Implementation Plan
- Evaluation Strategy

Although Enbridge Gas agreed with the TWG that economics is not the primary driver for pilot selection, a preliminary financial comparison was completed for the facility and non-facility alternatives so that outliers could be identified and to gain a general understanding of the economics of the alternatives.

The **Pilot Objectives** are to understand:

- Customer perspectives on disconnecting from the natural gas distribution system
- Customer responses to the Customer Offer (“Offer”) including the extent to which customers can be incented to disconnect from the natural gas system in a way that is economic relative to the replacement of the mains and services
- The economics of conversion relative to replacing mains and services
- What data or other information is relevant to collect for the Independent Electricity System Operator (“IESO”) and local distribution company (“LDC”) in the pilot area
- The effectiveness of program delivery approaches
- The transferability of the learnings from the pilot to Enbridge Gas’s broader distribution system assets

As they arise during the pilot, Enbridge Gas and TWG will identify policy issues that would need to be resolved for system pruning to be implemented on a larger scale. For example, the pilot may inform considerations around obligation to serve when there are holdouts on a street. System Pruning would benefit from clarity about the Policy Objective that it fulfils. Whereas TWG members have indicated that the main driver is reduction of stranded asset risk or lower cost, the Jurisdictional Scan reflected policy drivers that were linked to climate change and social benefits. It is likely that other issues will be identified for documentation as the pilot progresses

A set of **Selection Criteria** was determined for selecting a population of candidate parts of the gas system, with an overarching criterion being that the Pilot is focused on mains that would normally be replaced using system renewal capital, specifically dead-end mains to limit the scale and magnitude of the pilot. Additionally, individual services with high costs to replace the service were identified, where electrification may be an alternative. Enbridge Gas is planning to conduct two pilots based on this population – a pilot targeting a single main at a scale of approximately 10 customers, and a pilot targeting approximately 10 unconnected individual services that are scheduled for replacement.

Using this population of candidates as a basis, Enbridge Gas has started to narrow and evolve the Selection Process and will continue to do so with inputs from the Financial Comparison, Customer Research, and Stakeholder Engagement with the LDCs. This is further described in the Implementation Plan.

Customer Engagement is a central element of the pilot project. Engagement activities were undertaken to inform the development of the Approach and will be required to support the successful implementation of the pilot. Enbridge Gas has conducted qualitative and quantitative Customer Research to understand customer attitudes and to inform the development of the Offer and Implementation Plan. During implementation, it is expected that survey tools will be used to pre-screen customers, and outreach and delivery of the offer will be conducted using a general contractor.

The **Offer** was informed by feedback from the TWG, qualitative and quantitative customer research, the jurisdictional scan, and an understanding of overall program economics. The base offer will include the full replacement of the customer's natural gas equipment and appliances with efficient appliances with comparable features and functionality as well as any additional work required to remove natural gas facilities and upgrade customer electrical facilities including the electric service to the house and internal wiring and panel as required. Additional considerations and features have been included:

- The customer will be permitted to make equipment upgrades (i.e., selecting equipment of a higher capacity or with additional features, relative to the comparable equipment offered as part of the base offer. This will be facilitated by the general contractor and paid for by the customer
- The Offer will include a building energy efficiency assessment which will inform customers about energy saving measures that they can implement and the potential impact to their energy bills. Customers will be provided with information about available rebates that may be offered by government or utility energy efficiency incentive programs. The work to complete the improvements will be overseen by the general contractor if the customer so wishes. The Offer will not include any top-ups for energy efficiency measures.
- For customers that have the work overseen by Enbridge Gas's general contractor, a warranty on the installed equipment will be included in the Offer at no cost to the customer, providing this can be sourced as part of the procurement process.
- An additional incentive will be considered as a means of addressing potential customer uncertainty about risks, with the degree of this incentive being tested and determined during the pilot implementation upon discussion with customers.

Enbridge Gas is committed to honouring **Customer Choice** and will ensure that customers are provided with the information they need to make the decision that is right for them – whether that is to disconnect from the natural gas system or remain connected. Efforts have been made to make the Offer flexible to be responsive to the individual concerns of customers which Enbridge Gas anticipates will be further informed in the delivery of the Pilot Offer.

In addition to engagement with the TWG, **Stakeholder Engagement** has included the IESO and work is underway to engage with LDCs in the areas targeted for the Pilot. These organizations are interested in understanding the system impact from customers that electrify. In discussions with LDCs, areas may be identified where the infrastructure would not readily support the full electrification of a street. The TWG has suggested that these areas should not be excluded from consideration. If included, they may lead to increased complexity and delays – this is something that will be explored during pilot implementation.

Program Delivery is expected to occur through a general contractor that will work with customers, make recommendations as to the potential replacement equipment for the customer to consider in their decision process, and oversee the work. Enbridge Gas has completed a Request for Information ("RFI") process to gain a better understanding of how such a contract should be structured and will proceed with the procurement process during the implementation phase of the project.

This document includes some preliminary work that has been completed towards an **Implementation Plan**, primarily the use of a preliminary Financial Comparison and the results of the Customer Research to narrow down the list of potential candidates for the Pilot. A preliminary project plan is also included further below. Enbridge Gas has continued with this work as the timelines for project execution are short, and the development of the approach elements is iterative.

The **Evaluation Strategy** will primarily focus on comparing the outcomes of the pilot to the Pilot Objectives. Customer attitudes will be tracked throughout the evaluation and the TWG has specifically requested an analysis of the costs and benefits from the utility and customer perspectives. This will be completed for the pilot customers with best available data.

It is anticipated that these Elements will continue to evolve as the pilot moves into implementation.

Jurisdictional Scan

The objective of the jurisdictional scan and associated report is to gain a greater understanding about, and gain insights into, how natural gas utilities within North American and European jurisdictions, where informative to the Ontario context, are approaching system pruning of their natural gas distribution pipelines. The report is intended to provide Enbridge Gas, the 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(s) in Ontario.

The study objectives include:

1. Landscape assessment to identify which jurisdictions are undertaking natural gas system pruning projects.
2. Targeted research of utilities to conduct a deeper dive on natural gas decommissioning strategies and practices, supplemented with 1:1 interview with utility staff, government staff, and/or regulatory staff to discuss processes and experiences.
3. Final report on each utilities' processes and identification of emerging best practices, practices to avoid, lessons learned, and information gaps.

DNV was awarded the contract to conduct the jurisdictional scan on system pruning activities and has been engaging the TWG Subgroup for consultation on the key deliverables of the scan. The first draft of the jurisdictional scan report was completed for Enbridge Gas and TWG review on May 19, 2025. Therefore, the full jurisdictional scan report results were not available as the Approach was being developed. However, 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. Consideration from the jurisdictional scan included in the Approach include the following:

- The likely need for customers to receive some sort of incentive, beyond just equipment incentives, as part of the offer
- Customers are expected to respond positively to offers that provide greater certainty – for example extended warranties on work and equipment, and incentives that cover potential increases to utility bills

Although not something that will necessarily inform the pilot, DNV notes, and it has been clear through the development of the Pilot, that strong and clear regulatory policy is important for successful implementation of system pruning.

System Pruning Approach and Elements

The Pilot Approach has been developed as a set of Elements which includes both inputs and analysis used to inform the Approach and describes how Enbridge Gas intends to implement a Pilot. These Elements were defined early at the outset to ensure alignment between Enbridge Gas and the TWG. The Elements are:

1. Pilot Objectives
2. Selection Criteria
3. Customer Engagement
4. Customer Offer
5. Customer Choice
6. Stakeholder Engagement
7. Program Delivery
8. Implementation Plan
9. Evaluation Strategy

Details around each Element are described in the sections below.

1. Pilot Objectives

The Pilot is intended to generate insights that will inform the potential for a future broader system pruning program. The following objectives were developed through consultation with the TWG, whose feedback has been incorporated throughout, with additional details summarized around the specific feedback and discussion points raised by the TWG.

- Understand customer perspectives on disconnecting from the natural gas distribution system
  - Explore customer perceptions and the factors influencing their decision-making regarding disconnection from the natural gas network.
- Understand customer response to the Offer and the extent to which customers can be incented to disconnect from the system in a way that is economic[3] relative to the replacement of the mains and services
  - Identify non-economic factors that may impact willingness to convert.
  - Distinguish between controllable factors (e.g. cost transparency, contractor quality) and non-controllable factors (e.g. perceptions about home value, comfort)
  - The goal is to learn and document what factors are important to customers – customers will not be forced off of the system as part of the pilot. Enbridge Gas will document their reasons for remaining on the gas system and ask what further incentives or support could be offered. This will be reported as part of the pilot findings.
  - To this end, flexibility will be demonstrated in the pilot that might not be possible as part of a full program (e.g. some customers on a street will be allowed to disconnect even if others would like to remain on natural gas).
- Understand the economics of conversion:
  - Relative to replacing mains and services (utility perspective)
  - Relative to remaining on the natural gas distribution system (customer perspective)
  - The pilot itself does not need to be economic, but the economics at a system level and (once selected) at a pilot level will be assessed
  - Understand the cost-benefit analysis from both the utility and customer perspective (as recommended by the TWG).
- Understand what data or other information is relevant to collect for the IESO and LDC in the pilot area
  - Identify the customer and system-level data needed to assess the impact of system pruning on the electrical distribution system and evaluate how pruning can be integrated as an alternative within system planning. For

[3] In this context, the comparison is of the cost to replace mains and services relative to the cost of the Offer (inclusive of equipment replacement, labour, upgrades to service, and any incentive that may be paid to the customer to cover incidentals).

example, engage with the LDC's to determine whether there is standardized information they require before Enbridge Gas initiates a pruning project.

- Understand the effectiveness of program delivery approaches including:
  - The effectiveness of targeting individual customers versus a single main with multiple customers
  - The requirements for contractor engagement and associated customer support throughout the conversion process, including customer satisfaction and experience
  - Contractor performance and cost-efficiency in the delivery of the program
- Understand the transferability of the learnings from the pilot to Enbridge Gas's broader distribution system assets
- As they arise during the pilot, Enbridge Gas and TWG will identify policy issues that would need to be resolved for system pruning to be implemented on a larger scale. For example, the pilot may inform considerations around obligation to serve when there are holdouts on a street. System Pruning would benefit from clarity about the Policy Objective that it fulfils. Whereas TWG members have indicated that the main driver is reduction of stranded asset risk or lower cost, the Jurisdictional Scan reflected policy drivers that were linked to climate change and social benefits. It is likely that other issues will be identified for documentation as the pilot progresses This will be on a best-efforts basis. The pilot is small and, as such, there may be limited findings regarding these issues.

There was some discussion within the TWG about whether the pilot needed to be economic. Ultimately, it was established that it did not, but the TWG did want to understand the range of anticipated costs for the replacement of mains and services, compared to full electrification/conversion of natural gas equipment. Further details are discussed under Pilot Selection Process in the Implementation Section.

2. Selection Criteria

The basis for the Pilot was to explore non-facility alternatives to system renewal projects. As such, a set of Selection Criteria was developed accordingly, and includes the following:

- Mains and services are part of replacement programs (based on integrity) that would use system renewal capital
- Mains are dead end, meaning that they could be eliminated without further impact to downstream customers[4]
- Individual services are part of a targeted integrity replacement program

These criteria were applied to determine a base population for the development of the approach.

The System Pruning Pilot will contain two pilots. Enbridge Gas is planning to conduct a pilot targeting a single main at a scale of approximately 10 customers[5], and a second pilot targeting approximately 10 individual services that are scheduled for replacement. Enbridge Gas will attempt to include at least one commercial customer for targeting in the course of the pilot to broaden the potential for learnings beyond residential customers.

3. Customer Engagement

Customer Engagement is a central element of the pilot project. Engagement activities were undertaken to inform the development of the approach and will be required to support the successful implementation of the pilot.

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[4] A TWG member noted that the main need not be a dead end as a section of pipe could be removed from a main that has a two-way feed. Enbridge Gas agrees, provided the main is not also needed to allow for system resiliency and operational flexibility, inclusive of maintenance and integrity management. For the pilot, the dead-end legs were selected so that these conditions did not need to be analyzed in order to identify candidates.
[5] As discussed with the TWG, the number of customers on a single main may have to be reduced in identifying a candidate system as the pilot selection process is undertaken.

Customer Research to Support Approach

To inform the design of the pilot and development of the Offer, Enbridge Gas conducted Customer Research. This research included both qualitative and quantitative components, in which a sample of customers that meet the Selection Criteria were surveyed.

- **Qualitative:** Focus groups were conducted to help understand engagement approaches for gathering customer input and learn what customers may need to be included in an offer to disconnect from the natural gas distribution system should a project be identified in their area. The qualitative discussion guide was shared with the TWG Subgroup prior to conducting the Focus Group.
- **Quantitative:** An online customer survey was conducted to understand customer attitudes and perception to system pruning and what would be required by way of a customer offer to incent them to leave the natural gas distribution system. The survey language was informed by feedback received from both the focus groups and the TWG Subgroup.

Qualitative (Focus Groups) Key Findings

Four geographically dispersed focus groups were completed in February 2025, targeting the residential market. It was expected that non-residential customers would have more diverse needs that would be addressed directly. Innovative Research Group (“Innovative”) provided their final report (Appendix 2) with key findings shown below.

1. **People needed to know why they were being asked to go through what many see as a major disruption.**

   The descriptions that were shared focused on informing customers about what is happening. That is not enough. Many had a strong negative reaction to disconnection. They needed an explanation of why this is happening before they can give the idea a fair hearing.

2. **Opinions are split on whether it’s reasonable when reacting to stimulus.**

   Customers liked the idea that disconnection is voluntary, and some see the environmental benefit. However, most see potential disconnection as a huge, stressful hassle that may pit neighbour against neighbour. They are concerned about the short-term costs and risks as well as the likelihood of higher monthly energy costs. Every group also felt that fair compensation would include a monetary payment for the “hassle”.

3. **Options are vitally important regardless of chosen solution.**

   In all groups, it was very clear that the ability to choose was vital for participants to not feel upset with the outcome of losing their natural gas access. This meant the ability to feel as though the path forward for replacing their existing homes’ utilities was not just a narrow-chosen outcome by Enbridge Gas, but rather one where they had time to decide what was best for them.

4. **Monetary incentive and individualized treatment are the two biggest drivers to earning customer trust.**

   There are two large drivers to earning customer trust with alternatives – in addition to wanting to know what the alternatives to natural gas are. The first is ensuring that all of the costs of changing are fully covered by Enbridge Gas, including the risks associated with construction. This meant both short and long-term costs related to infrastructure changes to housing, as well as subsidizing alternative forms of energy. The other is ensuring that each customer receives individual treatment with replacements tailored to their needs and preferences.

5. **Multiple modes and stages of communication are a popular way to build trust.**

   When asked about how they would like this information communicated to them, most customers are looking for multiple information channels. Just as important, customers are looking for a personal touch. Customers each have unique circumstances and are looking for Enbridge Gas to deal with them individually, including personal calls and/or visits.

The qualitative survey provided guidance on the factors that were important to customers in deciding whether to disconnect from the natural gas distribution system as part of a system pruning project. Additionally, it provided insight on how to better walk survey participants through:

- Enbridge Gas's approach to maintaining natural gas mains and services,
- Enbridge Gas's obligation to consider alternatives to capital investment in the gas distribution system, and
- The role of the OEB in approving pipeline projects and overall spend.

Quantitative (Online Survey) Key Findings

The quantitative study was developed based on the findings from the qualitative study and was completed in April 2025 by Innovative. The study findings, including the detailed methodology, are documented in their Final Report (Appendix 3), with key findings summarized below.

1. **While a majority think Enbridge Gas should consider other options, customers are split on whether it should consider disconnection.**

   Over 2-in-3 think Enbridge Gas should consider other options to replacing pipelines. However, when presented with an option to disconnect customers and shift to other energy sources, 41% say Enbridge Gas should consider disconnection while 43% say they should just replace pipelines.

2. **The base offer is perceived as fair and garnered some interest to participate. After learning more, people become more polarized.**

   A majority (59%) say the base offer is fair, with over 2-in-5 saying they are likely to agree to participate. Having a reputable contractor to complete the work is the preferred approach. Additionally, having optional potential upgrades and extended warranty would make the offer better. After seeing more about the offer, likelihood to participate is up a small but significant 4 points[6], along with a decrease in reluctance to participate.

3. **Passion is lacking, so enrollment may be a challenge.**

   Passion drives action. After seeing the base offer on its own, only 14% say they would be definitely likely to participate and disconnect. The exact same proportion feels that way after seeing all incremental offers. However, it is not the same 14%, as there is a shift in opinion taking place below the surface.

4. **A majority anticipate an increase in energy bills as a result of a disconnection.**

   Most (57%) of those who believe the bill will increase feel there should be a variable payment to guarantee no increase in energy bills. Additionally, a plurality (44%) believe that compensation for any increase in energy bills should be provided for a period of five years.

5. **An underlying connection between climate concern and natural gas cost/benefits is the biggest driver of participation intent.**

   People who are more concerned about climate change are less likely to see negative impacts from shifting away from natural gas. This underlying attitude is the biggest driver of willingness to disconnect from natural gas. Conversely, the belief that converting away from natural gas would decrease home value is the strongest negative driver.

Enbridge Gas analyzed the results in different ways, including by region, by demographics and other variables included in the survey and customer list. The findings from this survey were used to further develop the Offer and the Program Delivery model. Enbridge Gas intends to use a similar survey instrument throughout the Implementation so that the attitudes and ultimate action of customers can be tracked and reported as part of the Evaluation Strategy.

[6] Per centage points

4. Customer Offer

The preliminary customer offer was shared with the TWG as an input to the Customer Research. Through that Customer Research, Enbridge Gas has further tailored the offer to address the things that customers and the TWG have indicated are important, and to control costs for ratepayers. In general, the Offer comprises of an amount that will cover the direct costs to convert the customer to non-natural gas equipment, additions that are cost-effective and attractive to customers, and an incentive.

- The Offer will include, at no cost to the customer:
    - Abandonment of the natural gas meter and pipelines on the property
    - Removal of natural gas equipment and appliances in the home
    - Installation of new efficient non-natural gas equipment and appliances with comparable features and functionality
    - Necessary upgrades to electrical service
- Based on Customer Research and feedback from the TWG, the Offer is expected to also include:
    - A building energy efficiency assessment that will provide customers with guidance on the measures they can take to make their homes more energy efficient. Customers will also be informed about rebates that can be accessed if they would like to complete these measures.
        - There will not be any additional top up to these rebates as part of the Offer.
        - If the customer wishes to proceed immediately, then the implementation of these measures can be overseen as part of the conversion work, and their impact considered in the sizing of the heating and cooling system. Where the customer has decided not to proceed with identified upgrades, Enbridge Gas will explore with the customer what further support could be provided that would encourage them to move ahead as part of the pilot.
        - Enbridge Gas will explore with the general contractor whether this energy assessment can include an estimate of the change to the customer's energy consumption and its anticipated impact on their energy bills, recognizing that this is significantly driven by customer behaviour, government policy, inflation, and other factors.
    - The availability of a maintenance & warranty provision that can be offered to customers will be explored with the general contractor. If one is available, this will be part of the Offer when the work is overseen by the general contractor.
    - A customer incentive that covers a range of things that are specific to each customer:
        - Many customers were concerned that their energy bills would increase and felt that they would like a 5-year guarantee against this. It is not clear at this time whether energy bills will increase or not and this may be dependent on the location of the pilot. Enbridge Gas proposes that when the pilot location is known, an estimate can be made of the change in energy bills and a lump sum included as part of this incentive that would defray this cost for customers.
        - Other things that the incentive could cover include: the need to take time off work, to perform minor home repairs that are required when equipment is removed or replaced.
- Not included in the Offer, but available to the customer:
    - Upgrades to electrical appliances and equipment, at the customer's own expense.

Non-natural Gas Equipment Equivalent

A list of natural gas equipment and the corresponding non-natural gas equipment equivalent will be considered as part of the Offer and is summarized in Table 1. While these are expected to be the most common equivalent, detailed review with the individual homeowners within the selected pilot area will be required to confirm.

Table 1 - Summary of Non-Natural Gas Equipment Equivalent

Appliance	Non-Natural Gas Equipment Equivalent
Natural Gas Furnace	Electric cold climate air source heat pump with electric backup
Natural Gas Boiler / Hydronic System	Electric air to water heat pump with electric backup
Natural Gas Water Heater	Electric heat pump hot water heater or electric water heater (tank or tankless). Note that preference will be given to heat pump hot water heaters because of their efficiency.
Natural Gas Cooktop / Stove	Induction stove (same number of burners)
Natural Gas Oven	Electric oven
Natural Gas Fireplace	Electric fireplace
Natural Gas Clothes Dryer	Electric clothes dryer
Natural Gas BBQ	Propane BBQ
Natural Gas Pool heater	Electric air source heat pump for pool

Additional feedback received from the TWG members regarding the equipment are summarized below:

Tankless Hot Water Heaters

Enbridge Gas's assumption is that customers will want to replace like for like equipment, but it was noted by some TWG members that electric tankless hot water heaters may not be feasible because of the draw that they would put on the local electrical infrastructure. With tankless natural gas water heater penetration in the 15%-20% range, it is possible that this will be encountered during the pilot. Based on the existence of tankless hot water heaters in the selected pilot area, and in discussion with the LDC in that area, Enbridge Gas will work with customers to establish the best approach on a case-by-case basis.

Propane BBQ's

It is expected that customers that have a natural gas BBQ will be converted to a propane BBQ. It was suggested by some TWG members that this could be accomplished inexpensively by a modification to the existing BBQ. Enbridge Gas will explore the feasibility of this on a case-by-case basis during implementation.

Flexibility in Fuel Choice

To provide customers with maximum flexibility and to assuage concerns that they may have about the reliability of the electricity distribution system in their area, customers will be allowed to participate if they would like to install appliances that do not run on electricity (e.g., a propane furnace).

Guaranteed Utility Bills

Many customers expressed concern that their energy bills will increase if they convert to electricity. A member of the TWG recommended that Enbridge Gas should cover the energy bill differential on an actual basis for customers so that there was no risk to the customer. Enbridge Gas notes that one of the pilot objectives is to determine the change in energy usage and costs before and after electrification. There are already many factors that will influence customer energy bills, from lifestyle to government policy. If there is no cost impact to customers associated with increased energy usage over a period of five years then these factors will possibly be supplemented by more incremental things like thermostat settings, shower-length, fireplace usage, etc. An up-front payment compensates the customer for the expected change in energy bills while leaving it in their best interest to control these costs, similar to what they would have done pre-pilot.

5. Customer Choice

Enbridge Gas values customer choice. In the context of the Pilot, Enbridge Gas is committed to ensuring that customers have the information they need to decide what is best for them without feeling pressured to either stay connected to, or to disconnect from, the natural gas distribution system. Customer Research has informed the Offer as described above and Enbridge Gas has committed to flexibility in meeting customer needs as the pilot moves into Implementation.

Specific to the pilot, not all customers on a given main will be required to disconnect for the disconnection of other customers to proceed. This will allow the full scope of the System Pruning Pilot (from customer engagement through to appliance conversion and abandonment of some gas facilities) to be tested even if some customers do not want to disconnect from the natural gas distribution system.

There has been some discussion at the TWG about whether the customer can convert to electricity and remain connected to natural gas – reasons cited including a later desire to convert back to natural gas and a concern about home value. The TWG has agreed that customers must make a choice to convert (or not) as it would render the pilot outcomes ambiguous if customers did not need to be definitive. Further, the mains and services are (by definition) in need of replacement for safety and integrity reasons – so the cost to the ratepayer to both convert the customer to electricity and replace mains & services is unreasonable. For customers who ultimately choose not to participate in the pilot, Enbridge Gas will consider exploring the impact of optionality on the customer's decision to confirm if the finality of disconnection was the material driver of non-participation.

There was some discussion in the TWG about whether it would be appropriate for a system pruning alternative to allow a customer to move to a solution with higher overall greenhouse gas emissions. The TWG believes that this should be an alternative for the purposes of the pilot, as such circumstances are expected to be limited (e.g., the earlier example of converting to a propane furnace) but flexibility may be required for some customers to agree to disconnect. As such, and with a view to flexibility and customer choice, Enbridge Gas will work with customers during the pilot execution if they would like to move off natural gas but not to electricity. The viability of this will be established on a case-by-case basis.

As the general contractor engages with customers, it is anticipated that other areas requiring flexibility will be encountered. Enbridge Gas will work through these as they arise with a view to understanding customer needs, pilot objectives, and ratepayer interests.

6. Stakeholder Engagement

Aside from the customers that are selected for the Pilot (see Customer Engagement), Enbridge Gas's Stakeholder Engagement plan is focused on the LDCs and IESO to determine how they can support the Approach and pilot implementation, as well as what data and information would be useful to collect through the pilot (as part of the pilot objectives).

As part of the Customer Research, some customers raised concerns during the focus groups and quantitative survey about the reliability of the electrical distribution system in their area[7] and were also concerned that the electricity system did not have the capacity to support the upgrades that might be needed if all customers converted their space and water heating to electricity.

As noted under the Selection Criteria section above, and moving into the Selection Process described below under Implementation Plan, Enbridge Gas will shortlist locations through discussions with LDCs. The purpose of this engagement will be to confirm that the infrastructure in the area can support the conversion of the customers to electric space and water heating without a negative impact on the reliability of the electrical distribution system. This may further focus the areas where a pilot project could be advanced.

With regards to addressing the pilot objective of understanding what data and information would be useful to collect through the pilot, initial discussions with the IESO have determined that the following would be useful:

- Collection of customer bill information for a number of years pre- and post- conversion.

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[7] This concern may be due to a lack of understanding of the role of electricity in the operation of their natural gas furnace, or they have backup facilities in the form of a gas-fired generator or a gas fireplace

- Consideration of sub-metering of equipment in the home to understand the peak electrical demand. This can be explored during implementation but will depend on the customer's willingness to participate and the value of the information relative to the cost of acquisition.

7. Program Delivery

Through Customer Research, most customers prefer a competent contractor/consultant to oversee the work. With a view to flexibility, Enbridge Gas will work with customers that would like to oversee their own work to ensure that the work is completed safely and efficiently, and in a manner that protects ratepayers and the project timelines.

Enbridge Gas intends to complete program delivery through the engagement of one or more general contractors who will oversee the interaction with the customer. It is expected that the general contractor will:

- Educate the customer on the process, available offer, costs and benefits related to converting off of natural gas
- Educate the customer on measures that can be taken to improve the building efficiency and rebates that are available
- Arrange for an energy assessment if the customer would like this completed.
- Educate the customer in a non-biased manner on the available efficient appliances and equipment with comparable features and functionality to the natural gas appliances already in the home
- Establish the customer’s interest in proceeding and the timing for doing so
- Coordinate with various trades to provide a seamless customer experience as appliances and equipment are exchanged, natural gas piping is removed, any required electrical upgrades are completed, and energy efficiency measures are implemented as required
- Coordinate with Enbridge Gas so that meter and riser can be removed, service cut off at main and main abandonment are completed
- Capture and report information shared by customers throughout the process to support learnings as outlined in the pilot objectives

Enbridge Gas issued a Request for Information (“RFI”) in April 2025 to gather input from contractors about the best way to ensure that:

- Contractors are incented to provide balanced information to customers with respect to energy source and equipment, and to spend the time that the customer needs to understand their alternatives.
- Customers feel supported through the process and do not feel forced to make a quick decision one way or another
- Ratepayers receive good value

RFI Key Findings

Respondents have communicated they are able to deliver the services required in an unbiased manner and, in general, have proposed that the contract be developed with the following elements:

- Project Setup fee which will cover the development of processes, survey instruments, development of (or identification of) brochures that can be left with customers, and training of the individuals that will deliver the program.
- Fee per customer to have an introductory discussion, review appliances & equipment, review alternatives, and perform building calculations.
- Fee to execute the work – some respondents have proposed an hourly fee while others have proposed a fee based on tiers that depend on the scale of the changes to be made.

Some respondents have also identified extras such as ongoing support to customers to support energy efficiency, and many have noted that electrical upgrades can be prohibitive for some customers. As noted above in the Offer, electrical upgrades will be implemented if they are required.

TWG members have stressed the importance of customer survey/interview information acquired throughout the project so that the evaluation can include what drives customers to make the decisions they do throughout the pilot. This was added to the contractor scope of work as a result of this input.

Enbridge Gas will proceed with the procurement process during the Implementation phase of the project.

8. Implementation Plan

The Implementation Plan will include several of the above Elements, where a formalized and detailed plan will be built off the Approach and developed as the pilot progresses beyond the Approach phase and into execution. Some preliminary planning on select Elements has been initiated given the short project timelines and iterative nature of the Approach development. The following Elements have been discussed and developed with the TWG, and include:

- Pilot Selection Process (including the role of Financial Comparison, Customer Research, and Stakeholder Engagement)
- Customer Engagement
- Project Schedule

i. Pilot Selection Process

As described above, a Selection Criteria was determined and applied to assets scheduled for replacement using system renewal capital to determine a base candidate population for the development of the Approach. Additional screening criteria were determined to help narrow down the population size to potential pilot project candidates, with consideration for maximizing the likelihood that the full system pruning process would be tested and to provide the broadest learnings possible from the pilot projects. As a starting point to develop a short list of pilot areas for consideration, the following data will be considered:

- Financial comparison
- Customer Research
- Stakeholder Engagement

Preliminary analyses using the data are further described below.

It is expected that further refinements will be made to the Selection Process as the pilot proceeds into implementation and feedback is received from customers.

Financial Comparison

To get an understanding of the general cost to replace natural gas mains and services relative to the cost to convert customers off natural gas, Enbridge Gas completed a preliminary financial comparison for the customers that met the Selection Criteria. The simplified assumptions and inputs to this analysis are detailed in Appendix 1. The data is separated by the legacy entities Union Gas ("LUG") and Enbridge Gas Distribution ("LEGD") as Figure 1 and Figure 2, respectively. The charts are histograms which illustrate the distribution of associated costs for the facility and electric alternative across the base population, with the cost shown along the X-Axis and the number of customers in each cost-bin on the Y-Axis.

For the replacement of main/service, the charts show a similar range of costs with the exception that the LEGD chart which has a spike on the left side that represents the service-only cost to replace customers with an AMP Fitting. Further, the analysis for LEGD assumes that an AMP Fitting replacement would require a service relay. However, the practice is to replace only the riser and, as such, the cost for these service replacements will be lower than what is shown in the charts.

For the conversion off natural gas, costs assumptions included the preliminary costs to abandon the main/service, the costs of the non-natural gas equivalent equipment, installation/replacement costs and electrical upgrade costs. However, there are additional categories of costs that were not included in the analysis at this stage, either because no reasonable estimate is available or because they apply to a relatively small number of customers, such as:

- The cost for the general contractor to work with the customer and oversee the work
- An amount to compensate the customer for any increase in the utility bill (expected or perceived)
- Conversion costs for customers with natural gas pool heaters, stoves, ovens, dryers, or generators

This analysis helped to identify some customers that are not likely to be economic (for example, single residential services requiring an AMP Fitting replacement), and others where it is possible that they could be (for example, commercial services in built up urban environments, and residential customers in sparsely populated areas). This guided the pilot selection process towards customers and streets where the facility cost replacement was higher.

Figure 1 - Replacement Cost per Customer for Mains & Services vs Cost per Customer for Conversion off Natural Gas (LEGD)

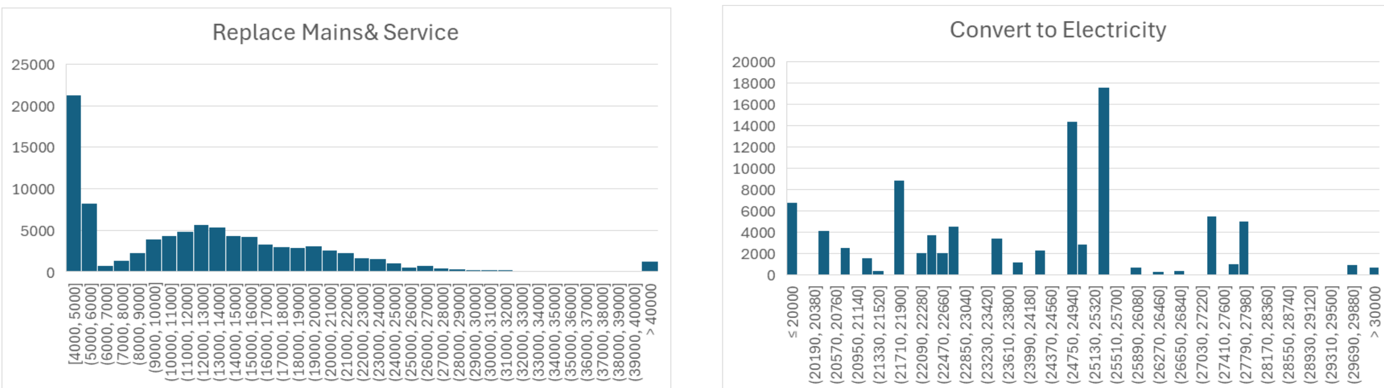
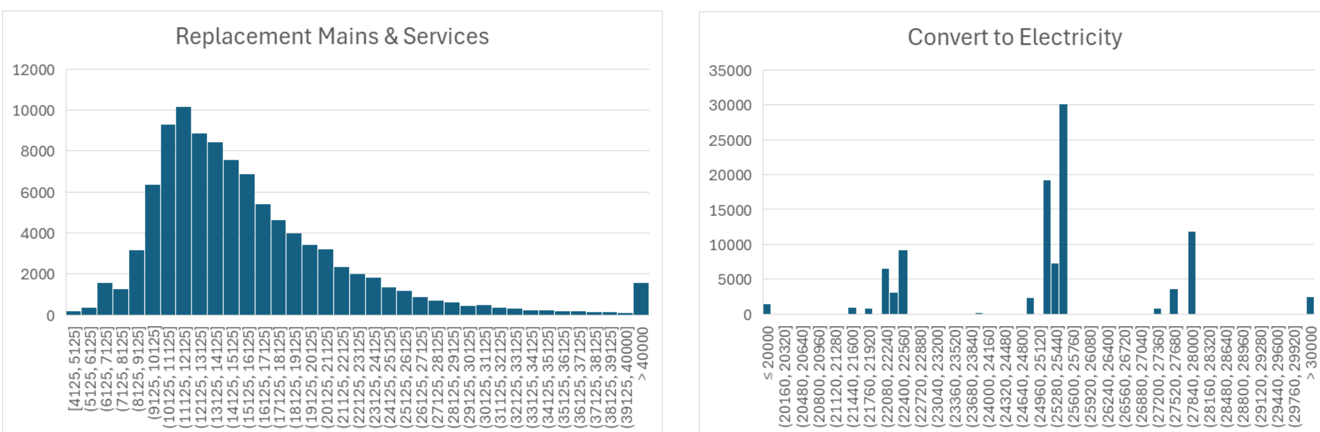


Figure 2 - Replacement Cost per Customer for Mains & Service vs Cost per Customer for Conversion off Natural Gas (LUG)



In reviewing the analysis with the TWG, additional feedback was provided and summarized below.

Cost Assumptions

The cost assumptions used as input to the analysis was provided to the TWG for review (Appendix 1). Some TWG members indicated that the cost for the electric heat pump hot water heater was too high, and that bulk discounts would be available to Enbridge Gas, while others indicated that they were reasonable. Enbridge Gas notes that the pilot is small, and bulk discounts will likely not be available. Further, a review of some of the heat pump hot water heaters installed through Enbridge Gas's Residential Demand Side Management Program in 2023/2024 reflects much higher costs, in some cases more than $5,000. The amount used in this analysis is $3,400 (materials and installation). During pilot execution, Enbridge Gas will work with the delivery contractors to see if bulk rates can be achieved through combination with other programs that the contractor might deliver.

A TWG member indicated that customers that have an existing natural gas BBQ could be converted to propane with the adjustment of the regulator on the equipment for less than $100. Enbridge Gas notes that with a penetration rate of 20-35%, the impact on the financial comparison is relatively small. This will be explored with customers during pilot execution and may be a good alternative for customers that like the features of their existing BBQ. It is possible though, that, depending on the age and features of the existing BBQ, customers may want a new BBQ if they are to be persuaded to disconnect from the natural gas system.

A TWG member noted that while equipment costs were reasonable, installation costs were low. More information on this is unlikely to be available until the procurement process is completed.

A TWG member indicated that electric tankless hot water heaters could have a very large draw on the electrical distribution system. With a penetration rate of 13-16%, Enbridge Gas will explore during pilot execution the prevalence of tankless water heaters in the pilot location and the LDC’s ability to support their use with the existing infrastructure.

A TWG member noted that electric heat pump hot water heaters are efficient, but their role in total cost and comfort can be difficult to assess because they cool the ambient air when they are operating. This has a positive effect in the summer and a negative effect in the winter. This will be reflected in the assessment of customer utility bills post-implementation, but its effect may be difficult to detect.

A TWG member noted that the cost in this analysis for electrical panel upgrades was too low but that they may not always be needed, even in houses that were built before 2000. Without clarity as to how this could be differently included in the analysis, the Enbridge Gas has not made an update but will try to understand this as part of the pre-screening of customers.

Method of Analysis

Recognizing that the replacement costs for mains and services were taken from a very small number of projects, TWG members requested a sensitivity analysis. As such, sensitivity analysis was completed for the cost of the facility replacement as well as the cost of the facility abandonment (captured under the cost to convert off natural gas).

The result of the sensitivity analysis on the mains and service replacement cost for the LEGD data are shown with the costs halved (-50%) and doubled (+100%) (see Figure 3 and Table 2). The data for LUG is not illustrated but will demonstrate similar results as the underpinning assumptions are the same. The replacement cost per customer is primarily driven by the amount of main that is associated to that customer except for the customers that require only a service replacement.

The chart on the left shows the distribution of facility cost replacement when the cost of mains and services are halved. The effect of this is to move the services that had a cost/customer from $4k-$6k in Figure 1 (the two bars at the extreme left) all into the first bar on the extreme left. Beyond that, the full chart is condensed horizontally and shifted to the left, with very few customers falling into the >$40k bin.

The chart on the right shows the distribution of facility cost replacement when the cost of mains and services are doubled. The effect of this is to move the services that had a cost/customer from $4k-$6k in Figure 1 into the bins on the left side of the graph – disproportionately the $8k-$9k and $11k-$12k bins. Further, any service in Figure 1 with a cost/customer >$20k is moved into the >$40k bin through the doubling. Beyond that, the remaining services are spread out horizontally and shifted to the right.

Figure 3 Cost per Customer of Facility Replacement - Sensitivity Analysis for Mains & Service Replacement Cost (LEGD)

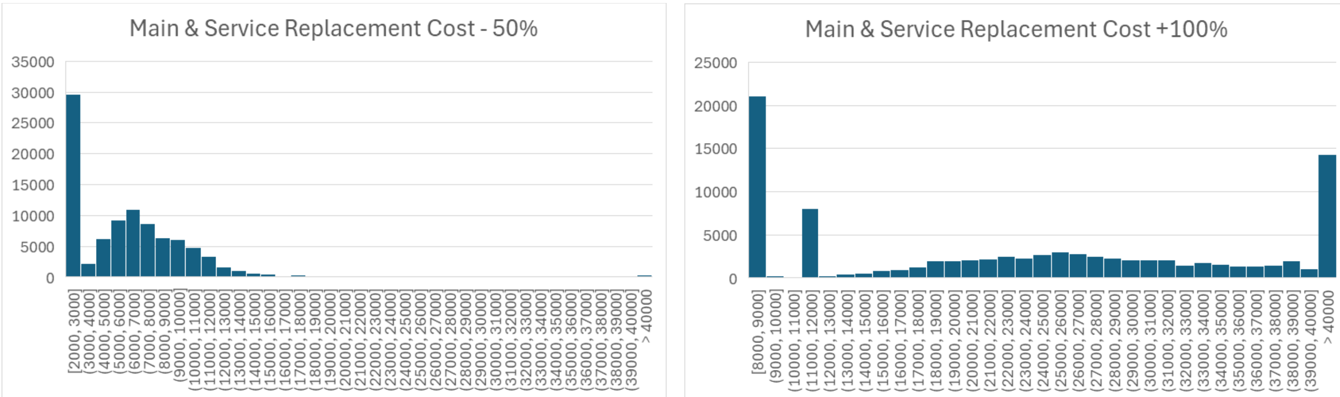


Table 2 - Cost per Customer of Facility Replacement Sensitivity Analysis and Population Size

	Base Case (Figure 1)	Mains & Services - 50% (Figure 3)	Mains & Service +100% (Figure 3)
Minimum Cost per customer	$4,000	$2,000	$8,000
Number of replacements > $40k per customer	1,249	281	14,290

The result of the sensitivity analysis on the abandonment cost for the LUG data are shown with the costs halved (-50%) and doubled (+100%) (see Figure 4 and Table 3). The cost of converting off natural gas includes the cost of abandoning the mains and services and represent about 30% of the conversion costs in LUG. The impact in LEGD is more muted because the analysis is dominated by the number of service relays for AMP Fittings, where these do not require a main abandonment.

Figure 4 - Cost per Customer of Converting off Natural Gas - Sensitivity Analysis for Facility Abandonment Cost (LUG)

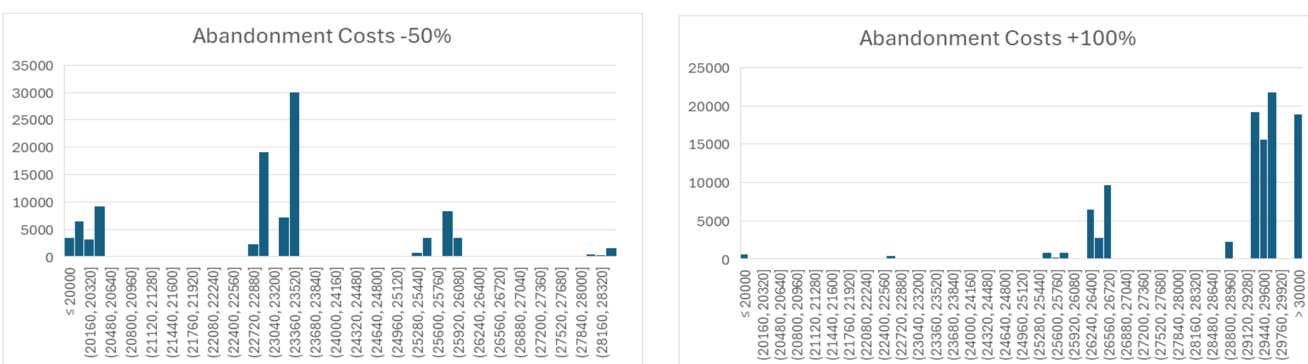


Table 3 - Cost per Customer of Converting off Natural Gas (Facility Abandonment) Sensitivity Analysis and Population Size (LUG)

	Base Case (Figure 2)	Mains & Service Abandonment -50% (Figure 4)	Mains & Service Abandonment +100% (Figure 4)
Customers below $20k	1441	3489	1611
Mean Cost/Customer	$25,100	$23,020	$29,258
Customers over $30k	2,475	663	18,940

The financial comparison shows that there can be scenarios where the cost of the alternatives may be comparable, and this will be explored during the implementation of the pilot, based on actual customers' equipment and the mains and services in the area.

TWG members indicated that the financial comparison did not fully take into account some factors, for example:

- It disregards the impact of reducing risk of stranded asset costs
- It does not recognize that some customers would be converting off natural gas in any case, and that the pilot served only to bring these costs forward in time
- It does not include costs and benefits to the customer or society because of lower greenhouse gas emissions, or changes to utility bills.

Enbridge Gas notes that it would be an assumption outside of the scope of this analysis to conclude that there would be stranded asset costs, or that customers would convert off natural gas without the prompting of the pilot or the degree to which this could happen. The analysis was not intended to explore various scenarios – rather to simply look at the up-front cost to replace facilities compared against converting off natural gas. For the purposes of the pilot, which is small, Enbridge Gas did not attempt to quantify any of the costs or benefits noted above and they are not included in the Tables above.

TWG members agreed that with respect to analyzing customer impact, it would be appropriate to do this in the Evaluation phase based on the actual costs and customer utility bills, noting that there may be other costs and benefits that are harder to quantify but which can be qualitatively documented.

TWG members recommended that Enbridge Gas look at the outliers to narrow down some of the pilot location alternatives. Specifically, it was agreed that the Company would not pursue a pilot focused on customers with AMP fitting replacements (where no main replacement is required) because the cost for these replacements is very low compared to the cost of electrification. Enbridge Gas does believe that there may be some individual customers where the cost of the service replacement is higher, and the comparison cost to electrify may be closer. Examples include commercial customers and single customers on a main.

TWG members recommended that Enbridge Gas focus its pilots on streets and customers where the cost per customer for facility replacement is highest. This increases the likelihood that the cost to replace the customer's gas equipment with electric equipment could be comparable to the cost of replacing the gas facilities.

TWG members suggested that there could be higher costs to electrify homes that did not already have central air conditioning, and that this information may be available within the MPAC data that Enbridge Gas has used as part of the financial comparison.

TWG members indicated that if the financial characteristics of the two pilots were similar that they could be diversified by looking at different geographies or income levels to increase learnings. It was agreed that the age of the home was not a factor for diversity because almost all the homes that meet the selection criteria are older – this is because they are generally on older mains that need to be replaced.

Customer Research

In the Customer Research, there were some variations across the province with respect to whether customers indicated that they were likely to participate in the pilot, if it were to happen in their area. With a view to increasing the likelihood of uptake, Enbridge Gas proposes to further filter candidate pilot areas to those where the likelihood of participation is >40%. Initial screening looked at communities with 20 or more completed surveys, but this yielded a small number of potential participants and omitted many smaller communities. This has been broadened to include communities with 5 or more completed surveys. The communities that meet these criteria are:

Table 4 - Communities where the Customer Response to the offer is Positive

Ajax	Barrie	Belleville	Bradford
Brampton	Brantford	Brockville	Burlington
Collingwood	Espanola	Etobicoke	Gloucester
Grimsby	Hamilton	London	Mississauga
Nepean	Newmarket	Niagara Falls	Niagara on the Lake
Oakville	Orangeville	Orleans	Oshawa
Ottawa	Pelham	Peterborough	Pickering
Picton	Port Hope	Richmond Hill	Scarborough
St. Catharines	Stratford	Thornhill	Thorold
Toronto	Wainfleet	Welland	

Stakeholder Engagement

Enbridge Gas is beginning outreach with the LDCs in these areas to identify any concerns and will use this as input to a further shortlist of pilot areas. Beyond this, the TWG agreed that it would be appropriate to do a preliminary screening of customers in each potential pilot area to establish interest.

There was discussion at the TWG about whether a lack of electrical capacity in an area should preclude its inclusion as a pilot area. Enbridge Gas has discussed with the IESO areas where they are already working with LDC's to implement neighbourhood level programs with associated upgrades to the infrastructure. The Company will, with input from the appropriate LDC's, determine if there are system constraints in some of the areas that meet the Selection Criteria. Although these system constraints would not preclude an area from consideration for the Pilot, it will add complexity and delays if an area cannot be electrified before system level improvements are made. An area of discussion within the TWG was whether the cost for these neighbourhood level upgrades would be borne by the customers involved in the Pilot (becoming Pilot project costs) or the electricity LDC. OEB staff provided guidance that it is the expectation that the costs of any distribution system upgrades that would be required to implement 200A service in a neighbourhood is borne by the electricity LDC.[8] It is expected that the cost for upgrades to the customer's electrical service, panel, and wiring within the home would be customer costs (within the scope of the Pilot cost).

Enbridge Gas is beginning outreach with the LDCs in these areas to identify any concerns and will use this as input to a further shortlist of pilot areas. Beyond this, the TWG agreed that it would be appropriate to do a preliminary screening of customers in each potential pilot area to establish interest.

[8] Ontario Energy Board Bulletin, Issued August 24, 2023, Re: Residential Customer Connections & Service Upgrades

ii. Customer Engagement

As noted above, the initial screening to narrow the population of pilot candidates down to those targeted for customer engagement will include the financial comparison (service replacement costs > $30K will be initial shortlist)[9], customer research (areas to those where the positive response rate to the offer is >40%) and LDCs (where capacity constraints are not identified).

As the pilot selection process is narrowed, customers will be pre-screened with a survey to determine (on a preliminary basis) their individual interest in participating in the pilot, appliances and demographic information. With this input, Enbridge Gas will identify customers that will be part of the pilot project, approximately twenty across two pilots. Enbridge Gas intends to consider the following criteria in narrowing the pilot candidates:

- Sentiment to conversion off of natural gas, to target customers that are more positive or undecided on the potential to participate in the offer.
    - Given the scale of the pilots, Enbridge Gas intends to exclude any streets that have an “opposer” identified in the street-level pilot screening.
    - An opposer could be included in the individual service pilot as a means of understanding the key drivers of their position in greater detail and as a potential for them to reconsider their position. However, in the event all individual service candidates where responses are received are strong opposers based on the pre-screen, Enbridge Gas will consider in consultation with the TWG if learnings would be better supported by a second street level pilot.
- A range of sentiment across the pilot customers in both the street level and individual service pilots will be sought to provide greater learnings.
- Diversity of candidate customers, inclusive of:
    - Greater equipment/appliance diversity among residential customers, as a street and individual services where at least some customers have more than space and water heating with natural gas will provide greater learnings
    - Representation of varying income level in the individual services pilot
    - Attempt to include at least one commercial customer for targeting in the course of the individual services pilot to broaden the potential for learnings beyond residential customers
- Operational efficiency in the location of the resulting candidates, to ensure the pilot candidates can be effectively served by the selected contractor

Following the screening Enbridge Gas will narrow the list to the pilot candidates and initial customer outreach will establish the legitimacy of the process and introduce the general contractor. The general contractor will then meet with these customers in person and provide information about the Offer as it relates to each customer and their specific appliances, equipment, and home characteristics. Consistent with feedback from the customer research, FAQ’s, websites, and brochures will be used to provide customers with information; communications will initially be made through email and physical mail. Survey tools will be used throughout the customer engagement so that results can be tracked as part of the pilot evaluation.

iii. Preliminary Project Schedule

A preliminary project schedule is outlined in Table 5. Detailed project planning will continue as the project moves towards execution.

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[9] The initial direction was to focus on customers with a replacement cost >$40k but this yielded a small population in the communities of interest. Enbridge Gas will focus on the higher cost services as a priority but recognizes that, dependent on engagement, this condition may need to be further relaxed to include customers with a replacement cost of >$20K.

Table 5 - Proposed Project Schedule

Activity	Proposed Timing for Completion
System Pruning Approach endorsed by Technical Working Group	June 2025
Engagement with LDC's in communities of interest	July 2025
Customer Pre-Screening	August 2025
Contractor Engagement with Customer to Establish Interest	October 2025
Customers Confirm Interest	January/February 2026
Customer Conversions	Summer 2026
Interim Report	Fall 2026
Facility Replacement Work Completed (if required)	Summer 2027
Customer Follow Up Survey Work Completed	Spring 2027
Final Report	Summer 2027

9. Evaluation Strategy

To evaluate the results of the Pilot, Enbridge Gas will compare the results of the pilot to the Pilot Objectives. It is anticipated that this will be a combination of data-driven analysis and commentary-style observations of the pilot results. Specifically, there will be analysis for the following:

Financial comparison

- Tracking the cost of customer conversion and mains & services replacement from the structured, unit-based analysis through a site-specific quote, and ultimately to the actual costs of the project – whether that is to convert the customer off natural gas or to replace their mains and services.
- If customers provide access to utility bills, Enbridge Gas will complete an analysis pre- and post- conversion. This will be an input to an overall assessment of costs and benefits from the customer perspective. Enbridge Gas will seek to get access to the customer's energy bills through Green Button. This is key to understanding the impact of electrification on the LDC, and to getting a better understanding of changes in customer utility costs that can be expected with full electrification.

Customer Uptake

- Tracking customer interest from an initial survey where no commitment is expected (customer research described above), through to a more directed survey in which interest is solicited (pre-screening), through to an in-person meeting where commitment is required (completed by the general contractor), and ultimate follow-through of the conversion journey.
- Data collection to assess potential influencing factors in the customers decision process, inclusive of the characteristics of the customer and their home
- Data collection to assess customer perceptions and rationale for participating/not participating in the Offer

Program Delivery Effectiveness

- Data collection to assess what components of the Offer, delivery approach and methodology for communicating information were most valued by customers
- Data collection on level of satisfaction achieved with Offer execution and approach to support throughout the customer journey.

Transferability of Learnings

- Comparison of customer characteristics to the broader population of assets in Enbridge Gas's distribution system that are system pruning candidates and the customer population as a whole to establish expectations for broader implementation given pilot results.

Policy and Framework Elements

- As they arise during the pilot, Enbridge Gas and TWG will identify policy issues that would need to be resolved for system pruning to be implemented on a larger scale. For example, the pilot may inform considerations around obligation to serve when there are holdouts on a street. System Pruning would benefit from clarity about the Policy Objective that it fulfils. Whereas TWG members have indicated that the main driver is reduction of stranded asset risk or lower cost, the Jurisdictional Scan reflected policy drivers that were linked to climate change and social benefits. It is likely that other issues will be identified for documentation as the pilot progresses.

Appendix 1 – Inputs to Financial Comparison

This section details the inputs and assumptions used in the financial comparison including the:

- Facility costs, which includes the replacement of associated services and/or mains
- Conversion off natural gas, which includes abandonment of the associated services and/or main, non-natural gas equipment cost, associated installation and replacement costs and electrical upgrade costs

These inputs and assumptions are high-level estimates and capture the primary cost categories to help inform the development of the approach and are not intended to represent an exhaustive list of all possible costs. Actual costs will be reviewed and captured during the implementation of the pilot. The purpose of the analysis is to compare the upfront cost of the facility replacement (mains and services) with the conversion of the customer off natural gas (replacement of gas equipment and appliances with non-gas alternatives, abandonment of mains and services).

Facility Costs

Facility costs for each candidate customer that met the Selection Criteria was estimated through using average service and/or main replacement cost (Table 6), based on data from two projects that were completed in 2024. Given the limited sample size, these estimates may not be fully representative, however, this limitation was, to an extent, mitigated by a sensitivity analysis.

Main replacement cost was calculated by determining an average length of main associated with each customer (using information from the Geographical Information System “GIS”) and multiplying that length by the average main replacement cost-per-meter. Each customer was also assumed to have a service replacement. For customers requiring only AMP fitting replacements, only the service replacement cost was applied, as no main replacement would be necessary. It should be noted that applying the total service replacement cost in these cases would overstate the costs, as field practice involves replacing only the affected riser rather than the entire service line.

Table 6 - Average Cost Assumptions for Service & Main Replacement

Region	Average Service Replacement Cost	Average Main Replacement Cost (per meter)
GTA EAST & TORONTO	$4,000	$1,000
GTA WEST	$4,000	$1,000
NORTHERN & EASTERN REGION	$4,000	$600
SOUTHEAST REGION	$6,000	$600
SOUTHWEST REGION	$6,000	$600

Conversion off Natural Gas Costs

i. Service and Main Abandonment

The cost associated with service and main abandonment for each candidate customer that met the Selection Criteria was estimated using the following cost and assumptions (Table 7). Service abandonment was assumed to be about half the cost of a service replacement. Based on 2024 averages, the cost for a Cut-Off at Main (“COAM”) is a little over $3500 for rural services and a little under $6,000 for urban services. The connection to the main is usually in the public right of way and, in an urban environment, this can involve complex permitting, traffic planning, and construction activity. Whereas service replacements are often part of a project and concentrated in a specific geography, COAM are driven by customer requests – demolition, alteration – and may be more scattered. The context for the System Pruning Pilot is different yet again. While the individual customers that participate in the pilot will require a COAM, it may be possible to reduce the number of cuts on a street if multiple customers participate in the pilot. With these variable factors, the cost to abandon the gas service was assumed to be 50% of the cost to replace it – this is a little lower than historical average for rural services and significantly lower than historical average for the urban services. Recognizing the range of potential costs for the service abandonments, a sensitivity analysis was completed in which the costs were halved and doubled – taking the service abandonment cost from $1,000-$1,500 up to $4,000-$6,000.

It was assumed that the main could be sectioned at each customer service connection, eliminating the need to do further sectioning on the main to abandon it. Further, it was assumed that some work would be required at the tie-in point where the abandoned natural gas main connects to the portion of the natural gas distribution system that remains active. This was represented as the replacement of 2m of main to allow for the proper disconnection and capping.

Table 7 - Cost Assumptions for Service & Main Abandonment

Region	Avg Service Abandonment Cost	Avg Main Abandonment Cost (beyond sectioning)
GTA EAST & TORONTO	$2,000	$2,000
GTA WEST	$2,000	$2,000
NORTHERN & EASTERN REGION	$3,000	$1,200
SOUTHEAST REGION	$3,000	$1,200
SOUTHWEST REGION	$3,000	$1,200

ii. Electric Heat Pump Costs

An estimate for installed electric heat pump costs (Table 8) was taken from a small sample of invoices for heat pumps installed through Enbridge Gas's residential Demand Side Management ("DSM") Program. These costs were increased for inflation and rounded to recognize the small sample. Median, upper, and lower quartile costs were assigned to houses based on their size and age as is shown in the table. Beyond these assumptions, a linear interpolation provided an installation cost for houses of each size and age. For each candidate (house) that met the Selection Criteria, an electric heat pump installation cost was assigned based on its size and age, determined through MPAC data. It is important to note that there is a wide range of installation costs for electric heat pumps, depending on the characteristics of each specific home. As a result, the actual installation cost for a specific home may vary from the figures presented in Table 8.

Table 8 - Cost Assumptions for Electric Heat Pump Installation

Installation Cost	
Lower Quartile	$8,000
Mean	$14,000
Upper Quartile	$19,000

Home Build Year	Home Size	Assigned Cost
1974 and Older	< 1500 sq ft	$14,000 (Mean)
1974 and Older	< 2500 sq ft	$16,500
1974 and Older	2500 sq ft +	$19,000 (Top Quartile)
1975-2006	< 1500 sq ft	$11,000
1975-2006	< 2500 sq ft	$14,000 (Mean)
1975-2006	2500 sq ft +	$16,500
2007 and Newer	< 1500 sq ft	$8,000 (Bottom Quartile)
2007 and Newer	< 2500 sq ft	$11,000
2007 and Newer	2500 sq ft +	$14,000 (Mean)

iii. Electric Heat Pump Hot Water Heater Costs

The 2024 Residential Customer End-Use Study provided the penetration percentage of customer with natural gas tank and tankless water heating, summarized in Table 9. The costs for the electric heat pump hot water heater (Table 10) were based on a review of the Home Depot online catalogue and included in the analysis on an expected value basis using the likelihood that customers have these appliances.

It should be noted that a review of installed costs for electric heat pump hot water heaters as part of Enbridge Gas's residential DSM Program indicates that the installed cost might be much higher than what is reflected here. On the other hand, some TWG members thought that the costs here were over-stated.

Table 9 - Penetration % of Natural Gas Hot Water Heating

Region	% of Customers with Tank Water Heating	% of Customers with Tankless Water Heating
GTA EAST & TORONTO	58%	16%
GTA WEST	69%	13%
NORTHERN & EASTERN REGION	62%	14%
SOUTHEAST REGION	69%	13%
SOUTHWEST REGION	66%	14%

Table 10 - Cost Assumptions for Electric Hot Water Replacement

Non-Gas Equipment Alternative	Equipment Cost ($)	Installation / Setup ($)
Electric Heat Pump Hot Water Heater	$3300	$100
Electric Tankless Hot Water Heater	$800	$300

iv. BBQ's and Fireplaces

The 2024 Residential Customer End-Use Study provided the penetration percentage of customers with natural gas BBQ and fireplace, summarized in Table 11 and Table 12 respectively. The costs for these products (Table 13) were based on a review of the RONA online catalogue, where a median price point was selected and included in the analysis on an expected value basis using the likelihood that customers have these appliances.

Table 11 - Penetration % of Natural Gas BBQ Replacement

Region	% of Customers with a Natural Gas BBQ
GTA EAST & TORONTO	26%
GTA WEST	35%
NORTHERN & EASTERN REGION	21%
SOUTHEAST REGION	29%
SOUTHWEST REGION	33%

Table 12 - Penetration % of Natural Gas Fireplace

Region	% of customers that have a fireplace	Of customers that have a fireplace, % with 1 fireplace	Of customers that have a fireplace, % with 2 fireplaces	Of customers that have a fireplace, % that have 3+ fireplaces
GTA EAST & TORONTO	35%	73%	23%	4%
GTA WEST	51%	73%	24%	3%
NORTHERN & EASTERN REGION	34%	75%	25%	3%
SOUTHEAST REGION	37%	67%	27%	5%
SOUTHWEST REGION	37%	74%	23%	3%

Table 13 - Cost Assumptions for Non-Gas Alternative for Natural Gas BBQ and Fireplace

Non-Gas Equipment Alternative	Equipment Cost ($)	Installation / Setup ($)
Propane BBQ	$700	$100
Electric Fireplace	$1000	$100

v. Electrical Panel and Service Line Upgrades

The cost associated with electrical panel and service line upgrades was based on internal and external input (Table 14). In discussions with the TWG, there was varied input on the costs and range and no consensus, indicating the cost assumptions will need to be confirmed during implementation.

It was assumed that any house built after 2000 would not require an electrical panel upgrade. However, despite changes to the Ontario Building Code around that time, it appears some houses constructed post-2000 do not have 200A service while some older homes do. The TWG also noted that there may be technology that can be installed so that panel and service upgrades are not required, even if the house does not have 200A service.

The cost of an electrical panel upgrade (if required) would be borne by the customer, however there is discretion provided to LDC's as to whether the cost of the electrical service line upgrade (if required) connecting the house to the distribution transformer would be borne by the LDC or the customer. This analysis assumes that it is borne by the customer and, because of the age of the homes in the population, most conversions include the $3,000 noted in Table 14. This will be explored with the LDC as implementation proceeds and may reduce by $3,000 the conversion cost per customer if it is determined that this cost would be borne by the LDC.

Table 14 - Cost Assumptions for Electrical Upgrades

Electrical Upgrades	Cost ($)
Panel Upgrades	$1,000
Customer Electric Service Upgrade	$3,000

Appendix 2 – Innovative Research Group: System Pruning Focus Group Report

INNOVATIVE RESEARCH GROUP

Focus Group Report

System Pruning Focus Groups

ENBRIDGE®

March 2025 | **REPORT**

STRICTLY CONFIDENTIAL

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Research Objectives and Methodology

Research Objective

Enbridge Gas Inc. commissioned **Innovative Research Group** (INNOVATIVE) to recruit and conduct exploratory focus groups to test their messaging and hear what customers reactions to “system pruning” would be.

The goal was to gather insights from Enbridge Gas Ontario customers who own their homes regarding their responses to potential transitions from natural gas. These insights will be used to help fine-tune a survey that will be provided to customers in particular areas to understand what they might need to be satisfied if system pruning is necessary.

INNOVATIVE RESEARCH GROUP

Methodology

This report summarizes the results of four in-person focus groups held between February 24th and 25th, 2025:

Group	Date	Time	Region	Participants
1	**February 24th**	**5:30pm – 7:30pm EST**	North / Eastern Ontario	8 participants
2		**8:00pm – 10:00pm EST**	Toronto / GTA	6 participants
3	**February 25th**	**5:30pm – 7:30pm EST**	Southwestern / Central Ontario	9 participants
4		**8:00pm – 10:00pm EST**	Southwestern / Central Ontario	8 participants

An incentive of $150 was provided to all individuals who participated in each group. Each group was approximately 2 hours.

The groups began with asking participants about their natural gas usage and any changes to that recently. This then transitioned into presenting the first of two stimuli about potential alternatives to relying solely on natural gas and presenting ways to reduce that usage. After collecting opinions on how clear that information was, stimulus two was presented which informed participants about "system pruning" and what that entails. From there, the discussion investigated if participants understood what system pruning was, how they felt about it, and what solutions they would want from Enbridge if it were something they needed to go through. The discussion concluded with asking participants how they would like to receive information and updates about such a project.

Caution: Qualitative research does not hold the statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used for strategic direction only. In focus group research, the value of the findings lies in the depth and range of information provided by the participants, rather than in the number of individuals holding each view.

Key Findings

Key Findings

01 People needed to know why they were being asked to go through what many see as a major disruption.

The descriptions that were shared focused on informing customers about what is happening. That is not enough. Many had a strong negative reaction to disconnection. They needed an explanation of why this is happening before they can give the idea a fair hearing.

02 Opinions are split on whether it's reasonable when reacting to stimulus.

Customers liked the idea that disconnection is voluntary, and some see the environmental benefit. However, most see potential disconnection as a huge, stressful hassle that may pit neighbour against neighbour. They are concerned about the short-term costs and risks as well as the likelihood of higher monthly energy costs. Every group also felt that fair compensation would include a monetary payment for the "hassle".

03 Options are vitally important regardless of chosen solution.

In all groups, it was very clear that the ability to choose was vital for participants to not feel upset with the outcome of losing their natural gas access. This meant the ability to feel as though the path forward for replacing their existing homes' utilities was not just a narrow-chosen outcome by Enbridge, but rather one where they had time to decide what was best for them.

04 Monetary incentive and individualised treatment are the two biggest drivers to earning customer trust.

There are two large drivers to earning customer trust with alternatives – in addition to wanting to know what the alternatives to natural gas are. The first is ensuring that all of the costs of changing are fully covered by Enbridge, including the risks associated with construction. This meant both short and long-term costs related to infrastructure changes to housing, as well as subsidizing alternative forms of energy. The other is ensuring that each customer receives individual treatment with replacements tailored to their needs and preferences.

05 Multiple modes and stages of communication are a popular way to build trust.

When asked about how they would like this information communicated to them, most customers are looking for multiple information channels. Just as important, customers are looking for a personal touch. Customers each have unique circumstances and are looking for Enbridge to deal with them individually, including personal calls and/or visits.

What do we think? – Earning Customer Trust

1

Clearer Messaging.

The messaging of the survey and project need to be clear for customers. Communication with customers needs to be concise and to-the-point to avoid issues of misinterpretation – which can lead to filling in the gaps with negatives. More detail and honesty provides Enbridge Gas trust from customers, which is crucial for successful communication.

2

Alternatives and Oversight.

Enbridge Gas needs to demonstrate that they are proactively looking into the costs and details of alternatives before approaching customers. This – along with communicating oversight from the OEB – can help customers make informed decisions about how they would like to approach possibly switching their energy from natural gas to something else.

3

Choice is Important.

One of the key themes found was how crucial choice was for customers. It allows them to take ownership over the decisions regarding their property and tailor the solution to their needs and preferences. Choice – from whether they are involved, to how they are notified about updates – is important to customers.

Stimulus

Stimulus

In the survey, customers were informed of the IRP process and the concept of system pruning. Stimuli were developed on these themes for testing during the focus groups for clarity and comprehension.

Stimulus One – Day One

When considering the work it needs to do, specifically its **pipeline projects**, Enbridge Gas is required by the Ontario Energy Board (OEB) to evaluate whether **non-pipeline alternatives** are available that would delay, reduce, or eliminate the need for the project.

Examples of potential **non-pipeline alternatives** include:

- Helping customers reduce the amount of natural gas they use through conservation programs or other options. Examples could include:
    - Incentives for installing new windows and doors; and/or
    - Adding insulation; and/or
    - Upgrading equipment, such as a furnace or water heater.
- Shifting customer's peak hour gas demand through demand response programs (this type of program encourages customers to use less gas during times of high demand)
- Delivering compressed natural gas by truck to locations
- Securing more natural gas through third parties in a specific area

In industry terms, this enhanced planning strategy and process is called IRP or **Integrated Resource Planning**.

Stimulus One – Day Two

Enbridge Gas has many kilometers of pipelines in the ground in Ontario. It manages the maintenance, growth and replacement of this network of pipelines through its asset management plan. Enbridge Gas is regulated by the Ontario Energy Board (the OEB).

When considering the work it needs to do, specifically its **pipeline projects**, Enbridge Gas is required to evaluate whether alternatives are available that could delay, reduce, or eliminate the need for the work.

These alternatives would be considered from both a technical (i.e. does it work?) and economic (i.e. is it cost-effective?) perspective.

Examples of potential **alternatives** that could help reduce the need for a growth or reinforcement pipeline project by reducing the demand include:

- Helping customers reduce the amount of natural gas they use during peak hours through conservation programs or other options. Examples could include:
  - Incentives for installing new windows and doors; and/or
  - Adding insulation; and/or
  - Upgrading equipment, such as a furnace or water heater.
- Shifting customers' peak hour gas demand through demand response programs (this type of program encourages customers to use less gas during times of high demand, such as through smart thermostat reprogramming)

Some other examples of alternatives include:

  - Delivering compressed natural gas by truck to locations that need natural gas (or need more natural gas)
  - Securing more natural gas through third parties in a specific area

- In industry terms, this enhanced planning strategy and process is called IRP or **Integrated Resource Planning**.

Stimulus Two

For each pipeline project, alternatives discussed earlier are evaluated from a **technical and economic perspective**.

There is also another option that could be considered for replacement type projects.

This option would apply for a single street, or a smaller area, and is something called System Pruning. This means that instead of repairing or replacing a pipeline, Enbridge Gas would give affected customers the option to disconnect from the pipeline. If everyone disconnects, then instead of repairing or replacing it, this pipeline could be removed.

