Vanessa Innis
Manager
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Enbridge Gas Inc.
P. O. Box 2001
50 Keil Drive North
Chatham, ON N7M 5M1

October 31, 2022

VIA RESS AND EMAIL

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

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas, or the Company)
EB-2022-0200 - 2024 Rebasing - Application and Evidence

Attached is the application and supporting evidence for Enbridge Gas's 2024 Rates Application. Enbridge Gas requests approval of rates for the sale, distribution, transmission, and storage of gas commencing January 1, 2024. Enbridge Gas also applies for approval of an incentive rate-making mechanism (IRM) for the years from 2025 to 2028.

This is the first cost of service rate application for Enbridge Gas since the Ontario Energy Board (OEB) approved the amalgamation of Enbridge Gas Distribution and Union Gas. As such, the Application includes detailed information about the costs of the amalgamated utility, and proposals for harmonized methodologies and processes that will apply going forward. The Application also includes harmonized cost allocation and harmonized rate proposals.

The structure and contents of this Application and supporting evidence follow the OEB's Filing Requirements for Natural Gas Rate Applications (Cost of Service Applications).

At this time, Enbridge Gas is filing the materials required for Exhibits 1 to 6, and 9 to 10 of the Filing Requirements. This covers the large majority of the filing for this case. The evidence relating to Exhibit 7 (Cost Allocation) and Exhibit 8 (Rate Design) will be filed on November 30, 2022.

Although the Cost Allocation and Rate Design evidence is not yet filed, Enbridge Gas is providing information about the estimated bill impacts and rate impacts of this Application as part of this current filing in Exhibit 1, Tab 1, Schedule 1. Also, the materials in Exhibit 1 being filed with this letter include the Index, draft Issues List and Approvals Requested in relation to the Cost Allocation and Rate Design evidence.

Enbridge Gas requests that the OEB issue its Notice of Hearing on the basis of this current filing. The Company believes that all information needed for the preparation and publication of the Notice of Hearing is included within this filing. Enbridge Gas notes that throughout Enbridge Gas Distribution's prior Custom IR term (2015 to 2018), the OEB took a similar approach for rate proceedings where the Company filed an Application and rate/bill impact information on September 1st, with supporting evidence on October 1st, and the OEB started its processing and timelines in advance of the evidence filing. The difference here is that the current 2024 Rates Application filing also includes most of the supporting evidence, allowing for a Notice of Hearing to be prepared and published.

Enbridge Gas will post the Application and supporting evidence on its website at www.enbridgegas.com/about-enbridge-gas/regulatory at the same time that this letter is filed. Enbridge Gas will send a copy of this letter, and a link to the website page, to all parties from its recent proceedings (MAADs, rate adjustment cases, Integrated Resource Planning, DSM Plan and major LTC proceedings) as well as all participants in the two recent Stakeholder Days. Enbridge Gas will take the same approach when it files the evidence in Exhibits 7 and 8 on November 30, 2022.

Enbridge Gas has held two Stakeholder Days (on June 16 and October 20) to provide interested parties and OEB staff information about this proceeding. There were more than 70 participants at the October 20 Stakeholder Day.

Enbridge Gas believes that the approach outlined above will ensure that those parties who are likely to have an interest in intervening in this proceeding will have all the information needed to decide whether to participate by early November 2022. If the OEB issues its Notice of Hearing in mid-November, with an intervention deadline in early December, then interested parties will have received all of the pre-filed evidence before deciding whether to intervene.

Enbridge Gas is not requesting confidential treatment for any of its evidence, so no process is needed to determine the status of the evidence and all interested parties will have immediate online access to the application materials.

Enbridge Gas requests that the OEB issue a decision in this case in time for rates to be implemented on January 1, 2024. This would require the decision and order on the Application by October 30, 2023 (one year after filing), and a decision and order on a Rate Order by November 30, 2023. Enbridge Gas recognizes that this is a large and complex case, and the Company is committed to work collaboratively and efficiently to assist in meeting this timing.

As one way to assist with having 2024 rates in place for January 1, 2024, Enbridge Gas is proposing that this case be heard in "phases". The items that need to be determined to support January 1, 2024, rates would be determined in the first phase, and then the remaining items could be determined in a second phase of this same proceeding.

As set out in the Application and the draft Issues List (found within the Administration evidence at Exhibit 1, Tab 3, Schedule 1), Enbridge Gas proposes that the issues related to cost allocation and rate design for its proposed new harmonized rates (which will be effective in 2025 and 2026), along with issues related to Energy Transition proposals, be heard as a second phase of the proceeding. The discovery, intervenor evidence, ADR and hearing (if needed) on those items could commence once the process to set rates for January 1, 2024 is complete or substantially complete. Based on the proposed schedule for phase 1 set out below. Enbridge Gas proposes that phase 2 could begin as early as September 1, 2024.

At Enbridge Gas's Stakeholder Day on October 20, 2022, OEB staff made a presentation about the potential process and schedule that could be followed for this case. Parties asked questions and made suggestions.

Enbridge Gas has considered the items discussed at the Stakeholder Day and has created a proposed schedule for phase one of this proceeding that would support the implementation of rates on January 1, 2024. It is set out below for the OEB's consideration.

Item	Date(s)
Enbridge files Application and evidence (Exhibits 1-6; 9-10)	October 31, 2022
OEB issues Notice of Hearing	November 14, 2022
Enbridge files remaining evidence (Exhibits 7-8)	November 30, 2022
Interventions close	December 7, 2022
Procedural Order #1	December 15, 2022
OEB staff files indication of planned expert evidence (to assist intervenor planning)	December 16, 2022
Issues Conference, based on draft Issues List from filing	January 9, 2023
Submissions on Issues List	January 13, 2023
Submissions and responses re OEB staff and intervenor proposed expert evidence	January 11, 2023 and January 16, 2023
Filing of interrogatories	January 20, 2023
Interrogatory responses	February 17, 2023
Technical Conference	March 6 to 10, 2023

Item	Date(s)
Motions re. interrogatories and undertakings	March 21, 2023
OEB staff/intervenor evidence filing date	March 24, 2023
Interrogatories on OEB staff/intervenor evidence	March 31, 2023
Interrogatory responses on OEB staff/intervenor evidence	April 17, 2023
Settlement Conference	April 17 to 28, 2023
Filing of Settlement Agreement	May 12, 2023
Oral Hearing	May 23 to June 2, 2023
Argument in Chief	June 19, 2023
OEB staff and intervenor submissions	July 10, 2023
Reply Argument	July 31, 2023
OEB Decision	October 30, 2023
Rate Order	November 30, 2023

Enbridge Gas believes that the proposed schedule set out above sets an appropriate balance to allow for a timely and efficient process while ensuring that all matters in this case can be appropriately reviewed and determined.

Should you have any questions, please let us know.

Sincerely,

[Original Signed By]

Vanessa Innis
Manager, Strategic Applications – Rate Rebasing

EXHIBIT LIST

1 – ADMINISTRATION

1 – ADMINISTRATION

2 – RATE BASE

3 – OPERATING REVENUE

3 – OPERATING REVENUE

3 – OPERATING REVENUE

4 – OPERATING EXPENSES

4 – OPERATING EXPENSES

5 - COST OF CAPITAL AND CAPITAL STRUCTURE

8 - RATE DESIGN

9 - DEFERRAL AND VARIANCE ACCOUNTS

9 - DEFERRAL AND VARIANCE ACCOUNTS

10 - INCENTIVE RATE-SETTING PROPOSAL

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, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2024.

APPLICATION

1. The Applicant, Enbridge Gas Inc. (referred to in the evidence as Enbridge Gas or the Company), is an Ontario corporation with its registered office in the City of Toronto. It carries on the business of selling, distributing, transmitting and storing natural gas within Ontario.

2. In the August 30, 2018, EB-2017-0306/0307 Decision and Order (the MAADs Decision), the Ontario Energy Board (OEB) approved the amalgamation of Enbridge Gas Distribution Inc. (referred to in the evidence as EGD) and Union Gas Limited (referred to in the evidence as Union) (together the pre-amalgamated Utilities). Effective January 1, 2019, the pre-amalgamated Utilities amalgamated to become Enbridge Gas.

3. In the MAADs Decision, the OEB approved a five-year deferred rebasing term from 2019 to 2023, during which time the OEB annually sets rates using a Price Cap rate adjustment model for rate zones associated with the pre-amalgamated Utilities. The MAADs Decision directed Enbridge Gas to file a rebasing application for 2024 rates.

4. Enbridge Gas hereby applies to the OEB, pursuant to section 36 of the *Ontario Energy Board Act, 1998* as amended (the Act), for an Order or Orders approving

or fixing just and reasonable rates for the sale, distribution, transmission, and storage of gas commencing January 1, 2024.

5. Enbridge Gas requests that the OEB use the cost of service (or revenue requirement) method to approve or fix just and reasonable rates for 2024.

6. Enbridge Gas also applies for approval of an incentive ratemaking mechanism (IRM) for the years from 2025 to 2028. The proposed IRM mechanism is a Price Cap model that is largely consistent with the IRM approved by the OEB and in place over the 2019 to 2023 deferred rebasing term. The main difference is a proposal for a two-factor inflation factor. Enbridge Gas is also proposing an updated X-factor (productivity and stretch factors).

7. The evidence filed in support of this Application describes and sets out the details and support for the specific approvals requested in order to implement rates for 2024 and set the IRM framework for future years. The approvals requested are listed at Exhibit 1, Tab 3, Schedule 1, of Enbridge Gas's evidence (Requested Approvals).

8. Key approvals requested include the following:

- overall revenue requirement for 2024, including all constituent parts of the cost and revenue forecasts;

- new harmonized methodologies and policies that will apply to forecasting and ratemaking for Enbridge Gas, including without limitation, a common gas reference price, updated depreciation rates, harmonized cost of capital (including updated equity thickness) and harmonized forecasting methodologies to determine demand;

- harmonized and updated deferral and variance accounts, including the creation of several new accounts and the closing of several existing accounts;

- 2024 rates to recover the 2024 revenue requirement, using existing rate classes and supported by a new cost allocation study;

- updated harmonized rates based on the 2024 cost allocation study, to be implemented starting in 2025 and 2026 (depending on rate class) using straight fixed variable demand charges, meaning that distribution charges will be determined on a fixed basis for each rate class;

- approvals in all other respects to give effect to the proposals described in the evidence filed in support of this Application and such modifications to those proposals as may be brought forward in this proceeding by Enbridge Gas and deemed appropriate by the OEB.

9. Overall, Enbridge Gas is requesting a 4% increase in revenues in 2024. Approval of the 2024 rates requested in this Application will result in the following bill impacts:

- the net annual bill increase for a typical residential customer formerly in the EGD rate zone consuming 2,400 m^3 per year will be approximately $28 per year for sales service customers;

- the net annual bill increase for a typical residential customer formerly in the Union South rate zone consuming 2,200 m^3 per year will be approximately $91 per year for sales service customers;

- the net annual bill decrease for a typical residential customer formerly in the Union North West rate zone consuming 2,200 m³ per year will be approximately $65 per year for sales service customers; and

- the net annual bill decrease for a typical residential customer formerly in the Union North East rate zone consuming 2,200 m³ per year will be approximately $193 per year for sales service customers.

10. Enbridge Gas requests that the OEB issue an order to enable the rates established as a result of this application to become effective January 1, 2024, in conjunction with the January 1, 2024, QRAM application.

11. In order to facilitate the approval of 2024 rates as expeditiously as possible, Enbridge Gas requests that the OEB determine this application in two phases. The first phase would consider all issues necessary for the setting of 2024 rates. The second phase would consider all remaining issues, including the approval of new harmonized rates to be effective in 2025 and 2026. Enbridge Gas has included a draft Issues List in its filing, provided at Exhibit 1, Tab 3, Schedule 1, that sets out the issues that would be included in phase 1, and those that would be considered in phase 2.

12. In the event that the OEB's Decision with Reasons approving or fixing these rates and other charges is not delivered by a date that accommodates implementation on January 1, 2024, Enbridge Gas requests that interim rates be set and implemented as of January 1, 2024, and that final rates be set to be effective January 1, 2024, to allow Enbridge Gas to recover the full year impact of the new rates in 2024.

13. In addition to the rate approvals described above, Enbridge Gas also requests that the OEB grant a partial exemption under Section 1.5.1 of the Gas Distribution

Access Rule (GDAR) related to certain Service Quality Requirements (SQR) performance measures, corresponding amendments to the Company's performance scorecard and a recommendation that the OEB's Chief Executive Officer review and amend these SQR performance measures in the GDAR.

14. Enbridge Gas also applies to the OEB for such interim order or orders approving interim rates or other charges and accounting orders as may from time to time appear appropriate or necessary.

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

16. This Application is supported by written evidence that will be filed with the OEB and may be amended from time to time as circumstances may require.

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

18. 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:

Vanessa Innis
Manager, Strategic Applications – Rate Rebasing
Enbridge Gas Inc.

Address for personal service	Enbridge Gas Inc. P. O. Box 2001 50 Keil Drive North Chatham, ON N7M 5M1
Telephone: Fax: Email	416-495-5499 or 1-888-659-0685 416-495-6072 EGIRegulatoryproceedings@enbridge.com

The Applicant's counsel:
David Stevens
Dennis M. O'Leary
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: Fax: Email:	416-863-1500 416-863-1515 dstevens@airdberlis.com doleary@airdberlis.com

DATED: October 31, 2022, at Chatham, Ontario

ENBRIDGE GAS INC.

[Original Signed By]

Vanessa Innis

Manager, Strategic Applications –
Rate Rebasing

RE: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2022-0200
Certification of Evidence

The undersigned, being Enbridge Gas's Vice President, Business Development and Regulatory, Malini Giridhar, in my capacity as an officer of that corporation and without personal liability, hereby certify, to the best of my knowledge, as at the date of certification, that the evidence submitted in support of Enbridge Gas's 2024-2028 delivery rate application (EB-2022-0200) is accurate, consistent, and complete.

DATED: October 28, 2022, at Toronto, Ontario

ENBRIDGE GAS INC.

[Original Signed By]

Malini Giridhar

Vice President,
Business Development and
Regulatory

2024 Cost of Service Checklist

Enbridge Gas Inc.

EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
CHAPTER 1 - OVERVIEW		
1.2 Certification of Evidence		
Ch 1, pp.3-4	Certification by a senior officer that the evidence filed is accurate, consistent and complete to the best of their knowledge	Exhibit 1, Tab 1, Schedule 3
1.5 Confidential Information		
Ch 1, pp.3-4	Confidential Information - Practice Direction has been followed	N/A, No Confidential Information provided.
CHAPTER 2 - COST OF SERVICE APPLICATIONS		
2.0 General Requirements		
2.0.5 Structure of Application		
Ch 2. p.6	Data models, spreadsheets and tables are filed in live Microsoft Excel format - In circumstances where this is not feasible or reasonable, utilities must provide an explanation.	
Ch 2. p.6	Applicants must isolate delivery-related sufficiency/deficiency separate and apart from the commodity-related sufficiency/deficiency. Additional information is provided in Exhibit 6.	Exhibit 1, Tab 5, Schedule 1, and Exhibit 6, Tab 1, Schedule 1
2.0.6 Variance Explanations		
Ch 2. p.7	The applicant must provide justification for annual changes to its rate base, capital expenditures, and operations, maintenance and administration costs. To ensure the OEB's review is focused on matters that are material, the OEB only requires variance explanations for changes above certain amounts.	Exhibit 2, Tab 1, Schedule 1, Exhibit 2, Tab 5, Schedule 3, and Exhibit 4, Tab 4, Schedule 2
Ch 2. p.7	A written explanation is required for rate base, capital expenditures, and operations, maintenance and administration costs if the revenue requirement impact of variances exceeds the applicable utility-specific threshold as follows: • $1 million for a utility with a revenue requirement of more than $200 million	Exhibit 2, Tab 1, Schedule 1, Exhibit 2, Tab 5, Schedule 3, and Exhibit 4, Tab 4, Schedule 2
2.0.7 Accounting Standards		
Ch 2. p.8	The accounting standard that is used as the basis of the application must be clearly stated, including the date of its adoption by the utility.	Exhibit 1, Tab 8, Schedule 2
Ch 2. p.8	If the applicant has changed its accounting standard from the accounting standard used in its previous rebasing application, the applicant must explain the reason for the change.	N/A, No change in Accounting Standards
Ch 2. p.8	The applicant must also discuss and quantify the impact of the change to the affected elements of the revenue requirement and overall application.	Exhibit 1, Tab 8, Schedule 2
Ch 2. p.8	Irrespective of the accounting standard used in the application, the applicant must provide a summary of changes to its accounting policies made since the applicant's last rebasing application (e.g. capitalization of overhead, capitalization of interest, depreciation, etc.).	Exhibit 1, Tab 8, Schedule 2
Ch 2. p.8	Revenue requirement impacts of any changes in accounting policies must be separately quantified.	Exhibit 1, Tab 8, Schedule 2

2024 Cost of Service Checklist

Enbridge Gas Inc.

EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
2.0.7.1 Modified IFRS Application		
Ch 2. p.8	Applicants should refer to the following documents for guidance relating to the use of IFRS in application filings: • Report of the Board: Transition to IFRS; dated July 28, 2009 • Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment, dated June 13, 2011 For those applicants that have adopted IFRS for financial reporting purposes, rate applications must be filed on the basis of MIFRS.	Exhibit 1, Tab 8, Schedule 2
2.0.7.2 USGAAP or ASPE Application		
Ch 2. p.9	The OEB requires a utility that adopts USGAAP or ASPE in its first rate application following the adoption of the new accounting standard, to provide the following:	Exhibit 1, Tab 8, Schedule 2
Ch 2. p.9	Evidence of the eligibility of the utility under the governing securities legislation to report financial information using that standard (if applicable)	Exhibit 1, Tab 8, Schedule 2
Ch 2. p.9	A copy of the authorization to use the standard from the corresponding Canadian securities regulator (if applicable)	Enbridge Gas is planning to file a request, more details provided in Exhibit 1, Tab 8, Tab 2
Ch 2. p.9	Evidence demonstrating the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation	Exhibit 1, Tab 8, Schedule 2
Ch 2. p.9	If the applicant has received approval from the OEB to use USGAAP or ASPE in a previous proceeding, the order should be filed (or referenced).	Exhibit 1, Tab 8, Schedule 2
Ch 2. p.9	The applicant must also provide evidence regarding the continued eligibility of the utility under the governing securities legislation to report financial information using that standard.	Exhibit 1, Tab 8, Schedule 2
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS		
	The items identified in this Exhibit provide the background and summary to the application and are grouped into the following sections:	
1.1 - Table of Contents		
Ch 2, p.9	Table of Contents listing major sections and subsections of the application. Electronic version of application appropriately bookmarked to provide direct access to each section and subsection of the Table of Contents	Exhibit 1, Tab 1, Schedule 1
1.2 Executive Summary and Business Plan		
Ch 2, pp.9-10	Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by the Rate Handbook including plain language information about its goals and its plans to meet them.-The applicant must include a discussion of bill impacts. The summary should also describe whether and how a distributor's objectives have changed, and how the plan to deliver on certain goals reflects customer feedback.	Exhibit 1, Tab 2, Schedule 1, and Exhibit 1, Tab 3, Schedule 1
1.3 Administration		
	This section must include the following:	
Ch 2, p.10	Primary contact information (name, address, phone, fax, email)	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.10	Identification of legal (or other) representation	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.10	Applicant's internet address for viewing of application and any social media accounts used by the applicant to communicate with customers	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.10	The number and percentage of customer email addresses retained by the applicant, but customer class for which the applicant may use to communicate a notice of application	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.10	The date by which the applicant would require on-bill or bill insert information to ensure inclusion in the next billing cycle.	Exhibit 1, Tab 3, Schedule 1

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, p.10	One or more proposed locations within the service area(s) of the utility for community meetings. Central, informal locations that are accessible are preferred.	N/A, See Exhibit 1, Tab 3, Schedule 1
Ch 2, p.10	Statement identifying where notice should be published and why	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.11	Bill impacts proposed bill impacts based on alternative consumption profiles and customer groups as appropriate given consumption patterns of its customers	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.11	Proposals in the application that constitute a change from the status quo and those that will have a material impact on customers, including any changes to rates, charges, or terms of service that may affect discrete customer groups. Applicants must also identify the specific customers or customer group that will be affected by such proposals to ensure the notice of the application is served appropriately	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.11	Form of hearing requested and why	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.11	Brief description of the proposed components of the Price Cap IR method.	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.11	Requested effective date	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.11	Statement identifying all deviations from Filing Requirements	Exhibit 1, Tab 1, Schedule 4
Ch 2, p.11	Statement identifying and describing any changes to methodologies used vs previous applications	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.11	Identification of OEB directions from any previous OEB Decisions and/or Orders. The applicant must clearly indicate how these are being addressed in the current application (e.g., filing of a study as directed in a previous decision)	Exhibit 1, Tab 13, Schedule 1
Ch 2, p.11	Reference to Conditions of Service and any other customer related policies and regulations; identify if there are changes to Conditions of Service (a) since last CoS application and (b) as a result of the current application.	Exhibit 8, Tab 5, Schedule 1, and Exhibit 1, Tab 15, Schedule 1
Ch 2, p.11	Confirmation that there are no rates and charges linked in the Conditions of Service or other policies and regulations of the application that are not on the utility's rate schedule.	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.11	Description of the corporate and utility organizational structure, Include a corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company's Board of Directors and a description of the reporting relationships between utility and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.12	List of approvals requested and accounting orders.	Exhibit 1, Tab 3, Schedule 1
Ch 2, p.12	A Draft issues List	Exhibit 1, Tab 3, Schedule 1
1.4 System Overview		
Ch 2, p.12	Description of System Assets and Service Area (including map, communities served)	Exhibit 1, Tab 4, Schedule 1
Ch 2, p.12	A franchise map should also be included clearly showing each franchise held. Identify the location of gas transportation assets, compressor stations, major meter stations, underground storage facilities, liquefied natural gas facilities, operations centres, interconnects and any other significant assets.	Exhibit 1, Tab 4, Schedule 1, Attachment 1

2024 Cost of Service Checklist

Enbridge Gas Inc.

EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
1.5 Application Summary		
	At a minimum, the items below must be provided. Applicants must also identify all proposed changes that will have a material impact on customers.	
Ch 2, p.12	Revenue Requirement - Test Year RR, increase/decrease ($ and %) from change from previously approved and main drivers, Revenue deficiency or sufficiency Schedule of main drivers of revenue requirement and deficiency/sufficiency changes from the last OEB approved year	Exhibit 1, Tab 5, Schedule 1. Note: comparison of the requested deficiency for the 2024 Test Year to the last OEB approved deficiency has not been completed as there is no prior OEB approved
Ch 2, p.12	Budgeting and Accounting Assumptions - economic overview (such as growth and inflation), and identification of accounting standard used for test year and brief explanation of impacts arising from any change in standards	Exhibit 1, Tab 5, Schedule 1
Ch 2, p.12	Throughput Forecast Summary - Throughput and customer growth, % change and customer numbers from last OEB-approved, description of forecasting method(s) used	Exhibit 1, Tab 5, Schedule 1
Ch 2, pp.12-13	Rate Base and USP - rate base for test year, change in rate base from last approved ($ and %), capital expenditures requested for the test year, change in capital expenditures from last approved ($ and %), Summary, key elements, and main drivers of the applicant's capital investment plan	Exhibit 1, Tab 5, Schedule 1
Ch 2, p.13	OM&A Expense - OM&A for test year and change from last approved ($ and %), summary of drivers and cost trends, inflation assumed, total compensation for test year and change from last approved ($ and %). Summary of any proposed gas supply, transportation and storage costs, Summary of any changes in depreciation rates	Exhibit 1, Tab 5, Schedule 1
Ch 2, p.13	Cost of Capital - A statement as to the use of the OEB's cost of capital parameters, Summary and rationale for any deviations from the OEB's cost of capital methodology, The weighted average cost of capital proposed in the application, and a summary breakdown of the proposed rates for each component of capital financing: o - Return on equity - Return on preferred shares - Weighted average cost of long-term debt -Cost of short-debt debt	Exhibit 1, Tab 5, Schedule 1
Ch 2, p.13	Cost Allocation & Rate Design - Summary of any deviations from OEB-approved cost allocation and rate design methodologies, including any changes to miscellaneous service charges Summary of any new proposals, Summary of any new proposals, Summary of any significant changes proposed to revenue-to-cost ratios and fixed/variable splits, Summary of any proposed mitigation plans to address rate impacts on specific customer classes or overall rate impact	Exhibit 1, Tab 5, Schedule 1
Ch 2, pp.13-14	Performance and Reporting - Scorecard proposal and a brief explanation of the performance results and drivers for the last five years for measures that contain historical data, Summary of any reporting requirements proposed, Description of how the applicant has addressed the Service Quality, Performance and Measurement requirements as outlined in the OEB's Gas Distribution Access Rule (GDAR), Discussion of any outstanding areas of non-compliance and the effect they have had on the application, including any relief sought	Exhibit 1, Tab 5, Schedule 1
Ch 2, p.14	Bill Impacts - total impacts ($ and %) for all classes for typical or average customers in all customer classes	Exhibit 1, Tab 5, Schedule 1
Ch 2, p.14	Deferral and Variance Accounts - Accounts requested for disposition including account balances, disposition methodology and timing , Any new deferral and variance accounts requested and any request for the discontinuation of existing accounts	Exhibit 1, Tab 5, Schedule 1
Ch 2, p.14	Rate Schedules - Summary of any other changes to the current OEB-approved rate schedules that are being proposed in the new rate schedules, which are filed and discussed in Exhibit 8	Exhibit 1, Tab 5, Schedule 1

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, p.14	Incentive Rate-Setting - Price Cap IR method for the incentive rate-setting period.	Exhibit 1, Tab 5, Schedule 1
1.6 Customer Engagement		
	The OEB expects natural gas utilities to provide an overview of customer engagement activities undertaken and how their customer's needs, preferences and expectations have been reflected in the elements of the application.	
Ch 2, p.14	Discussion on how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates	Exhibit 1, Tab 6
Ch 2, pp.14-15	Discussion of any feedback provided by customers and how the feedback shaped the final application. This analysis must encompass all customers, including direct purchase, transportation and storage customers.	Exhibit 1, Tab 6, Schedule 1
Ch 2, p.15	Reference to any other communication sent to customers about the application i.e. bill inserts, town hall meetings or other forms of out reach and the feedback received from customers through these engagement activities. Provide summary of feedback received through engagement activities.	Exhibit 1, Tab 6, Schedule 1
Ch 2, p.15	Applicants should document how the proposals were explained to customers and how the application serves customers' needs and expectations. Applicants should document the feedback heard from customers through these engagement activities.	Exhibit 1, Tab 6
Ch 2, p.15	Explicit identification of the outcomes of customer engagement in terms of the impacts on the distributor's plans, and how that information has shaped the application *(See 2-AC (Customer Engagement Activities Summary) from the Electricity filing requirements for possible structuring of the evidence)*	Exhibit 1, Tab 6, Schedule 1
Ch 2, p.15	All responses to matters raised in letters of comment filed with the OEB during the course of the proceeding	N/A
Ch 2, p.15	Planning Elements of customer engagement activities are to be filed as part of the USP (Exhibit 2).	Exhibit 2, Tab 6, Schedule 1
1.7 Performance Measurement		
Ch 2, p.15	The format of the proposed scorecard should be similar to the scorecard developed for electricity distributors (available on the OEB's website) and must include measures for customer focus, operational effectiveness, public policy responsiveness, and financial performance. In the scorecard proposal, the applicant is expected to discuss its plans for continuous improvement. The applicant may propose additional performance categories or measures that it believes would be meaningful for its operations as a natural gas utility. Scorecard reporting is expected during the term of the incentive plan, as the data becomes available.	N/A, Note:Enbridge Gas is not proposing a new scorecard
Ch 2, p.16	Discussion of performance for each of the distributor's scorecard measures over the last five years; drivers for its performance, plans for continuous improvement currently and going forward	Exhibit 1, Tab 7, Schedule 1
Ch 2, p.16	In addition to any analyses or reports previously ordered by the OEB, the Rate Handbook discusses two types of benchmarking that are required in rate applications. These are: - External benchmarking to analyze specific measures or specific programs by comparing year over year performance against key metrics and/or comparing unit costs (or other measures) against best practice benchmarks amongst a comparator group - Internal benchmarking to assess continuous improvement by the utility over time.	N/A, Note:Enbridge Gas is not proposing a new scorecard
Ch 2, p.16	The application should discuss how the utility's assessment has informed its business plan and the application.	Exhibit 1, Tab 7, Schedule 1
Ch 2, p.16	Any benchmarking, productivity or other related studies must be filed as an appendix to Exhibit 1.	Exhibit 1, Tab 7, Schedule 1
1.8 Financial Information		
Ch 2, p.16	Non-consolidated Audited Financial Statements for 3 most recent historical years (i.e. 2 years statements must be filed, covering 3 years of historical actuals)	Exhibit 1, Tab 8, Schedule 1, Attachment 1 and 2

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, p.16	Detailed reconciliation of AFS with regulatory financial results filed in the application, including a reconciliation of the fixed assets in order to, as one example, separate non-distribution business. This must include identification of any deviations that are being proposed between AFS and regulatory financial results, including the identification of any prior OEB approvals for such deviations	Exhibit 1, Tab 8, Schedule 1, Attachment 3 to 8
Ch 2, p.17	Pro-forma statements for the regulated utility for the bridge and the test year with separate disclosure regarding its operating segments	Exhibit 1, Tab 8, Schedule 1, Attachment 9
Ch 2, p.17	Annual Report and MD&A for most recent year of distributor and parent company, as available and applicable	Exhibit 1, Tab 8, Schedule 1, Attachment 10
Ch 2, p.17	Rating Agency Reports, if available;	Exhibit 1, Tab 8, Schedule 1, Attachment 11 and 12
Ch 2, p.17	Prospectuses, etc. for recent and planned public issuances	Exhibit 1, Tab 8, Schedule 1, Attachment 13
Ch 2, p.17	Description of existing accounting orders and departures from these orders, as well as any departures from the USoA	Exhibit 1, Tab 8, Schedule 1, and Exhibit 9, Tab 1, Schedule 1, Attachment 1
Ch 2, p.17	Any departures from the Uniform System of Accounts for Class A Gas Utilities	N/A, No Departures
Ch 2, p.17	Any change in tax status	N/A, No Change
Ch 2, p.17	Accounting Standards used for financial statements and when adopted	Exhibit 1, Tab 8, Schedule 2
Ch 2, p.17	Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities. Applicants owning generation facilities and energy storage facilities should consult the relevant OEB accounting treatment guidelines.	Exhibit 1, Tab 8, Schedule 1
1.9 Utility Consolidation		
Ch 2, pp.17-18	In the first cost of service application following a consolidation, the applicant is expected to address any rate-making aspects of the MAADs transaction, including a rate harmonization plan and /or customer rate classifications post consolidation.	Exhibit 8, Tab 2, Schedule 1
EXHIBIT 2 - RATE BASE (Includes Utility System Plan)		
	This exhibit must include the following sections outline below:	
2.1 Rate Base Overview		
Ch 2, p.18	For rate base, the applicant must include continuity statements with opening and closing balances for each year for gross fixed assets and accumulated depreciation, and year-over-year variance analyses. Continuity statements must include interest during construction, and overheads. Variance analyses should include a written explanation when there is a variance greater than the amount set out in Section 2.0.6.	Exhibit 2, Tab 2, Schedule 1, Attachment 3 to 8
Ch 2, p.18	The applicant must document the method used to calculate the value of average in-service fixed assets for the test year, such as the average of monthly or quarterly values, or the half-year rule. Rate base may also include an allowance for working capital (described below).	Exhibit 2, Tab 2, Schedule 1
Ch 2, p.18	If continuity statements have been restated for the purposes of the application (e.g., due to changes in accounting standards or to reflect corrections in historical audited values), the utility must provide a thorough explanation for the restatement and also provide a reconciliation to the original statements.	N/A, No Restartment

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, p.18	Continuity statements (year end balance, including interest during construction and overheads). Explanation for any restatement (e.g. due to change in accounting standards) Year over year variance analysis; explanation where variance greater than materiality threshold The following comparisons must be provided: - Hist. OEB-Approved vs Hist. Actual (for the most recent historical OEB-approved year) - Hist. Act. vs. preceding Hist. Act. (for the relevant number of years) - Hist. Act. vs. Bridge - Bridge vs. Test	Exhibit 2, Tab 2, Schedule 1, Attachment 3 to 8, and Exhibit 2, Tab 1, Schedule 1, Attachment 1
Ch 2, p.19	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation and reconciliation must be provided. This reconciliation must be between or among the last actual year, bridge year and any test year net book value balances reported on a fixed asset continuity schedule and the balances included in the rate base calculation.	Exhibit 2, Tab 2, Schedule 1
Ch 2, p.19	When proposed capital expenditures are related to projects which require a contribution from customers, such amounts should be shown separately as an offset to rate base.	Exhibit 2, Tab 2, Schedule 1
2.2.2 Gross Assets - PP&E and Accumulated Depreciation		
Ch 2, p.19	Breakdown by function (distribution plant, storage plant, transportation plant, general plant, other plant) for required statements and analyses	Exhibit 2, Tab 2, Schedule 1, Attachment 3 to 8
Ch 2, p.19	Detailed breakdown by major plant account for each functionalized plant item. For the test year, each plant item must be accompanied by a description	Exhibit 2, Tab 2, Schedule 1, Attachment 3 to 8
Ch 2, p.19	Detailed breakdown of the capital additions for the test year	Exhibit 2, Tab 2, Schedule 1, Attachment 8
Ch 2, p.19	Summary of any capital adjustment(s), including what was approved and what was spent, if the utility received approval for a capital factor adjustment as part of a previous application	N/A
Ch 2, p.19	Reconciliation of continuity statements to the calculated depreciation expenses, reported under Exhibit 4 – Operating Expenses, and presented by asset account	Exhibit 2, Tab 2, Schedule 1, Attachment 3 to 8, and Exhibit 4, Tab 5, Schedule 1, Attachment 2
Ch 2, p.19	Identification and detailed explanations for any asset disposals, asset retirement obligations, site restoration costs or asset utilization impacts	Exhibit 2, Tab 2, Schedule 1, Attachment 3 to 8
2.3 Allowance for Working Capital		
Ch 2, pp.19-20	If an applicant is proposing to include a working cash allowance in rate base, it must support this with a lead/lag study, provide the date when the lead/lag study was prepared, and when it was last formally reviewed and approved by the OEB.	Exhibit 2, Tab 3, Schedule 2, and Attachment 1
Ch 2, p.20	A lead/lag study for two time periods is required, namely: • The time between the date customers receive service and the date that the customers' payments are available to the distributor (the lag) • The time between the date when the applicant receives goods and services from its suppliers and vendors and the date that it pays for them (the lead) - Leads and lags are measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e. lag minus lead) days is then divided by 365 (366 in a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. This amount is included in the applicant's rate base determination.	Exhibit 2, Tab 3, Schedule 2
Ch 2, p.20	Other working capital items may include: • Gas in inventory • Supplies and materials • Prepaid expenses • Miscellaneous accounts receivable • Security deposits	Exhibit 2, Tab 3, Schedule 1
Ch 2, p.20	For each of the items, a calculation of the average of monthly averages ($ for each and volumes for gas in inventory) must be provided.	Exhibit 2, Tab 3, Schedule 1, Attachment 3

2024 Cost of Service Checklist

Enbridge Gas Inc.

EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
2.4 Capitalization Policy		
Ch 2, p.20	Capitalization policy including changes since its last rebasing application. Must identify the changes and the causes of the changes. - If an accounting standard other than IFRS is used and if the accounting standard relies on the approval of a regulator for the determination of certain costs (for example, capitalization of costs), then this must be disclosed to the OEB in the rate application.	Exhibit 2, Tab 4, Schedule 1, and Attachment 1
2.4.1 Capitalization of Overhead		
Ch 2, p.20	Overhead costs on self constructed assets, including breakdown of amounts capitalized year over year.	Exhibit 2, Tab 4, Schedule 2
Ch 2, p.20	Any changes to the overhead capitalization methodology must be explained.	Exhibit 2, Tab 4, Schedule 2
2.4.2 Burden Rates		
Ch 2, p.21	Identify burden rates related to the capitalized of costs of self-constructed assets. If the burden rates were changed since the last rebasing application, the applicant must identify the burden rates prior to and after the change and explain the reason for the change.	Exhibit, Tab 4, Schedule 3
2.5 Capital Expenditures		
Ch 2, p.21	The applicant must provide a summary of capital expenditures over the past five historical years, which would include the bridge year, and five future years including the test year, showing capital expenditures, treatment of contributed capital and additions, and treatment of Construction Work in Progress.	Exhibit 2, Tab 5, Schedules 1 to 3
Ch 2, p.21	Detailed explanation of the key drivers of capital expenditure increases for the test year, by capital expenditure category	Exhibit 2, Tab 5, Schedules 1 to 3
Ch 2, p.21	Proposed capital expenditures by investment category, with a reconciliation showing the contribution of these aggregated amounts to the applicant’s total capital budget for each category	Exhibit 2, Tab 5, Schedules 1 to 3
Ch 2, p.21	Written explanation of variances, including that of actuals versus the OEB- approved amounts for the applicant’s last OEB-approved rebasing application	Exhibit 2, Tab 5, Schedules 1 to 3
Ch 2, p.21	The proposed accounting treatment, including the treatment of the cost of funds, for investments spanning more than one year	Exhibit 2, Tab 5, Schedules 1 to 3
2.6 Utility System Plan (USP)		
Ch 2, p.21	The natural gas system encompasses regulated above and below-ground assets which can include distribution, storage, and transportation system assets. The USP must include all applicable elements from the Rate Handbook and the OEB’s guidelines for natural gas utilities’ transportation and distribution system projects (E.B.O. 134 and E.B.O. 188)	Exhibit 2, Tab 6, Schedule 1
	The USP must include the following:	
Ch 2, p.22	A description of the utility’s investment planning process	Exhibit 2, Tab 6, Schedule 1, Section 3
Ch 2, p.22	The engineering plan for the utility, including the overall plan for capital investments	Exhibit 2, Tab 6, Schedule 2
Ch 2, p.22	The longer term economic and planning assumptions, including expectations of natural gas prices	Exhibit 2, Tab 6, Schedule 1
Ch 2, p.22	The asset management plan (see 2.2.6.1)	Exhibit 2, Tab 6, Schedule 2
Ch 2, p.22	A description of how investments are selected and prioritized	Exhibit 2, Tab 6, Schedule 1, Section 4
Ch 2, p.22	Highlights of recent and proposed investments and the relationship to the engineering plan	Exhibit 2, Tab 6, Schedule 1, Section 4

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, p.22	A description of how the needs of customers and overall system planning policy objectives are being reflected, including obligations stemming from Ontario Government policy including the facilitation of a cap and trade framework, relevant greenhouse gas (GHG) legislation, Demand Side Management (DSM) programs and consideration of the OEB's statutory objectives, as applicable	Exhibit 2, Tab 6, Schedule 1, Section 2
Ch 2, p.22	Linkages to the gas supply plan	Exhibit 2, Tab 6, Schedule 1, Section 3
Ch 2, p.22	Linkages and trade-offs between capital projects and ongoing OM&A spending	Exhibit 2, Tab 6, Schedule 1, Section 3
Ch 2, p.22	a discussion of how cost benchmarking studies or utility cost comparisons conducted by or for the applicant are used to support the applicant's proposed expenditures.	Exhibit 2, Tab 6, Schedule 1, Section 6
Ch 2, p.22	description of quantifiable continuous improvements, cost savings or efficiency gains that are expected to be achieved over the Price Cap IR term must be provided and the means by which those improvements, savings and efficiencies will be achieved.	Exhibit 2, Tab 6, Schedule 1, Section 6
Ch 2, pp.22-23	For projects or programs not subject to a leave to construct application: - Need, scope, and purpose of project or program, related customer attachments, capital costs, as well as any applicable cost-benefit analysis - A discussion of the relative benefits and costs of the capital and non-capital alternatives considered and rejected in favour of the proposed project or program - Detailed information on the priority of the project or program relative to other investments and risks of deferring or not proceeding with the project or program - For any renewal investment, details on the change in condition and service life of the asset(s) expected to be achieved by the proposed expenditure - Detailed breakdown of the construction milestone dates and in-service dates for each project or program - Information on the basis for the budget estimate by project or program (e.g. historical cost, preliminary engineering estimates, request for proposals) - Explanation of how the project or program links directly to the asset management plan - In service date for each planned capital project - Contingency costs and the basis for determining the contingency amounts	Exhibit 2, Tab 6, Schedule 1, Section 7.2
Ch 2, p.23	A brief summary of the evidence for any project that requires leave to construct approval under the OEB Act	Exhibit 2, Tab 6, Schedule 1, Section 7.1
Ch 2, p.23	Information on customer additions and PI values	Exhibit 2, Tab 6, Schedule 1, Section 7.3
Ch 2, p.23	Identification of any project that has been undertaken in relation to a directive issued by the Minister of Energy to the OEB	Exhibit 2, Tab 6, Schedule 1, Section 7.4
Ch 2, p.23	Identification of any project that is going into service during the IR term for which the utility is considering requesting capital factor treatment if such a mechanism is being proposed as part of Exhibit 10	N/A, No projects being considered for capital factor treatment
2.6.1 Asset Management Plan		
Ch 2, p.23	File an asset management plan as a component of the utility system plan. The plan should include the utility's asset management policy, strategy and objectives, an inventory and assessment of the condition of all capital assets or asset categories whose net book value is material, and how this information is used to plan for new and renewal capital, and maintenance expenditures.	Exhibit 2, Tab 6, Schedule 1, and Exhibit 2, Tab 6, Schedule 2
2.7 Service Quality and Reliability Performance		
Ch 2, p.24	The applicant must include information for the past five historical years on its service quality performance and measurement requirements as outlined in the OEB's GDAR. A discussion on the reasons for any minimum standards not met must be provided along with a plan for addressing any deficiencies.	Exhibit 1, Tab 7, Schedule 1
Ch 2, p.24	The applicant must also discuss its reliability performance over the past five years for matters such as unplanned interruptions and outages and how it has informed it's USP.	Exhibit 2, Tab 6, Schedule 1
EXHIBIT 3 - OPERATING REVENUE		
3.1 Throughput and Revenue Forecast		
Ch 2, p.24	The applicant must provide an explanation of the drivers, assumptions and adjustments underpinning the throughput forecast. All economic assumptions and data sources used in the preparation of the volume and customer count forecast, including expansions and the impact of any demand side management, cap and trade or other GHG reduction-related activities, must be identified and included in this section. Forecasts should include a date of preparation.	Exhibit 3, Tab 2, Schedule 3, to Exhibit 3, Tab 2, Schedule 8 and all associated Attachments

2024 Cost of Service Checklist

Enbridge Gas Inc.

EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, pp.24-25	The applicant must also provide an explanation of the weather normalization methodology used and indicate in which OEB proceeding approval was granted for its use. All economic models, econometric models, end-use models, customer forecast surveys and other material inputs must also be described and documented. The applicant must provide a description of how demand side management, cap and trade or any other GHG reduction-related activities affect throughput forecasts in each year of the rate-setting plan.	Exhibit 3, Tab 2, Schedule 3, and Exhibit 3, Tab 2, Schedule 5
3.2 Accuracy of Throughput Forecast and Variance Analyses		
Ch 2, p.25	The applicant must demonstrate the historical accuracy of the throughput forecast for at least the past five years by providing the following, as applicable: Schedule of throughput volumes, revenues, customer count by rate class, and total system throughput: - Historical OEB-approved - Historical actual for the past five years - Historical actual for the past five years – weather normalized - Bridge year - Bridge year – weather normalized - Test year	N/A Please see paragraphs 1 and 2 of Exhibit 3, Tab 3, Schedule 1
Ch 2, p.25	The applicant must provide the following variance analyses and relevant discussion for volumes, revenues, customer/connections count, and total system throughput: - Historical OEB-approved vs. historical actual - Historical OEB-approved vs. historical actual – weather normalized - Historical actual – weather-normalized vs. preceding year's historical actual –weather-normalized (for the necessary number of years) - Historical actual – weather normalized vs. bridge year – weather-normalized - Bridge year – weather-normalized vs. test year	N/A Please see paragraphs 1 and 2 of Exhibit 3, Tab 3, Schedule 1
3.3 Transactional Services / Storage and Transportation Revenue		
Ch 2, p.25	The applicant must present five years of actual data including the gross and net margin realized from transactional services activities. The actuals should include year-over-year comparisons to the OEB-approved amounts with explanations for material variances.	Exhibit 3, Tab 4
Ch 2, p.25	The applicant must provide the bridge year and test year revenue forecasts for transactional services activities together with an explanation of the key drivers of the multi-year forecast.	Exhibit 3, Tab 4
Ch 2, pp.25-36	The applicant must present its treatment and mechanics for sharing revenues based on OEB-approved mechanisms and for any new proposals made in the rate application.	Exhibit 3, Tab 4, Schedule 1
3.4 Other Revenue		
Ch 2, p.26	The applicant must provide the following information: - Comparison of actual revenues for historical years to forecast revenue for the bridge and test years, including explanations for significant variances in year-over-year comparisons - A list of the specific elements comprising Other Revenue. - How costing and pricing for other revenues is determined that are not covered under Exhibit 8 with respect to specific miscellaneous service charges - Any revenue from affiliate transactions, shared services or corporate cost allocations. For each affiliate transaction the applicant must identify the service, the nature of the service provided to affiliated entities, accounts used to record the revenue, and the associated costs to provide the service.	Exhibit 3, Tab 5, Schedule 1 and Exhibit 3, Tab 5, Schedule 1, Attachment 1
Ch 2, p.26	Applicants must identify any discrete customer groups that may be materially impacted by changes to other rates and charges.	Multiple customer groups are impacted by proposed changes to other rates and service charges as this Application is harmonizing other rates and charges.

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Exhibit 4: Operating Expenses		
	This exhibit includes information that summarizes the following:	
4.1 Gas Supply, Transportation and Storage Costs		
Ch 2, p.26	The applicant must provide an overview of its gas supply planning process including a discussion of its gas supply planning principles. A gas supply plan must be presented for the bridge year and forward test year showing supply sources, volumes, and a summary of gas transportation contracting arrangements. Expected gas costs should be provided for the bridge and forward test year together with a gas supply/demand balance sheet.	Exhibit 4, Tab 2, Schedule 1, and Attachments 1 to 4
Ch 2, p.26	The applicant is required to present a summary of the gas cost consequences of its gas supply plan, including transportation and storage.	Exhibit 4, Tab 2, Schedule 1, and Attachment 1
Ch 2, pp.26-27	The applicant must provide a five year historical summary of its volumes, gas costs, supply basin sourcing arrangements, and storage.	Exhibit 4, Tab 2, Schedule 1, and Attachment 1 and Attachment 7
4.2 Lost and Unaccounted for Gas		
Ch 2, p.27	Applicants must provide five years of historical information relating to actual versus OEB-approved forecasts of lost and unaccounted for gas.	Exhibit 4, Tab 3, Schedule 1, and Attachments 1 to 2
Ch 2, p.27	Applicants must provide annual forecasts, and an explanation of the methodology underpinning lost and unaccounted for gas forecasting for the bridge and forward test years. Variance explanation of material changes should also be provided.	Exhibit 4, Tab 3, Schedule 1
4.3 Operating, Maintenance, and Administrative Costs (OM&A)		
Ch 2, p.27	OM&A costs should be presented on an output/program-focused basis. Applicants are expected to do a year-over-year variance analysis based on their OM&A programs. In addition, the applicant may also present the information on a departmental basis (i.e. by operating department). This exhibit must include the following sections outlined below:	Exhibit 4, Tab 4, Schedule 1 to 3
4.3.1 OM&A Overview		
Ch 2, p.27	The overview should provide a brief explanation (quantitative and qualitative) of the following: - OM&A levels for the test year - Associated cost drivers and significant changes that have occurred relative to historical and bridge years - Overall trends in costs including OM&A per customer - Business environment changes - Cost benchmarking studies (internal and external) or utility cost comparisons conducted by or for the applicant relevant to OM&A - A description of the continuous improvement or efficiency gains that will be achieved over the term, and the means by which those gains and savings will be achieved, and how the benefits will be realized for customers - Inflation rate assumed: The utility must provide evidentiary support for the appropriateness of any inflation rate used in forecasting OM&A costs	Exhibit 4, Tab 4, Schedule 1, and Exhibit 4, Tab 4, Schedule 2, and Attachment 2, and Exhibit 4, Tab 4, Schedule 3 ,and Attachments 1 and 2
4.3.2 Summary and Cost Driver Tables		
Ch 2, p.28	The applicant must include the following tables as part of its evidence: - Summary of recoverable OM&A expenses - OM&A cost drivers	Exhibit 4, Tab 4, Schedule 2, and Attachment 2

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, p.28	Irrespective of the accounting standard used, the applicant must identify the overall change in OM&A expense in the test year that is attributable to a change in capitalized overhead.	Exhibit 4, Tab 4, Schedule 2, and Exhibit 2, Tab 4, Schedule 2
Ch 2, p.28	The applicant must also provide a variance analysis for the change in OM&A expense for the test year in respect to each of the bridge year and the historical years.	Exhibit 4, Tab 4, Schedule 2
4.3.3 Program Delivery Costs with Variance Analysis		
Ch 2, p.28	The applicant should provide details of costs in the following categories:	
Ch 2, p.28	<u>1) Workforce Planning and Employee Compensation</u> The OEB expects that utilities will provide a description of their previous and proposed workforce plans, including compensation strategy. Utilities must discuss the outcomes of previous plans and how those outcomes have impacted their plans including an explanation of the reasons for all material changes to head count and compensation. A complete explanation for all years includes: • Year over year variances with an explanation of contributing factors, inflation rates used for forecasts, and the plan for any new employees • Basis for performance pay, eligible employee groups, goals, measures, and review processes for any pay-for-performance plans • Relevant studies conducted by or for the applicant (e.g., compensation benchmarking) *-See Appendix 2-K (electricity guidelines) for structuring of this evidence*	Exhibit 4, Tab 4, Schedule 2, and Attachment 2, and Exhibit 4, Tab 4, Schedule 3, and Attachment 1
Ch 2, p.29	The applicant must provide details of employee benefit programs, including pensions and other costs charged to OM&A for the last OEB-approved rebasing application, historical, bridge and test years. The most recent actuary report(s) must be included in the pre-filed evidence. The actuary information disclosed in any other area of the application (e.g. tax) must agree with the actuarial analysis.	Exhibit 4, Tab 4, Schedule 3, and Attachment 2, and Exhibit 4, Tab 4, Schedule 2, and Attachment 1 and 2
Ch 2, p.29	In May 2015 the OEB initiated a consultation on rate-regulated utility pensions and other post-employment benefits (OPEBs) in the electricity and natural gas sectors5. Pending the completion of this consultation, utilities should provide information on the accounting method used by the applicant in the area of pensions and OPEBs as well as a discussion of the differences between the forecast pension and OPEBs amounts proposed for the test year and the amounts forecasted to be paid to the applicable plans or beneficiaries.	Exhibit 4, Tab 4, Schedule 2 and Attachment 1
Ch 2, p.29	<u>2) Shared Services and Corporate Cost Allocation</u> The applicant must identify all shared services between or among its affiliated entities.	Exhibit 4, Tab 4, Schedule 3 and Attachments 3 and 4
Ch 2, p.29	The applicant must provide the allocation methodology, a list of costs and allocators, and any third party review of the corporate cost allocation methodology used. The applicant must provide a self-certification that its costs are in compliance with the OEB's Affiliate Relationships Code for Gas Utilities. If the OEB has previously approved the allocation methodology, the relevant docket, date and/or decision granting such approval should be identified.	Exhibit 4, Tab 4, Schedule 2, and Attachments 3, 5 and 6
Ch 2, p.30	The applicant must provide details about each service provided or received for the historical (actuals), bridge and test years. Variance analyses, with explanations, are required for the following: - Test year vs. last OEB-approved - Test year vs. most current actuals	Exhibit 4, Tab 4, Schedule 3, and Attachment 3
Ch 2, p.30	The applicant must identify any Board of Director-related costs for affiliates that are included in its costs.	Exhibit 4, Tab 4, Schedule 3
Ch 2, p.30	<u>3) Purchase of Non-Affiliate Services</u> An applicant must provide a copy of its procurement policy, including information in such areas as the level of signing authority, a description of its competitive tendering process and confirmation that its non-affiliate services purchases are in compliance with the policy.	Exhibit 4, Tab 4, Schedule 3, and Attachments 7 to 11

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, p.30	For any material transactions that are not in compliance with the applicant's procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, the applicant must provide an explanation as to why this was the case, as well as the following information for these transactions: - Summary of the nature and cost of the product or service that is the subject of the transaction - A description of the specific methodology used for selecting the vendor, including a summary of the tendering process/cost approach, etc.	N/A, No material transactions that are not in compliance
Ch 2, p.30	<u>4) One Time Costs</u> The applicant must identify material one-time costs in the historical, bridge and test years and provide an explanation as to how the costs included in the test year are to be recovered. If a utility is not proposing that one-time costs be recovered over the test year and the subsequent IR term (i.e., amortization of the cost recovery over the five-year period), an explanation must be provided	Exhibit 4, Tab 4, Schedule 3
Ch 2, p.30	<u>5) Low Income Programs</u> The applicant must provide a description of any low income programs it is administering and identify amounts it is proposing to recover from ratepayers, together with the supporting rationale.	Exhibit 4, Tab 4, Schedule 3
Ch 2, pp.30-31	<u>6) Charitable and Political Donations</u> The recovery of charitable donations will not be allowed for the purpose of setting rates, except for contributions to programs that provide assistance to customers in paying their energy bills. Applicants must provide detailed information for all contributions that are claimed for recovery.	Exhibit 4, Tab 4, Schedule 3
Ch 2, p.31	The applicant must also confirm that no political contributions have been included for recovery.	Exhibit 4, Tab 4, Schedule 3
4.4 Depreciation Expense		
Ch 2, p.31	The applicant must provide details of depreciation and amortization by asset group for the historical, bridge and test years, including asset amount (breaking out asset additions) and rate of depreciation or amortization. The information must tie to the accumulated depreciation balances in the continuity schedule under rate base.	Exhibit 4, Tab 5, Schedule 1, and Attachment 3, and Exhibit 2, Tab 2, Schedule 1, and Attachments 3 to 8
Ch 2, p.31	The applicant must identify any asset retirement obligations (AROs) and any associated depreciation or accretion expenses in relation to the AROs, including the basis and calculation of how these amounts were derived. Any site restoration costs must be disclosed and described.	N/A, No AROs
Ch 2, p.31	The applicant must provide a description of the depreciation approach underpinning the depreciation expense calculations in the year a capital asset enters service. The applicant must clearly present the details of its deprecation calculation in regards to the number of months a new capital asset is in service during the year.	Exhibit 4, Tab 5, Schedule 1
Ch 2, p.31	The applicant must provide a copy of its depreciation/amortization policy, if available. If not, the applicant must provide a written description of the depreciation practices followed and used in preparing the application.	Exhibit 4, Tab 5, Schedule 1
Ch 2, p.31	Irrespective of the accounting standard used in the application, the applicant must provide a summary of changes to its depreciation/amortization policy made since the applicant's last revenue requirement filing, or since the OEB last approved a methodology, whichever is most recent. If the applicant has developed a new depreciation study, it must file that study.	Exhibit 4, Tab 5, Schedule 1, and Attachments 1 and 2
Ch 2, p.31	The applicant must also discuss how the depreciation/amortization expense is calculated under the new depreciation/amortization policy.	Exhibit 4, Tab 5, Schedule 1, and Attachment 3
Ch 2, p.31	The applicant must ensure that the significant parts or components of each plant item are being depreciated separately, in accordance with its adopted accounting standard. Any deviations from this practice must be explained.	Exhibit 4, Tab 5, Schedule 1
4.5 Taxes		
	The applicant must provide the information outlined below:	
Ch 2, pp.31-32	Detailed calculations of actual and forecasted regulatory taxable income and income tax, including derivation of adjustments (e.g., tax credits, Capital Cost Allowance adjustments) for the historical, bridge and test years to regulatory taxable income	Exhibit 4, Tab 6, Schedule 1, and Attachments 1 to 2

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, p.32	Supporting schedules and calculations for reconciling items and adjustments	Exhibit 4, Tab 6, Schedule 1, and Attachments 1 to 2
Ch 2, p.32	A description of the methodology used to calculate income tax	Exhibit 4, Tab 6, Schedule 1
Ch 2, p.32	Copies of most recent Federal and Provincial tax returns (non-utility tax items, if material, must be separated)	Exhibit 1, Tab 8, Schedule 1
Ch 2, p.32	Taxes other than income taxes, (e.g. property taxes) should be clearly identified and separately filed.	Exhibit 4, Tab 6, Schedule 2
4.6 Demand Side Management Costs		
Ch 2, p.32	Natural gas utilities are expected to include detailed information of all approvals for DSM funding from prior proceedings as part of any rate application.	Enbridge Gas's multi-year DSM Plan Application is before the OEB in EB-2021-0002, See Exhibit 1, Tab 5, Scheudle 1, Notes.
Ch 2, p.32	Information related to annual budget amounts (including rate class allocation) and the total amount to be recovered through rates to support prior DSM approvals must be clearly described.	Enbridge Gas's multi-year DSM Plan Application is before the OEB in EB-2021-0002, See Exhibit 1, Tab 5, Scheudle 1, Notes.
2.5 Exhibit 5: Cost of Capital and Capital Structure		
Ch 2, p.32	*An applicant may apply for a utility-specific return on equity and/or capital structure. If an applicant wishes to take such an approach, it must provide appropriate justification and expert supporting evidence for its proposal.*	Exhibit 5, Tab 1, Schedule 1, and Exhibit 5, Tab 3, Schedule 1, Attachment 1
5.1 Cost of Capital (Return on Equity and Cost of Debt)		
Ch 2, p.33	The applicant must provide the following information for each year:	
Ch 2, p.33	Calculation of the cost for each capital structure component	Exhibit 5, Tab 2, Schedule 1, Attachments 1 to 6
Ch 2, p.33	Profit or loss on redemption of debt and/or preference shares, if applicable	N/A, None
Ch 2, p.33	Copies of any current promissory notes or other debt arrangements with affiliates	N/A, None
Ch 2, p.33	Explanation of the applicable debt rate for each existing debt instrument, including an explanation on how the debt rate was determined and how each is in compliance with the policies documented in the 2009 Report	Exhibit 5, Tab 2, Schedule 1, and Attachments 1 to 6
Ch 2, p.33	Forecasts of any new debt anticipated in the bridge and test year, including estimates of the applicable rate and any pertinent information on each new debt instrument (e.g. whether the debt is affiliated or with a third party, expected term/maturity, and any capital project(s) directly related to the new debt)	Exhibit 5, Tab 2, Schedule 1, Attachments 5 and 6
Ch 2, p.33	If the applicant is proposing any deviations from OEB policy as documented in the 2009 Report or any successor document, thorough justification must be provided.	N/A, None
5.2 Capital Structure		
Ch 2, p.33	*The elements of the capital structure are shown below and must be presented with the appropriate schedules showing current OEB-approved, historical actuals, bridge and test years:* - Long-term debt - Short-term debt - Preference shares - Common equity	Exhibit 5, Tab 3, Schedule 1

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, p.33	Explanations of material changes in actual capital structure are required including: - Retirements of debt or preference shares and buy-back of common shares - Short-term debt, long-term debt, preference shares and common share offerings	Exhibit 5, Tab 3, Schedule 1
Ch 2, p.33	Any proposal for a change to the deemed capital structure for a natural gas utility from that currently approved by the OEB, must be adequately supported in accordance with the 2009 Report or a successor document. As documented in the 2009 Report, any change in the deemed capital structure would be triggered by a significant change in financial, business or corporate fundamentals.	Exhibit 5, Tab 3, Schedule 1
2.6 Exhibit 6: Revenue Deficiency / Sufficiency		
Ch 2, p.34	This exhibit should include the following: - Determination of net utility income - Statement of rate base - Actual utility return on rate base - Indicated rate of return - Requested rate of return - Deficiency or sufficiency in revenue - Gross deficiency or sufficiency in revenues	Exhibit 6, Tab 1, Schedule 1 and Attachment 1
Ch 2, p.34	The applicant must provide a summary of the drivers (including numerical schedules showing the causes) of the test year deficiency/sufficiency, along with the relative contribution of each driver. Specific references to the data contained in the detailed schedules and tables filed in the application must be provided to enable mapping of the summary cost driver information in this exhibit, to the supporting evidence.	Exhibit 6, Tab 1, Schedule 2 and Attachments 2-3
Ch 2, p.34	Impacts must be provided for any change in methodologies (e.g. accounting standards or policies) on the overall deficiency/sufficiency and on the individual cost drivers contributing to it.	Exhibit 6, Tab 1, Schedule 2
Ch 2, p.34	The applicant must isolate delivery-related deficiency/sufficiency separate and apart from the gas supply-related deficiency/sufficiency. Utilities should provide revenue deficiency or sufficiency calculations net of gas supply-related changes captured in the QRAM.	Exhibit 6, Tab 1, Schedule 2 and Attachments 1-3
Ch 2, p.34	The commodity cost to be used when filing the gas supply-related information will be that available from the most recent OEB-approved QRAM, at the time of filing. The applicant should update the commodity and transportation costs for the most recently approved QRAM for the draft rate order process.	Enbridge Gas has used the April 2022 QRAM application for the gas supply-related information given the time required to prepare the Application. The gas supply commodity and transportation rates will be updated for the most recently approved QRAM as part of the draft rate order.
2.7 Exhibit 7: Cost Allocation		
Ch 2, p.34	The applicant must provide its proposed cost allocation methodology in the form of a Cost Allocation Study including illustrative step-by-step schedules explaining the approach, and revenue-to-cost ratios.	Exhibit 7, Tab 1, Schedule 2 and Exhibit 8, Tab 1, Schedule 3
Ch 2, p.34	The revenue-to-cost ratios must also include a comparison to the most recent OEB-approved revenue-to-cost ratios and the ratios proposed for the test year.	Exhibit 8, Tab 1, Schedule 3