The affected customers would need to rely on other energy sources, such as electricity to fuel their equipment and appliances. The funds no longer needed for the pipeline can be used to support the disconnection and help customers through the process.

Understanding the IRP Process

Understanding the Changes

Participants understood the information but need clarification.

Participants were looking for information about why this background is being presented.

- One common reaction across the groups seemed to be confusion when asked about the first stimulus. It seemed that while some did understand and others didn't understand the information, there was still a sizeable group asking why it was being presented in the first place.

Questions about conflict-of-interest.

- Some pointed that they didn't understand how there isn't some kind of conflict-of-interest with Enbridge Gas providing alternatives to their service and wanted to know what would prevent that from being problematic.

"I just wasn't sure what they were talking about alternatives. It made me think of alternative energy, and then I just, I had to go back and see what they were talking about."
– Woman in Southwestern/Central Ontario

"One other thing is that I have so little trust that Enbridge has my best interests at heart, I would need to have other people involved, third party involved."
– Woman in North/East

Stimulus One

Breakout:
This stimulus can be broken out into two sections (OEB oversight and potential alternatives) and add a comprehension question after each section to ensure understanding. Section one would introduce the OEB as a way of building customer trust, reassuring them that there is a third party looking out for them. Section two would then look at the alternatives, showing what Enbridge Gas has considered before approaching customers

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Some other examples of alternatives include:

- Delivering compressed natural gas by truck to locations that need natural gas (or need more natural gas)
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- In industry terms, this enhanced planning strategy and process is called IRP or **Integrated Resource Planning**.

Graphical Elements:
One trait that can be helpful for readers are visuals that break up large amounts of text. This can also be tremendously helpful for those that have a harder time reading large amounts of text at once. No specific suggestions were mentioned.

Industry Jargon:
If industry jargon isn't absolutely necessary in order to understand the core issue, it can turn into a barrier for customers to understand the proposal.

Transparency about Reasons:
Overall, transparency as to the reasons for providing the information is crucial for gaining trust with customers. Providing large amounts of information without plainly stating what intentions are can make readers skeptical about why they are being presented the information in the first place.

Making it Less General:
Targeting the messaging to be about specific lines, and stressing that it does not mean **all** lines, can make customers more comfortable with the idea. This can make the proposal seem more reasonable.

Reacting to System Pruning

How well did Stimulus Two work as a Stimulus?

Participants understood the idea of system pruning, but further clarification needed.

Why are you doing this?

- When it came to reacting to the second stimulus – much like the first – one of the common first reactions was that despite having read what it was for, they didn't understand why it was happening. For many it just simply wasn't clear what it was for or why it needed to happen. To many, the thought of going off natural gas seemed overwhelming at first and they wanted more information to ease this feeling. However, there were some who felt it made sense and seemed somewhat reasonable.

Unclarity leads to misinterpretation.

- While it was mentioned in some capacity that it would require everyone's participation to proceed, nonetheless some participants expressed that if something like this were mandatory, they would have big issues with it. To some it *suggested* that it would require everyone's consent, but others felt confused whether it was mandatory or not. Overall, to participants, this aspect of it was unclear.

"I would want to be very clear about the justification for why these decisions were being proposed, like why this plan was being proposed, so that I understood what was behind it"
– Woman in Southwestern/Central

"I don't feel like I should be forced to be try use something else. You know, I moved and bought this house and bought a, you know, a furnace, and spent a lot of money buying a furnace to use Enbridge, and now I don't want to be forced to use something else. It's just an inconvenience to me."
– Man in Southwestern/Central

Stimulus Two

For each pipeline project, alternatives discussed earlier are evaluated from a **technical and economic perspective**.

There is also another option that could be considered for replacement type projects.

This option would apply for a single street, or a smaller area, and is something called System Pruning. This means that instead of repairing or replacing a pipeline, Enbridge Gas would give affected customers the option to disconnect from the pipeline. If everyone disconnects, then instead of repairing or replacing it, this pipeline could be removed.

The affected customers would need to rely on other energy sources, such as electricity to fuel their equipment and appliances. The funds no longer needed for the pipeline can be used to support the disconnection and help customers through the process.

Clarification:
One way to rephrase this would be to mention that Enbridge Gas would not proceed until all customers agree to disconnect. This could put some at ease that it is in the hands of the customer.

"System Pruning":
The term "system pruning" was not particularly effective or even necessary in explaining the process. "Disconnection" was cited as an alternative.

Addition:
One thing that is important to add here is that for a *variety* of listed reasons, it makes more sense to change to another energy source rather than replace the pipeline to continue providing natural gas.

Last Line Confusion:
The last line can be seen as confusing to customers, as rather than listing some possibilities, it leaves it open to interpretation. Because of the vagueness of the statement, it can be seen as unreasonable rather than something that could be positive towards the customer and their transition.

Costs are Important:
If available, adding the costs of a pipeline – and what that would mean for the customer – at the end can make the idea seem more reasonable if they understand the costs and possible savings.

Reasonable vs Unreasonable

Does this approach seem reasonable to you? (Poll Results)

Support

- **Seems reasonable from an operations perspective:** One individual said they understood the proposal in terms of operational benefits.
- **Asking impacted folks if they would like the choice to disconnect:** Some individuals highlighted it was reasonable to give people the option of choosing whether to accept the proposal.
- **The compensation offered by Enbridge:** Some stated they would be more likely to support the proposal, if an offer included like-for-like replacements or financial compensations for the inconveniences.

Barriers

- **Lack of initial trust:** For quite a few, there is an initial lack of trust towards Enbridge Gas about this kind of change, which would need to be worked on.
- **Short and long-term financial consequences:** Many said they were worried about both the short- and long-term costs of the switch, such as higher monthly bills, or repair costs.
- **Doubtful about the quality of new energy:** Others voiced their concerns on the quality of the new energy, and if it would match that of their current system.
- **Decreased property value:** Several participants stated their concerns on property value diminishing due to the switch.
- **Potential for bullying:** Some were worried about the potential for bullying if everyone must agree in a certain area to the changes.

Reactions to System Pruning (1)

Participants were asked how they felt about system pruning, as shown in Stimulus Two.

Initial reactions were split when asked if it is reasonable.

- Each group was polled after being shown stimulus two, which explains system pruning and what the process would mean for customers in affected areas. Reaction was divided, with 12 stating very or somewhat reasonable, while 11 stated not very reasonable (2 voted "not sure").

Some find it reasonable from an operations perspective.

- Some participants found it reasonable from understanding that it may be necessary to make the change, and if some agency is given in how to remedy it, that it's fair to explore that. This sentiment came from the few that stated "very" reasonable when polled on how they felt about Stimulus Two.

Choice is important.

- It was clear that to most participants, choice is an important part of the process. This includes choice in participation, as well as choice in what compensation is provided, and how.

"I said very [reasonable] because it looks like the option is in the hand of the consumer, right? So if the customer is saying, if all of those customers on a street are saying, like, yeah, I'm good to disconnect. For me, I'm like, that's very reasonable."
– Man in North/East

"To be honest with you, first read, from an operations point of view, it seems somewhat reasonable, but thinking about it and listening, it doesn't seem reasonable."
– Man in Southwestern/Central

Reactions to System Pruning (2)

Participants were asked how they felt about system pruning, as shown in Stimulus Two.

Compensation goes a long way.

- Overwhelmingly, the idea of compensation goes a long way in making people more comfortable. Participants cited different levels or amounts of compensation, and the methods varied. This allowed people to feel less like the switch was simply converting them to something worse without adequate compensation.

Lack of initial trust.

- Some participants believed that Enbridge Gas' main motive for the proposed change was profit-driven, showing a strategic intent. One individual stated that they had doubts Enbridge Gas had their best interests at heart. There were also requests for third-party involvement, as several people were uneasy about letting Enbridge Gas solely manage decisions related to replacements and information. Additionally, others mentioned that the change was significant and intimidating.

Short- and long-term financial issues with switching.

- Many participants pointed out their problem with the financial implications of switching, as well as the risks associated with it. Participants wanted to know who would be incurring the costs of the switch – both current and future – and if Enbridge Gas would be taking on the potential risks if something were to go wrong during the switch, or into the future.

"I think about the resale value. When we bought our gas stove, we were thinking of getting an induction stove. And the sales rep said, you know, when it comes to resale of your house, a gas stove is a real selling feature. And you know, so I think all of that has to be part of the negotiation."
– Man in Toronto/GTA

"Be compensated on any cost that I would have to undertake, and maybe even for my time and pain going through this process. I think we should be, you should be compensated for, okay, fair enough."
– Man in Southwestern/Central

Reactions to System Pruning (3)

Participants were asked how they felt about system pruning, as shown in Stimulus Two.

Alternative quality concerns.

- One concern was the worry of alternative energy sources not having the same quality as natural gas when it came to particular appliances. Home heating was mentioned, with one participant stating they didn't think alternate forms of energy would do as good a job as natural gas in heating their home. Cooking appliances were also mentioned, particularly when switching to electricity from gas, as some felt it wasn't the same.

Possible decreased property value.

- Several mentioned the potential detrimental effect that switching from natural gas to another energy form could have. As natural gas is currently one of the most sought-after forms of energy due to its reliability, making the switch to another form has some participants worried about the future value of their property should they wish to sell. However, some believed that upgrades such as new windows, better insulation and overall improved energy efficiency as well as all new equipment/ appliances – which were mentioned as potential aspects of the switch – would raise value.

Potential for bullying.

- Some thought about the potential problem that could come with not everyone agreeing to a solution. This could result in a situation where one or two households feel bullied by others unless they agree to switch, causing disruption to relationships with neighbours.

"I would be afraid that it be preying on people who need the kind of short-term injection, who don't necessarily know the long-term cost. Like, if you're switching somebody from natural gas to electric and it's going to cost them 10 times as much in the long term."
– Man in Southwestern/Central

"To put it in my terms, it would be like bullying. If you are the holdout on the street – we've all seen the picture of the one guy with farmland surrounded by a city. And you would have to choose where to live if you WANTED to live with natural gas."
– Man in Southwestern/Central

Additional Reactions to System Pruning

Participants were asked how they felt about system pruning, as shown in Stimulus Two.

Initial reactions of headache regarding construction and materials.

- One of the reactions cited was the headache it would cause to undertake such a project, especially without knowing the scale. For some who thought it unreasonable, their minds immediately went to how big of an ordeal it would be to have their house involved in the project, and depending on the scale, their whole neighborhood affected. Many felt there should be compensation for this type of hassle.

Some noted the absence of pipeline costs.

- For some, it was noted what the costs of what replacing an area's pipeline would be was absent from the information provided. This was part of a wider theme of people wanting more transparency with what the costs of the project are and areas that would be affected.

Environmental considerations made.

- Some found when weighing the idea of making the switch, that there is an environmental benefit to consider when going to some alternative forms of energy. This seemed to be the case for some of the younger participants in particular.

"Is my house going to be under construction and for how long? And is it really feasible, like, is it to get into all that? Because in Hamilton there's hundreds."
– Man in Southwestern/Central

"And in terms of, like, the funding that's, I guess, no longer needed to maintain that pipeline. Like, is that just like an initial sum that they might help us at the beginning when we do get pruned? Or is this an ongoing annual sort of fund that we should be seeing that might offset the higher cost of, you know, switching to electric or something like that?"
– Man in Southwestern/Central

Additional Reactions to System Pruning (2)

Participants were asked how they felt about system pruning, as shown in Stimulus Two.

Uncertainty about future pricing.

- One common issue that arose for participants when they thought about switching or not was whether pricing for different energy sources would be rising or dropping. Factors like demand, availability, and costs of infrastructure all were considered, leaving participants uneasy about the situation.

Concerns about switching to electricity.

- One large concern about switching to something like electricity centered around availability and security. Some had issues with home appliances and heating being at the mercy of power outages. Others thought about whether or not the power grid is able to take on fully powering homes. Some questioned whether EV's being on the grid could make that even more troublesome.

Immediate thoughts to home remodeling.

- When discussion was focused on switching, different unique circumstances were brought up. Certain appliances, like hot water radiators for example, might require full home remodeling to accommodate a switch in heating.

"So the thought of having to increase or add any cost to myself and potentially even remodel my whole home, depending on whether or not I have to take out all my hot water rads, that is such an overwhelming thought."
– Woman in North/East

"But the other problem I have with this whole idea of changing from gas to electric. I've already been hearing so much about whether the hydro grid will be able to support the tremendous increase in the number of electric cars that need charging every night and so forth. So if they have that to worry about, and on top of that there, they have to worry about people weaning themselves off a gas furnace and a gas hot water tank. That, to me, is going to put a tremendous strain on hydro."
– Man in Toronto/GTA

Approaching Alternatives

What are the concerns?

Many felt the switch to an alternative was a big change.

- Many expressed anxieties and reservations about such a significant change. Some noted that they have relied on natural gas for many years and are accustomed to it. Others showed skepticism due to a lack of knowledge and information about the alternatives. Overall, there was consensus on wanting more information about what the switch might look like financially, both now and in the future.

Gaining trust is important for influencing decisions.

- Many expressed skepticism on the proposed changes, assuming that Enbridge Gas' motivations were driven by profit rather than focused on customer benefits. Individuals voiced concerns that Enbridge Gas does not have their best interests at heart. Many participants also lacked background and financial knowledge about pipelines, which may have contributed to confusion and hesitancy. However, many seemed more receptive after receiving additional information and clarification. Participants wanted more information readily available about the background of the project to understand and trust Enbridge Gas.

"I mean, I just think everything, because it's such a huge change for people to wrap their heads around. And nobody wants to be the first person, and this is a totally new way of doing it. So I think it would have to be a huge education campaign."
– Woman in Toronto/GTA

"I did consider, when we were going through this, is the strategic perspective of Enbridge. Right? Enbridge is there to make money? Why wouldn't Enbridge want to invest in more pipelines to deliver their fuel more efficiently and instead encourage."
– Man in North/East

How would customers like to see the concerns addressed?

Nearly all participants cited equal-value replacement as a fair incentive to consider the proposal.

- For quite a few, at a minimum, they would expect a like-for-like replacement of the appliances that will be switched out. Others suggest there should be a standard replacement with an option for consumers to upgrade their appliances for an additional cost. Some did mention that certain older replacements wouldn't require the same kind of incentive as newer appliances being replaced.

Opinion is divided among individuals; some want to manage the transition themselves while others want Enbridge Gas to handle it.

- Many individuals chose to oversee the process themselves to save money or because they have trust in their ability to handle the transition more effectively. Others preferred Enbridge Gas to manage it, citing time savings and a lack of knowledge on appliance replacement. There were also mentions of a neutral third-party involvement, to assist in the process.

"I think like for like would be reasonable, right? Yeah, it, I mean, it could give someone the chance to upgrade and maybe pay for an upgrade if they wanted to do that. But I think like for like is reasonable."
– Man in North/East

"I'd prefer the check and just do it myself that way. You know, I make sure that, you know, I get what I want, and I've just done the way that I want."
– Man in Southwestern/Central

What replacement and financial concerns did participants have?

Participants suggested Enbridge Gas should offer more than just replacements.

- Some suggested that Enbridge Gas should include a feature in their package to help reduce overall energy consumption, considering the potential increase in monthly bills from switching to an alternative energy source. Others wanted Enbridge Gas to provide additional services beyond just replacements, such as consulting with a realtor and assessing the impact of the changes on home values.

Individuals voiced questions on long-term price implications of alternatives.

- Concerns were raised about the long-term effects of the change. Some expressed that the current compensation proposal wouldn't be fair since their heating bills would increase over time, as well as differences in future repairs and appliance longevity. Others believe they should be receiving subsidies for the difference in monthly bill increase and/or be financially compensated for the potential consequences of the change.

"If you have to take time off work, if it's you know, there's, I don't know. And then what? What is the compensation for that? Like, do you compensate them a day's wages?"
– Woman in Southwestern/Central

"Who don't necessarily know the long-term cost. Like, if you're switching somebody from natural gas to electric and it's going to cost them 10 times as much in the long-term."
– Man in Southwestern/Central

What additional concerns exist, and how long will it take to reach a decision?

Majority felt their current method of natural gas heating was better quality.

- Concerns were raised about the effectiveness of electric heating compared to natural gas, with some stating that electric heat often doesn't provide warmth as quickly or effectively. Additionally, one participant pointed out that electric heat tends to be drier. Others highlighted that electricity is generally costlier than natural gas, and concerns were voiced about the impact of power outages on electric heating, affecting its reliability.

Several participants agreed they would need at least half a year before coming to a decision.

- Responses varied from one month to a year, yet the majority of participants indicated they would need at least six months to make a decision. This duration allows for consulting with family, assessing potential costs, gathering additional information about the agreement, and sometimes seeking advice from other related companies.

"So humidity might be something that would be taken into effect there. The difference between a gas furnace and electric can be significant"
–Man in Southwestern/Central

"I think, as far as heating our home and had where we are, we always have power outages. That's why we decided to put in a Generac. So yeah, would negate the fact of actually putting it in in the first place. If you're going to solely rely on electricity with battery backup, good luck."
– Woman in Southwestern/Central

Letting Customers Know

How would participants like to be initially contacted?

Majority feel detailed email and/or mail is a proper way to reach out to customers on the proposed plan.

- Many people preferred emails for receiving initial proposals because it allows for digital record-keeping, alongside a mailed letter to provide a physical copy for reference. Some individuals strongly opposed phone calls for these communications, noting that calls can be missed or might come at inconvenient times. Some also noted that receiving a physical copy feels more personal and has a better chance of being noticed compared to emails, which can be skimmed over in a crowded inbox. An email or letter outlining all the things they need to know, or how to research it, was key so participants weren't left feeling in the dark.

"I'm going to say paper copy, but I'm going to say paper copy, yeah, and like, email, I like both, I like that double kind of, oh yeah, there's something going on. And it's confirmed that this is for real."
– Woman in Southwestern/Central

"I would want in that initial email, like, all the information I need to research. You know, why is this happening? What is the information about it? What you know?"
– Man in Southwestern/Central

Personalized communication is preferred by most participants.

- It was noted by participants that personalizing the communication instead of using a generic greeting such as "Dear Homeowner" is preferred because it tends to be read more seriously and shows that Enbridge Gas cares. Many indicated that the initial proposal should include the compensation, background information, how Enbridge Gas will collaborate with the customer, and the reasons behind the changes.
- The initial contact information was an important deciding factor in determining whether they will schedule an appointment for the next steps. Additionally, many preferred to have a primary point of contact following the initial proposal to ensure efficient and trustworthy communication. This will help build trust between Enbridge Gas and customers.

Do any specific contact methods raise any concerns?

Others have stated a preference for receiving a phone call.

- Some participants expressed a preference for phone calls over written communication, stating that letters are often discarded, and emails are sometimes overlooked. They highlighted that phone calls allow for immediate interaction and clarification of details, offering a quicker way to communicate than emails or mailed letters.

Scheduled time and place.

- Many participants mentioned wanting a scheduled phone call or meeting (in their home) to address their questions and concerns.

Concerns about internet-based contact types.

- It was noted that alternative contact methods are necessary for those who may not be familiar with or have access to computers, such as the elderly. Many felt this raised valid points about the fact that both digital and physical formats are important for customers to be able to access the content, and if needed, a customer should be able to go through the entire multi-step process of communication whichever way is most comfortable for them. It also raised conversation about individuals who might have trouble with certain forms of contact – due perhaps to cognitive issues – and finding ways to accommodate them.

"I think probably both almost, because I think with the phone call, that would probably be my preferred because I would likely have questions right off the bat and prefer to have somebody answer those."
–Woman in Southwestern/Central

"if we're talking about older pipelines, with seniors who have no access to the internet or who choose not to use it, and therefore, I think the letter mail or some other method than just computer is important."
– Woman in North/East

How do participants prefer to receive additional information?

Many felt in-person appointments are the most effective methods for sharing additional information.

- Some participants preferred in person appointments which allow for immediate answers or clarification, as well as a presentation-like structure on how changes would advance is important. Many also said the proposal would be a significant change to various aspects of their life, so an opportunity to discuss further implications is necessary.

Some believed a town hall or meeting seminar was important.

- Many individuals suggested a town hall gathering, a group seminar, or a group Zoom meeting. Some expressed the benefit of creating an environment where overlapping questions can encourage exchanging of ideas, as well as introducing new questions participants may have not thought of before. Individuals also noted the benefit of combining individual appointments with subsequent group discussions, as that approach ensures that participants will come to the group session with a foundational understanding of the topic. This allows them to ask more informed and specific questions, raise concerns, and understand the proposal more thoroughly.

"But if I'm going to make a big decision like this, it's I want to be in person. I want to be able to ask all the questions."
– Man in Southwestern/Central

“Never mind the email and that sure you have to notify people, but have a few town hall meetings where everybody can get together and share in each other, hear your neighbors questions of the whoever would be representing Enbridge and so forth.”
– Man in Toronto/GTA

Appendix I: Poll Question

Poll Question #1

Filed: 2025-07-04, EB-2025-0064, Exhibit I.1.13-ED-4, Attachment 1, Page 171 of 321
Filed: 2025-10-30, EB-2025-0155, Exhibit G, Tab 2, Schedule 1, Page 171 of 321

Individuals were polled on the reasonableness of system pruning (Stimulus Two).

Does this approach seem reasonable to you?

	Total	Group 1	Group 2	Group 3	Group 4
Very reasonable	2	1	-	1	-
Somewhat reasonable	10	3	-	4	3
Not very reasonable	11	3	-	3	5
Not sure	2	1	-	1	-

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Note: Poll not asked of Group 2

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Appendix 3 – Innovative Research Group: System Pruning Survey Report

INNOVATIVE RESEARCH GROUP

Survey Report

System Pruning Survey

ENBRIDGE

May 2025 | **REPORT**

STRICTLY CONFIDENTIAL

Table of Contents

Research Methodology

Methodology (1 of 2): *Respondent Qualification*

Innovative Research Group (INNOVATIVE) was commissioned by Enbridge Gas Inc. to conduct a survey to gauge response to system pruning – that is, removing customers from the natural gas system.

- This online survey of 2,198 Enbridge Gas customers was conducted between April 1st and April 21st, 2025.
- Potential respondents were identified by Enbridge Gas according to initial selection criteria developed for potential system pruning pilot projects. This includes residential customers who are serviced by a natural gas main line that meets specific age and/or condition criteria, or those who have individual services that need replacement (e.g. a farm tap, or an AMP fitting).
- Further, respondents were required to be homeowners in single-family homes, and responsible for making energy-related decisions (including decisions about home and water heating equipment as well as other major appliances) that impact their household.

Note: *Graphs may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.*

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Methodology (2 of 2): *Data Weighting*

- The sample was stratified by region in order to establish a balanced sample according to actual Enbridge Gas customer distribution across five operations regions.
- The data was weighted according to the Enbridge Gas customer distribution across five operations regions represented by the areas initially identified as potential system pruning pilot project areas based on the actual distribution of residential customers in these areas, for a final, weighted sample of 2,000.

	Unweighted (n)	Unweighted (%)	Weighted (n)	Weighted (%)
GTA East & Toronto	525	24%	555	28%
GTA West	604	27%	633	32%
Northern & Eastern	577	26%	381	19%
Southeast	429	20%	372	19%
Southwest	63	3%	59	3%
TOTAL	2,198	100%	2,000	100%

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Key Findings

Key Findings

01

While a majority think Enbridge should consider other options, customers are split on whether it should consider disconnection.

Over 2-in-3 think Enbridge Gas should consider other options to replacing pipelines. However, when presented with an option to disconnect customers and shift to other energy sources, 41% say Enbridge should consider disconnection while 43% say they should just replace pipelines.

02

The base offer is perceived as fair and garnered some interest to participate. After learning more, people become more polarized.

A majority (59%) say the base offer is fair, with over 2-in-5 saying they are likely to agree to participate. Having a reputable contractor to complete the work is the preferred approach. Additionally, having optional potential upgrades and extended warranty would make the offer better. After seeing more about the offer, likelihood to participate is up a small but significant 4 points, along with a decrease in reluctance to participate.

03

Passion is lacking, so enrollment may be a challenge.

Passion drives action. After seeing the Base Offer on its own, only 14% say they would be *definitely likely* to participate and disconnect. The exact same proportion feels that way after seeing all incremental offers. However, it is not the <u>same</u> 14%, there is a shift in opinion taking place below the surface.

04

A majority anticipate an increase in energy bills as a result of a disconnection.

Most (57%) of those who believe the bill will increase feel there should be a variable payment to guarantee no increase in energy bills. Additionally, a plurality (44%) believe that compensation for any increase in energy bills should be provided for a period of five years.

05

An underlying connection between climate concern and natural gas cost/benefits is the biggest driver of participation intent.

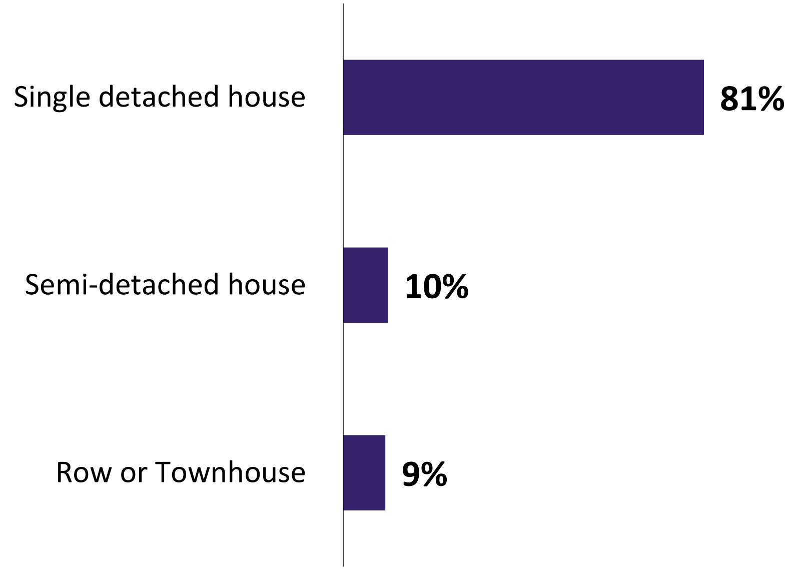
People who are more concerned about climate change are less likely to see negative impacts from shifting away from NG. This underlying attitude is the biggest driver of willingness to disconnect from natural gas. Conversely, the belief that converting away from NG would decrease home value is the strongest negative driver.

Respondent Profile

Respondent Profile: *Qualifiers*

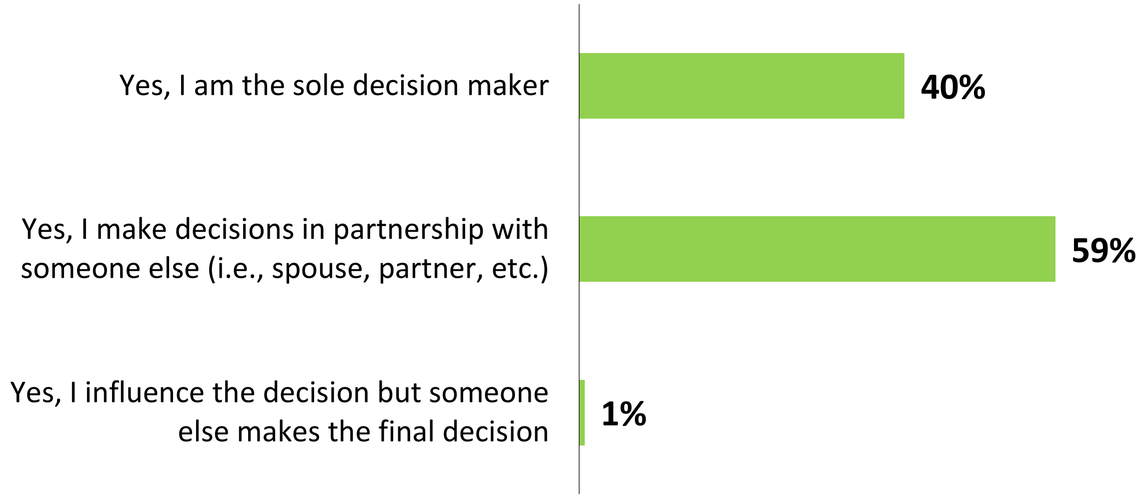
In addition to owning their home, respondents had to meet the following two criteria:

Primary residence



Respondents had to live in one of these types of buildings

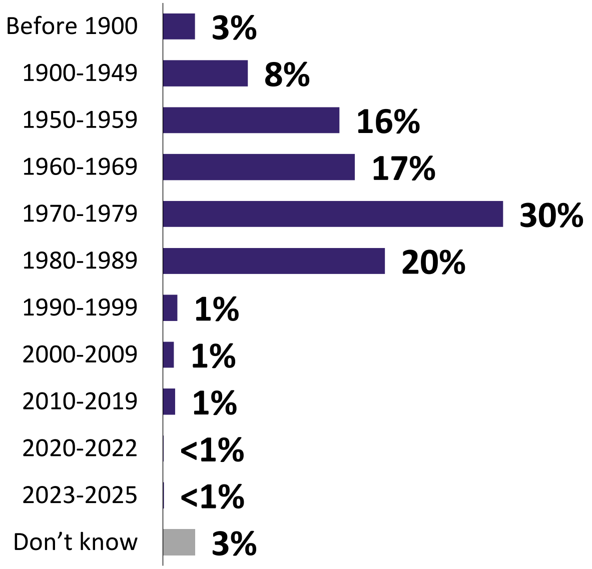
Are you involved in making energy-related decisions…?



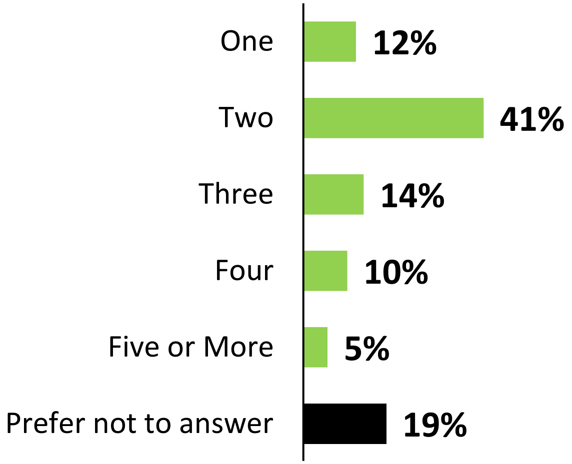
Respondents had to be at least somewhat involved in energy-related decisions in their home

Respondent Profile: *Respondent Housing*

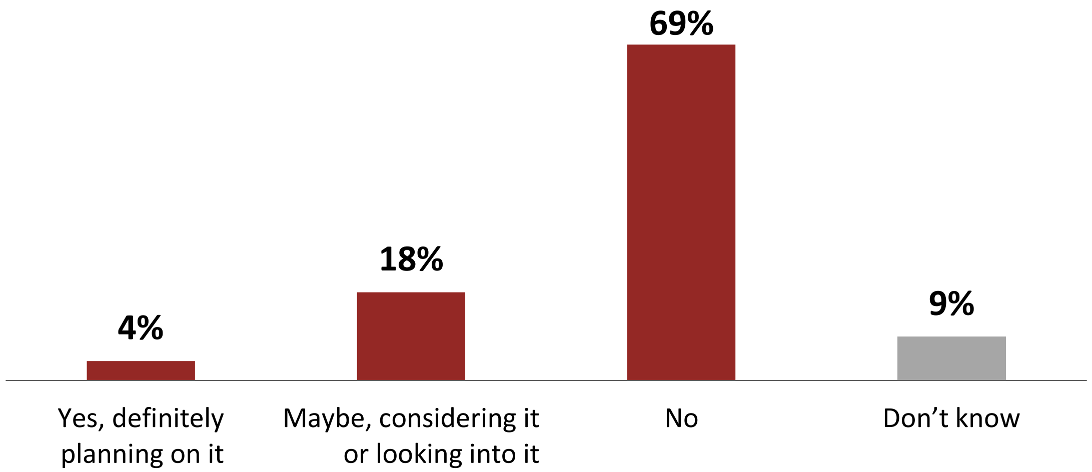
In what year was your house built?



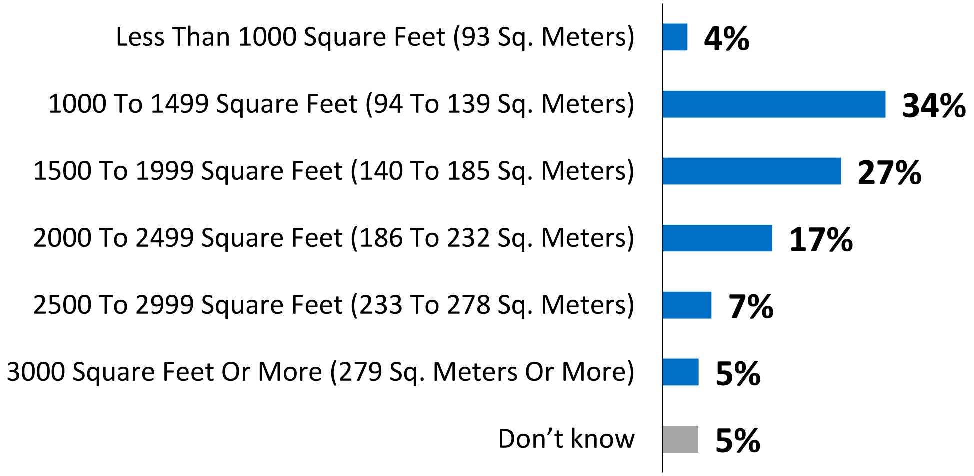
Including yourself, how many people in total live in your household?



Do you have any plans to sell your home in the next 2 years?

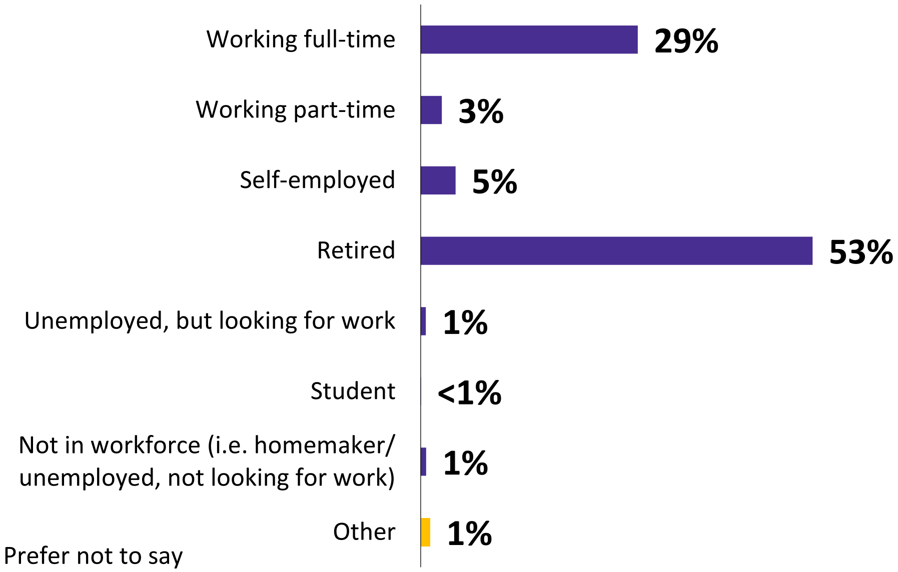


Residence size



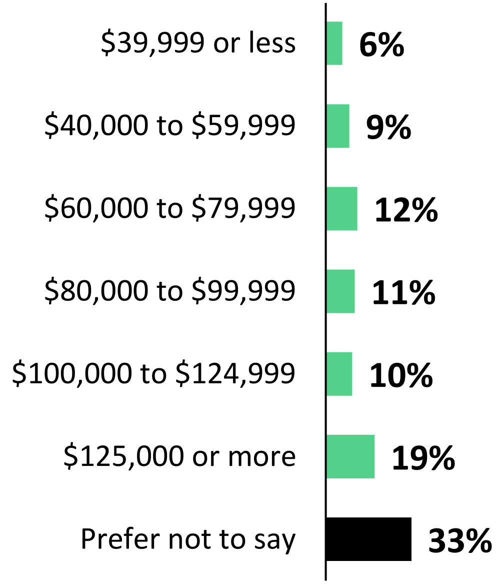
Respondent Profile: *Demographics*

How would you best describe your current employment status?

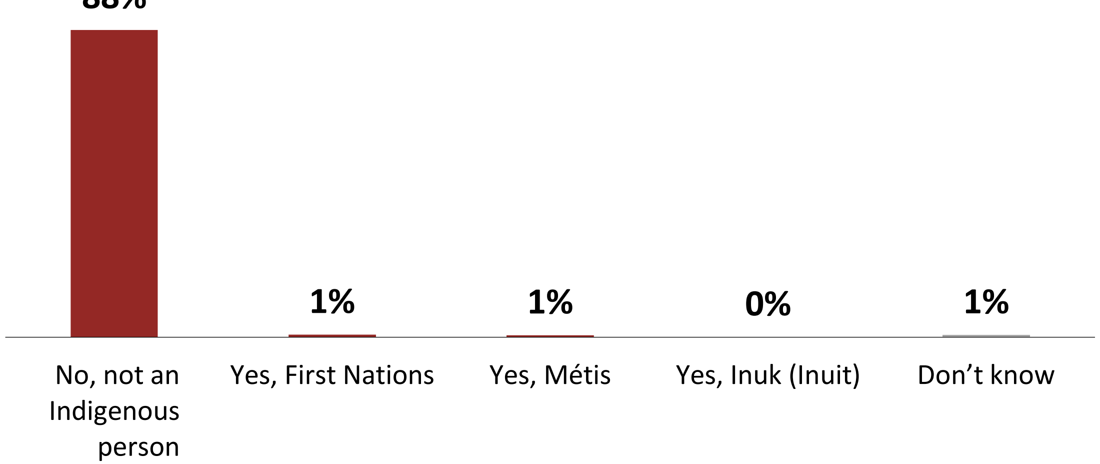


Note: 8% Prefer not to say

Household income

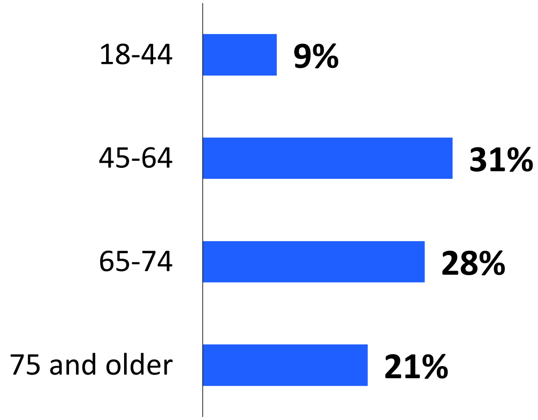


Indigenous Background



Note: 10% Prefer not to say

Age



Note: 11% Prefer not to say

Participant Introduction

Survey Introduction:

Introduction

Enbridge Gas is continually working on its business plan for its assets and would like to hear your feedback on a part of this plan, which includes a new pilot project.

It is important to Enbridge Gas that its projects are informed by customer needs and preferences. This is a preliminary survey to make sure that this pilot project is informed and refined by customer feedback.

We will share more details about this project through the questions in this survey and look forward to your feedback.

Please note that the project and related offers described in this survey are in the preliminary stages of development and finalized project and offer details will be communicated to affected customers through direct communications from Enbridge Gas at the time of implementation.

Near the end of this survey, you will have the opportunity to provide any additional comments that you would like to share with Enbridge Gas.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback.

Throughout this survey, if you aren't sure what your response is, please indicate this. Thank you in advance for your feedback and participation!

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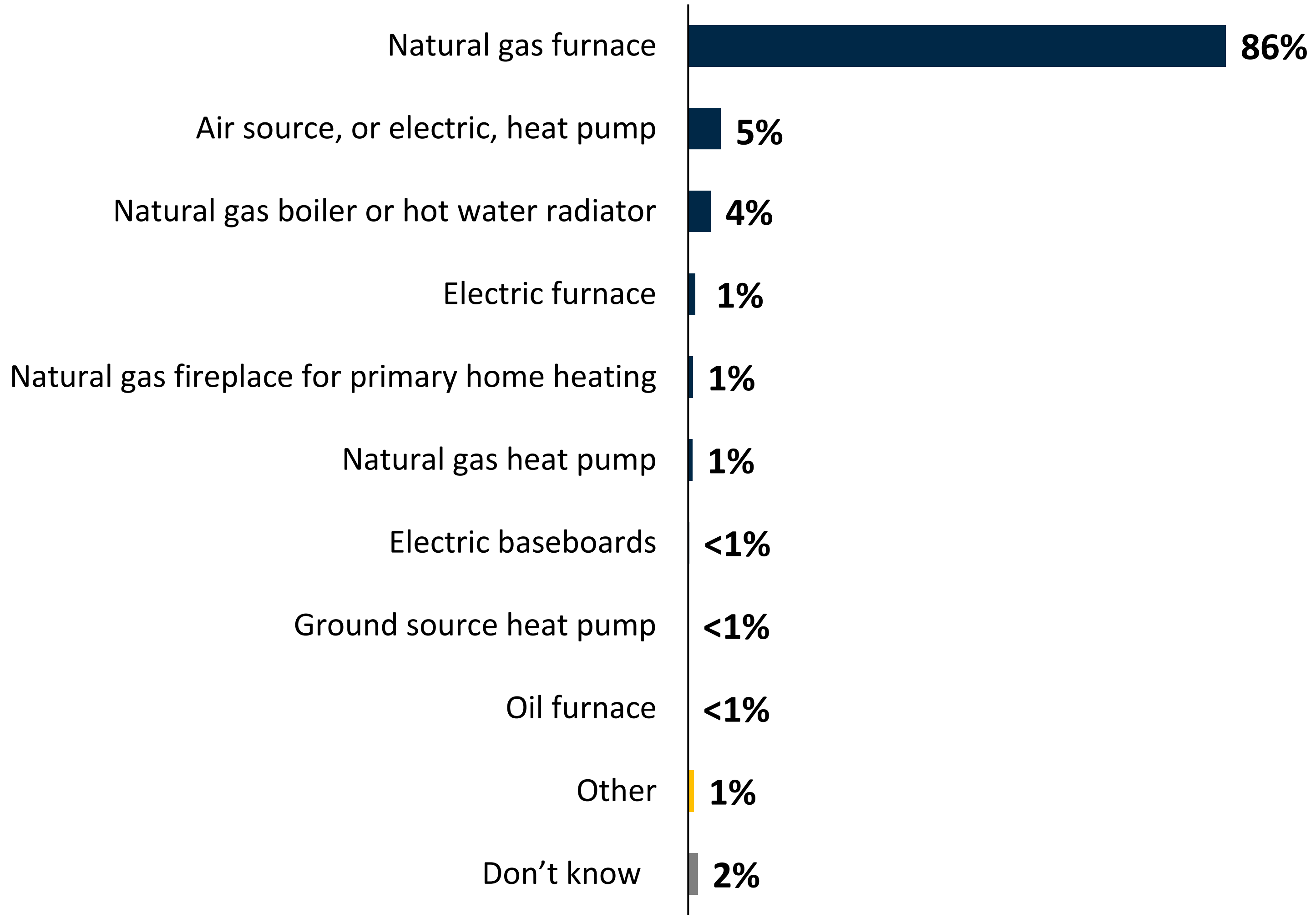
Current Natural Gas Equipment

Home Heat Generation: Majority (86%) of respondents use natural gas furnace for heating; lowest among houses built before 1950

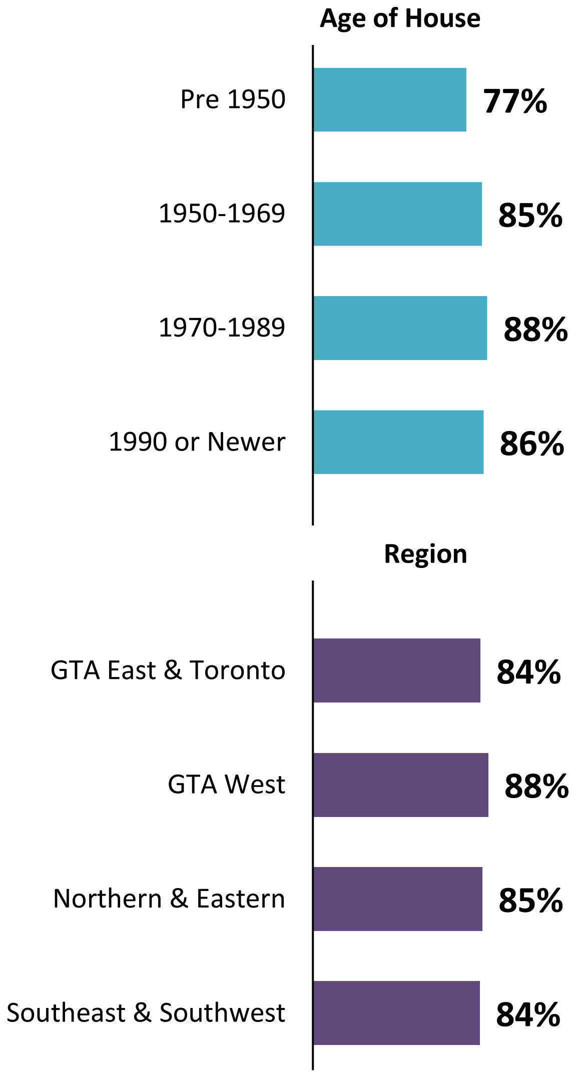
Q

How do you primarily generate heat in your home?
[asked of all respondents, n=2,000]



Segmentation

Those who say "Natural gas furnace"

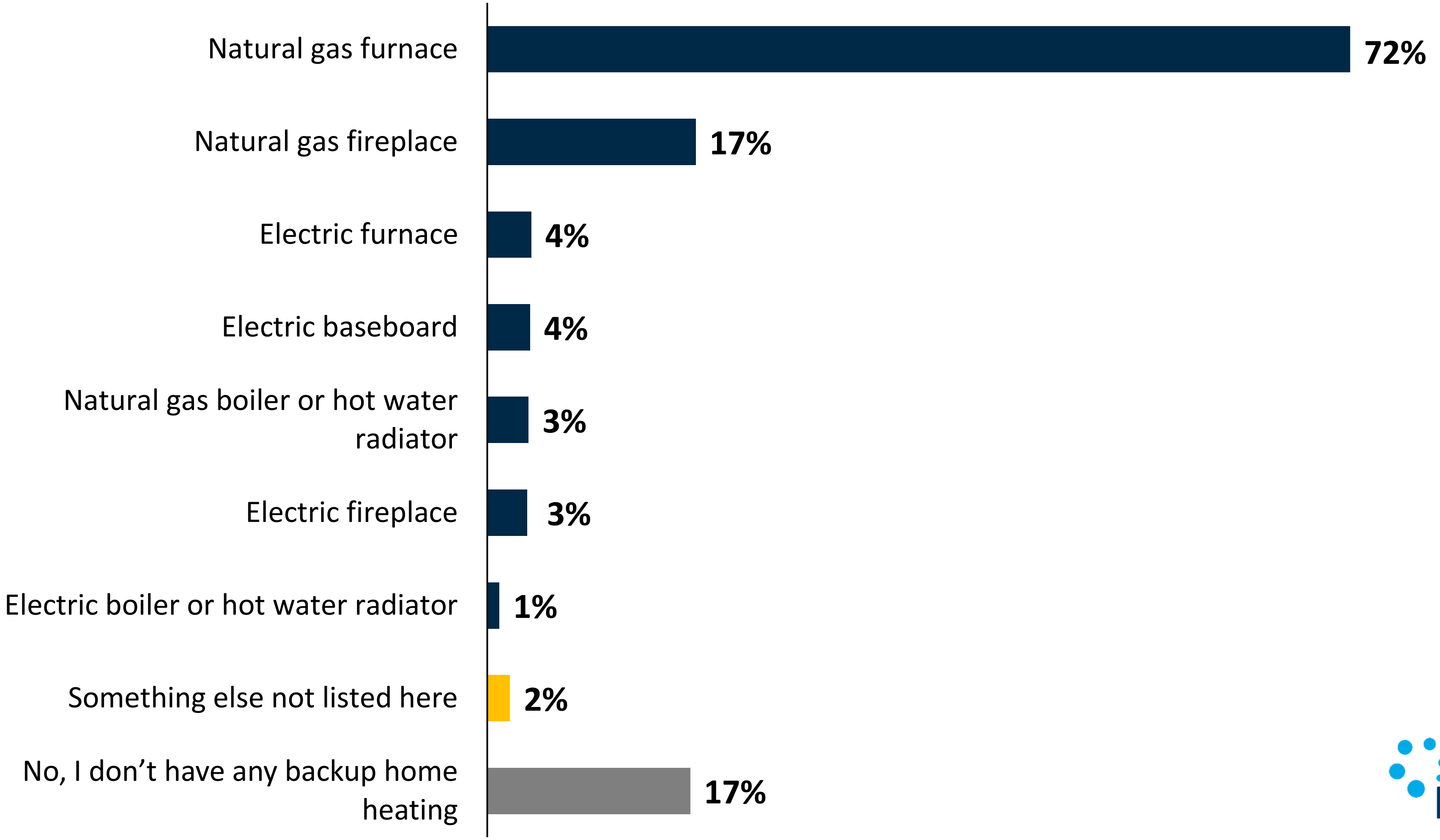


Home Heat Backup: Over 7-in-10 have a natural gas furnace as a backup; almost 1-in-5 have a natural gas fireplace

Q

Do you have any other home heating equipment as a backup to your heat pump, and if so, what kind of equipment do you have? *Please select all that apply.*

[asked of those who said, "Air source, or electric, heat pump" for primary heat generation, n=105]



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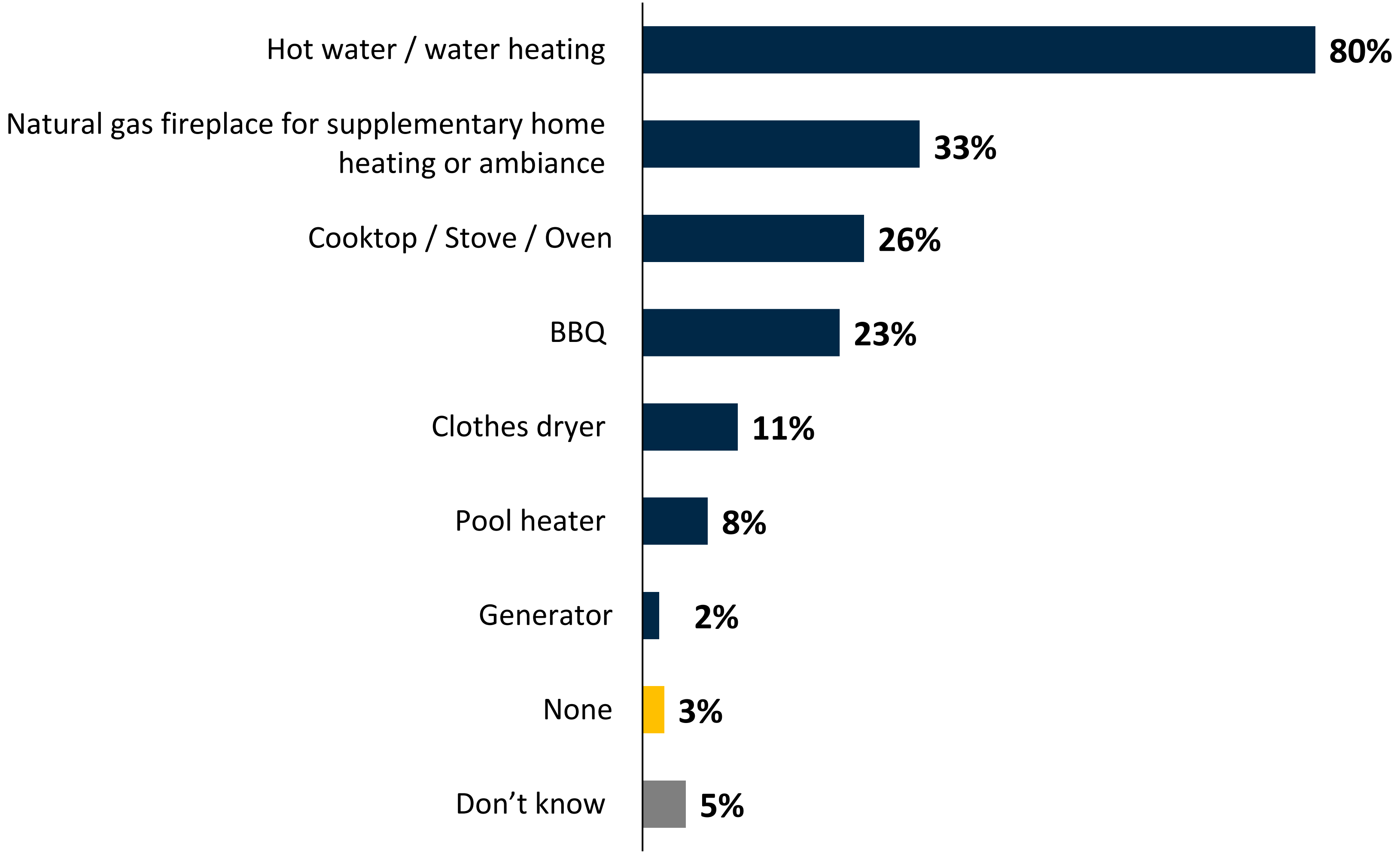
Natural Gas Appliances: Hot water/water heating is a popular use of natural gas

Q

Do you use natural gas for any of the following in your home? *Please select all that apply*.

[asked of all respondents, n=2,000]



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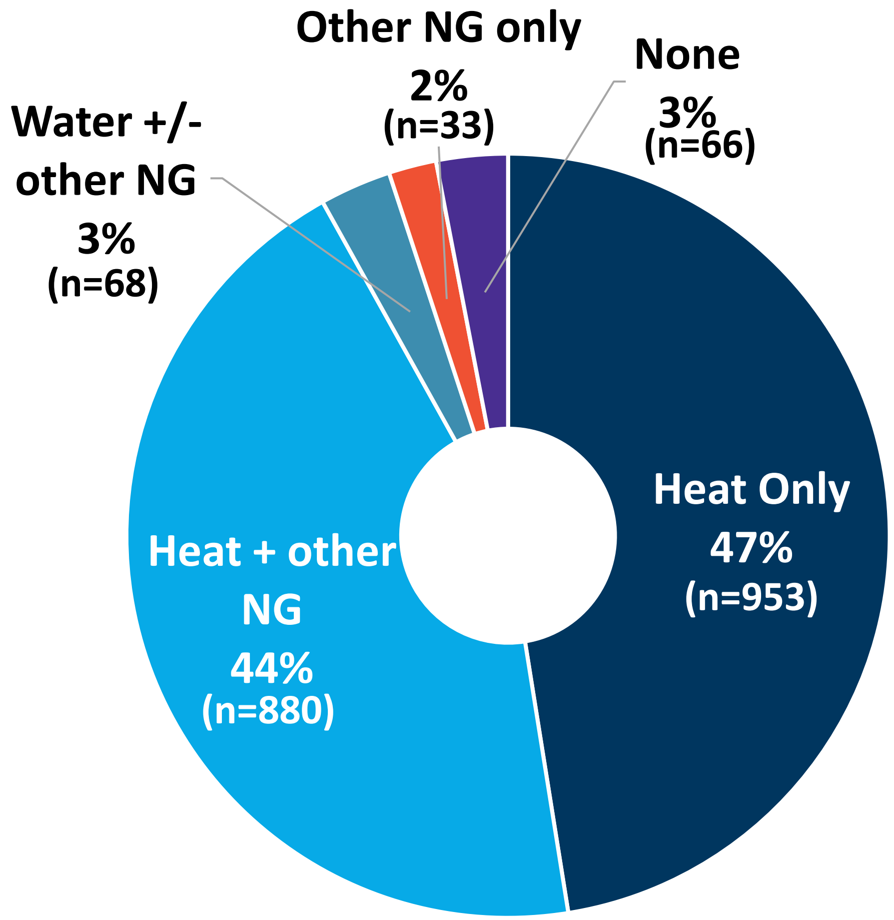
Natural Gas Appliances | Segmentation: Customers were segmented according to the type of NG appliances they have in their homes



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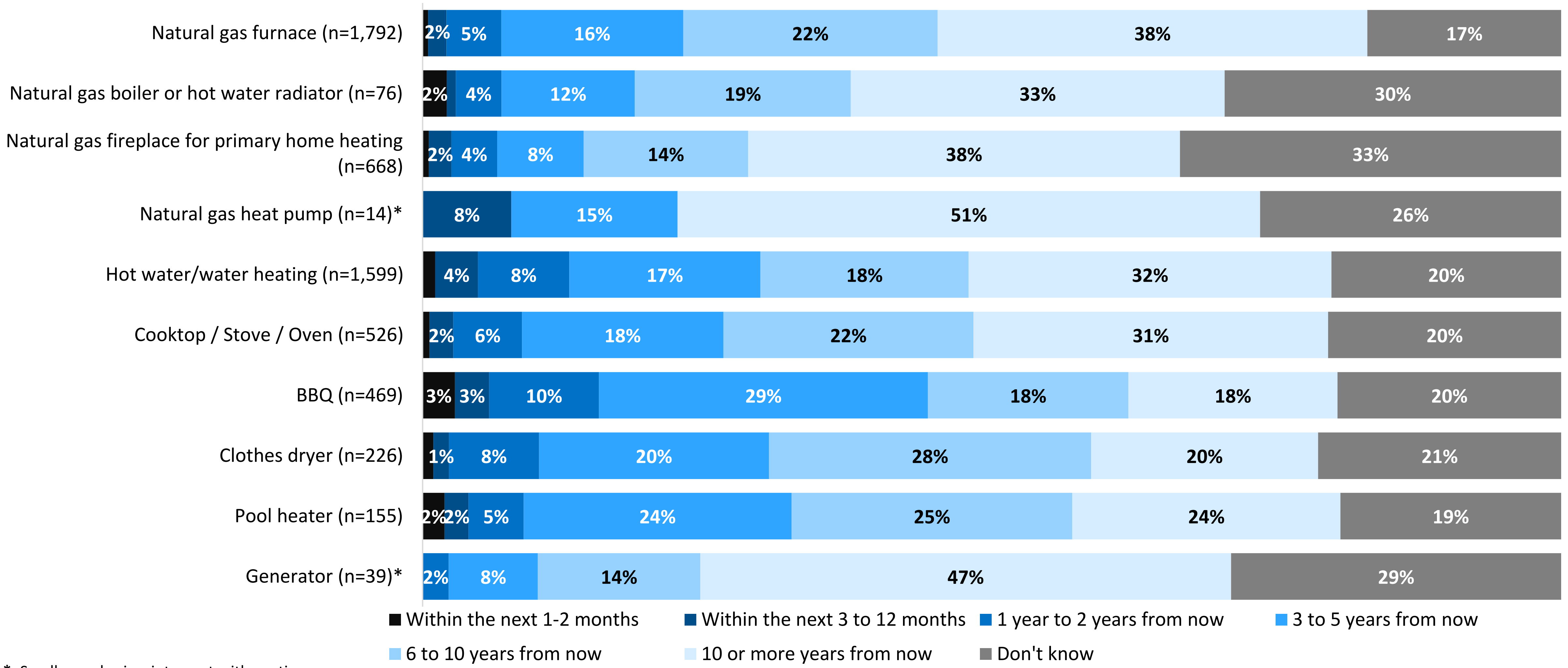
Appliances Replacement: Only a minority plan to replace their NG appliances within 2 years; plurality plan to replace 6+ years from now

Q

Based on what you know today, when would you approximately expect you would be replacing or upgrading your equipment? If needed, please share your best guess.

[asked of those who had the following appliances, n sizes shown below for each item]



Note*: Small sample size, interpret with caution.

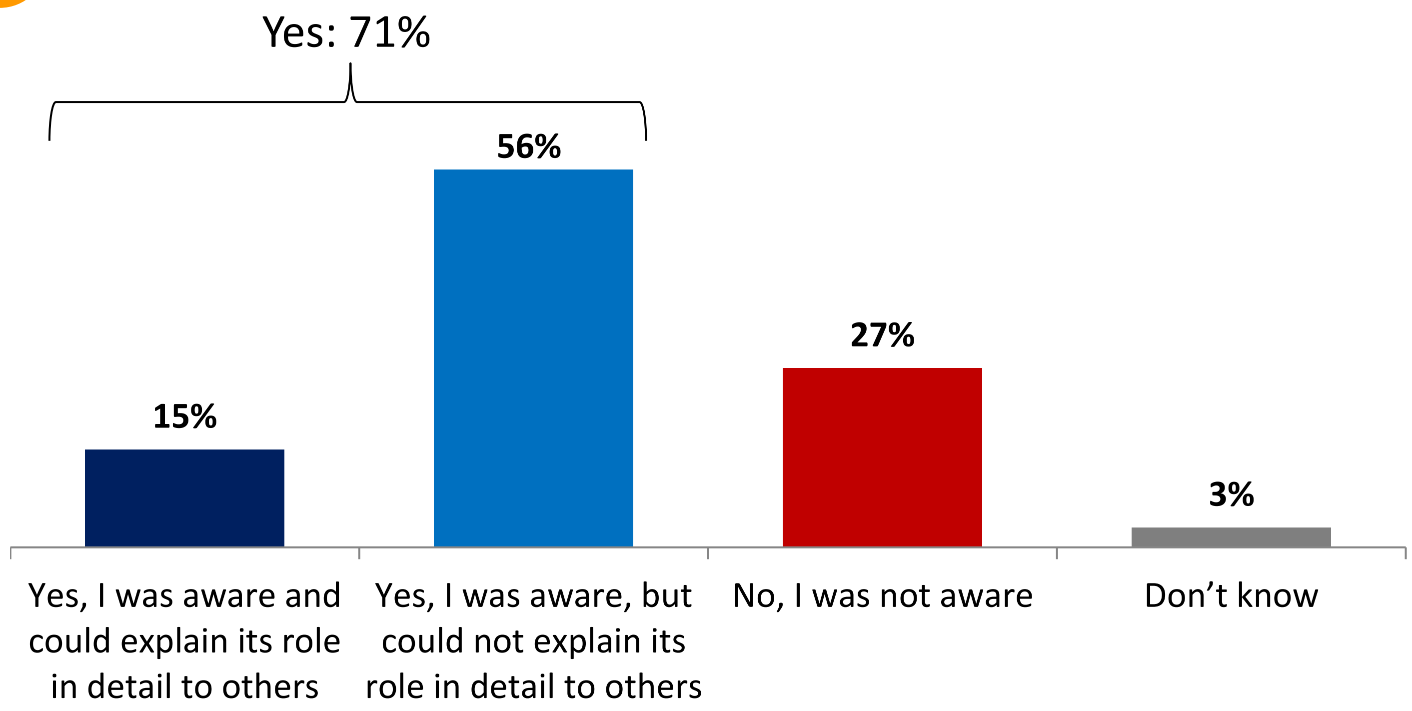
Explaining IRP and System Pruning

OEB Recognition: OEB awareness at 71% overall, with only 15% who could explain its role in detail

Enbridge Gas has many kilometers of pipelines in the ground in Ontario to deliver natural gas to its customers. It maintains, replaces, and expands parts of this pipeline network to meet customer needs with approval from the Ontario Energy Board (OEB). The OEB regulates natural gas utilities in Ontario and approves the rates charged to customers.

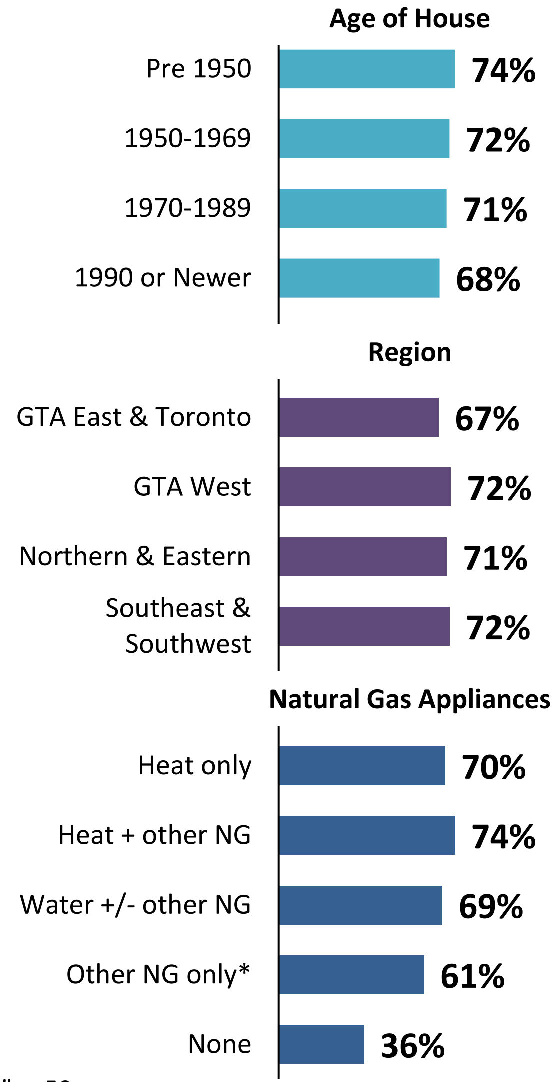
Q

Before today, were you aware of the OEB and its role?
[asked of all respondents, n=2,000]



Segmentation

Those who say "yes"



Note*: "Other NG only" n<50

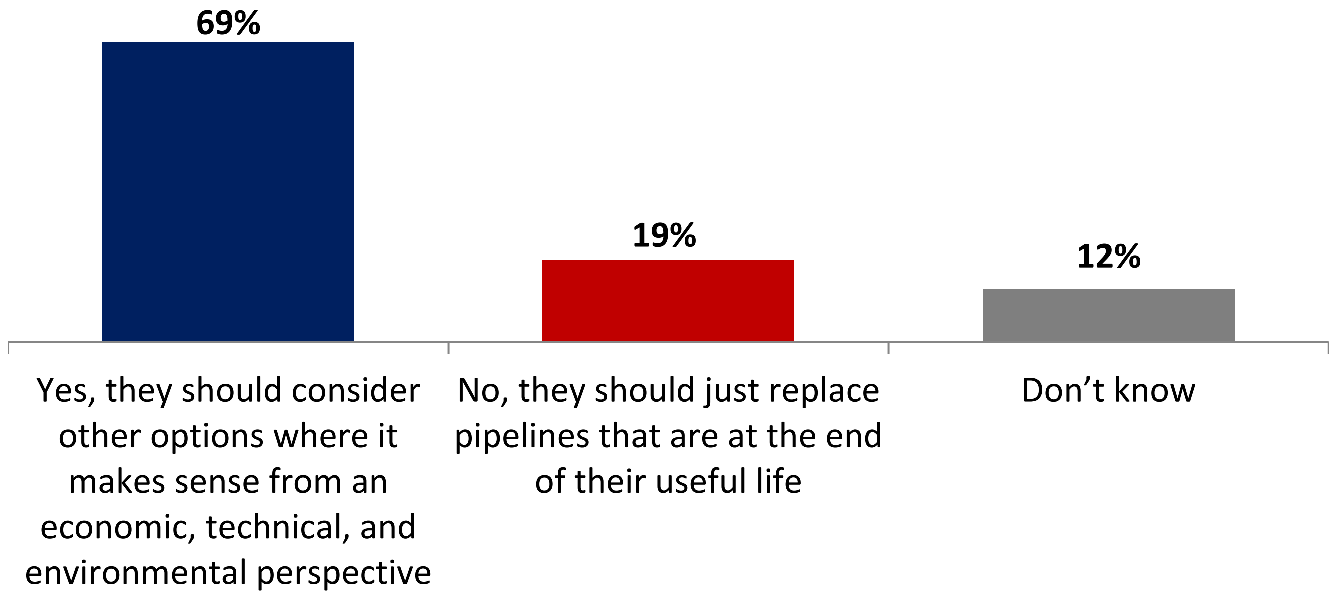
Enbridge Alternative Options: Majority of respondents believe Enbridge should look into alternative options before replacement

Over time, pipelines wear out and need replacing. Pipeline projects can vary greatly in cost, due to materials, labour, and changing requirements for construction to protect environmentally sensitive areas and reduce inconvenience in built-up areas.

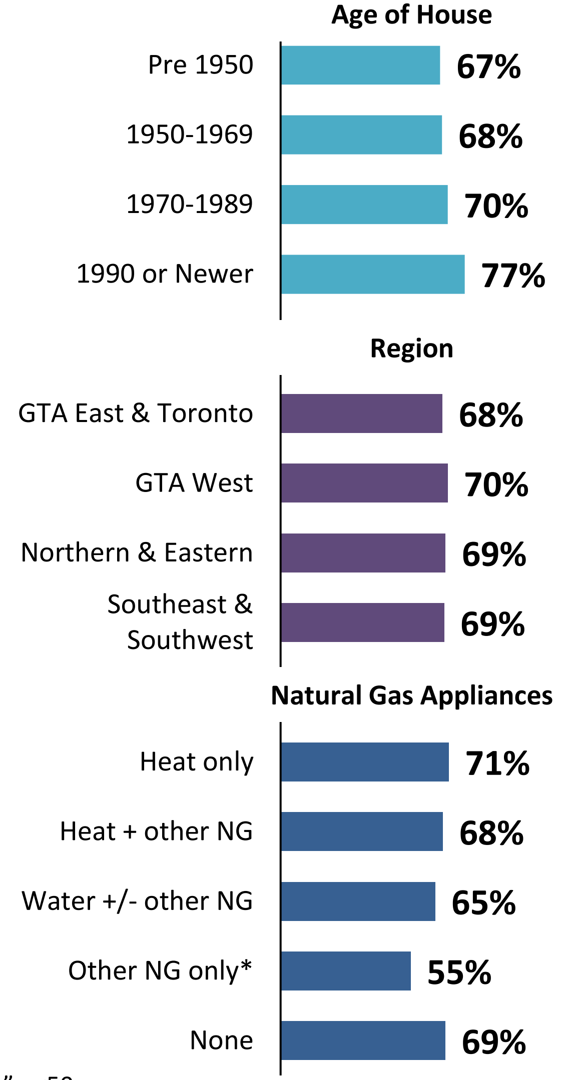
When considering any pipeline replacements, Enbridge Gas must evaluate whether other options are available that could either delay, reduce, or eliminate the need for work on the pipelines at a lower cost and/or lower environmental impact.

Q

Based on this information, do you think it makes sense for Enbridge Gas to look at other options before replacing older pipelines?
[asked of all respondents, n=2,000]



Segmentation
Those who say "yes"



Note*: "Other NG only" n<50

Voluntary Disconnection: Respondents are divided on whether Enbridge should consider the option of disconnection

There is an option that could be considered for pipeline replacement projects.

This option would apply to a single street, or a smaller area and considers disconnecting customers and removing the pipeline *instead of* replacing it.

This option would only be considered if everyone agrees, voluntarily, to disconnect.

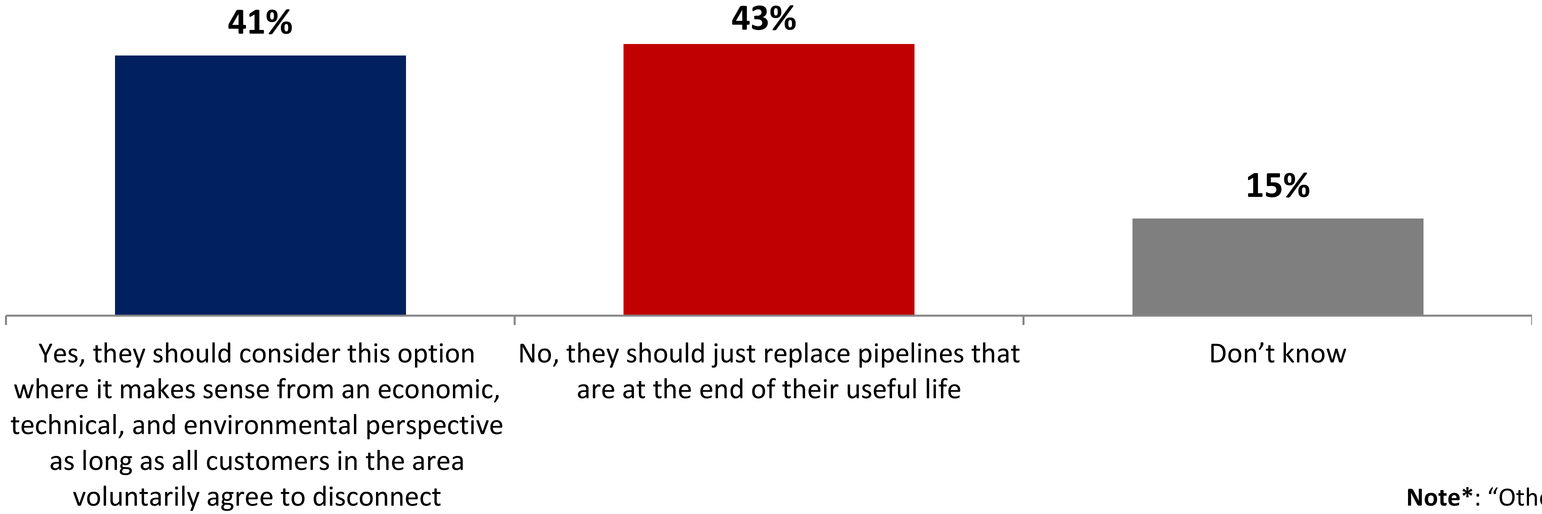
Customers who agree to disconnect would shift to other energy sources, such as electricity, to fuel their equipment and appliances. Instead of money being spent on replacing the pipelines, money can be used to support the disconnection process and provide affected customers with the replacement equipment they would need.

Enbridge Gas would work with the local electric utility to ensure that sufficient electrical supply was available to support customer upgrades that might be required.

Q

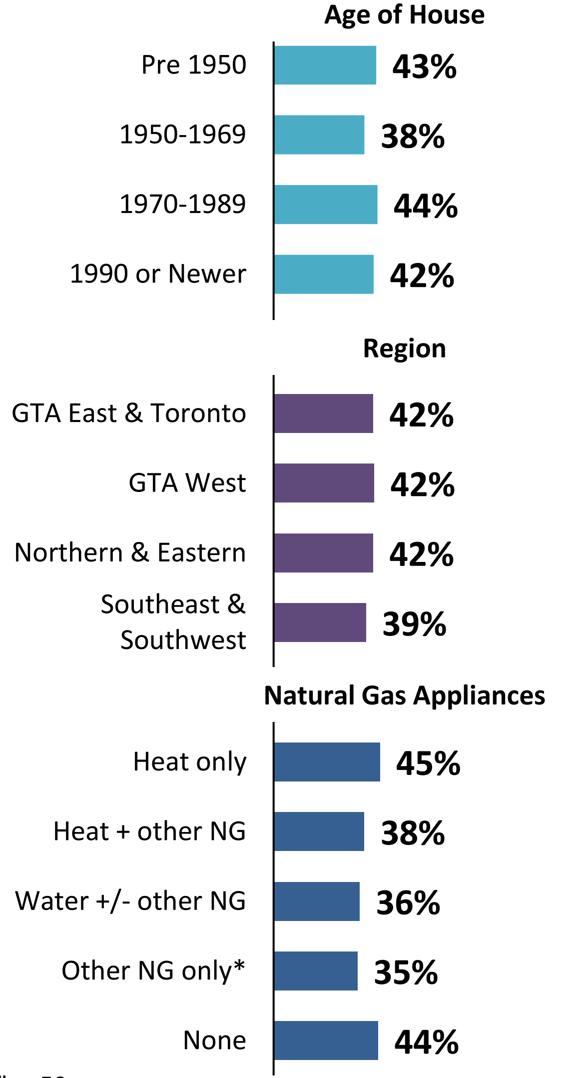
Based on this information, do you think it makes sense for Enbridge Gas to consider this option?

[asked of all respondents, n=2,000]



Segmentation

Those who say "yes"



Note*: "Other NG only" n<50

Testing the Customer Offer

Base Offer:

We'll now look at a potential offer that could be made to help customers with the transition away from natural gas and to facilitate the disconnection.

The offer would include the following, at no cost, to the affected customers:

- ✓ Removal of the natural gas meter and pipelines on the property
- ✓ Removal of natural gas equipment and appliances in the home (or elsewhere on the property, as applicable)
- ✓ Installation and all equipment costs for new replacement electric (or alternative fuel) equipment based on the closest equivalent or available option (in terms of size and features)
- ✓ Necessary upgrades to the electrical service (for example, electrical panel upgrades)

	Most common replacement option **(subject to review with the homeowner)**
Natural Gas Furnace	Cold climate air source heat pump with electric backup
Natural Gas Boiler / Hydronic System	Air to water heat pump with electric backup
Natural Gas Water Heater	Heat pump hot water heater or electric water heater (tank or tankless)
Natural Gas Cooktop / Stove	Induction stove (same number of burners)
Natural Gas Oven	Electric oven
Natural Gas Fireplace	Electric fireplace
Natural Gas Clothes Dryer	Electric clothes dryer
Natural Gas Barbecue	Propane BBQ
Natural Gas Pool heater	Air source heat pump for pool

Regardless of the age of the current equipment, the replacement equipment would be new. Appliances and equipment with an ENERGY STAR® rating or equivalent would be installed.

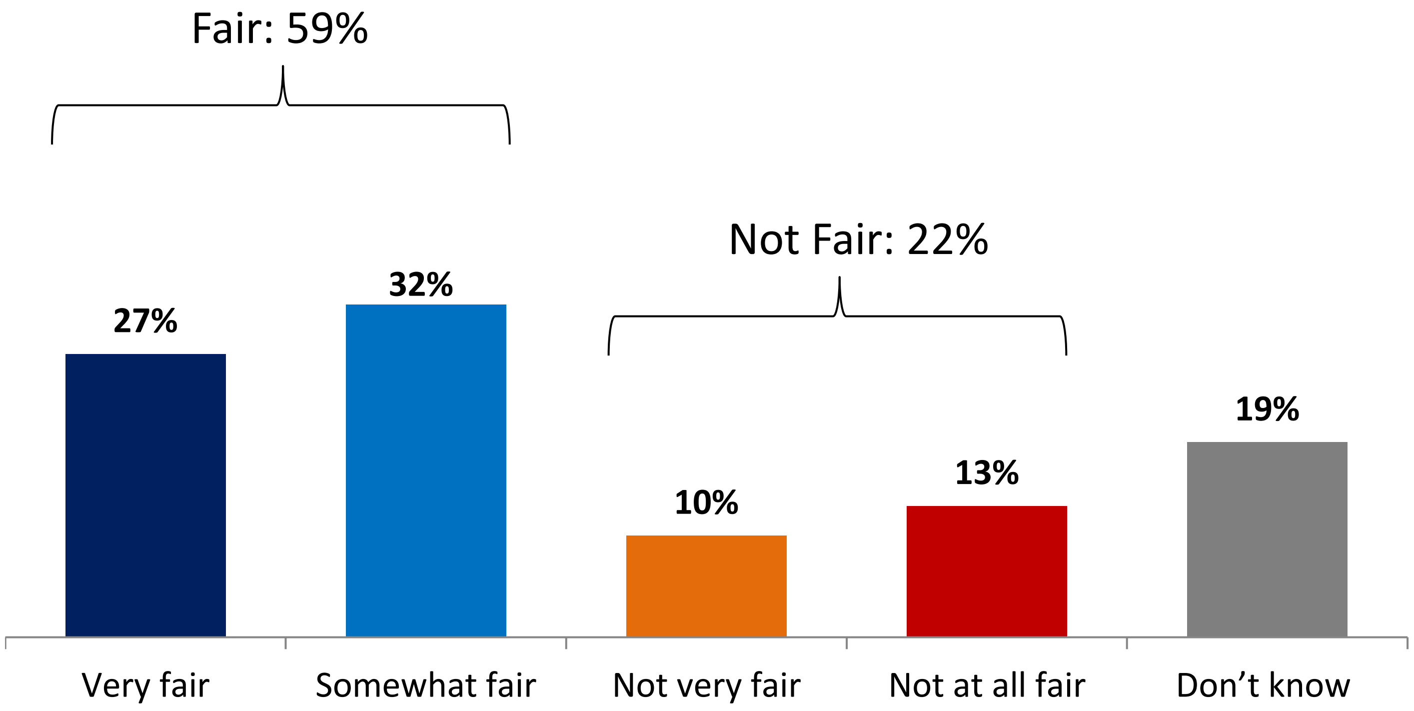
The cost for the project, whether a pipeline or an alternative option, is shared by all rate payers in Ontario.

To ensure all Enbridge Gas rate payers benefit, this approach would only be used where/when the cost of helping customers get off the natural gas system, through the potential offer made, is lower than the cost of investing in new natural gas pipeline infrastructure.

Base Offer Fairness: Nearly 3-in-5 (59%) say the offer is fair, while 22% say it is not; those with houses built pre-1950 most likely to say fair

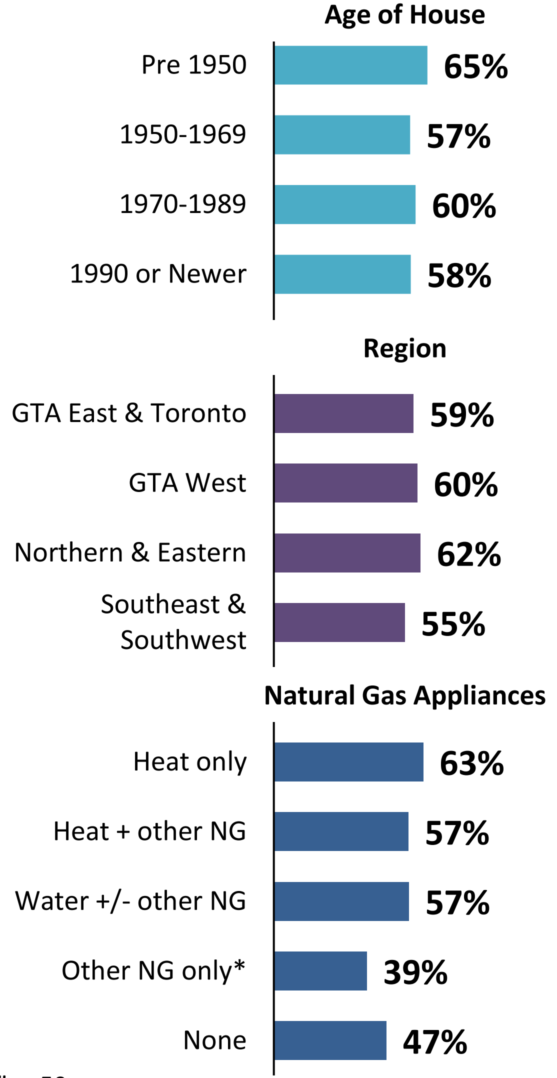
Q

Considering the specific elements of this offer, how fair would you say this offer is?
[asked of all respondents, n=2,000]



Segmentation

Those who say "very/somewhat fair"



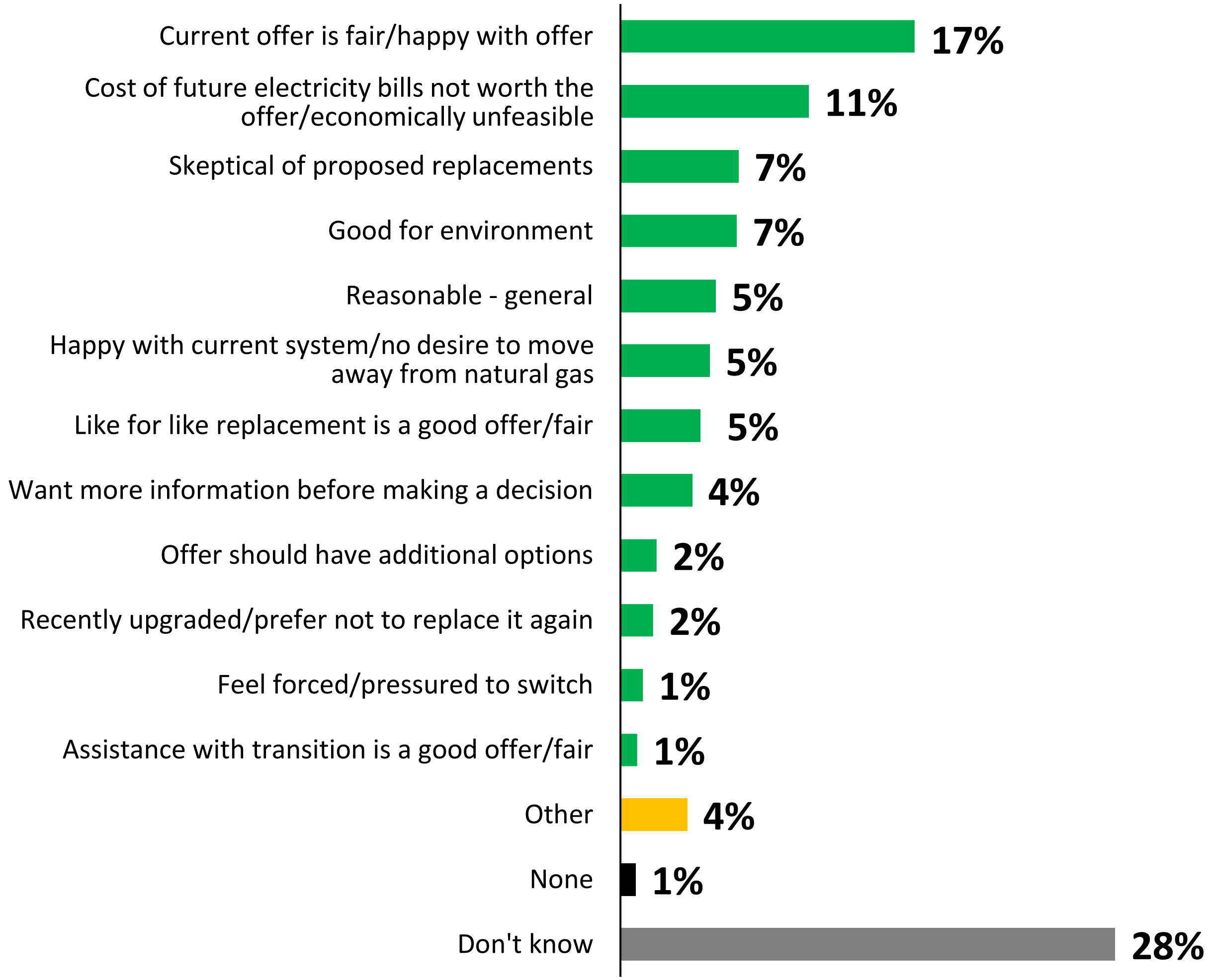
Note*: "Other NG only" n<50

Base Offer Fairness Reasoning: Top reason among those who say fair is happiness with offer; among not fair is no desire to move from NG

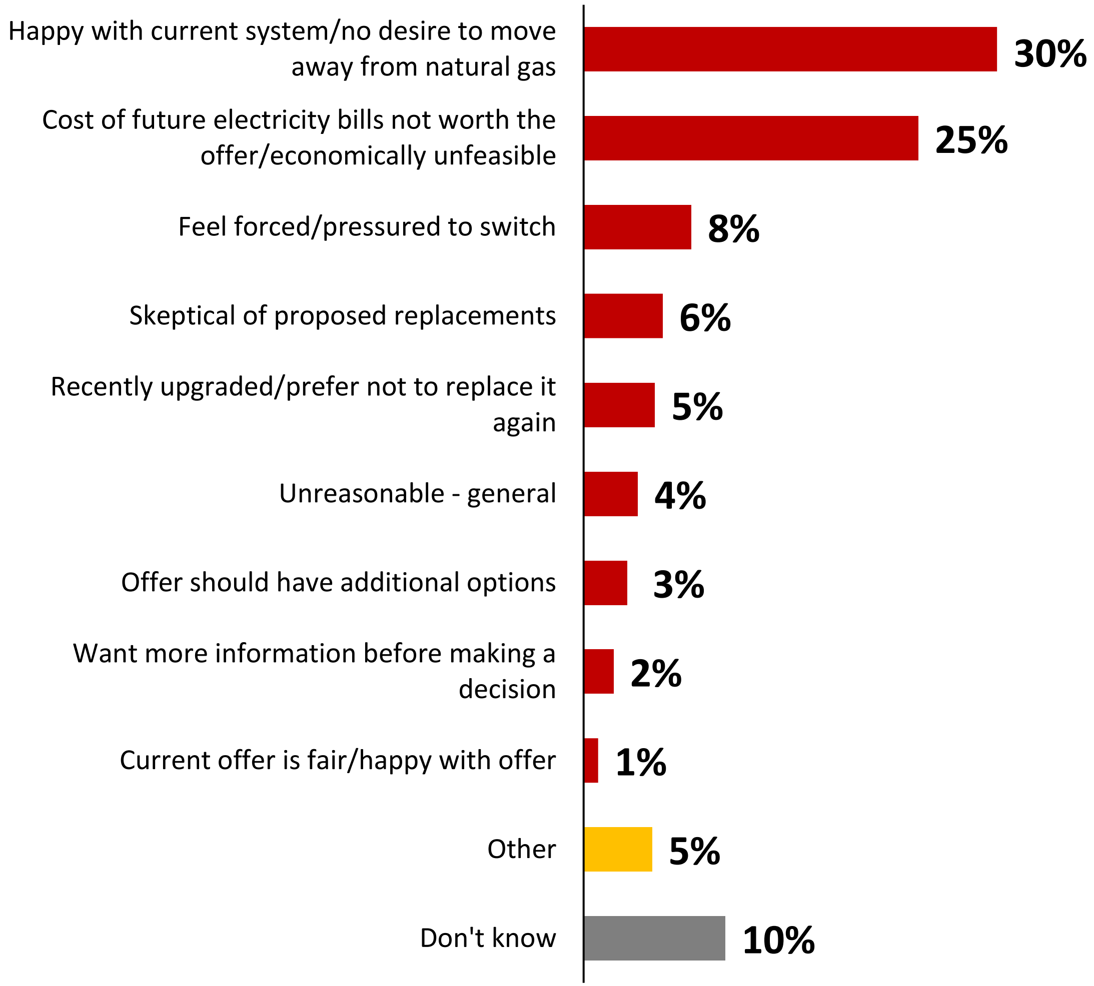
Q

Why do you feel that way?
[asked of all respondents, n=2,000]

Fair (n=1,180)



Not Fair (n=447)



Sample Verbatim Comments

Fair

"I don`t like the idea of having everything electrical I am concerned about the costs associated with usage. I also worry about electrical outages. However I think if company replaces all my natural gas equipment and parts and covers any associated costs with replacement at their expense and it won`t cost me anything that is very fair."

It seems a very fair offer. I'm not sure I want electricity to be the heat source for my home and I definitely do not want oil/propane.

"My house has been using both natural gas and electricity for heating and cooling since 1988. If they can be combined into one at lower cost and improved efficiency, I am all for it. "

"As long as I am not cost affected and the new system works as good as or better than gas , I am ok with it!"

"I feel that it is fair in terms of costs covered for those who agree and want to do this with their homes and energy supply. However I think relying solely on one energy source (ie electric) for a home is not wise and many people may also feel the same and not want this offer."

Not Fair

"Because it will increase the cost of heating my home enormously."

"I do not want to use electricity for heating the house. It's too expensive and not feasible when one considers climate change causing storms that take down electricity. I, as an honest tax paying citizen should be the person who decides on whether I want to use gas or electricity for heating my home."

"Do not want to give up natural gas as a heat source. When power goes off, we lose heat. This is not good in the winter."

"I do not wish to go all electric."

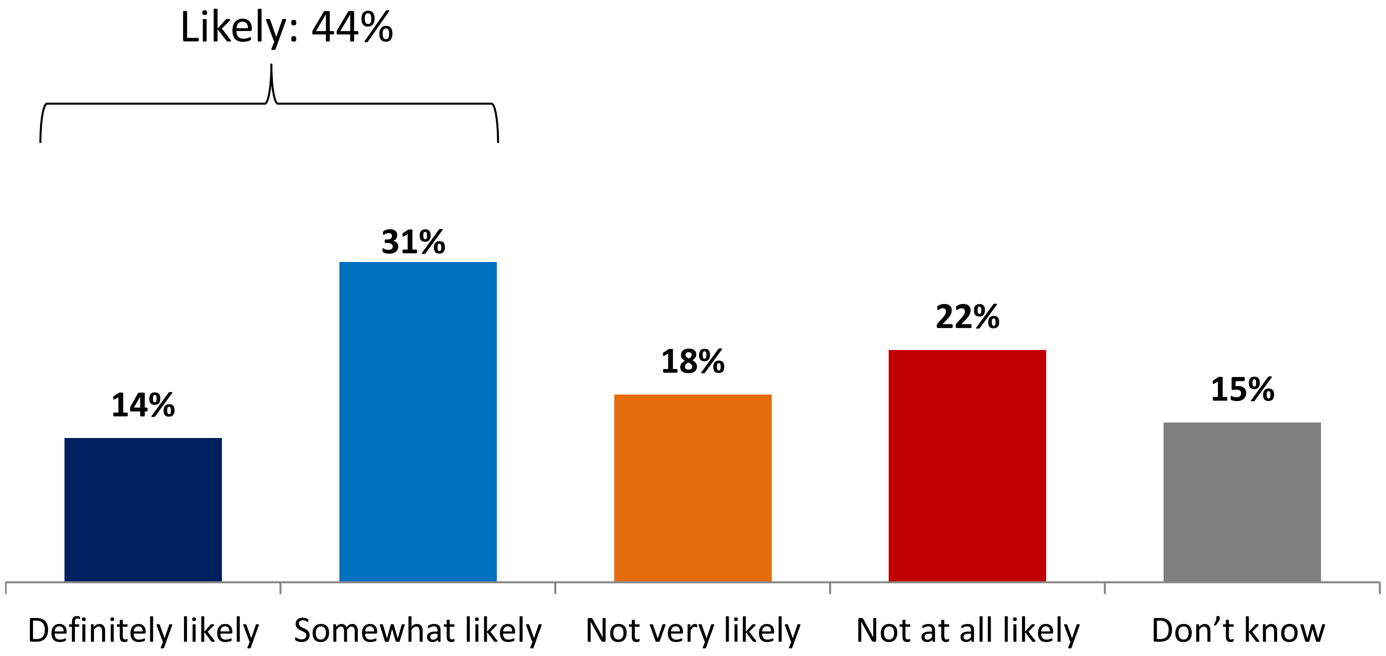
Because electric bills are high enough already…….we have an electric and a gas fireplace and do not use the electric fireplace at all because it pumps up our electrical bill so much. Electric heat is very expensive.

"Cost for electricity is substantially higher than natural gas. Supply and demand, with more customers relying on electricity, the cost for electricity will increase even more. Furthermore, is the current electrical infrastructure capable of handling the added loads?"

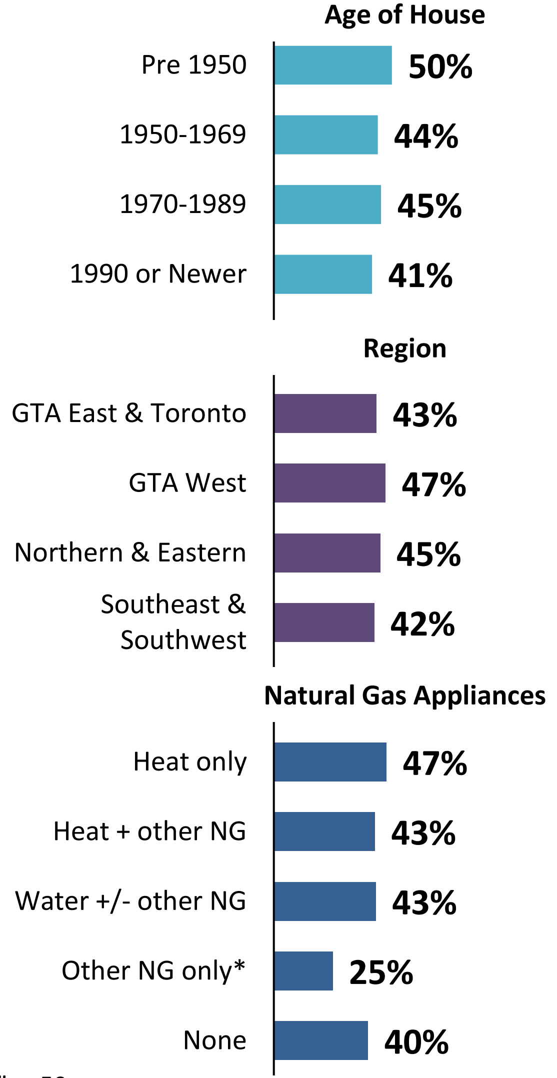
Base Offer Participation: Over 2-in-5 (44%) are likely to participate and disconnect; slightly higher among those with a house built before 1950

Q

If this project were happening in your area, based on this offer, how likely would you be to agree to participate and disconnect?
[asked of all respondents, n=2,000]



Segmentation ▶▶
Those who say "definitely/somewhat likely"

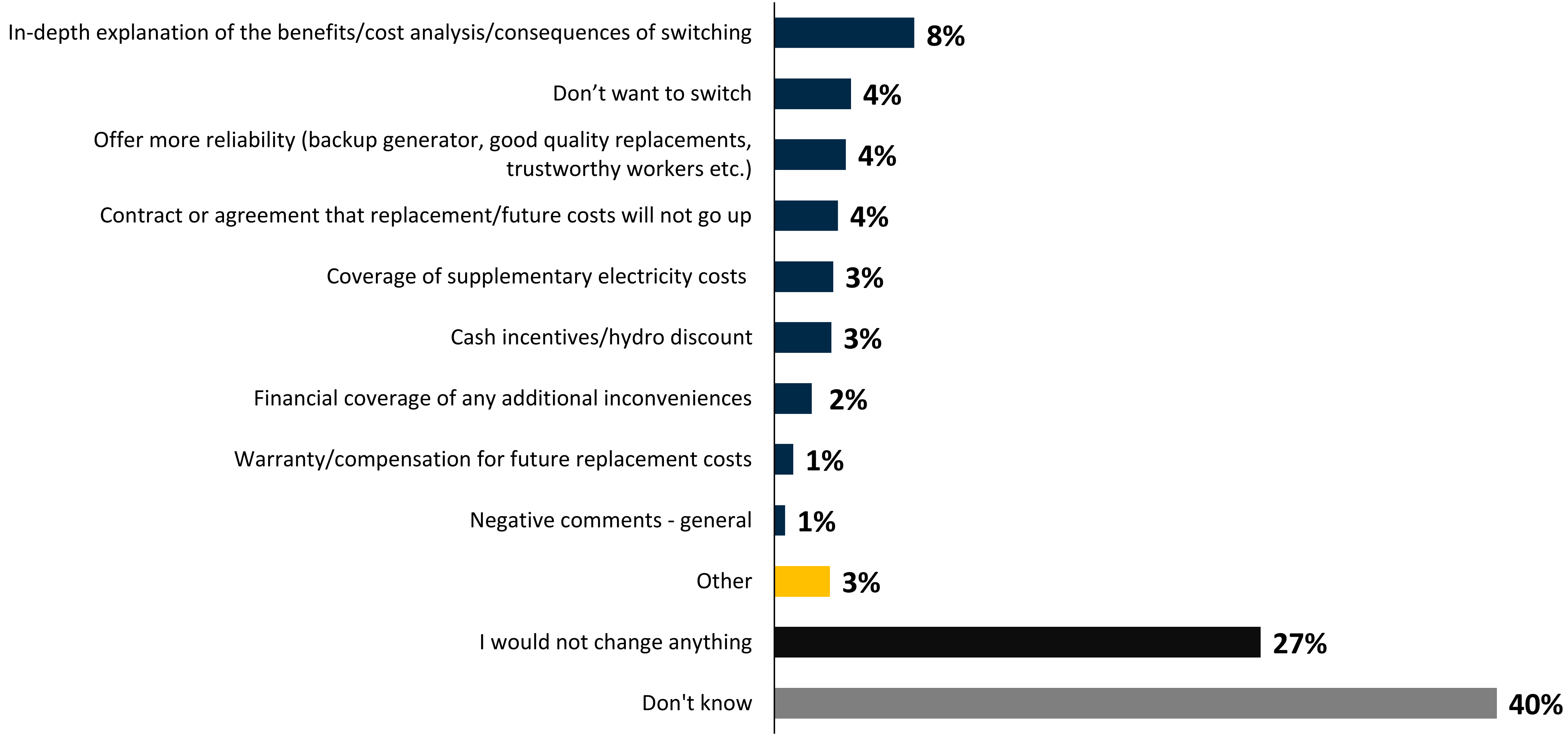


Note*: "Other NG only" n<50

Base Offer Changes: Most had nothing to offer, but those who had suggestions wanted a more in-depth explanation

Q

What, if anything, would you change to make this offer better?
[asked of all respondents, n=2,000]



Sample Verbatim Comments

"I would like to see the cost analysis or savings breakdown going to the new system vs the original gas pipeline. I would like to see some data the reliability, safety and overall performance of the new system vs the old."

"Customer should be given an estimate of electricity cost to heat the home based on their natural gas usage history. Electrical utility may need to cap rates for home heating vs other use somehow."

"I would need another alternative energy source other than hydro electricity. Solar panels and battery storage that directly service my house would be fine (not feed back into the grid). Or if your proposed offer to switch my gas appliances to electric also came with a free generator large enough to run major appliances in the house in the case of a blackout."

"I would only consider moving away from natural gas as home use if the price of natural gas became exorbitantly higher than electricity."

"If there was a guarantee that whatever alternative is chosen costs the same or less, maybe I would consider it. But I have major concerns that this would end up costing the homeowner more."

"I would need a long-term guarantee on the appliances and that my monthly costs would not be higher."

"Ensure that there is a range of model, brands and quality types."

"I'm all for helping the environment, but I think, in my case at least, I would need have proof that I could rely on having heat or A/C when I need it without worrying about a power failure."

"Not about a better offer, about making sure it is done right. Me equipment is 6 years old and I paid a lot for really good equipment, I want to make sure the replacement is equally as good."

"I would have to see the costs of running with electricity vs running with gas. I really like having alternative energy supplies to my house. If the gas is out (which it never is), I can switch to electric heaters as needed. If the electricity is out (more often), then my gas appliances still work. That redundancy is very useful. How stable will our electricity supply be in 15 years? It all depends on which government is looking after it."

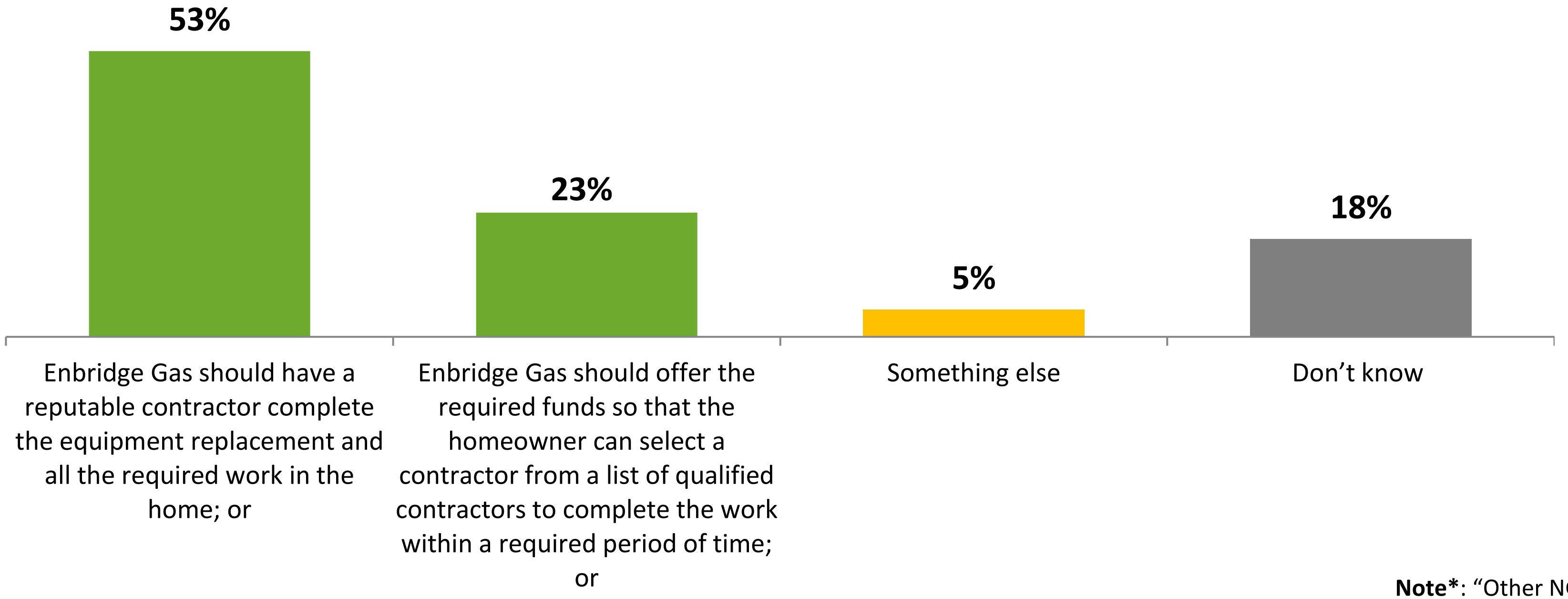
"Rebate for money spent into paying for the replacement over the years. So that my bills will remain the same or be less."

Base Offer Approach: More than half (53%) say Enbridge should have a reputable contractor complete the work; lower in Southeast/Southwest

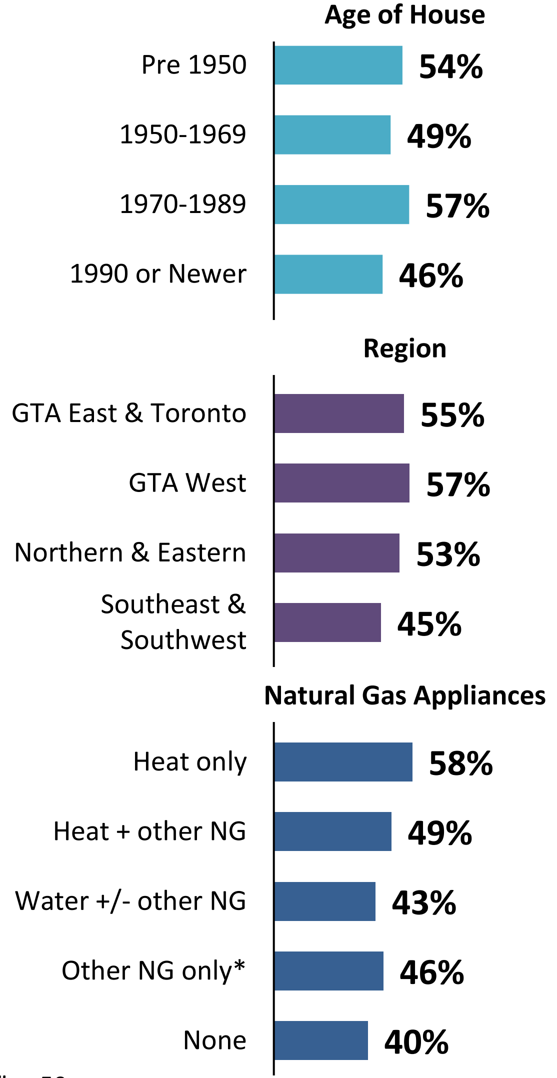
There are some additional elements to the offer that you may have already mentioned or that could be considered. Please consider each of these elements and share your thoughts on whether you think these should be considered as part of the offer that would be made to customers if Enbridge Gas were to look at an alternative option to a pipeline project.

As indicated such a project would only be considered where it makes sense from an economic, technical, and environmental perspective, and if all customers were to voluntarily agree.

Q In terms of the work that is described above, which of the following would be your preferred approach?
[asked of all respondents, n=2,000]



Segmentation
Those who say "reputable contractor"



Note*: "Other NG only" n<50

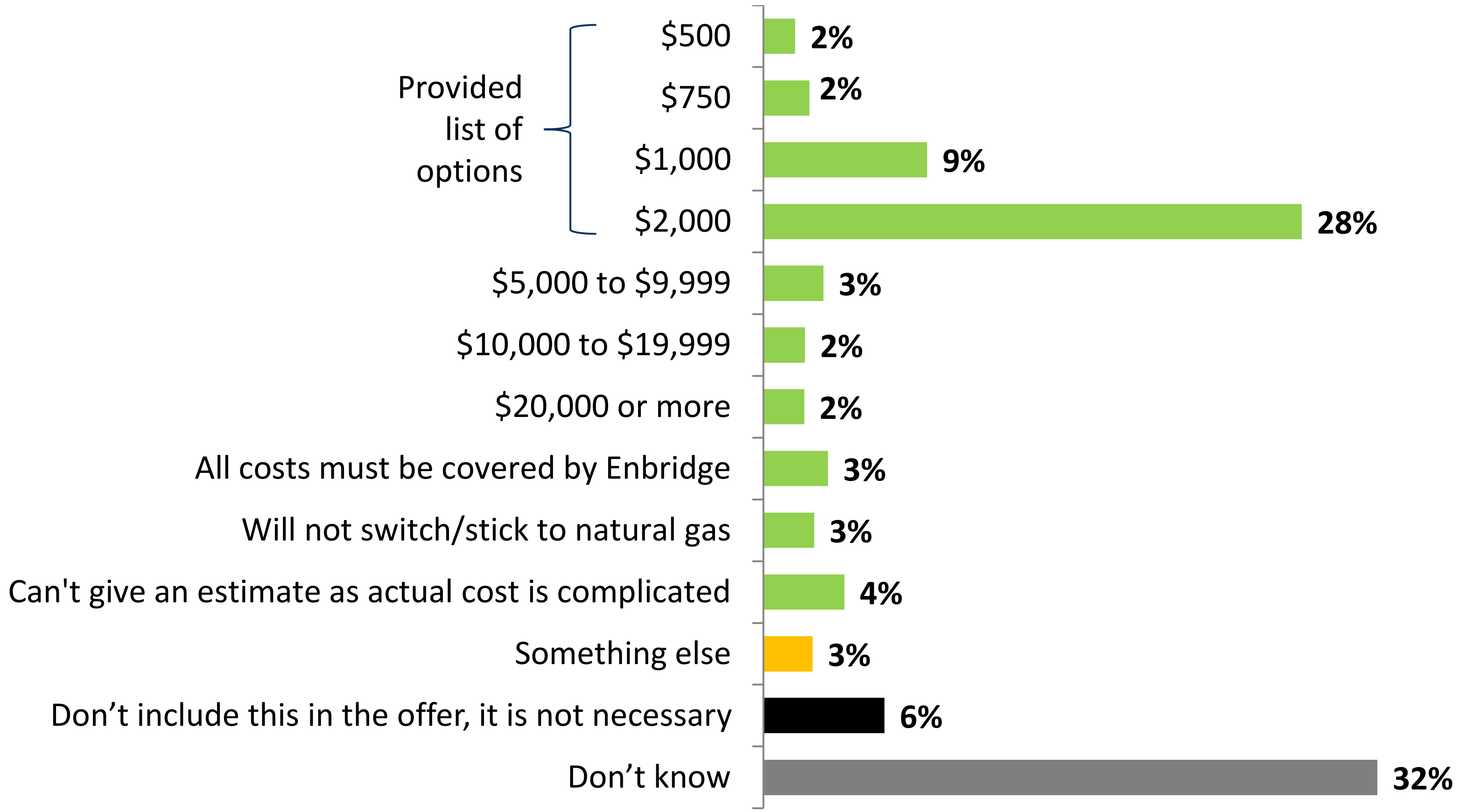
Kitchen Incidentals Offer: Over 1-in-4 say a reasonable amount of additional funds is $2,000 while nearly one third don't know

When it comes to replacing natural gas cooking equipment, with an electric option, this may require some additional funds to manage the cabinetry, cookware, or other changes in the kitchen.

Q

What do you think is a reasonable amount of additional funds, if any at all, to be included in the offer to cover this?

[asked of those who have a natural gas cooktop/stove/oven, n=526]



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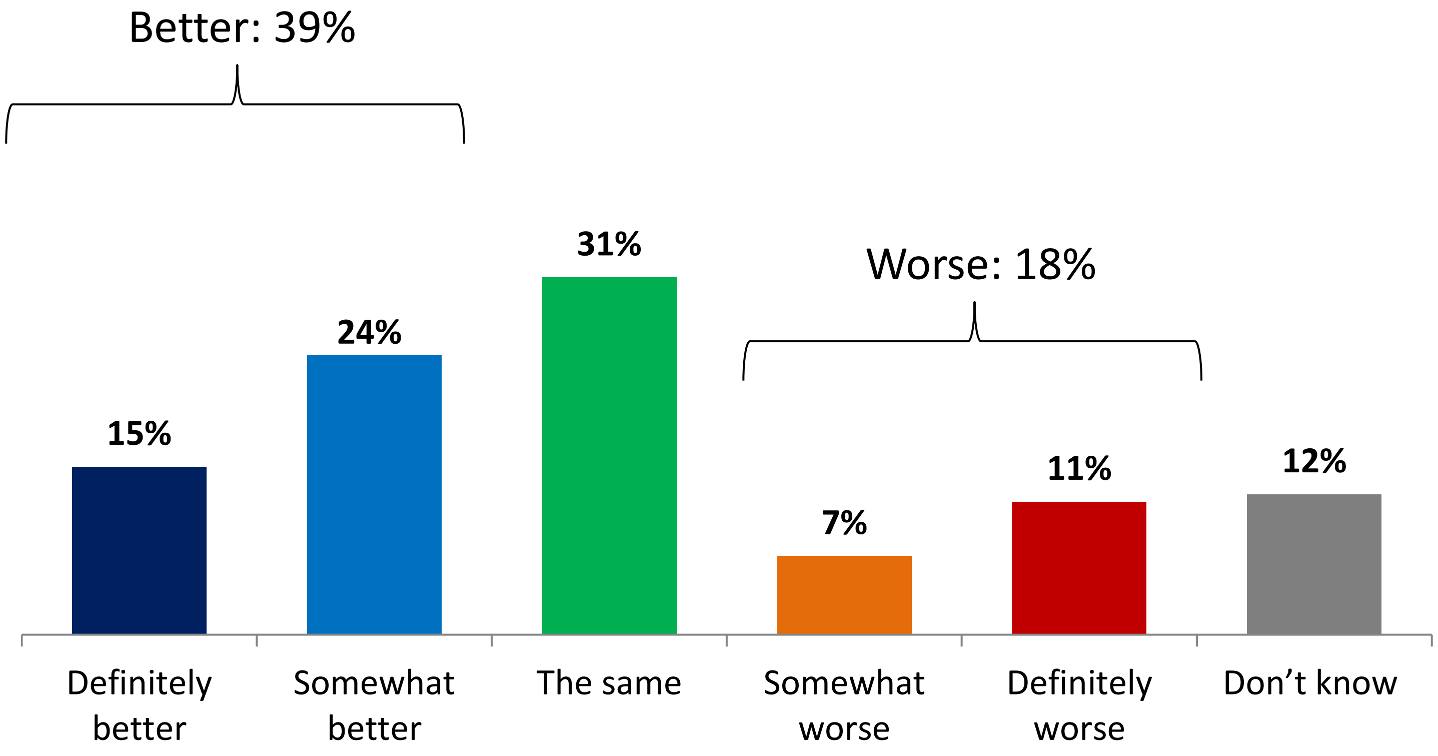
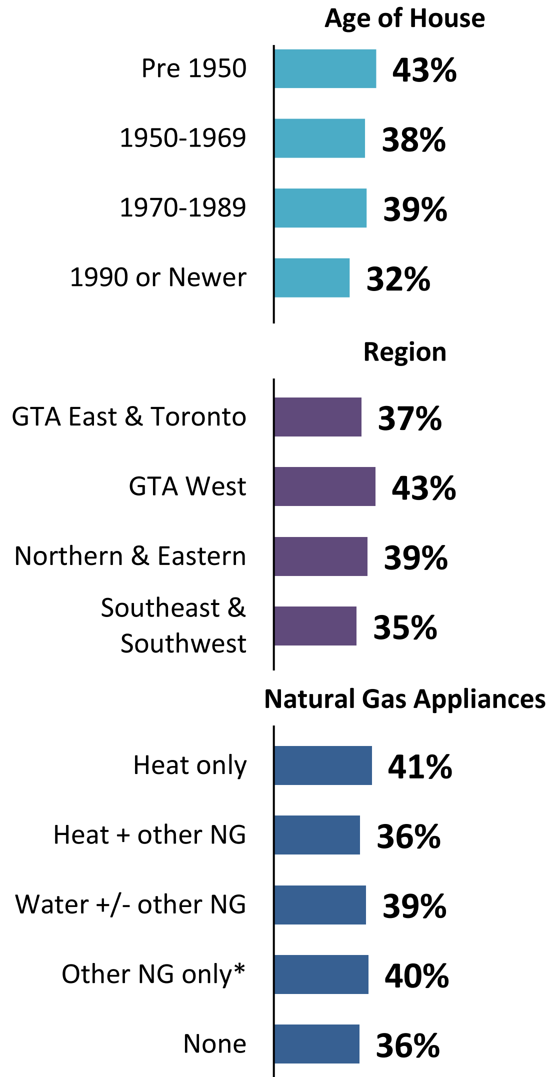
Upgrade Equipment Offer: About 2-in-5 (39%) say the option makes it better while almost a third (31%) say the same

If a customer is interested in potential upgrades, for example increasing the size of their water heater, changing their cooktop/stove, or choosing a higher-end option, Enbridge Gas could make this available, with the extra costs to be paid for by the customer.

Q In your opinion, does adding this option make the offer better or worse?
[asked of all respondents, n=2,000]



Segmentation
Those who say "better"



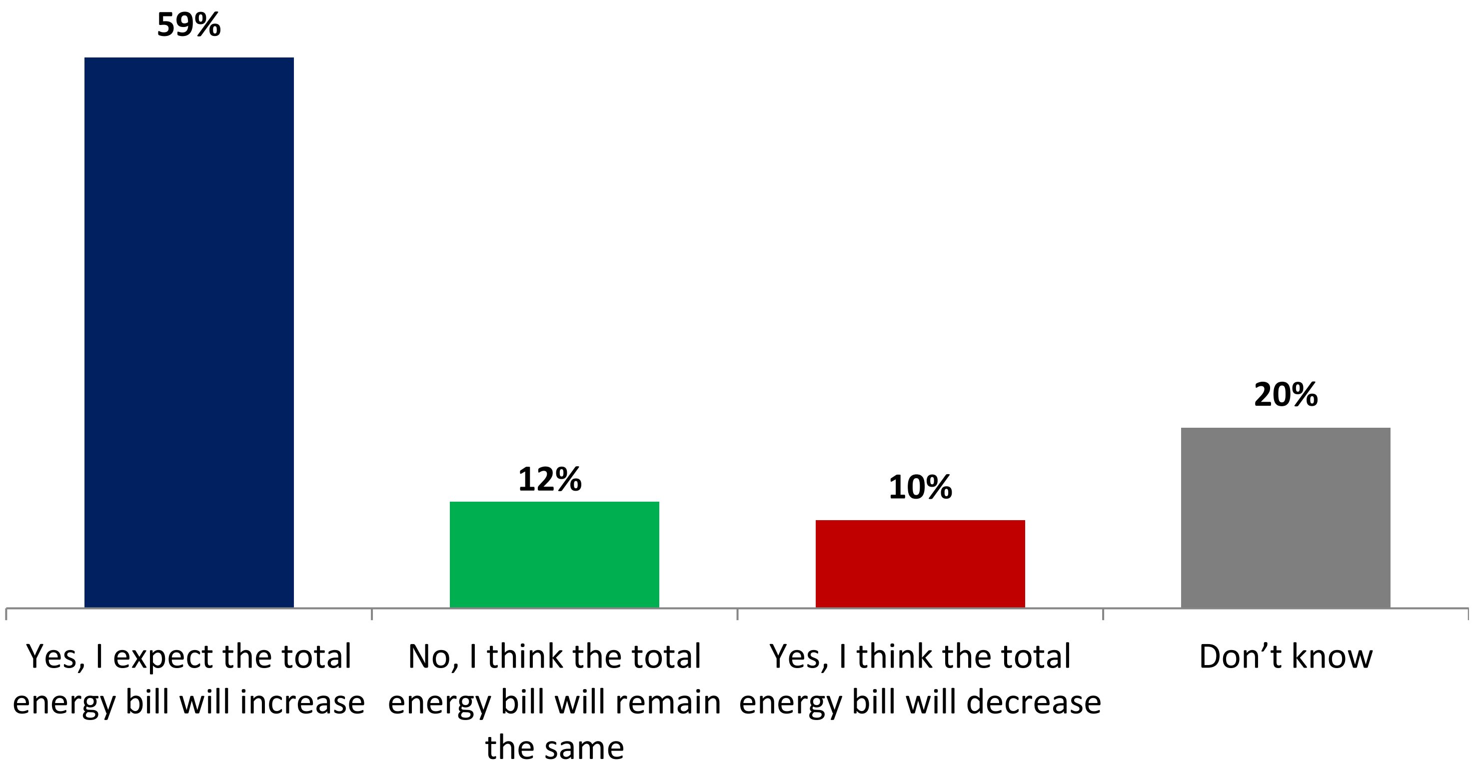
Note*: "Other NG only" n<50

Energy Costs Offer: About 3-in-5 think the bill will increase as a result; those with a house built in 1990 or later most likely to say so

A home's total energy bill includes the costs of the energy sources used in the home – natural gas, electricity, propane, or anything else that might be used. It includes fixed customer costs, energy usage, taxes and subsidies.

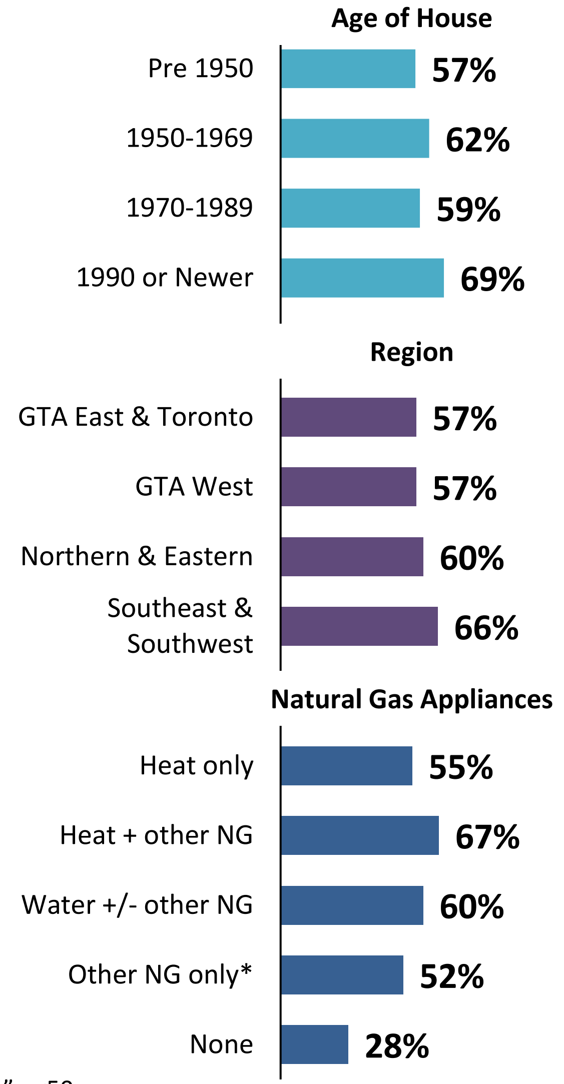
Q

When you think about the total bill, on average, over the course of the year, do you think that it will change as a result of a disconnection from natural gas?
[asked of all respondents, n=2,000]



Segmentation ▶▶

Those who say "bill will increase"

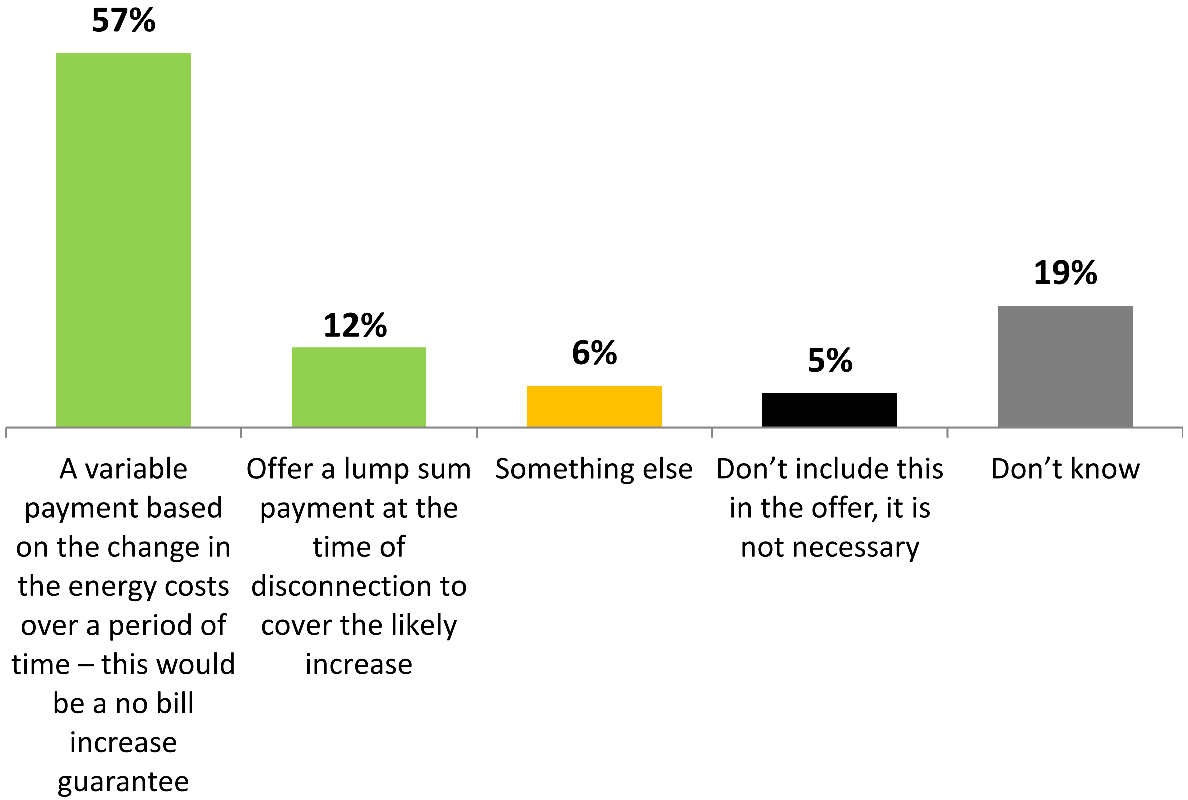


Note*: "Other NG only" n<50

Energy Costs Offer Compensation: Majority think disconnected customers should be compensated; over half saying variable payment

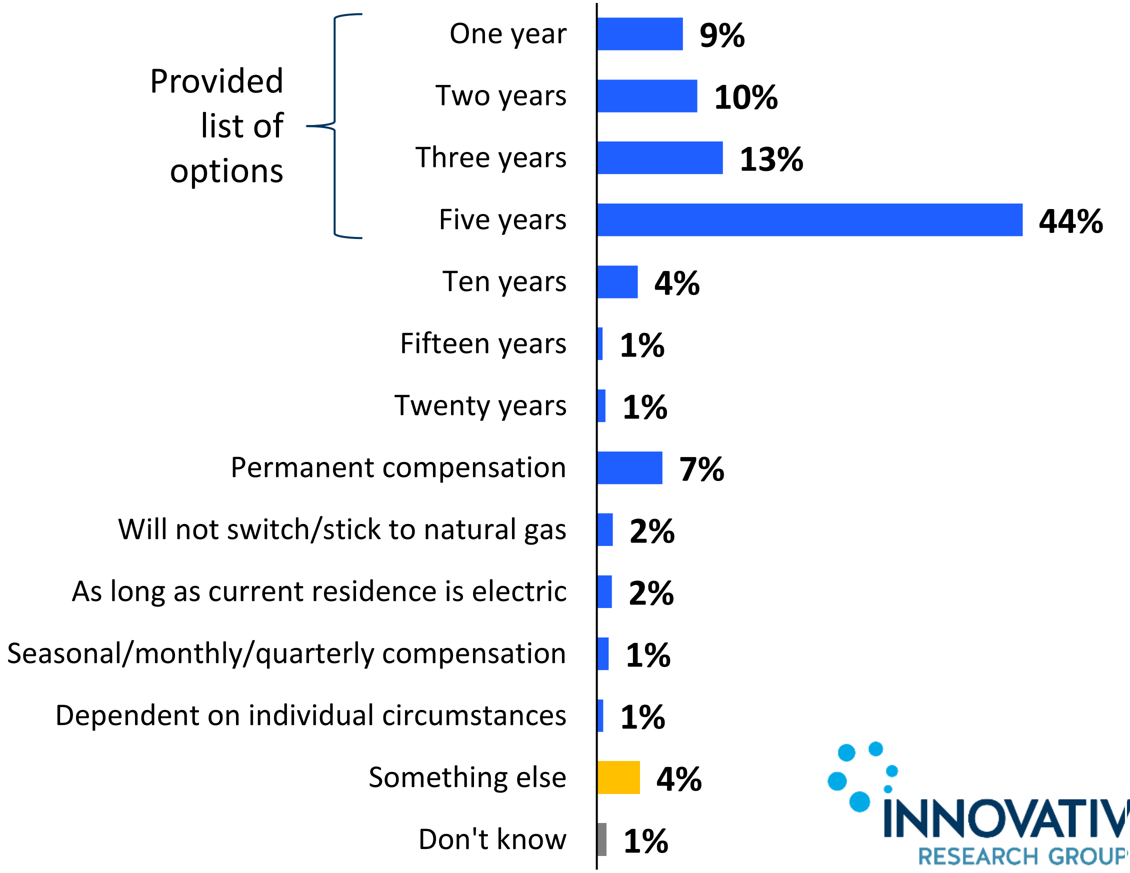
Q Since the total energy bill may vary because of the change in equipment, but also because of other influences on the price, how do you think disconnected customers should be compensated for this if the total energy bill increased because of this project?

[asked of those who expect the total energy bill will increase, n=1,189]



Q Thinking again about compensation for an increase, if there is one, in a household's total energy bill, what is a reasonable amount of time that the increase in the total energy bill should be reviewed and compensated for?

[asked of those who agree with compensation for bill increase, n=1,127]



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Energy Efficiency Offer:

One option to reduce the total energy bill would be to look at ways to improve the energy efficiency of the home as part of the offer. This would include a visit to the home by a registered energy auditor who would be able to provide recommendations on ways to improve the energy efficiency of the home. Implementing these recommendations could help address the total energy bill.

Recommendations could include:

- ✓ Weatherstripping, or air sealing to reduce air leakage from the home;
- ✓ Add insulation in the home (attic, wall, foundation, exposed floor);
- ✓ Upgrade windows and doors; or
- ✓ Install a smart thermostat

The Home Renovation Savings Program currently offers rebates and incentives for these recommendations, and the offer could include elements of this program.

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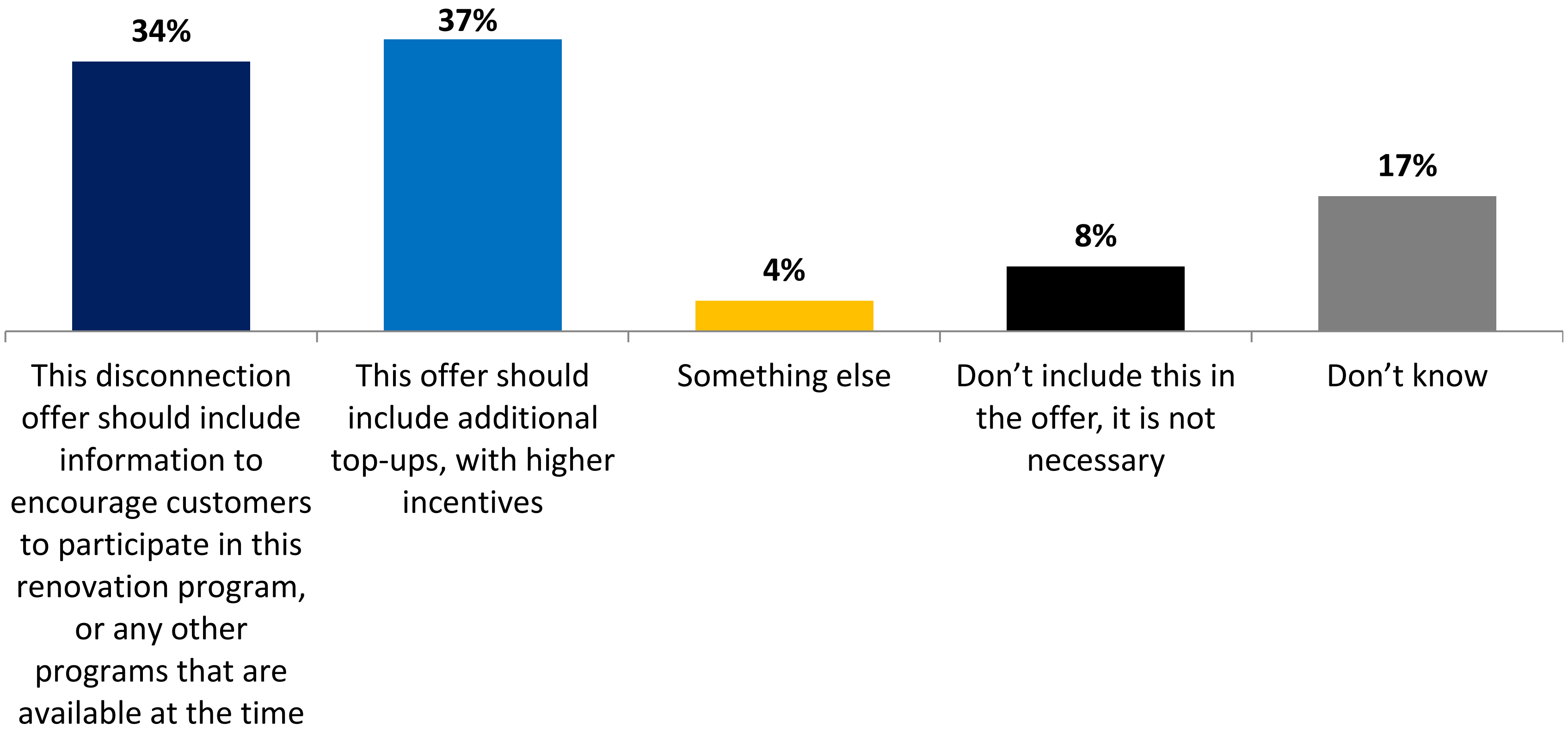
Energy Efficiency Offer Inclusion: 34% say the offer should include information to encourage participation while 37% say additional top-ups

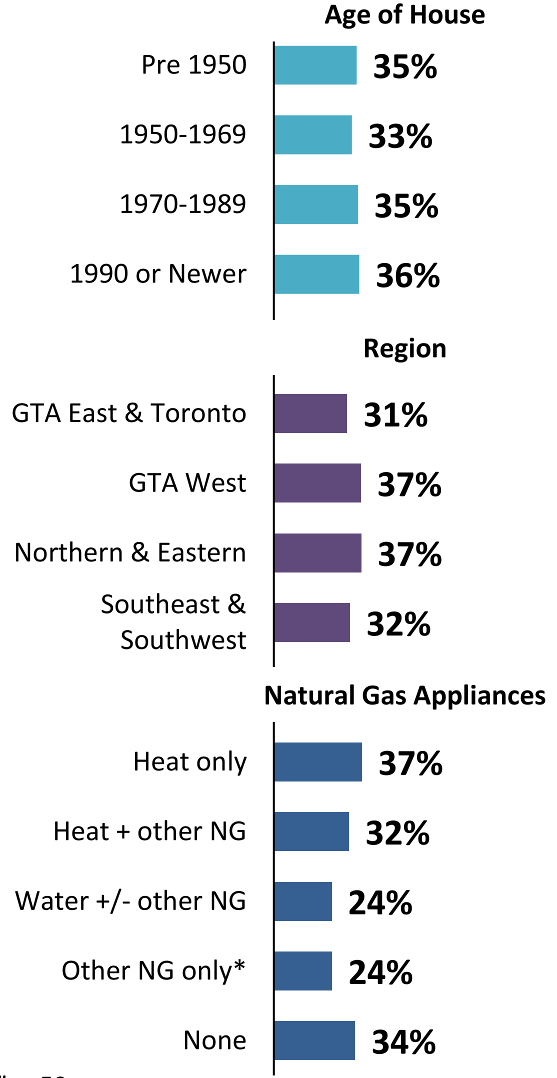
Q

How do you think this should be included in the offer?
[asked of all respondents, n=2,000]



Segmentation

Those who say "include information"



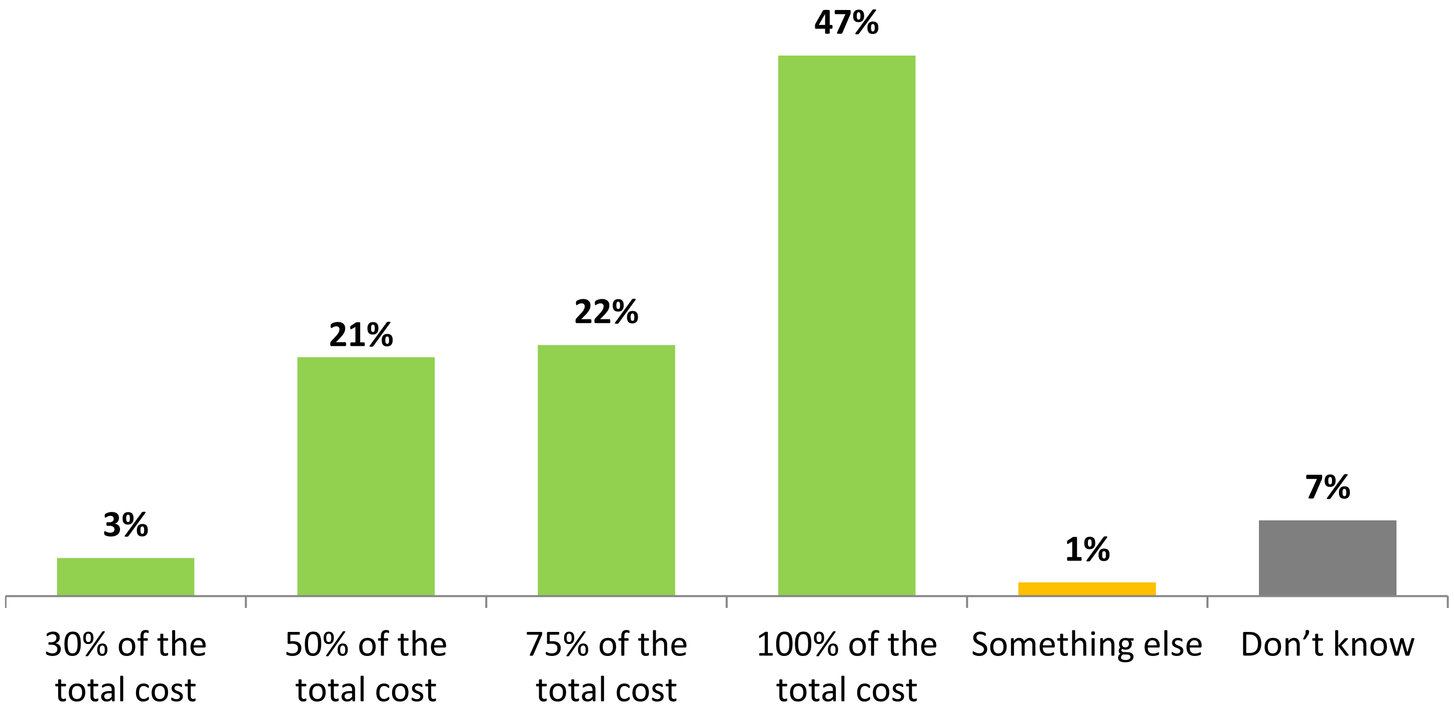
Note*: "Other NG only" n<50

Energy Efficiency Offer Incentive: Almost half (47%) say the incentive should be 100% of the total cost

Q

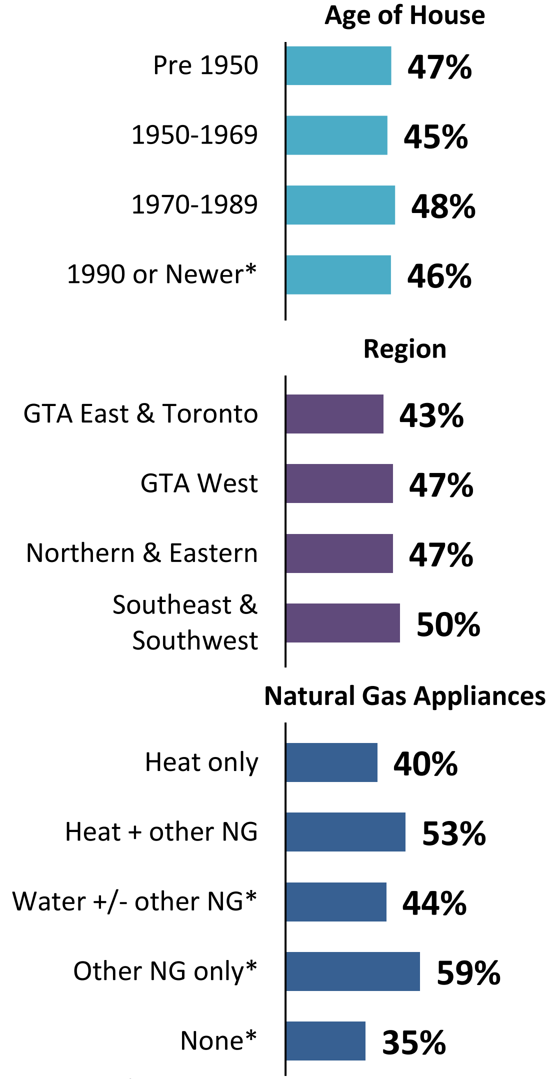
What is a reasonable incentive level that you think would need to be included as part of the offer?