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, pp.34-35	Any new cost allocation proposals, or changes to an existing methodology, the applicant is required to provide a detailed description of the change, the related financial impact, and the supporting rationale.	Exhibit 7, Tab 1, Schedule 3 and Exhibit 7, Tab 1, Schedule 4 Given the different approaches and the availability of information for Enbridge Gas, the Company cannot provide a complete comparison of the proposed cost allocation methodologies to the OEB approved cost allocation methodologies for the EGD and Union rate zones in aggregate, as the Company was not able to recreate two stand-alone cost allocation studies for the EGD and Union rate zones in the same format that was approved in EGD's and Union's respective 2013 Cost of Service proceedings. Enbridge Gas, can, however, provide comparisons of the OEB-approved cost allocation methodologies to the proposed cost allocation methodologies and is able to provide impacts of the different cost allocation approaches.
Ch 2, p.35	The applicant must also include a schedule that compares the allocated customer-related costs per customer per month by rate class (and the cost functions included) to the level of the proposed fixed monthly customer charges.	Exhibit 8, Tab 1, Schedule 4
Ch 2, p.35	An explanation supporting the level of the proposed fixed monthly cost charges as compared to the allocated customer-related costs must be provided.	Exhibit 8, Tab 1, Schedule 4
Ch 2, p.35	The cost allocation evidence must be sufficient to demonstrate that the costs of providing each of the utility services, namely distribution, storage and/or transportation, have been assigned or allocated to assure that there is no undue cross subsidization among customer classes.	Exhibit 7, Tab 1 and Exhibit 7, Tab 2
2.8 Exhibit 8: Rate Design		
Ch 2, p.35	The rate design exhibit must provide details of proposed changes to rates, proposed volume and revenue recovery, details regarding changes to proposed rate schedules, and detailed annual bill impacts. Applicants must provide the existing rate schedules and the proposed rate schedules. The exhibit must include the following:	Exhibit 8, Tab 1 and Exhibit 8, Tab 2
Ch 2, p.35	Proposed rate and revenue adjustments	Exhibit 8, Tab 2, Schedule 8 and Exhibit 8, Tab 2, Schedule 9
Ch 2, p.35	Detailed calculations of revenue per rate class under current rates and proposed rates by customer class	Exhibit 8, Tab 2, Schedule 8 and Exhibit 8, Tab 2, Schedule 9
Ch 2, p.35	Detailed reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate blocks, seasons, zones, etc.)	Exhibit 8, Tab 2, Schedule 8 and Exhibit 8, Tab 2, Schedule 9
Ch 2, p.35	Calculation of differences between revenue allocated under current rates and proposed rates by customer class	Exhibit 8, Tab 2, Schedule 8 and Exhibit 8, Tab 2, Schedule 9
Ch 2, p.35	Explanation and application of non-cost factors to rate design	Exhibit 8, Tab 1, Schedule 1
Ch 2, p.35	Impact of changes on representative samples of end-users, i.e. volume, % rate change, revenue	Exhibit 8, Tab 2, Schedule 6
Ch 2, p.35	Explanation of proposed changes to terms and conditions of service and rationale supporting those changes	Exhibit 8, Tab 5, Schedule 1

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, pp.35-36	Presentation of miscellaneous service charges including the rationale for any changes relative to OEB-approved and how costing and pricing for any proposed new service charges, and/or changes to rates or rules for existing service charges is determined (utilities must ensure that the revenue from the total of the proposed miscellaneous service charges corresponds with the evidence under Operating Revenue)	Exhibit 8, Tab 3, Schedule 1 and Exhibit 8, Tab 3, Schedule 2
8.1 Bill Impacts		
Ch 2, p.36	Applicants must provide in summary form, bill impact information in both percentage and absolute dollar terms for all customer classes at the rate class level calculated at typical customer volumes.	Exhibit 8, Tab 2, Schedule 6
Ch 2, p.36	Applicants should also provide an average bill impact based on volumes at the rate class level.	Exhibit 8, Tab 2, Schedule 8 and Exhibit 8, Tab 2, Schedule 9
Ch 2, p.36	The utility must file a mitigation plan if the total bill increase for any customer class is material. The mitigation plan must include the following information:	Exhibit 8, Tab 2, Schedule 6
Ch 2, p.36	Identification of all customer classes or groups of customers that would experience material bill increases	Exhibit 8, Tab 2, Schedule 6
Ch 2, p.36	A description of mitigation measures proposed, e.g. reductions to the revenue requirement, inter-class shifts, or longer disposition periods for deferral and variance account balances	Exhibit 8, Tab 2, Schedule 6
Ch 2, p.36	A justification for all mitigation measures proposed, including reasons if no mitigation is proposed	Exhibit 8, Tab 2, Schedule 6
Ch 2, p.36	Any other information believed to be relevant to the mitigation proposal	Exhibit 8, Tab 2, Schedule 6
8.2 Rate Harmonization Plan and Mitigation Issues		
Ch 2, p.36	Utilities which have merged or amalgamated service areas since their last cost of service or Custom IR application, must file a rate harmonization plan subject to established cost allocation and rate design principles for the natural gas sector. The plan must include a detailed explanation and justification for the implementation plan, and an impact analysis.	Exhibit 8, Tab 2, Schedule 1 and Exhibit 8, Tab 2, Schedule 6
Ch 2, p.36	In the event that the combined impact of the cost of service based rate increases and harmonization effects result in total bill increases for any customer class that is material, the utility must include a discussion of proposed measures to mitigate any such increases in its mitigation plan discussed in section 2.8.1 above, or provide justification in its plan as to why mitigation is not required.	Exhibit 8, Tab 2, Schedule 6
Ch 2, p.36	A migration to fully harmonized rates (where appropriate) that is to be accomplished over more than one year must be supported by a detailed plan for accomplishing this during the subsequent Price Cap IR term.	Exhibit 8, Tab 2, Schedule 1
2.9 Exhibit 9: Deferral and Variance Accounts		
Ch 2, p.37	List of all outstanding deferral and variance accounts including a description of the account	Exhibit 9, Tab 1
Ch 2, p.37	Confirmation that the interest rates established by the OEB were used to calculate the carrying charges for each deferral and variance account where carrying charges apply	Exhibit 9, Tab 2, Schedule 1
Ch 2, p.37	Listing of accounts to be discontinued and the reasons	Exhibit 9, Tab 1, Schedule 4
Ch 2, p.37	A statement as to whether or not the applicant has made any adjustments to deferral and variance account balances that were previously approved by the OEB on a final basis. If this is the case, the applicant must provide an explanation of the nature and amount of any adjustment and include supporting documentation; under a section titled “Adjustments to Deferral and Variance Accounts”.	N/A, No adjustments
9.1 Disposition of Deferral and Variance Accounts		
Ch 2, p.37	Identify all accounts for which it is seeking disposition	Exhibit 9, Tab 2, Schedule 1

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, p.37	Identify any accounts for which the applicant is not proposing disposition and the reasons	Exhibit 9, Tab 2, Schedule 1
Ch 2, p.37	Propose the methodology and rationale for the recovery, or refund, of balances including the allocation methodology used, timing and duration of any rate riders, rate class impacts, and typical customer bill impacts	Exhibit 9, Tab 2, Schedule 2
Ch 2, p.37	Provide a statement as to whether the balances proposed for disposition are consistent with the account balances reported in the RRR and the relevant year's audited financial statements and if not, provide explanations for variances	Exhibit 9, Tab 2, Schedule 1
Ch 2, p.38	For each account requested for disposition, the applicant should provide a continuity schedule for the period commencing from the establishment of the account or from the last approved disposition of the account, whichever is more recent, to the date of the most recent audited actuals.	Exhibit 9, Tab 2, Schedule 1, Attachment 2 and 6
9.2 Establishment of New Deferral and Variance Accounts		
Ch 2, p.38	In the event an applicant seeks an accounting order to establish a new deferral or variance account, the request must be accompanied by evidence of how the following eligibility criteria will be met:	
Ch 2, p.38	Causation – The forecasted expense must be clearly outside of the base upon which rates were derived	Exhibit 9, Tab 1, Schedule 3
Ch 2, p.38	Materiality – The forecasted amounts must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements	Exhibit 9, Tab 1, Schedule 3
Ch 2, p.38	Prudence – The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers	Exhibit 9, Tab 1, Schedule 3
Ch 2, p.38	The materiality thresholds differ for each applicant, depending on the magnitude of the revenue requirement. The default materiality thresholds for the establishment of new accounts are as follows: - $50,000 for a utility with a revenue requirement less than or equal to $10 million - 0.5% of revenue requirement for a utility with a revenue requirement greater than $10 million and less than or equal to $200 million -$1 million for a utility with a revenue requirement of more than $200 million	Exhibit 9, Tab 1, Schedule 3
Ch 2, p.38	Applicants must include a draft accounting order that contains a description of the new account and its mechanics, the proposed general ledger entries, and the manner and timing proposed for disposition.	Exhibit 9, Tab 1, Schedule 1, Attachment 3
9.3 Z-Factor		
Ch 2, p.39	Natural Gas utilities may propose a Z-factor mechanism as part of its application to address material cost increases or decreases associated with unforeseen events outside of the control of management for the incentive rate-setting term. The cause of the increase or decrease must be reasonably outside the control of utility management and must be a cause that utility management could not reasonably control or prevent through the exercise of due diligence.	Exhibit 10, Tab 1, Schedule 1, section 3, Z factor Mechanism proposal
Ch 2, p.39	An applicant seeking Z-factor relief must include in its proposal a calculation of its regulated return from its most recent complete audited year. If the regulated return exceeds the deemed return on equity embedded in the utility's rates, an applicant must justify why the relief sought is reasonable. Any Z factor proposal must address the four criteria of causation, materiality, prudence and management control.	N/A, Enbridge is proposing a Z factor Mechanism
Ch 2, p.40	Causation – The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine event and must be clearly outside of the base upon which rates were derived	N/A, Enbridge is proposing a Z factor Mechanism
Ch 2, p.40	Materiality –The cost increase or decrease must meet a materiality threshold, in that its effect on the utility's revenue requirement in a fiscal year must be equal to or greater than the established threshold	N/A, Enbridge is proposing a Z factor Mechanism

2024 Cost of Service Checklist
Enbridge Gas Inc.
EB-2022-0200

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch 2, p.40	Prudence – The cost subject to an increase or decrease must have been prudently incurred	N/A, Enbridge is proposing a Z factor Mechanism
Ch 2, p.40	Management Control - The cause of the cost increase or decrease must be: (a) not reasonably within the control of utility management; and (b) a cause that utility management could not reasonably control or prevent through the exercise of due diligence	N/A, Enbridge is proposing a Z factor Mechanism
Ch 2, p.40	The materiality threshold must be met on an individual event basis in order for the utility to apply for recovery of the relevant costs.	N/A, Enbridge is proposing a Z factor Mechanism
Ch 2, p.40	Consistent with the Z-factor policy applicable to electricity distributors and transmitters, if an applicant proposes a Z factor claim, the applicant must:	N/A, Enbridge is proposing a Z factor Mechanism
Ch 2, p.40	Notify the OEB promptly of all Z-factor events. Failure to notify the OEB within six months of the event may result in disallowance of the claim.	N/A, Enbridge is proposing a Z factor Mechanism
Ch 2, p.40	Record costs for which recovery will be sought	N/A, Enbridge is proposing a Z factor Mechanism
Ch 2, p.40	At the time of the disposition review, outline the manner in which it intends to allocate the Z-factor award to the various rate classes, the proposed disposition period, the rationale for the selected approach and a discussion of the merits of alternative allocation methods	N/A, Enbridge is proposing a Z factor Mechanism
Ch 2, p.40	At the time of the disposition review, provide a detailed calculation of the incremental revenue requirement	N/A, Enbridge is proposing a Z factor Mechanism
2.10 Exhibit 10:Incentive Rate-setting Proposal		
Ch 2, p.40	This exhibit must include details of the components proposed for the Price Cap IR method including the basis for the inflation, productivity and stretch factors, customer protection measures, any capital factor proposed for the incentive rate-setting period, and any other elements that may be included in the proposal.	Exhibit 10, Tab 1, Schedule 1
Ch 2, p.40	Utilities must also file their plan for any annual applications that may make up part of their proposal for the incentive rate-setting period.	Exhibit 10, Tab 1, Schedule 1
Ch 2, p.41	Consistent with the Rate Handbook requirement for a Custom IR filing, if a utility proposes an earnings sharing mechanism (ESM) as part of a Price Cap IR plan as its mechanism to protect customers against excess earnings, it should generally be based on overall earnings at the end of the term, not an assessment of earnings in each year of the term. An applicant may propose a threshold to trigger the disposition of a significant ESM balance during the IR plan term.	Exhibit 10, Tab 1, Schedule 1, Paragraph 29.

CURRICULUM VITAE OF
GILMER BASHUALDO-HILARIO

Experience:

Enbridge Gas Inc.

Manager Economic Evaluation & Forecast
2019

Union Gas Limited.

Manager Demand Forecasting & Analysis
2015

Senior Advisor Demand Forecasting & Analysis
2005

Northern Lima Hydro-Edelnor (currently Enel) – Lima, Peru

Senior Auditor
2001

Manager Meter Shop Department
2000

Manager Commercial Process Department
1998

Manager Billing Department
1997

Commercial Analyst
1995

Central Hydro-Electrocentro – Huancayo, Peru

Financial Analyst
1994

Education:

MBA -
San Ignacio de Loyola University, Lima - Peru (2000)

Master of Arts in Economics - National Agrarian La Molina University, Lima - Peru (2000)

	Bachelor of Arts in Economics - National Agrarian La Molina University – Lima, Peru (1993)
Memberships:	None
Appearances:	None

CURRICULUM VITAE OF
NICOLE BRUNNER

Experience:	Enbridge Gas Inc.
	Technical Manager, New Energy Supply 2022
	Manager, Gas Supply 2019
	Union Gas Limited
	Team Lead, Gas Scheduling 2017
	Advisor, Strategic Accounts 2016
	Capacity Management Utilization Administrator 2015
	Advisor, Regulatory Affair 2014
	Buyer, Gas Supply 2012
	Sr. Analyst, Cost of Gas 2011
	Sr. Analyst, Gas Scheduling 2009
Education:	Master Business Administration University of Fredericton (2015)
	Honors Bachelor of Commerce McMaster University (2009)
Memberships:	None
Appearances:	None

CURRICULUM VITAE OF
JENNIFER BURNHAM

Experience:

Enbridge Gas Inc

Director, Field Services and Growth
2021

Manager, Operations Integration
2019

Union Gas Limited

Manager, Customer Growth and System Improvement
2014

Manager, Damage Prevention
2013

District Support Manager, Waterloo
2009

GIS Project Lead
2008

Manager, Distribution Operations Technical Support
2006

Manager, Field EHS
2004

Utility Services Manager, Waterloo
2002

Team Lead, Chatham Meter Shop
2001

District Engineer, Windsor/Chatham
2000

Assistant to The Senior Operations Engineer, Stations
1997

Education:	Bachelor of Mechanical Engineering Carleton University (1995)
Memberships:	Professional Engineers Ontario
Appearances:	None

CURRICULUM VITAE OF
TOM BYNG

Experience:	Enbridge Gas Inc.
	Specialist Integration 2019
	Union Gas Limited
	Supervisor, Contracting and Customer Support 2018 – 2019
	Manager, Contracting and Customer Support 2009 – 2018
	Manager, Customer Support Services 2002 – 2009
	Manager, Regulatory Applications 1999 – 2002
	Manager, Regulatory Accounting and Rate Case Administration 1997 – 1999
	Manager, Financial Forecasts 1995 – 1997
	Supervisor, Financial Forecasts 1992 – 1995
	Coordinator, Regulatory Accounting 1990 – 1992
	Senior Rate Design Analyst 1988 – 1990
	Financial Forecast Analyst 1986 – 1988
Education:	Master of Business Administration University of Windsor (1985)
	Bachelor of Commerce University of Windsor (1983)

Appearances: (Ontario Energy Board)

RP-1999-0017
E.B.R.O. 499
E.B.R.O. 493-04/494-06
E.B.O. 177-15
E.B.R.O. 493/494

CURRICULUM VITAE OF
BRADLEY CLARK

Experience:	Enbridge Gas Inc.
	Manager, Distribution Optimization Engineering 2020
	Manager, Regional Execution Manager 2019
	Enbridge Gas Distribution Inc.
	Manager, Construction – GTA East 2014
	Manager, Major Projects 2013
	Project Manager, Major Projects 2011
	Project Manager, Engineering 2009
	Special Projects Planner, Distribution Planning 2005
Education:	Bachelors of Engineering Ryerson University (2002)
Memberships:	PEO
Appearances:	(Ontario Energy Board)
	EB-2020-0091

CURRICULUM VITAE OF
JACKIE COLLIER

Experience:	Enbridge Gas Inc. Rate Design Specialist 2019 Enbridge Gas Distribution Inc. Manager, Rate Design 2003 Manager, Rate Research 2000 Senior Rate Research Analyst 1996 Centra Gas Ontario Inc. Manager, Rate Design 1995 Supervisor, Cost of Service Studies 1990
Education:	Bachelor of Business Management Ryerson Polytechnical Institute (1988)
Memberships:	None
Appearances:	(Ontario Energy Board) EB-2012-0459 EB-2011-0242 EB-2006-0034 EB-2005-0001 RP-2003-0203 RP-2002-0133 EBRO 489

EBRO 474-B, 483,484
EBRO 474-A
EBRO 474
EBRO 471

(Régie de l'énergie/Régie du gaz naturel)

R-4122-2020
R-4032-2018
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R-3969-2016
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R-3840-2013
R-3793-2012
R-3758-2011
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R-3692-2009
R-3637-2008
R-3637-2007
R-3621-2006
R-3587-2005
R-3537-2004
R-3464-2001
R-3446-2000

CURRICULUM VITAE OF
SEAN COLLIER

Experience:	Enbridge Gas Inc.
	Director, Operations Services & EGI Sync 2022
	Union Gas
	Director, EGI Sync Transformation & Integration 2018
	Manager, Operations Services 2018
	District Manager, Windsor/Chatham 2016
	Director, Corporate Real Estate Services 2014
	Manager, Corporate Real Estate Services 2012
	Manager, Distribution Operations Services 2010
	Manager, Fieldwork Planning Process Improvement 2008
	Manager, Emergency Dispatch 2006
Education:	Bachelor Of Commerce, Entrepreneurial Management Royal Roads University, Victoria British Columbia
	Primary Care Paramedic Justice Institute of British Columbia
Appearances:	None

CURRICULUM VITAE OF
DWAYNE CONROD, MHRM

Experience:

Enbridge Inc

HR Director, Gas Distribution and Storage (GDS)
2019

Morneau Shepell

HR Director, Lifeworks (Global)
2018

Corporate Strategy Transformation Office Director / HR Director
2018

HR Director, Absence Management Solutions / Ontario Region / Corporate
2015

Loblaw Companies Limited

HR Senior Director, Finance and Real Estate
2014

HR Senior Director, Ontario Market Retail and Operations
2012

HR Senior Director, Loblaws Retail and Operations
2011

HR Senior Director/Director, nofrills Retail and Operations
2008

Canadian Tire Corporation

Staffing Manager
2008

Team Lead, Distribution Employee Resource Planning
2006

Human Resources Consultant, Distribution
2004

Human Resources Specialist, Logistics, Transportation and SCM Projects
2003

Staffing Specialist
2001

Education: Master of Human Resources Management (MHRM)
York University (2008)

Bachelor of Business Administration (BBA)
University of New Brunswick (1999)

Memberships: None

Appearances: None

CURRICULUM VITAE OF
JOEY CYPLES

Experience:	Enbridge Gas Inc.
	Specialist, Business Development 2019
	Union Gas Limited
	Business Development Manager, Business Development 2018
	Manager, Accounts Payable 2017
	Senior Consultant, Audit 2016
	Team Lead, Accounts Payable 2013
	St. Clair Technologies Ltd.
	Financial Controller 2013
	Information Systems Manager 2012
	Senior Financial Analyst 2010
	Financial Analyst 2008
Education:	Chartered Professional Accountant, Institute of Chartered Professional Accountants of Ontario (2012)
	Honours Bachelor of Commerce Laurentian University (2007)
Appearances:	None

CURRICULUM VITAE OF
STEVE DANTZER

Experience:

Enbridge Gas Inc.

Supervisor, Gas Supply Planning
2020

Supervisor, Upstream Regulation
2019

Union Gas Limited

Specialist, Carbon
2018

Program Manager, Cap and Trade
2016

Project Manager, Upstream Regulation
2013

Team Lead, General Accounting
2012

Team Lead, Affiliate Reporting
2010

Senior Analyst, Financial Reporting
2008

Education:

Chartered Professional Accountant, Chartered Accountant (2006)

Honours Business Commerce
University of Windsor (2004)

Memberships:

Chartered Professional Accountants Canada
Chartered Professional Accountants of Ontario

Appearances:

(Ontario Energy Board)

EB-2017-0255

CURRICULUM VITAE OF
MELISSA DEBEVC, P. ENG

Experience:	Enbridge Gas Inc.
	Engineer Specialist, Transmission System Planning 2019
	Union Gas Limited
	Principal Engineer, System Planning 2013
	Senior Engineer, System Planning 2010
	Intermediate Engineer, System Planning 2006
	Intermediate Engineer, Distribution Planning 2004
	Engineer, Distribution Planning 1998
	City of Windsor
	Engineer, Roads Department 1997
	Dillon Consulting
	Engineer 1996
	Engineer in Training 1993
Education:	Bachelor of Applied Science (Honours Civil Engineering Co-op) University of Windsor (1992)
Memberships:	Professional Engineers Ontario
Appearances:	None

CURRICULUM VITAE OF
GORD DILLON, P. ENG.