[asked of all those that said "This offer should include additional top-ups, with higher incentives", n=717]



Segmentation

Those who say "100% of total cost"



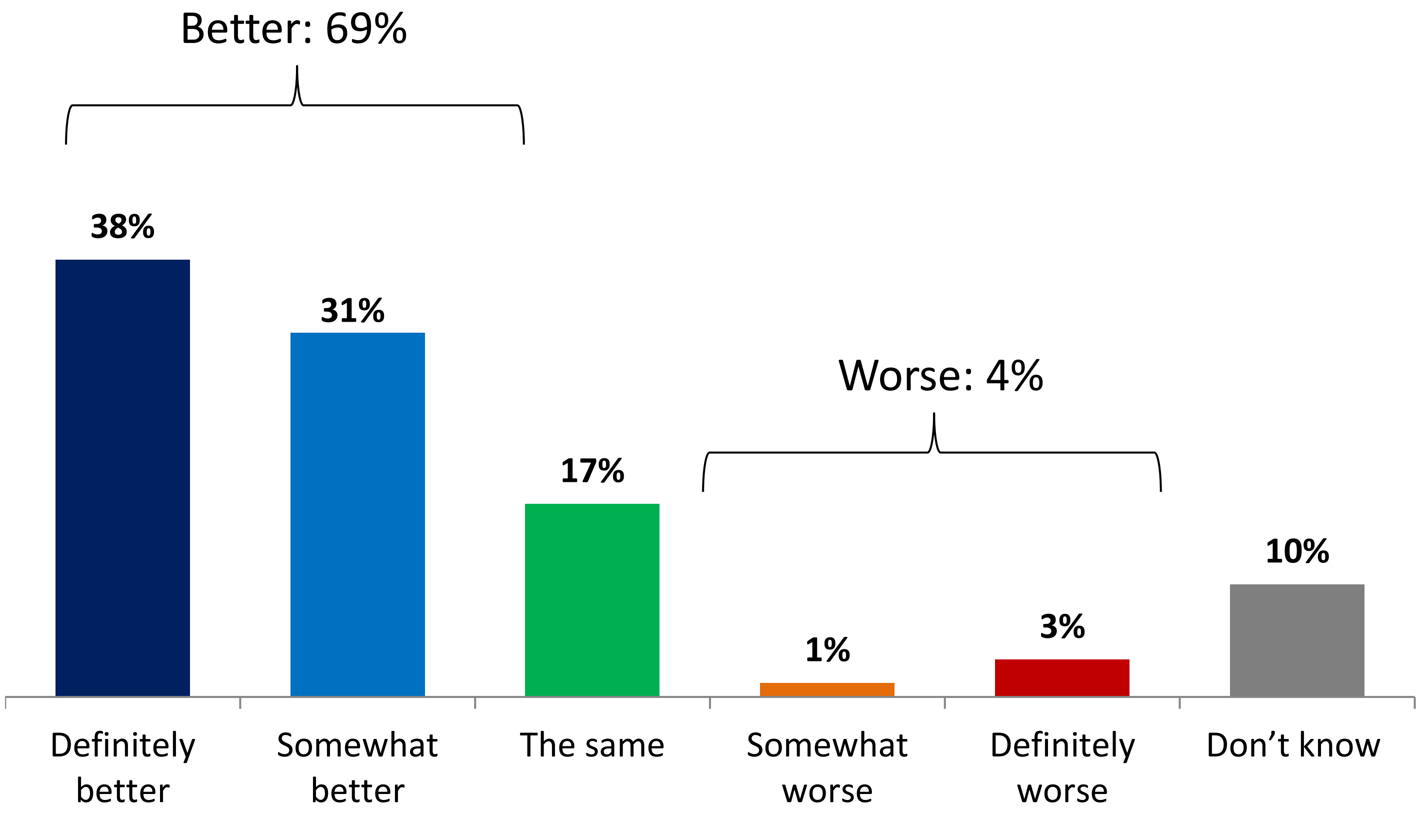
Note*: "1990 or newer", "Water +/- other NG", "Other NG only", and "None" n<50

Extended Warranty Offer: Over 2-in-3 (69%) say the option would make the offer better; highest among those w/ a house built prior to 1950

Q

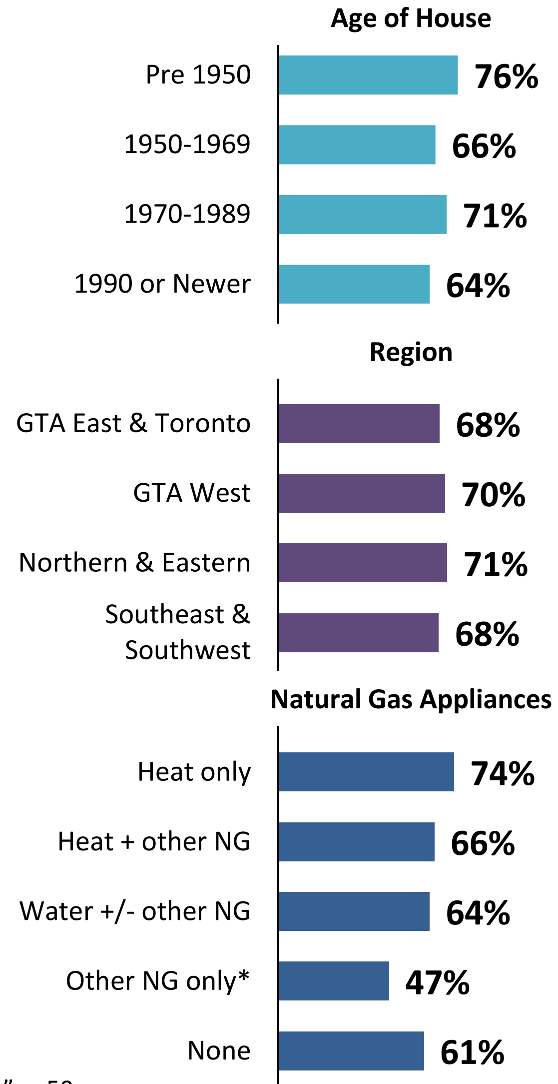
If Enbridge Gas were to offer, through the contractor completing the work, an extended warranty on the equipment, with the extra costs to be paid for by Enbridge Gas, in your opinion, would this option make the offer better or worse?

[asked of all respondents, n=2,000]



Segmentation

Those who say "better"



Note*: "Other NG only" n<50

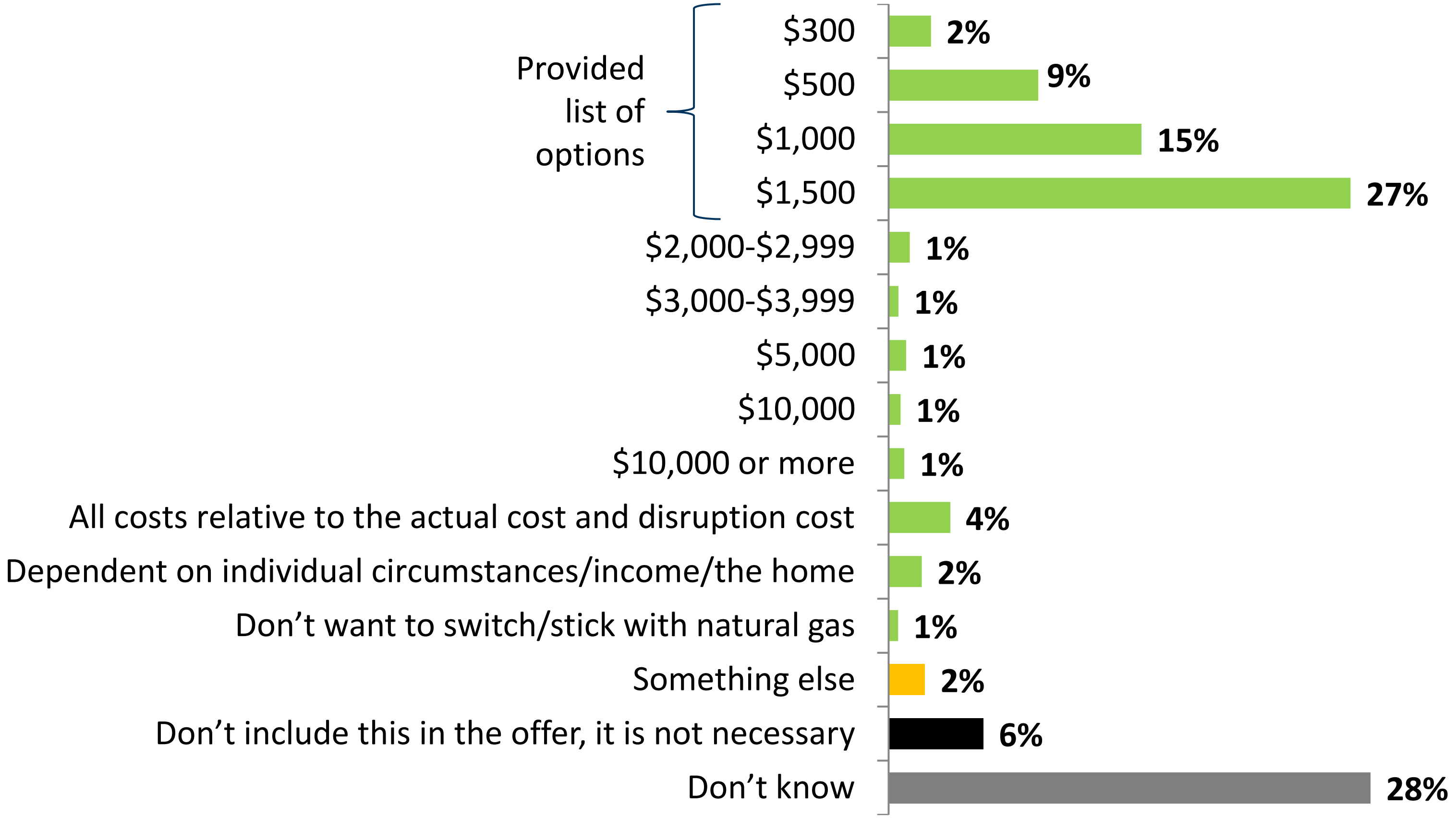
Incidentals/Additional Incentive: More than 1-in-4 say reasonable amount is $1,500; similar share say don't know

Q

When it comes to the overall disruption and inconvenience that would come with a project like this, what do you think is a reasonable amount that should be offered?

This amount could help to offset any costs if someone had to take a day off work during the equipment change, cover any small fix-ups in paint, or trim, or other incidentals, as needed.

[asked of all respondents, n=2,000]



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Sample Verbatim Comments

"'A day off work' would not come near to covering the hassle of this sort of change. Definitely more than $1500 should be offered. There will be multiple days off work dealing with contractors. There will be disruption to the household routine. There will be screw ups that need additional baby sitting and expenditure of time and patience."

"Everyone's costs are different. One person's day off work may be more expensive than another person's day off work. Some renovations may create more holes and fix ups than other homes. I don't know how you determine this."

"Not sure but changes could affect our kitchen cabinets as well as brand new countertop. We have two gas fireplaces that may need changes to outside finishes. Digging up gas line would affect some landscaping. Time to perform the jobs would disrupt household and pets."

"Could be more depending on the individual household. We had major renovations so our cost could be more than $1500."

"Every home will be different therefore costs to compensate will be different. An assessment should be done per home to really know how much to compensate."

"$2000 to $3000 If you have to take a day or two off work and pay for extra repairs this might not even cover it."

"$5000. My home has just been COMPLETELY renovated. I do NOT need this inconvenience."

"Will vary on a customer-to-customer basis. Could be 300 enough for some, while others will have to do repairs that require 50K+ due to finished basements and custom cabinetry."

"Would be at least $1500/ day to start. Depending on how badly its disrupted work/day to day life it could be quite a bit more. I run a business and have tools etc. that I store at my home so if it disrupts me doing business much more."

"The amounts listed above are far too low to do some necessary repairs to home interiors that would be ruined in finished basements. Landscape repairs to remove old pipelines and such. The amounts of money and time to repair far exceed any of the above $ amounts."

"500 should bare minimum for 1 person to stay home. Working the math, $500 is $12.50/hr. for 40hrs and that's before taxes! so really it should be $1,000- $1,500 for a lost day."

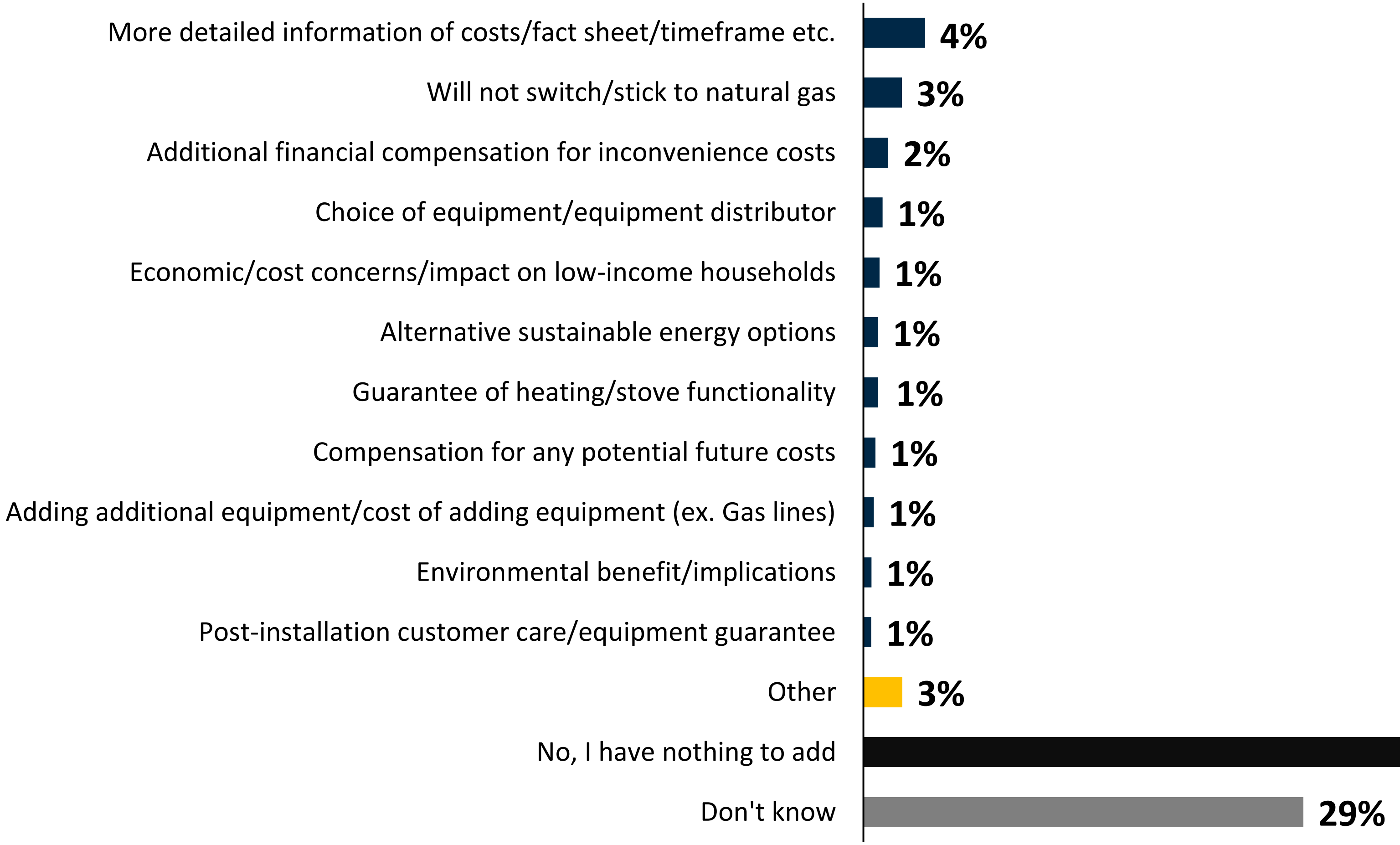
"$500 /day that contractors are on site. This includes the initial consultation, installation date and any required follow up."

Additional Feedback: More than half have nothing to add; most cited suggestion is more detailed information of costs/timeframe

Q

Now that we have looked at some offer options in more detail, is there anything that you would expect to see as part of the offer that has not been asked about? What would that be?

[asked of all respondents, n=2,000]



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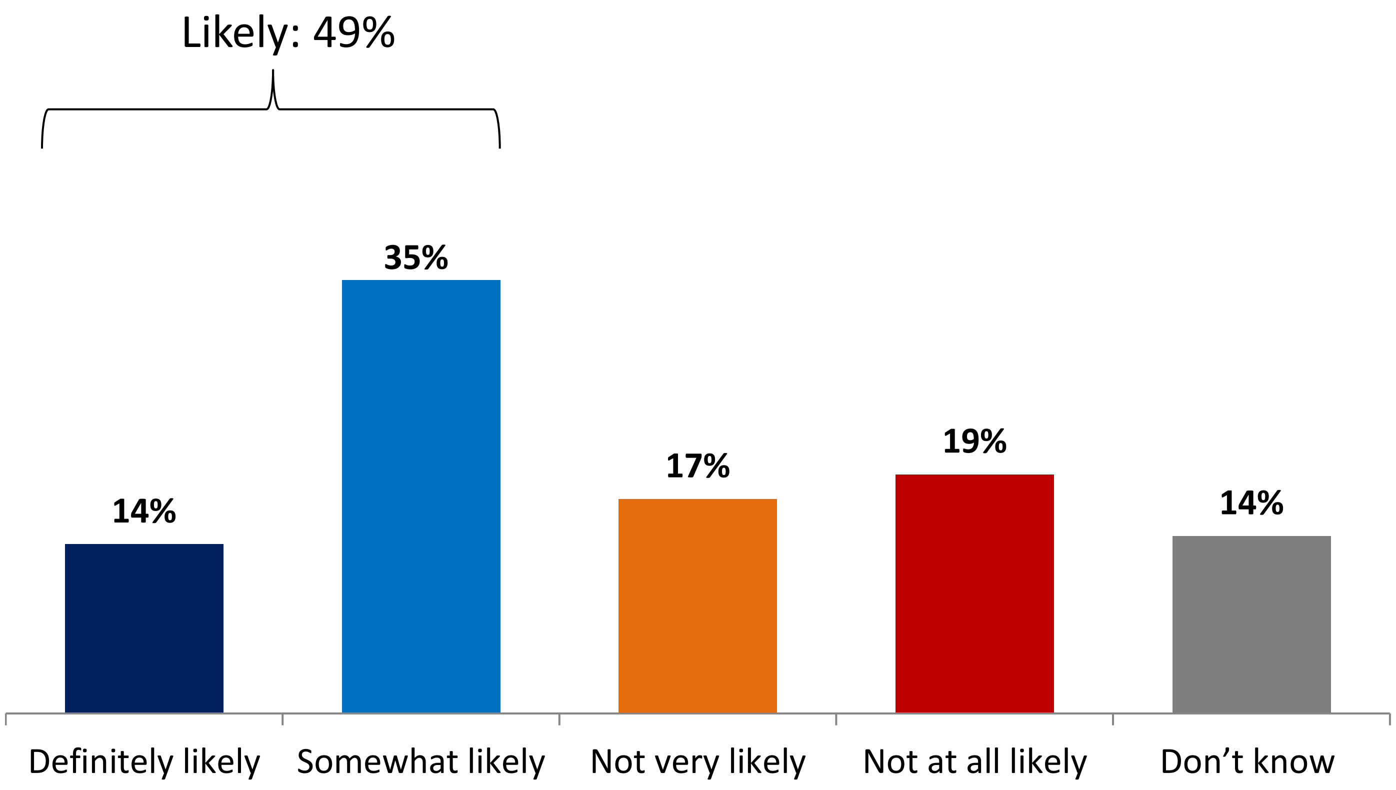
Likelihood to Disconnect: Nearly half say they would likely participate; those with a pre-1950 house most likely to say so

Q

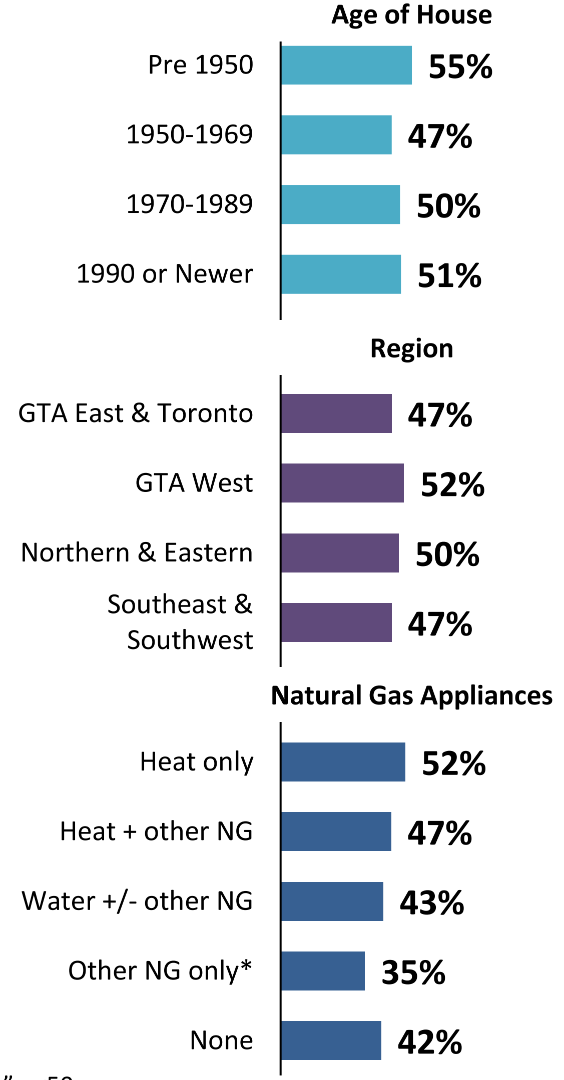
Considering what you have seen about the offer that would help affected customers to disconnect, and the choices you have been making, if this project were happening in your area, and all the offer elements you chose or suggested were included, how likely would you be to agree to participate and disconnect?

[asked of all respondents, n=2,000]



Segmentation

Those who say "definitely/somewhat likely"



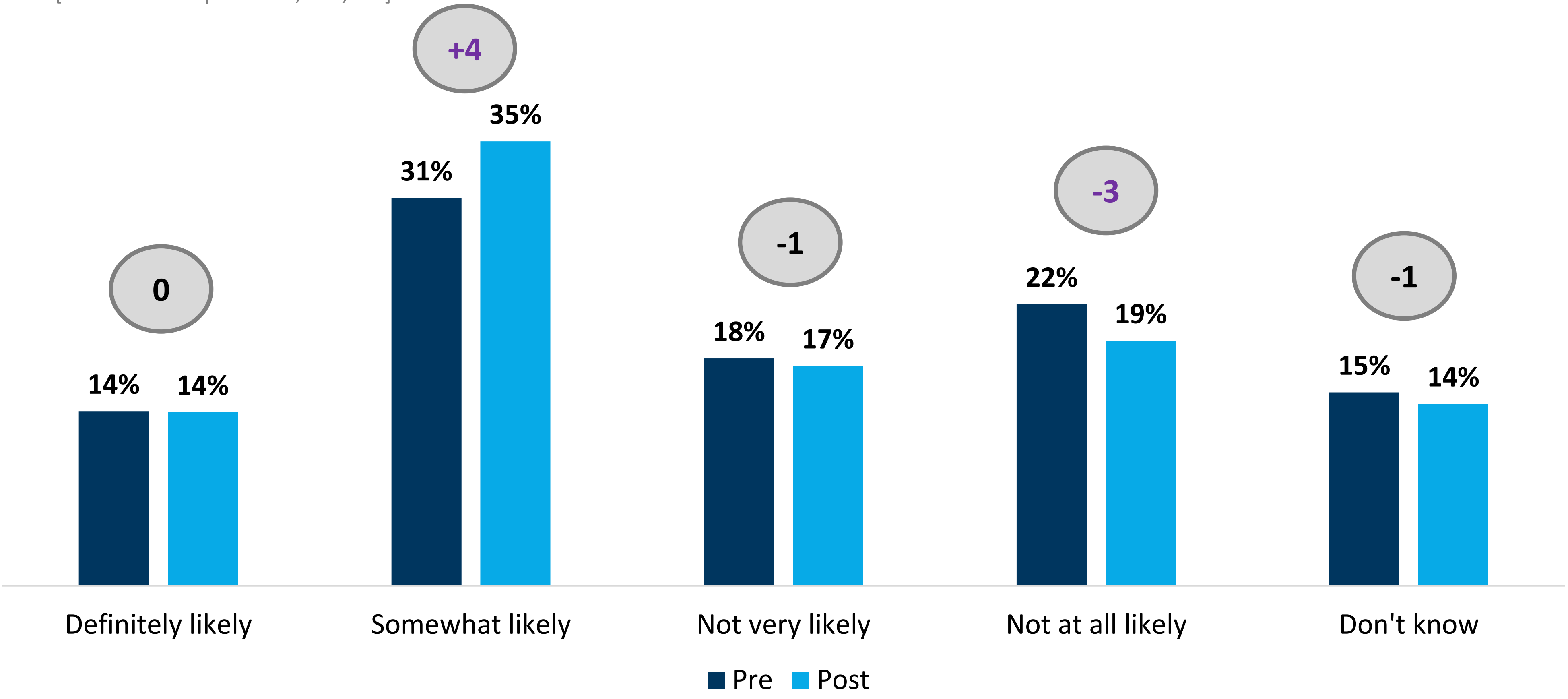
Note*: "Other NG only" n<50

Pre-Post on Disconnection: There is a net neutral change pre vs post with a 4pt gain in likelihood as well as a decrease on unlikely

Q

Pre: If this project were happening in your area, based on this offer, how likely would you be to agree to participate and disconnect?

Post: Considering what you have seen about the offer that would help affected customers to disconnect, and the choices you have been making, if this project were happening in your area, and all the offer elements you chose or suggested were included, how likely would you be to agree to participate and disconnect?
[asked of all respondents, n=2,000]



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Note: Differences that would be statistically different in an equivalent random probability-based sample are highlighted in purple (95% confidence) or blue (90% confidence).

Change of Opinion on Disconnection: Despite the consistent 14% *definitely likely*, there is some movement "under the hood"

Q

If this project were happening in your area, based on this offer, how likely would you be to agree to participate and disconnect?

BY

Considering what you have seen about the offer that would help affected customers to disconnect, and the choices you have been making, if this project were happening in your area, and all the offer elements you chose or suggested were included, how likely would you be to agree to participate and disconnect?

[asked of all respondents, n=2,000]

Likelihood of participating prior to incremental offer exposure

Likelihood after exposure to offers	Definitely likely	Somewhat likely	Not very likely	Not at all likely	Don't know
Definitely likely	198	64	3	4	5
Somewhat likely	67	461	85	26	64
Not very likely	2	44	187	74	41
Not at all likely	2	5	45	317	18
Don't know	7	40	40	23	177

This table shows frequencies rather than percentages so that it is easier to see the shift in opinion

We take a closer look at this "under the hood" movement on the next slide.

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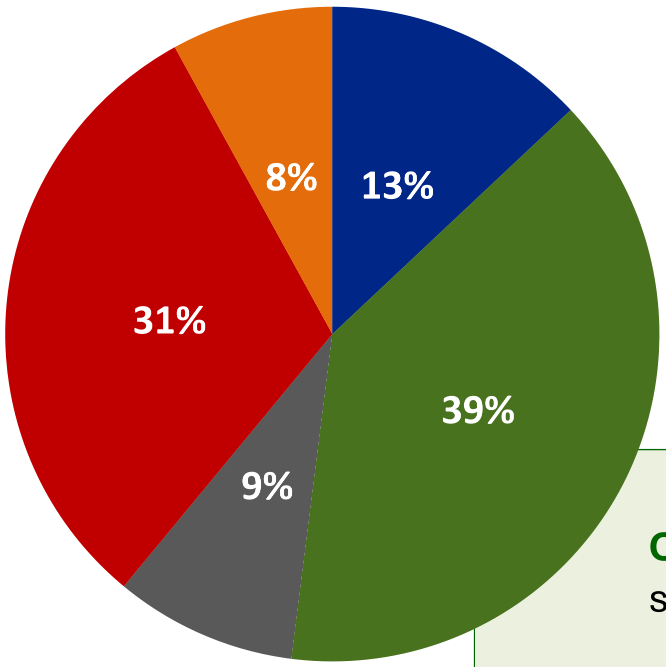
How likely are customers to be persuaded to participate in a disconnection?

The following chart illustrates five unique groups among survey respondents based on their likelihood of being persuaded to **participate in a natural gas pipeline disconnection**.

Respondents were placed in each group based on their answers pre- and post- exposure to the components of the offer.

Opinion Breakdown:



Likelihood After Exposure to Offers	Likelihood Prior to Incremental Offer Exposure: Definitely likely	Somewhat likely	Don't know	Not very likely	Not at all likely
Definitely likely	Core Likely	Core Likely	Gains	Gains	Gains
Somewhat likely	Core Likely	Core Likely	Gains	Gains	Gains
Don't know	Losses	Losses	Pure Undecided	Gains	Gains
Not very likely	Losses	Losses	Losses	Core Unlikely	Core Unlikely
Not at all likely	Losses	Losses	Losses	Core Unlikely	Core Unlikely

Core Likely and **Gains** make up 52% of customers. That said, the second largest segment of customers are the **Core Unlikely**.

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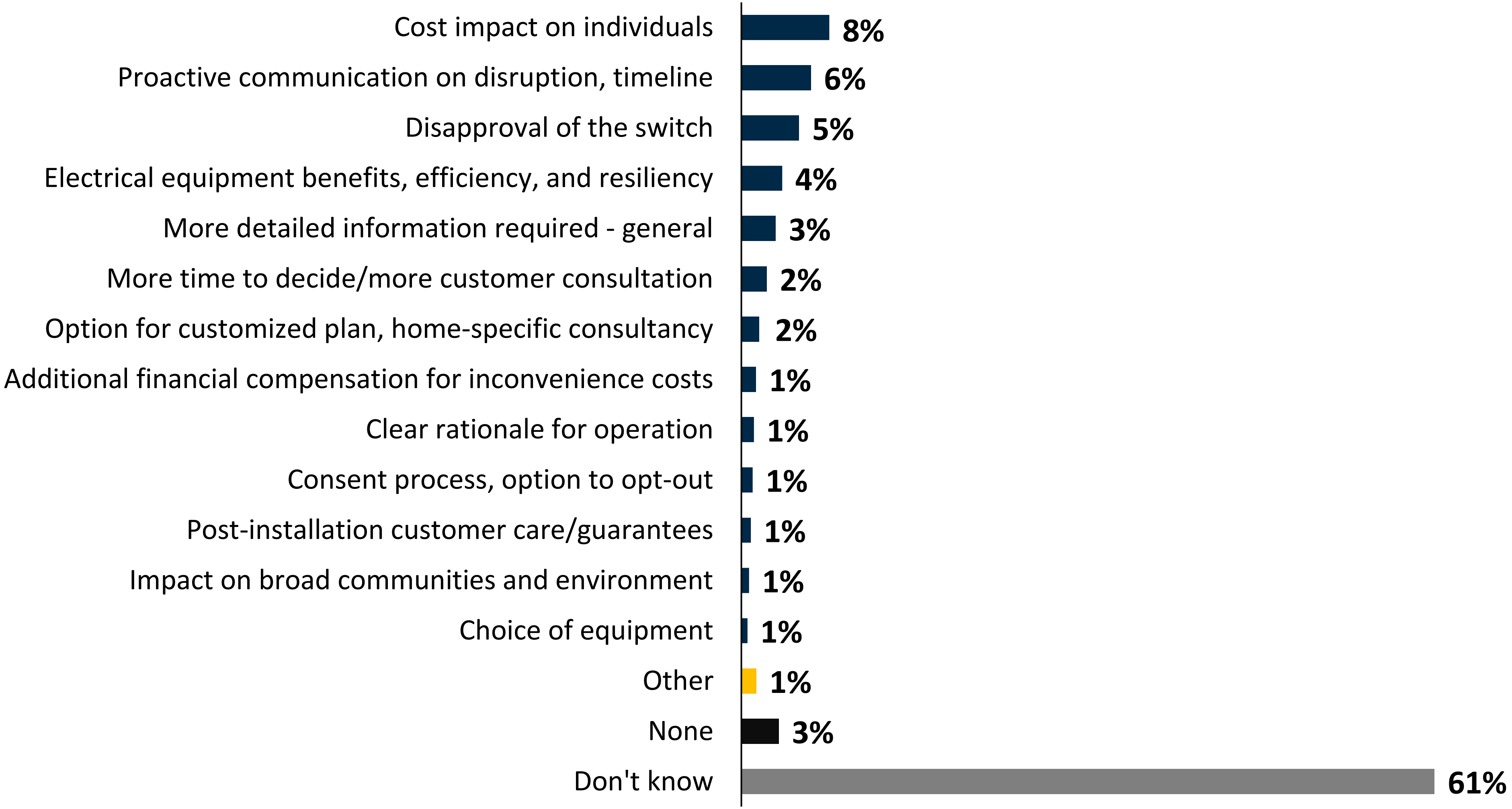
Disconnection Information: 3-in-5 (61%) don't know what would help them make the decision to participate; 8% say cost impact on individuals

Q

If this project were happening in your area, would there be anything else that you would need to know more about to help make the decision to agree to participate and disconnect?

[asked of all respondents, n=2,000]



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Sample Verbatim Comments

"I would want to know exactly what equipment was to be used in replacing my existing equipment, who was going to be doing the demolition and instillation, the time frame involved and how much choice do I have in the quality of the new equipment being used?"

"Someone from Enbridge would need to physically be there to explain the process step by step. This isn't something people will voluntarily agree to by email or online. People need reassurance and a clear understanding."

"Oh yeah! Many things. Such as how would it affect property taxes, resale value, safety if there is a power failure, is the electricity coming from carbon emitting sources, etc. what about hydrogen? What about geothermal? How will you protect power lines and power grid-move lines underground? Too many insecurities with the current electric system. Is the grid capable to support this influx? What happens when the next ice storm comes? With gas, I still have heat and cooking."

"I've been reading heat pumps don't have a long-life span when used for air conditioning."

"Meeting someone who could explain face to face what was said in this survey and make sure that I understand all the implications."

"Difference in my monthly bill. You have not even given an example of possible monthly costs."

"I just upgraded all my equipment, so I'd be really, really angry if I had to do this now."

"I would like to see statistics and evidence of how this would be beneficial to all of us in the long run and why. I would also like to see more innovative and modern choices of energy that are environmentally sound and efficient. This town is too poor to afford huge improvements and we need to make sure we all have efficient and effective energy that is not too expensive for the average lower income individuals and retirees to afford."

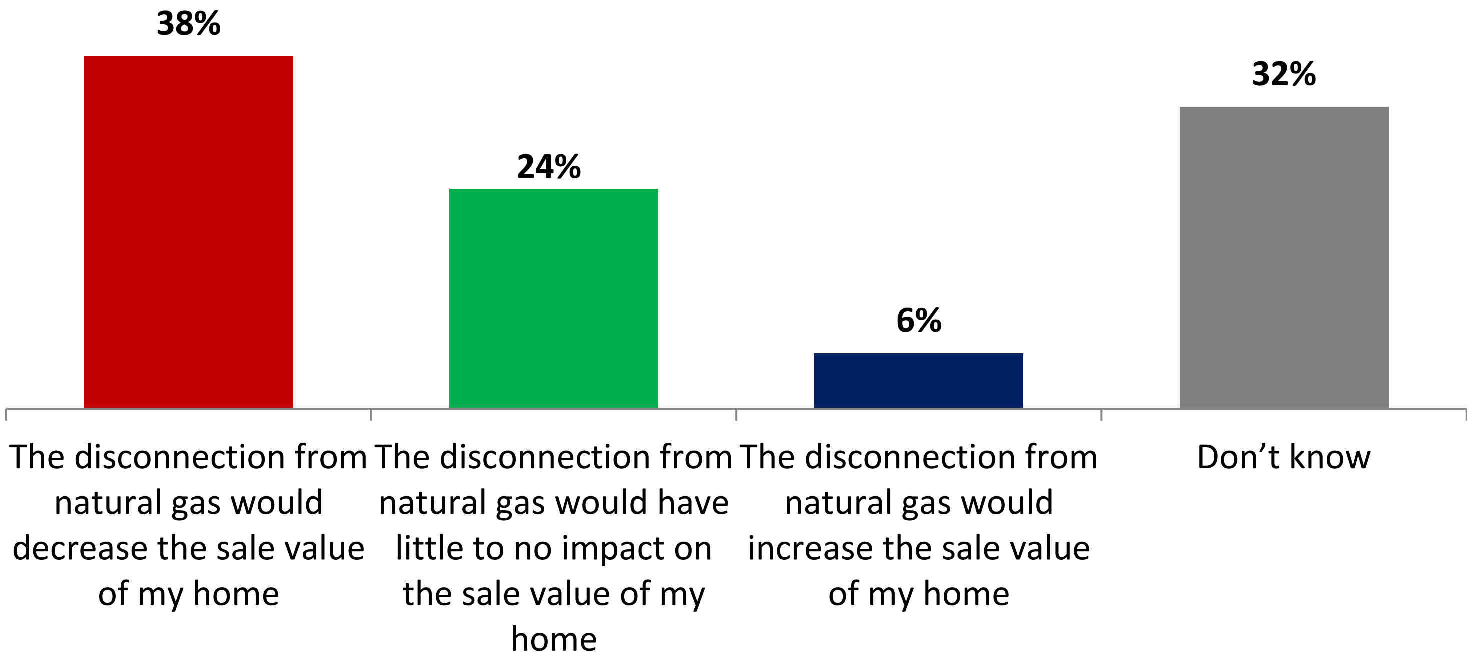
"do I have to leave the house? How many hours or days would I be without gas appliances? What would my monthly costs be going forward? How do I operate the equipment? will my property/landscaping be affected?"

"I would want to see a timeline. None of your info mentioned timelines. People need to have time to make an informed decision, and not feel rushed."

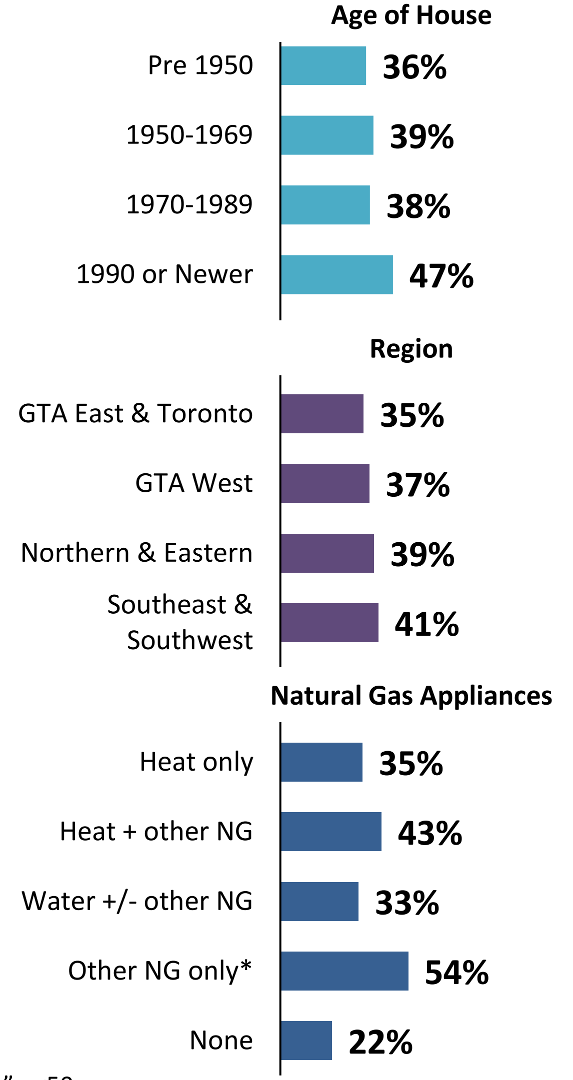
Home Sale Value: Almost 2-in-5 say the disconnection would decrease their home's sale value; higher among those with newer homes

Q

Some have suggested that a project like this may affect the value of their home. If this project were happening in your area, considering both the disconnection from natural gas and the new equipment that would have been installed as a result, how do you think that this would affect the sale value of your home?
[asked of all respondents, n=2,000]



Segmentation
Those who say "decrease sale value"



Note*: "Other NG only" n<50

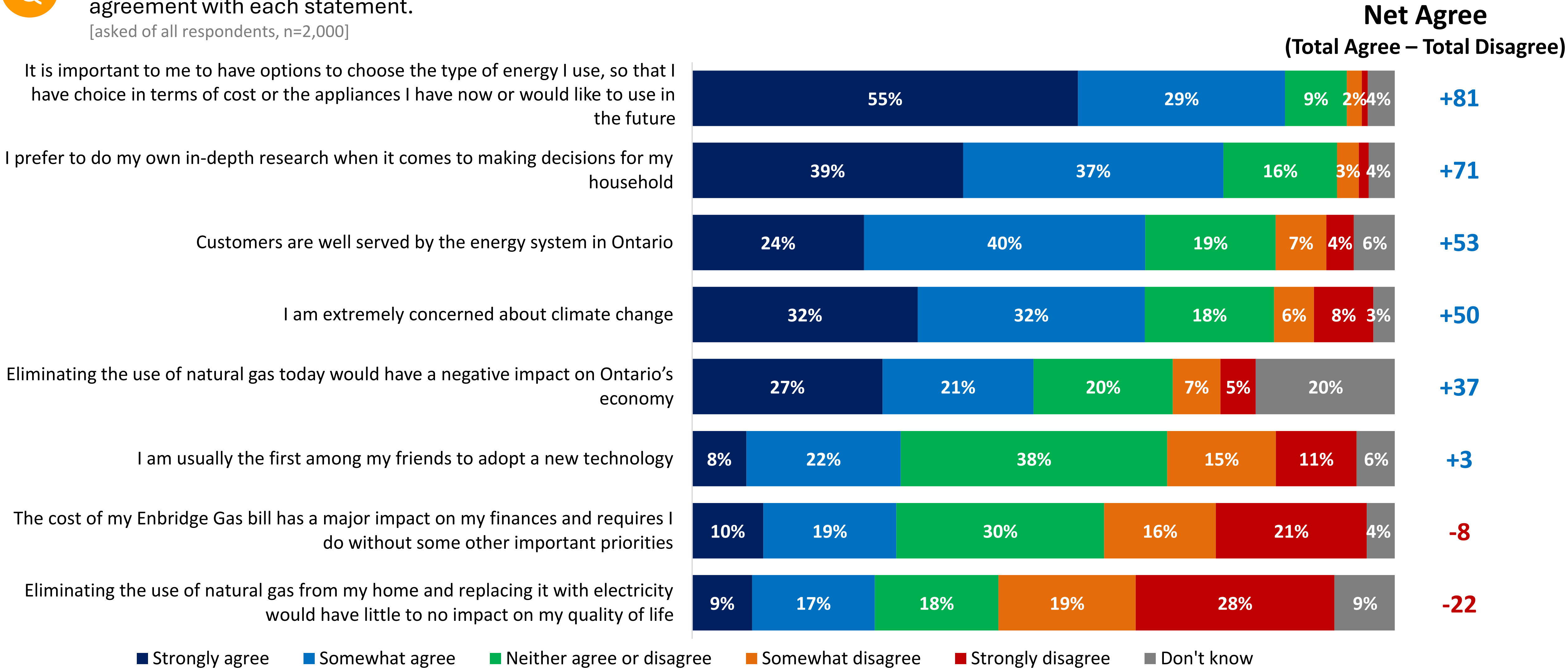
Overall Attitudes and Perceptions

Overall Attitudes: Net agreement highest on importance of having options and doing in-depth research when making decisions

Q

You will now see a list of statements related to energy topics, please read each statement carefully and indicate your level of agreement with each statement.

[asked of all respondents, n=2,000]



Likelihood to Participate by Overall Attitude: Those who anticipate little quality of life impact due to electrification are most likely to participate

Likelihood to Participate and Disconnect (Q14)

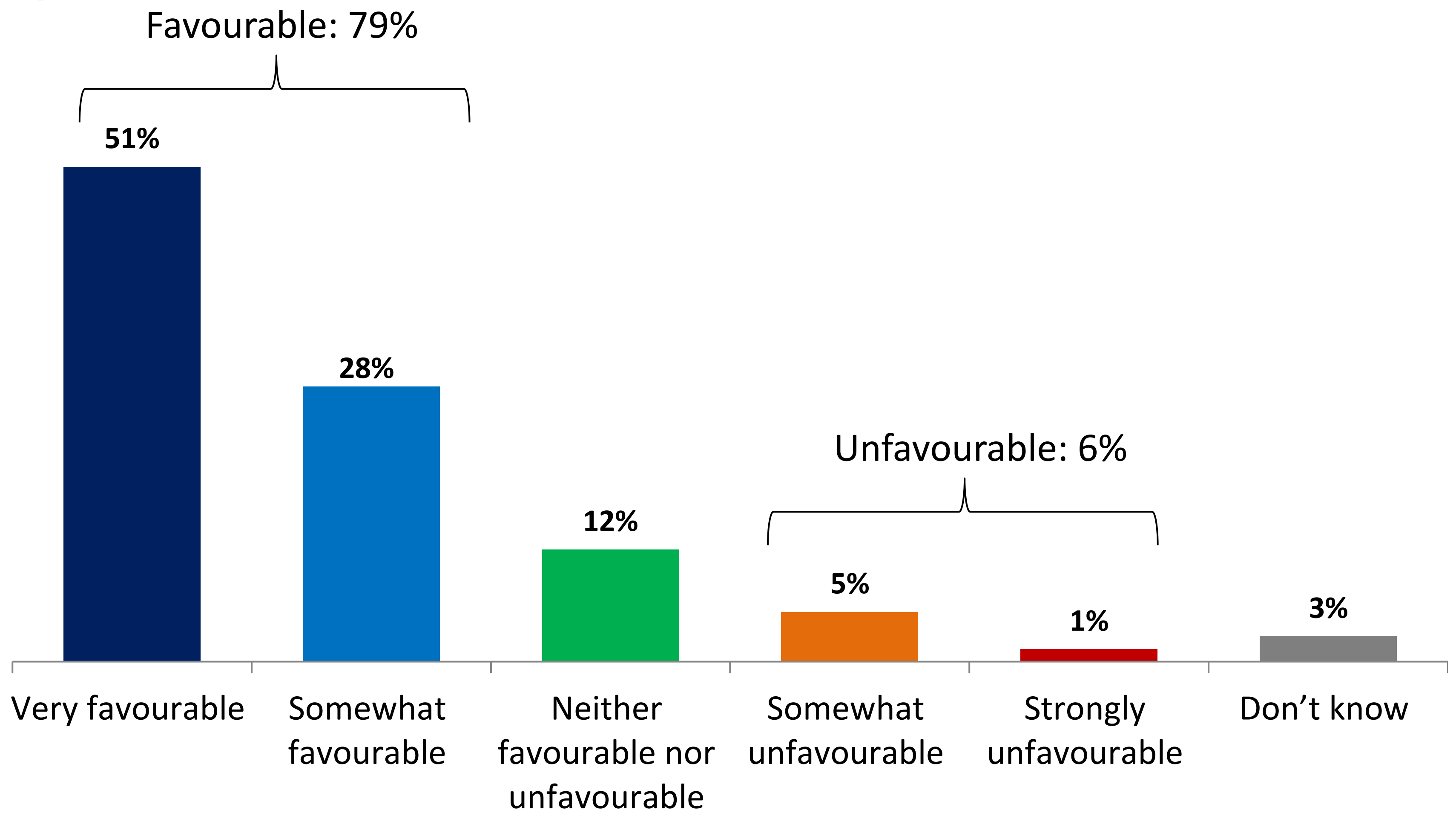
AGREE WITH STATEMENT	Definitely/ Somewhat Likely	Not Very/ Not at all Likely
Eliminating the use of natural gas from my home and replacing it with electricity would have little to no impact on my quality of life	73%	19%
I am usually the first among my friends to adopt a new technology	57%	32%
I am extremely concerned about climate change	55%	31%
Customers are well served by the energy system in Ontario	49%	39%
The cost of my Enbridge Gas bill has a major impact on my finances and requires I do without some other important priorities	46%	39%
It is important to me to have options to choose the type of energy I use, so that I have choice in terms of cost or the appliances I have now or would like to use in the future	45%	42%
I prefer to do my own in-depth research when it comes to making decisions for my household	44%	43%
Eliminating the use of natural gas today would have a negative impact on Ontario's economy	31%	58%

Natural Gas Impression: 8-in-10 (79%) have a favourable impression with half *very favourable*; lowest among those without NG appliances

Q

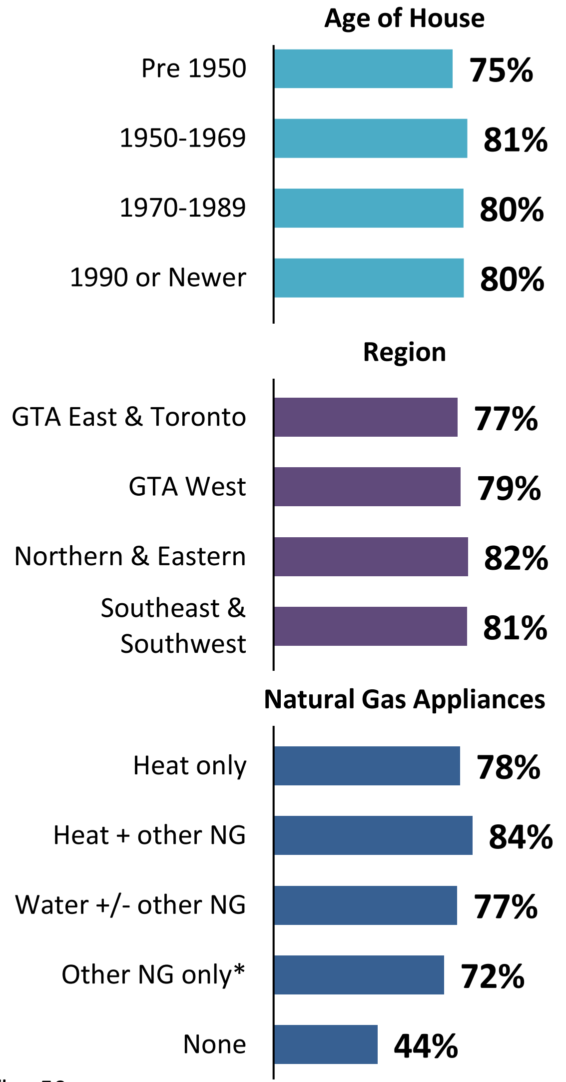
Generally speaking, what is your impression of natural gas as an energy source?

[asked of all respondents, n=2,000]



Segmentation

Those who say "favourable"

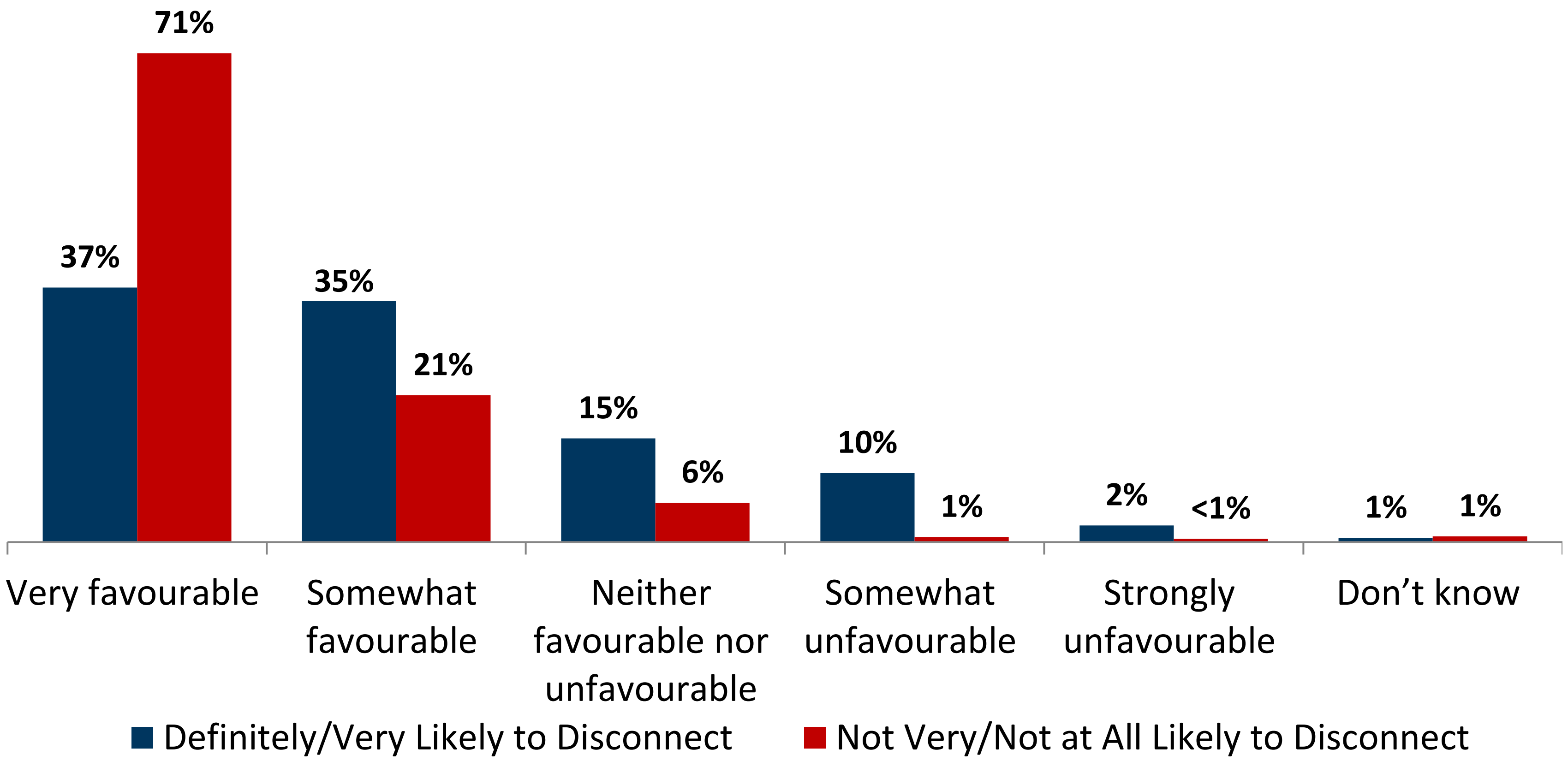


Note*: "Other NG only" n<50

Likelihood to Participate by Natural Gas Impression: Respondents who are very favourable towards NG are less likely to disconnect

Q If this project were happening in your area, based on this offer, how likely would you be to agree to participate and disconnect?
[asked of all respondents, n=2,000]
BY

Q Generally speaking, what is your impression of natural gas as an energy source?
[asked of all respondents, n=2,000]



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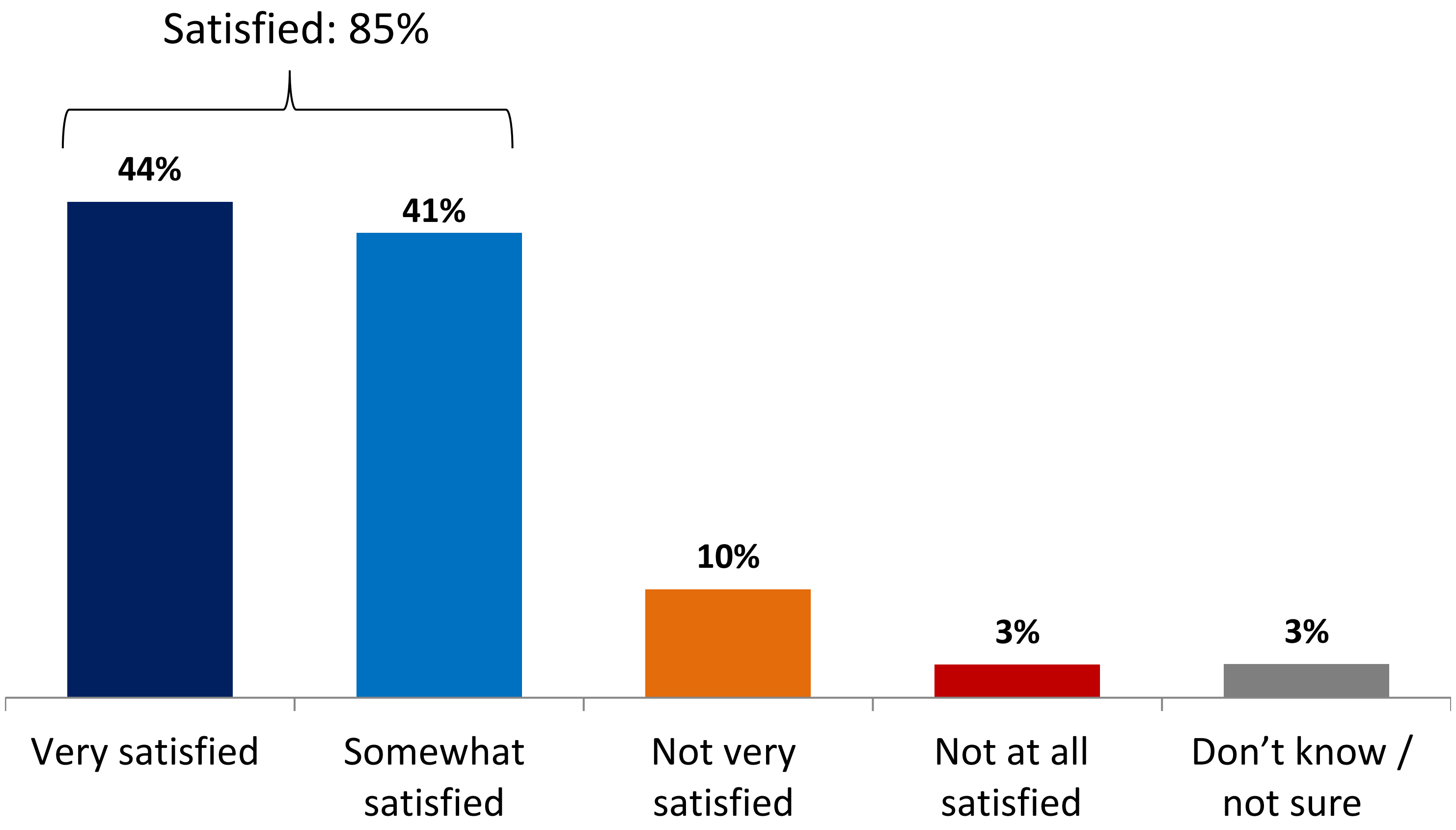
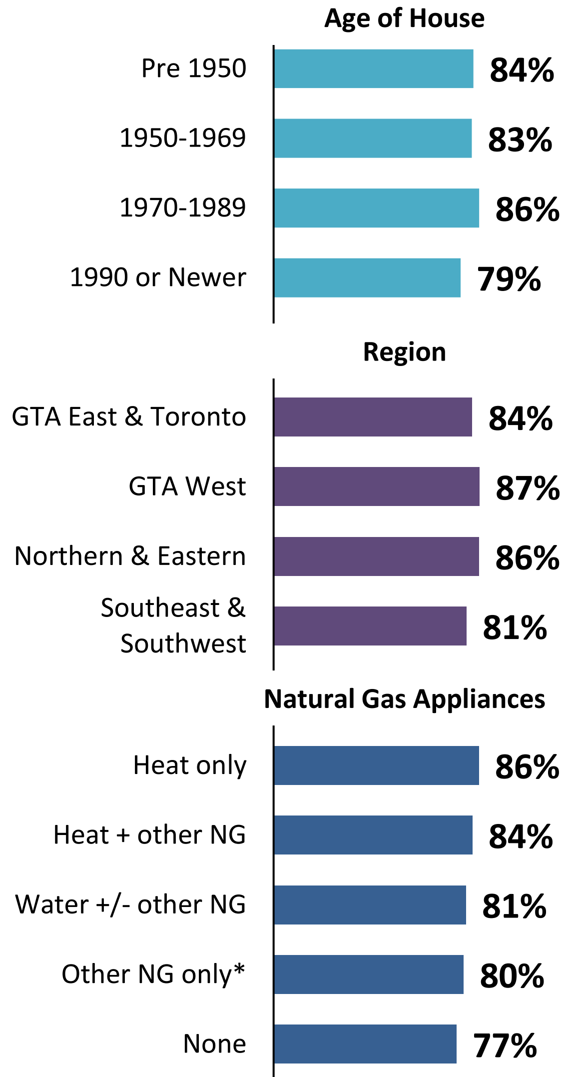
Electricity Reliability Satisfaction: Majority (85%) are satisfied with 44% *very satisfied*; satisfaction lower among those with newer homes

Q

How satisfied are you with the reliability – lack of interruptions or outages – of the electricity provided to your home, overall?
[asked of all respondents, n=2,000]



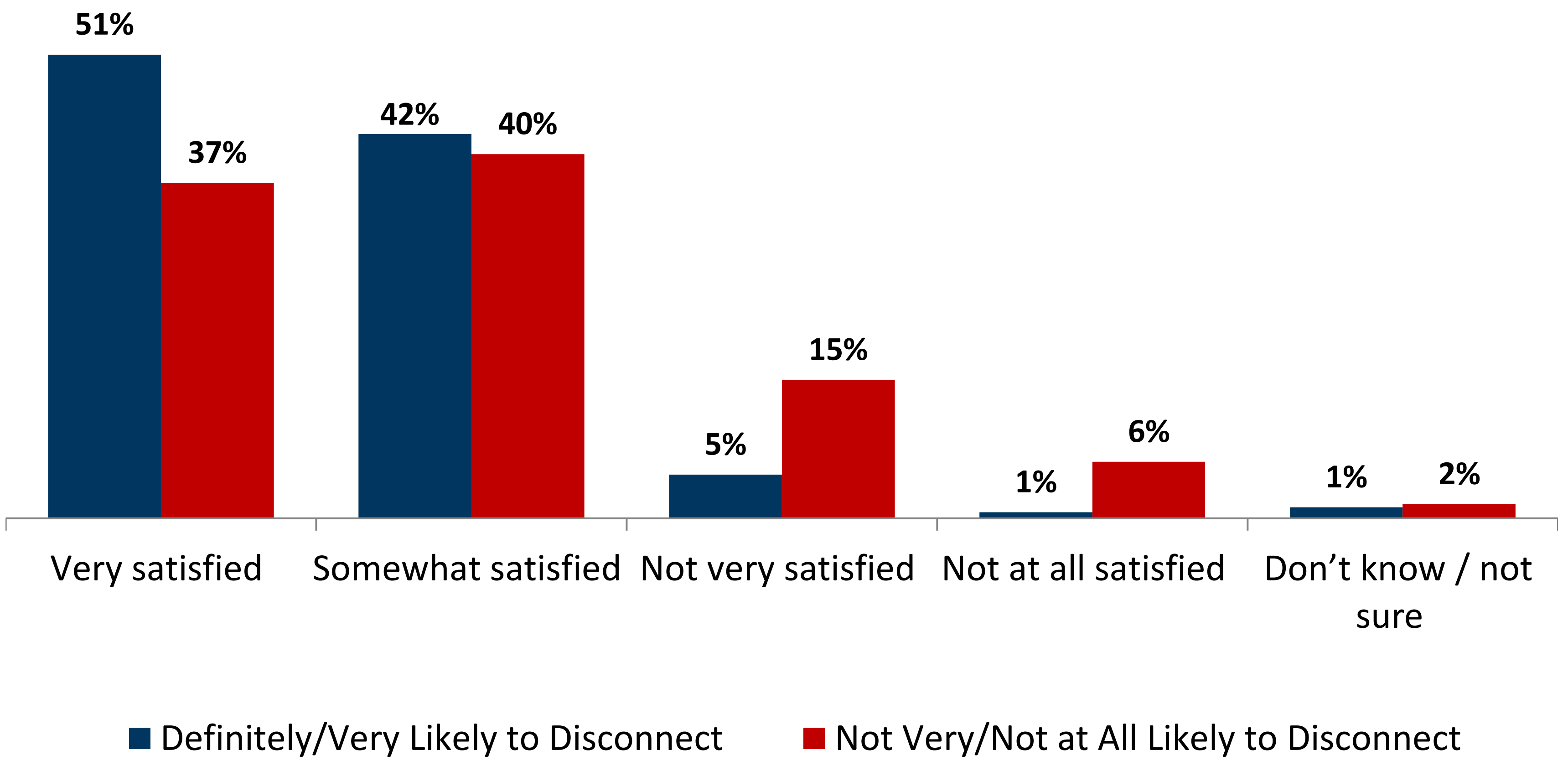
Segmentation ▶▶
Those who say "very/somewhat satisfied"



Note*: "Other NG only" n<50

Likelihood to Participate by Electricity Reliability Satisfaction: Those more satisfied with electricity reliability are more likely to participate

Q If this project were happening in your area, based on this offer, how likely would you be to agree to participate and disconnect?
[asked of all respondents, n=2,000]
BY
Q How satisfied are you with the reliability – lack of interruptions or outages – of the electricity provided to your home, overall?
[asked of all respondents, n=2,000]



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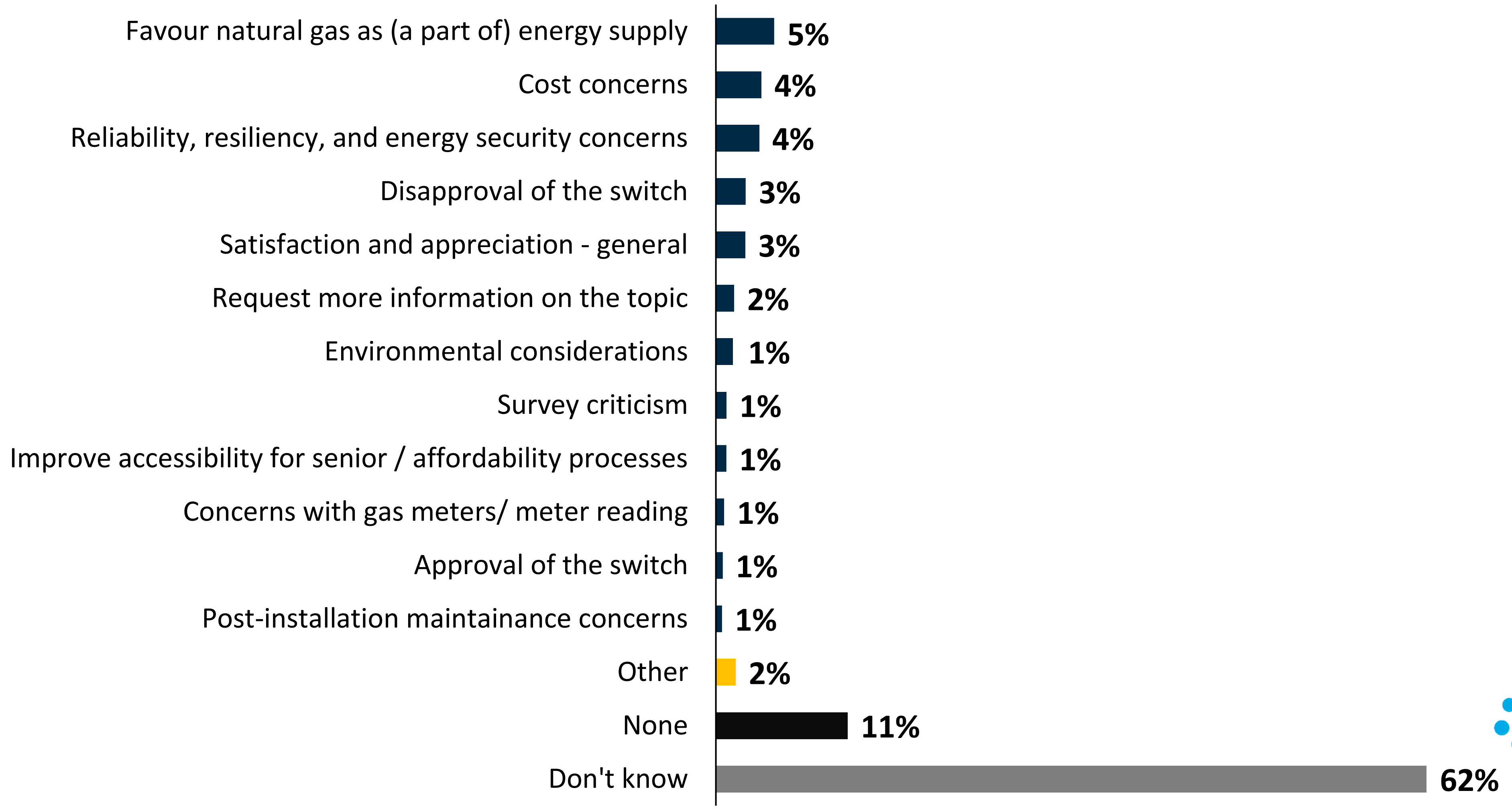
Additional Comments

Additional Comments: Majority (73%) don't know/don't have anything to add; top comment among those who have say 'favour natural gas'

Q

Is there anything you would like to share with Enbridge Gas about the topics in this survey?
[asked of all respondents, n=2,000]



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Sample Verbatim Comments

"I'm presently happy with the services I am receiving. And not too sure, what to expect, based on the questions asked in this survey. From a technical point, I do not feel I have the expertise to decide what work or upgrade is necessary. Maybe from a simpletons view (myself), as long as I am paying a reasonable amount for services and prices do not go up dramatically, then I have no need to complain. Hope my explanation/reasoning is sufficiently."

"Beyond free equipment, I'd want assurances regarding the electrical grid's capacity and reliability in Ottawa with increased demand, and how potential electricity cost increases will be managed. The offer should also consider backup power solutions due to greater electricity dependence. Furthermore, clarify contractor quality, timelines, warranty, and the long-term environmental impact considering Ontario's electricity sources. Finally, I'd be interested in knowing potential impacts on home insurance."

"I like the idea of electrifying, but NG isn't so bad, I think we should try to get other nations off of coal first. And maybe NG to hydrogen could be an option to get coal Out of steel and cement. Right now I'd like a heat pump to go with my NG furnace. It just makes sense for now."

"As already mentioned, a natural gas fireplace is essential for us as backup heat in case of power grid failure in our very frigid winters to protect from burst water pipes."

"For years natural gas was the best energy source to have, now when most people in urban settings have it, why change???? It is clean, dependable and reasonably priced, more so than other sources. It would be a monumental task to disconnect all those people that are customers as well as industrial businesses and replace equipment with what may or may not be better. Personally I think it is not a worth while idea."

"I love using Natural Gas because when there is a power outage, I still have heat from fireplace and I can still use stove top burners by manually lighting them."

"If there is a plan to switch to more energy efficient equipment at home that would help the environment and save money why wouldn't we take advantage of it. I'd be happy to see some action soon, personally my furnace and hot water needs urgent replacement but I lack funds to get something better or switch to hydro powered equipment."

Regression Analysis

Explaining Likelihood to Participate Using Multivariate Analysis

Regression Analysis:

Identifying the solution

Multivariate Regressions are a way of determining what is most important.

Regression allows us to take all the questions that may explain a key question we are interested in and see which is most important.

The regression model holds the likely suspects constant, varying one question at a time to see which questions (explanatory variables) have the greatest impact on the key question (dependent variable).

For this analysis, we are interested in **understanding what measures drive customers towards wanting to participate in the program**.

To reduce the overlap of variables to be included in the regression model, we first ran a factor analysis of all the attitudinal variables. This model contains two factors:

F: Climate concern/No negative impact from NG loss

(Q31) Overall Climate Change Concern +
(Q32) Electrification Province (reversed) +
(Q33) Electrification Home

F: Personal Efficacy

(Q35) Trust +
(Q36) Choice

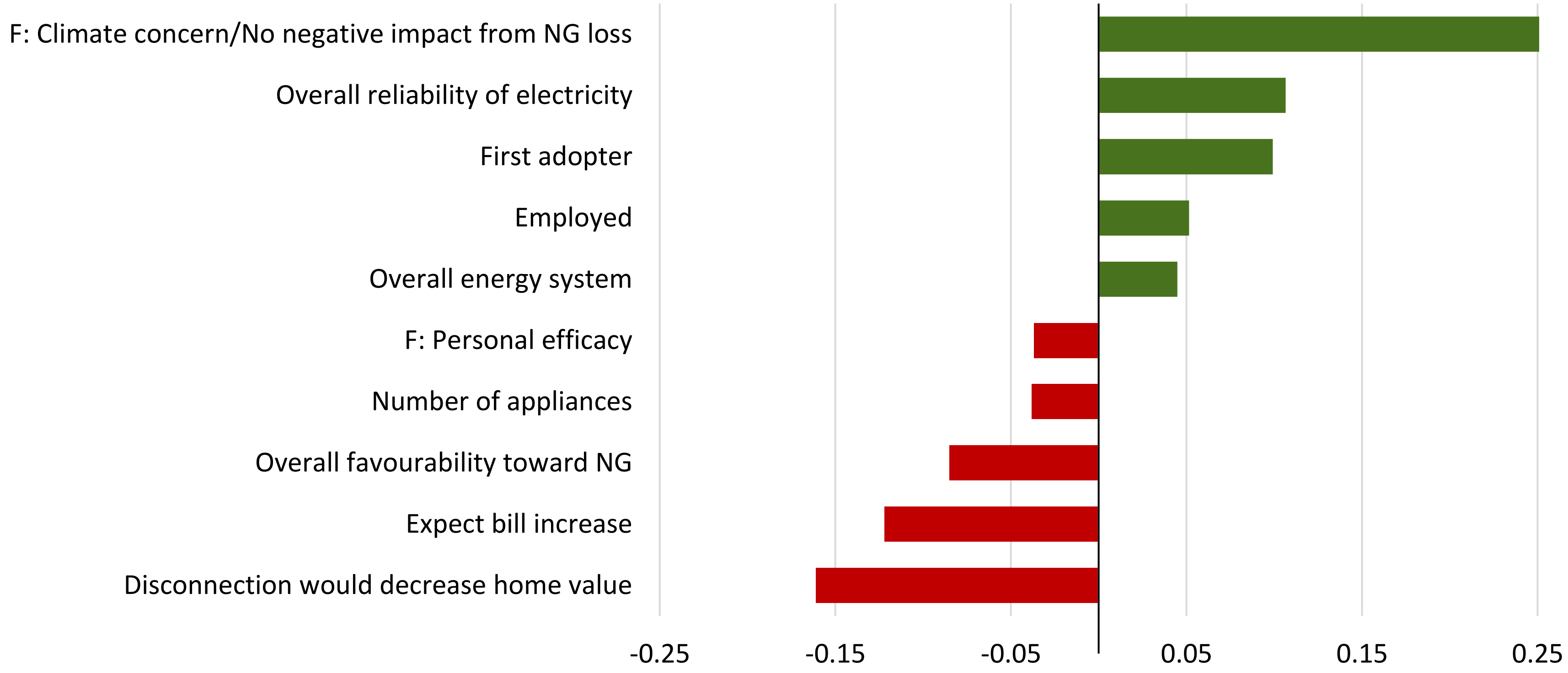
Q31 [OVERALL CLIMATE CHANGE CONCERN] I am extremely concerned about climate change
Q32 [ELECTRIFICATION PROVINCE] Eliminating the use of natural gas today would have a negative impact on Ontario's economy
Q33 [ELECTRIFICATION HOME] Eliminating the use of natural gas from my home and replacing it with electricity would have little to no impact on my quality of life
Q35 [TRUST] I prefer to do my own in-depth research when it comes to making decisions for my household
Q36 [CHOICE] It is important to me to have options to choose the type of energy I use, so that I have choice in terms of cost or the appliances I have now or would like to use in the future

Regression Model: Overall Drivers of Program Participation

What does the regression analysis tell us?

The regression results are below. The model controls for many variables such as employment, age of home, home size, and household income. The chart below displays variables that are significant in driving participation willingness at a 95% confidence level.

We see that the biggest driver of willingness to participate in the program is having concerns for the climate and confidence that switching from natural gas won't have a negative impact. The overall reliability of the electricity they receive follows as a distant second. The biggest negative drivers are the belief that disconnection would decrease participants' home value and the expectation of bill increases.



Dependent Variable

Program Participation Willingness (Q14)

Adjusted R^2 = 0.429

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Note: Chart shows standardized beta scores. All drivers shown are significant at a 95% confidence level.

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Appendix H: IRP Pilot Project Update

Southern Lake Huron Pilot Program

Design and Implementation Plan

July 4, 2025

ENBRIDGE

Table of Contents

Overview

The Southern Lake Huron ("SLH") Pilot is designed to implement demand-side IRP Alternatives ("IRPAs"), including enhanced targeted energy efficiency ("ETEE") programming and a residential demand response ("DR") program in the City of Sarnia and Village of Point Edward in the county of Lambton, Ontario. The SLH Pilot ("Pilot") covers premises located in the following areas:

- City of Sarnia and Village of Point Edward (N7S, N7T, N7V, N7W, N7X)
- Brights Grove (N0N 1C0)

The SLH Pilot offers include an enhanced version of the following Demand Side Management ("DSM") offerings:

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

As well as:

- A limited ETEE offering for electrification measures (featuring limited units of electric air source heat pumps and electric ground source heat pumps) for residential only
- Residential Demand Response program.

All incentives contributed by Enbridge Gas Inc. ("Enbridge Gas" or the "Company") through the Pilot's ETEE programs (i.e. within the Pilot area) are funded by the Pilot and not by DSM. Accordingly, all results attributed to Enbridge Gas from the Pilot's ETEE programs will be entirely attributed to the Pilot's ETEE program and not to DSM programs.

The Pilot is expected in field by the end of July 2025 and will accept projects until Q4 2026, with DR events extending into Q1 2027. Pilot reporting is expected by Q4 2027.

The SLH Pilot scope currently excludes the limited ETEE offering for natural gas-based Advanced Technologies (including thermal energy storage) and the reallocation of budget related to the natural gas-based Advanced Technologies to electrification IRPAs, pending the outcome of the OEB's Review Motion on the IRP Pilot Decision.[1] The Pilot scope in this offer plan is consistent with Enbridge's response letter[2] to the Review Motion.

Customer Insights

The delivery of energy efficiency programming is generally implemented on a customer sector basis. Enbridge Gas intends to implement its SLH Pilot using this same customer sector approach. A sectoral summary of the Enbridge Gas customers in the SLH Pilot Project Area as was filed within the Company's updated application and pre-filed evidence (EB-2022-0335) dated June 28, 2024, is shown in Table 1.

[1] EB-2025-0124, Ontario Energy Board. Notice of Review on the OEB's Own Motion, March 27, 2025.
[2] EB-2025-0124, Enbridge Gas. Scope of Review Motion Re: IRP Pilot Project Decision, April 15, 2025.

Table 1 – SLH Pilot Area Customer Sector Breakdown

Sector	Number of Customers	Number of Customers (%)	% of 2023 Weather Normalized Annual System m^3 Load
Residential	25,452	91.1%	64.7%
Commercial	1,820	6.5%	26.1%
Multi-Residential	547	2.0%	7.6%
Industrial	112	0.4%	1.5%
Total	27,931	100.0%	100%

Customers in the commercial, multi-residential and industrial sectors will be eligible for the SLH Commercial & Industrial Program offers. Within the commercial and industrial sector, understanding the size of the customer is vital to the engagement approach taken in energy efficiency programming. Table 2 provides a breakdown of commercial and industrial customers in the SLH Pilot Project area by the size of the customer on a natural gas consumption basis.[3]

Table 2 – Southern Lake Huron Commercial, Industrial, and Multi-Residential Customer Breakdown

Sector	Number of Customers	Number of Customers (%)
$<50K\ m^3$	2,356	95.0%
$50K\text{-}100K\ m^3$	84	3.4%
$100K\text{-}1M\ m^3$	39	1.6%
$>1M\ m^3$	0	0.0%
Total	2,479	100.0%

Pilot Objectives

There are no formal peak hour flow/demand savings or participation targets associated with the SLH Pilot. The primary objectives of the SLH Pilot are twofold[4,5]:

i. **Objective 1** – Develop an understanding of how ETEE and DR programs impact peak hour flow/demand. This will be investigated for various groups of customers, and for various ETEE and DR program offerings. The learnings gained will help Enbridge Gas evaluate and estimate the potential impact of such programming on other parts of its distribution system in the future, including how to:
    a. quantify actual peak hour flow reductions (m^3/hr) resulting from ETEE and DR programming by customer type. This is expected to be done by comparing peak hour flow per customer prior to and after ETEE and DR programming is implemented

[3] ETEE programming as part of the SLH Pilot Project will not be available to contract service customers.
[4] Objective 1 work is being led by the Enbridge Gas Distribution Optimization Engineering team with a third-party pilot Evaluation Contractor.
[5] Objective 2 work has been contracted by Enbridge Gas to a third-party pilot Evaluation Contractor.

b. evaluate DR event parameters on peak hour flow reductions and the adoption and persistence of customer participation in DR programming over time.

ii. **Objective 2** – Develop an understanding of how to design, deploy, and evaluate ETEE and residential DR programs. The learnings that Enbridge Gas is seeking to gain in this regard include:

   a. assessing the impacts to participant uptake resulting from increased incentives for ETEE programming
   b. assessing the effectiveness of various marketing/community engagement tactics to generate awareness of and to increase ETEE/DR program participation
   c. understanding differences in participant uptake within ETEE programming versus broad-based DSM programming
   d. understanding the costs of ETEE programming (incentives, delivery costs, promotion costs, administration costs) versus broad-based DSM programming
   e. gathering learnings on customer barriers and contractor installation and service barriers to adoption for all measures and DR to support wider market deployment in potential future IRP applications
   f. gathering initial learnings of the impact of electrification measures on the local electric grid via engagement with Local Distribution Companies ("LDCs") to support future integrated energy planning with the electric sector
   g. understanding the cost of DR programming (i.e., incentives, delivery, promotion, administration)
   h. getting a better understanding of any ratepayer equity-related implications of investing in geographic-specific offerings of ETEE and DR programming.

SLH Pilot Barriers

Many of the customer and project barriers within the existing DSM offers also apply to the SLH Pilot offers. The enhancements made when designing the pilot offers' delivery, eligibility and incentive structure aim to reduce or eliminate barriers and in turn increase participation. The barriers that are addressed by the enhanced SLH Pilot offer designs are the following:

Customer barriers

- **Limited Knowledge and Awareness**. Customers will need to become aware of the enhanced offers in short order with a limited window for pilot participation.
- **Skepticism Toward the Offer.** Customers can question the legitimacy of energy conservation offers, including why Enbridge Gas would encourage reduced natural gas use and offer incentives at full cost.
- **Financial Constraints**. Customers often lack capital for upgrades, especially for equipment that is not broken or deemed unnecessary. Economic uncertainty and inflation are putting further pressure on customers and limit available resources for investments in efficiency projects.
- **Time and Expertise Constraints.** Customers can have a lack of in-house resources with the capacity and/or expertise to assess energy options.
- **Complexity of Incentive Programs**. Customers can view incentive programs as overly complicated, discouraging engagement.

Proposed solutions

- **Simplified Qualification Process:** Reduced eligibility criteria will allow for more equipment upgrades and faster project timelines for customers.
- **Increased Financial Support and Project Guidance:** Customers will be able to receive up to 100% upfront project cost coverage on an expanded list of measures.

The SLH Pilot Offer Details sections link the enhancements made within each SLH Pilot offer to the barriers above that they aim to address.

SLH Pilot Offer Details

This section presents a description of key features of each SLH Pilot offer, eligibility criteria and incentive structure.

Direct Install

Description & Rationale

The SLH Pilot Small Business Direct Install ("DI") offer is similar to the DSM offer of the same name. The Pilot DI offer provides a turnkey solution designed to engage small to mid-sized commercial, multi-residential, and industrial customers and help them implement energy-saving projects they would not have pursued without the enhanced support and incentives offered. The Pilot DI offer will target small to mid-sized businesses with annual natural gas consumption up to 50,000 m^3, which covers approximately 95% of commercial, multi-residential, and industrial customers in the Pilot area. However, the Pilot DI offers are not exclusive to this initial outreach group.

Goals

1. Increase offer participation through streamlined customer journey at no cost to participants.
   - Provide enhanced incentives covering up to 100% of project costs, eliminating upfront investment barriers for customers.
   - Simplify the process by reducing eligibility and paying incentives directly to customers via trade allies, avoiding the requirement for customers to make an upfront investment and wait for a rebate.
   - Provide comprehensive support throughout the project lifecycle, from initial opportunity assessment to equipment installation.
   - Raise awareness of energy efficiency benefits among small businesses, emphasizing both operational and financial advantages.
2. Broaden appeal by expanding the measure mix
   - Introduce new technologies to attract a diverse customer base and meet various business needs.
   - Encourage repeat participation by offering a broader selection of measures, enabling businesses to pursue multiple energy-saving projects.
3. Leverage collaboration
   - Partner with stakeholders such as local trade allies to boost program awareness, participation, and delivery coverage.
   - Explore opportunities to enhance awareness of all available offers in the community with programs like IESO's Save on Energy initiatives
   - Engage with local municipalities to identify opportunities for synergies and community-level targeted engagement.

Minimum Eligibility Criteria

To participate in the SLH Pilot DI offer, the following minimum criteria must be met:

Customers must:

- Be a commercial, multi-residential or industrial customer with an active Enbridge Gas account.

Projects must:

- Be an upgrade to more energy-efficient equipment. Replacement of existing equipment with a like-for-like energy-efficient measure is not eligible.
- Be unrelated to an upgrade needed to satisfy safety or code requirements.
- Meet measure-specific minimum eligibility requirements.

Key Features of the SLH Pilot Direct Install Offer

Table 3 highlights the key features of the Pilot DI offer. Any feature, eligibility, customer/project requirement etc. not noted in the table (except for incentive enhancements, which are provided below the table) should be assumed consistent with the Ontario-wide DSM offers.

Table 3 – Key Features and the barriers addressed: SLH Pilot Direct Install Offer

Program Features	SLH Pilot Direct Install	Barriers Addressed
Eligible equipment list	• Air curtains – shipping door • Air curtains – pedestrian door • Dock door seals • Destratification fans • Ozone laundry • Condensing makeup air unit (“MUA”) • Demand control kitchen ventilation (“DCKV”) • Demand control ventilation (“DCV”) • Energy recovery ventilators (“ERV”) • ERV (multi-res in-suite) • Heat recovery ventilators (“HRV”) • HRV (multi-res in-suite) Measure list is subject to change over the course of the Pilot.	N/A
Enhanced Incentives	Offer provides full project cost (equipment and installation) up to a maximum incentive of $100,000 per project.	Financial Constraints
Expanded Delivery Options	Delivery of this Pilot offer will include an upfront incentive Direct Install option for all measures.	Skepticism Toward the Offer Financial Constraints. Complexity of Incentive Programs
Delivery Agent	Offer is delivered by a contracted program delivery agent responsible for managing engagement and relationships with the local trade allies for all measures.	Time and Expertise Constraints
Measure Eligibility	Measure eligibility is not restricted by the technical specifications within the Technical Resource Manual (“TRM”). If the measure meets minimum measure eligibility, it is eligible for the offer. Minimum eligibility: • An upgrade to more energy-efficient equipment; replacement of existing equipment with like-for-like energy-efficient measures is not eligible. • Not a replacement to satisfy safety or code requirements • Must meet measure-specific minimum eligibility criteria.	Complexity of Incentive Programs

Program Features	SLH Pilot Direct Install	Barriers Addressed
Measure Eligibility – Qualified Product List ("QPL")	A pre-vetted QPL will be available. Equipment that meets the minimum measure eligibility but is not included in the QPL can also be eligible for an incentive.	Complexity of Incentive Programs
Measure Eligibility – Building Type	Existing buildings and retrofit applications are eligible. For some measures, new construction is eligible.	Complexity of Incentive Programs
Customer Eligibility – Ownership Type	No restrictions on ownership type.[6]	Complexity of Incentive Programs
Customer Eligibility – Repeat Participation	Repeat participation is allowed within the timeframe of the Pilot offer if the equipment is being upgraded to a more energy efficient measure.	Financial Constraints Time and Expertise Constraints
Customer Eligibility – Number of buildings	Target businesses remain independent small medium businesses. However, franchisees/property owners who own more than one location are eligible.	Financial Constraints Complexity of Incentive Programs
Customer Eligibility – Multi-unit Residential Buildings ("MURB") Income Qualification	There are no separate enhanced SLH Pilot income-qualified offers since Pilot offers already cover full equipment cost. MURB buildings are eligible regardless of their eligibility for the Affordable Housing offer.	Complexity of Incentive Programs
Project Measurement and Verification ("M&V")	Customers must: • Agree to provide trade allies with project and site details needed to quantify annual natural gas savings • Agree to provide project and site details needed for Objective 1 M&V activities (i.e. peak hourly savings) as requested • Agree to participate in Objective 2 M&V activities (i.e. Pilot learnings) if selected	N/A
Project M&V adjustments	Annual and cumulative savings and Benefit Cost ("B/C") testing: • Reported as net using SLH Pilot-wide free-rider ("FR") and spillover ("SO") values of zero. Peak hourly savings are reported without Net-To-Gross ("NTG") adjustments or any other adjustments.	N/A
Marketing	Marketing geotargeted to the SLH Pilot area is being developed. See details in the accompanying SLH Pilot Marketing Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer
Stakeholder Engagement	Stakeholder engagement geotargeted to the SLH Pilot area is being developed. See details in the accompanying SLH Pilot Stakeholder Engagement Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer

[6] The customers served by the Southern Lake Huron system are general service customers. With the exception of 1 interruptible service contract class customer, there are no other contract class customers served by the Southern Lake Huron system.

Incentive Structure

For the measures included in the DI offer, Enbridge Gas will cover 100% of costs up to the maximum equipment and installation incentive caps per unit. The total incentive cannot exceed $100,000 per project. Enbridge Gas has structured the incentive costs based on the best available data (invoices, market research, past project data). The measure incentive maximums are meant to be internal facing for the delivery agent rather than external facing incentive maximums to the customer. All SLH Pilot equipment and installation incentive values per unit in Table 4 are currently under review and will be finalized prior to Pilot launch.

Table 4 – SLH Pilot Direct Install Incentive Structure by Measure

Measure Name	SLH Pilot DI Maximum Equipment Incentive*	SLH Pilot DI Maximum Installation Incentive*	Equipment and Installation Cost Covered in SLH Pilot DI (Maximum Incentive)*
Air Curtain Shipping Door (Dock In): 8x8 to 10x10	$6,000 per unit	$4,000 per unit	Up to 100% ($10,000 per Unit)
Air Curtain Shipping Door (Drive Thru): 10x10 to 20x20	$15,000 per unit	$4,000 per unit	Up to 100% ($19,000 per Unit)
Dock Door Seals - Compression & Shelter: 8x8 8x10 10x10	$4,000 per unit	$2,000 per unit	Up to 100% ($6,000 per Unit)
Air Curtain Pedestrian Doors: Single, Double & w/Vestibule	$10,000 per unit	$4,000 per unit	Up to 100% ($14,000 per Unit)
Destratification Fans: 20 & 24 Ft Fans	$10,000 per unit	$5,000 per unit	Up to 100% ($15,000 per Unit)
Demand Control Kitchen Ventilation	$20,000 per unit	$15,000 per unit	Up to 100% ($35,000 per Unit)
Ozone Laundry	$25,000 per unit	$5,000 per unit	Up to 100% ($30,000 per Unit)
Condensing Makeup Air (Constant, 2 speed & VFD)	$30,000 per unit	$10,000 per unit	Up to 100% ($40,000 per Unit)
Demand Control Ventilation	$10,000 per unit	$5,000 per unit	Up to 100% ($15,000 per Unit)
Energy Recovery Ventilator	$50,000 per unit	$10,000 per unit	Up to 100% ($60,000 per Unit)
Energy Recovery Ventilator MURB In-Suite	$50,000 per building	$10,000 per building	Up to 100% ($60,000 per Building)
Heat Recovery Ventilator	$50,000 per unit	$10,000 per unit	Up to 100% ($60,000 per unit)
Heat Recovery Ventilator MURB In-Suite	$50,000 per building	$10,000 per building	Up to 100% ($60,000 per Building)

**The maximum equipment and installation incentive values are currently under review and will be finalized. Additionally, the SLH Pilot will be exploring what should be considered as eligible installation costs.*

Delivery Approach

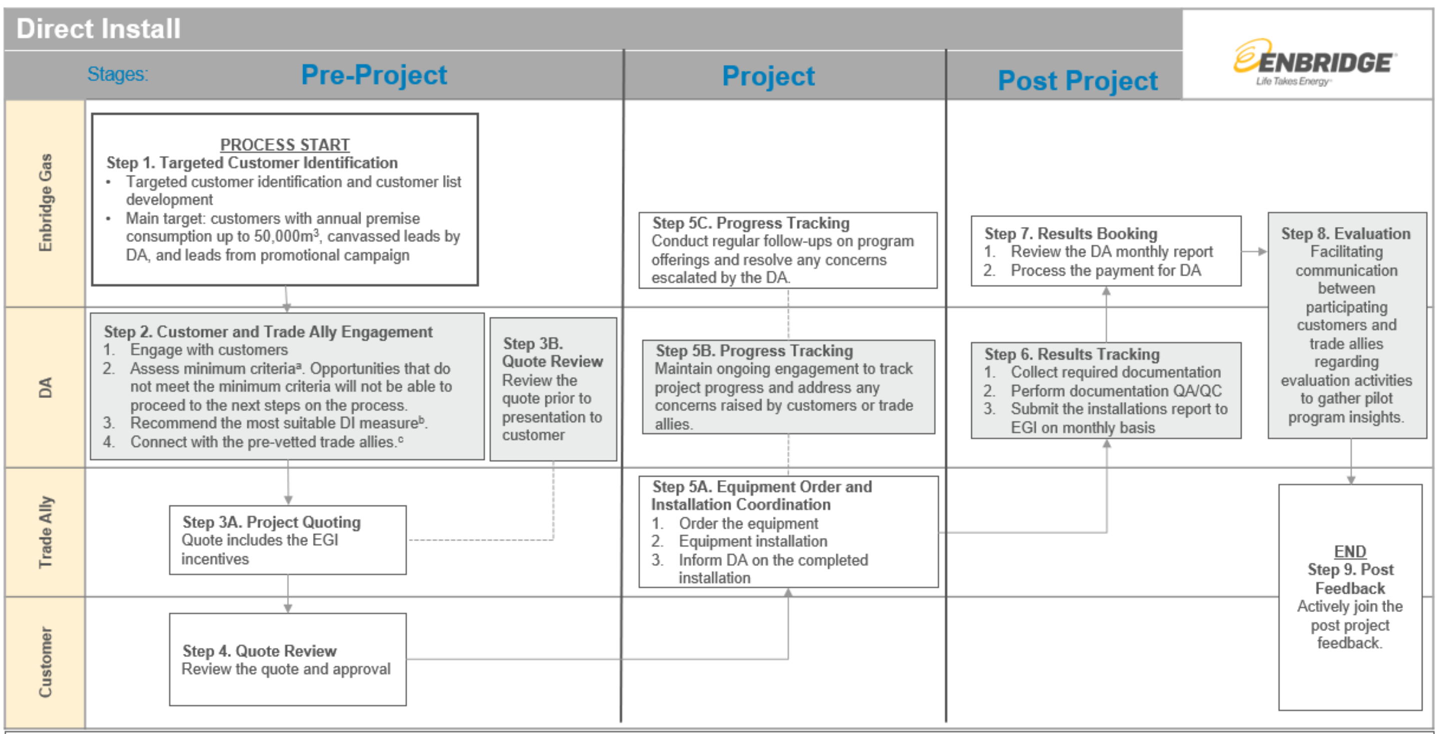
The SLH Pilot DI offer will be delivered by a contracted delivery agent (“DA”), who will manage relationships with local trade allies to deliver turnkey solutions customized for smaller customers within the Pilot area. The DA will recruit and onboard local trade allies, coordinate outreach efforts, identify opportunities, connect customers with these trade allies, and provide support throughout the process from engagement to equipment installation. This includes eligibility confirmation, managing and reviewing contractor[7] costs, authorizing work, and reviewing/gathering submitted project documentation. A detailed delivery plan is currently under development with the DA and will be finalized prior to Pilot launch.

To support effective outreach, Enbridge Gas will develop a targeted customer list to maximize program participation. Additionally, lead generation may be driven by the DA through leveraging existing customer relationships, or word-of-mouth referrals from previous participants. Enbridge Gas will also seek to identify leads via promotional campaigns or direct inquiries from interested customers.

To simplify equipment selection, Enbridge Gas will establish a Qualified Product List (“QPL”) that will help the DA provide informed recommendations and offer customers access to pre-approved equipment options. The QPL includes equipment that meets all the TRM eligibility criteria. Measure eligibility is not restricted by inclusion on the QPL. If the measure meets minimum measure eligibility, it is eligible for the offer.

The delivery process flow is outlined in Table 5.

Table 5 – Delivery Process Flow for the SLH Pilot Direct Install Offer



Notes:
a. The minimum criteria assessment involves evaluating the potential for gas savings by analyzing the available space and existing equipment at the customer's site.
b. Customers with more complex systems and interested to install multiple measures beyond those listed on the Qualified Product List (QPL) will continue working with ESA through the custom path.
c. Customers interested in installing equipment listed on the QPL through their own contractor will continue working with ESA for guidance on incentive applications and follow the prescriptive downstream process.

[7] Contractors sell, source, and install energy efficiency measures.

Prescriptive Downstream

Description and Rationale

The SLH Pilot Prescriptive Downstream offer is similar to the DSM Prescriptive Downstream offering and is tailored for small commercial, multi-residential, and industrial customers. This offer includes all measures eligible under the Direct Install program offer while providing customers the flexibility to work with their own contractors outside the Direct Install trade ally network. It incents up to 100% coverage for both equipment and installation costs for all eligible measures, eliminating financial barriers and facilitating the efficient adoption of energy-saving technologies. This updated offer will target small to mid-sized businesses with annual natural gas consumption of up to 50,000 m^3, which covers approximately 95% of commercial, multi-residential, and industrial customers in the Pilot area. However, the Pilot Prescriptive Downstream offers are not exclusive to this initial outreach group.

Goals

1. Increase offer participation through engagement and enhanced incentives
   - Provide incentives covering up to 100% of project costs, removing financial barriers for customers.
   - Simplify participation by offering flexibility for customers to work with their own contractors while maintaining full incentive coverage.
   - Provide comprehensive support throughout the project lifecycle, from initial opportunity assessment to equipment installation.
   - Raise awareness of energy efficiency benefits among small businesses, emphasizing both operational and financial advantages.
2. Leverage collaboration
   - Provide trade allies with resources and ongoing support during the incentive application process for customers.
   - Grow the number of trade allies actively engaged with the offer to expand market reach and program delivery.
   - Explore opportunities to enhance awareness of available offers in the community with programs like IESO's Save on Energy initiatives
   - Engage with local municipalities to identify opportunities for synergies and community-level targeted engagement.

Minimum Eligibility Criteria

To participate in the SLH Pilot Prescriptive Downstream offer, the following minimum criteria must be met:

Customers must:

- Be a commercial or industrial customer with an active Enbridge Gas account.

Projects must:

- Be an upgrade to more energy-efficient equipment. Replacement of existing equipment with a like-for-like energy-efficient measure is not eligible.
- Be unrelated to an upgrade needed to satisfy safety or code requirements.
- Meet measure-specific minimum eligibility requirements.

Key Features of the SLH Pilot Prescriptive Downstream Offer

Table 6 highlights key features of the SLH Pilot Prescriptive Downstream Offer aimed at addressing the barriers and challenges within this target market. Any feature, eligibility, customer/project requirement etc. not noted in the table (except for incentive enhancements, which are provided below the table) should be assumed consistent with the Ontario-wide DSM offers.

Table 6 – Key Features and the barriers addressed: SLH Pilot Prescriptive Downstream Offer

Program Features	SLH Pilot Prescriptive Downstream	Barriers Addressed
Eligible equipment list	• Air curtains – shipping door • Air curtains – pedestrian door • Dock door seals • Destratification fans • Ozone laundry • Condensing makeup air unit • Demand control kitchen ventilation ("DCKV") • Demand control ventilation ("DCV") • Energy recovery ventilators ("ERV") • ERV (multi-res in-suite) • Heat recovery ventilators ("HRV") • HRV (multi-res in-suite) • Hybrid Rooftop Unit ("Hybrid RTU") – This measure is available only in SLH Prescriptive Downstream and not in SLH Direct Install Measure list is subject to change over the course of the Pilot.	N/A
Enhanced Incentives	Offer provides 100% project cost coverage (equipment and installation), except for Hybrid RTU for which the incentive structure will remain consistent with the current DSM offer. Maximum incentive is $100,000 per project.	Financial Constraints
Measure Eligibility	Measure eligibility is not restricted by the technical specifications within the Technical Resource Manual ("TRM"). If the measure meets minimum measure eligibility, it is eligible for the offer. Minimum eligibility: • An upgrade to more energy-efficient equipment; replacement of existing equipment with like-for-like energy-efficient measures is not eligible. • Not a replacement to satisfy safety or code requirements. • Must meet measure-specific minimum eligibility criteria.	Complexity of Incentive Programs
Measure Eligibility – Qualified Product List ("QPL")	A pre-vetted QPL list will be available. Equipment that meets the minimum measure eligibility but is not included in the QPL can also be eligible for an incentive.	Complexity of Incentive Programs
Measure Eligibility – Building Type	Existing buildings and retrofit applications are eligible. For some measures, new construction is eligible.	Complexity of Incentive Programs

Program Features	SLH Pilot Prescriptive Downstream	Barriers Addressed
Customer Eligibility – Ownership Type	No restrictions on ownership type.[8]	Complexity of Incentive Programs
Customer Eligibility – Repeat Participation	Repeat participation is allowed within the timeframe of the Pilot offer if the equipment is being upgraded to a more energy efficient measure.	Financial Constraints Time and Expertise Constraints
Customer Eligibility – Number of Buildings	Target businesses remain independent small medium businesses. However, franchisees/property owners who own more than one location are eligible.	Financial Constraints Complexity of Incentive Programs
Customer Eligibility – Customer Gas Consumption	All businesses within the Pilot area are eligible.	N/A
Customer Eligibility – Quantity of Equipment per Project	High-volume projects (more than 10 units) will be reviewed if the customer incentive exceeds $100,000 per project.	Complexity of Incentive Programs
Customer Eligibility – Multi-unit Residential Buildings (“MURB”) Income Qualified	There are no separate enhanced SLH Pilot income-qualified offers since Pilot offers already cover full equipment cost. MURB buildings are eligible regardless of their eligibility for the Affordable Housing offer.	Complexity of Incentive Programs
Project M&V	Customers must: • Agree to provide trade allies with project and site details needed to quantify annual gas savings • Agree to provide trade allies with project and site details needed for Objective 1 M&V activities (i.e. peak hourly savings) as requested • Agree to participate in Objective 2 M&V activities (i.e. Pilot learnings) if selected	N/A
Project M&V adjustments	Annual and cumulative savings and B/C testing: • Reported as net using SLH Pilot-wide FR and SO values of zero. Peak hourly savings are reported without NTG adjustments or any other adjustments.	N/A
Marketing	Marketing geotargeted to the SLH Pilot area is being developed. See details in the accompanying SLH Pilot Marketing Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer

[8] The customers served by the Southern Lake Huron system are general service customers. With the exception of 1 interruptible service contract class customer, there are no other contract class customers served by the Southern Lake Huron system.

Program Features	SLH Pilot Prescriptive Downstream	Barriers Addressed
Stakeholder Engagement	Stakeholder engagement geotargeted to the SLH Pilot area is being developed. See details in the accompanying SLH Pilot Stakeholder Engagement Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer

Incentive Structure

For the measures included in the SLH Pilot Prescriptive Downstream offer (Table 7), Enbridge Gas will cover 100% of project costs up to the maximum equipment and installation incentive per unit. The only exception is the Hybrid Rooftop Unit ("RTU"), for which the incentive cap structure will remain consistent with the current DSM offer. The total incentive cannot exceed $100,000 per project. Enbridge Gas has structured the incentive costs based on the best available data (invoices, market research, past project data). The measure incentive maximums are meant to be internal facing for the delivery agent rather than external facing incentive maximums to the customer. Business partner incentives will remain consistent with the current DSM offer. All SLH Pilot equipment and installation incentive values per unit in Table 7 are currently under review and will be finalized prior to Pilot launch.

Table 7 – SLH Pilot Presriptive Downstream Incentive Structure by Measure

Measure Category	SLH Pilot Prescriptive Downstream Maximum Equipment Incentive*	SLH Pilot Prescriptive Downstream Maximum Installation Incentive*	SLH Pilot Prescriptive Downstream Maximum Total Incentive*
Air Curtain Shipping Door (Dock In): 8x8 to 10x10	$6,000 per unit	$4,000 per unit	$10,000 per unit
Air Curtain Shipping Door (Drive Thru): 10x10 to 20x20	$15,000 per unit	$4,000 per unit	$19,000 per unit
Dock Door Seals - Compression & Shelter: 8x8, 8x10, 10x10	$4,000 per unit	$2,000 per unit	$6,000 per unit
Air Curtain Pedestrian Doors: Single, Double & w/Vestibule	$10,000 per unit	$4,000 per unit	$14,000 per unit
Destratification Fans: 20 & 24 Ft Fans	$10,000 per unit	$5,000 per unit	$15,000 per unit
Demand Control Kitchen Ventilator	$20,000 per unit	$15,000 per unit	$35,000 per unit
Ozone Laundry	$25,000 per unit	$5,000 per unit	$30,000 per unit
Condensing Make-Up Air Unit (Constant, 2 speed & VFD)	$30,000 per unit	$10,000 per unit	$40,000 per unit
Demand Control Ventilation	$10,000 per unit	$5,000 per unit	$15,000 per unit
Energy Recovery Ventilation	$50,000 per unit	$10,000 per unit	$60,000 per unit

Measure Category	SLH Pilot Prescriptive Downstream Maximum Equipment Incentive*	SLH Pilot Prescriptive Downstream Maximum Installation Incentive*	SLH Pilot Prescriptive Downstream Maximum Total Incentive*
Energy Recovery Ventilation MURB In-Suite	$50,000 per building	$10,000 per building	$60,000 per building
Heat Recovery Ventilation	$50,000 per unit	$10,000 per unit	$60,000 per unit
Heat Recovery Ventilation MURB In-Suite	$50,000 per building	$10,000	$60,000 per building
Hybrid Rooftop Unit (Hybrid RTU)	Match DSM incentives	N/A	Match DSM incentives

**The maximum equipment and installation incentive values are currently under review and will be finalized. Additionally, the SLH Pilot will be exploring what should be considered as eligible installation costs.*

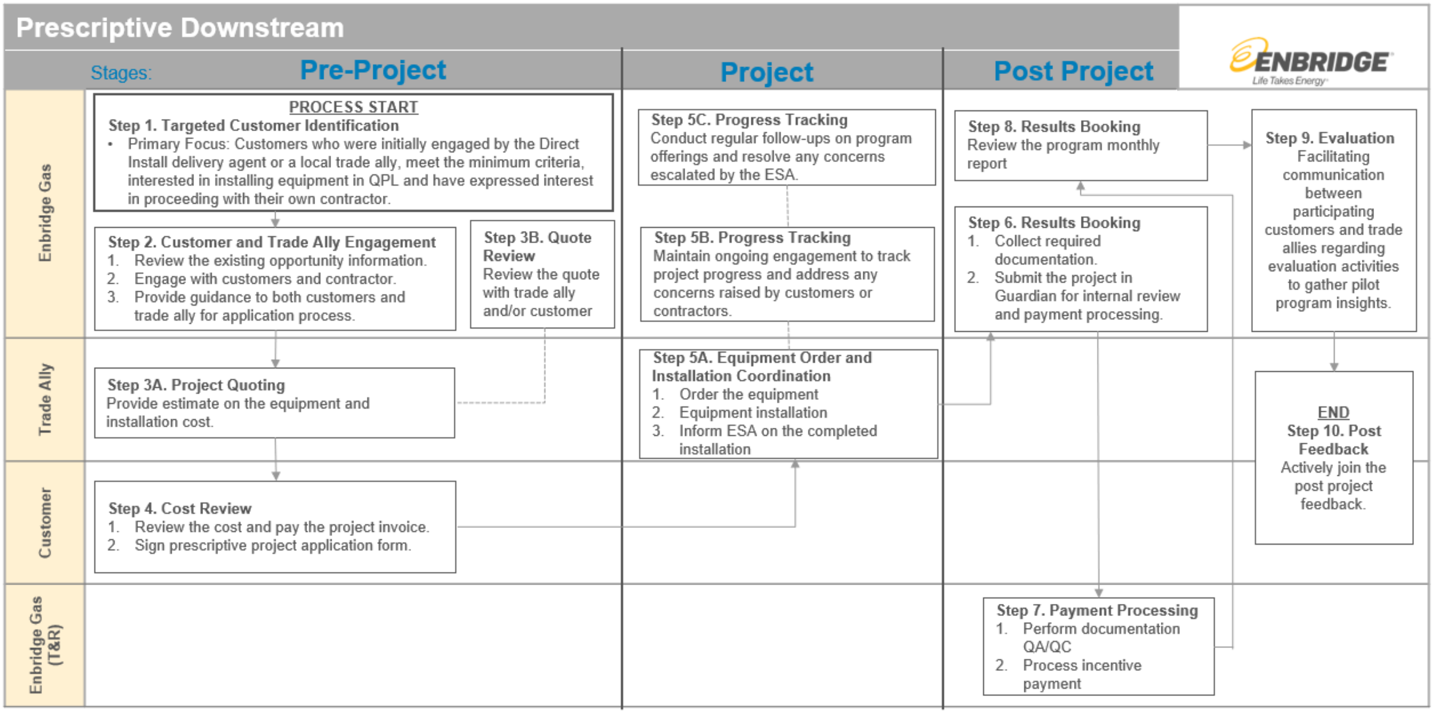
Delivery Approach

The delivery of the SLH Pilot Prescriptive Downstream offer will be led by an Enbridge Gas Energy Solutions Advisor (“ESA”) who will manage the relationships with customers and trade allies that are not part of the SLH Pilot DI network. This will provide flexibility for the customers to participate in the offer and receive incentives despite working with their own selected trade ally. The ESA will work with both customers and trade allies on the application process and provide support from engagement to the equipment installation. Additionally, Enbridge Gas’s IRP Pilot project team includes a dedicated Program Advisor who will collaborate closely with the ESA to address escalated market-related inquiries and assist in supporting engagement efforts between the ESA, customers, and trade allies.

To simplify equipment selection, Enbridge Gas will establish a Qualified Product List (“QPL”) which will help the ESA provide informed recommendations and offer customers access to pre-approved equipment options. The QPL includes equipment that meets TRM eligibility criteria. However, equipment that meets the minimum criteria but is not included in the QPL could also be eligible for full measure cost coverage up to measure caps.

Details of the delivery process flow are outlined in Table 8.

Table 8 – Delivery Process Flow for the SLH Pilot Prescriptive Downstream Offer



ENBRIDGE

Commercial and Industrial Custom Offers

The SLH Pilot Commercial and Industrial Custom offers are similar to the Ontario-wide DSM offers of the same name. Key SLH Pilot custom offer elements include:

- Reduced customer, project and measures restrictions in comparison to the similar DSM offers.
- Increased customer project implementation incentives (typically awarded based on dollar per cubic meter saved)
- Opportunity identification through site walk-throughs and/or assessments
- Quantification of savings leveraging standard proprietary calculators such as eTools, other engineering calculations as verified by Enbridge Gas's Technical Services team, or metering where savings cannot be quantified through established calculations
- Audit/assessment/metering incentives
- Portfolio benchmarking and prioritization of opportunities to support business case development
- Connecting customers to implementation service providers
- Other elements consistent with the Ontario-wide DSM offers unless specifically highlighted in this SLH Pilot offer plan

The SLH Pilot Commercial and Industrial Custom offers target customers with annual gas consumption exceeding 50,000 m^3. This is a small market with approximately 83 customers. However, the Pilot custom offers are not exclusive to this group.

Initial ESA outreach will focus on customers that have expressed interest in the Pilot through early targeted communications and that have or are in the process of getting hourly data capability installed on their meters. However, the Pilot Custom offers are not exclusive to this initial outreach group.

Goals

1. Increase offer participation through engagement and enhanced incentives
    - Provide enhanced incentives covering up to 100% of project cost, eliminating investment barriers for customers.
    - Raise awareness of energy efficiency benefits, emphasizing operational and financial advantages for customers.
    - Provide tailored educational resources, technical guidance, and comprehensive support throughout the project lifecycle from opportunity assessment to implementation.
2. Leverage collaboration
    - Build customer trust and satisfaction by delivering personalized service and ongoing support, positioning Enbridge Gas as a valuable partner in energy efficiency.
    - Partner with stakeholders such as local trade allies to boost program awareness, participation, and delivery coverage.
    - Explore opportunities to enhance awareness of available offers in the community with programs like IESO's Save on Energy initiatives
    - Engage with local municipalities to identify opportunities for synergies and community-level targeted engagement.

Minimum Eligibility Criteria

To participate in the SLH Pilot custom offers, the following minimum criteria must be met:

- Customer criteria:
    - Be a commercial, multi-residential or industrial customer with an active Enbridge Gas account. Customers must agree to provide site and project details to quantify annual and peak period gas savings as requested.
- Project criteria:
    - Custom solutions with the potential to impact annual natural gas consumption are eligible. This remains consistent with the equivalent custom DSM offers. While Objective 1 of the SLH Pilot is to estimate impacts to peak period

(hourly) flows and demands[9], the SLH Pilot Commercial and Industrial custom offers will be available to all project types that are eligible within the similar DSM custom offerings.

- Replacement of equipment to satisfy safety or code requirements is not eligible.
- Incentive quotes must be received directly or indirectly from Enbridge Gas for their project prior to installation of equipment.

Key Features of the SLH Pilot Commercial and Industrial offers

The table below highlights the key features of the Pilot Commercial and Industrial custom offers. Any feature, eligibility, customer/project requirement etc. not noted in the table (except for incentive amounts, which are provided below the table) should be assumed consistent with the Ontario-wide DSM offers.

Table 9 – Key Features and the barriers addressed: SLH Pilot Custom Commercial and Industrial Offers

Program Features	SLH Pilot Commercial and Industrial Custom	Barriers Addressed
Initial target market	All businesses within the Pilot area are eligible.	N/A
Income-qualified customers	There are no separate enhanced SLH Pilot income-qualified offers since Pilot offers already cover full equipment cost. Income-qualified customers are eligible regardless of their eligibility for the Affordable Housing offer.	Complexity of Incentive Programs
Incentive structure	Incentives shall not exceed 100% of the total project cost, excluding elements of the project cost not associated with energy conservation.	Financial Constraints
Incentive estimates	Incentives are based on Enbridge Gas approved natural gas savings estimates relative to an approved baseline, as determined by Enbridge Gas. However, there is a potential exception for custom projects that include a measure offered in the SLH Pilot Direct Install or SLH Pilot Prescriptive Downstream offers. See the minimum incentive guarantee.	Financial Constraints
Minimum incentive guarantee	Customers who incorporate eligible measure(s) from the SLH Pilot Direct Install or Prescriptive Downstream offers into their custom project will receive a minimum incentive of 100% of that prescriptive measure's costs (including equipment and installation, up to the per measure cap). This prevents a disincentive for customers who are going beyond the installation of a standalone prescriptive measure in the scenario where the custom offer $/m^3 rate results in a project incentive that is smaller than the incentive offered on the standalone prescriptive measure.	Financial Constraints

[9] Measures that are expected to impact peak period (hourly) flows and demands are those associated with space heating end-use loads, particularly during winter morning periods. However, other end-uses can also impact peak period flows.

Program Features	SLH Pilot Commercial and Industrial Custom	Barriers Addressed
Project timing	Customers must install and commission the project before Q2 2027 for the incentive quote to remain valid. Date is subject to change.	Time and Expertise Constraints
TRM restriction	If a TRM substantiation document exists for a measure, the measure should be put through the SLH Pilot DI or Prescriptive Downstream offer unless multiple measures with interactive effects are involved, and/or the incentive calculated using the custom $/m^3 rate is closer to total cost coverage.	Complexity of Incentive Programs
Total Resource Cost ("TRC") criteria	There are no specific TRC-related criteria including meeting a TRC ratio of 1 at either the project and Pilot offer level.	Complexity of Incentive Programs
Marketing	Marketing geotargeted to the SLH Pilot area is being developed. See details in the accompanying SLH Pilot Marketing Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer
Stakeholder Engagement	Stakeholder engagement geotargeted to the SLH Pilot area is being developed. See details in the accompanying SLH Pilot Stakeholder Engagement Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer
Project M&V	Customers must: Agree to provide Enbridge Gas with project and site details needed to quantify annual natural gas savings Agree to provide Enbridge Gas project and site details needed for Objective 1 M&V activities (i.e. peak hourly savings) as requested Agree to participate in Objective 2 M&V activities (i.e. Pilot learnings) if selected	Complexity of Incentive Programs
Project M&V adjustments	Annual and cumulative savings and B/C testing: - Reported as net using SLH Pilot-wide FR and SO values of zero. - Reported with best available custom project savings verification results applied. Peak hourly savings are reported without NTG adjustments or custom program savings verification ("CPSV") adjustments.	N/A

Incentive Structure

All incentive values in Table 10 are currently under review and will be finalized prior to Pilot launch. The custom rates were determined by assessing the current Limited Time Offers ("LTOs") available under the DSM custom offers and ensuring SLH Pilot rates are not less than what is currently being offered.

Table 10 – SLH Pilot Custom Commercial and Industrial Incentives

Customer Type	SLH Pilot Incentive Structure
General Commercial Customers	$2.00 per estimated annual natural gas savings (m³), up to 100% of total project cost (including equipment and installation), capped at $250,000 per project.
Institutional Customers (e.g., hospitals and post-secondary institutions)	$2.00 per estimated annual natural gas savings (m³), up to 100% of total project cost (including equipment and installation), capped at $500,000 per project.
Industrial Customers	$2.00 per estimated annual natural gas savings (m³), up to 100% of total project cost (including equipment and installation), capped at $500,000 per project.
Industrial Agriculture Customers	New Construction: $1.00 per estimated annual natural gas savings (m³), up to 100% of total project cost (including equipment and installation). Retrofit: $2.00 per estimated annual natural gas savings (m³), up to 100% of total project cost (including equipment and installation). Incentive cannot exceed $500,000 per project.
Minimum incentive guarantee	Customers who incorporate eligible measure(s) from the SLH Pilot Direct Install or Prescriptive Downstream offers into their custom project will receive a minimum incentive of 100% of that measure's costs (including equipment and installation, up to the prescriptive per measure cap). The relevant overall maximum incentive for the custom project remains.
Energy Assessment Incentives	100% of eligible costs up to $20,000

Jointly with the IESO, Enbridge is providing industrial and agriculture customers incentives for the following training initiatives: Building Operator Certification ("BOC"), Certified Energy Manager ("CEM"), and Dollars to $ense ("D2$") workshops. Incentive amounts in the SLH Pilot area will be kept consistent with those offered in this Ontario-wide DSM offer.

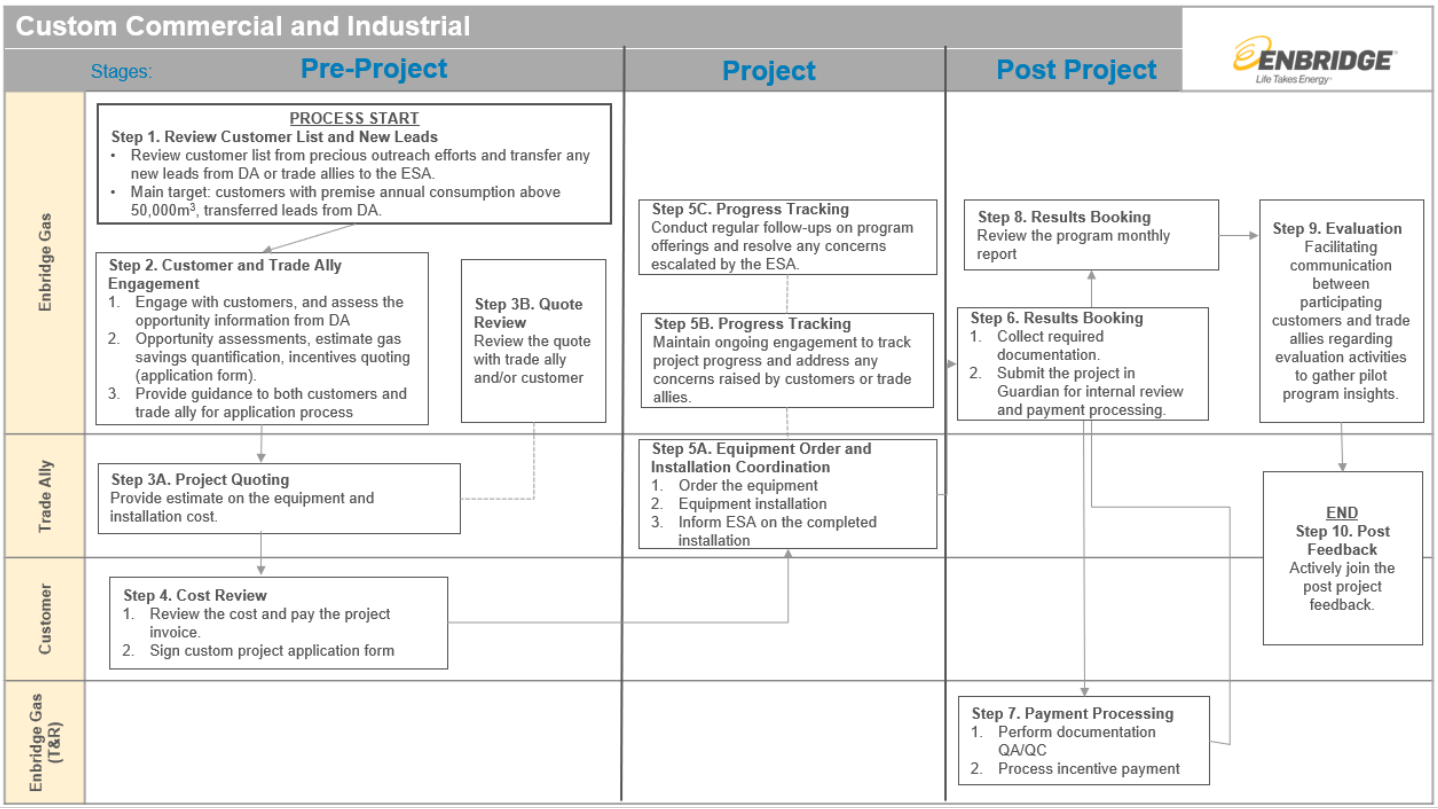
Workshop	EGI Incentives		IESO Incentives		Max Joint Incentive
	Max %	Max $	Max %	Max $	
BOC	30%	$750	45%	$1,600	$2,350
CEM	30%	$900	45%	$1,600	$2,500
D2$	30%	$200/day (max 3 days)	45%	$300/day (max 3 days)	$500/day (max 3 days)

Delivery Approach

The delivery of the SLH Pilot Commercial and Industrial Custom offers will be led by an Enbridge Gas Energy Solutions Advisor ("ESA") who will manage relationships with customers and trade allies. The ESA will provide guidance on the application process and provide support from engagement to the equipment installation. Additionally, Enbridge Gas's IRP Pilot project team includes a dedicated Program Advisor who will collaborate closely with the ESA to address escalated market-related inquiries and assist in supporting engagement efforts between the ESA, customers, and trade allies.

Details of the delivery process flow are outlined in Table 11.

Table 11 – Delivery Process Flow for the SLH Commercial and Industrial Custom Offers



Residential Whole Home Offer

Description & Rationale

The SLH Pilot Residential Whole Home Offer is similar to the Enbridge Gas Ontario-wide Home Renovation Savings ("HRS") offer. The Pilot offer provides a holistic approach to residential home renovations by offering customers full cost coverage towards their home energy assessments, insulation upgrades, window replacement and some water heating mechanicals. The intent is to ensure customers have the information required through the home energy assessment to be aware of the holistic opportunities throughout their home, and through offering full cost coverage to motivate homeowners to pursue energy savings across additional measures than they may have not otherwise undertaken by taking a whole home view.

Goals

1. Increase offer participation through focused engagement and enhanced incentives
   - Provide enhanced incentives covering up to 100% of project costs, eliminating investment barriers for customers.
   - Simplify customer access to incentives by providing the option to pay incentives up front directly to customers via trade allies, avoiding the requirement for customers to make an upfront investment and wait for a rebate.
   - Provide comprehensive support throughout the project lifecycle from initial energy assessment to installation.

2. Leverage collaboration
   - Build customer trust and satisfaction by delivering personalized service and ongoing support, positioning Enbridge Gas as a valuable partner in energy efficiency.
   - Partner with stakeholders such as local trade allies to boost program awareness, participation, and delivery coverage.
   - Explore opportunities to enhance awareness of available offers in the community with programs like IESO's Save on Energy initiatives.
   - Engage with local municipalities to identify opportunities for synergies and community-level targeted engagement.

Minimum Eligibility Criteria

To participate in the SLH Pilot Whole Home offer, the following minimum criteria must be met:

- Have an active Enbridge Gas account.
- Be an eligible customer type that primarily space-heats their dwelling type with natural gas at the time of the pre-assessment and/or the post-assessment.
- Complete a pre-assessment, install at least one qualified measure and complete a post-assessment within the Pilot window.
- Have an NRCan licensed Registered Energy Advisor[10] ("REA") conduct the pre- and post-assessments who is an employee or subcontractor of an Enbridge Gas approved Service Organization[11].
- Participants who completed their initial assessment on or after January 28, 2025 through the current DSM HRS offer can transfer to the SLH Pilot offer if the post-assessment has not yet been completed.

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[10] Registered Energy Advisors ("REA") are certified energy advisors who conduct EnerGuide Assessments to inform customers about energy efficiency opportunities in their homes. These assessments are also used to measure whole-home energy savings after a post-assessment is completed.
[11] Service Organizations are licensed through Natural Resources Canada ("NRCan") and perform several key functions such as HOT2000 training, quality assurance and quality control, and employing a team of REAs. These advisors are certified to perform the pre- and post-assessments.

IRP Pilot Offer Key Features

Table 12 highlights key features of the SLH Whole Home offer. Any feature, eligibility, customer/project requirement etc. not noted in the table (except for incentive enhancements, which are provided below the table) should be assumed consistent with the current in-field Ontario-wide DSM offer.

Table 12 – Key Program Features and the barriers addressed: SLH Pilot Residential Whole Home

Key Program Features	IRP Pilot Residential Whole Home Custom Offer	Barriers Addressed
Expanded customer eligibility	Eligible residential dwelling types for the offering are listed below: • Single detached and semi-detached homes. • Row housing. • Townhomes. • Mobile homes on a permanent foundation. • Microbusiness (small businesses operating from former residential dwellings with residential sized heating and cooling equipment.) The following residential dwelling types are not eligible: • Homes that are not space-heated by natural gas at either the time of the Pre-Audit or the Post-Audit. • Homes less than 6 months old. • Multi-unit residential buildings ("MURB") with more than 3 stories or building area larger than 600 m^2, including retirement homes. • Low-rise MURB's (3 stories or less with a building area of 600 m^2 or less).	Complexity of Incentive Programs
Expanded Delivery Options	Delivery of this Pilot offer will include an upfront incentive Direct Install option as well as a back-end incentive Rebate option. See the Delivery Approach section below for more detail.	Skepticism Toward the Offer Financial Constraints. Complexity of Incentive Programs
Eligible Measures List	• Attic Insulation • Exposed Floor Insulation • Exterior Wall Insulation • Basement Insulation • Crawl Space Insulation • Air Sealing • Window/Door/Skylight/Sliding Door (2025 only) • Water Heaters	N/A
Reduction in minimum measures required	Customers must install at least **one** qualified insulation measure. For clarity, Window/Door/Skylight/Sliding Doors, Heat Pump Water Heaters and Air sealing must be done in conjunction with an eligible insulation measure.	Complexity of Incentive Programs

Key Program Features	IRP Pilot Residential Whole Home Custom Offer	Barriers Addressed
Elimination of maximum time between pre- and post-home energy assessment	Customers must complete the post-upgrade home energy assessment by the end of the Pilot period	Complexity of Incentive Programs
Enhanced Incentives – measure costs	Offer provides full project cost coverage (equipment and installation) subject to approval by Enbridge Gas prior to start of work. Customers are eligible for up to $15,000 for eligible energy efficiency measures.	Financial Constraints
Enhanced Incentives – assessment costs	Enbridge Gas will cover the combined cost of the pre- and post-assessments upon successfully installing qualified measures and satisfying all other program requirements. Combined costs of assessments above $1,000 will be reviewed by Enbridge Gas prior to approval.	Financial Constraints
Project M&V	Annual and cumulative savings and B/C testing: • Reported as net using SLH pilot-wide FR and SO values of zero. Peak hourly savings are reported without Net-To-Gross adjustments or any other adjustments.	N/A
Marketing	Marketing geotargeted to the SLH pilot area is being developed. See details in the accompanying SLH Pilot Marketing Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer
Stakeholder Engagement	Stakeholder engagement geotargeted to the SLH pilot area is being developed. See details in the accompanying SLH Pilot Stakeholder Engagement Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer

Incentive Structure

Enbridge Gas will cover up to 100% of insulation measure and installation costs. For Windows/Doors/Skylights/Sliding Doors, and Heat Pump Water Heaters, the Pilot incentive amounts will remain consistent with the in-field DSM offer. Insulation between two interior spaces is not eligible for an incentive and must be separated on an invoice. Measures for which an incentive is being claimed must be separated and itemized on an invoice.

All SLH Pilot equipment and installation incentive values per unit are currently under review and will be finalized prior to Pilot launch. The total incentive cannot exceed the project cost of the upgrade or $15,000 per participant.

Table 13 – SLH Pilot Residential Whole Home Incentive Structure by Measure

Item	Measure	Qualifiers	SLH Pilot Maximum Incentive
Energy Assessments	Pre- and post-install Energy Assessments	Can only receive this once per premise.	Up to full cost coverage
Exposed Floor Insulation	Exposed floor	Minimum R-20	Up to full cost coverage
Exterior Wall Insulation	Exterior wall	Minimum R-7.5	Up to full cost coverage
Attic Insulation	Attic	Increase attic insulation to at least R-50 from greater than R-12	Up to full cost coverage
	Cathedral/Flat Roof	Increase cathedral ceiling/flat roof insulation to at least R-20 from R-12 or less. Increase cathedral ceiling/flat roof insulation to at least R-28 from R-25 or less.	Up to full cost coverage
Basement Insulation	Basement wall	For adding insulation value greater than R-10	Up to full cost coverage
	Basement slab	Minimum R-3.5	Up to full cost coverage
	Foundation header	Minimum R-20	Up to full cost coverage
Exterior Crawl Space Insulation	Exterior crawl space wall	Minimum R-10	Up to full cost coverage
	Crawl space ceiling	Minimum R-24	Up to full cost coverage
Air Sealing	Air Sealing	Achieve 10% or more above the base target on your Renovation Upgrade Report	Up to full cost coverage
	Air Sealing	Achieve the target in your Renovation Upgrade Report.	Up to full cost coverage
Windows, Doors, Skylights and Sliding Doors	Windows, Doors, Skylights and Sliding Doors	Each window, door, skylight or sliding door replaced with an ENERGY STAR certified model. (Minimum of 3 windows or 1 door or 1 skylight or 1 sliding door replaced with ENERGY STAR certified models required)	$50 per rough opening
Water Heating	Heat pump water heater	Replace your natural gas domestic water heater with an ENERGY STAR certified Domestic Heat Pump Water Heater ("HPWH") ENERGY STAR technical specifications	$500

Delivery Approach

The SLH Pilot Residential Whole Home offer will be delivered by a contracted delivery agent ("DA"), who will manage relationships with local trade allies to deliver turnkey solutions customized for residential customers within the Pilot area. The DA 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. This includes eligibility confirmation, managing and reviewing contractor[12] costs, authorizing work, and reviewing/gathering submitted project documentation.

[12] Contractors sell, source, and install energy efficiency measures.

The Pilot offer will be delivered in both a Direct Install and a post-install Rebate path.

For the Direct Install path, the customer chooses to proceed with installing eligible measures using contractors provided via the DA. Through this path, the DA will pay incentives directly to customers via contractors, avoiding the requirement for customers to make an upfront investment. See Table 14 for the Direct Install delivery process.

The Rebate path offers the customer additional flexibility. The customer can choose to work with their own contractors outside the DA's trade ally network. In this case, the customer must notify the DA once the eligible measures are installed and would subsequently receive any incentives through a rebate process facilitated by the DA. See Table 15 for the Rebate delivery process

Detailed delivery plans for both the Direct Install and Rebate paths are currently under development with the DA and will be finalized prior to Pilot launch.

To support effective outreach, Enbridge Gas will develop an intake form on the SLH Pilot website to promote the offer and facilitate lead generation. Additionally, lead generation may be driven by the DA through leveraging existing customer relationships, or word-of-mouth referrals from previous participants.

Details of the delivery process flow are outlined in Table 14 and Table 15 below.