Experience:	Enbridge Gas Inc.
	Manager, Transmission System Planning 2019 – Present
	Union Gas Limited
	Manager, Distribution Planning 2013 – 2019
	Technical Account Manager, Market Development 2013
	Project Manager, Market Development Engineering Services 2009 – 2013
	Firebridge Inc.
	Business Development 2006 – 2009
	Stelco Manager – Utilities Energy Environment 2004 – 2006
	Supervisor – Utilities Combustion and Energy 2002 – 2004
	Energy Analyst 2000 – 2002
Education:	Bachelor of Chemical Engineering Dalhousie University
	Diploma, Mechanical Engineering Technology University of Cape Breton
Memberships:	Professional Engineers of Ontario
Appearances:	None

CURRICULUM VITAE OF
ROB DiMARIA

Experience:	Enbridge Gas Inc.
	Manager, Contracting and Compliance 2019
	Enbridge Gas Distribution Inc.
	Manager, Direct Purchase and Large Volume Customer Strategy 2014
	Manager, Key Accounts and Vendor Relationships 2009
	Account Executive 2006
	Senior Marketing Specialist 2003
	Residential Program Manager 2001
	Senior Analyst, Planning and Evaluation 2000
	Rate Research Analyst 1998
	Plant Accounting Chief Clerk 1993
	Accounting Trainee 1992
Education:	Bachelor of Administration, Business Management Athabasca University
	Diploma in Accounting and Financial Management, Centennial College

Memberships: None

Appearances: None

CURRICULUM VITAE OF
JOSEPH DIMEO

Experience:	Enbridge Gas Inc.
	Customer Care Supervisor June 2013 - present
	Customer Care Collection Analyst April 2010 - June 2013
	Bell Canada
	Project Manager Credit & Collections Oct 2001 - January 2010
	Rogers
	Credit & Collection Manager February 1995 - Oct 2001
Education:	Project Management Professional (PMP) Master Certificate in Project Management (MCPM) Business Analysis Evolution Certificate Schulich School of Business
	BA Accounting & Economics York University
Memberships:	None
Appearances:	None

CURRICULUM VITAE OF
DANIELLE DREVENY

Experience:	Enbridge Gas Inc.
	Manager, Capital Financial Planning & Analysis 2019
	Union Gas Limited
	Manager, Operating & Maintenance 2017
	Team Lead, Operating & Maintenance 2015
	Analyst, Operating & Maintenance 2009
	Siemens VDO Automotive
	Business Development Analyst 2002
	Union Gas Limited
	Fulfillment Support Analyst 2001
Education:	Bachelor of Commerce University of Windsor (2001)
Memberships:	None
Appearances:	None

CURRICULUM VITAE OF
TANYA FERGUSON

Experience:	Enbridge Gas Inc.
	Vice President, Finance and Business Partner GDS 2020
	Enbridge Gas Distribution Inc.
	Director, Financial Planning and Analysis, GDS 2017
	Enbridge Gas Distribution Inc.
	Manager, Procurement Operations, Supply Chain Management 2013
	Manager Customer Care Operations, Customer Care 2010
	Manager Customer Care Financial Administration, Customer Care 2006
	Manager Special Projects, Customer Care 2005
Education:	Masters of Business Administration Schulich School of Business, York University (2002)
	Certified Professional Accountant Certified Professional Accountants of Ontario (2000)
	Honours Bachelor of Commerce University of Windsor (1996)
Memberships:	Certified Professional Accountant Certified Professional Accountants of Ontario
Appearances:	None

CURRICULUM VITAE OF
STEPHANIE FIFE

Experience: Enbridge Gas Inc.

Manager, Performance Reporting & Analytics
2018

Union Gas Limited

Performance Specialist, Portfolio and Planning
2017

SAP Project Manager
2013

Integrated Supply Planning Specialist, Gas Supply Planning
2010

Sr. IT Audit Consultant
2008

Business Information Specialist, Customer Support
2005

Web Specialist
1999

Education: Master of Business Administration
Sandermoen School of Business, University of Fredericton (2015)

Bachelor of Commerce, Honours Business Administration,
University of Windsor (2009)

Bachelor of Arts, Honours,
University of Guelph (1997)

Memberships: None

Appearances: None

CURRICULUM VITAE OF
ROB FORD

Experience:	Enbridge Gas Inc.
	Specialist, Property Tax 2019
	Sr Advisor, Property Tax 2018
	Union Gas Limited.
	Advisor, Property Tax 2015
	City of Calgary
	District Assessor 2008
	Compuware Corporation
	Accounting Analyst 2006
	Daimler Chrysler
	Budget Analyst 2002
Education:	Bachelor of Administrative and Commercial Studies University of Western Ontario (2002)
	Certificate Program in Real Property Assessment University of British Columbia (2010)
	Diploma of Urban Land Economics University of British Columbia (2012)
Memberships:	Canadian Property Tax Association Institute of Municipal Assessors – M.I.M.A
Appearances:	None

CURRICULUM VITAE OF
JEREMY GETSON

Experience:	Enbridge Gas Inc.
	Manager, Customer Attachment 2020
	Manager, Construction 2019
	Union Gas Limited
	Manager, Construction & Growth 2015
	Manager, Utility Services 2012
	District Engineer, EIT 2010
	Operations Support, EIT 2008
	Pipeline Engineering, EIT 2006
Education:	Bachelor of Mechanical Engineering Dalhousie University (2006)
Appearances:	None

CURRICULUM VITAE OF
JASON GILLETT

Experience:	Enbridge Gas Inc.
	Director, Gas Supply 2020
	Manager, Strategic and Power Markets 2019
	Union Gas Limited
	Strategic Markets Account Manager 2016
	Manager, Upstream Regulation 2015
	Manager, Transportation Acquisition 2014
	Manager, Planning and Technology 2009
	IT Project and Operations Manager 2007
	Application Developer 2003
Education:	Bachelor of Science, Computer Science Western University (2003)
Memberships:	None
Appearances:	(Ontario Energy Board)
	EB-2020-0091 EB-2015-0166
	(Canada Energy Regulator)
	RH-001-2016

CURRICULUM VITAE OF
RACHEL GOODREAU

Experience:

Enbridge Gas Inc

Manager, Revenue and Cost of Gas
2019

Manager, Revenue
2018

Union Gas Limited

Manager, Financial Planning & Analysis
2017

Manager, Accounts Payable Projects
2016

Team Lead, Accounts Payable
2011

Capacity Utilization Planner, Capacity Management & Utilization
2007

NOVA Chemicals

Coordinator, Accounts Payable
2002

Labour Contracts Administrator, Accounts Payable
2000

King Agro Inc./Pride Seeds

Accountant
1999

Education:

Certified Management Accountant (2002)

Bachelor of Arts in Business
Redeemer University (2000)

Memberships:	Certified Public Accountants - Ontario Certified Public Accountants - Canada
Appearances:	None

CURRICULUM VITAE OF
MAX HAGERMAN

Experience:	Enbridge Gas Inc.
	Manager Capacity Management and Utilization 2020
	Union Gas Limited.
	Manager S&T Sales 2015
	Manager Strategic Accounts 2013
	Manager Industrial Sales 2010
	Manager Strategic and Agricultural Sales 2007
	Manager Institutional Sales 2005
	Manager Municipal Operations 2003
	Account Manager Acquisitions 2000
	Commercial Account Manager 1997
Education:	Diploma Energy Management Strategy Fanshawe College
	Strategic Leadership Program Duke University
	Effective Leadership Program Western University

Memberships: None

Appearances: None

CURRICULUM VITAE OF
AMIR HASAN

Experience:	Enbridge Gas Inc.
	Manager Third Party Programs 2021
	Enbridge Gas Distribution Inc.
	Supervisor Third Party Programs 2016
	Team Lead Finance Customer Care 2012
	Senior Business Analyst Customer Care 2005
Education:	Chartered Professional Accountant, Ontario 2013
Memberships:	Chartered Professional Accountants of Ontario
Appearances:	(Ontario Energy Board)
	EB-2018-0319

CURRICULUM VITAE OF
COLIN HEALEY

Experience:

Enbridge Gas Inc.

Director, Financial Planning and Analysis
2021

Enbridge Inc.

Manager, Internal Controls
2017

Technical Manager, Transformation
2016

Senior Manager, Green Energy Commercial and Financial
2016

Manager, Internal Audit
2014

Specialist, Major Projects Planning and Reporting
2013

Team Lead, Green Energy Commercial and Financial
2010

IFRS Implementation
2008

Davies and Wyngaarden Chartered Accountants

Senior Accountant
2005

Grant Thornton LLP

Accountant
2003

Education:

Master of Business Administration
University of Calgary (2012)

Chartered Accountant / Chartered Professional Accountant (2006)

	Bachelor of Commerce (Accounting) Dalhousie University (2003)
Memberships:	Chartered Professional Accountants of Ontario Chartered Professional Accountants of Alberta Chartered Professional Accountants of Canada
Appearances:	None

CURRICULUM VITAE OF
ANN-MARIE HESSIAN

Experience:	Enbridge Gas Inc.
	Senior Advisor, Asset Management Governance 2021- Present
	Stations & Odourant Engineer 2020-2021
	EIT Stations Engineering 2018-2020
	Union Gas Limited
	EIT Commercial/Industrial Energy Efficiency Programs 2016-2018
Education:	Bachelor of Chemical Engineering Dalhousie University (2016)
Memberships:	P.Eng – Professional Engineers Ontario PMP – Project Management Institute
Appearances:	None

CURRICULUM VITAE OF
CATHERINE HO, CPA, CA

Experience:

Enbridge Gas Inc.

Manager, Financial Planning and Analysis
2019

Enbridge Gas Distribution Inc.

Manager, EGD Financial Planning and Analysis
2018

Manager, Accounts Payable and Special Projects
2016

Manager, Accounting
2012

Manager, Gas Accounting
2012

Manager, Finance Projects
2008

Senior Audit Advisor
2005

Ernst & Young LLP

Senior Staff Accountant
2004

Horwath Orenstein LLP

Staff Accountant
2002

Goldfarb, Shulman, Patel & Co. LLP

Staff Accountant
2000

Education:	Chartered Accountant / Chartered Professional Accountant (2005) Certified Public Accountant Delaware (2004) Master of Accounting (MAcc) University of Waterloo (2003) Bachelor of Arts Honours Chartered Accountancy Studies – Co-operative program (Dean's Honours List) University of Waterloo (2002)
Memberships:	Chartered Professional Accountants of Ontario
Appearances:	None

CURRICULUM VITAE OF
EDWARD HOU

Experience: Enbridge Gas Inc.

TIS Director, Utility Enablement and Delivery
2020

Celestica Inc.

Senior IT Director, Global Customer Engagement and Delivery
2018

IT Director, Customer and Market Solutions (Aerospace & Defense)
2016

IT Director, Mergers and Acquisitions
2015

Senior Manager, IT Customer Solutions
2010

Manager, IT Customer Solutions
2008

Project Manager, Large Project Transformation
2006

IT Application Advisor
2004

IT Application Analyst
2001

Quest International Pty Limited

Regional Purchasing Analyst
2000

Education: Master of Operations Management
University of Western Sydney (1997)

Bachelor of Commerce (Accounting & Economics)
University of Bombay (1993)

Designation	Project Management Professional (PMP)
Appearances:	None

CURRICULUM VITAE OF
JANE HUANG

Experience:	Enbridge Gas Inc. Supervisor, Technology Development 2022 Supervisor, DSM Commercial Sales 2020 Enbridge Gas Distribution Inc. Advisor, DSM Program Design 2016 Manitowoc Foodservices Project Manager, Strategic Projects 2012 ZENN Motor Company Project Engineering Manager 2009
Education:	Master of Business Administration, Operations and Strategy York University (2009) Master of Applied Science, Mechanical Engineering University of Toronto (1999) Bachelor of Engineering, Mechanical Engineering Xi’an Jiaotong University (1997)
Memberships:	Professional Engineers Ontario Certified Energy Manager, Association of Energy Engineers Project Management Professional, Project Management Institute
Appearances:	None

CURRICULUM VITAE OF
DAVE JANISSE

Experience:	Enbridge Gas Inc.
	Manager, Gas Supply Acquisition 2022-Present
	Technical Manager, Leave to Construct Applications 2021-2022
	Supervisor, Gas Supply 2020-2021
	Specialist, S&T Sales 2019-2020
	Union Gas Limited
	Senior Advisor, Strategic Sales 2018-2019
	Senior Buyer, Carbon Markets 2017-2018
	Senior Buyer, Gas Supply 2015-2017
	Buyer, Gas Supply 2014-2015
	Financial Planning & Forecast Analyst 2012-2014
	Financial Analyst, CA Stream 2010-2012
Education:	Honours Bachelor of Commerce University of Windsor (2010)
Memberships:	CPA Ontario: Chartered Professional Account, Chartered Accountant
Appearances:	None

CURRICULUM VITAE OF
LOUIE JEROMEL

Experience:	Enbridge Gas Inc
	Technical Manager, Engineering 2021
	Manager, STO Integration 2020
	Manager, Records 2019
	Union Gas Limited
	Manager, Measurement Support 2017
	Principal Project Manager – Regional Support 2014
	Manager, Compressor Operations 2011
	Manager, System Planning 2010
	Senior Project Manager 2006
	Manager, Meter Shop Services 2004
	Senior Pipeline Engineer 2002
	Measurement Engineer 1999
Education:	MASc, Geotechnical/Environmental Engineering, Queen's University (1998)
	BEng, Civil Engineering Royal Military College of Canada (1996)

Memberships:	Professional Engineers of Ontario
Appearances:	None

CURRICULUM VITAE OF ANTON KACICNIK

Experience:	Enbridge Gas Inc.
	Manager, Regulatory Applications 2021
	Enbridge Gas Distribution Inc.
	Manager, Rates 2007
	Manager, Cost Allocation 2003
	Program Manager, Opportunity Development 1999
	Project Supervisor, Technology & Development 1996
	Pipeline Inspector, Construction & Maintenance 1993
Education:	Bachelor of Applied Science (Civil Engineering) University of Waterloo (1996)
Memberships:	P.Eng. License: Professional Engineers of Ontario (PEO) Pipeline Inspector Certificate: Technical Standards and Safety Authority (TSSA)
Appearances:	(Ontario Energy Board)
	EB-2017-0307 EB-2017-0306 EB-2016-0300 EB-2007-0615 EB-2007-0724 EB-2006-0034 EB-2005-0551 EB-2005-0001

(RÉGIE DE L'ÉNERGIE)

R-4032-2018
R-4003-2017
R-3924-2015
R-3884-2014
R-3840-2013
R-3793-2012
R-3758-2011
R-3724-2010
R-3665-2008
R-3637-2007
R-3621-2006

CURRICULUM VITAE OF
GREG KAMINSKI

Experience:	Enbridge Gas Inc.
	Specialist I, Cost Allocation 2016
	Union Gas Limited
	Senior Supply Planning Specialist 2014
	Rates & Pricing Specialist, In-franchise Rates 2008
	Rates & Pricing Analyst 2007
Education:	Bachelor of Science, Honours Kinesiology University of Western Ontario (2003)
Appearances:	None

CURRICULUM VITAE OF
KENT KERRIGAN

Experience:	Enbridge Gas Inc.
	Specialist, Rate Design 2021 - Present
	Advisor, Rate Design 2019
	Union Gas Limited
	Advisor, Regulatory Applications 2017
	Finance Analyst, Cap and Trade 2016
	Finance Analyst, Cost of Gas 2013
	Clerk, Accounts Payable 2012
Education:	Bachelor of Commerce (Honours) Business Administration, Minor in Classical Studies University of Windsor
Memberships:	Chartered Professional Accountant (CPA) Certified Management Accountant (CMA)
Appearances:	None

CURRICULUM VITAE OF
SHAWN KHOSHAIEN

Experience:

Enbridge Gas Inc.

Director, Integrity & Asset Management
2020

Director, IMS and Integrity
2019

Union Gas Limited

Director, Engineering
2012

District Manager, London
2008

Manager, Construction and Growth, London
2006

Manager, Technicians, Windsor
2004

Manager, Meter shops, Chatham
2003

Senior Operations Support Engineer, Operations
2002

Senior Operations Engineer, Engineering
2000

Senior Corrosion Control Engineer, Engineering
1997

Junior/ Intermediate/ Senior Distribution Planning Engineer, Engineering
1991

Education:	Bachelor of Science, Mechanical Engineering (Honours) University of Windsor – Faculty of Applied Science
Memberships:	Professional Engineers Ontario (P.Eng. Licence Holder)
Appearances:	None

CURRICULUM VITAE OF
TRINETTE LINDLEY

Experience: Enbridge Gas Inc.

Manager Utility Portfolio Management
2021

Director Integration and Business Support
2020

Manager Portfolio Management
2019

Union Gas Limited

Manager Internal and Executive Communications
2017

Manager Project and Documentation Support
2011

Manager Business Integration
2009

Manager Operations Services
2008

Manager Operations Systems Development
2006

Manager Logistics
2005

Team Lead, Customer Support Services
2004

Project Manager, Business Transformation & Sustainment
1999

S&T Analyst, Customer Support
1998

	<u>TD Bank</u>
	Manager Personal Banking 1997
	Manager Personal Banking Implementation & Customer Care 1995
	Personal Banker & Customer Support Officer 1991
Education:	Western University, London, Ontario, Canada Bachelor of Arts
Designation:	Project Management Professional (PMP)
Appearances:	None

CURRICULUM VITAE OF
TRACY LYNCH

Experience:

Enbridge Gas Inc.

Director, Customer Care Operations
2020

Director, Large Volume Contracting & Policy
2019-2020

Union Gas Limited

Director, Large Volume Contracting & Policy
2018-2019

Director, Distribution Marketing
2017-2018

Director, Energy Conservation Strategy
2012-2017

Manager, Residential Program Delivery
2009-2012

Manager, Demand Side Management
2005-2009

Manager, Market Analysis
2003-2005

Team Lead, Market Analysis
2001-2003

Senior Customer Markets Advisor
2000-2001

Canadian Enerdata Ltd.

Vice President
1998-2000

Senior Energy Analyst
1996-1998

<u>Canadian Chamber of Commerce</u>

Policy Analyst
1996

Education: Master of Arts, Economics
University of Guelph (1995)

Honours Bachelor of Arts, Economics
Brock University (1994)

Bachelor of Business Economics
Brock University (1993)

Appearances: (Ontario Energy Board)

EB-2006-0021
EB-2012-0337
EB-2015-0029
EB-2018-0319

CURRICULUM VITAE OF
IAN B. MACPHERSON

Experience:

Enbridge Gas Inc.

Director Distribution In-Franchise Sales
Customer Care
2018

Enbridge Gas Distribution Inc.

Director Distribution In-Franchise Sales
Customer Care
2018

Director DSM
Business Development & Regulatory
2016

Director Business Development
Gas Supply & Development
2013

Senior Manager Storage Development
Gas Supply & Development
2011

Senior Manager Strategic Planning
Strategy Research and Planning
2010

Senior Manager Direct Purchase
Customer Care
2008

Manager Contract Relationships
Strategic & Key Accounts
2006

Senior Account Executive
Strategic & Key Accounts
2001

Energy Solutions Consultant
Operations
1998

	Project Engineer Operations 1995
Education:	Bachelor of Science (Mechanical Engineering) Queen's University (1991) Certified Industrial Gas Consultant (CIGC)
Memberships:	Professional Engineers Ontario
Appearances:	(Ontario Energy Board) EB-2020-0094

CURRICULUM VITAE OF
PAOLO MASTRONARDI

Experience:	Enbridge Gas Inc.
	Manager Gas Management Services 2019 – Present
	Union Gas Limited
	Manager Storage & Transportation Business Development 2012
	Strategic Storage & Transportation Account Manager 2010
	Storage & Transportation Account Manager 2008
	Storage & Transmission Business Development Coordinator 2006
	Rates & Pricing Analyst 2003
	Sr. Financial Analyst 2000
	Financial Analyst 1998
Education:	Bachelor of Commerce – Management Economics & Finance University of Guelph
Memberships:	None
Appearances:	None

CURRICULUM VITAE OF
SAMUEL MCDERMOTT

Experience:

Enbridge Gas Inc.

Technical Manager Renewable Hydrogen, Business Development
2019

Enbridge Gas Distribution Inc.

Technical Manager Renewable Hydrogen, Business Development
2015

Senior Account Manager, Strategic Accounts
2015

Construction Manager, GTA Project
2012

Construction Contracts Manager, Extended Alliance
2008

Project Manager, Engineering Special Projects
1997

Zenon Environmental Inc.

Project Manager, Mechanical Engineer Designer
2002

Progressive Moulded Products Limited

Project Manager
2001

Mecon Industries Inc.

Project Manager, Mechanical Engineer Designer
2005

Education:

Master of Engineering in Design and Manufacturing - University of Toronto (2015)

Bachelor of Engineering, Mechanical Engineering - Toronto Metropolitan University (1995)

Diploma Mechanical Engineering – Seneca College of Applied Arts and Technology (1992)

Appearances: (Ontario Energy Board)

EB-2005-0305

CURRICULUM VITAE OF
MICHAEL MCGIVERY

Experience:	Enbridge Gas Inc.
	Manager, Distribution Protection 2019
	Enbridge Gas Distribution Inc.
	Supervisor, Operations Survey 2016
	Sewer Safety Program Manager, Damage Prevention 2014
	Field Manager, Damage Prevention 2011
	Operations Supervisor, Operations 2010
	Special Projects Supervisor, Planning 2007
	Pipeline Inspector, Construction 2005
	Labour/Gas Technician, Operations 2003
Education:	Master of Business Administration Clarkson University (2013)
	Bachelor of Commerce Ryerson University (2008)
	Business Diploma George Brown College (2004)
Memberships:	Gas Pipeline Inspector, Technical Standards & Safety Authority (TSSA)
Appearances:	None

CURRICULUM VITAE OF
AMY MIKHAILA

Experience:	Enbridge Gas Inc.
	Manager, Rate Design 2019
	Union Gas Limited
	Manager, Rates & Pricing 2015
	Manager, Plant Accounting 2012
	Manager, Plant Accounting 2012
	Team Lead, General Accounting 2009
	Senior Coordinator, Operations Budgets 2006
	Ernst & Young LLP
	Assurance Manager 2005
	Senior Staff Accountant 2003
	Staff Accountant 2001
Education:	Honours Business Administration, University of Western Ontario (2001)
Memberships:	Chartered Professional Accountants of Canada Chartered Professional Accountants of Ontario Illinois Department of Financial and Professional Regulation, Registered Certified Public Accountant

Appearances:	(Ontario Energy Board)
	EB-2017-0306/0307 EB-2016-0296 EB-2016-0186

CURRICULUM VITAE OF JENNIFER MURPHY

Experience:	Enbridge Gas Inc.
	Manager, Carbon and Energy Transition Planning 2022 – present
	Supervisor, Carbon Strategy 2019 – 2022
	Enbridge Gas Distribution Inc.
	Climate Policy/Cap and Trade Compliance Sr. Advisor 2017 – 2019
	Environmental Senior Advisor, Carbon Strategy 2016 – 2017
	Environmental Advisor 2015 – 2016
	Environmental Specialist 2007 – 2015
	SKD Automotive Group
	Environmental Management System Coordinator 2002 – 2007
Education:	Bachelor of Science in Environmental Engineering University of Guelph (2003)
	Environmental Science Technician Sheridan College (1997)
Memberships:	Professional Engineers of Ontario
Appearances:	(Ontario Energy Board)
	EB-2016-0300 EB-2017-0224

CURRICULUM VITAE OF
PETER MUSSIO

Experience:

Enbridge Gas Inc.

Manager Carbon Strategy
2022

Technical Manager Environment
2019

Union Gas Limited

Technical Manager Environment
2017

Principal EHS Technical Advisor
2016

Manager, Environment
2005

Supervisor, Environmental Engineering
1995

Coordinator, Environmental Analysis
1992

Allied Chemical

Environmental Process Engineer
1991

Bayer Canada.

Process Design Engineer
1990

Education:

Master of Applied Science, Chemical/Environmental Engineering - University of Windsor (1989)

Bachelor of Applied Science, Chemical Engineering
University of Windsor (1986)

Memberships:	Professional Engineers Ontario Environmental Careers Organization
Appearances:	None

CURRICULUM VITAE OF
JANEE O'DONOHUE

Experience:

Enbridge Gas Inc.

Supervisor, Reporting and Contract Management / Product & Policy Dev
2021

Supervisor, Industrial and Agricultural Energy Conservation
2019

Union Gas Limited

Manager, Permit Acquisitions
2017

Manager, Land Services
2014

Account Manager, Greenhouse Market
2013

Team Lead, Credit
2010

Senior Analyst, Credit
2007

Analyst, Credit
2005

Business Information Support Analyst
2003

National Bank Financial

Licensed Sales Associate
1994

Education:

Canadian Securities Course
Canadian Securities Institute (1994)

Business Marketing
St Clair College (1993)

	Public Relations Humber College (1992)
Memberships:	None
Appearances:	None

CURRICULUM VITAE OF
RYAN ORGAN

Experience:	Enbridge Gas Inc.
	Manager, Billing & Collections 2022 - Present
	Manager, Policy & Sales Support 2021-2022
	Supervisor, Policy & Sales Support 2020-2021
	Team Lead, Policy & Sales Support 2019-2020
	Union Gas Limited
	Manger, Sales Support 2017-2019
	Project Manager, Business Development 2016-2017
	Account Manager, Greenhouse Market 2014-2016
	Buyer, Gas Supply 2013-2014
	Coordinator, Regulatory Applications 2009-2013
	Direct Purchase Business Specialist 2008-2009
	Forecast Analyst 2007-2008
Education:	Bachelor of Commerce Saint Mary’s University
Appearances:	None

CURRICULUM VITAE OF
STEVEN PARDY, P. ENG.

Experience:	Enbridge Gas Inc.
	Manager, Underground Storage & Reservoir Engineering 2019
	Union Gas Limited
	Manager, Underground Storage & Reservoir Engineering 2015
	Transmission Pipeline and Storage Manager 2014 – 2015
	Manager, Business Development 2011 – 2013
	Manager Reservoir and Drilling Engineer 2006 – 2011
	Senior/Principal Reservoir and Drilling Engineer 1998 – 2006
	Intermediate Reservoir Engineer 1997 – 1998
	Storage Reservoir Engineer 1995 – 1997
	Assistant to Storage Planning Engineer 1993 – 1995
Education:	Bachelor of Applied Science Honours Industrial Engineering Co-op University of Windsor (1993)
Memberships:	Professional Engineers of Ontario

Appearances: (Ontario Energy Board)

RP-1999-0047

CURRICULUM VITAE OF
WARREN REINISCH

Experience:	Enbridge Inc.
	Director, Treasury Planning 2022
	Director, Finance Transformation 2018
	Union Gas Limited
	Director, Planning and Forecasting 2016
	Project Manager, Cap & Trade Initiative 2015
	Manager, Upstream Regulation 2013
	Strategic Account Specialist 2011
	Coordinator, Business Development Storage & Transportation 2008
	Buyer Gas Supply 2005
	Credit Analyst 2004
Education:	Masters of Business Administration, High Distinction University of Michigan – Stephen M. Ross School of Business Ann Arbor, Michigan, United States of America (2014)
	Bachelor of Commerce, Honours, Finance University of Windsor (2001)
	Bachelor of Arts, Economics University of Manitoba (1999)

Memberships: None

Appearances: (Ontario Energy Board)

EB-2017-0306/0307
EB-2016-0186

CURRICULUM VITAE OF
HULYA SAYYAN

Experience:

Enbridge Gas Inc.

Specialist, Economic Evaluation & Forecast
2020

Enbridge Gas Distribution Inc.

Senior Advisor, Economic & Financial Analysis
2016

Advisor, Economic & Market Analysis
2011

Senior Market Analyst
2007

Risk Software Technologies

Economic Specialist
2005

Marmara University

Assistant Professor, Econometrics Department
2002

Instructor, Econometrics Department
2001

Research Assistant, Econometrics Department
1994

Education:

Ph.D. in Econometrics
Marmara University (2000)

Master of Science in Statistics
Marmara University (1995)

Bachelor of Science in Statistics
Mimar Sinan University (1992)

Memberships:	Toronto Association for Business & Economics (CABE)
Appearances:	(Ontario Energy Board)
	EB-2012-0459

CURRICULUM VITAE OF
ANGELA SCOTT

Experience:	Enbridge Gas Inc.
	Manager, Integrity Management 2019
	Union Gas Limited:
	Supervisor Storage and Transmission Operations 2017-2019
	Manager Pipeline Engineering 2015-2017
	Manager Station Engineering 2012-2015
	Station Engineering EIT, P. Eng and Senior Engineer 2003-2012
	Distribution Planning EIT 2001-2003
Education:	Bachelor of Geological Engineering University of New Brunswick (2000)
Memberships:	P.Eng – Professional Engineers Ontario
Appearances:	None

CURRICULUM VITAE OF
Andrea Seguin

Experience:

Enbridge Gas Inc.

Director, S&T Sales
2020

Union Gas Limited

Director, S&T Business Development
2018

Director, Regulatory Projects, Lands and Permitting
2016

District Manager – Windsor/Chatham
2013

Construction and Growth Manager
2011

District Support Manger
2009

Distribution System Development Process Optimization Coordinator
2007

Utility Services Admin Manager
2006

Distribution System Development Team Lead
2005

Workplace Safety Insurance Board

Adjudicator
2000

Union Gas Limited

Manager Asset Project Development
1999

Education:	Bachelor of Public Administration - B.Pa. (Hons) University of Windsor
	Queen’s University - Strategy Program
	Queen’s University - Leadership Program
Appearances:	None

CURRICULUM VITAE OF
RYAN SMALL

Experience:	Enbridge Gas Inc.
	Technical Manager, Regulatory Accounting 2019
	Enbridge Gas Distribution Inc.
	Manager, Regulatory Accounting 2018
	Manager, Revenue and Regulatory Accounting 2016
	Manager, Regulatory Accounting 2014
	Senior Analyst, Regulatory Accounting 2006
	Analyst, Regulatory Accounting 2004
	Supervisor, Gas Cost Reporting 2001
	Senior O&M Clerk 2000
	Bank Reconciliation Clerk 1999
	Accounting Trainee 1998
Education:	Chartered Professional Accountant, Certified Management Accountant
	Chartered Professional Accountants of Ontario (2014)
	The Society of Management Accountants of Ontario (2003)

	Diploma in Accounting Wilfrid Laurier University (1997)
	Bachelor of Arts in Economics The University of Western Ontario (1996)
Appearances:	(Ontario Energy Board)
	EB-2012-0459

CURRICULUM VITAE OF
BRANDON SO

Experience:	Enbridge Gas Distribution Inc.
	Cost Allocation Specialist 2016
	Senior Gas Cost Accountant, Gas Accounting & Analytics 2009
	Senior Financial Analyst, Business Development & Customer Strategy 2007
	Toronto Hydro
	Senior Financial Analyst 2003
	Ballard Power Systems
	Senior Accountant 1999
Education:	Master of Business Administration Richard Ivy School of Business
	Bachelor of Business Administration (Accounting) University of Texas at Austin
	Bachelor of Arts (Economics) University of Texas at Austin
Memberships:	Charter Professional Accountants of Ontario Chartered Professional Accountant (CPA, CGA)
Appearances:	(Régie de l'énergie/Régie du gaz naturel)
	Requête 4122-2020 Requête 4032-2018 Requête 4003-2017 Requête 3969-2016

CURRICULUM VITAE OF
ADAM STIERS

Experience:	Enbridge Gas Inc.
	Manager, Regulatory Applications – Leave to Constructs 2021 - Present
	Union Gas Limited
	Technical Manager, Regulatory Applications 2017
	Specialist, Strategic Accounts 2015
	Project Manager, Business Development 2014
	Coordinator, Strategic Sales 2011
	Buyer, Gas Supply 2010
	Specialist, Gas Management Services 2009
	Coordinator, Gas Supply 2008
Education:	Masters of Business Administration University of Windsor
	Honours Bachelor of Commerce - Business Administration University of Windsor
Appearances:	(Ontario Energy Board)
	EB-2020-0091

CURRICULUM VITAE
RUTH SWAN

Experience:	Enbridge Gas Inc.
	Specialist, Property Tax 2018
	Enbridge Gas Distribution Inc.
	Specialist, Property Tax 2018
	Senior Advisor, Property Tax 2017
	Team Lead, Property Tax 2015
	Analyst, Property Tax 2000
	City of Oshawa
	Assessment Review Officer 1999
	Municipality of Clarington
	Tax Collector/Revenue Supervisor 1989
	Ministry of Revenue – Assessment Division
	Property Analyst 1986
Education:	Real Property Administration Diploma Seneca College (1986)
Memberships:	Canadian Property Tax Association Institute of Municipal Assessors – M.I.M.A. Ontario Municipal Tax & Revenue Association

Appearances: (Ontario Energy Board)

EB-2012-0459

CURRICULUM VITAE OF
KAREN SWEET

Experience:	Enbridge Gas Inc.
	Supervisor, Customer & Market Insights 2020
	Team Lead, Market Research & Analysis 2019 - 2020
	Union Gas Ltd.
	Manager, Market Research & Analysis 2015 - 2019
	Specialist, Residential Marketing 2010-2015
	Market Researcher, Market Research & Analysis 2008-2010
	Coordinator, Market Analysis 2006-2008
Education:	Bachelor of Business Administration with Honours Schulich School of Business - York University (2006)
Appearances:	None

CURRICULUM VITAE OF
TRACEY TEED MARTIN

Experience:

Enbridge Gas Inc

Director, Engineering
2022

Director, Toronto Regional Operations
2018

Enbridge Gas Distribution Inc.

Director, Distribution Protection & Operations Services
2016

Senior Manager, Damage Prevention
2015

Senior Business Lead, Interdependent Forecasting
2013

Senior Manager, Network Operations
2012

Senior Manager, Leak and Corrosion Management
2009

Senior Manager, Operations Solutions
2007

Manager, Customer Solutions
2006

Sector Manager, LNG Transportation
2005

Celestica

Manufacturing engineer
1998

Nova Chemicals

Process Engineer
1997

Education:	MBA, Schulich School of Business York University (2003)
	BASc, in Chemical Engineering, University of Ottawa (1997)
	BSc Biochemistry University of Ottawa (1994)
Memberships:	Professional Engineers of Ontario
Appearances:	None

CURRICULUM VITAE OF
HILARY THOMPSON

Experience:

Enbridge Gas Inc.

Director, S&T Business Development
2020

Enbridge Gas Distribution Inc.

Director, Asset Management
2016

Manager, Distribution Planning
2014

Manager, Regulatory Projects
2012

Manager, Technical Services
2011

Field Manager, Measurement & Regulation
2011

Senior Engineering Project Leader, Measurement & Regulation
2010

Senior Engineering Project Leader, Special Projects
2008

Engineering Project Leader, Special Projects
2007

Engineering Project Leader, Engineering Standards & Technical Services
2006

Education:

Global Professional Master of Laws
University of Toronto – Faculty of Law

Bachelor of Science, Chemical Engineering
Queen's University – Faculty of Applied Science

Memberships:	Professional Engineers Ontario (P.Eng. Licence Holder)
Appearances:	(Ontario Energy Board)
	EB-2015-0049

CURRICULUM VITAE OF
JASON VINAGRE

Experience:

Enbridge Gas Inc.

Manager, Regulatory Accounting
2020

Manager, Power Accounting
2019

Union Gas Limited

Manager UPO (Utility and Power Operations), Special Projects
2018

Manager, Financial Reporting and Accounting
2016

Manager, Cost of Gas
2013

Team Lead, Cost of Gas
2011

Team Lead, IFRS
2008

Senior Analyst, Financial Reporting
2007

Coco Paving Ltd

Lead Accountant
2006

Roth Mosey LLP

Senior Associate
2005

PricewaterhouseCoopers LLP

Associate, Senior Associate
2000

Education:	Bachelor of Commerce, Honours Business Administration, University of Windsor (2000)
Memberships:	CPA (Chartered Professional Accountant), Institute of Chartered Accountants of Ontario (2012) CA (Chartered Accountant), Institute of Chartered Accountants of Ontario (2004)
Appearances:	None

CURRICULUM VITAE OF
CARA-LYNNE WADE

Experience:

Enbridge Gas Inc.

Director, Energy Transition Planning
2022

Manager, Energy Transition Planning
2021

Manager, Marketing & Customer Insights
2019

Union Gas Limited

Manager, Energy Conservation Strategy
2017

Manager, Marketing Communications
2016

Manager, DSM Program Design & Delivery - Low Income (LI) Market
2013

Manager, DSM Program Design & Delivery – Residential Market
2011

Program Lead, DSM Program Design & Delivery – Commercial & Industrial Market
2009

Specialist, DSM Program Design & Delivery – Commercial & Industrial Market
2007

Education:

Masters in Business Administration (MBA)
Schulich School of Business, York University

Honours Business Administration (HBA)
Richard Ivey School of Business, University of Western

Memberships: None

Appearances: None

CURRICULUM VITAE OF
VICTORIA WANG

Experience:	Enbridge Gas Inc.
	Manager, Billing 2020
	Supervisor, Billing 2019-2020
	Enbridge Gas Distribution Inc.
	Supervisor, Billing 2017-2018
	Customer Contact Manager 2013 - 2017
Education:	Travel & Tourism Hospitality Diploma Seneca College (2001)
Appearances:	None

CURRICULUM VITAE OF
BOB WELLINGTON

Experience: Enbridge Gas Inc.

Manager, Asset Management Governance & Risk
2022

Manager, Distribution and Transmission Asset Classes
2021

Enbridge Inc.

Manager, Projects
2019

Union Gas Limited

Manager, Station Design
2014

Principal Design Engineer
2013

Maintenance Engineer
2010

Mechanical Design Engineer
2007

District Engineer
2005

Construction Engineer
2005

Pipeline Engineer
2003

Assistant to the Design Engineer
2002

Education:	Bachelors Degree in Mechanical Engineering Lakehead University (2002) Diploma in Mechanical Engineering Technology Lakehead University (2002)
Memberships:	P.Eng - Professional Engineers Ontario PMP – Project Management Institute
Appearances:	None

CURRICULUM VITAE OF
YOUSUF ZAKI

Experience:

Enbridge Inc.

Director, Finance Business Partner, FP&A
September 2018 - present

Manager, Finance Business Partner, FP&A
April 2017 to September 2018

Manager/Sr. Manager, External Reporting
December 2012 to April 2017

Manager, Corporate Accounting
June 2012 to December 2012

PricewaterhouseCoopers LLP, Calgary, Canada

Senior Manager
January 2010 to June 2012; August 2007 to October 2009

Manager (May 2006 to July 2007)

KPMG LLP, Edmonton, Canada

Senior Manager, Public Companies Audit Group
November 2009 to December 2010

PricewaterhouseCoopers, Karachi Pakistan
(Operating as A. F. Ferguson & Co.)

Various positions leading to Sr. Manager Audit & Business Advisory Group
March 1997 to May 2006

Education:

Bachelor of Commerce
University of Karachi, Pakistan (1995)

Master of Business Administration (specialization in Digital Transformation)
McMaster University (September 2021)

Memberships:	Chartered Professional Accountant, Canada - CA & CPA, Alberta (September 2010) Chartered Accountant, Pakistan (June 2000) Chartered Certified Accountant - ACCA, U.K. (June 1999)
Appearances:	None

CURRICULUM VITAE OF
ERIC ZHANG

Experience: Enbridge Inc. (Alberta)

Manager, Income Tax Reporting – GDS & Special Projects
2022

Manager, Income Tax Reporting – LP Canada & Special Projects
2020

Manager, Income Tax Reporting – GTM Canada
2018

Tax Specialist, Sr. Tax Advisor & Tax Advisor, LP Canada
2008

Sr. Financial Analyst, FP&A – LP Canada
2007

Sr. Financial Analyst, Financial Analyst, Capital Assets – LP Canada
2004

Operating Cost Analyst, Engineering – LP
2003

Maple College (BC)

Accountant
2001

Simon Fraser University (BC)

Teaching Assistant (Part-Time)
1998

China National Technology Import and Export Corporation (China)

Accountant
1995

Education:	Master of Arts, Economics Simon Fraser University (2000) Bachelor of Arts, Accounting Renmin University of China (1995)
Memberships:	CPA, CGA
Appearances:	None

CURRICULUM VITAE OF
BYRON MADRID

Experience: Enbridge Gas Distribution Inc.

Manager Capital Development & Delivery
2019

Senior Manager Asset Management, Major Project
2016

Senior Manager Engineering & Construction, GTA Project
2012

Manager Project Planning, GTA Project
2012

Manager Operations, Central Region West
2008

Manager Accelerated Mains Repl. & Construction
2005

Manager Sales & Construction, Toronto Region
2004

Construction Manager, Toronto Region
2003

Engineering Project Manager, Engineering Construction
2001

Manager Drafting, Distribution Planning
1999

Supervisor Planning & Records, Western Region
1997

Supervisor System Design / Special Projects
1993

Supervisor Pipeline Inspection
1992

Construction Pipeline Inspector, Engineering Services
1992

Special Foundation Systems Company

Construction Estimator
1990

Education: B. Eng. (Civil Engineering), 1990
Ryerson University

Memberships: PEO

Appearances: (Ontario Energy Board)
EB-2012-0451 GTA Project

CURRICULUM VITAE OF
CATHERINE PENNINGTON

Experience:

Enbridge Gas Inc.