Table 14 – Delivery Process Flow for the SLH Pilot Residential Whole Home Offer Direct Install Path

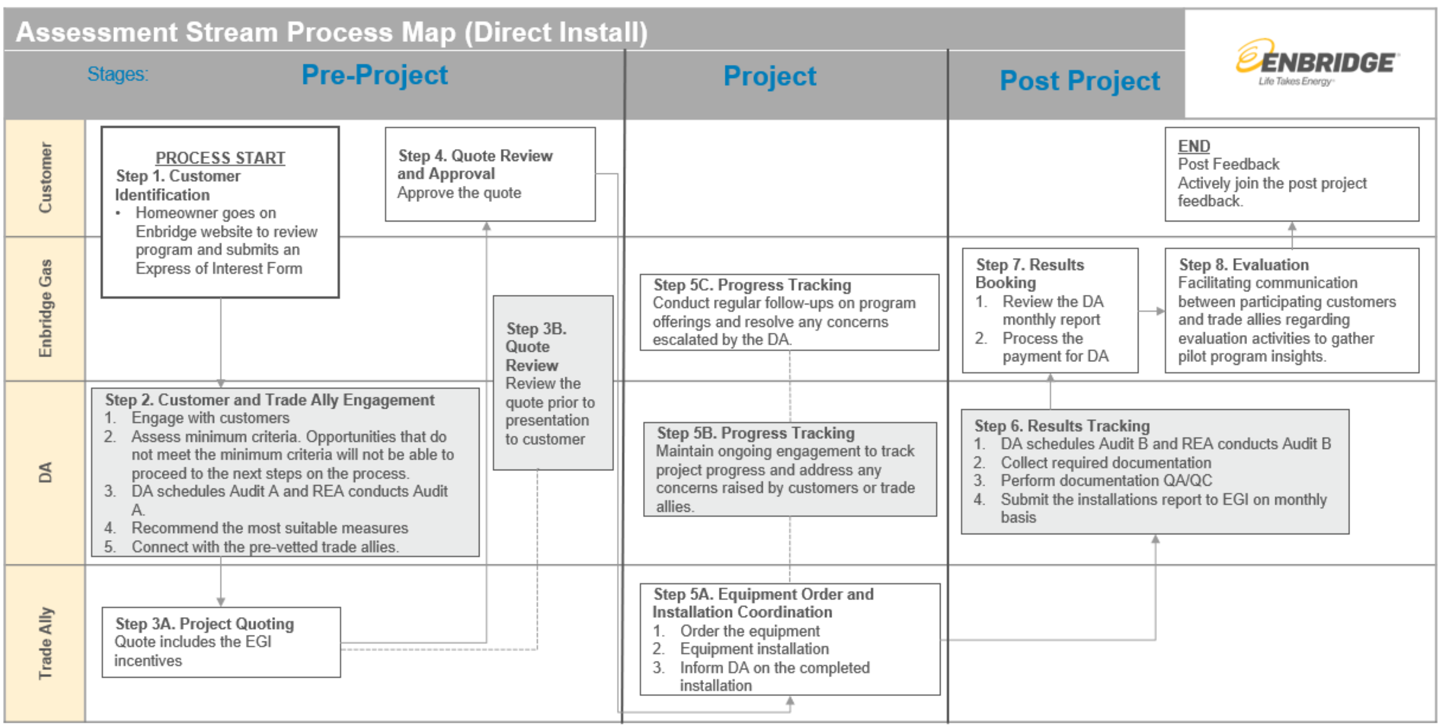
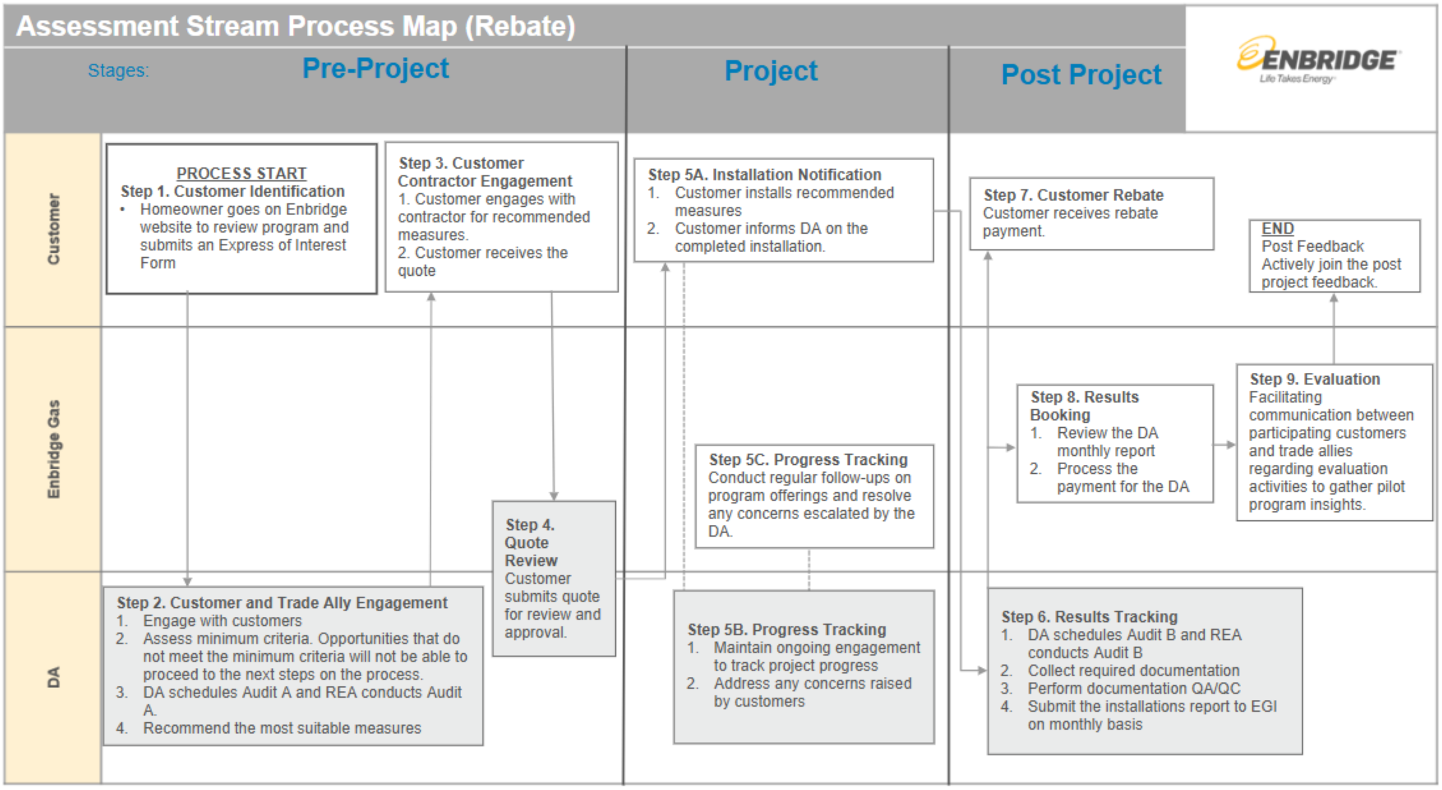


Table 15 – Delivery Process Flow for the SLH Pilot Residential Whole Home Offer Rebate Path



Residential Single Measure Attic Insulation Offer

Description & Rationale

The SLH Pilot Single Measure Attic Insulation Offer is similar to the Ontario-wide DSM single measure attic insulation offer. The goal of this Pilot offer is to encourage broader participation in the Residential Program through the delivery of a simplified, single measure alternative to the Residential Whole Home offer without the need for a pre- and post-installation energy assessment. The Single Measure Offer adds flexibility to the Residential Program, meeting customers at different stages of their energy journey and providing a simplified turnkey solution for the installation of attic insulation.

Goals

1. Increase offer participation through streamlined customer journey at no cost to customers
   - Provide enhanced incentives covering up to 100% of project costs, eliminating investment barriers for customers.
   - Simplify the process and easing access to incentives and paying incentives directly to contractors, avoiding the requirement for a customer to make an upfront investment and wait for a rebate.
   - Simplified approach without the requirement to schedule pre and post home energy assessments
   - Raise awareness of energy efficiency benefits among residential customers, emphasizing comfort, financial and other advantages.

2. Leverage collaboration
   - Build customer trust and satisfaction by delivering personalized service and ongoing support, positioning Enbridge Gas as a valuable partner in energy efficiency.
   - Partner with stakeholders such as local trade allies to boost program awareness, participation, and delivery coverage.
   - Explore opportunities to enhance awareness of available offers in the community with programs like IESO's Save on Energy initiatives.
   - Engage with local municipalities to identify opportunities for synergies and community-level targeted engagement.

Minimum Eligibility Criteria

To participate in the SLH Pilot Single Measure Attic Insulation offer, the following minimum criteria must be met:

- Have an active Enbridge Gas account.
- Be an eligible customer type that primarily space-heats their dwelling type with natural gas at the time of the insulation installation.
- Complete the attic insulation upgrades with a program-approved contractor.

IRP Pilot Offer Key Features

Table 16 highlights the key features of the SLH Pilot Single Measure offer. Any feature, eligibility, customer/project requirement etc. not noted in the table (except for incentive enhancements, which are provided below the table) should assumed to be consistent with the Ontario-wide DSM offer.

Table 16 – Key Features of the SLH Pilot Enhanced Single Measure Offer

Key Program Features	IRP Pilot Single Measure Offer	Barriers Addressed
Enhanced Rebate Amount	The rebate will be capped at 100% of the project costs or the maximum incentive.	Financial Constraints

Key Program Features	IRP Pilot Single Measure Offer	Barriers Addressed
Simplified Cost Coverage	Upfront cost coverage with the expectation of no out-of-pocket payment needed from the customer.	Complexity of Incentive Programs
Measure Eligibility – Building Type	Eligible: • single-detached • semi-detached • row house • townhome • mobile home on a permanent foundation • Part 9 MURB (multi-unit residential buildings) • Microbusiness (small businesses operating from former residential dwellings with residential sized heating and cooling equipment Ineligible: • Homes less than 6 months old.	Complexity of Incentive Programs
Customer Eligibility Criteria	Be an eligible customer type that primarily space-heats their dwelling type with natural gas at the time of the insulation installation.	Complexity of Incentive Programs
Delivery Agent	The offer is delivered by a contracted program delivery agent responsible for managing engagement and relationships with the local trade allies.	N/A
Project M&V	Annual and cumulative savings and B/C testing: • Reported as net using SLH Pilot-wide FR and SO values of zero. Peak hourly savings are reported without NTG adjustments or any other adjustments.	N/A
Marketing	Marketing geotargeted to the SLH Pilot area is being developed. See details in the accompanying SLH Pilot Marketing Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer
Stakeholder Engagement	Stakeholder engagement geotargeted to the SLH Pilot area is being developed. See details in the accompanying SLH Pilot Stakeholder Engagement Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer

Incentive Structure

Enbridge Gas will cover up to 100% of insulation measure and installation costs. Enbridge Gas must review quotes with eligible measures presented as separate line items prior to approval of incentive amounts. Insulation between two interior spaces is not eligible for an incentive and must be separated on an invoice.

All SLH Pilot equipment and installation incentive values per unit are currently under review and will be finalized prior to Pilot launch.

Table 17 - Enhanced Single Measure Incentive Structure by Measure

Item	Measure	Qualifiers	SLH Pilot Maximum Incentive
Attic Insulation	Attic	Increase attic insulation to at least R-50 from greater than R-12	Up to full cost coverage
	Cathedral/Flat Roof	Increase cathedral ceiling/flat roof insulation to at least R-20 from R-12 or less. Increase cathedral ceiling/flat roof insulation to at least R-28 from R-25 or less.	Up to full cost coverage

Delivery Approach

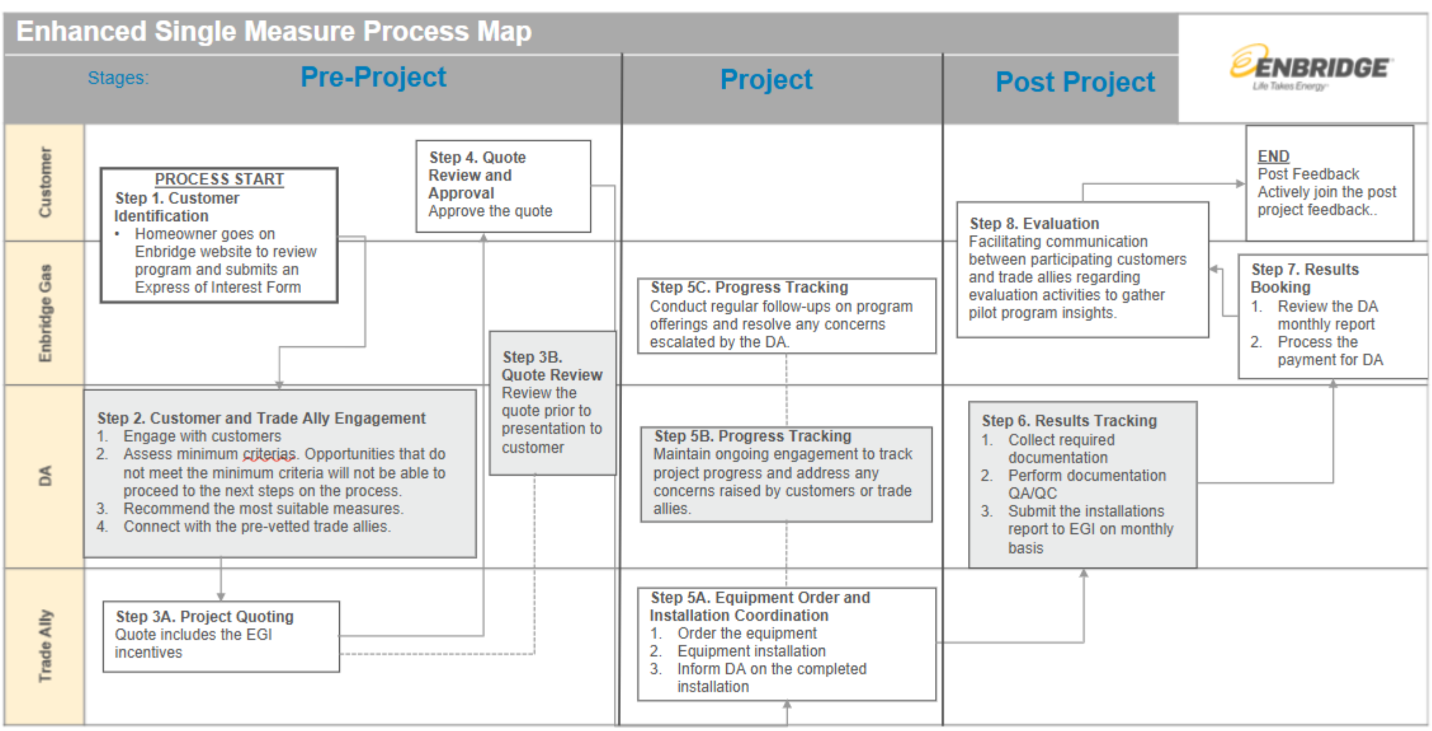
A detailed delivery plan is currently under development with the SLH Single Measure Pilot Delivery Agent.

The SLH Single Measure offer will be delivered by a contracted delivery agent ("DA"), who will manage relationships with the contractors and customers within the Pilot area. The DA will recruit local contractors, coordinate outreach efforts, connect customers with contractors, and provide support throughout the process from engagement to equipment installation. This includes eligibility confirmation, managing and reviewing contractor costs, authorizing work, and reviewing/gathering submitted project documentation. A detailed delivery plan is currently under development with the SLH Single Measure Pilot Delivery Agent.

To support effective outreach, Enbridge Gas will develop an intake form on the SLH Pilot website to promote the offer and facilitate lead generation. Additional leads may also be generated by the DA through methods such as leveraging existing customer relationships, or word-of-mouth referrals from previous participants.

The delivery process flow is outlined in Table 18.

Table 18 – Delivery Process Flow for the Enhanced Single Measure Stream



Limited Electrification Offer

Description & Rationale

The SLH Pilot Limited Electrification Offer is designed to evaluate the feasibility of electrification measures, specifically electric cold climate air source heat pumps ("ccASHP") and electric ground source heat pumps ("GSHP"), on a limited participation basis. This offer leverages insights from the DSM offer on these same measures, enhances incentives and refines the delivery approach to encourage participation. This offer aims to gather valuable insights to explore the potential applicability and feasibility of electricity-based IRP measures in an isolated environment that can help support future broad-based integrated resource planning efforts with local LDCs and the IESO.

Participation incentives for electric ccASHPs will be limited to 20 participants, while electric GSHPs will be limited to 10 participants.

Goals

1. Drive offer participation through a streamlined customer journey at no cost to customers
    - Provide enhanced incentives covering up to 100% of project costs, eliminating investment barriers for customers.
    - Simplify participation by providing a turnkey offer and paying incentives directly to contractors, avoiding the requirement for a customer to make an upfront investment and wait for a rebate.
    - Raise awareness of these measures among residential customers.
2. Maximize learnings to inform future integrated energy planning
    - Gather initial learnings of the impact of electrification measures on the local electric grid via engagement with Local Distribution Companies ("LDCs") to support future integrated energy planning with the electric sector.
3. Leverage collaboration
    - Build customer trust and satisfaction by delivering personalized service and ongoing support, positioning Enbridge Gas as a valuable partner in energy efficiency.
    - Partner with stakeholders such as local trade allies to boost program awareness, participation, and delivery coverage.
    - Explore opportunities to enhance awareness of available offers in the community with programs like IESO's Save on Energy initiatives
    - Engage with local municipalities to identify opportunities for synergies and community-level targeted engagement.

Minimum Eligibility Criteria

To participate in the SLH Pilot Electrification offer, the following minimum criteria must be met:

Customers must:

- Have an active Enbridge Gas account.
- Fully switch from natural gas space heating to electric after measure installation without any back up natural gas space heating options.[13] Participant does not need to disconnect their natural gas service.

Projects must:

- Be a first-time installation of an eligible electric heat pump system.
- Be located in one of the following eligible building types:
    - Single detached, semi-detached, row house, townhome, or mobile home on a permanent foundation

[13] Participants that keep an existing natural gas fireplace will remain eligible.

- Microbusiness (small businesses operating from former residential dwellings with residential sized heating and cooling equipment.)
- Part 9 MURB (Multi-unit residential buildings).

- Meet measure-specific minimum eligibility requirements.

Key IRP Pilot Offer Features

Table 19 highlights key features of the SLH Pilot Electrification offer.

Table 19 – Key Features of the SLH Pilot Electrification Offer

Program Features	SLH Pilot Electrification Offer	Barriers Addressed
Eligible Equipment List	• Electric Cold Climate Air Source Heat Pumps ("ccASHP") Option 4D only. Only 4D can be run without natural gas as a backup heating source. • Electric Ground Source Heat Pumps ("GSHP")	N/A
Enhanced Incentives	Offer provides full project cost (equipment and installation) up to a maximum incentive of $30,000 per project.	Financial Constraints
Eligibility Criteria	Offer requires customers to fully switch from natural gas space heating to electricity after the measure installation without any back up natural gas space heating options. Participant does not need to disconnect their natural gas service.	N/A
Measure Eligibility – Building Type	Eligible: • single-detached • semi-detached • row house • townhome • mobile home on a permanent foundation • Part 9 MURB (multi-unit residential buildings) • Microbusiness (small businesses operating from former residential dwellings with residential sized heating and cooling equipment • Existing buildings and new construction are eligible	Complexity of Incentive Programs
Project M&V	Annual and cumulative savings and B/C testing: • Reported as net using SLH Pilot-wide FR and SO values of zero. Peak hourly savings are reported without NTG adjustments or any other adjustments.	N/A
Marketing	Marketing geotargeted to the SLH Pilot area is being developed. See details in the accompanying SLH Pilot Marketing Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer
Stakeholder Engagement	Stakeholder engagement geotargeted to the SLH Pilot area is being developed. See details in the accompanying SLH Pilot Stakeholder Engagement Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer

Incentive Structure

Enbridge Gas will cover up to 100% of measure and install costs. Enbridge Gas must review quote with the eligible electric ccASHP or electric GSHP measure presented as a separate line item prior to approval of incentive amounts. The total incentive cannot exceed the project cost of the upgrade or $30,000.

The rebate applies to the purchase and installation of eligible electric heat pumps, including centrally ducted, partially ducted, or ductless electric ccASHPs—such as mini-split and multi-split systems—or electric GSHPs. The maximum equipment and installation incentive values are currently under review and will be finalized. Additionally, the SLH Pilot will be exploring what should be considered as eligible installation costs.

Table 20 – SLH Pilot Electrification Offer Incentive Structure by Measure

Electric Heat Pump Measure	SLH Pilot Maximum Incentive*
Electric ccASHP Full Equipment	Up to full cost coverage
Electric GSHP Full System	Up to full cost coverage

**The maximum equipment and installation incentive values are currently under review and will be finalized.*

Delivery Approach

A detailed delivery plan is currently under development with the SLH Pilot Electrification Delivery Agent.

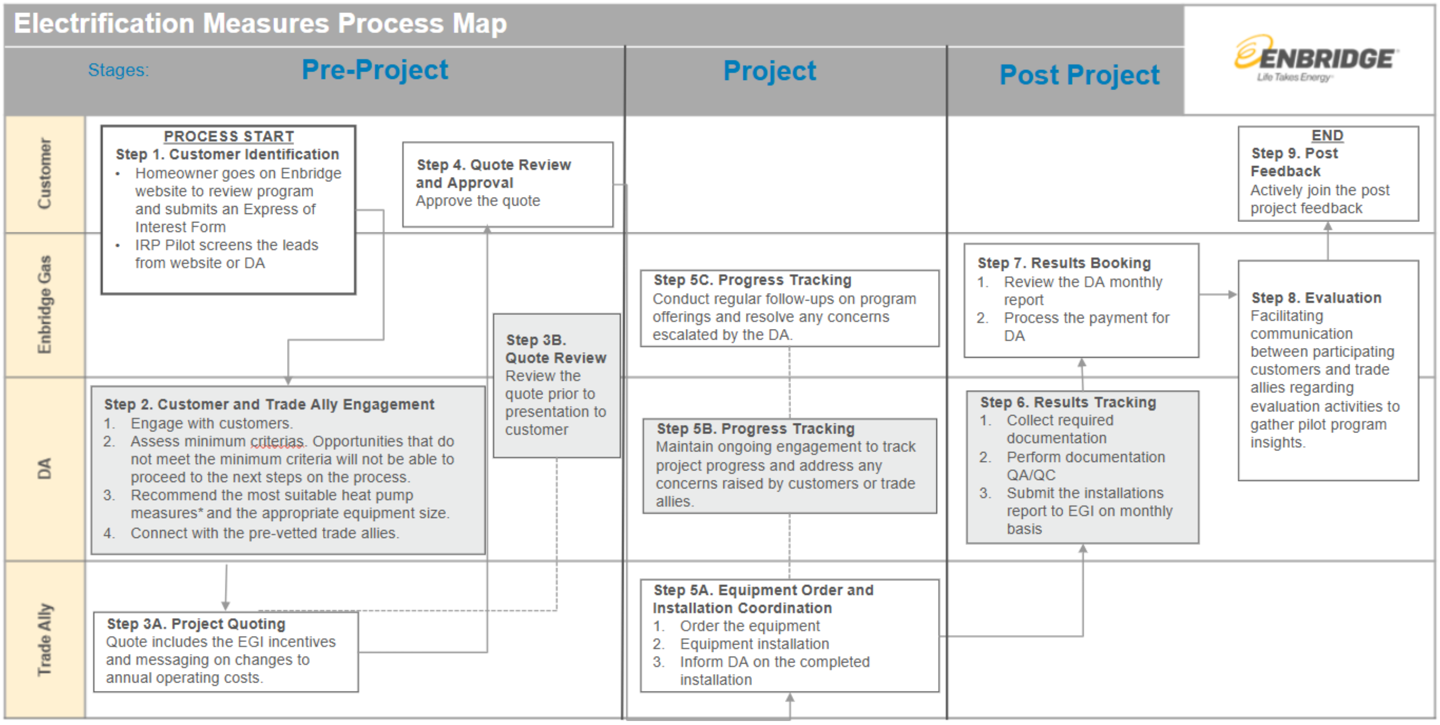
The SLH Pilot Electrification offer will be delivered by a contracted delivery agent ("DA"), who will manage relationships with the HVAC Contractors (trade allies) and customers within the Pilot area. The DA will recruit local trade allies, coordinate outreach efforts, identify opportunities, recommend appropriate equipment sizing, connect customers with trade allies, and provide support throughout the process from engagement to equipment installation. This includes eligibility confirmation, managing and reviewing contractor costs, authorizing work, and reviewing/gathering submitted project documentation. A detailed delivery plan is currently under development with the SLH Pilot Electrification Delivery Agent.

To support effective outreach, Enbridge Gas will develop an intake form on the SLH Pilot website to promote the offer and facilitate lead generation. Additional leads may also be generated by the DA through methods such as leveraging existing customer relationships, or word-of-mouth referrals from previous participants.

To simplify equipment selection, Enbridge Gas will establish a Qualified Product List that will help the DA provide informed recommendations and offer customers access to pre-approved equipment options. If a measure is not included in the QPL, it may be submitted to Enbridge Gas's IRP Pilot project team for further assessment to determine its potential eligibility for incentives.

The delivery process flow is outlined in Table 21.

Table 21 – Delivery Process Flow for the SLH Pilot Electrification Stream



*To streamline the equipment selection, the eligible measures will be listed in Qualified Product List (QPL)

Residential Demand Response Offer

Description & Rationale

The SLH Pilot Demand Response ("DR") offer seeks to understand the impact of shifting hourly natural gas flows/demands during peak periods on the natural gas distribution system. The offer targets residential customers in the Pilot area with natural gas central heating systems controlled by an eligible Wi-Fi connected smart thermostat with DR capabilities (including, but not limited to, devices manufactured by Ecobee, Google Nest, Emerson Sensi, and Honeywell). The program will apply a bring-your-own-device ("BYOD") approach, leveraging customers' existing smart thermostats. Customers will be financially incented to enroll in the DR program in exchange for allowing Enbridge Gas to control their smart thermostat during the winter heating season; specifically, during peak demand.

Goals

1. Raise awareness of the program and its benefits, emphasizing the simplicity of participation using devices customers already own and are familiar with.
2. Drive offer enrollment through a simple enrollment process
3. Maximize learnings to inform future integrated energy planning
   - Gather learnings on the impact of the DR program and evaluate event parameters to understand the effect on peak hour flow and demand reductions.
4. Leverage collaboration
   - Explore opportunities to enhance awareness of available offers in the community with programs like IESO's Peak Perks initiatives.

Minimum Eligibility Criteria

To participate in the SLH Pilot Residential DR, the following minimum criteria must be met:

Customers must:

- Have an active Enbridge Gas account.
- Have a functioning smart thermostat and reside in one of the following eligible building types:
  - Single detached, semi-detached, row house, townhome, or mobile home on a permanent foundation
  - Microbusiness (small businesses operating from former residential dwellings with residential sized heating and cooling equipment.)
  - A unit within a multi-unit residential building where the customer has access and control of a smart thermostat.

Key IRP Pilot Offer Features

Table 22 highlights key features of the SLH Pilot Demand Response offer.

Table 22 – Key Features of the SLH Pilot Demand Response Offer

Program Features	SLH Pilot Residential Demand Response Offer	Barriers Addressed
Eligibility Criteria	Be an eligible customer type that primarily space-heats their dwelling type with natural gas and have a functioning smart thermostat.	N/A
Measure Eligibility – Building Type	Eligible: • single-detached • semi-detached	N/A

Program Features	SLH Pilot Residential Demand Response Offer	Barriers Addressed
	• row house • townhome • mobile home on a permanent foundation • Units within a multi-unit residential building where the customer has access and control of a smart thermostat • Microbusiness (small businesses operating from former residential dwellings with residential sized heating and cooling equipment) • Existing buildings and new construction are eligible	
Marketing	Marketing geotargeted to the SLH Pilot area is being developed. See details in the accompanying SLH Pilot Marketing Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer
Stakeholder Engagement	Stakeholder engagement geotargeted to the SLH Pilot area is being developed. See details in the accompanying SLH Pilot Stakeholder Engagement Plan.	Limited Knowledge and Awareness Skepticism Toward the Offer

Incentive Structure

The incentive values and structure are currently under review and will be finalized prior to the Pilot launch.

Up-Front Enrollment Incentive:

- Customers who enroll in the program will receive a one-time incentive of $75 for their participation.

Bonus Participation Incentive:

- For each heating season that participants remain enrolled in the program and meet eligibility requirements, they will enter a draw for a chance to win $2000.
- Eligibility requirements include participation in at least 50% of DR event hours each heating season.

Conditions for Continued Participation:

Participants who consistently opt out of DR events (e.g., by overriding temperature setbacks or taking thermostats offline during event hours) may be removed from the program.

Delivery Approach

The SLH Residential DR program will be implemented by a Distributed Energy Resource Management System ("DERMS") service provider, responsible for deploying the program. Key responsibilities include integrating devices with the software platform, contracting with device partners, coordinating outreaching efforts, enrolling participants, and processing participant incentives. A detailed delivery plan, delivery process flow and the number of DR events and their design are currently under development with the Residential DR Delivery Agent.

- Enbridge Gas anticipates calling approximately 10 total DR events during the program's first heating season (2025/2026) depending on weather conditions.
- DR events typically occur between November 1 and April 1.
- During DR events, smart thermostat setpoints will be adjusted (e.g., up to 2 degrees Celsius) between midnight and noon, with potential adjustments occurring more than once during an event.

SLH Pilot Marketing Plan

Introduction

Marketing strategy:

Enbridge Gas will launch a geo-targeted marketing campaign to increase awareness and participation among the population in the area, where the median age is 46.0 years and 24.1% of residents are 65 or older[14]. The Pilot region has a community-oriented, predominantly English-speaking population with a homeownership rate of about 70–85%[15]. Proven marketing tactics from Enbridge Gas's previous DSM campaigns will help to address this demographic. This strategy will enable Enbridge Gas to refine the geo-targeting and use business intelligence data effectively to reach and engage customers for the Pilot program.

Enbridge Gas marketing strategy will be focused on the following three pillars:

A. Community centric approach:

To increase awareness, Enbridge Gas will employ a community-first approach through local media and grassroots engagement. Local participant testimonials and case studies demonstrating the benefits of energy-efficient upgrades will build authentic engagement.

B. Omnichannel engagement:

To generate leads across all customer types, Enbridge Gas will implement an integrated omnichannel strategy that aligns mass marketing with digital touchpoints. By delivering the appropriate message at the right time through the correct medium, Enbridge Gas aims to improve message retention and lead quality.

C. Data driven optimization and decision making:

Implement data-driven targeting and real-time campaign optimization to increase awareness and generate leads. Leverage data types such as gas usage, property types, and past participation to identify high-potential segments and tailor messaging accordingly.

Marketing phases:

The marketing efforts will begin with an initial phase focused on building awareness. The next phase will aim to maintain this awareness and generate leads. The final phase will further enhance awareness and concentrate on lead generation through focused messaging and direct outreach initiatives. To effectively initiate the awareness-building phase, certain marketing assets need to be developed beforehand to ensure that the content is strong, relevant, and locally resonant.

Residential Marketing

Table 23 – Marketing for Residential Customers

Tactic	Objectives	Description	Timing
Pre-launch preparation - May to June 2025 Establish a solid foundation by developing all of the marketing content and assets needed for the campaigns.			
Program landing page (Webpages)	Awareness	Building a hub for residential offers under Enhanced Target Energy Efficiency (ETEE) and Demand Response (DR) streams to provide information and enable participation.	Live July 2025
Community photo and video shoot	Awareness	Custom image and video shoot to capture local community footage for all campaign tactics.	June 2025
Phase 1: July to November 2025 – Awareness building			

[14] https://www12.statcan.gc.ca/census-recensement/2021/dp-pd/prof/details/page.cfm?Lang=E&SearchText=Sarnia&DGUIDlist=2021S0504562&GENDERlist=1,2,3&STATISTIClist=1&HEADERlist=0
[15] https://www.point2homes.com/CA/Demographics/ON/Sarnia.html

Tactic	Objectives	Description	Timing
▪ Launch marketing campaign focused on driving awareness across residential, small business, and commercial-industrial segments. ▪ Emphasize program availability, value propositions, and incentives that fund full cost.			
Customer-facing brochures with all residential offers	Awareness	Customer-facing brochure will highlight different whole home residential offers, other residential offers including attic insulation and home winterproofing offers. It will outline incentives amounts, feature and benefits of energy efficient upgrades, and specific call to action. Demand Response and heat pump offers will also be promoted.	July to Nov 2025
Direct Mail — Focused on program launch	Awareness / test and learn	Direct mail skews provides space to detail the pilot program and offers. The initial direct mail and follow-up postcard will reach roughly 25,000 residential customers.	July to Aug 2025
Direct mail — follow-up postcard	Awareness / test and learn	Follow-up postcards in the fall to remind residents about the offers. Delivered by Canada Post via neighborhood mail.	Sept to Oct 2025
Eblasts (x3)	Awareness / test and learn	Eblasts are a cost-effective tool of targeting customers.	July, Sep, Nov 2025
Google Search (Always-on)	Awareness / test and learn	The Google search campaign will target users searching for energy rebate information	July to Dec 2025
Digital campaign (Summer)	Awareness / test and learn	Digital marketing tactics will be implemented to target the local population, utilizing platforms such as Google, Meta, and websites like the Weather Network.	July to Sept 2025
Digital campaign (Fall)	Awareness/ test and learn	Enbridge Gas will relaunch the digital marketing campaign based on insights from the initial summer campaign.	Oct to Nov 2025
Radio	Awareness / test and learn	Traditional radio consumption is strong in Sarnia and a cost-efficient way to reach the audience. Radio approach may include 30 second spot development for approximately four weeks.	Sep to Oct 2025
Out of home (OOH) marketing campaign	Awareness / test and learn	OOH campaigns have the potential for large audiences and can reinforce radio advertisements. It allows geo-targeting to connect with commuters, drivers and walking traffic. Tactics can include Transit shelters, bus kings, and digital OOH.	Sep to Oct 2025
Print ads	Awareness / test and learn	Community newspapers are an important resource in smaller centres and can also be geo-targeted.	Sep to Oct 2025
Events	Awareness / test and learn	Events are to be confirmed and will be staffed by an events agency team and/or Enbridge's event team. The local events to be considered are Fright Night at Canatara Park, Earth Day Cleanup, and First Friday Arts and Culture Walkabouts.	TBC
Phase 2: January to October 2026 – Awareness and lead generation • Balanced focus between educating target segments and generating qualified lead and will start to focus on highlighting success stories and real-world outcomes.			
Testimonials — photos/quotes/video	Awareness	Authentic footage of current participants' neighbors and residents can influence and persuade others to participate. Video and photo shoot of 1 to 2 customers (TBD).	Q1 2026

Tactic	Objectives	Description	Timing
Search	Awareness, with an objective of lead generation	The Google search campaign will target users searching for energy rebate information	Jan to May 2026
Eblasts x 3	Interest and lead generation	Eblasts can be an additional means to connect to those who haven't signed up yet. Eblasts may be refreshed with new imagery, headlines and specific messaging.	Jan, March, and May
Digital (Google, Meta, TWN, Influencers)	Awareness and interest	Placeholder marketing tactics — TBC based on results of Phase 1.	Jan to May 2026
Traditional (radio, DM, print, OOH, events)	Awareness and interest	Placeholder marketing tactics — TBC based on results of Phase 1.	Jan to May 2026
Phase 3: May to November 2026 – Awareness with focused on leads generation • Enbridge Gas will tailor the content and marketing assets to address specific barriers identified among non-participating customers, ensuring relevance and clarity. • Lead generation efforts will intensify with focused messaging and direct outreach initiatives.			
Search	Awareness, with an objective of lead generation	The search campaign will target users searching for energy rebate information.	June to Oct 2026
Eblasts x 3	Interest and lead generation	EBlasts can be refreshed with new imagery, headlines and specific messaging.	July, Sep, and Nov.
Digital (Google, Meta, TWN, Influencers)	Awareness and interest	Placeholder marketing tactics — TBC based on results of Phase 2.	June to Nov 2026
Traditional (radio, DM, print, OOH, events)	Awareness and interest	Placeholder marketing tactics — TBC based on results of Phase 2.	June to Nov 2026

Commercial and Industrial Marketing

Table 24 – Marketing for Small Business Customers

Tactic	Objectives	Description	Timing
Pre-launch preparation - May to June 2025 **Establish a solid foundation by developing all the marketing content and assets needed for the campaigns.**			
Dedicated program landing page (Webpages) & Online Intake form	Awareness	Building a hub to provide information and enable participation.	June 2025
Community photo and video shoot	Awareness	Capture authentic local community images and videos for use in all campaign tactics.	June 2025
Brochure with all offers	Awareness	Outline the program and all offers provided to ESA.	July 2025
Phase 1: July to November 2025 – Awareness building ▪ Launch marketing campaign focused on driving awareness across small business, and commercial-industrial segments.			

▪ Emphasize program availability, value propositions, and incentives.			
Direct mail	Awareness/test and learn	Direct mail to promote the program and offers. Two versions are expected: one for restaurant and food services with Demand Control Kitchen Ventilation (DCKV) information, and another for general businesses.	Aug to Sep 2025
Digital campaign Launch (LinkedIn)	Awareness/test and learn	LinkedIn facilitates connections with professionals and businesses interested in rebates, energy efficiency, and sustainability. Users can be targeted based on industry, job functions, and seniority.	July to Sep 2025
Event Sponsorships	Awareness/test and learn	Sponsorships can support business events run by the City or Chamber of Commerce, such as Outstanding Business Achievement Awards (Oct. 24, 2025).	Oct to Nov 2025
Eblasts x 2	Awareness/test and learn	Eblasts can be an additional means to connect to those who haven't signed up yet. Eblasts may be refreshed with new imagery, headlines and specific messaging. Enbridge Gas will leverage data to send Eblasts to the right set of customers.	Sept and Nov 2025
Phase 2: January to April 2026 – Awareness and lead generation Balanced focus between educating target segments and generating qualified lead and will start to focus on highlighting success stories and real-world outcomes.			
Testimonials (photos, quotes and Case Studies)	Awareness	Authentic footage of peers to influence and persuade other businesses to participate.	Q1 2026
Event Sponsorships	Awareness and interest	Sponsorships can support business events run by the City or Chamber of Commerce.	Q1-2
Eblasts x 2	Interest and lead generation	EBlasts can be refreshed with new imagery, headlines and specific messaging.	Jan and Mar 2026
Digital (LinkedIn)	Awareness, with an objective of lead generation	Placeholder marketing tactics — TBC based on results of Phase 1.	Jan/Feb to March 2026
Traditional (radio, DM, Print, OOH)	Awareness and interest	Placeholder marketing tactics — TBC based on results of Phase 1.	Feb to May 2026
Phase 3: May to November 2026 – Full lead generation • Enbridge Gas will tailor the content and marketing assets to address specific barriers identified among non-participating customers, ensuring relevance and clarity. • Lead generation efforts will intensify with focused, focused messaging and direct outreach initiatives.			
Eblasts x 1	Interest and lead generation	Eblasts messaging will adjust depending on results and available applicable customer success stories	May 2026

Digital (LinkedIn)	Awareness, with an objective of lead generation	Placeholder marketing tactics — TBC based on results of Phase 2.	May to July 2026
Traditional (radio, DM, Print, OOH)	Awareness and interest	Placeholder marketing tactics — TBC based on results of Phase 2.	May to July 2026

Table 25 – Marketing for Commercial and Industrial Customers

Marketing tactic	Objectives	Description	Timing
Pre-launch preparation - May to June 2025 Establish a solid foundation by developing all the marketing content and assets needed for the campaigns.			
Webpage with all offers	Awareness	Building a hub to provide information and enable participation	June 2025
Sales Support Material	Awareness	Work with ESA to build a customized approach to build sales support material. Tactics may include Brochure, eblast templates.	July 2025
Aug 2025 to July 2026 – Awareness and lead generation ▪ Support local ESAs and Key Account Managers with materials like email templates, sell sheets, webinars, or postcards to build business relationships. ▪ Tailor content and marketing assets to address barriers for non-participating customers, ensuring relevance and clarity. And intensify lead generation with focused, conversion-driven messaging and direct outreach.			
Content requests, refreshes	Awareness and interest	Content refreshes can include ad hoc requests or collateral refreshes.	Q1 to Q2 2026
Testimonials (photos, quotes and Case Studies)	Awareness and interest	Case studies from customers who have participated in programs will help influence and persuade others to participate.	Q1 to Q2 2026

Stakeholder Engagement Plan

Engagement objectives

The Pilot stakeholder engagement plan identifies the processes and actions that will drive awareness and participation in the Pilot. The plan builds on engagement activities conducted in 2023 and 2024.

Priority objective: *build consumer awareness and participation in the Pilot through direct engagement and coalition building.*

- Drive awareness and lead generation through channel partnerships and direct engagement.
- Engage and activate a network of channel partners, Pilot delivery agents, HVAC contractors/trade allies, local organizations, and the Pilot area's LDC to build awareness through their networks and support consumer conversion.
- Establish an organic, peer-to-peer based campaign that encourages customers to serve as community opinion leaders and ambassadors for the Pilot to help generate uptake.
- Engage with municipal government, cultural and social organizations, civic-based associations, Environmental Non-governmental Organizations ("ENGO"), and housing providers on the benefits of participating in the Pilot.
- Provide timely and meaningful updates to incumbent Indigenous and municipal government leaders on the Pilot.

Stakeholder mapping

This section prioritizes stakeholder groups into three tiers based on their ability to influence the uptake and outcome of the Pilot.

Tier 1		
Direct users/ service providers: high interest, high influence, engage early and often. These stakeholders are a primary target for all promotional, engagement, and awareness building activities.		
Stakeholder	**Strategies and tactics**	**Objective**
Local residents and businesses: • Homeowners and renters • Commercial, Industrial, Multi-family customers • Resident associations	• Refer to the Pilot marketing plan for geo-targeted strategy and tactics • Direct engagement with larger businesses	• Awareness • Lead generation • Peer-to-peer sharing
Housing providers/organizations: • Municipal housing providers • Housing and tenant groups (Sarnia-Lambton Housing Corp) • Community Living Sarnia-Lambton	• Targeted briefings with administrators • Seek feedback/opportunities on information sharing channels • Provide collateral for visibility • Key messages on the Pilot and potential benefits	• Awareness • Lead generation
Local business groups: • Point Edward Business Improvement Areas ("BIA") • Sarnia-Lambton Business Development Corporation • Sarnia Downtown BIA	• Targeted briefings • Key messages on Pilot and potential benefits • Seek feedback/opportunities on information sharing channels	• Awareness • Lead generation
Trade allies: • HVAC contractors • Insulation contractors • Window contractors	• Targeted briefings • Engage in opportunities to boost Pilot awareness to customers via contractors, enhance participation, and delivery coverage	• Ensure clarity on offerings • Strengthen trade allies' approach to delivering and referring clients to offerings • Awareness, with an objective of lead generation

Tier 1		
Direct users/ service providers: high interest, high influence, engage early and often. These stakeholders are a primary target for all promotional, engagement, and awareness building activities.		
Stakeholder	**Strategies and tactics**	**Objective**
Local Distribution Company: • Bluewater Power	• Explore potential for cross promotional opportunities • Engagement on potential data sharing	• Awareness, with an objective of lead generation • Support future integrated energy planning considerations
IESO: • Conservation & Resource Adequacy group • Regional Planning/ IRRP/ Stakeholder unit	• Explore opportunities to enhance awareness of available offers in coordination/cross-referral	• Awareness, with an objective of lead generation • Collaboration around Save On Energy audiences

Tier 2		
Community opinion leaders/ local government/ industry groups/ technical parties: These stakeholders can provide feedback and help identify opportunities to reach audiences. This is a secondary audience with medium influence, but that supports awareness.		
Stakeholder	**Strategies and tactics**	**Objective**
Municipal government: • Mayor Bev Hand/ Council • CAO Jim Burns • Local councillors • Special Projects Coordinator, Shelley Archer • County of Lambton Planning and Development Services • Village of Point Edward Public Works Department • County of Lambton, Sustainable Lambton team	• Targeted briefings with elected and administration officials • Engage to identify and execute opportunities for synergies and community-level targeted engagement, information sharing channels (e.g. events, newsletters, social media channels, involvement of the municipality in milestone announcements and events) • Provide collateral for visibility • Key messages on Pilot and potential benefits	• Awareness • Identifying incremental channels that will best drive awareness and generate leads
Provincial, federal elected officials, ministries: • MP for Sarnia—Lambton—Bkejwanong, Marilyn Gladu • MPP for Sarnia-Lambton Bob Bailey	• Targeted briefings with constituency office officials • Seek feedback on information sharing channels (newsletters, social media channels) • Provide collateral for visibility • Key messages on Pilot and potential benefits	• Awareness, constituency engagement
Indigenous community: • Aamjiwnaang First Nation	• Provide collateral for visibility • Key messages on Pilot and potential benefits • Inform for ongoing awareness	• Awareness, engagement
Housing and tenant organizations: • Property management networks	• Targeted briefings with administrators • Seek feedback on information sharing channels • Provide collateral for visibility	• Awareness • Channel sharing

Tier 2		
Community opinion leaders/ local government/ industry groups/ technical parties: These stakeholders can provide feedback and help identify opportunities to reach audiences. This is a secondary audience with medium influence, but that supports awareness.		
Stakeholder	**Strategies and tactics**	**Objective**
• Tenants' advocacy groups (e.g. Ontario Tenants Association branches) • Ministry of Municipal Affairs and Housing	• Key messages on Pilot and potential benefits	
Schools and parent councils: • Lambton Kent District School Board (and schools within Pilot catchment) • Bridgeview Public School • School Parent Councils – represent families and educational interests	• Targeted briefings with administrators • Seek feedback on information sharing channels (e.g. newsletters) • Provide collateral for visibility • Key messages on Pilot and potential benefits	• Awareness • Macro lead generation • Peer-to-peer sharing • Channel sharing
ENGOs: • Lake Huron Community Action Initiative • Climate Action Sarnia Lambton	• Targeted briefings with administrative staff • Seek feedback on information sharing channels (newsletters, social media channels) • Provide collateral for visibility • Key messages on Pilot and potential benefits	• Awareness • Channel sharing

Tier 3		
Enabling parties with influence over targeted stakeholders: These stakeholders can provide feedback and help identify opportunities to reach audiences.		
Stakeholder	**Strategies and tactics**	**Objective**
Conservation authorities; Environmental: • St. Clair Region Conservation Authority (SCRCA) • Essex Region Conservation Authority (ERCA)	• Targeted briefings with administrators • Key messages on Pilot and potential benefits	• Awareness • Channel sharing
Economic development/ business corporations: • Sarnia-Lambton Economic Partnership • Sarnia-Lambton Chamber of Commerce	• Targeted briefings with administrative staff • Seek feedback on information sharing channels (newsletters, social media channels) • Provide collateral for visibility • Key messages on Pilot and potential benefits • Offer to provide webinars to members	• Awareness • Channel sharing
Community organizations: • YMCA of Southwestern Ontario • Wyoming Lioness Lions Club	• Targeted briefings with administrative staff • Seek feedback on information sharing channels (newsletters, social media channels)	• Awareness • Channel sharing

Tier 3		
Enabling parties with influence over targeted stakeholders: These stakeholders can provide feedback and help identify opportunities to reach audiences.		
Stakeholder	**Strategies and tactics**	**Objective**
• Sarnia Legion Branch 62 • Sarnia Community Foundation • Rotary Club of Sarnia	• Provide collateral for visibility • Key messages on Pilot and potential benefits • Monitor to determine sentiment and market awareness	

Stakeholder engagement approach

This section describes the approaches that will be taken to engage Tier 1 to 3 stakeholders.

Approach	Actions
1. Engage residents and customers on the Pilot	• Dedicated Pilot website will be the central point for information on the Pilot (i.e. could serve as lead page for marketing campaign; links and QR codes to connect back to page) • Leverage earned/owned traditional media (news release, media pitches, organic social media), for example, launch announcement news release hat can be amplified over social media and shared with stakeholders for re-sharing. • Marketing collateral (see marketing plan) comprised of geo-targeted paid social media posts, newspaper inserts, postcards, etc. • Development of content (messaging) for stakeholder newsletter, social media channels, speaking remarks, etc. • Proactive key messages about the system and customer benefits of the Pilot and reactive messages about potential concerns.
2. Sustained municipal advocacy	• Maintain direct communication with the municipality and councillors (both working level, senior staff officials, and elected officials). • Publish notices and information in the councillors newsletters, as well as their respective websites, linking back to the webpage. • Involvement of the municipality in milestone announcements and events (e.g. Pilot kick-off). • Ongoing touchpoints with the municipality to ensure it is kept informed of project progress, issues, and next steps.
3. Build community and Tier 3 support	• Leverage relationship with local-area chambers and boards of trade to disseminate information, and to promote the Pilot. • Participate in speaking engagements and provide information on the importance of the Pilot (i.e. incorporate into speaking remarks). • Foster continued support from local stakeholders for reliable energy access, promote with local media, social media.

4. Enhanced monitoring of traditional media/ social media	• Monitor traditional media outlets covering local and regional news in the area.
	• Determine marketing and visibility opportunities (e.g. banner ads).
	• Source and develop opportunities for proactive media outreach to community-based media outlets:
	  ○ The Sarnia Observer
	  ○ Sarnia & Lambton This Week

Approach	Actions
	○ The Sarnia Journal ○ Blackburn News Sarnia ○ The Independent • Source and develop opportunities for proactive media outreach to community social media sites: ○ Point Edward "Loud and Proud!" ○ Village of Point Edward ○ County of Lambton ○ Sarnia- Lambton Newcomer Hub ○ Optimist Club of Point Edward

Engagement and activation schedule

This section details the description and timing of engagement items used to connect with Tier 1 to 3 stakeholders.

Engagement items	Objectives	Description	Timing
Pre-launch Phase: May – June 2025			
Detailed stakeholder lists	**Coordination, Awareness**	Develop detailed stakeholder contact lists for Tier 1-3 entities	June 2025
Briefing collateral	**Awareness**	Build briefing material toolkit for Tier 1, 2 priority audiences	June 2025
External communications collateral	**Awareness**	Develop public and media-facing materials (news release, backgrounder, key messages, template remarks)	June 2025
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 (invite to participate in launch event)	June 2025
Phase 1: July – December 2025			
Priority stakeholder briefings	**Awareness, information sharing**	Tier 1, 2 priority briefings to occur (in advance of launch of marketing campaign where possible); capture feedback	Early July 2025
Pilot launch	**Awareness**	Execute a launch event with local-area stakeholders (supported by media materials)	July 2025
Sustained engagement	**Awareness**	Tier 3 briefings to generate interest, awareness, information sharing across channels; capture feedback	July - August 2025
Channel amplification	**Awareness**	Encourage Tier 1-3 stakeholders to promote the Pilot through organic owned/ earned channels (e.g. social, newsletters, e-blasts)	July - August 2025

Engagement items	Objectives	Description	Timing
		Create additional lift around milestone activities (e.g. back to school planning)	
Visibility with Tier 3 community	**Awareness**	Work with local business associations, chambers, identify speaking opportunities to address members and leverage respective engagement channels	August - October 2025
Additional (Fall) media push	**Awareness; uptake**	Drive seasonal messaging through media and public-facing channels; leverage case studies, testimonials	October - December 2025

Engagement items	Objectives	Description	Timing
Phase 3: January-December 2026			
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.	January - December 2026

Southern Lake Huron Pilot Program

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Pilot Objective 1: Evaluation Plan and Skeleton

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Pilot Objective 1 - Evaluation Plan and Skeleton

Below is a skeleton of the structure of the Objective 1 (Peak Hour Evaluation) Plan. Enbridge Gas will be responsible for Section 4 Data Sources & Section 5 Customer Load Extrapolation Methodology. The data sources are being managed internally at Enbridge Gas but will require consultant review and evaluation/verification. The plan is for a consultant to document the remainder of the report so the structure will be adjusted to meet their requirements. The updated skeleton and detailed plan should be available in Q3 2025 after the successful proponent is determined. Sections 6 and 7 focus on what the interim and final evaluation and verification report may look like.

1) **Executive Summary**
2) **Pilot Background**
3) **Key Research Objectives**
4) **Data Sources**
   a) **Overview and Summary**
   b) **ERT Data**
      i) **Summary**
      ii) **Description and Scope**
      iii) **Data Quality**
      iv) **Challenges & Potential Improvements**
   c) **Brightlync Data**
      i) **Summary**
      ii) **Description and Scope**
      iii) **Data Quality**
      iv) **Challenges & Potential Improvements**
   d) **Weather Data**
      i) **Summary**
      ii) **Description and Scope**
      iii) **Data Quality**
      iv) **Challenges & Potential Improvements**
   e) **Smart Thermostat Data for DR**
      i) **Summary**
      ii) **Description and Scope**
      iii) **Data Quality**
      iv) **Challenges & Potential Improvements**
   f) **Other Data – house type, age, sizing, previous DSM opt-ins, geography etc.**
      i) **Summary**
      ii) **Description and Scope**
      iii) **Data Quality**
      iv) **Challenges & Potential Improvements**

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- b. **Limitations and Intended Uses of Results**
- c. **Limitations of Load Regression for DR**
    - a. **Smaller data set**
    - b. **DR Impacts on Regression**
    - c. **Zero Heat Hours and Recovery Time**
    - d. **Extrapolating to Design Hour**
- d. **Thermostat details and options (runtime, setpoint, heating stage)**
- e. **DR Event Alternatives and Considerations**
- f. **Measurables and Data Evaluation**
    - a. **Summary of control group (non-participants)**
        - i. **Pre and Post DR Comparison**
    - b. **Summary of Participants**
        - i. **Pre and Post DR Comparison**
    - c. **Effects of DR**
    - d. **System level impacts of DR**
        - i. **Impacts of Opt-outs and participation changes over time**
    - e. **Sources of Error**
- g. **Conclusions**

9) Reporting

- a. **Annual Report**
- b. **Final Pilot Report**

Southern Lake Huron Pilot Program

Pilot Objective 2: Evaluation Plan

resource innovations

ETEE and DR Pilots Evaluation Plan

2025-2026 Program Years

Prepared by Resource Innovations
Date: June 19, 2025

Table of Contents

1 Pilot Description

The Southern Lake Huron (SLH) Pilot offers include an enhanced version of the following Demand Side Management ("DSM") offerings:

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

As well as:

- A limited ETEE offering for electrification measures (featuring limited units of electric air source heat pumps and electric ground source heat pumps) for residential only
- Residential Demand Response program.

Descriptions of these offers are provided in Enbridge's Southern Lake Huron Pilot Program Design and Implementation Plan.

The SLH Pilot will run from July 2025 through December 2026 with Residential Demand Response events extending into Q1 2027.

2 Key Research Objectives

The primary objective of the evaluation is to support Enbridge's pursuit of the SLH Pilot Objective 2 in developing an understanding of how to effectively design, deploy, and evaluate Enhanced Targeted Energy Efficiency (ETEE), residential demand response and other programs throughout the duration of the Pilot term through evaluation activities. The evaluation will assist Enbridge in the refinement of these offers for future IRP Plans. The scope of the evaluation will include outcome evaluation of financial spending and participation in the programming and process evaluation to undertake a systematic assessment of the design and delivery approach of the offerings to provide insights, and considerations for ongoing enhancement.

Learnings gained from the Pilot evaluation will focus on the following objectives:

1. Assessing the impacts on participant uptake resulting from increased incentives for ETEE programming, which consist of a portfolio of measures, and key customer characteristics and motivations associated with participation rates.
2. Assessing the effectiveness of various marketing/community engagement tactics to generate awareness of and to increase ETEE/DR program participation.
3. Understanding differences in participant uptake within ETEE programming versus broad-based DSM programming.
4. Understanding the costs of ETEE programming (incentives, delivery costs, promotion costs, administration costs) versus broad-based DSM programming.
5. Gathering learnings on customer barriers and contractor installation and services barriers to adoption for all measures and DR to support wider market deployment in potential future IRP applications.
6. Understanding the cost of DR programming (i.e., incentives, delivery, promotion, administration).

Our evaluation process to achieve these research objectives will involve the following steps:

- Pre-launch research to achieve familiarity with the pilot plans and intentions, as well as to establish data tracking and integration of evaluation activities into Enbridge's processes;
- Post-launch data collection to understand perspectives of participants, non-participants, and near-participants during their pilot participation;
- Analysis and synthesis to bring together insights from pre-launch and post-launch research;
- Reporting during the pilot to help inform Enbridge on early results, challenges, and opportunities for pilot improvements or adjustments (as needed); and
- Post-pilot reporting to inform decisions about any full-scale program efforts.

Table 2-1 outlines the metrics and data sources that will allow for an analysis and understanding of each numbered research objective above.

Table 2-1: Linking Research Objectives to Metrics and Data Collection Activities

Research Objective	Key Performance Metrics	Participant Surveys	Near, Non-, & Opt-Out Participant	Broad-Based Program Surveys	Service Provider / Contractor Surveys	Peer Program Research / Interviews	Cost Assessment
1. Assessing participant uptake from increased incentives	Quarterly participation per measure, by similar pilot offers, building types (including expanded building types), incentive type (such as removing upfront cost barrier) and incentive level.	X	X		X		
2. Assessing marketing, community engagement	By engagement type, trends in participation and awareness pre- and post-event, by quarter. Determine what marketing was most effective.	X	X		X		
3. Compare EETE and broad-based DSM participant uptake	Comparative analysis of all metrics for pilot versus broad based initiative, within pilot location, to like region, and Ontario as a whole, specifically on measure type, dropout rates, and barriers reduction.	X	X	X	X	X	
4. Assess cost difference between ETEE and BB	Cost per peak m^3 and cost per participant by measure/offer annually, distinguishing between pilot only start-up costs and continuing costs, to broad based programs.						X
5. Customer and contractor barriers	Measure the significance rating of barriers by each respondent group.	X	X	X	X	X	
6. Understand cost of DR programming	Quarterly cost per peak m^3 and by participants.						X

The following sections outline these activities and tasks that will be conducted to satisfy the objectives in greater detail.

3 Pre-Launch Research

The following research activities will be conducted prior to the pilot launch in late July to 1) inform the evaluation team on pilot strategy, plans, and uncertainties, 2) begin data collection to inform baselines, and 3) assist Enbridge Gas with additional pilot design and implementation considerations:

1. Pilot documentation review
2. Initial pilot staff interviews
3. Broad-based DSM customer baseline survey
4. Near-participant broad-based DSM survey
5. Initial service provider/contractor IDIs
6. Peer program benchmarking research

3.1 Pilot Documentation Review

First, we have requested relevant pilot information from Enbridge Gas. The review of these documents is ongoing at the time of this plan, with more information expected in the near future. The information provided thus far includes preliminary details regarding the design and implementation strategy for the current Southlake Huron (SLH) Pilot outlining:

- Target market for the offer
- Eligibility criteria
- Incentive structure and amounts, including a comparison to the 2025 DSM program incentives
- Links to DSM resources available in the market and relevant brochures

Other pilot information requested are:

- Any draft or final pilot delivery plans and parameters for the ETEE and DR pilots.
- Any existing pilot logic models or similar conceptual documents that define market knowledge and assumptions, the pilot intervention theory, and intentions about what interim and ultimate outcomes the pilot activities will create.
- Summary information about the underlying broad-based DSM program, including descriptions of offerings and delivery approaches, annual reports or program summaries; and any evaluation reports or primary data gathering that may have been conducted.
- Descriptions of program tracking data maintained by Enbridge for the broad-based DSM program and currently intended pilot tracking for the ETEE and DR pilots.
- Any other information sources suggested by Enbridge.

3.2 Pilot Staff Interview

We will conduct an in-depth interview with Enbridge Gas staff, likely prior to finalizing the evaluation plan. We will include: 1) all key pilot managers running one or more aspects of the pilot, as well as 2) peers running the parallel broad-based DSM programs and 3) a small sample of account managers to ensure that the perspective of managed accounts is included. We will perform two staff group interviews, one with residential and one with non-residential staff.

The in-depth interview will cover the following topics:

- Understanding pilot design and why that design was selected (specific differences from broad-based programs as the baseline)
- Understanding objectives and priorities of the pilot
- Understanding data structures
- Uncovering anticipated challenges and potential solutions
- Comparison to broad-based DSM program
- Account manager perceptions and observations about pilot fit for their accounts
- What Enbridge Gas staff would like from pre-launch research and outcomes from the evaluation

3.3 Broad-Based DSM Customer Baseline Survey

The ETEE pilot builds on existing DSM programs provided by Enbridge Gas. To thoroughly evaluate the ETEE pilot, the Enbridge Gas team has requested a survey of individuals in the DSM program areas to serve as a reference and baseline comparison point, as referenced in Task 3 in the revised proposal. The RI team will work collaboratively with Enbridge to define strategies to collect the data, including leveraging Enbridge's existing market outreach and surveys. If data collection is to be done by RI, then we will develop a detailed scope of work and budget in consultation with Enbridge.

3.4 Broad-Based Near-Participant Survey

RI will utilize data gathered by broad-based programs on customers that showed interest in participation but did not ultimately complete a project through the program, termed near-participants. We will coordinate with Enbridge Gas to receive a list of contact information for near participants to survey. We will determine appropriate sample sizes based on the available data going back one to two years, and by program. Respondents will be offered a $50 incentive for completing the survey, using Tango for immediate gift card fulfillment.

The survey instruments (residential and non-residential) will be developed by the RI team and provided to the Enbridge Gas team and the TWG in advance to provide feedback. Once the instruments are approved, recruitment will begin by email, phone, and direct mail, if necessary.

The following topics will be covered:

- Program communication
- Initial drivers and perceived value
- Barriers encountered
- Ultimate reasons for non-participation
- Customers characteristics
- What could have convinced them to participate

3.5 Service Provider/Contractor IDIs

In order to gain a more thorough understanding of the participation experience, we will conduct in-depth interviews with service providers and contractors participating in the existing DSM programs and recruited for the ETEE pilot. Through these interviews, we will seek to understand specific aspects of service provider/contractor participation and gather their opinions regarding the existing programs, any relevant trainings they have participated in, potential challenges they expect in the pilot, and other thoughts and questions they have about the pilot.

The interviews will cover:

- Perceived benefits to the contractor/service provider of promoting the pilot
- Perceived benefits to customers
- Marketing approach taken by Enbridge and the utilization by contractors/providers (what they communicate, to whom, in what circumstances, how it is being received by customers)
- Perception about the participation experience for contractors/service providers and customers
- Training participation and feedback
- Potential challenges that may arise
- Missed opportunities
- Suggestions for improvement

3.6 Peer Program Benchmarking Research (but not interviews)

As part of the pre-launch efforts, we will conduct benchmarking research to identify peer programs that are already established or also in pilot phases. The research will be a broad scan of major utilities and program delivery agencies across North America to identify those with similar efforts in peak gas DR, community marketing strategies and geotargeting, elimination of up-front cost barriers, and both gas and electric utilities pursuing non-pipe and non-wires solutions. The purpose of this research will be to understand similar program design methods, implementation efforts, and program successes and challenges. The research will rely on a review of publicly available materials (using sources such as E-Source, jurisdictional program plans and frameworks) and Resource Innovation's knowledge and implementation of programs across North America. This research is intended to inform program design elements before launch. As originally stated in the proposal, key programs identified will be interviewed in early 2026, after Enbridge Gas's pilots have been running for a few quarters.

4 Post-Launch Data Collection

4.1 Activities Summary

The following table summarizes the data collection activities, estimated sample sizes, and frequency of data collection for the pilot after successful launch. Given the anticipated pilot start of July, quarterly data collection will begin in Q4 2025 (on Q3 2025 participants) through Q1 2027 (on Q4 2026 participants), for a total of six quarterly fieldings.

Table 4-1: Evaluation Data Collection Activities

Data Collection Activity	Mode	Total Sample	Each Feilding	Frequency
Pilot Staff Interviews	IDI	Census	Census	Quarterly
ETEE Participant Surveys	Web Survey	140	24	Quarterly
Electrification Participant Surveys	Web Survey	Up to 30	5	Quarterly
DR Participant Surveys	Web Survey	Up to 64	10	Every Event
Pilot Participant IDIs (Selected from ETEE, Electrification, and DR Participants)	IDI	90	15	Quarterly

Data Collection Activity	Mode	Total Sample	Each Feilding	Frequency
Broad-Based Participant Surveys	Web Survey	140	24	Quarterly
Service Providers/Contractor Surveys	IDI	90	15	Quarterly
ETEE/Electrification Near Participant Surveys	Web Survey	72	12	Quarterly
ETEE/Electrification Non-Participant Surveys	Web/Phone	200	100	Q1 2026, Q1 2027
DR Frequent Opt-Out Participants	Web Survey	TBD	TBD	Twice, after each heating season
Peer Program Interviews	IDI	5-10	5-10	Q1 2026

4.2 Staff Interviews

Interviews with Enbridge Gas staff will occur quarterly from Q3 2025 to Q1 2027. These interviews will occur with the same staff who were interviewed in the pre-launch staff interview (see section 3.2).

The purpose of these interviews is to have group discussions to discuss:

- Pilot design changes
- Challenges that are coming up
- Any new data obtained between discussions
- Staff interpretations of results and feedback the Resource Innovations team obtains
- For the final discussion, staff reactions to potential recommendations and collaboration to ensure final recommendations are actionable

4.3 Participant Surveys and IDI's

Table 4-2 outlines which data source will allow for an analysis and understanding of each research objective of the process evaluation.

Table 4-2. Outreach Research Topics Addressed by Data Sources

Outreach Research Topics		Participant Surveys	Near Participant Surveys	Non-Participant Surveys	Frequent Opt-Out Participant Surveys
Awareness and Engagement	Participant awareness sources of the pilot	✓	✓	✓	✓
	Participant awareness sources of energy efficient technologies	✓	✓	✓	
	Need for modifications to marketing strategies or additional marketing	✓	✓	✓	✓
Program experience and satisfaction	Number of challenges/concerns with the overall pilot	✓	✓	✓	✓
	Percentage of participants satisfied with the pilot	✓			✓
Motivations	Motivation for participation	✓			
	Motivation for opting out of events (DR)				✓
Challenges and opportunities for improvement	Potential barriers to the delivery of the pilot	✓	✓	✓	✓
	Suggestions on how to improve the delivery of the pilot	✓	✓	✓	✓
Participant characteristics	Income, location, homeownership, and household size	✓	✓	✓	✓
	Explore potential for participation in other segments of the population	✓	✓	✓	✓

4.3.1 EE Pilot Participants

We will conduct participant surveys and IDI's for EE Pilot Participants for both residential and C&I pilot offerings. We will coordinate with Enbridge Gas to receive a list of participants to survey and interview. Instruments and guides will be provided to Enbridge Gas and the TWG in advance for review. Participants will be offered a $50 incentive for completing the survey, using Tango for immediate gift card fulfillment. The following topics will be covered:

- Information sources
- Marketing clarity
- Motivations/perceived value
- Likelihood to have participated had they been offered the broad-based equivalent
- Relationship with any prior DSM participation
- Barriers/limitations to participation
- Experience with the program process
- Missed or future opportunities
- Suggestions for program improvement

The ETEE data collection will be broken into the following offers:

- C&I Direct Install
- C&I Prescriptive Downstream
- Commercial Custom
- Industrial Custom
- Residential Whole Home – both Direct Install and Rebate streams
- Single Measure Residential Program – Attic Insulation

C&I Analysis Considerations

To better characterize the feedback of commercial and industrial customers, large customers will be segmented by:

- Building size and type
- Building ownership type
- Industry/business type
- Processes relevant to energy use occurring in the building

By segmenting the larger customers in this way, program benefits and barriers can be understood in the context of the relevant building and market characteristics. Tailored recommendations will be made about enhancing incentives for larger customers that use more energy.

4.3.2 Electrification Pilot Participants

We will conduct participant surveys and IDI's for Limited ETEE Offering for Electrification Measures participants. We will coordinate with Enbridge Gas to receive a list of participants to survey and interview. We will attempt to survey all potential participants (up to 30) and interview a subset of each the ccASHP and GSHP participants. Participants will be offered a $50 incentive for completing the survey, using Tango for immediate gift card fulfillment. We will recruit participating customers for interviews from among survey respondents who have shown a willingness to conduct a follow-up phone interview in exchange for a $150 gift card. We anticipate that interviews will last, on average, 30-40 minutes.

Survey instruments and IDI guides will be developed by the RI team and provided to the Enbridge Gas team and the TWG in advance to provide feedback. Once the instrument and guide are approved, recruitment will begin by email, phone, and direct mail, if necessary.

The following topics will be covered:

- Information sources
- Marketing clarity
- Motivations/perceived value
- Relationship with any prior DSM participation
- Barriers/limitations to participation
- Experience with the pilot process
- Missed or future opportunities
- Suggestions for pilot improvement

4.3.3 DR Pilot Participants

We will conduct participant surveys and IDI's for Residential Demand Response ("DR") participants. We will coordinate with Enbridge Gas to receive a list of participants to survey and interview. We will target 64 total completed surveys, and 20 completed IDIs throughout the pilot. Participants will be offered a $50 incentive for completing the survey, using Tango for immediate gift card fulfillment. We will recruit participating customers for interviews from among survey respondents who have shown a willingness to conduct a follow-up phone interview in exchange for a $150 gift card. We anticipate that interviews will last, on average, 30-40 minutes.

Survey instruments and IDI guides will be developed by the RI team and provided to the Enbridge Gas team and the TWG in advance to provide feedback. Once the instrument and guide are approved, recruitment will begin by email, phone, and direct mail, if necessary.

The following topics will be covered:

- Information sources
- Marketing clarity
- Motivations/perceived value
- Relationship with any prior DSM participation
- Barriers/limitations to participation, such as any impact on comfort
- Experience with the pilot process
- Missed or future opportunities
- Suggestions for pilot improvement

4.3.4 Broad-Based Program Participants

We will conduct participant surveys and IDIs with Enbridge Gas Program participants outside of the pilot territory to understand:

- How program participation differs in this program path compared to the pilot
- How motivation to participate in this program path differs compared to the pilot
- The perceived value of participating in the program
- The challenges of participating in the program

We will coordinate with Enbridge Gas to receive a list of participants to survey and interview. We will target 140 completed surveys in total throughout the pilot. Participants will be offered a $50 incentive for completing the survey, using Tango for immediate gift card fulfillment.