Manager, Community & Indigenous Engagement, Eastern Canada
(Ontario, Quebec, Maritimes)
2021

Enbridge Gas Distribution

Manager, Community & Indigenous Engagement, British Columbia/
NWT/Athabasca
2017

Director, Community Partnerships & Sustainability
Enbridge Northern Gateway Project (NGP) LP.
2015

Senior Manager, Community Partnerships
Enbridge Northern Gateway Project (NGP) LP.
2012

Supervisor, Indigenous Engagement, Education & Training
Enbridge Northern Gateway Project (NGP) LP.
2010

EnCana Corp

Senior Aboriginal Relations Advisor, Aboriginal & Corporate Relations
2005

Education:	Tech University Professional Master's Degree in Clinical and Health Psychology (in progress) Thompson Rivers University Graduate Studies in Counselling Mount Royal University Certificate in Conflict Resolution, Mediation & Negotiation University of Victoria Indigenous Governance Studies Justice Institute of BC Child Protection Delegation University of Victoria BA Human and Social Development
Memberships:	Canadian College of Canadian College of Professional Counsellors and Psychotherapists (CCPCP) Canadian Counselling & Psychotherapy Association (CCPA) Metis Nation of British Columbia, Citizen
Appearances:	(Ontario Energy Board) EB-2022-0086 EB-2022-0157 (National Energy Board) OH-4-2011 GHW-002-2018

CURRICULUM VITAE OF
Cody Wood

Experience:	Enbridge Gas Inc.
	Specialist Energy Transition, Carbon and Energy Transition Planning 2021
	Sr. Advisor Long Range Planning, Distribution Optimization Engineering 2020
	Advisor Long Range Planning, Distribution Optimization Engineering 2019
	Enbridge Gas Distribution Inc
	Advisor Long Range Planning, Distribution Planning 2016
	Advisor Network Planning, Distribution Planning 2013
	Sr Analyst, Planning and Design 2011
Education:	Master of Applied Science, Chemical Engineering University of Toronto (2011)
	Bachelor of Applied Science, Chemical Engineering University of Toronto (2009)
Memberships:	P.Eng – Professional Engineers Ontario
Appearances:	None

CURRICULUM VITAE OF
FAHEEM AHMAD

Experience:	Enbridge Gas Inc.
	Specialist, Customer Portfolio and Policy 2016
	Manager, Customer Portfolio and Policy 2010
	Program Manager, Financial Assessment 2007
	Supervisor, Gas Supply Analysis 2006
	Program Manager, Portfolio Management 2004
	Program Manager, Capital Appropriations 2003
	Senior Advisor, Financial Business Performance 2001
Education:	Certified Management Accountant (CMA) Society of Management Accountants, 2004
	Master of Business Administration Wilfred Laurier University, 1999
	Master of Science, Electrical Engineering University of Engineering and Technology, Lahore, Pakistan, 1992
Memberships:	Chartered Professional Accountants of Ontario
	Professional Engineers of Ontario
Appearances:	(Ontario Energy Board)
	EB-2020-0094 EB-2017-0147

EB-2017-0261
EB-2016-0004
EB-2011-0354
EB-2011-0277
EB-2010-0146

CURRICULUM VITAE OF
MOHAMAD CHEBARO

Experience:	Enbridge Gas Inc.
	Director, Integrity 2022
	Senior Strategist, Operations 2022
	Manager, Electrical Controls and Energy Systems 2019
	Enbridge Gas Distribution Inc.
	Manager, Engineering 2017
	Gazifère Inc. (an Enbridge Company)
	Manager, Operations 2015
	Enbridge Liquids Pipelines Inc.
	Senior Engineer, Supervisor, Manager, Integrity 2011
	C-FER Technologies Inc.
	Engineer in Training to Research Engineer 2005
Education:	Bachelor of Science (Mechanical Engineering) University of Alberta
	Master of Arts (Leadership) University of Guelph
Memberships:	Professional Engineers Ontario The Association of Professional Engineers and Geoscientists of Alberta The Project Management Institute

Appearances: (Régie de l'énergie - Québec)

Requête 3969-2016

CURRICULUM VITAE OF
MALINI GIRIDHAR

Experience: Enbridge Gas Inc.

Vice President, Business Development and Regulatory
2019

Enbridge Gas Distribution Inc.

Vice President, Market Development, Regulatory and Public Affairs
2018

Vice President, Business Development, Energy Conservation and Public Affairs
2016

Vice President, Business Development
2015

Vice President, Gas Supply
2013

Senior Director, Gas Supply and GTA Project
2012

Director, GTA Project
2011

Director, Energy Supply and Policy
2007

Manager, Rate Research and Design
2003

Manager, Rate Design
1999

Manager, Rate Research
1997

Financial Analyst, Financial Studies
1994

Borealis Energy Research Consultants

Consultant
1994

Gas and Fuel Corporation of Victoria, Australia

Senior Analyst, Tariffs
1992

Economic Analyst
1989

Education: Chartered Financial Analyst, 2005

Master of Philosophy (Econometrics)
University of Madras, India, 1988

Master of Arts (Economics)
Gokhale Institute of Politics and Economics, India, 1987

Appearances: (Ontario Energy Board)

EB-2020-0091
EB-2012-0451
EB-2010-0333
EB-2010-0231
EB-2008-0106
EB-2008-0219
EB 2006-0034
EB-2005-0551
EB-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
RP-1999-0001
EBRO 497

(National Energy Board)
RH-001-2013
RH-003-2011

(Régie de l’énergie)
R-3537-2004
R-3464-2001
R-3430-99
R-3406-98

CURRICULUM VITAE OF
STUART MURRAY

Experience:	Enbridge Gas Inc.
	Manager, Strategic Financial Evaluations 2021
	Manager, Investment Review and Capital FP&A 2019
	Senior Manager, Investment Review 2013
	Manager, Investment Review and Economic Analysis 2011
	Manager, Financial Assessment 2006
Education:	Master of Business Administration McMaster University (1995)
	B.A. Economics, Administrative & Commercial Studies University of Western Ontario (1993)
Memberships:	None
Appearances:	None

CURRICULUM VITAE OF
ROBERT RUTITIS

Experience:	Enbridge Gas Inc.
	Supervisor, Finance Rebasing Strategy 2021
	Supervisor, Reporting and Research 2019
	Enbridge Gas Distribution Inc.
	Team Lead, Reporting and Research 2018
	Specialist, Accounting Operations 2017
	Advisor, Financial Reporting 2016
	Algonquin Power & Utilities Corp.
	Senior Auditor, Internal Audit 2015
	Union Gas Limited
	Finance Analyst 2012
Education:	Chartered Accountant / Chartered Professional Accountant (2015)
	Honours Bachelor of Business Administration Wilfrid Laurier University (2011)
Memberships:	Chartered Professional Accountants of Ontario
Appearances:	None

CURRICULUM VITAE OF
JAMES E. SANDERS, P.Eng.

Experience: Enbridge Gas Inc.

Senior Vice President, Operations and Engineering
2023

Senior Vice President, Operations
Vice President, Enterprise Asset and Work Management, EI
2022

Senior Vice President, Operations
Vice President of Engineering and Technical Services, Power Operations,
President, Gazifere, Quebec
2021

Senior Vice President, Operations
President, St. Lawrence Gas, New York
President, Enbridge Gas New Brunswick
President, Gazifere, Quebec
2019

Enbridge Gas Distribution

President, Enbridge Gas Distribution
President, St. Lawrence Gas, New York
President, Enbridge Gas New Brunswick
President, Gazifere, Quebec
2017

Vice President, Engineering and Asset Management
President, St. Lawrence Gas, New York
President, Enbridge Gas New Brunswick
President, Gazifere, Quebec
2015

Vice President, Engineering and Pipeline Integrity
President, Niagara Gas Transmission Ltd.
2013

Director, Market and Business Development
President, Niagara Gas Transmission Ltd.
2011

Director, Storage and Transmission Operations
2008

Manager, Strategic Distribution Alliances
2006

Duke Energy Gas Transmission
Manager, Major Projects
2004

Union Gas
Various Operations, Business Development and Engineering Roles
1989 - 2003

Nuclear Activation Services Ltd.
Manager of Operations
1986

Education: McMaster University
Masters of Engineering and Public Policy
2010-2011

University of Waterloo
Bachelor of Applied Science, Civil Engineering
1981-1986

Memberships: Professional Engineers of Ontario, 1988, 40537201

Appearances: (Ontario Energy Board)
EB-2011-0354
RP-2003-0063
E.B.A. 691
E.B.A. 691
E.B.C. 206,
E.B.A. 670
E.B.A. 700-708
E.B.C. 233-255
E.B.L.O. 253
E.B.C. 213
E.B.A. 687

CURRICULUM VITAE OF
MELINDA YAN

Experience:	Enbridge Gas Distribution Inc. Manager, Operations & Maintenance 2023
	Supervisor, Operations & Maintenance 2020
	Specialist, Finance Alignment 2018
	Supervisor, Business Performance 2015
	Supervisor, Internal Audit 2012
	Manager, Internal Controls 2010
	Accenture Inc. Manager, Control Assurance 2008
	CAA South Central Ontario Senior Auditor 2005
Education:	Chartered Professional Accountant, Certified General Accountant (CPA, CGA) Chartered Professional Accountants of Ontario, 2014 Certified General Accountants of Ontario, 2007
	Certified Fraud Examiner (CFE), Association of Certified Fraud Examiners, 2012
	Certified Internal Auditor (CIA), Institute of Internal Auditors, 2010
	Bachelor of Business Administration (BBA)

	University of Toronto, 2003
Appearances:	None

Lawrence Kaufmann

Resume

September 2022

Address: 12520 Central Park Drive
Austin, Texas 78732
(608) 443-9813 (cell)

Education:

	Ph.D.:	Economics, University of Wisconsin-Madison, 1993
	BA & MA:	Economics, University of Missouri-Columbia, 1984
	High School:	St. Louis University High, St. Louis, MO, 1980

Relevant Work Experience, Primary Positions:

February 2021 – present: President, LKaufmann Consulting
Senior Advisor, Black & Veatch Knowledge Network

December 2008 – February 2021: President, LKaufmann Consulting
Senior Advisor, Pacific Economics Group and Navigant Consulting
Fellow, Canadian Energy Research Institute

Advise companies and public agencies, particularly energy utilities and regulators, on various regulatory and industry restructuring issues. Duties include consultation on performance-based regulation (PBR), developing service quality incentive plans, analyzing appropriate code of conduct policies for competitive markets, and providing supporting empirical research. Duties involve preparing public testimony and written reports, overseeing empirical research, client contact and briefings, and public presentations.

January 2001 – December 2008:Partner, Pacific Economics Group, Madison, WI
November 1998 – December 2000: Vice President, Pacific Economics Group, Madison, WI

Advise energy utilities and regulators on various industry restructuring issues. Duties include consultation on performance-based regulation (PBR), developing service quality incentive plans, analyzing appropriate code of conduct policies for competitive markets, and providing supporting empirical research. Duties involve preparing public testimony and written reports, overseeing empirical research, client contact and briefings, and public presentations.

August 1993 – October 1998: Senior Economist, Christensen Associates, Madison, WI

Assisted in the development and evaluation of PBR plans for energy utilities and other regulated enterprises. Duties included theoretical and empirical research (including the estimation of total factor productivity trends), written reports, client contact and briefings, public presentations, and monitoring regulatory trends in the United States and overseas.

January 1993 - July 1993: Research Assistant to Dr. Robert Baldwin, Department of Economics, University of Wisconsin-Madison

Project investigated whether dumping penalties imposed by the United States have led to a diversion of imports from the nations on which the duties were assessed to other exporters.

January 1991 - May 1993: Dissertation research on the impact of foreign investment on Mexican firms.

Dissertation examined whether there has been any spillover of advanced multinational technologies to competing Mexican firms. Research included development of a theoretical model of spillovers through Mexican recruitment of multinational personnel, interviews and data collection in Mexico, and empirical tests of theoretical conclusions. Dissertation research was funded through a fellowship from the Mellon Foundation.

June 1989 - December 1990: Research Associate, Credit Union National Association, Madison, WI

Initiated and assisted on several long-term research projects, including the assessment of capital positions at Corporate credit unions, comparing the asset portfolios of credit unions and banks, and analysis concerning the development of credit union industries in Poland and Costa Rica.

January 1988 - August 1988: Investment Banking Officer and Associate Economist, Centerre Bank, St. Louis, MO

April 1985 - December 1987: Assistant Economist, Centerre Bank, St. Louis, MO

As Assistant Economist, the primary duty was to prepare country risk reports on nations to which the bank was lending. As Associate Economist and Investment Banking Officer, duties expanded to include writing a twice-weekly column on interest rate trends and preparing special reports on regional, national and international economic trends for senior management.

August 1983 - December 1984 and four semesters during the period September 1988 - May 1993:

Teaching assistant for classes in introductory microeconomics, introductory macroeconomics, international economics and the history of economic thought.

Professional Memberships: American Economic Association
National Association of Business Economists

Foreign Language Proficiency: Spanish

Major Consulting Projects:

1. Plan design, policy testimony, total factor productivity and cost benchmarking in support of a performance-based regulation plan, EGI, 2021-2023.

2. Plan design, policy testimony, cost benchmarking in support of a performance-based regulation plan. Plan confidential at this time, 2021-2022.
3. Plan design, policy testimony, cost benchmarking in support of a performance-based regulation plan. Eversource Energy, 2021-2022.
4. Advise on appropriate labor and consumer price indices in labor compensation dispute. Crescent River Port Pilots' Association.
5. Plan design, policy testimony and cost benchmarking study in support of performance-based regulation plan. National Grid/Boston Gas, 2020-2021.
6. Advice on PBR strategy and application. Fortis BC, 2018-2020.
7. Policy testimony and cost benchmarking study in support of performance-based regulation plan. National Grid/Massachusetts Electric, 2018-2019.
8. Confidential advice on regulatory strategy. Client wishes to remain anonymous at this time, 2018.
9. Advice on regulatory environment and investment strategy. Client wishes to remain confidential at this time, 2017-2018.
10. Escalators for operating and construction expenses. Epcor Water West, 2017-18.
11. Rebuttal testimony on cost and wage benchmarking. Puerto Rice Electric Power Authority, 2016-2017.
12. Review and respond to comments on Epcor Water testimony. Epcor Water, 2016.
13. Review of regulatory framework to encourage efficient investment and accommodate uncertainty. Client wishes to remain confidential at this time, 2016.
14. Assessment of Ontario Power Generation ratemaking proposal. Ontario Energy Board, 2016.
15. Testimony on cost and wage benchmarking. Puerto Rico Electric Power Authority, 2016.
16. Testimony recommending updated inflation escalators in performance-based regulation plan. Epcor Water, 2015-2016.
17. Testimony recommending productivity factor for updated performance-based regulation plan. Epcor Water, 2015-2016.
18. Finalize reliability standards for electricity distributors in Ontario. Ontario Energy Board, 2015-2016.
19. Testimony on benefits of expanding bidding process for expansion of Alliant Riverside Energy Center facility. Associated Builders and Contractors of Wisconsin, 2015.
20. Cost benchmarking study. Puerto Rico Electric Power Authority, 2015.
21. Multi-client “Utility of the Future” and PBR study. Clients wish to remain confidential at this time, 2015.
22. Advise on benchmarking methods for electricity distribution. ANEEL, Brazilian Electricity Regulatory Agency, 2014.

23. The impact of gas extension tariffs on the development of the CNG market in Wisconsin. Reinhart Boerner Van Deuren on behalf of Kwik Trip, 2014.
24. TFP study and review of price controls in New Zealand. New Zealand Electricity Network Association, 2014.
25. Advise on benchmarking and regulatory issues in Toronto Hydro Custom IR application. Ontario Energy Board, 2014-15.
26. Advise on interrogatory responses. Consumer Energy Coalition of British Columbia, 2014.
27. Survey and analysis of implementation issues associated with customer-specific reliability metrics. Ontario Energy Board, 2013-15.
28. Empirical analysis and recommendation of appropriate reliability benchmarks. Ontario Energy Board, 2013-15.
29. Cost of service review (transmission and distribution operations) and cost benchmarking for Israel Electric Corporation. Public Utility Authority of Israel, 2013-15.
30. Value of reliability improvements from undergrounding power lines. Wisconsin Public Service, 2013.
31. Advise on and assess gas distribution incentive regulation plans. Ontario Energy Board, 2013-14.
32. Advise on price control application. UK Power Networks, 2013.
33. Advise on electricity distribution incentive regulation plans and other aspects of renewed regulatory framework for electricity. Ontario Energy Board, 2012-13.
34. Response to Productivity Commission Report on Energy Network Regulatory Frameworks. Energy Safe Victoria, 2012.
35. Statement on appropriate opt-out policies for smart meters to Wisconsin Public Service Commission. SMART Water, 2012.
36. Submission to Australia's Productivity Commission on the role of benchmarking in utility regulation. Energy Safe Victoria, 2012.
37. Assist Staff on review of cost of service applications for Enbridge Gas Distribution and Union Gas. Ontario Energy Board, 2012.
38. Assist with responses on data requests in testimony on alternative regulation plan. Potomac Electric Power, 2011-12.
39. Assess incentive regulation plans for Union Gas and Enbridge Gas Distribution in Ontario. Ontario Energy Board, 2011.
40. Advise on demand-side management and decoupling plans, and utility involvement in conservation and renewable energy businesses. ATCO Gas, 2011.
41. Advise on defining and measuring utility performance and the use of performance measures and standards in electric utility regulation. Ontario Energy Board, 2011-12.
42. Advise on rate mitigation strategies. Ontario Energy Board, 2011.
43. Advise on PBR strategy in Alberta. EDTI, 2011-12.

44. Estimate total factor productivity trend for gas distributors in New Zealand. Powerco, on behalf of industry, 2011.
45. Evaluation of reliability standards and alternative regulatory approaches for maintaining the reliability of electricity supplies. Ontario Energy Board, 2010-12
46. Prepare submission on rule change application and respond to consultant reports on TFP spreadsheet simulations and the impact of the regulatory framework on energy safety. Energy Safe Victoria, 2010.
47. Research on operating productivity and input price changes and testimony in support of an incentive-based formula to recover changes in gas distribution operating expenses. National Grid, 2010.
48. Prepare submission on rule change application and respond to consultant reports on TFP methodology. Essential Services Commission, 2010.
49. Advise on submission on rule change application. Victoria Department of Primary Industries, 2010.
50. Productivity research Victoria gas distribution industry, Essential Services Commission, 2010.
51. Productivity research Victorian power distribution industry, Essential Services Commission, 2010.
52. Advise on revenue decoupling and alternative regulatory strategies in context of upcoming gas distribution rate case. Northwest Natural Gas, 2009-2010.
53. Advise on revenue decoupling. Ontario Energy Board, 2009-2010.
54. Develop a “top down,” econometrically-based measure of reductions in gas consumption resulting from utility DSM programs, and evaluate the merits of this approach compared to the existing “bottom up” methodology. Ontario Energy Board, 2009-2010.
55. Respond to proposals to amend National Energy Regulatory Framework to allow alternative approaches to incentive regulation. Essential Services Commission, 2009-2010.
56. Evaluate consultant reports and prepare submission on the update of price control formulas. New Zealand Energy Network Association, 2009.
57. Evaluate consultant reports in review on alternate regulatory arrangements. Essential Services Commission 2009.
58. Estimate TFP trend for New Zealand electricity distributors. New Zealand Energy Network Association 2009.
59. Evaluate consultant reports in review on alternate regulatory arrangements. Essential Services Commission 2009.
60. Submission on the application of total factor productivity in utility network regulation. Essential Services Commission, 2008-09.
61. Estimate total factor productivity trends, benchmark gas distribution cost performance, and testify in support of research. Bay State Gas, 2008-09.

62. Advise on appropriate regulatory treatment of early termination fees in retail energy markets. Essential Services Commission, 2008.
63. Advise on appropriate regulation of gas connection charges. Essential Services Commission, 2008.
64. Advise on appropriate cost of capital. Jamaica Public Service, 2008.
65. Estimate total factor productivity trends and benchmark bundled power cost performance for use in a productivity based regulation plan. Jamaica Public Service, 2008.
66. Estimate gas distribution total factor productivity trends. Essential Services Commission, 2008.
67. Update estimate total factor productivity trends electricity distributors. Essential Services Commission, 2008.
68. Respond to productivity and benchmarking studies. New Zealand Electricity Networks Association, 2008.
69. Response to comments on appropriate productivity and input price measures to be used to update gas distributors' operating expenses. Essential Services Commission, 2007-08.
70. Advise on update of performance based regulatory plan for power distributors, including recommendations for total-factor productivity based X factors. Ontario Energy Board, 2007-08.
71. Estimate lost wage and health damages. Wolfgram and Associates, 2007.
72. Response to critique of X factor recommendations. Ontario Energy Board, 2007.
73. Review of benchmarking methods and proposed benchmarking for the pricing of unbundled copper local loop. Telecom NZ, 2007.
74. Report on the relationship between revenue decoupling and performance-based regulatory mechanisms. Massachusetts energy distribution companies, 2007.
75. Research on revenue decoupling experience in California. National Grid, 2007.
76. Report on regulatory reforms needed to facilitate demand response, advanced metering infrastructure and energy efficiency objectives. Essential Services Commission, 2007.
77. Estimate lost wage and health damages. Wolfrgram and Associates, 2007.
78. Evaluation of gas distribution construction cost trends. Essential Services Commission, 2007.
79. Appropriate productivity trends and labor inflation rates to be used to adjust operating expenses in incentive-based ratemaking. Essential Services Commission, 2007.
80. Testify in support of rate adjustment under a performance based regulation plan. Bay State Gas, 2007.
81. Report on service quality regulation and benchmarking, submitted as expert witness testimony. Detroit Edison, 2007.

82. Develop and testify in support of alternative regulation plan for gas distribution services. Client confidential at this time, 2007.
83. Evolution of energy asset management companies and outsourcing relationships. Davidson Kempner Advisers, 2007.
84. O&M partial factor productivity trends for gas distribution services. Essential Services Commission, 2006-07.
85. Principles for designing gas supply PBR plans and assessing the impact of retail gas costs. DLA Piper Rudnick, 2006-07.
86. Framework for analyzing appropriate early termination fees in competitive retail electricity markets. Essential Services Commission, 2006-07.
87. Testify in support of exogenous factor recovery of revenues lost due to declining natural gas usage. Bay State Gas, 2006.
88. Service quality benchmarking. Canadian Electricity Association, 2006.
89. Analyze natural resource and recreational damage calculations for environmental damage to trout stream. Michael, Best and Friedrich, 2006.
90. Evaluate outsourcing contract and report benchmarking Envestra's gas distribution operations and maintenance expenses. ESCOSA, 2006.
91. Report on the use of partial factor productivity trends in the updated gas access arrangement. Essential Services Commission, 2006.
92. Advise on approved X factors and total factor productivity trends in approved alternative regulation plans for electric utilities. Central Maine Power, 2006.
93. Estimate total factor productivity and input price trends power distribution industries in all Australian States and territories, Essential Services Commission, 2006.
94. Develop and testify in support of an alternative regulation plan for gas distribution services. Client wishes to remain confidential at this time, 2006.
95. Develop and testify in support of an alternative regulation plan for gas distribution services. Client wishes to remain confidential at this time, 2006.
96. Testimony on treatment of outsourcing contract costs and labor-nonlabor cost allocations. Essential Services Commission, 2005-06.
97. Incorporate lessons from incentive regulation and benchmarking overseas into newly-established regulatory framework for nation's electric utilities. Bundesnetzagentur (BNA), Bonn Germany, 2005-2006.
98. Submission to Ministerial Council on Energy related to Regulatory Rulemaking. Essential Services Commission, 2005.
99. Evaluation of early termination fee policies for energy retailers. Essential Services Commission, 2005.
100. Advise on alternative regulation strategies for gas distribution services. Client wishes to remain confidential at this time, 2005-2006.