Survey instruments and IDI guides will be developed by the RI team and provided to the Enbridge Gas team and the TWG in advance to provide feedback. Once the instrument and guide are approved, recruitment will begin by email, phone, and direct mail, if necessary.

4.4 Service Providers/Contractor IDIs

Service providers/contractors serve a key role in helping participants through the pilot process. As such, we will conduct in-depth interviews with service providers and contractors participating in the existing DSM programs and the ETEE pilot to gain a better understanding of their role and how they interact with participants and what feedback they have to improve the existing programs and pilot.

We will coordinate with Enbridge pilot staff to obtain a list of contact information for service providers/contractors on a regular basis. From this list, we will identify potential interviewees based on their participation.

We will conduct the interviews quarterly and target up to 15 completions each round. Interviewees will be offered $150 gift cards for their time to participate in an interview, and we will use the Tango gift card platform for immediate fulfillment. We anticipate interviews will last, on average, 30-40 minutes.

IDI guides will be developed by the RI team and provided to the Enbridge Gas team in advance to provide feedback. Once the guide is approved, recruitment will begin by email, phone, and direct mail, if necessary.

The following topics will be covered:

- Information sources
- Marketing clarity
- Motivations/perceived value of the pilot
- Relationship with any prior DSM participation
- Barriers/limitations to participation, such as any impact on comfort
- Experience with the pilot process
- Missed or future opportunities
- Suggestions for pilot improvement

4.5 Near and Non-Participants

In addition to collecting survey data from pilot participants, we will also gather data from customers that chose not to engage with the pilot to some extent. This will include engaging those that began the pilot process, but did not move forward, as well as non-participants.

4.5.1 EE and Electrification Pilot Near Participants

For this effort, we will conduct web surveys with customers who had some level of engagement with the limited ETEE Offering and Electrification Measures. We will coordinate with Enbridge Gas to receive a list of contact information for near participants to survey. We will target 12 completed surveys each quarter, for a total sample of up to 72 near participants. Respondents will be offered a $50 incentive for completing the survey, using Tango for immediate gift card fulfillment.

Survey instruments will be developed by the RI team and provided to the Enbridge Gas team and the TWG in advance to provide feedback. Once the instruments are approved, recruitment will begin by email, phone, and direct mail, if necessary.

The following topics will be covered:

- Pilot communications
- Initial drivers and perceived value
- Barriers encountered
- Reason for non-participation (and current perceptions of value)
- Recommendations for improvements
- Potential for reengagement (with existing or modified pilot offers)
- Customers characteristics

4.5.2 Non-Participants

We will also conduct web surveys with customers who have not engaged with the limited ETEE Offering and Electrification Measures but were eligible to participate. These web surveys will be supplemented with phone survey efforts, if needed. We will coordinate with Enbridge Gas to receive a list of contact information for non-participants to survey. We will target up to 100 completed surveys, once in Q1 2026 and again in Q1 2027, for a total sample of up to 200 non-participants. Respondents will be offered a $50 incentive for completing the survey, using Tango for immediate gift card fulfillment.

Survey instruments will be developed by the RI team and provided to the Enbridge Gas team and the TWG in advance to provide feedback. Once the instruments are approved, recruitment will begin by email, phone, and direct mail, if necessary.

The following topics will be covered:

- Awareness
- Understanding of the pilot offering
- Perception of the pilot and measures
- Potential value
- Barriers to participation
- Recommendations for improvements
- Customer characteristics

4.5.3 DR Opt-Out Pilot Participants

For customers participating in the DR offering that frequently[1] opt-out of events, we will conduct web surveys to understand their justifications. We will coordinate with Enbridge Gas to receive a list of contact information for customers who frequently opt-out of events. We will target up to a statistically significant number of surveys based on the population of opt-outs after each heating season. Respondents will be offered a $50 incentive for completing the survey, using Tango for immediate gift card fulfillment.

Survey instruments will be developed by the RI team and provided to the Enbridge Gas team in advance to provide feedback. Once the instruments are approved, recruitment will begin by email, phone, and direct mail, if necessary.

The following topics will be covered:

- Participant and event experience
- Communications provided
- Opt-out process
- Reason for opting out
- Impact on customer of events/timing of events
- Recommendations for improvements to retain participants

4.6 Peer Program Interviews

In addition to the peer program benchmarking research that will be conducted at the beginning of the evaluation during the pre-launch phase, we will identify and conduct more detailed research, including interviews with key staff of identified programs. After the review of publicly available information, we will reach out to the jurisdiction to introduce ourselves to key staff, explain the purpose of our reach and request any additional information they have on their efforts and programs. We will coordinate will Enbridge any outreach to jurisdictions, to ensure we follow an acceptable approach, and Enbridge is involved with jurisdictions, where Enbridge has connections. We will target completing between 5-10 interviews with jurisdictions, in Q1 of 2026.

We will take this opportunity to ask if they would be willing to take part in an in-depth interview and, if so, to schedule a time after we have had a chance to review their additional materials. As an incentive to participate in the in-depth interview, we will share a summary of the findings and recommendations of the jurisdictional research with the jurisdiction.

[1] This will be defined with delivery agent input.

These in-depth interviews will follow a predetermined interview guide of questions but will also allow our team to ask off-screen questions related to their experience and lessons learned. We will review and finalize the interview guide with input from Enbridge.

The information obtained from the interviews will address the following topics:

- Program objectives and design
- Program performance
- Challenges, experiences, and adjustments made
- Lessons learned and best practices

5 Analysis and Synthesis

The above data collection activities and resulting findings will be synthesized into comprehensive findings for each element of the pilot.

5.1 ETEE Participation Analysis

Fundamental data for understanding the pilot's effectiveness, successes, and challenges will be available from the core data that Enbridge is already tracking. We will request EE participation data by measure, list of marketing and engagement activities with copies of the marketing material used, and pilot costs. We will analyze this data in combination with insights from the EE participant surveys and interviews. Analyses to complete include:

- Pilot goals and anticipated levels of participation
- Correlations of pilot participation upticks to discrete periods of marketing and engagement activities
- Expected costs and budgets compared to actual expenditure
- Compare differences in attitudes, behaviours, exposure to marketing for participants, near-participants, and non-participants

We will summarize findings into quarterly summary memos to answer questions about "why" participation levels differed from expected or met expectations, for example. We will provide recommendations for how to increase participation, improve marketing materials, and how to address barriers that near- and non-participants experience.

5.2 Electrification Participation Analysis

Similar to ETEE, we will request all pertinent pilot data to analyze the pilot's effectiveness, successes, and challenges. We will analyze this data in combination with insights from the electrification pilot participant, near, and non-participant surveys and interviews. Analyses to complete include:

- Pilot goals and anticipated levels of participation
- Correlations of pilot participation upticks to discrete periods of marketing and engagement activities
- Expected costs and budgets compared to actual expenditure
- Motivations for electrification
- Barriers to electrification

We will summarize findings into quarterly summary memos to answer questions about "why" participation levels differed from expected or met expectations, or what motivates people to electrify, for example. We will provide recommendations for how to increase participation, improve marketing materials, and how to address barriers to electrification.

5.3 DR Participation Analysis

Following the survey process, we will analyze responses to gather the primary takeaways from the DR pilot participants, near participants, and frequent opt-out participants. The survey data will be collected from Qualtrics and stored securely. An analysis template will be created in Excel outlining the research objectives and any notable findings and responses from the surveys that address the objectives. The survey data will be analyzed in Microsoft OfficeReports, where descriptive statistics and cross tabulations will be created for comparisons across different groups.

Similar to other efforts, some fundamental data for understanding the pilot's effectiveness, successes, and challenges will be available from the core data that Enbridge is already tracking. We will analyze this data in combination with insights from the DR pilot participant, near participant, and frequent opt-out participant surveys. We will summarize findings into quarterly memos synthesizing the findings of the DR pilot implementation. We will provide recommendations for how to increase participation, improve marketing materials, how to address barriers to ongoing participation, and any other feedback provided by the participants, near participants, and frequent opt-out participants.

5.4 Service Provider/Contractor Analysis

Following the interview process, we will analyze responses from the IDIs to gather the primary takeaways. The IDIs will be recorded and transcribed to aid in analysis (if permitted). An analysis template will be created in Excel outlining the research objectives and quotations from the interviews that address the objectives.

Similar to other efforts, some fundamental data for understanding the pilot's effectiveness, successes, and challenges will be available from the core data that Enbridge is already tracking. We will request electrification participation data by measure, list of marketing and engagement activities with copies of the marketing material used, and pilot costs. We will analyze this data in combination with insights from the electrification pilot service provider/contractor interviews. Analyses to complete include:

- Correlations of pilot participation upticks to discrete periods of marketing and engagement activities
- Customer engagement
- Customer motivations for electrification and increasing efficiency
- Barriers to electrification and increasing efficiency
- Potential for pilot improvements

We will summarize findings into quarterly summary memos to answer questions about "why" participation levels differed from expected or met expectations, or what motivates people to electrify, for example. We will provide recommendations for how to increase participation, improve marketing materials, how to address barriers to electrification, and any other feedback provided by the service providers/contractors.

5.5 Peer Program Research

The peer program research and interview findings will be layered into the final report in applicable measures and sectors, highlighting similarities and differences between Enbridge Gas's pilot and other programs. Any pertinent information will be shared with Enbridge staff at the time of discovery.

5.6 Tracking Data Analysis

To augment the primary data collection and provide additional insights into the pilot's effectiveness, successes, and challenges, we will compile and analyze the core pilot data that Enbridge tracks on a quarterly basis. After the participant database is set up, we will request the data fields being tracked by Enbridge, analyze it, and recommend any changes or additions to the data points being tracked.

After the first quarter of participation, we will submit a data request memo to Enbridge in which we define the data we will need and specify the cadence for any updates, with quarterly cadence being appropriate for most data points. The types of data we envision requesting and analyzing include:

- Pilot participation data for the ETEE pilot (by subpilot and measure) and the DR pilot (with project-level start and completion dates)

- Participating customer characteristics available in Enbridge's customer information system (for classification and analytical purposes)
- Participating customer contact information (for survey sampling and outreach)
- Participating participation data for the broad-based DSM program (historic and concurrent)
- List of marketing and engagement activities with identification of targeted customers and dates of activity
- Copies of marketing and pilot information used
- Costs data for the ETEE and DR pilots
- Comparative cost data for the broad-based DSM programs (historic and concurrent)

Analysis of these data will be self-contained in some cases and combined with survey and interview data in other cases. Analyses we intend to perform include:

- Comparisons of measure and subprogram-level participation in the pilot to:
    - Pilot goals and anticipated levels of participation
    - Relative experiences from the underlying broad-based DSM programs outside the pilot area
    - Pre-pilot participation in the comparable broad-based DSM programs inside the pilot area (and to concurrent participation, if relevant)
- Correlations of pilot participation upticks to discrete periods of marketing and engagement activities
- Comparisons of overall and unit-level incentive, marketing, and administrative costs for the pilots compared to:
    - Expected costs and budgets
    - Underlying broad-based DSM program costs

These analyses can stand on their own, and we will summarize our findings in quarterly summary memos. These analyses will also raise unanswered questions of the "why" nature. That is, we may see higher or lower participation levels in aspects of the pilot than one would expect but now know why. We will rely on observations from pilot staff and partners and on carefully crafted exploratory questions included in customer surveys and in pilot participant interviews to better understand what decisions and reactions to the pilot by the market are leading to the results Enbridge is experiencing. We will update the analyses to be conducted and document them in the quarterly memo. This memo will build on the data tracking and analyses we have begun to describe above and combine insights from the core data analysis with insights from pilot participants, implementers, contractors and service providers, and Enbridge staff.

5.7 Cost Analysis

During the preliminary review of core pilot data being tracked by Enbridge, we will ensure that the metrics required to calculate cost effectiveness at the measure, project, and pilot level are adequately being tracked. Additional data points such as pilot administration, delivery, marketing, and incentive costs will be defined within a data request memo to Enbridge in which we specify the need and timing of these additional cost metrics. As part of the interim report of the first year of the pilot and in the final evaluation report we will include results of the cost analysis. The analysis will be performed separately for the pilots as well as the broad-based programs and normalized into a savings per dollar metric for better comparison.

Specific, pilot-only and start up, costs will also be isolated to compare the cost per savings to identify if the additional pilot activities were successful in increasing not only participation but overall savings achievement. Electrification and DR pilot that do not have a direct comparison to broad-based programs can be qualitatively compared to other programs identified in the peer program benchmarking task.

5.8 Comparative Analysis

RI will identify a comparative Ontario city that resembles Sarnia in both weather and building make up. It is possible that there may be a suitable city for residential (with similar building types and vintage, as well as low to moderate income designation) and a different one for C&I (based on business type, size, and building types). Analysis of characteristics is ongoing, but potential options for comparison cities are Hamilton for C&I (based on similar weather and heavy industry) and Chatham or London for residential (based on weather and residential building types).

Enbridge Gas is currently compiling the available data on customers and projects achieved through the existing broad-based programs to assist in selecting the comparison location(s). Important, ideal data fields include:

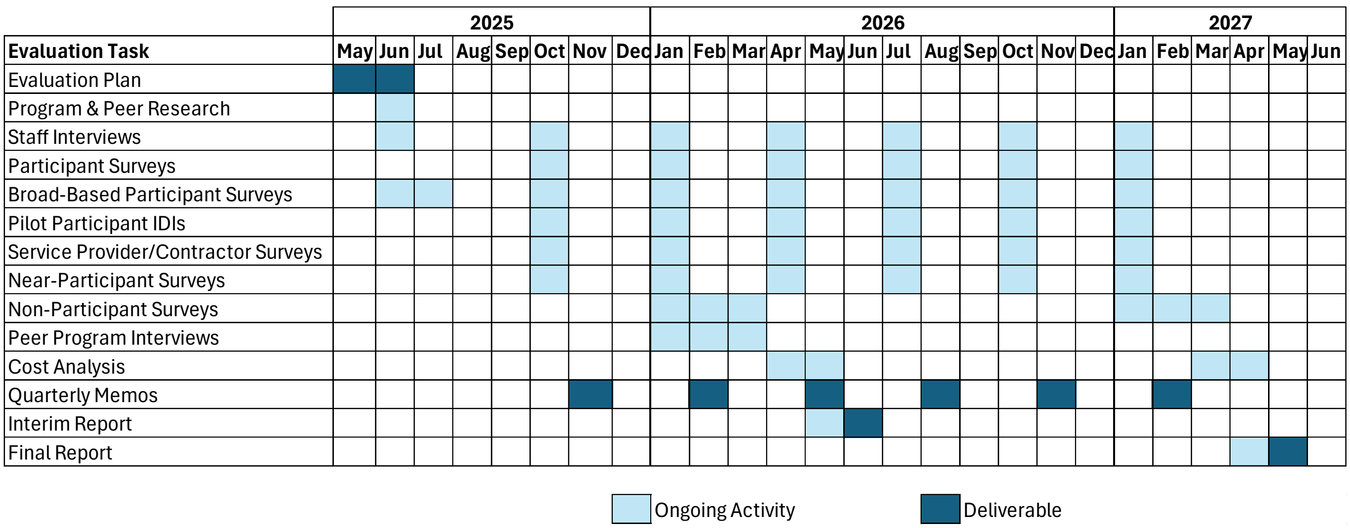
- Program name
- Location (postal code, urban vs rural)
- Building type
- Business type (if applicable)
- Pre- and post- project natural gas consumption
- Project measures and specifications

These characteristics will allow RI to create like for like comparison groups for specific program offerings and analyze the differences or similarities between participation rates, costs, energy savings, satisfaction, perceived motivators, barriers, program awareness, and more. Comparisons will be made at the average project level, town/city level, as well as Ontario overall.

6 Timeline

The evaluation will begin in Q2 2025 to support pilot pre-launch activities and will run through Q2 of 2027. Evaluation tasks and timing are shown below.

Figure 1. Evaluation Timeline



7 Reporting

As discussed throughout the plan, each evaluation activity performed quarterly will be summarized into quarterly memos and shared with Enbridge staff. Throughout the pilot, and when deemed appropriate, RI and Enbridge will hold technical working group meetings to discuss progress and findings to date, and future evaluation and program plans.

An interim report will be provided in Q2 2026 that will pull together all activities, findings, and potential recommendations. A final report summarizing the pilot in its entirety will be provided in Q2 of 2027. Both the interim and final reports will be first provided in draft form for review by Enbridge for a minimum of two weeks and finalized after any necessary discussions.

Southern Lake Huron Pilot

—

Estimated Unit Rate and Bill Impact

ENBRIDGE

IRP Capital Costs Revenue Requirement - Southern Lake Huron Pilot Project

Line No.	Particulars ($000s)	2023	2024	2025	2026	2027	2028
		(a)	(b)	(c)	(d)	(e)	(f)
	Incremental Rate Base Investment						
1	Capital Expenditures (1)	-	99	235	-	-	-
2	Average Rate Base	-	-	41	317	287	258
	Incremental Revenue Requirement Calculation:						
	Return on Incremental Rate Base: (2)						
3	Long-term Debt Interest	-	-	1	8	7	7
4	Short-term Debt Interest	-	-	0	0	0	0
5	Preference Shares	-	-	-	-	-	-
6	Equity	-	-	1	11	10	9
7	Total Return on Incremental Rate Base	-	-	2	19	17	16
	Incremental Operating Expenses:						
8	Depreciation Expense (3)	-	-	2	30	30	30
9	Total Incremental Operating Expenses	-	-	2	30	30	30
	Incremental Income Taxes:						
10	Return on Equity and Preference Shares (line 5 + line 6)	-	-	1	11	10	9
	Utility Timing Differences						
11	Add: Depreciation Expense (line 8)	-	-	2	30	30	30
12	Less: Current Year Tax Deductions	-	-	(20)	(19)	(18)	(17)
13	Taxable Income (line 10 + line 11 + line 12)	-	-	(16)	22	22	22
14	Income Taxes Before Gross Up (line 13 x 26.5%) (4)	-	-	(4)	6	6	6
15	Total Incremental Income Taxes After Gross Up (line 14 / (1-26.5%) (4) (5)	-	-	(6)	8	8	8
16	Total Incremental Revenue Requirement (line 7 + line 9 + line 15)	-	-	(1)	57	55	53

Notes:

(1) Capital expenditures including indirect overheads per EB-2023-0335, Exhibit E, Tab 1, Schedule 1, Attachment 2.

(2) The return on rate base is calculated based on Union's 2013 Board-approved capital structure:

Capital Structure	Component %	Cost Rate	Return Component
Long-term Debt	61.30%	6.53%	4.00%
Short-term Debt	-0.03%	1.31%	0.00%
Preference Shares	2.74%	3.05%	0.08%
Equity	36.00%	8.93%	3.21%
Total	100.00%		7.30%

(3) Depreciation expense at Board-approved depreciation rates.

(4) Enbridge Gas's current provincial and federal tax rate is equal to 26.5%.

(5) Incremental taxes related to utility timing differences are negative if the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

ENBRIDGE GAS INC.
Allocation of EGI 2025 IRP Project Deferral Costs to Rate Zones

Line No.	Particulars ($ millions)	Allocation to Rate Zone (1)	Allocation Total ($000's) (2)
		(a)	(b)
1	EGD rate zone	6,729	3,571
2	Union rate zones	6,018	3,194
3	Total Balance (lines 1 + 2) (3)	12,748	6,765

Notes:
(1) 2018 actual rate base per EB-2019-0105, Exhibit B, Tab 2, Appendix B, Schedule 1 for the EGD rate zone and EB-2019-0105, Exhibit C, Tab 2, Appendix A, Schedule 4 for the Union rate zones.
(2) Column (b) allocated in proportion to column (a)
(3) The total balance in column (b) is from EB-2022-0335, Exhibit E, Tab 1, Schedule 2, Table 2.

Allocation
2025 IRP Operating & Capital Costs Account Balance

Line No.	Particulars	Board Approved Rate Base ($000s) (1)	Allocation ($000s) Operating Costs Southern Lake Huron (2)	Capital Costs Southern Lake Huron (2)	Allocation Total
		(a)	(b)	(c)	(d) = (b+c)
	EGD Rate Zone				
1	Rate 1	3,835,982	2,343	(0)	2,343
2	Rate 6 (3)	1,619,704	989	(0)	989
3	Rate 100	18,199	11	(0)	11
4	Rate 110	70,193	43	(0)	43
5	Rate 115	25,757	16	(0)	16
6	Rate 125	56,370	34	(0)	34
7	Rate 135	3,224	2	(0)	2
8	Rate 145	5,772	4	(0)	4
9	Rate 170	8,090	5	(0)	5
10	Rate 200	14,649	9	(0)	9
11	Rate 332 (4)	189,704	116	(0)	116
12	Total EGD Rate Zone (5)	5,847,642	3,572	(0)	3,571
	Union North Rate Zone				
13	Rate 01	659,800	571	(0)	571
14	Rate 10	101,688	88	(0)	88
15	Rate 20	72,027	62	(0)	62
16	Rate 25	19,712	17	(0)	17
17	Rate 100	55,495	48	(0)	48
18	Total Union North Rate Zone	908,722	786	(0)	786
	Union South Rate Zone				
19	Rate M1	1,441,159	1,247	(0)	1,247
20	Rate M2 (6)	218,335	189	(0)	189
21	Rate M4	54,282	47	(0)	47
22	Rate M5	46,033	40	(0)	40
23	Rate M7	18,903	16	(0)	16
24	Rate M9	3,583	3	(0)	3
25	Rate T1	37,644	33	(0)	33
26	Rate T2	166,377	144	(0)	144
27	Rate T3	21,976	19	(0)	19
28	Total Union South Rate Zone	2,008,293	1,738	(0)	1,738
	Union Ex-Franchise				
29	Rate C1	6,894	6	(0)	6
30	Rate M12	765,893	663	(0)	663
31	Rate M13	521	0	(0)	0
32	Rate M16	947	1	(0)	1
33	Total Union Ex-Franchise	774,255	670	(0)	670
34	Total Union Rate Zones (7)	3,691,271	3,194	(0)	3,194
35	Total Enbridge Gas (8)	9,538,913	6,766	(1)	6,765

Notes:

(1) EGD rate zone rate base per EB-2017-0086, Exhibit G2, Tab 5, Schedule 1, Item No. 6 and Union rate zone rate base per EB-2011-0210, Exhibit G3, Tab 2, Schedule 2, pp.1-3, RATE BASE line.

(2) Allocated by rate zone in proportion to column (a).

(3) Includes Rate 300 rate base of $0.449 MM.

(4) The amount in column (a) is equal to 60% of the 2018 utility rate base amount, for the shared transportation component of Segment A of the GTA Project, as per EB-2012-0459, Exhibit C1, Tab 5, Schedule 1, Appendix D, page 2, updated to reflect the approved depreciation rates.

(5) Total in column (d) as per Page 1, line 1, column (b).

(6) Includes Rate M10 rate base of $0.138 MM.

(7) Total in column (d) as per Page 1, line 2, column (b).

(8) The total balance in columns (b) & (c) from EB-2022-0335, Exhibit E, Tab 1, Schedule 2, Table 2.

Unit Rates for Disposition
2025 IRP Operating & Capital Costs Account Balance

Line No	Particulars	Account Balance for Disposition (1) ($000s)	2025 Forecast Usage (2) (10^3m^3)	Billing Units	Unit Rate for Disposition
		(a)	(b)	(c)	(d) = (a/b*100)
	EGD Rate Zone				
1	Rate 1	2,343	4,997,086	10^3m^3	0.0469
2	Rate 6	989	4,714,489	10^3m^3	0.0210
3	Rate 100	11	27,429	10^3m^3	0.0405
4	Rate 110	43	1,068,281	10^3m^3	0.0040
5	Rate 115	16	381,873	10^3m^3	0.0041
6	Rate 125	34	824,971	10^3m^3	0.0042
7	Rate 135	2	52,646	10^3m^3	0.0037
8	Rate 145	4	15,714	10^3m^3	0.0224
9	Rate 170	5	323,254	10^3m^3	0.0015
10	Rate 200	9	188,852	10^3m^3	0.0047
11	Rate 332	116			
12	Total EGD Rate Zone	3,571			
	Union North Rate Zone				
13	Rate 01	571	1,002,145	10^3m^3	0.0570
14	Rate 10	88	308,113	10^3m^3	0.0286
15	Rate 20	62	929,101	10^3m^3	0.0067
16	Rate 25	17	126,831	10^3m^3	0.0134
17	Rate 100	48	1,076,378	10^3m^3	0.0045
18	Total Union North Rate Zone	786			
	Union South Rate Zone				
19	Rate M1	1,247	3,190,446	10^3m^3	0.0391
20	Rate M2	189	1,223,186	10^3m^3	0.0154
21	Rate M4	47	592,623	10^3m^3	0.0079
22	Rate M5	40	59,493	10^3m^3	0.0670
23	Rate M7	16	789,737	10^3m^3	0.0021
24	Rate M9	3	90,073	10^3m^3	0.0034
25	Rate T1	33	431,289	10^3m^3	0.0076
26	Rate T2	144	5,005,643	10^3m^3	0.0029
27	Rate T3	19	249,200	10^3m^3	0.0076
28	Total Union South Rate Zone	1,738			
	Union Ex-Franchise				
29	Rate C1	6			
30	Rate M12	663			
31	Rate M13	0			
32	Rate M16	1			
33	Total Ex-Franchise	670			
34	Total Union Rate Zones	3,194			
35	Total Enbridge Gas	6,765			

Notes:
(1) 2024 IRP Annual Report, Appendix H: IRP Pilot Project Update, Attachment 2, page 2, column (d).
(2) EB-2024-0111, Rate Order, Working Papers, Schedule 5, column (k).

Bill Impacts for Typical Customers
2025 IRP Operating & Capital Costs Account Balance

Line No.	Particulars	Unit Rate for Disposition (1) (cents/m³)	Annual Volume		Bill Impact ($)
		(a)	(b)	(c)	(d)
	EGD Rate Zone				
1	Rate 1 - Small	0.0469	2,400	m³	1.13
2	Rate 1 - Large	0.0469	5,048	m³	2.37
3	Rate 6 - Small	0.0210	5,048	m³	1.06
4	Rate 6 - Average	0.0210	22,606	m³	4.74
5	Rate 6 - Large	0.0210	339,124	m³	71.15
6	Rate 100 - Small	0.0405	339,188	m³	137
7	Rate 100 - Average	0.0405	598,567	m³	243
8	Rate 100 - Large	0.0405	1,500,000	m³	608
9	Rate 110 - Small	0.0040	598,568	m³	24
10	Rate 110 - Average	0.0040	9,976,120	m³	400
11	Rate 110 - Large	0.0040	9,976,121	m³	400
12	Rate 115 - Small	0.0041	4,471,609	m³	184
13	Rate 115 - Large	0.0041	69,832,850	m³	2,877
14	Rate 125 - Average	0.0042	598,567	m³	25
15	Rate 135 - Average	0.0037	598,567	m³	22
16	Rate 145 - Small	0.0224	339,188	m³	76
17	Rate 145 - Average	0.0224	598,567	m³	134
18	Rate 170 - Average	0.0015	9,976,120	m³	152

Notes:
(1) 2024 IRP Annual Report, Appendix H: IRP Pilot Project Update, Attachment 3, column (d).

Bill Impacts for Typical Customers
2025 IRP Operating & Capital Costs Account Balance

Line No.	Particulars	Unit Rate for Disposition (1) (cents/m³)	Annual Volume		Bill Impact ($)
		(a)	(b)	(c)	(d)
	Union North Rate Zone				
1	Rate 01 - Small	0.0570	2,200	m³	1.25
2	Rate 01 - Large	0.0570	40,000	m³	22.79
3	Rate 10 - Small	0.0286	60,000	m³	17
4	Rate 10 - Average	0.0286	93,000	m³	27
5	Rate 10 - Large	0.0286	250,000	m³	71
6	Rate 20 - Small	0.0067	3,000,000	m³	201
7	Rate 20 - Large	0.0067	15,000,000	m³	1,006
8	Rate 25 - Average	0.0134	2,275,000	m³	306
9	Rate 100 - Small	0.0045	27,000,000	m³	1,205
10	Rate 100 - Large	0.0045	240,000,000	m³	10,707
	Union South Rate Zone				
11	Rate M1 - Small	0.0391	2,200	m³	0.86
12	Rate M1 - Large	0.0391	40,000	m³	15.63
13	Rate M2 - Small	0.0154	60,000	m³	9
14	Rate M2 - Average	0.0154	73,000	m³	11
15	Rate M2 - Large	0.0154	250,000	m³	39
16	Rate M4 - Small	0.0079	875,000	m³	69
17	Rate M4 - Large	0.0079	12,000,000	m³	951
18	Rate M5 - Small	0.0670	825,000	m³	552
19	Rate M5 - Large	0.0670	6,500,000	m³	4,352
20	Rate M7 - Small	0.0021	36,000,000	m³	746
21	Rate M7 - Large	0.0021	52,000,000	m³	1,077
22	Rate M9 - Small	0.0034	6,950,000	m³	239
23	Rate M9 - Large	0.0034	20,178,000	m³	695
24	Rate T1 - Small	0.0076	7,537,000	m³	569
25	Rate T1 - Average	0.0076	11,565,938	m³	874
26	Rate T1 - Large	0.0076	25,624,080	m³	1,935
27	Rate T2 - Small	0.0029	59,256,000	m³	1,704
28	Rate T2 - Average	0.0029	197,789,850	m³	5,688
29	Rate T2 - Large	0.0029	370,089,000	m³	10,644
30	Rate T3	0.0076	272,712,000	m³	20,809

Notes:
(1) 2024 IRP Annual Report, Appendix H: IRP Pilot Project Update, Attachment 3, column (d).

Indigenous Working Group Report

May 30, 2025

ENBRIDGE
Life Takes Energy

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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 that have joined the IWG are Mississaugas of Scugog Island First Nation, Chippewas of the Thames First Nation, 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. April 30, 2024 in-person
2. July 30, 2024 in-person
3. October 17, 2024 Virtual
4. December 10, 2024 in-person
5. March 4, 2025 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 approved 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:

- OEB Notice of Appeal and Filing of Review Motion on Phase 1
- IWG report for Deferrals Filing
- Enbridge Indigenous Procurement Policy
- Enbridge Indigenous Employment Practices
- Retention of IWG experts
- Information on the Brattle Group report
- Energy transition and demand side management programs
    - Heat pumps – determining pilot on First Nation reserve
    - CGHG/HER+
    - Regional scenario analysis project
- Fugitive emissions and unaccounted for gas
- IWG Reconciliation Requirements
- IWG Way of Life and Stewardship over the Land
- IWG engagement protocols and template
- Engagement Template process
- Brattle Group presentation
- Enbridge Inc. Indigenous Reconciliation Action Plan (IRAP)
- DSM Intervenor Response Letter
- Reconciliation – Discussion on IWG Principles and Enbridge Reconciliation Approach
- Toronto Star Green Loans Article

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:

- Fugitive Emissions Presentation, led by Enbridge Gas Manager of Carbon Strategy, which included an overview of GHG emission sources, reduction and targets, with an introduction to the Federal Methane Regulations, current emissions reductions, and the Fugitive Emissions Measurement Plan. Presented to the IWG on December 14, 2023, at the request of TFG. A follow up presentation on the progress of the Enbridge Gas study into the measurement plan was presented to the IWG on April 30, 2024, at the request of Don Richardson and Minogi Corp.
- Federal Greener Homes Program Update, presented by Enbridge Gas Manager of Residential Energy Conservation, which discussed updates and status of the program, and how the changes will affect Enbridge Gas's offerings and role as a gas service provider. Presented to the IWG on April 30, 2024, at the request of Don Richardson and Minogi Corp.
- Supply Chain Management (SCM) – Indigenous Engagement, presented by Richard Brant, Supply Chain Analyst – Indigenous Engagement, on Enbridge Gas's procurement policy, reporting and target setting in SCM. Presented to the IWG on April 30, 2024, at the request of TFG.
- Indigenous Employment Practices, presented by Enbridge Inc. Senior Strategist on Indigenous Collaboration and Enbridge Inc. Indigenous Recruitment Advisor. Presentation provided an update on the employment practices and opportunities at Enbridge corporate and outlined resources available to Indigenous employees across the entire company. Presented to the IWG on April 30, 2024, at the request of TFG.
- IWG Reconciliation Requirements, presented by Kate Kempton, Woodward and Company, which identified ten principles or requirements that the Indigenous

IWG members would like Enbridge Gas to follow. She explained that all ten are necessary components and cannot go without each other. Presented to the IWG on July 30, 2024.

- IWG Way of Life and Stewardship of Land, presented by Kodi Chrisjohn-Deleary, Chippewas of the Thames, which identified the ongoing challenges for Indigenous groups and proposed opportunities, including Indigenous buy-in, increasing inclusivity in the decision-making space, increasing equity and project creditability leaving the earth better than now for further generations. Presented to the IWG on July 30, 2024.
- Engagement Protocol, presented by Emily Ferguson, Minogi Corp, which emphasized the need for stronger engagement in all stages of Enbridge Gas project process. The presentation provided an engagement checklist for Enbridge Gas during pre-construction, construction and restoration and post construction. IWG suggested setting up a smaller group to address. Presented to the IWG on July 30, 2024.
- Enbridge Inc. IRAP, presented by Enbridge Inc. Kim Brenneis - Director, Community and Indigenous Engagement, which provided an overview on the Enbridge IRAP and the progress in meeting the commitments outlined in the plan. Presented to the IWG on December 10, 2024.
- The Brattle Group report, presented by Bruce Tsuchida, Tom Chapman and Peter Fraser from The Brattle Group. The presentation reviewed Enbridge Gas's current transition plans and identified areas for improvement. The presentation also outlined opportunities for Enbridge Gas to further its efforts towards energy transition and address the IWG's feedback. The three recommendations from The Brattle Group were improving on the analysis already completed by Enbridge Gas, committing to equity and how the IWG could be improved. Presented to the IWG on December 10, 2024.
- Regional Scenarios Analysis Project, presented by Enbridge Gas, Cody Wood-Supervisor Energy Policy & Planning, who discussed the planning process for

external and Indigenous engagement for the Project. Presented to the IWG on December 10, 2024.

- Enbridge Gas discussion on IWG Reconciliation Requirements and Enbridge Inc.'s reconciliation approach, presented by Enbridge Inc. Kim Brenneis - Director, Community and Indigenous Engagement, who reviewed the 2025 IRAP refresh that Enbridge Inc. had completed and addressed the 10 reconciliation requirements previously provided by Kate Kempton. The discussion addressed themes of decision making, co-management and the lifecycle approach, accommodation, and projection of the environment. This discussion was held on March 4, 2025.

6. Summary of IWG Initiatives

In addition to the two initiatives identified in 2023, fugitive emissions and Home Winterization Program, the IWG and Enbridge Gas have been working together to identify a First Nation community to advance a heat pump pilot.

A smaller group within the IWG was struck to develop an Engagement Template to assist with the IWG's review of the Indigenous engagement policies and practices on Enbridge Gas projects, including with respect to: early engagement and information sharing; understanding values, rights, histories, culture, laws, jurisdiction; and environmental protection during all phases of construction.

7. IWG Capacity Funding for 2026

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 2026 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 2026 of $800,000, described as follows:

1. There is a reasonable likelihood that First Nation membership of the IWG will continue to increase, which would mean increased representation and/or coordination costs.
2. There is an expectation that 2026 will likely see an increased need for legal and technical expert assistance, given the issues for the year including the 2025 Indigenous Reconciliation Action Plan refresh and preparation for 2026, 2027, and 2028 rate planning issues that will play into the 2029 rate rebasing application expected to be filed in 2027/2028.
3. There is a growing need to reflect the changing composition of representatives attending and supporting the IWG by amending the previous category of "consultants" to include First Nation representatives who are rightsholders and not consultants.
4. Finally, the capacity funding costs of the IWG over its first full year of operation are likely not representative of the reasonable ongoing costs that will be necessary to participate in and support the IWG, as a significant portion of the expenses incurred during 2024 were invoiced in 2025.
5. The requested capacity funding costs for the IWG for 2026 are:
    i. $295,000 for legal support;
    ii. $255,000 for consultants and First Nation representatives; and
    iii. $250,000 for experts.

Enbridge Gas will pay the capacity funding in accordance with the Settlement Agreement, based on actual reasonable costs incurred and appropriately invoiced by the Indigenous Parties to participate in the IWG.

Enbridge Gas Inc. Indigenous Working Group Minutes - FINAL

Minutes of a meeting of the Indigenous Work Group (IWG) held on **April 30,2024** at 9:00 a.m. EST at Enbridge Gas Inc., 500 Consumers Road, North York, Ontario M2J 1P8.

PRESENT

Don Richardson (in-person)	Minogi Corp
Emily Ferguson (virtual	Minogi Corp
Todd Jardine (virtual)	Three Fires Group
Reggie George (virtual)	Three Fires Group
Jessica Wakefield (in-person)	Three Fires Group
Nick Daube (in-person)	Resilient LLP, Three Fires Group, Minogi Corp
John Glover (virtual)	Minodahmun Development LP
Kate Kempton (in-person)	Woodward and Company, Ginoogaming First Nation
Jordan George (virtual)	Kettle and Stony Point First Nation
Jennifer Mills (virtual)	Chippewas of the Thames First Nation
Tracy Skye (in-person)	Six Nations Natural Gas
Diana Audino (in-person)	Enbridge Gas Inc.
Lauren Whitwham (in-person)	Enbridge Gas Inc.
Tania Persad (in-person)	Enbridge Gas Inc.
Brent Bullough (in-person)	Enbridge Gas Inc.
Sarah Taylor (in-person)	Enbridge Gas Inc.
Craig Fernandes (in-person)	Enbridge Gas Inc.
Richard Brant (in-person)	Enbridge Gas Inc.
Mark Shilliday (virtual)	Enbridge Gas Inc.
Peter Mussio (virtual)	Enbridge Gas Inc.
Sarah Crowell (virtual)	Enbridge Gas Inc.
Henry Ren (virtual)	Enbridge Gas Inc.
Jody Whitney (virtual)	Enbridge Gas Inc.

1. MATTERS FOR DISCUSSION

Review of Agenda (attached at Appendix A) and Logistics.

- Lauren Whitwham, Enbridge Gas Inc., chaired the meeting, consensus to continue to rotate the facilitator/chair of each IWG meeting.
- Brent Bullough provided a safety moment. Lauren Whitwham proposed that going forward any interested IWG members could share a safety or cultural moment at a future meeting.
- IWG welcomed additional Indigenous representatives from Three Fires Group and confirmed as per the Ontario Energy Board (OEB) Settlement Agreement any interested Indigenous Party could be included in the IWG.
- IWG confirmed that the meetings should continue to be hybrid (in person, but with a virtual option) to ensure inclusion and accessibility.
- IWG discussed and approved the minutes of the December 14, 2023 IWG meeting.

1. Updates related to OEB Rebasing Proceeding
   - Tania Persad provided an overview of the OEB Decision and Order EB-2022-0200, Enbridge Gas Inc. Application for 2024 Rates – Phase 1 (Rebasing Decision) and its implications to the IWG.
     - Details of the Rebasing Decision were discussed and explained to the IWG.
     - Enbridge Gas advised that it has filed a Motion to Review with OEB (Review Motion) and a Notice of Appeal with the Ontario Divisional Court. The Review Motion will be dealt with first but is currently in abeyance until June. The OEB stayed part of the Rebasing Decision dealing with the revenue horizon.
     - Discussions of the Provincial Government's proposed legislation, Bill 165, to set aside the revenue horizon portion of the Rebasing Decision and to require the OEB to set a revenue horizon through a generic proceeding that takes into account the views of impacted parties.
     - Noted Enbridge Gas's plan to file an amended notice of Review Motion, to remove at least the revenue horizon issue.
   - Phase 2 of the rebasing proceeding has commenced with Enbridge Gas's evidence filed at the end of April 2024.
     - The procedural order issued by the OEB and the issues included in the order were discussed.
   - Kate Kempton on behalf of Ginoogaming gave notice to the group that Ginoogaming is thinking of challenging Bill 165 on the basis that it is not tough on climate change and places an undue burden on Indigenous groups who already pay a higher proportion of their income on basic living expenses including natural gas costs.
     - A request was made that Enbridge Gas Inc. consider changing its stance on the legislation and voicing to the government that this legislation is not in the best interest of Indigenous groups.
     - A request was made that a meeting in the future include both the Chief of Ginoogaming and a high level representative of Enbridge Gas to discuss the direction Enbridge Gas is heading with this.
   - Kate Kempton, on behalf of Ginoogaming, spoke at length about Indigenous way of life including a much more holistic and interconnected worldview and relationship to all beings, of caring for all beings and Mother Earth. She spoke on how the Western worldview, which came to dominate North America through colonialism, is atomistic, linear and based on dominance and exploitation of the Earth, which is what has led to the catastrophe of climate change that threatens to be an extinction event. Unless and until those who are responsible and profit from goods that cause climate change accept that the status quo and incremental change will only see us to an extinction, and that fundamental change is necessary now, we will fail. One of those is Enbridge, and we are appealing to Enbridge to learn from and work with First Nations to make this fundamental shift away from gas, starting right now.
   - Frustration by all IWG parties was shared about the recent IESO Expedited Long Term Procurement process, where many clean energy projects were not selected for funding, including the battery storage project between Enbridge Gas and Three Fires Group.

2. Updates on the Enbridge Gas fugitive emissions study.
   - Presentation by Peter Mussio, Manager of Carbon Strategy at Enbridge Gas Inc. as requested by Don Richardson and Minogi Corp.
   - The presentation gave an outline and purpose of the study that has been completed, and a review of the findings and technology that is available.
   - The study was outlined to the group with explanations on the measurements and the technology review that took place. The purpose of the study is to improve the accuracy of methane emissions being detected and recorded, and determining which technology is best suited to measure these emissions on the Enbridge Gas system. The goal is to implement this technology on the system to improve data accuracy to help identify potential options for mitigation going forwards.
   - Reviews of technology are being undertaken to determine potential capabilities to not only detect a source, but to quantify the type of emission. Mobile ground detection is most effective and practical for

the system, and a pilot program using these methods is being created to develop a system specific assessment.
- A final draft of the pilot program and assessment will be circulated to the Enbridge Gas consultant in the next few weeks, and once finalized, will make a part of the deferral account in June.
- A request was made to promptly involve Emily Ferguson of Minogi Corp in the process, so she can be involved in the next steps as much as possible. IWG members would like this to be a collaborative and ongoing commenting process.
    - Enbridge Gas will get in touch with Emily and facilitate a way to keep her more involved going forward.

3. Presentation update on CGHG/HER+ programs, as requested by Minogi Corp.
    - Presentation by Energy Conservation Team Craig Fernandes of EGI, on the wind down of CGHG/HER+.
    - Program uptake was wildly successful such that the initial budget forecast for 2023-Q1 2027 was exceeded on a forecast basis for the CGHG/HER+ federal program, and the entry was closed in Feb. 2024. There was an amendment to increase the budget in order to include additional participants.
    - A question was posed on whether there is specific funding allocated for Indigenous groups. Enbridge Gas representative reiterated that the home winter proofing program (“HWP”) is better funded and suited directly for Indigenous communities, and those interested in the CGHG/HER+ programs have been directed by Enbridge Gas to pursue the route of HWP.
    - A request was made to get in contact with Tasha Esquega with Enbridge Gas Inc. on the pilot program for the Indigenous specific winter proofing and heat pump program and which communities have been selected and/or consulted with for the pilot.
    - It was confirmed that due to OEB restrictions on the funding allocation of the program, that they were only open to Enbridge Gas customers, and those on other gas systems would not be covered under the program – Six Nations Natural Gas customers would not be eligible.
        - Request was made for Enbridge Gas to pen an informative email that Six Nations Natural Gas may use to pass on to their community members about why they are not eligible as they are customers of another gas utility – Six Nations Natural Gas.

4. Group discussion of the IWG Settlement Agreement Report for 2024 (IWG Report) and budget estimate for 2025.
    - The IWG discussed the draft IWG Report and members pointed to any changes that they would like to see in the report.
    - A request was made to include additional detail in the IWG Report about the presentations that have been provided during the IWG meetings.
    - The Budget was discussed and an Action item for the Indigenous IWG members to discuss together and propose a new budget for 2025 that will reflect what they believe they will need for representative involvement and legal/consultant advice.

5. Updates on the retention of experts
    - Brattle Group is close to being retained by the Indigenous parties. The main focus of Brattle Group as contemplated by the Indigenous parties will be to review the expert reports from the rebasing application and determine what is important information that may have been missed in those reports that would help mitigate energy-related risks and identify energy-related opportunities of First Nation groups in Ontario. There is also an expectation that other experts will be retained to address other significant issues relevant to the IWG. A potential example of these additional topics is fugitive emissions.

6. IWG Indigenous Parties Coordinator
    - Proposed that the IWG have a participant take on the role of an Indigenous parties coordinator. Jessica Wakefield of Three Fires Group will start to take on that role with tasks such as canvasing the Indigenous

participants about any topics or items they would like to see on the agenda and who should be at the table presenting for those topics.

7. Supply Chain Management (SCM) Indigenous Engagement.
   - Presentation by Richard Brant, Supply Chain Analyst Indigenous Engagement at Enbridge Gas, at the request of Three Fires Group.
   - Topics of the presentation were the Enbridge Indigenous Peoples Policy, the reporting and the target setting in SCM.
   - The Indigenous Peoples Policy is focused on including opportunities for partnership, employment, procurement, and equity participation, with a commitment to increase participation. SCM collects information that is provided by communities of contractors and Indigenous businesses to create a database of those companies. These companies have a leg up for bids against non-Indigenous companies when all parties are competitive.
   - There is an Enbridge enterprise-wide target of $1 billion to be spent over the course of 7 years on Indigenous spend included in the Indigenous Reconciliation Action Plan (IRAP) published in September 2022. All money spent on Indigenous benefits from projects and operations across North America is included in the target.
     - A request was made that Enbridge Gas Inc. share more regional (Ontario-specific data, if available).
   - Kate Kempton on behalf of Ginoogaming indicated there are no penalties for not meeting these targets and that this should change if the targets are going to be taken seriously. Would like a better emphasis on strict wording and equity.
     - Suggestion from Three Fires Group that equity be a commitment with Enbridge playing a role in skill building, to facilitate employment in Projects as well as O&M and post-project restoration.
   - Request from Ginoogaming that the next IWG meeting in July include an in-depth discussion about procurement of Indigenous peoples and equity.

8. Enbridge Employment practices and opportunities presentation.
   - Presentation from Jody Whitney and Mark Shilliday, Enbridge Inc. Senior strategist on Indigenous Collaboration and Enbridge Inc. Indigenous Recruitment Advisor, to provide an update on the employment practices and opportunities as requested by Three Fires Group. Mark Shilliday is the Indigenous recruiting advisor and sources Indigenous talent and then advocates for the Indigenous talent when positions become available within the company. Mark shared many of the categories in which Indigenous peoples have filled roles recently in Enbridge corporate.
   - An overview of the Indigenous wellness program, funds and the Indigenous Employee Resource Group was provided.
   - The numbers and data collected is for Enbridge Corporate, as the jobs in the field with contractors are largely restricted by Unions, especially in Ontario. Enbridge has had discussions with these Unions to seek exemptions where possible and have had some success in Thunder Bay.
   - A request to provide, or compile if not already available, more specific Ontario numbers as well as providing the presentation to the IWG.

Action Items

- Item 1: Enbridge Gas Inc. to incorporate a list with a description of the presentations given to the IWG during meetings in the IWG Report.
- Item 2: Enbridge Gas Inc. to request an update from Tasha Esquega with Enbridge Gas Inc. on the pilot program for the Indigenous specific winter proofing program and which communities have been selected and/or consulted with for the pilot.

- Item 3: Enbridge Gas Inc. Energy Transition team will determine how they can incorporate the expertise of Emily Ferguson and utilize her input on fugitive emissions.
- Item 4: Enbridge Gas Inc. to draft information about the qualifications for the Home Heating Initiative for Six Nations Natural Gas to disseminate to inquiring community members.
- Item 5: Enbridge Gas Inc. to share the presentation materials on the topics of Employment Practices and Opportunities and SCM Indigenous Engagement to IWG members.
- Item 6: Enbridge Gas Inc. to share letter to the OEB on the HER+ replacement program offer with IWG members.
- Item 7: Indigenous Parties to discuss the budget they will require for 2025 to be included in the IWG Report and provide this information to Enbridge Gas.

9. NEXT MEETING

Next meeting will be held on Tuesday, July 30, 2024, 9:00 a.m. at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8. Jessica Wakefield of Three Fires Group will be facilitating the meeting and acting as IWG Coordinator. She will canvass Indigenous IWG members on topics they would like to discuss at the next meeting.

APPENDIX A – AGENDA FOR MEETING OF IWG ON APRIL 30, 2024

Time	Matter	Participants
9:00-9:15 a.m.	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Group
9:15-9:30 a.m.	Enbridge Gas Notice of Appeal and Filing of Review Motion with the OEB regarding Phase 1 rebasing decision	Tania Persad, Associate General Counsel, Enbridge Gas
9:30-10:00 a.m.	OEB Rebasing reporting – IWG report	Group review
10:00-10:30 a.m.	Fugitive Emissions Update – Progress on Enbridge study on available technologies and potential involvement of Emily Ferguson in the study. Consideration of funding support through capacity funding for IWG.	Peter Mussio, Manager, Carbon Strategy, Enbridge Gas
10:30-11:00 a.m.	Federal Greener Homes Program update and how the changes will affect Enbridge's offerings and role as a provider	Craig Fernandes, Manager Residential Energy Conservation, Enbridge Gas
11:00-11:15 a.m.	Break	
11:15-12:00 p.m.	Independent Expert/Speaker schedule: - Energy Transition - Fugitive Emissions (Tie to anticipated May 2024 technology study release) - Economic Reconciliation - Rights-based Jurisdiction - Indigenous Knowledge	Group
12:00-1:00 p.m.	Lunch	
1:00-2:00 p.m.	EGI's Indigenous procurement policy; Reporting and target-setting; Efforts to proactively identify procurement opportunities for Indigenous participants; Capacity building efforts; employment policies and opportunities relating to construction projects	Richard Brant, SCM Indigenous Engagement, Enbridge
2:00-3:00 p.m.	EGI's Indigenous employment practices; general corporate policies and opportunities	Jody Whitney, Sr Strategist Indigenous Collaboration Mark Shilliday, Indigenous Recruitment Advisor, Enbridge
3:00-3:30 p.m.	Next steps, future meetings etc.	Group

Enbridge Gas Inc. Indigenous Working Group Minutes - FINAL

Minutes of a meeting of the Indigenous Work Group (IWG) held on **July 30,2024** at 9:00 a.m. EST at Enbridge Gas Inc., 500 Consumers Road, North York, Ontario M2J 1P8.

PRESENT

Don Richardson (virtual)	Minogi Corp
Emily Ferguson (virtual)	Minogi Corp
Jessica Wakefield (in-person)	Three Fires Group
Nick Daube (in-person)	Resilient LLP, Three Fires Group, Minogi Corp
Kate Kempton (in-person)	Woodward and Company, Ginoogaming First Nation
Jennifer Mills (virtual)	Chippewas of the Thames First Nation
Kodi Chrisjohn-Deleary (virtual)	Chippewas of the Thames First Nation
Jaclyn Martin-Hill (virtual)	Chippewas of the Thames First Nation
Diana Audino (in-person)	Enbridge Gas Inc.
Lauren Whitwham (in-person)	Enbridge Gas Inc.
Tania Persad (in-person)	Enbridge Gas Inc.
Brent Bullough (in-person)	Enbridge Gas Inc.
Cara-Lynne Wade (in-person)	Enbridge Gas Inc.
Sarah Taylor (virtual)	Enbridge Gas Inc.
Craig Fernandes (in-person)	Enbridge Gas Inc.
Kim Brenneis (in-person)	Enbridge Gas Inc.
Sarah Crowell (virtual)	Enbridge Gas Inc.
Henry Ren (in-person)	Enbridge Gas Inc.
Greg Asmussen (virtual)	Enbridge Gas Inc.
Tausha Esquega (virtual)	Enbridge Gas Inc.
Erin Nolan (in-person)	Enbridge Gas Inc.
Peter Mussio (in-person)	Enbridge Gas Inc.

1. MATTERS FOR DISCUSSION

Review of the Agenda for today (attached at Appendix A) and Logistics.

- Lauren Whitwham of Enbridge Gas Inc. confirmed that Enbridge Gas Inc. filed the IWG report and thanked everyone for their patience and quick responses when finalizing details.
- Jessica Wakefield of Three Fires Group chaired the meeting, consensus was to continue to rotate the facilitator/chair of each IWG meeting. The chair will return to Enbridge Gas Inc. for the next meeting.
- IWG confirmed that the meetings should continue to be hybrid (in person, but with a virtual option) to ensure inclusion and accessibility.
- There was an item and timing update to the agenda that the “home winterization” item should read “heat pump update” and will be moved to 1 pm.
- Nick Daube of Resilient LLP suggested starting with the Indigenous IWG members presentation on energy transition before moving onto economic transition which is longer.

1. IWG led discussion and presentations
    a. Powerpoint was circulated with the agenda prior to the meeting. Nick introduced the presentation on Environmental and Economic Reconciliation.
    b. Kate Kempton of Woodward and Company presented on Reconciliation requirements. Kate advised:
        i. Enbridge Gas Inc. needs to change and commit to the proposed 10 principles of Reconciliation. Reconciliation means co-existence and mutual respect. First Nations must be engaged at the level of strategic planning.
        ii. Accommodation is always required though the case law says it's not. There is a conflict in Supreme Court of Canada decisions. Intent to address concerns is the duty to accommodate, but accommodation is not always required, which may contradict each other. Sustainability means giving more to the future than you take away.
        iii. There are ten principles or requirements of reconciliation that Indigenous IWG members would like Enbridge Gas Inc. to follow. All ten are necessary components and cannot go without the others:
            1. Co-management - First Nations need to be involved in decision making. This is a group that gives recommendations and that is not enough and not meaningful because the IWG does not make yes or no decisions.
            2. Life cycle decision making – consultation and accommodation cannot only be once the plans are already finished.
            3. Old and new projects alike– First Nations view that we need to do more, there should be a greater duty owed because of how much has been used and how much disruption there has been. The same type of decision-making and accommodation needs to exist for both new and existing projects.
            4. Multigeneration sustainability – there is a need to do more to balance before moving forward equally. There are formulas for future damage in car accidents, why are there not for damage caused by projects?
            5. Environment includes climate – not approving anything unless it leaves the environment in a better position than it is now. We are the last generation who can take too much, and we need to take less.
            6. Accommodation required – taking the contradicting paragraph from Haida – engaging with First Nations must always be with the intent to address their concerns. The onus is on Enbridge to offer the accommodation after the consultation, but taking the accommodation is not required either. First Nations do not always have to be reasonable when asking for the accommodation
            7. Accommodation required to make whole – goes to what accommodation really entails. Canadian law is racist going along with the concept that accommodation doesn't have to make First Nations whole. In any other area of law, where there is harm, the intent is to make whole with the remedy. Sui generis – the relationship between the crown and First Nations, sounds good in concept, but the decision is that they get less and can be discriminated against in our law.
            8. Accommodation required to share - It is also First Nation land, and they need to benefit from it.
            9. Accommodation to prevent and mitigate the adverse effects is Environmental reconciliation.
            10. Accommodation to compensate for adverse effects and share in positive effects is economic reconciliation. First Nations want compensation that is equal to other private landowners and at least as much as other crown government for sharing in tolling or taxing revenues.
    c. Kodi Chrisjohn-Deleary of Chippewas of the Thames First Nation presented to the group on the Way of life and Stewardship over the Land

    i. Way of life includes stewardship over the land. First Nation legal systems are rooted in the relation to the land and where the stories are derived from. Cultural heritage preservation entails access to land and supporting the health and wellbeing of First Nations including how impacts to lands and resources have negatively impacted First Nations. There is opportunity in climate change mitigation to involve First Nations in the decision making for economic participation and opportunities while occupying a decision-making space. There should be a focus on conservation with self-determination and co-management.
    ii. Stewardship faces ongoing challenges:
        1. Capacity funding, consultation departments are busy and need more consultation support. The degree of consultation should be up to the communities and allowing them to consult their own experts;
        2. A lack of recognition and respect by project proponents and regulators;
        3. Socio economic realities should be putting best efforts to economic reconciliation;
        4. Sufficient time and opportunity requires engaging early and follow up throughout;
        5. Adequate understanding of culture, history, and traditional ecological knowledge as there may be differences for non-treaty nations;
        6. General absence of engagement and assessment roadmaps; and
        7. Cumulative impacts, making even smaller projects potentially significant to impacted First Nations. Some projects are not deemed as necessary to do some things like environmental impacts like the big projects are, but the smaller ones still impact access to land, being the true treaty partners in the respective territories. It is almost like death by a thousand cuts where the small projects and permits add up and impacts the access to land which in turn relates to the socio-economic realities.
    iii. Stewardship offers significant opportunities including Indigenous buy-in, increasing inclusivity in the decision-making space, increasing equity to allow First Nations to make profits on the land similar to taxes and honouring treaties, and project credibility leaving the earth better than it is now for future generations.
d. Nick Daube of Resilient LLP spoke briefly on the principles for improved engagement
    i. The challenges First Nations face in adequately advancing stewardship in leave to construct should be addressed and getting this right is really an opportunity for all people involved. There is support for and improvement of projects with stewardship.
    ii. IWG members appreciate that this is a complex conversation and want to establish lanes that they can develop at this table, specific examples or themes that IWG would like to advance. They are shortcomings that will take a long time to improve, but the most important being:
        1. Include First Nations at the table in decision making structures;
        2. Include First Nations in all stages of the process;
        3. Have First Nations perspectives included – more time and more funding; and
        4. Prevent and mitigate adverse consequences based on First Nation perspectives.
e. Emily Ferguson of Minogi Corp presented on Engagement
    i. Overall, there is a need for stronger engagement at all stages, not just checking boxes of what we would think is enough, but meaningful engagement and long-term relationships. There needs to be a deep understanding of impacts on rights before the start of a project.
    ii. Capacity funding and broad agreements at its best is usually only enough to cover one person for the funding that is offered project per project. The agreement may look good in principle and may cover a lot of projects in the next few years, but a big project would be overwhelming. If funding is not project specific, it can be poorly reflective of work required for different projects and experts that may be needed.
    iii. IWG would like to make a tangible checklist with Enbridge Gas Inc. and agree on the smaller items to then work on the larger broader ask
        1. Pre-construction

a. Improving First Nation engagement at large with a shared draft of all reports and inviting engagement early on.
b. Establish a pre-construction record. A good step they have seen is that Enbridge Gas Inc. shares the environmental report prior to filing an Ontario Energy Board leave to construct application and invites comments. Too many times, the response in the tables is that the response will be addressed in the Environmental Protection Plan, which is not finalized or filed until leave to construct has been granted. First Nations will feel like it's over and any input isn't going to change things. A first ask is for Enbridge Gas Inc. to present on contractor training and how they are trained.
c. Monitoring plans should be in place early if any of the items are needed before the project starts. Anticipated fugitive emissions should be included.
d. Sharing information should include a commitment to sharing drafts with a focus on sharing the Environmental Protection Plan draft for comments to make it as strong as it can possibly be.
e. Capacity support at an early stage.

2. Construction
    a. Many of the same themes as above.
    b. Soil and environmental protection plans should be in place with a focus on suspect soils and notification of soil remediation.
    c. Adequate working conditions should be prioritized and work should be postponed on poor air quality days.
    d. Employment and training opportunities should be increased with a focus on the energy transition.
    e. Develop and share plans, working collaboratively. First Nations are overwhelmed. A SharePoint where all documents are available with one link for everything would be best to avoid having to look around all the time for the project information.
3. Restoration and post construction
    a. Adequate capacity funding with ongoing funding for people as well as project per project funding.
    b. Site restoration.
    c. Environmental protection plan that are individual to a project. There are opportunities to look at specific sites to see what opportunities could make the area better. Thinking outside of the box, for example a temporary staging area could be later developed for ecological advancement.
    d. Long term monitoring to assess the ongoing impacts and the restoration and reclamation.
    e. Evaluate, review, and adapt processes for First Nations to show where there can be improvements. Feedback and lessons learned could be shared by First Nations and implemented to reflect a better working relationship.

f. Nick Daube of Resilient LLP led a discussion about the Watford decision (EB-2023-0175)
    i. There are issues that keep getting raised in Ontario Energy Board proceedings, and it would be nice if those issues were dealt with outside of the proceedings. Many solutions have been endorsed by the Ontario Energy Board. Suggesting that the Indigenous IWG representatives identify a set of priority items to start with. There is a rough list of the probable major items which will then circle back to the major aspects that Kate and Kodi had said.
    ii. Enbridge Gas Inc. agrees that we can move things forward and address some of the common issues together. Including the Ontario Energy Board can create a timeline that is difficult with

projects. There are already new monitoring programs that are being developed since Watford. Group consensus that getting ahead of the timeline is best for all parties.

iii. Kate Kempton of Woodward and Company raised an issue that many of the items Enbridge Gas Inc. includes First Nations on are tokens. Kate Kempton wants, as a priority, to discuss practical steps and allow First Nations to develop plans as they know what's best for them. There should be a focus on reconciliation at every meeting and throughout all project planning that comes with a policy or process. Kim Brenneis of Enbridge Gas Inc. agreed this working group format is a good place to work through some issues and create a product that may create a streamlined process and priorities.

iv. Action item with a target of a few weeks where Emily Ferguson of Minogi Corp and/or Nick Daube of Resilient LLP put together a chart with the questions that can be dealt with in discussions to make progress through the issues. Then Emily Ferguson can work alongside someone from Enbridge Gas Inc. to identify the priority items and develop a work plan so that progress can be made before the next meeting.

v. Possible future item – to create a smaller working group within this group to discuss some of the priority items to speed up the process and have work done between meetings.

vi. A point was raised as a group to ensure that the proper representatives are involved in any created working groups. There will need to be subject matter experts, people with decision making powers, but also incorporating the views of Indigenous groups that would be affected but cannot be at the table.

vii. A general request was made by Kodi Chrisjohn-Deleary of Chippewas of the Thames First Nation that Enbridge Gas Inc. do a proper review as to who the rights holders are in this discussion and put that effort forward to try to accomplish the meaningful big issues, and not just taking the easy wins.

viii. A request was made by Nick Daube of Resilient LLP that once the list is created, Enbridge Gas Inc. will go through it first and identify any non-starters and any items that may be ready to go so the time of the group is not wasted.

ix. Kate Kempton of Woodward and Company requested that wording be developed for Enbridge Gas Inc. to make a commitment to negotiate in good faith this checklist/template for Indigenous engagement and accommodation for all projects on a go forward basis with the intention of coming to an agreement.

2. Updates on the retention of experts.
    a. Nick Daube, of Resilient LLP, provided an update on the retention of the Brattle Group by the IWG Indigenous parties.
    b. Brattle is able to present at the next IWG meeting in October. Cara-Lynne Wade offered to be a point of contact if Brattle would like assistance or wanted to have discussions with Enbridge Gas Inc. before the next meeting.
    c. Brattle has read the materials that Enbridge Gas Inc. had provided, and they have come back to the IWG Indigenous members with notes that the materials will take time for them to read, and that their original budget was not in anticipation of reading the materials. Their original budget may need to increase by 25% (flex) based on the number previously provided. Brattle is already familiar with the 2023 Report of the Ontario Energy Board to Ontario's Electrification and Energy Transition Panel ("EETP Report").
    d. In response to the question raised by Enbridge Gas Inc. about how the Brattle Group's work will be unique to the IWG, Nick Daube, of Resilient LLP, offered that the Brattle Group is aware of the IWG mandate and are familiar with the EETP Report and are not trying to reproduce a similar report. The Brattle Group could be directed to a specific area of the EETP Report that they should draw their attention to and will work to provide the scenario from the perspective of First Nations, as that was not included in the original.
    e. A possible trip to Ginoogaming was raised by Indigenous IWG members. Chief Taylor would like the Brattle Group to meet with membership and staff, to understand what something from their

perspective means and why it is important, so the Brattle Group may properly reflect the important items and cultural sensitivities. There was a request for the budget for this trip to be agreed to be reasonable by Enbridge Gas Inc. prior to proceeding with incurring the costs. Enbridge Gas Inc. confirmed that a response to an email with an outline of the estimated costs will be provided and will confirm that these expenses should fall within the budget.

3. Reconciliation Action Plan
   - Presented by Kim Brenneis, Director Community & Indigenous Engagement CAN, Enbridge Inc.
   - Enbridge will be coming out with a refreshed Indigenous Reconciliation Action Plan that will have some of the same commitments from the reconciliation action plan, some that are new, and some where language is updated. Indigenous business information sheets that are provided go into a data base that is used for the external Contractors who are obligated to help Enbridge increase Indigenous economic inclusion.
   - Noteworthy within the new action plan is the Indigenous Advisory Group that meets 5 times a year to provide advice about what direction they want and a work plan, to provide the Enbridge Vice President level reconciliation committee and the Enbridge Board at least once a year. Enbridge is not at liberty to share the names of the Indigenous groups or representative who are members of the Indigenous Advisory Group at the group's request.
     - o Kate Kempton of Woodward and Company finds this difficult and requested that the Indigenous Advisory Group be included in the IWG meetings.
     - o Kim Brenneis of Enbridge Gas Inc. responded that he could reach out to see if the Indigenous Advisory Group would be open to having a conversation with the IWG.
     - o Two questions were raised in relation to procurement, how different are the approaches to procurement of Enbridge Inc. and Enbridge Gas Inc., and whether there could be a benchmark for Enbridge Gas Inc. and its progress.
       - ▪ Kim Brenneis provided the response that Enbridge Gas Inc. is implementing the core programs where possible, and that the Indigenous Reconciliation Action Plan is a central function and is therefore also followed by Enbridge Gas Inc.
     - o Kate Kempton of Woodward and Company stated that First Nations would prefer more certainty and clarity baked into policy to ensure that it is being followed. Kim Brenneis of Enbridge Inc. responded that the Indigenous Reconciliation Action Plan is a culmination of strategic goals, and these programs flow from the Action plan.
4. Heat pump presentation from Tausha Esquega, Senior Advisor, Indigenous Energy Conservation and Craig Fernandez, Manager Residential Energy Conservation, Energy Transition Planning at Enbridge Gas Inc.
   a. The presentation shared a brief overview of what a heat pump is and what information is to be shared with Indigenous groups when introducing the pilot program to a community. Intention was for pilot program to be for residential buildings, with full information and fully funded capital installation. Requirements for the homes were discussed including that to qualify, they would need to be an Enbridge Gas customer, and that the home would need a backup source for heat. It was noted that many communities are on propane and would not qualify for the program.
   b. Question from Nick Daube of Resilient LLP – Is there a rational for the selection of the participating nations?
      i. Craig Fernandes of Enbridge Gas Inc. provided the answer that the main rational is location or weather zone. The need to get data for the pilot program between the north and south of the province and will need at least two years for the data to be sustainable in order to finalize a report back.
   c. Request from Emily Ferguson of Three Fires Group if Enbridge would provide a briefing note so groups can better understand what is on the table for this pilot program. In order for the IWG to provide an endorsement for the project, there is additional information that would be needed from Enbridge Gas Inc. which may be provided in draft:
      i. Provide details of the proposed pilot and the qualifications for each participant clearly stating in writing;
      ii. Provide the number of residences that are eligible for the program from each IWG nation;

iii. Provide the questions posed to Indigenous groups to receive the required information and an outline about what will be required for their participation and collaboration.

d. Statement from IWG member that Enbridge Gas Inc. needs to understand the full scope of the cost of electricity to the nations, including the potential to reduce social and environmental "costs". Depending on the situation (geographic location, user knowledge, taxes and access to subsidies for example), heat pumps may cost more to operate in the long run, however, consumers may still choose to install one given the potential social and environmental benefits. Heat pump information/education provided by Enbridge Gas Inc. should be clear about potential costs and benefits so consumers can make informed choices.

5. Fugitive emissions
   a. Presentation and discussion led by Peter Mussio, Manager, Carbon Strategy, of Enbridge Gas Inc. The discussion was focused on past discussions of emissions and targets. Peter provided some information to answer questions posed previously by Indigenous IWG members.
   b. A technical question was raised by Emily Ferguson of Minogi Corp about gas and what the rate payers are paying for any lost gas/unaccounted for gas across the system. Emily requested someone present on this topic at the IWG if this information is available. Enbridge Gas Inc. advised of the Ontario Energy Board proceeding where certain evidence on this topic has been filed. Emissions and climate change should remain an outstanding item.
6. Dates for the future meetings
   a. Proposed dates for the next meeting were discussed, and the IWG confirmed that October 17, 2024, will be the next meeting date.
   b. Planning for the meeting following October to ensure all IWG members and the retained experts may attend. December 10, 2024, is a tentative hold for the final IWG meeting of 2024.
   c. IWG agree that the facilitator will rotate back to Enbridge Gas Inc. for the October 2024 meeting.
   d. There is a list of outstanding items from the agenda that were not touched on in this meeting and they should be included in the next meeting's agenda.

Action Items

- Item 1: Enbridge Gas Inc. to present on contractor training at a future IWG meeting including additional information on the weighting for the SEP (socio-economic program) and whether there are penalties if suppliers/contractors don't meet the targets.
- Item 2: Emily Ferguson of Minogi Corp and/or Nick Daube of Resilient LLP to put together a chart with the common issues from the Watford decision that can be dealt with in these group discussions.
- Item 3: Once the list is created, Enbridge Gas Inc. will go through and identify any non-starters and any items that may be ready to go for discussion.
- Item 4: Emily Ferguson of Minogi Corp will reach out to Enbridge Gas Inc. to meet and identify the priority items and develop a work plan so that progress can be made before the next meeting.
- Item 5: Enbridge Gas Inc. to respond to an email provided by Nick Daube, that outlines the estimated costs for the Brattle Group to travel to and meet with Ginoogaming First Nation, with confirmation that these expenses should fall within the budget.
- Item 5: Enbridge Gas Inc. to provide a briefing note on the pilot program.
- Item 6: Enbridge Gas Inc. to present to the IWG at a future meeting on lost gas and what the rate payers are paying for any unaccounted for gas across the system.
- Items 7: Enbridge Gas Inc. to share the presentation materials with IWG members.

7. NEXT MEETING

Next meeting will be held on Thursday October 17, 2024, at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8. The meeting will begin at 9:00am and lunch and refreshments will be provided throughout the day.

APPENDIX A – AGENDA FOR MEETING OF IWG ON JULY 30, 2024

Indigenous Working Group Meeting

July 30, 2024 – Enbridge Victoria Park Centre

AGENDA

9am – Recap of last meeting, opening comments
9:30am – IWG-led Discussion
- Environmental and Economic Reconciliation
- Energy Transition

11am – Enbridge-led Discussion on
- Business-ownership (specifically, how recognition of FN business was decided on)
- Update on the Equity Discussion
- Indigenous Reconciliation Action Plan
- Indigenous Peoples Policy (specifically, how was this developed?)
- Update on Heat Pump Pilot

12pm – Lunch
1pm – Enbridge-led discussion continued from before lunch
1:30pm – Enbridge-led discussion/updates on
- Fugitive Emissions
- Climate Change

2:30pm – Questions/comments, plan for IWG
3pm – End

Enbridge Gas Inc. Indigenous Working Group Minutes - FINAL

Minutes of a meeting of the Indigenous Work Group (IWG) held on **October 17, 2024** at 10:00 a.m. EST virtually via Microsoft Teams.

PRESENT

Emily Ferguson	Minogi Corp
Jessica Wakefield	Three Fires Group
Jana George	Three Fires Group
Nick Daube	Resilient LLP, Three Fires Group, Minogi Corp
Kate Kempton	Woodward and Company, Ginoogaming First Nation
Jennifer Mills	Chippewas of the Thames First Nation
Kodi Chrisjohn-Deleary	Chippewas of the Thames First Nation
Jacklyn Martin-Hill	Chippewas of the Thames First Nation
Diana Audino	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.
Tania Persad	Enbridge Gas Inc.
Brent Bullough	Enbridge Gas Inc.
Levi Gordian	Enbridge Gas Inc.
Craig Fernandes	Enbridge Gas Inc.
Jennifer Murphy	Enbridge Gas Inc.
Sarah Crowell	Enbridge Gas Inc.
Henry Ren	Enbridge Gas Inc.
Greg Asmussen	Enbridge Gas Inc.
Tausha Esquega	Enbridge Gas Inc.
Erin Nolan	Enbridge Gas Inc.
Kelsey Mills	Enbridge Gas Inc.
Peter Mussio	Enbridge Gas Inc.

1. MATTERS FOR DISCUSSION

Review of the Agenda for today (attached at Appendix A) and Logistics.

- The minutes of the meeting of the IWG on July 30, 2024 were approved with the following changes:
  - Add “Chrisjohn” before “Deleary” for Kodi’s last name, where referenced in the minutes
  - Add a comment in the discussion about heat pumps to specify that a lot of communities are on propane, so they cannot change to heat pumps because of the nature of the program.

- The update from the Brattle Group was rescheduled to the December 10 meeting agenda.
- Due to time constraints, meeting chair made a decision to move the update on the Engagement Template to the next IWG meeting on December 10, 2024.

1) Reconciliation Principles
   a) Kate Kempton discussed the reconciliation principles that had been presented at the July 30, 2024 IWG meeting. She advised that Enbridge Gas Inc. should provide an update at every IWG meeting on what Enbridge Gas Inc. is doing to address the concerns raised in the presentation.
   b) Kate Kempton indicated there is a reaction from Ginoogaming First Nation and herself that the status quo is insufficient.
      i) Kate Kempton raised concerns over whether Enbridge Gas Inc. is only checking boxes with respect to the concerns raised by the Reconciliation Powerpoint.
      ii) Diana Audino advised that Enbridge Gas Inc. has been working through the reconciliation principles, and that it would be added to an item on the agenda for the next IWG meeting on December 10, where we will be able to discuss the matter in-person.
         (1) Action item: include an update on every subsequent agenda on reconciliation and Enbridge Gas Inc.'s response to those reconciliation principles.

2) Nick Daube provided an update on Brattle group report.
   a) Brattle had two of their representatives visit Ginoogaming First Nation to meet with their representatives. Discussed how First Nation interests would be accounted for in the context of the energy transition, meeting with Three Fires, Minogi, and Chippewas.
   b) Jennifer Murphy joined the meeting. Nick Daube asked if there was a preferred deadline on when to receive the Brattle report. Jennifer Murphy advised that there is no material difference - whether it be in November or December. Nick Daube requested a 1-hour or 1.5-hour presentation from Enbridge Gas Inc. for an overview of the report.
      i) Action item: Brent Bullough to add 1.5 hours to the Agenda for the next IWG meeting.
   c) Jennifer Murphy said that in Phase 1, Enbridge Gas Inc. did a scenario analysis and a decarbonization study. Enbridge Gas Inc. is now looking at 4-5 different scenarios that could happen in Ontario. Unlike the first scenario where Enbridge Gas Inc. was looking at it from a regional perspective. Enbridge Gas Inc. would like to include Indigenous perspectives in this work as well as including perspectives from other stakeholders. Enbridge Gas Inc. is currently working on a rebasing application with Phase 2 and Phase 3 to come. They are also filing for the 2027 for the 2029 rate period and have already completed some scenario analyses. The Brattle report would provide input into the project and Enbridge Gas Inc. advised that it would like to receive it over the next few months. However, that is not the only input it is seeking from the IWG.
      i) Nick Daube and Jennifer Murphy agreed that the sooner they receive the Brattle report, the better, but that it makes no material difference whether it is received between November and December 2024.
      ii) Nick Daube inquired whether Jennifer Murphy's team would be interested in summarizing, in a presentation, the work that has been done since their rebasing application. Jennifer Murphy said she would coordinate with her team to arrange for a presentation at the December IWG meeting.
      iii) Since Brattle's update was shifted from the agenda, the next topic was set to be a discussion around the Heat pump Pilot, followed by a discussion around the Engagement Templates.

3) Heat Pump Pilot and community selection
   a) Craig Fernandes provided an update with regard to the heat pump pilot program.
      i) Nick Daube informed the IWG that some of the Indigenous representatives he has spoken with have asked for more information around emission reductions, cost, and the general viability of the pilot program before moving to the next stage of the project.
      ii) There is also concern around the next federal election and the implications it will have on carbon pricing. Craig Fernandes confirmed that there is uncertainty around that. If the carbon tax is removed, the economic benefits that the consumer will see may be significantly reduced. He advised

that consumers keep a hybrid system, which would protect them from changes to the carbon tax and allow them the flexibility to choose which system to operate at a given time.

(1) Craig Fernandes responded to Nick Daube's concerns and clarified that there will be no cost to the participant occupants when it comes to the equipment upgrades needed for the heat pump pilot. Moreover, Craig Fernandes explained that the actual savings will depend on the specific energy choices that the occupant makes, but estimated one could expect roughly a 30% decrease in gas usage, if the occupant is using a hybrid system that uses both a heat pump and a conventional furnace. On the higher end, if the system is upsized, one could expect up to 70-90% reduction.

(2) Craig Fernandes said that in order to provide an exact estimate, Enbridge Gas Inc. would need to select a community to run an analysis on. Kate Kempton noted some distinct differences between northern and southern Indigenous communities, and suggested that one in each region should be selected. Craig Fernandes responded to this suggestion saying Enbridge Gas Inc's recommendation was to start with a community in the south and then use that information to model the outcome for the north, before launching a pilot in the north.

(3) Nick Daube suggested that in order to effectively bring these proposals to First Nation leadership, there needs to be more concrete and tailored cost savings or emission reduction values.

(4) Craig Fernandes referred to the memo that contained some engineering analysis for a generic home in Ontario, showing estimated savings in 4 different zones. However, for a northern community, the savings might be too low and, without the carbon tax benefit, there would basically be no savings. Therefore, for a northern community, Craig Fernandes recommended building a better envelope for the home to keep the heat inside, regardless of the heating source.

(5) Nick Daube advised that we are approaching a point where First Nation representatives might give a "maybe" to the project, but are unlikely to get a "yes".

(6) Jennifer Mills reported that Tasha Esquega and Craig Fernandes had a meeting in February 2024 with regard to housing matters, but noted there was a vacancy in the Housing Director role. Now that there is a Public Works and Housing Director, their team plans to discuss it with them and see if there is interest in pursuing a more detailed analysis.

(7) Emily Ferguson asked if Enbridge Gas Inc. has piloted a heat pump program in a non-Indigenous community. Tausha Esquega confirmed that they are currently receiving feedback from participants who have had it installed in their homes.

(8) Emily Ferguson asked if it would be possible to put together a few case studies comparing different scenarios depending on the size of home, the system used (wholly gas, hybrid pump, etc), and then present what the GHG reductions and costs of the pilot are. Craig Fernandes explained that they have done a study like that in the past, but with townhouses, and that the results might not be transferable to the circumstances here.

(9) Nick Daube noted two significant protections afforded by the Pilot: first, there are no costs to the consumer; second, the occupant participating in the pilot is not getting rid of their current heat source, such as a furnace.

(10) Craig Fernandes estimated that the cost would be around $6500 for each house installation, which Enbridge Gas Inc. would cover.

4) Engagement Template Update:

a) Emily Ferguson and Brent Bullough advised that they would provide a written update on the Engagement Template, since there was no time to include it in this meeting. They mentioned that have already had two meetings on the Engagement Template. There is commitment on both sides to progress with the work that has been done. Emily Ferguson noted that a key priority is to highlight items in the Engagement Template that Enbridge Gas Inc. can immediately agree to, so Enbridge Gas Inc. should scan through to see which ones are already being done, highlight and commit to them, and if there are items that Enbridge Gas Inc. cannot commit to, explain why and what the next steps might be.

Action Items

- Item 1: Enbridge Gas Inc. to update minutes and re-send final version. Note: IWG members want Reconciliation Principles to be an agenda item at every meeting, so that Enbridge Gas Inc. can provide an update on how they are doing with respect to those principles.
- Item 2: Next meeting will include an Enbridge Gas Inc. update from Jennifer Murphy, an update from the Brattle group, and the Reconciliation Principles.
- Item 3: Emily Ferguson and Brent Bullough to send a written update on the Engagement Template. Next step is for Enbridge Gas Inc. to identify which items it can do, is currently doing, and which items it will need more time to consider.
- Item 4: Lauren Whitwham and Jessica Wakefield will coordinate who will chair the next meeting in December.

2) NEXT MEETING

The next meeting of the IWG will be held on Tuesday, December 10, 2024, to take place at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8.

APPENDIX A – AGENDA FOR MEETING OF IWG ON OCTOBER 17, 2024

Indigenous Working Group Meeting

October 17, 2024 – Virtual, Microsoft Teams Meeting

AGENDA

Time	**Matter**	**Participants**
10:00-10:15 a.m.	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Group
10:15-11:30 a.m.	Heat Pump Pilot and Community Selection	Craig Fernandes and Group
11:30-Noon	Engagement Template Update	Emily Ferguson and Brent Bullough

Enbridge Gas Inc. Indigenous Working Group Minutes – FINAL

Minutes of a meeting of the Indigenous Work Group (IWG) held on **December 10, 2024,** at 9:00 a.m. at Enbridge Gas Inc., 500 Consumers Road, North York, Ontario M2J 1P8.

PRESENT

Nick Daube	Resilient LLP, Three Fires Group, Minogi Corp
Jessica Wakefield	Three Fires Group
Reggie George	Three Fires Group
Jana George	Three Fires Group
Kate Kempton	Woodward and Company, Ginoogaming First Nation
Jennifer Mills	Chippewas of the Thames First Nation
Tracy Skye	Six Nations Natural Gas
Bruce Tsuchida	The Brattle Group
Tom Chapman	The Brattle Group
Peter Fraser	The Brattle Group
Don Richardson	Minogi Corp
Robert Lukacs	Minogi Corp
Diana Audino	Enbridge Gas Inc.
Kim Brenneis	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.
Tania Persad	Enbridge Gas Inc.
Brent Bullough	Enbridge Gas Inc.
Levi Gordian	Enbridge Gas Inc.
Henry Ren	Enbridge Gas Inc.
Erin Nolan	Enbridge Gas Inc.
Kelsey Mills	Enbridge Gas Inc.
Ainslie Murdock	Enbridge Gas Inc.
Cody Wood	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.

1. MATTERS FOR DISCUSSION

Reviewing of the Agenda for today (attached at Appendix A).

a. Review and approval of minutes from the IWG meetings on July 30 and October 17, 2024, pending any additional feedback that may be received by the IWG by the end of the day.
b. Diana Audino of Enbridge Gas Inc. noted a correction raised by Jennifer Mills to remove Jaclyn Martin-Hill's name from the October 17, 2024 minutes.

2. IWG Reconciliation Principles – Kim Brenneis

a) Kim Brenneis provided an overview of Enbridge Inc's Indigenous Reconciliation Action Plan (IRAP), which applies to the whole company including Enbridge Gas Inc, and its alignment with corporate reconciliation goals:
    i. Indigenous Workforce Representation
        - Enbridge Inc. has achieved 3.2% representation in Canada, nearing its 3.5% target originally set in 2025.
        - After the recent acquisition of Dominion Energy Inc., which brought an influx of new employees in the United States, the percentage is below 1%.
        - The IRAP refresh will introduce jurisdiction-specific targets for Canada and the U.S. to address these disparities.
    ii. Lifecycle Relationship Approach
        - Enbridge aims to embed reconciliation within its corporate "DNA" by taking a lifecycle, relationship-based approach to relationships.
    ii. Removing Barriers for Participation
        - Efforts are underway to facilitate greater Indigenous participation in employment and contracting opportunities, addressing systemic challenges.
    iii. Equity Partnerships
        - Enbridge Inc. has historically completed four financial and equity partnerships with Indigenous communities and is actively pursuing more.
    iv. Environmental Stewardship
        - Increased Indigenous involvement in fieldwork and environmental assessments is a priority, aligning with principles proposed by the IWG.
    v. Sustainability and Governance
        - Enbridge Inc. is committed to refreshing the IRAP every three years, with the next version scheduled for release in early 2025, followed by a subsequent refresh in 2028.
b) Enbridge Gas Inc. conducted a survey to receive feedback on best practices and how the organization has been doing with regard to its reconciliation efforts and is aiming to host more sessions to listen and learn.
c) Discussion on the IRAP and Reconciliation
    i. Tracy Skye of Six Nations Natural Gas inquired about how barriers for Indigenous contractors are identified.
        - Kim Brenneis explained that barriers are identified through consultations with Indigenous nations and contractors. Enbridge Inc. also relies on the expertise of individuals such as Richard Brant, Indigenous Supply Chain Management Lead,

who works closely with communities and businesses to learn about these barriers.

- Socio-Economic Requirements of Contractors (SERC):
    - Contractors are required to submit a SERC to show how they are going to work with Indigenous communities and their members.
    - The SERC process ensures that companies will have to go beyond their "best efforts" and be held to account by Enbridge Inc., contractually, through this more robust process.

ii. Kate Kempton of Woodward and Company commented that the deliberateness of this process is great, highlighting that it is laid out, particularized, and not just a bunch of vague policy commitments from the company. Kate Kempton noted that while many companies have broad policy commitments, there is often little measurable change at the ground level. Kate Kempton drew parallels to land acknowledgments, suggesting that you often hear these when you attend meetings, but they only allow the individual giving them to pat themselves on the back.

- Kate Kempton raised three key indicators of decolonization: 1) Protection, 2) Control and 3) Benefit.
    - Protection: Speaking on behalf of Ginoogaming First Nation, Kate Kempton emphasized the critical importance of energy transition as part of Enbridge Gas Inc's purposeful targets. While acknowledging the difficulty of such a transition, she highlighted the need for direct goals and measurable outcomes from Enbridge Inc. She noted that this issue is not particularly Indigenous, since all of humanity depends on this, but that Indigenous peoples bear a disproportionate burden due to their connection to the land. Kate's position is that while many of the elements of the IRAP are good, they are comparatively "low hanging fruit" to the more meaningful engagement and results on energy transition.
    - Control: Kate Kempton discussed the importance of Indigenous engagement, not only at the operations level, but within Enbridge Inc's leadership structures, such as the company's board of directors. She pointed out that corporate culture changes primarily from the top-down, and such structural shifts are essential for meaningful change.
    - Benefit: Kate Kempton challenged Enbridge Inc's current Indigenous workforce representation target of 3.5%, stating that it is a low target relative to the 5.7% of Indigenous peoples living in Canada, and much lower compared to provinces such as Manitoba which have an even higher percentage of Indigenous peoples. She advocated for significantly higher targets, particularly for new projects, to address cumulative harms, including systemic unfairness of how the costs of resource extraction and environmental degradation have historically been borne by First Nations, and align workforce goals with the actual population. Further, she proposed setting a more ambitious target to drive progress and address this issue with Enbridge Inc's leadership at a future IWG

meeting. She also addressed the lack of compensation for existing land uses, stating that some First Nations may sue to get backpay for compensation for historical use of their lands. She suggested that companies should get ahead of this and preemptively negotiate royalty fees for existing assets. She proposed that these costs could potentially be included in the rate base, similar to how municipalities are compensated, which would ensure that there is a fair distribution among all. Kate Kempton concluded by advocating for these three elements: Protection, Control, and Benefit – to be embedded in Enbridge Inc's IRAP, with the IWG collaborating with the company to implement these changes.

- Kim Brenneis acknowledged and responded to Kate Kempton's points, outlining Enbridge Inc's approach to ensuring accountability with regard to its IRAP. He noted that unlike other companies that may have failed to deliver on their promises, Enbridge Inc. has implementation working groups for each of the six pillars of the IRAP along with annual work plans and regular reporting. He emphasized that there is also an Indigenous Advisory Group (IAG), a panel of six Indigenous leaders from across North America that provides focused advice and holds Enbridge Inc. accountable. The IAG operates independently and reports to the reconciliation steering committee, engaging directly with Enbridge Inc.'s board of directors to provide strategic guidance on its reconciliation goals.
  - Kate Kempton, and Nick Daube of Resilient LLP followed up on requests to explore the possibility of meetings or potential collaboration with the IAG, and asked questions about Enbridge Gas Inc.'s statement that the IAG is unwilling to disclose their names or work in collaboration with the IWG, including whether there were ways to mitigate any confidentiality concerns on the part of IAG members so as to facilitate cooperation. Kim Brenneis responded by saying that the IAG is still a new group, and that it may take time before the members allow their names to be published in the future or if they would like to work with the IWG. However, Kim Brenneis agreed to ask whether the IAG is willing to explore the option of working with the IWG on a confidential basis.
- Kim Brenneis responded to Kate Kempton's challenge to its Indigenous workforce target of 3.5% by noting that it was established in 2020 based on a market analysis of what was considered achievable at the time, given that Indigenous representation was sitting between 1.9% and 2.1%. He emphasized that once targets are met, Enbridge Inc. intends to reset them to higher figures.
- Kim Brenneis agreed to organize a discussion with Enbridge Inc.'s Indigenous employment program lead in response to the concerns raised by Kate Kempton and other IWG members.

iii. Nick Daube inquired about how the IRAP applies to Ontario specifically and how Enbridge Inc. tracks progress. He sought clarity on whether Enbridge adopts formal regional targets to measure progress and how the IWG can access an itemized list of Enbridge Inc.'s achievements on the plan's objectives.

- Kim Brenneis clarified that the IRAP is a corporate-wide policy that applies uniformly across North America and is not tailored to specific regions like Ontario. He emphasized that while the policy provides overarching guidance, it encompasses all areas of Enbridge Inc.'s operations.

iv. Nick Daube followed up by asking how employment and procurement targets are approached on a regional level. He questioned whether Ontario-specific activities contribute significantly to these targets or if progress is disproportionately driven by other provinces.
    - Kim Brenneis used the 3.5% Indigenous workforce target example, noting that this is an aggregate corporate goal that might be historically more influenced by provinces such as Alberta, British Columbia, or Saskatchewan. However, Enbridge Gas Inc. has its own sub-targets, with a significant portion of recent hires this past year coming from Ontario. He agreed with Nick Daube who suggested establishing regional-specific data to better understand the gaps and implement targeted improvements.

v. Jennifer Mills of Chippewas of the Thames First Nation asked how new projects at existing facilities, such as new wells and pipelines at existing natural gas storage facilities, are addressed within the IRAP framework.
    - Kim Brenneis explained that Enbridge Inc.'s lifecycle approach to projects ensures that any ongoing work, including small capital projects, aligns with the IRAP framework. He highlighted Enbridge Gas Inc.'s performance for Indigenous procurement, specifically that operational opportunities have increased year-over-year because the business is focusing in on those smaller sustainable opportunities ("singles and doubles") rather than just larger high-profile projects ("home runs").

<u>3. The Brattle Group Presentation – Bruce Tsuchida, Tom Chapman, Peter Fraser</u>

a) Discussion on Energy Transition and Scenarios

i. The IWG engaged with Bruce Tsuchida and Tom Chapman of the The Brattle Group to review Enbridge Gas Inc.'s current transition plans and identify areas for improvement.

ii. A comprehensive report has been prepared by The Brattle Group for further review and discussion by the IWG. The Brattle Group's presentation on the report outlined opportunities for Enbridge Gas Inc. to further its efforts toward energy transition and address the IWG's feedback.

iii. The Brattle Group presented their findings and recommendations on energy transition scenarios.

iv. The Brattle Group compared the two scenarios employed as part of Enbridge Gas Inc.'s most recent rebasing application – a diversified scenario, which involves replacing natural gas with low or no carbon gas, and an electrification scenario, which looks at electrifying heating processes to reduce usage of natural gas.

b) Recommendations from The Brattle Group

i. Recommendation #1: Energy Transition Plan - There are opportunities to improve on the analysis that has already taken place and it would be beneficial to explain how potential options would impact daily lives. For example, if communities used heat pumps, what would it look like in a daily scenario. Or, if new infrastructure is proposed in an Indigenous community, what would the process look like, how could the Indigenous community participate in the development (e.g., renewable natural gas), and what are the potential risks (e.g., stranded assets) and benefits (e.g., compensation for land usage, new local jobs, equity, etc.): Enbridge Gas Inc.'s Transition Plan should include details on how each scenario will impact traditional land use activities. Enbridge Gas Inc. will need to increase its support for First Nations to build sufficient human, financial and technical capacity to plan their energy future.

ii. Recommendation #2: Commitment to Equality – The Brattle Group heard from a number of First Nations that they want to be involved early on as partners in the process. Reconciliation for historic grievances was identified as an important part of the process moving forward.

iii. Recommendation #3: IWG Process - The Brattle Group reported that impacted First Nation communities wanted to hear from Enbridge Gas Inc. in person ideally. Additional effort to engage in person would be well received and would pay dividends. The information The Brattle Group received on their in-person visit was magnitudes better because it helped contribute to a more engaged dialogue. Having a terms of reference for the IWG may also help to establish common goals, objectives and expectations. Sharing materials on a hosted website would allow important information to be shared more broadly, especially to community members who cannot attend meetings in-person.

iv. Recommended Next Steps from the The Brattle Group - Initiate second phase of pathway analysis. Consult with IWG on scope in Q1, 2025 – Enbridge Gas Inc. should provide resources to jointly manage and participate in the assessment. Complete studies by Q4 2025. Initiate work on developing options on potential economic opportunities for First Nations. Establish an Economic Development forum to oversee development of partnership opportunities. Enbridge Gas Inc. needs to address gaps in the current engagement approach to ensure all voices are heard.

c) Discussion on Scenarios and Net-Zero Pathways

i. Rob Lukacs of Scugog First Nation asked The Brattle Group whether Enbridge Gas Inc. collected the data accurately since the two pathways discussed in the report do not give an indication about what is meant by "renewable natural gas" (RNG). He commented that, for example, today "RNG" is not yet a defined product. He suggested that the more tangible examples of RNG that can provide to First Nations, the better.

- Examples of RNG were presented to the IWG, including poultry litter, landfill waste, biomethane, organic materials, agricultural residue or waste, landfill gas, wastewater treatment plants, forestry, pulp mill, or municipal solid waste. There may also be some programs within a given municipality, such as food waste, forest and wood residues, energy crops, and organic industrial waste.
- Cody Wood of Enbridge Gas Inc. provided other examples involving the repurposing of existing pipelines in the diversified scenario. He explained that this would involve repurposing hydrogen or the delivery of RNG. He also contemplated expanding pipeline infrastructure to facilitate this scenario. In either scenario, it would involve consideration for consumer demand.

ii. Rob Lukacs raised concerns that Scope 3 emissions were not considered in the scenarios presented.
    - Bruce Tsuchida acknowledged that the study conducted by Enbridge Gas Inc. addressed Scope 3 emissions, but only at a high-level. Suggesting that a more detailed analysis could take place in the future, though it would require additional work.

iii. Kate Kempton questioned whether a third scenario might be missing from the analysis.
    - Bruce Tsuchida recommended that, rather than analyzing a third or fourth scenario, it might be worth delving deeper into the two scenarios already developed by Enbridge Gas Inc. and reviewed and presented by The Brattle Group.
    - Tom Chapman highlighted that, while alternative solutions might coexist with the scenarios they presented, achieving net-zero emissions without the use of electricity or natural gas remains unlikely, and commended Enbridge Gas Inc. for attempting to shape a new industry. Bruce Tsuchida continued on this point, stating that at the current state of technology and feasible options today, there may not be an alternative scenario that can be considered and will provide meaningful insights.
    - Cody Wood confirmed that the diversified scenario includes Carbon Capture, Utilization, and Storage (CCUS).
        - Bruce Tsuchida reiterated the need to set boundaries around these scenarios and then consider costs implications, positioning the two scenarios as "book-ends", which provide a high-level framework for Enbridge Gas Inc. to explore emission reductions by 2050.

d) Equity and Economic Opportunities

i. Peter Fraser discussed the potential for opportunities around equity ownership or option deals. Though he highlighted the risks involved if equity shares in a project loses value, he encouraged a careful evaluation of these opportunities to mitigate risk for the communities involved.

ii. Jennifer Mills emphasized that both scenarios assume a ramp up of hydrogen, which will have impacts to land. She highlighted that the Ontario Government is currently involved in consultation around a low-carbon strategy, which presents opportunities to involve First Nations while expanding Enbridge Gas Inc.'s business.

iii. Don Richardson of Minogi Corp. suggested that, while Ontario has the capacity to produce RNG, the most attractive markets happen to be outside of Ontario. He noted that First Nations could play a significant role in RNG production but that they might also prioritize export opportunities to jurisdictions like Quebec, British Columbia, or California. Don Richardson also critiqued Ontario's lack of integrated planning for electricity and natural gas markets, explaining that new developments default to natural gas distribution even when alternative heat sources, like geothermal, may be viable options.
    - Jennifer Mills acknowledged that the Ontario Government is launching integrated resource planning. That the Independent Electricity System Operator

(IESO) has webinars about planning processes and some are targeted to First Nations.
- Bruce Tsuchida noted that solving integrated planning challenges is beyond Enbridge Gas Inc.'s scope alone, requiring broader collaboration.

e) Collaboration and Future Steps
  i. Tom Chapman, on behalf of The Brattle Group, invited the IWG to provide feedback on their presentation materials. Bruce Tsuchida suggested the IWG focus on recommendations it provided during their presentation. Peter Fraser advised the IWG to develop the vision for a net zero emissions future for First Nations communities in order to help identify the implications and opportunities.

4. Enbridge Gas Inc. Regional Scenario Analysis Project

a. Cody Wood presented on Enbridge Gas Inc.'s Regional Scenario Analysis Project. Planning is in process for external engagements that will begin in Q1 2025 and will consist of virtual workshops and online requests for input. Cody asked the IWG to consider how best to engage to get Indigenous perspectives.
b. Cody Wood said he would like to read through The Brattle Group's presentation before providing comments on it. Bruce Tsuchida suggested willing participants can put their name on the list to be part of this process. Lauren Whitwham said Enbridge Gas Inc. would reach out to First Nations through their engagement process to see if they are interested in participating.
c. Cody Wood said for Scope 3 emissions, they are going to look at emissions from Enbridge Gas Inc.'s customers. He is not certain if they can analyze upstream emissions. Cody Wood said they can likely incorporate some of The Brattle Group's recommendations and is open to talking to the IWG about engagement with Nations.
   i. Action Item – Enbridge Gas Inc. to confirm whether they can disclose the name of their consultant on the Regional Scenario Analysis Project.
d. Kate Kempton said they want The Brattle Group to return at a future IWG meeting. Tracy Skye said there is a trust issue because people are not brought into discussions in the beginning.
e. Future Agenda Item: Enbridge Gas Inc. to provide a response to The Brattle Group's report. Nick Daube suggested the following plan:
   i. Enbridge Gas Inc. to review and consider The Brattle Group's report and have any needed internal discussions. Can ask IWG or The Brattle Group through its First Nation representatives any necessary/helpful follow up questions.
   ii. Ideally, by the end of December 2024, Enbridge Gas Inc. Provides the IWG with a short document supplementing Cody Wood's presentation. The requested short document would summarize ongoing scenario work and speak to how it considers the interests of First Nations, including specific impacts, stranded assets, cost implications, economic opportunities, and relevant lifecycle/environmental impacts. Once Enbridge Gas Inc. has considered The Brattle Group's presentation and produced the draft summary outlined above, The Brattle group, Enbridge Gas Inc. representatives, and Enbridge Gas Inc.'s consultant may conduct a preliminary meeting to discuss the two documents (i.e. The Brattle Group presentation and the Enbridge Gas Inc. Draft/summary), including implications for First Nations and potential omissions in Enbridge Gas Inc.'s current approach

iii. Broader conversation at a future meeting of the IWG where The Brattle Group and Enbridge Gas Inc.'s Energy Transition representatives (and/or consultant) attend, providing enough time for Enbridge Gas Inc. to consider and respond to feedback generated through the above steps.

5. Engagement Template

a) All members of the IWG have this information and will review it in preparation for the next meeting.

6. Draft Agenda for Next Meeting

a) Enbridge Gas Inc. to provide a response to The Brattle Group's report
b) Compensatory Regime
c) Engagement Template

Action Items:

- Item 1: Enbridge Gas Inc. to confirm whether the Indigenous Advisory Group is willing to meet with the IWG.
- Item 2: Future meeting invite lead for Enbridge's Indigenous Employment Program to hear about progress and discuss opportunities to raise the target moving forward
- Item 3: Enbridge Gas Inc. to reach out to communities to seek interest in participating in the Regional Scenario Analysis
- Item 4: Enbridge Gas Inc. to confirm whether the name of their consultant on the Regional Scenario Analysis Project can be disclosed.
- Item 5: Enbridge Gas Inc. to prepare short document responding to The Brattle Group report for further discussion.

7. 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 March 2025.

Enbridge Gas Inc. Indigenous Working Group Minutes - FINAL

Minutes of a meeting of the Indigenous Work Group (IWG) held on **March 4, 2025,** at 9:00 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
Jessica Wakefield	Three Fires Group
Todd Jardine	Three Fires Group
Kate Kempton	Woodward and Company, Ginoogaming First Nation
Tracy Skye	Six Nations Natural Gas
Bruce Tsuchida	The Brattle Group
Tom Chapman	The Brattle Group
Peter Fraser	The Brattle Group
Robert Lukacs	Minogi Corp
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 Murphy	Enbridge Gas Inc.
Heidi Steinberg Laxton	Enbridge Gas Inc.
Gabrielle 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.
    - Lauren Whitwham provided a safety moment.
    - IWG discussed and approved the minutes of the December 10, 2024 IWG meeting.
    - Lisa DeMarco suggested creating a timeline for addressing the recommendations from the Regional Scenario Analysis
    - Kate Kempton asked if the DSM Intervenor Response Letter could be moved earlier in the meeting and if the Reconciliation discussion could be moved to the next IWG meeting given Kate Kempton had to leave the meeting early
    - IWG agreed to move the DSM Intervenor Response Letter to the beginning of the agenda. Reconciliation discussion took place with IWG members who were able to remain at the meeting with the understanding additional discussion would be needed at upcoming meetings
2. **DSM Intervenor Response Letter**
    - Kate Kempton indicated a concern about the ministry renewal directive regulatory efficiency and process. Specifically, that the passage on page 6 of the letter suggests the OEB requires Indigenous participants to coordinate legal counsel efforts. Kate Kempton, on behalf of Ginoogaming First Nation, objects to this and finds it offensive, pointing to historical efforts to divide and fragment Indigenous interests, the forced collaboration implied in the statement, and reinforced that Nations are unique with differing views and should not be forced to work with legal counsel they do not know and may not trust. Kate Kempton also asked for clarification on the term “Indigenous Group”. Kate Kempton requested that the statement on page 6 of the letter be retracted
    - Lisa DeMarco added that Indigenous rights holders have *sui generis* rights to the land, and they come to the table in good faith, whereas the wording in the passage on page 6 detracts from this sense of good faith to achieve progress together. Lisa DeMarco also emphasized that efficiency comes from among and between Indigenous groups and intervenors and the ‘without constraint’ piece is important to address. Lisa DeMarco requests that Enbridge Gas Inc. send a letter to the OEB to correct and clarify this statement.
    - Kim Brenneis apologized on behalf of Enbridge Gas Inc. for the offense that was taken and emphasized that Enbridge Gas Inc. will work with communities individually or as a group if they have common interests and want to share legal representation. Kim Brenneis also clarified that the use of the term “Indigenous groups” intends to capture the many ways Indigenous communities choose to work with Enbridge Gas Inc. including as individual communities, groups of communities, or through representative organizations, including legal counsel that represent multiple communities.
    - Tania Parsad appreciates the IWG’s comments on the matter and agreed that the wording needs to be clarified and confirmed that Enbridge Gas Inc. will speak to their external counsel about the DSM proceeding to determine what the appropriate place is to clarify their comments and submit the clarification to the OEB.
3. **Regional Scenario Analysis (RSA)**
    - Jennifer Murphy of Enbridge Gas Inc. presented on how The Brattle Group’s recommendations may be included in the RSA. It was noted that several of The Brattle Groups recommendations are not specific to the RSA and will be considered by other groups at Enbridge Gas Inc. Though some of those opportunities are mentioned here, Jennifer Murphy’s presentation is focused on the RSA, which included the following key items:

- The 2024 Rebasing application was informed by the Energy Transition Scenario Analysis (ETSA), the "Pathways to Net Zero" report, and the Energy Transition Plan.
- The 2029 Rebasing application will be informed by the in-progress Regional Scenario Analysis (target completion Q4 2025) and the subsequent Energy Transition Plan (not yet started).
- Enbridge Gas Inc. does not intend to update the Pathways to Net Zero at this time.

- The RSA is focused on forecasting the impact of the energy transition on the company and system in Ontario, which are used in future planning
    - Some of the Brattle recommendations may be incorporated into the next rebasing application, such as asset planning, but there are limited opportunities to incorporate in the RSA (as the recommendations would be out of scope), and the Pathways to Next Zero report will not be updated so there is no opportunity to include any specific recommendations related to that project.
    - Enbridge Gas Inc. acknowledged that stakeholder and rights holder engagement was limited in the ETSA. The intention going forward is to include more engagement including discussions with the IWG and connecting with First Nations directly for the current RSA and the development of the next Energy Transition Plan (ETP).
    - Lisa DeMarco noted that engagement must recognize that engaging separate Indigenous rightsholders is different from general Indigenous stakeholder engagement.
    - One of The Brattle Group's recommendations was that Enbridge Gas Inc. look at the impacts on communities in the scenarios, however, the level of information feeding into the RSA does not allow for this (not in scope of the RSA). That said, Jennifer Murphy indicated Enbridge Gas Inc. says it may be possible to complete a qualitative review and/or provide illustrative examples, but more time and discussion is needed to see how it could be done.
    - Lisa DeMarco asked how Enbridge Gas Inc. gets from the RSA to the updated energy transition plan without considering needs or the pathway to get there and asked how Enbridge Gas Inc. stays within greenwashing laws and Bill C59? Jennifer Murphy answered that the study was to look at a pathway and if the scenario came to fruition, examine the impact. Further, Enbridge Gas Inc. is not suggesting that any of the scenarios are the pathway to net zero or insinuating that the government should take them to get to net zero, and we are not necessarily supporting one particular pathway.
    - Lisa DeMarco suggested that the new tariffs require immediate and proactive planning, particularly as it pertains to storage and transportation services
        - Jennifer Murphy agreed and acknowledged that those dealing with tariffs more directly are other teams at Enbridge Gas Inc. (i.e. Energy Services and the Gas Supply Group)
    - Lisa DeMarco stated that they understood that the Gas Supply Plan had been delayed from March 5 until May and that it might be relevant to energy services and gas supply. Lisa DeMarco further strongly encouraged convening the IWG proactively on this process, virtually if necessary and with the Gas Supply team.
        - Enbridge Gas Inc. confirmed the delay of the Gas Supply Plan was not directly related to the tariffs. The timing was coincidental.
    - The IWG inquired about the impact of tariffs, participating in decision making and how tariffs may impact planning, including whether "safe bet" actions from the Pathways report are still relevant.
        - Jennifer Murphy acknowledged that the safe bet actions were part of Enbridge Gas Inc.'s energy transition plan starting in 2024. The current plan didn't anticipate tariffs

and the company's response. Enbridge Gas Inc. will be looking for feedback from external engagement including the IWG for its next Energy Transition Plan for the 2029 Rebasing filing.

- Lisa DeMarco says this is too little, too late. The current energy transition plan is working on faulty assumptions, and it would be beneficial to be brought into the gas supply planning and related services discussions now with Enbridge Gas Inc. leadership. She further suggested tariffs provide an opportunity for Indigenous rights holders and Enbridge Gas Inc. to work together at the highest levels.
- Tom Chapman agreed that it is important to look at how customers are using gas going forward and the importance of engaging with Nations
- Todd Jardine agreed that good feedback will come from involving Nations
- Enbridge Gas Inc. confirmed that they are looking to engage larger industrial customers to understand their energy transition plans.

- Regarding RSA External Engagement, Jennifer Murphy indicated they are open to ideas about how to consult and find interest among First Nations to participate, including looking at how the IWG and Nations see energy transition rolling out in the community. Enbridge Gas Inc. confirmed it will engage IWG and Nations as part of the 2029 Rate Rebasing process to solicit input on the engagement process and how best to include Indigenous perspectives in the updated ETP and will review and discuss with IWG how best to include ETP impacts on First Nation communities (community level, daily lives).
    - Bruce Tsuchida suggested it would be helpful to the IWG to look at past developments and compensation as examples of what it means for new developments
    - Jennifer Murphy said they could likely complete a qualitative review or provide illustrative examples of impacts to daily life, but the Regional Analysis Work is not proposing specific projects. Jennifer Murphy noted that Enbridge Gas Inc. could look at how this could be done as ET planning in the future.
- Regarding general engagement and role of IWG, Kate Kempton reiterated that the IWG shouldn't be reactive and that IWG should be at certain tables, such as Enbridge's Indigenous Advisory Group that reports directly, and would like to explore how the IWG can get inside the room as the IWG still feels like it is receiving things when they are already mostly 'baked', and that there is always a substantive component to engagement and it is not just a process of discussion, it's also the content of discussions and deliverables, as it is this substantive output that measures the engagement.
    - Enbridge Gas Inc. indicated that IWG provides opportunity to receive feedback and discussion in spirit of collaboration and have robust discussions and have these conversations accelerate engagement and to think about how to seize opportunity for collaboration, make sure sharing information and take responses back for consideration.
    - Lisa DeMarco said the role of the IWG is seen as being more than just discussions.
- Regarding Integrated Resource Planning (IRP), Lisa DeMarco referred to one of the recommendations and noted that there is an OEB-led IRP Technical Working Group that doesn't currently have Indigenous participation and suggested Enbridge Gas Inc. and IWG jointly ask the OEB to be involved in the group
    - Jennifer Murphy agreed that she could pass this idea onto the IRP Manager, who could comment on the recommendation. Lauren Whitwham indicated that information on IRP projects webinars is distributed to Nations from CIE senior advisors

4. Reconciliation – Discussion on IWG Principles and Enbridge Reconciliation Approach

- Kim Brenneis presented on reconciliation and Enbridge Inc.'s current and upcoming Indigenous Reconciliation Action Plan (IRAP) refresh. Note that the IRAP is an Enbridge Inc. document that applies enterprise-wide, including with respect to Enbridge Gas Inc. The 2025 refreshed IRAP will be in place for the next three years before the next refresh. Summary of the discussion is as follows:
    - Enbridge Gas Inc. was asked and confirmed that the refresh involved a similar process to the initial IRAP, which included speaking with Indigenous groups leaders and seeking their feedback on what they wanted to see going forward, along with benchmarking best practices. Conversations also continued with Enbridge Inc.'s Indigenous Advisory Group (IAG), which is comprised of Indigenous representatives (not representing individual rights bearing Nations, but Indigenous leaders from around North America who were invited to join the IAG). Enbridge Gas Inc. reminded the IWG that IAG members have asked to remain anonymous to ensure they can provide honest feedback and perspectives to Enbridge Inc.'s executive team and Board of Directors. The general breakdown of IAG representation is as follows:
        - 3 people in the United States
        - 4 people in Canada
            - 2 in the Prairies
            - 1 in British Columbia
            - 1 currently vacancy in Ontario/eastern Canada
    - The IAG meets with Enbridge Inc.'s Reconciliation Steerco (made up of senior VPs from across the company who operate Enbridge Inc.'s four major business units)
        - Lisa DeMarco requested an organizational chart of Enbridge Inc. and the Steerco and Enbridge Gas Inc. agreed this could be provided including structure of the company; the different business units; reconciliation Steerco; and where the Indigenous Advisory Group fits in
    - As requested by the IWG, Kim Brenneis provided Enbridge Gas's feedback on the 10 principles that were shared by Kate Kempton on behalf of the IWG
    - Enbridge Gas Inc. is very aligned with some but not all of the IWG principles
    - Kim Brenneis acknowledged that Kate Kempton had to leave and a more targeted look into specific principles should include her. With this in mind, Kim Brenneis shared the following reflections and observations on what Enbridge Inc. sees as some common themes/alignment within the principles:
    - Theme 1 - Decision making, Co-management and the Lifecycle approach
        - Lifecycle approach
            - This relationship-based approach has fundamentally evolved within Enbridge Inc. in the past 10 years from what was generally considered to be more of a historically transactional approach (engagement only when there was a project) to a lifecycle approach that involves engagement from initial project concept, into construction, operations and ultimately abandonment. Doing this requires building and sustaining meaningful relationships with the goal being to have ongoing relationships with Nations throughout each business unit. The IAG, through the IRAP offers another way of gaining different Indigenous perspectives and advice.
        - Free prior, informed consent
            - This is an area where Enbridge Gas Inc. and the IWG may not totally agree.

- Enbridge Gas Inc.'s goal of relationship building is to collaborate and work towards consensus through robust engagement
- Enbridge Gas Inc. is seeking consensus, but believes consent is not required in most circumstances. Kim Brenneis acknowledged that sometimes consent is required, for example for activities on reserve or other specific matters or circumstances and again further emphasized a focus on collaborating towards consensus in these circumstances.

▪ Co-management
- Our belief is that co-management is an opportunity to work together and for Enbridge Gas Inc. to get input from the Nations, including individual rights bearing Nations and other groups, and to consider these perspectives in the company's processes
- The ultimate goal is to better align interests, with the IWG being an example of where we can find alignment with interests from Ontario First Nations (also happens through increased information sharing, collaboration, addressing issues and fostering a less adversarial environment)
- Kim Brenneis further clarified that co-management in this context, is increased collaboration and perspective-sharing to make more informed decisions as opposed to co-management of day-to-day business decisions. As a company committed to operating energy assets safely, it is important that we retain decision making authority
- For example, we are driving increased Indigenous inclusion in environmental field work and regulatory environmental review processes to make them more wholesome, providing capacity funding, and increasing participation in processes beyond regulatory requirements
  - Kim Brenneis discussed the Sunrise Expansion Program in BC as an example. Here, most of the field work is being done by Indigenous companies owned or working for the Indigenous Nations. Indigenous partners are being involved from the start and it is building trust and aligning interests on how fieldwork should be done.

o Theme 2 - Accommodation

▪ Kim Brenneis read the acknowledgement in the 2025 IRAP refresh, which was developed with input and support from the IAG:

We recognize the injustices Indigenous groups have historically faced, and the ongoing challenges they continue to face today. (Seventy-six years ago, in 1949, Interprovincial Pipe Line Company began the construction of what would eventually become Enbridge's vast portfolio of energy assets and infrastructure today). We acknowledge the lack of inclusion in our collective historical activities within the broader societal context at the time, including the impacts to cultures, languages and socio-economic well-being of Indigenous peoples.

We commit to listening and learning from the lived experiences of Indigenous people and to apply that knowledge with action to continue to forge a path towards reconciliation—in service of ensuring that our future is increasingly inclusive and respectful of Indigenous rights, values and heritage, and in recognizing their vital role and contributions in shaping a more inclusive society.

- Accommodation is likely another area where Enbridge and the IWG are not well aligned. Enbridge Gas Inc.'s view is we try to avoid or mitigate impacts, and where we can't mitigate, we try accommodation measures to address those impacts. This does not automatically mean compensation
- Kim Brenneis discussed the Indigenous Advisory and Monitoring Committee (IAMC) established by the federal government for the Line 3 Replacement Program (Line 3) as an example of an accommodation measure:
    - The IAMC was announced by the government as part of its approval of Line 3, but it was not a condition of approval. Instead, it was formed to provide a form of accommodation and a mechanism to encourage further participation by Indigenous Nations in Line 3. Enbridge Inc. is not a member but attends meetings when requested
    - Lisa DeMarco requested interaction and relationship between Enbridge and IAMC be included in the organizational chart to be provided by Enbridge Gas Inc.
- Accommodation on historical assets
    - Enbridge Gas Inc.'s view on accommodation of historical assets is that accommodation on historical impacts is not required, and the company will not provide compensation for historical impacts or use
    - Enbridge Gas Inc. knows and acknowledges the complex history that they've been a part of is committed to a more inclusive future through the IRAP, lifecycle engagement process, Social Economic Requirement of Contractors (SERC) process, etc.; this is the focus and approach to reconciliation going forward
- Taxes and compensation for assets on private and Crown land
    - Kim Brenneis further discussed Enbridge Gas Inc.'s view that they do not pay compensation or revenue sharing for assets on private or Crown land or compensation to Nations for assets on private or Crown land
    - Enbridge Gas Inc. will not commit to paying taxes or other compensation to First Nations for assets on private land or crown land, although we pay taxes on reserve where the Nation is the taxing authority or pay "in kind" payments on reserve in lieu of taxes.
    - The issue of taxation and compensation on all assets is a significant societal issue and Enbridge Gas Inc. can't address this in isolation. It requires government to First Nation government resolution
- Indigenous economic inclusion
    - Enbridge developed an industry leading SERC process based on the Line 3 experience and success in economic inclusion
        - The SERC process – contractually obligates contractors to work with Enbridge Gas Inc. to maximize indigenous inclusion through procurement and labour side of business
        - Socio-economic plan – anyone bidding on work needs to demonstrate how they will include Indigenous businesses, preferably local Indigenous businesses from impacted areas
        - Contractual requirement is critical

- Indigenous equity ownership
    - Kim Brenneis explained that Enbridge believes that Indigenous equity ownership is a powerful tool for creating true partnerships, but it is not a question of rights, interests or impact. We view it as a commercial opportunity
    - One example of a successful Indigenous partnership was on our Athabasca pipeline system. 23 Indigenous partners purchased 5% of pipeline and receive disbursements (income) every quarter. The deal required no money down for Indigenous groups, utilizing government loan programs, and the deal was structured to shield participating Indigenous groups from risk, including the construction risk and any risk of debt default.
    - Enbridge Gas Inc. has heard from other Nations and Metis groups that economic inclusion is a rights issue. Again, while we are committed to economic inclusion through our procurement and hiring processes, and equity deals are powerful partnership opportunities, the company views them as a commercial deal
    - Equity opportunities are not part of the regulatory process
    - We view these deals as helpful in building partnerships but not a sole solution; it is a step on the path to reconciliation
        - Lisa DeMarco asked about the current power proceeding and Enbridge Gas Inc.'s involvement
            - Kim Brenneis said he can't speak for the power group
        - Lisa DeMarco asked about Carbon Capture Storage (CCS) in Alberta Wabamun Hub
            - Enbridge Gas Inc. said it is a partnership with five Indigenous groups to create a carbon hub. No project yet, but the partnership continues to work on it.
            - Tania Parsad said legislation in Ontario related to CCS is still fairly new and projects have not yet been implemented
- Follow up on this item from the last IWG meeting minutes
    - Kim Brenneis confirmed he was asked whether the IAG was willing to meet with the IWG and relayed he did not yet have a response but would follow up again. IWG members noted that the IWG is willing to sign a confidentiality agreement if appropriate.
    - IWG requested regional specific data for gaps and targeted improvements of procurement

- Theme 3 - Protection of environment and climate
    - Enbridge Gas Inc. is increasingly involving/ seeking indigenous involvement in field work and reviewing reports (further aligning interests)
- Tying back to the IWG mandate

- Enbridge Gas Inc. believes there is an opportunity to better use the IWG to share and collaborate (bringing the right people from Enbridge Gas Inc. to hear issues and discuss opportunities)
- The IWG was born from a regulatory proceeding, but there is an opportunity to use this mechanism to have honest and robust conversations
- Lisa DeMarco explained that after the fact consultation muffles the IWG impacts, and would expect things like the IRAP refresh and similar initiatives to be shared before it is released
- Rob Lukacs indicated he doesn't agree with Enbridge Gas Inc.'s position on commercial equity not being a rights-based request. Rob Lukacs highlighted how the courts have clarified in many cases that Indigenous rights are recognized as including economic components linked to land and resource use. Rob Lukacs, Diana Audino and Lisa DeMarco had a discussion with the following points:
    - Diana Audino outlined how Enbridge Gas Inc. recognizes the court's position that economic benefits derived from impacts on rights can be considered a benefit through the consultation process and should be considered as well as impacts on rights. When Enbridge Gas Inc. considers economic opportunity, it's not based on potential impacts on rights. Many factors go into who gets offered partnership opportunities but it's not based on impacts to rights. In Enbridge's view equity opportunities are not tied to consultation or rights.
    - Diana Audino further discussed how providing equity opportunities is separate from an assessment of impacts on rights. The Nations would be receiving an economic benefit.
    - Lisa DeMarco discussed how Enbridge Gas Inc. has been receiving an economic benefit from the use of Aboriginal territories for years without providing compensation.
    - Diana Audino noted that Enbridge understands them as two separate issues
    - Rob Lukacs agreed with Lisa DeMarco and said the position Enbridge Gas Inc. is taking reinforces economic dependence and denies revenue sharing on projects impacting their lands. Indigenous Nations continue to remain dependent on government funding. Rob Lukacs further sees this as a missed opportunity to address economic sovereignty and strongly encourages Enbridge Gas Inc. to reconsider this position because it is still tied to rights.
    - Diana Audino emphasized partnerships as one form of economic reconciliation
    - The IWG agreed that everyone was hearing each other but are not on the same page

5. **Green Loan discussion**

- Brent Bullough presented Enbridge Gas Inc.'s response to a January 15, 2025 Toronto Star article questioning Enbridge Gas Inc.'s use of Sustainability-linked green loans. The IWG also wanted to know if similar loans were used by Enbridge Gas Inc.
    - Enbridge Gas Inc. clarified that they do not participate in similar loan programs
    - Key to note that the article contained dishonest and incorrect information, including the premise that CO_2 emissions have increased since 2018. This is not true. Enbridge Inc.'s absolute emissions from its operations have decreased by 20% (Scope 1 and 2) since the 2018 baseline.

- The authors of the article claimed Enbridge Inc. used 2018 as the baseline because it was a year of high emissions, however, 2018 was selected because it was the first year of full operations after Enbridge Inc.'s merger with Spectra Energy. Reporting any information prior to this date would not be possible because it would involve two different companies, with different data sets and methodologies.
- Enbridge Inc. is transparent about its progress and adheres to all rules and regulations regarding the issuing and public disclosures relating to sustainability-linked bonds and loans and is in compliance with the International Capital Market Association's Climate Transition Finance Handbook 2020 and Sustainability-Linked Bond Principles 2020
- Enbridge Inc. obtained a second-party opinion from ISS ESG on both its sustainable finance framework and the selected key performance indicators
- These facts and others were explained to the authors but were ignored. Enbridge subsequently submitted a letter to the editor in response to the article, but the Toronto Star did not publish it.
- IWG members asked to see the letter to the editor and suggesting keeping this item on the agenda when Kate Kempton and Lisa DeMarco are both in attendance.
    - Enbridge Gas Inc. will provide the IWG with a copy of the letter to the editor that was not published and will revisit this item at a future meeting

6. Engagement template + next steps

- Brent Bullough provided an update on the Engagement Template and reminded that, at a previous meeting, IWG members presented recommendations for engagement principles for the gas utility level Leave to Construct projects and a sub-working group identified the following priority items:
    - Priority 1. Early engagement and information sharing
    - Priority 2. Understanding values
    - Priority 3. Environmental protection (pre and during construction)
  - Next steps were identified by the sub-working group members, seeking input from the full IWG.
    - IWG members to review the Engagement Template Priorities document and confirm the priority items.
      - Rob Lukacs requested that "cultural heritage" be included in Priority 3 and language from Pillar 2 of the updated IRAP, related to lifecycle, be included
        - Enbridge Gas Inc. will attempt to include this for IWG review and consideration
    - First Nation representatives to provide Enbridge Gas Inc. with a short, preliminary summary of questions and concerns in relation to the item under discussion in order to frame a discussion at the IWG (Timeframe: March 4 meeting to before the next IWG meeting)
    - With the benefit of the summary of questions and concerns, Enbridge Gas Inc. will present on the item at the IWG, providing an opportunity for Enbridge Gas Inc. to describe its current policies and practices, as well as provide any early response to First Nation questions and concerns (Timeframe: next IWG meeting after March 4)
    - The presentation at the IWG would include time for questions from First Nations representatives, as well as a general discussion
    - On the basis of the presentation and discussion at the IWG, the IWG may request that further steps be taken to advance discussions and possible areas of agreement. For example, the IWG might request a sub-group to undertake further work, or Enbridge

Gas Inc. may be asked to report back to the IWG on specific points from the IWG discussion.

7. Action Items

- Item 1: Enbridge Gas Inc. to provide approved meeting minutes from IWG meeting on December 10, 2024 with the IWG
- Item 2: Enbridge Gas Inc. to provide updated wording from page 6 of the DSM letter or a draft clarification letter to the IWG for review prior to filing the letter with the OEB
- Item 3: Enbridge Gas Inc. to respond further to RSA recommendations at future IWG meetings
- Item 4: Enbridge Gas Inc. to follow up with their Energy Services group and include Jennifer Murphy's team
- Item 5: Enbridge Gas Inc. to provide an organizational chart of the company to the IWG, including structure of the company; the different business units; reconciliation Steerco; where the IAGs fits in;
- Item 6: Enbridge Gas Inc. to provide regional specific data for gaps and targeted improvements of procurement
- Item 7: Enbridge Gas Inc. to inquire about sharing the letter sent to the Green loan article's editor to the IWG
- Item 8: Enbridge Gas Inc. to share Engagement template table with the IWG seeking feedback and edit it to include cultural heritage and IRAP Pillar 2 principles

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 middle to end of May 2025. Jessica Wakefield to chair and team to canvas for an Agenda closer to the date. Meeting to start later in the day (10am).

APPENDIX A – AGENDA FOR MEETING OF IWG ON MARCH 4, 2025

Time	Matter	Participants
9:00-9:15 am	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Lauren Whitwham and Group
9:25-9:45 am	DSM Intervenor Response Letter	Diana Audino, Kate Kempton, Tania Persad and Group
9:45-10:50 am	Regional Scenario Analysis and The Brattle Group Recommendations	Jennifer Murphy, The Brattle Group and Group
10:50-11:05 am	Break	
11:05-11:35 am	IWG internal coordination	IWG members
11:35-12:30 pm	Reconciliation – Discussion on IWG Principles and Enbridge Reconciliation Approach	Kim Brenneis and Group
12:30-1:00 pm	Lunch	
1:00-1:30 pm	Enbridge and Green Loans	Brent Bullough and Group
1:30-2:00 pm	Engagement Template – Next Steps	Brent Bullough and Group
2:00 pm	Wrap-up/Adjourn	Group

Distribution Integrity Management Program (DIMP) and Enhanced Distribution Integrity Management Program (EDIMP)

Report on Activities - 2024

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 2024 amounted to $12.480 million. This report describes the activities and work that comprised this spend. A breakdown of actual expenditures is shown in Table 1.

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.31.
[2] Ibid, p.56.

Table 1

2024 DIMP/EDIMP Actuals VA Breakdown

Line No.	Description	2024 Actuals ($ millions)
	DIMP Admin	
1	Labour, Training, Travel & Accommodations (T&A), Professional Dues, Other Materials/Supplies	1.596
	DIMP Projects	
2	Investigations & Assessments	0.670
3	Pipe Inspections	0.459
4	Station Inspections	0.236
5	Regulator Set Inspections	0.862
6	2023 DIMP Carryover Costs	0
7	Total DIMP	3.823
	EDIMP Admin	
8	Labour, Training, T&A, Professional Dues	0.887
	EDIMP Projects	
9	ILI & Digs	7.267
10	CP Surveys and Geohazard Assessments	0.493
11	Assessments	0.005
12	2023 EDIMP Carryover Costs	0.005
13	Total EDIMP	8.656
14	Total DIMP and EDIMP	12.480

2. DIMP and EDIMP Administration

The total costs to administer the DIMP and EDIMP portfolios amounted to $2.483 million. These costs included Full Time Equivalent (FTE) positions, contractor positions, and employee expenses such as travel & accommodations (T&A), training and professional dues and any other materials or supplies required to support the DIMP and EDIMP portfolios. In addition, staff that supported the DIMP and EDIMP teams charged their time worked to these portfolios.

3. DIMP Projects

DIMP Projects consist of five distinct work categories: Investigations & Assessments; Pipe Inspections; Station Inspections; Regulator Set Inspections; and 2023 DIMP Carryover Costs. The actual spend for these work categories in 2024 was $2.228 million.

3.1 Investigations & Assessments

a) Water Crossing Inspections: Two hydrotechnical inspections were performed in 2024:
    - A hydrotechnical inspection was performed on an exposed NPS 8 intermediate pressure steel pipeline that was located in a creek in Ancaster. The inspection was initiated to assess potential hazards, including vortex induced vibration hazards, to determine the appropriate mitigation plan; and
    - A hydrotechnical inspection was performed on an NPS 10 intermediate pressure steel pipeline located in St. Catharines that had not previously been inspected due to access constraints. The pipeline was identified as one of the higher-risk distribution pipelines in the region, with specific concerns noted regarding the pipe crossing through Twelve Mile Creek. The inspection was therefore initiated to assess potential hazards for this pipeline.

b) Bare Protected Steel Special Corrosion Survey: Bare steel is generally known to exhibit higher leak rates than coated steel, so a special cathodic protection survey was performed. A sample of approximately 13 km of the approximately 415 km of bare protected steel pipe was surveyed to better understand the cathodic protection status of this subset of steel assets. The over-the-line survey was comprised of a Close Interval Potential Survey (CIPS) assessment.

c) Special Leak Survey of Suspect Saddle Fusions: This is a special annual leak survey used 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.

d) TR-418 Assessments: This is associated with completing the final TR-418 plastic assessment report. This broader assessment was undertaken to determine the performance of TR-418 plastic pipe relative to other pipe, such as plastic (Aldyl “A”) pipe. The assessment was used to determine the reliability of TR-418, which can now be used for quantitative risk assessments. The assessment determined that, on average, TR-418 plastic pipe has approximately 7-9 times longer life expectancy than Aldyl "A" plastic pipe.

e) Heavier Hydrocarbon Contamination on PE Pipe: Hydrocarbon contamination is a phenomenon seen primarily in Southwestern Ontario where pock-marks are formed at joints on plastic pipe during the fusion joining process. When this occurs, 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. The investigation includes field sampling combined with a series of mechanical testing and optical microscopy.

f) Exceptional Services Risk-Informed Prioritization: Exceptional services are service pipe that have been disconnected from the gas meter, but are still energized with natural gas (i.e., inactive services). A consultant was engaged to develop a risk-informed approach for assessing and prioritizing mitigation work on the approximately 5,200 exceptional services within the Enbridge Gas Ontario distribution system. This emerging risk was identified following an incident at Enbridge Gas Ohio that resulted in major property damage and fatalities.

g) Aldyl “A” Plastic Pipe Reliability Model Validation: This work was prioritized due to recent safety-related incidents resulting in fatalities involving Aldyl “A” polyethylene (PE) pipelines in the U.S..

   A consultant was engaged to review and validate Enbridge Gas Ontario’s internally developed reliability model that estimates the Probability of Failure (PoF) for Aldyl “A” mains, service pipes and service connections. PoF values are inputs to the quantitative risk assessment (QRA) of Aldyl "A" plastic pipe. The results of the QRA will be used to define next steps for Aldyl "A" plastic piping.

h) Aldyl "A" PE Pipe Survey: This work was prioritized due to recent safety-related industry incidents in the US.

Enbridge Gas Ontario requires more certainty on its inventory of vintage plastic pipe to inform a broader strategy to manage the risk associated with Aldyl "A" plastic pipelines. The survey was initiated on approximately 200 gas mains installed in the 1970s to verify and reduce the amount of unknown plastic pipe that may be Aldyl "A" plastic pipe and will ensure all known Aldyl "A" plastic pipe is included in any potential future risk management program.

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. The information obtained from the inspection will support mitigation plans for identified electrically isolated steel services and risers.

Casings: Casing inspections were performed to identify any deterioration of a casing that could cause it to come in contact with the carrier pipe, resulting in potential corrosion and premature failure of the carrier pipe. Additionally, the inspections assessed the functionality of the test points and effectiveness of the cathodic protection for the steel carrier pipe.

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.

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.

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, and perform a pipe-to-soil measurement to determine if the below ground piping was adequately cathodically protected.

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, and perform a pipe-to-soil measurement to determine if the below ground piping was adequately cathodically protected.

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, and perform a pipe-to-soil measurement to determine if the below ground piping was adequately cathodically protected.

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. 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.

3.5 DIMP Carryovers

DIMP carryover costs are residual costs for DIMP projects commenced in 2023 but not charged until 2024. All 2023 DIMP costs were captured in 2023, and as a result there were no actuals in this category in 2024.

4. EDIMP Projects

EDIMP Projects consists of four distinct work categories: In-line inspection (ILI) & Digs; Cathodic Protection (CP) Surveys and Geohazard Assessments; Assessments; and 2023 EDIMP Carryover Costs. The actual spend for these work categories in 2024 was $7.770 million.

4.1 ILI & Digs

Five pipelines within the EDIMP portfolio were selected for in-line inspection in 2024:

- NPS 12 Wilson Ave.
- NPS 12 Martin Grove
- NPS 10 Sarnia South
- NPS 8 Port Stanley
- NPS 8 St. Thomas

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 2024 EDIMP ILI results are shown in Table 2.

Table 2
2024 EDIMP ILI Results

Pipeline Name	NPS	Major Vintage	Length (km)	ILI Runs	Length Inspected (km)	% Inspected	Phase 1 Anomalies Identified(1)
Wilson Ave.	12	1962	11.5	6	2.93	~25%	27
Martin Grove	12	1955	5.3(2)	6	2.45	~46%	3
Sarnia South	10	1946	60.8	10	4.49	~7%	3
Port Stanley	8	1947	9.0(2)	3	0.59	~7%	2
St. Thomas	8	1959	4.4	2	0.83	~19%	0

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.
(2) Pipe that was installed pre-2000.

All 35 Phase 1 anomalies that were identified through in-line inspections across the five inspected pipelines have been mitigated. 31 Phase 1 anomalies were remediated in 2024, with the remaining 4 Phase 1 anomalies mitigated in Q1 2025. Remediation was completed through a combination of integrity digs / subsequent repairs (15) and pipeline replacement (20). A summary of the mitigation activities completed for each pipeline are shown below.

- NPS 12 Wilson Ave.: A total of four integrity digs were executed to remediate seven Phase 1 anomalies. Three integrity digs (four Phase 1 anomalies) were executed in 2024, and one integrity dig (three Phase 1 anomalies) was completed in Q1 2025. Due to the quantity and close proximity of the other 20 Phase 1 anomalies, an approximately 0.5km NPS 12 steel gas main replacement project was completed in 2024, with the new main being placed in-service and existing main abandoned in November 2024. The estimated cost of the replacement project is approximately $3.7 million, with approximately $2.6 million incurred in 2024. The Wilson Ave replacement project was executed as an emerging capital project within the 2024 Asset

Management Plan, and therefore did not contribute any O&M spend to the 2024 DIMP Variance Account.

- NPS 12 Martin Grove: A total of three integrity digs were completed in 2024 to remediate three Phase 1 anomalies.

- NPS 10 Sarnia South: A total of three integrity digs were completed to remediate the three Phase 1 anomalies. Two integrity digs were completed in 2024 and one integrity dig was completed in Q1 2025.

- NPS 8 Port Stanley: A total of four integrity digs were completed in 2024. Two integrity digs targeted the two Phase 1 anomalies. Two additional integrity digs were completed with the dual purpose of collecting NDE data to support validation of the ILI crawler tool performance while also remediating two Phase 2 anomalies that had ILI indicated metal loss of 65%.

- NPS 8 St. Thomas: No Phase 1 anomalies were identified, and no integrity digs were issued for this pipeline. Tool validation will be completed in conjunction with the NPS 8 Port Stanley integrity dig non-destructive examination (NDE) results.

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 assessment (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 will be implemented 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, slabbing, leak surveys, odourant checks, 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 2024 EDIMP inspected pipeline by the end of 2025. The work required to implement long-term mitigations is planned to begin in 2026. Once the evaluation of potential required alternatives is completed, Enbridge Gas will be able to better quantify the cost/benefit analysis of the 2024 EDIMP work and what facilities work was deferred or avoided.

4.2 Corrosion Survey and Geohazard Assessments

This work category is for Corrosion Protection (CP) system surveys and Geohazard

Assessment Consultant work.

The CP surveys were performed on high priority EDIMP pipelines considered for potential in-line inspection in 2025 or beyond. 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.

The following pipelines were surveyed in 2024:

- NPS 10 Dawn West
- NPS 12 Fisher Ave.
- NPS 20 Winston Churchill
- NPS 20 Queensway
- NPS 6/8 Tillsonburg
- NPS 12 Wilson Ave (to complete a portion of the pipeline which was not surveyed previously)

The Geohazard Assessment Consultant work was focused on high priority EDIMP pipelines. The consultant performed a desktop study and produced an inventory of Geotechnical and Hydrotechnical areas of concern for the following pipelines:

- NPS 12 Wilson Ave, NPS 12 Martin Grove, NPS 8 Port Stanley, NPS 8 St. Thomas, NPS 10 Sarnia South
- NPS 10 Sarnia North, NPS 20 Winston Churchill, NPS 20 Queensway, NPS 12 Fisher Ave, NPS 10 Dawn West
- NPS 6 Alvinston, NPS 6 Petrolia, NPS 8 Bentpath, NPS 10 Dominion, NPS 30 Derry Rd and Old Creditview, NPS 10 Tecumseh, NPS 16 9th Line, pipeline 102196, NPS 8 Chatham South, NPS 10 Petrosar

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.

4.3 Assessments

The Assessments work category is used to fund any assessments or surveys carried out on EDIMP pipelines. A primary focus in the original 2024 workplan involved completing work on migration explosion and distribution leak targets for EDIMP. However, reprioritization resulted in the majority of these funds instead being allocated to focus on risk assessments associated with DIMP. Therefore, the only costs incurred in this work category are attributed to surveys (CIPS, Direct Current Voltage Gradient (DCVG), and depth of cover (DOC)) carried out on the Sarnia North pipeline.

4.4 EDIMP Carryovers

EDIMP carryover costs are residual costs for EDIMP projects commenced in 2023 but not concluded until 2024.