101. Report on comprehensive framework for using performance indicators to evaluate market power abuses, efficiency gains, and the distribution of benefits to stakeholders. Essential Services Commission, 2005.
102. Evaluation of regulatory options and estimation of total factor productivity for Port of Melbourne Corporation. Essential Services Commission, 2005.
103. Evaluation of regulatory options for taxi services in Melbourne, Australia. Essential Services Commission, 2005.
104. White Paper advising government agency on regulatory reform of State's electric power industry. Department of Natural Resources Newfoundland and Labrador, 2005.
105. Review report on CAPM and differences in beta between rural and urban power distributors. Essential Services Commission, 2005.
106. Develop "incentive power" model and apply towards evaluation of regulatory options in Victoria, Australia. Essential Services Commission, 2004-2005.
107. Review report on labor price forecasts for Victoria, Australia. Essential Services Commission, 2004-2005.
108. Develop and testify in support of performance-based regulation plan. Bay State Gas, 2004-2005.
109. Review of gas regulatory framework in Ontario, Canada. Ontario Energy Board, 2004-2005.
110. Benchmarking gas distribution operations. Powerco, Vector, NGC (New Zealand), 2004.
111. Report on methodologies for updating CPI-X price controls and assemble US gas transmission pipeline data, to be used in update of price controls for gas transmission services. Comision Reguladora de Energia (Mexico), 2004-2005.
112. Benchmark comprehensive power and water utility operations. Aqualectra (Curacao, Netherlands Antilles), 2004-2005.
113. Benchmarking power distribution operations. Energex and Ergon Energy, 2004.
114. Regulatory treatment of hub and storage facilities. NICOR Gas, 2004.
115. Review and comment on proposed service quality regulation. Essential Services Commission, 2004.
116. Review and contribute to report on ring fencing policies. Essential Services Commission, Victoria Australia, 2004.
117. Estimate lost earnings in litigation case. Wolfgram and Gherardini, 2004.
118. Respond to Productivity Commission report on Gas Access Arrangements. Essential Services Commission, Victoria Australia, 2004.
119. Analysis of PBR plans for rates and service quality worldwide. Jamaica Public Service, 2004.
120. Undertake benchmarking and total factor productivity studies in support of an X factor in a performance-based regulatory plan. Jamaica Public Service, 2003-2004.
121. Evaluate incentive regulation options. Questar Gas, 2003-2004.

122. Project evaluating implementation of total factor productivity in energy utility regulation. Essential Services Commission, Victoria Australia, 2003-2005.

123. Evaluate incentive regulation reports commissioned by Australian Competition and Consumer Commission. Essential Services Commission, Victoria Australia, 2003.

124. Evaluate proposed regulatory thresholds regime. Powerco New Zealand, 2003.

125. Evaluate benchmarking methods and regulatory reform proposals. Jamaica Public Service, 2003.

126. Evaluate proposals for service quality regulation in province of Ontario. Hydro One, 2003.

127. Evaluate benchmarking methods and regulatory reform proposals. Overseas New Zealand client wishes to remain confidential at this time, 2003.

128. US-Japan power transmission benchmarking. Central Research Institute of Electric Power Industry (Japan), 2003.

129. Benchmarking power distribution operations and maintenance (O&M) costs benchmarking and O&M productivity growth. Superintendente de Electricidad (Bolivia), 2003.

130. Benchmarking gas distribution operations and maintenance expenses. ACTEW (Australia), 2003.

131. Estimate lost earnings in wrongful death case. Wolfgram and Gherardini, 2003.

132. Advise on updating incentive plan for demand-side management. Hawaiian Electric, 2003.

133. Estimate and testify in support of damages in patent infringement case, Trombetta, LLC vs. Dana Corporation and AEC. Ryan, Kromholz and Mannion, 2003.

134. Analyze service quality proposals for a natural gas distributor, recommend modifications and testify in support of recommendations. New England Gas, 2002-2003.

135. Develop a service quality incentive plan for power distributors in Queensland, Australia; the plan is to be developed through a consultative process between the companies, major customer groups, and the regulator. Queensland Competition Authority, 2002-2003.

136. Consultation on developments regarding Wisconsin Electric's "Power the Future" initiative. Fidelity Investments, 2002.

137. Confidential report on US experience with benchmarking and alternative regulation. Central Research Institute of Electric Power Industry (Japan), 2002-2003.

138. Confidential report on capital cost measurement. Central Research Institute of Electric Power Industry (Japan), 2002-2003.

139. Report on merits and feasibility of benchmarking New Zealand power distributors. United Networks, 2002.

140. Impact of gas marketing expenditures on residential gas consumption. Envestra, 2002.

141. Advise on index-based performance-based regulation plan for a power distribution utility. Client wishes to remain confidential at this time, 2002.

142. Estimate productivity trend gas distribution industry and testify in support of trend. Boston Gas, 2002-2003.

143. Gas distribution benchmarking study. TXU Australia, Envestra and Multinet, 2002.

144. Benchmarking power transmission cost. Transend, 2002.

145. Advise on the development of an incentive regulation proposal for a North American power transmission utility. Hydro One Networks, 2001-2002.

146. Application of productivity and econometric benchmarking in an update of an incentive regulation plan. Ameren UE, 2001-2002.

147. Litigation regarding violations of Unfair Trade Practices Act for Tamoxifen, Taxol, and Buspar prescription drugs. Miner, Barnhill, and Galland, P.C., 2001-2002.

148. Recommend reforms of Western Australia power market, including reforms of wholesale markets, retail markets, structure of the incumbent utility, and regulatory arrangements; work was summarized in a report to the Electricity Reform Task Force. Western Power, 2001.

149. Faculty member of Regulatory Training Seminar in Bolivia. Seminar organized by the Public Utility Research Center and sponsored by SIRESE, 2001.

150. White Paper on implementing total factor productivity measures in regulation for the Utility Distributor's Forum. CitiPower, 2001.

151. Electronic forum on service quality incentives and research topics. Edison Electric Institute, 2001.

152. Economies of scale and scope in power services. Western Power, 2001.

153. Report evaluating the merits of alternative benchmarking methods and their application to energy distributors. Electricity Supply Association of Australia, 2001.

154. Response to report on benchmarking and incentive regulation. Client confidential at this time, 2000-2001.

155. Report on consistency of Price Determination with legislative mandates. TXU Australia, 2000-2001.

156. Develop methodology for service quality benchmarking and construction of appropriate deadbands. Massachusetts Gas and Electric Distribution Companies, 2000.

157. Advise on Performance-Based Regulation strategy, including development of a service quality incentive. BCGas, 2000.

158. Power distribution benchmarking. Queensland Competition Authority, 2000.

159. Develop and testify in support of service quality incentive. Western Resources, 2000.

160. Response to regulatory proposals for "ring fencing" operations. CitiPower, 2000.

161. Benchmarking evaluation of power distribution costs. Client name withheld, 2000.

162. Updated White Paper on Metering and Billing Competition in California. Edison Electric Institute, 2000.
163. Economies of scale and scope in power delivery and metering services. Massachusetts Utility Distribution Companies, 2000.
164. Evaluation of merger benefits. Client wishes to remain anonymous at this time, 2000.
165. Response to study on benchmarking capital spending. CitiPower, 2000.
166. Response to incentive regulation proposals of Pareto Economics in Victorian distribution price review. CitiPower, 2000.
167. Estimate scale economies in power generation, scope economies between power transmission and power generation, and implications for public policy in Western Australia. Western Power, 2000.
168. White Paper on “best practice” regulation and evaluation of price and non-price regulation of energy and water utilities in Australia, the US, and the UK. Electricity Association of New South Wales, 2000.
169. Power transmission benchmarking. Client confidential at this time, 2000.
170. Development of performance-based regulation plan for power distribution services. Texas Utilities, 2000.
171. Response to UMS benchmarking study on O&M costs. Victorian power distributors, 2000.
172. Response to Consultation Paper on Detailed Proposal for Form of the Price Control. CitiPower, 1999-2000.
173. White Paper on cost structure of power distribution. Australian power distributors (coalition contact: the Electricity Supply Association of Australia), 1999-2000.
174. White Paper on benchmarking principles and applications. Victorian power distributors, 1999-2000.
175. Service quality testimony. Hawaiian Electric, Maui Electric, and Hawaii Electric Light, 1999.
176. Faculty member of Regulatory Training Seminar in Argentina. Seminar organized by the Public Utility Research Center and sponsored by Enargas, 1999.
177. Service quality benchmarking study. Southern California Edison, 1999.
178. US-Australia performance benchmarking study. Victorian Distribution Businesses, Victoria, Australia, 1999.
179. Cost benchmarking for power delivery and customer services. Southern California Edison, 1999.
180. Development of Service Quality Incentive and Testimony in Support of Plan. Oklahoma Gas and Electric, 1999.
181. Evaluation of Intervenor Assessments of Customer Benefits in Proposed Merger. Western Resources, 1999.

182. Response to Regulator Proposals for Regulatory Methodology, Efficiency Measurement and Benefit-Sharing, and Form of Distribution Price Controls. CitiPower, Australia, 1999.
183. Response to Incentive Regulation Proposal of Australian Competition and Consumer Commission. CitiPower, Australia, 1998.
184. Report on Metering and Billing Competition in California. Edison Electric Institute, 1998-99.
185. Evaluation of Economies of Vertical Integration for Electric Utilities in Illinois. Edison Electric Institute, 1998.
186. Assessment of Cost Performance of Power Distributors in the United States and Australian state of Victoria. Victorian Power Distributors, 1998.
187. Formal Response to Regulatory Proposals for Price Cap Regulation/Development of Regulatory Options. Victorian Power Distributors, 1998.
188. Development of Service Quality Incentive and Testimony in Support of Plan. Louisville Gas and Electric/Kentucky Utilities, 1998.
189. Regulatory Support for Overall PBR Strategy. Louisville Gas and Electric/Kentucky Utilities, 1998.
190. Testimony on Impact of Brand Name Restrictions in Maine’s Retail Energy Markets. Edison Electric Institute, 1998.
191. Development of Service Quality Incentive. Hawaiian Electric, 1998.
192. Regulatory Support for Comprehensive PBR Strategy and Feasibility of Retail Competition in Power Supply Services. Hawaiian Electric, 1997-98.
193. White Paper on Controlling Cross-Subsidization in Electric Utility Regulation. Edison Electric Institute, 1997-98.
194. White Paper on Cost Structure of Integrated Electric Utilities and Implications for Retail Competition. Edison Electric Institute, 1997-98.
195. Regulatory Support for a Price Cap Plan for Combination Utility. San Diego Gas and Electric, 1997-98.
196. White Paper on Price Cap Methodologies for Power Distributors in Victoria, Australia. Victorian Power Distributors, 1997.
197. Development of a Price Cap Plan for a Local Gas Distribution Utility. Atlanta Gas Light, 1997.
198. White Paper on Price Cap Regulation for Power Distribution. Edison Electric Institute, 1997.
199. Comprehensive Report on Performance-Based Regulatory Options for a Local Gas Distribution Utility. Atlanta Gas Light, 1997.
200. White Paper on Use of Electric Utility Brand Names in Competitive Markets. Edison Electric Institute, 1997.
201. Options for Price Cap Regulation for Power Distribution in Colombia. Comision Reguladora de Energía y Gas en Colombia, 1997.

202. Options for Performance-Based Regulation for Power Transmission and Stranded Cost Recovery for an Electric Utility. Client wishes to remain confidential at this time, 1997.
203. Regulatory Support for an Index-Based Incentive Plan of a Local Gas Distribution Utility. BCGas, 1997.
204. Recommendations for a service quality incentive plan. Hawaiian Electric, 1997.
205. Survey of Service Quality Incentive Plans and Assessment of Options. BCGas, 1996.
206. Regulatory Support for a Price Cap Plan. Southern California Gas, 1996.
207. Determination of service territories for newly-privatized gas distributors in Mexico. Comisión Reguladora de Energía, 1996.
208. Assessment of Regulatory Options for a Public Enterprise. United States Postal Service, 1996-97.
209. Regulatory support for a Price Cap Plan of a Local Gas Distribution Utility. Brooklyn Union Gas, 1996.
210. Development of a Price Cap Plan for the Gas Operations of a Combination Utility. Client wishes to remain confidential at this time, 1996.
211. Assessment of Options for Service Quality Incentives. Client wishes to remain confidential at this time, 1996.
212. Development of a Price Cap Plan for an Electric Utility. Client wishes to remain confidential at this time, 1996.
213. Assessment of Lessons from Natural Gas Restructuring for Electric Utilities. Client wishes to remain confidential at this time, 1996.
214. Advised on the Establishment of a Regulatory Framework for the Mexican Natural Gas Industry. Comision Reguladora de Energia, 1996.
215. White Paper on Unbundling Electric Utility Services. Edison Electric Institute, 1996.
216. Regulatory support for a Price Cap Plan of a Local Gas Distribution Utility. Boston Gas, 1995.
217. Development of a Price Cap Plan for a Local Gas Distribution Utility. Client wishes to remain confidential at this time, 1995.
218. Assessment of Incentive Regulation Options in the Context of a Proposed Restructuring of the Electric Utility Industry. Client outside of the United States wishes to remain confidential at this time, 1995.
219. Organization of a Conference on Price Cap Regulation. Edison Electric Institute, 1995.
220. Development of Regulatory Strategies Regarding the Transition to Retail Competition in the Electric Power Industry. Niagara Mohawk Power, 1995.
221. Assessment of Incentive Regulation Options in the Context of a Proposed Restructuring of the Electric Utility Industry. Alberta Power Limited, 1995.
222. Development of a Price Cap Plan for the Gas Operations of a Combination Utility. Public Service Electric and Gas, 1995.

223. Development of a Price Cap Plan for the Electric Operations of a Combination Utility. Public Service Electric and Gas, 1995.

224. White Paper on Incentive Regulation Theory and Its Application to Electric Utilities. Electric Power Research Institute, 1994-95.

225. Productivity Trends of U.S. Gas Distributors. Southern California Gas, 1994-95.

226. White Paper on Price Cap Regulation. Edison Electric Institute, 1994.

227. Regulatory Support for a Price Cap Plan. Central Maine Power, 1994.

228. Advanced Benchmarking Methods for U.S. Electric Utilities. Southern Electrical System, 1994.

229. Development of and Regulatory Support for a Price Cap Plan. Niagara Mohawk Power, 1994.

230. Competitive Price Scenarios for Power Markets in the Northeastern U.S. Niagara Mohawk Power, 1993-94.

231. Survey of Price Cap Plans in the U.S. and Abroad. Niagara Mohawk Power, 1993.

Expert Witness Testimony:

1. Before the Ontario Energy Board, evidence on behalf of Enbridge Gas Inc., 2021-2023. Subject: plan design, policy testimony, total factor productivity and cost benchmarking in support of a multi-year, incentive ratemaking plan.

2. Currently in settlement negotiations, client confidential at this time, 2021-2022. Subject: plan design, policy testimony, cost benchmarking in support of a performance-based regulation plan.

3. Before the Massachusetts Department of Public Utilities, evidence on behalf of Eversource Electric, 2021-22. Subject: performance-based regulation and performance benchmarking.

4. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2020. Subject: rebuttal testimony on performance-based regulation and performance benchmarking

5. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2020. Subject: performance-based regulation and performance benchmarking.

6. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2019. Subject: rebuttal testimony on performance-based regulation and performance benchmarking.

7. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2018. Subject: performance-based regulation and performance benchmarking.

8. Before the Puerto Rico Energy Commission, evidence on behalf of the Puerto Rico Electric Power Authority, 2016. Subject: rebuttal testimony on cost and wage benchmarking.

9. Before the Puerto Rico Energy Commission, evidence on behalf of the Puerto Rico Electric Power Authority, 2016. Subject: cost and wage benchmarking.

10. Before the Edmonton City Council, evidence on behalf of Epcor Water and Sewer Inc., 2016. Subject: updated inflation factors in a performance-based regulation plan.

11. Before the Edmonton City Council, evidence on behalf of Epcor Water and Sewer Inc., 2016. Subject: updated inflation factors in a performance-based regulation plan.

12. Before the Wisconsin Public Service Commission, evidence on behalf of Associated Builders and Contractors of Wisconsin, 2015. Subject: assessing the merits of an expanded bidding process for the expansion of the Alliant Riverside Energy Center facility.

13. Before the Ontario Energy Board, evidence on behalf of OEB Staff, 2015. Subject: review of Custom Incentive Regulation proposal and benchmarking evidence of Toronto Hydro.

14. Before the Wisconsin Public Service Commission; evidence on behalf of Kwik Trip, 2014. Subject: surrebuttal testimony on the impact of gas extension tariffs on the development of the CNG marketplace in Wisconsin.

15. Before the Wisconsin Public Service Commission; evidence on behalf of Kwik Trip, 2014. Subject: the impact of gas extension tariffs on the development of the CNG marketplace in Wisconsin.

16. Before the Ontario Energy Board; evidence on behalf of OEB Staff, 2014: Subject: review of Customized Incentive Regulation proposal for Enbridge Gas Distribution.

17. Before the Ontario Energy Board; evidence on behalf of OEB Staff, 2013. Subject: total factor productivity estimation, cost benchmarking, and establishing incentive regulation plans for Ontario electricity distributors.

18. Before the Wisconsin Public Service Commission; evidence on behalf of Wisconsin Public Service, 2013. Subject: sur-surrebuttal testimony on the value of reliability improvements from undergrounding power lines.

19. Before the Wisconsin Public Service Commission; evidence on behalf of Wisconsin Public Service, 2013. Subject: rebuttal testimony on the value of reliability improvements from undergrounding power lines.

20. Before the Wisconsin Public Service Commission; evidence on behalf of SMART Water, 2012. Statement on appropriate opt-out policies for smart meters.

21. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of National Grid, 2010. Subject: rebuttal testimony in support of a net inflation adjustment mechanism applied to operating and maintenance expenditures.

22. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of National Grid, 2010. Subject: empirical support for a net inflation adjustment mechanism applied to operating and maintenance expenditures.

23. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2009. Subject: direct testimony on performance based regulation.

24. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2008. Subject: estimating partial factor productivity growth for O&M expenditures for natural gas distributors.

25. Before the Ontario Energy Board, 2008. Subject: appropriate values for total factor productivity-based productivity factor; benchmarking-based productivity "stretch factors;" and appropriate thresholds for capital investment modules; in an incentive regulation plan for electricity distributors in the Province.

26. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2007. Subject: direct testimony on performance based regulation.

27. Before the Circuit Court of the City of St. Louis, Missouri, Division 9, in Michele Thrash v. Freightliner *et al*, 2007. Subject: deposition testimony on estimated damages for lost income and medical treatment.

28. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2007. Subject: panel testimony on revenue decoupling and performance based regulation.

29. Before the New Zealand Commerce Commission, evidence on behalf of Telecom New Zealand, 2007. Subject: principles for price benchmarking and the merits of alternative methods of benchmarking unbundled copper local loop prices.

30. Before the Circuit Court of the City of St. Louis, Missouri, Division 13, in Anastacia McNutt v. Globe Transport, Inc *et al*, 2007. Subject: deposition testimony on estimated damages for lost income and past and future medical treatment.

31. Before the Michigan Public Service Commission; evidence on behalf of Detroit Edison, 2007. Subject: service quality regulation and benchmarking.

32. Before the Appeal Panel, South Australia, Australia; evidence on behalf of the Essential Services Commission of South Australia, 2006. Subject: the operating expenditures and outsourcing management fee of Envestra Ltd.

33. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2006. Subject: rebuttal testimony on exogenous recovery of revenues lost due to declining natural gas usage.

34. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2006. Subject: direct testimony on exogenous recovery of revenues lost due to declining natural gas usage.

35. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2006. Subject: regulatory treatment of an outsourcing contract to a related corporate party in a power distribution price determination.

36. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2005. Subject: labor and non-labor shares in operating expenditures.

37. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2005. Subject: rebuttal testimony on performance based regulation and benchmarking.

38. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2005. Subject: performance based regulation and benchmarking.

39. Before the New Zealand Commerce Commission, evidence on behalf of Vector and NGC, 2004. Benchmarking evidence for New Zealand gas distributors.

40. Before the New Zealand Commerce Commission, evidence on behalf of Powerco, 2003. Evaluation of total factor productivity and benchmarking evidence in studies undertaken for the Commission.

41. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Boston Gas, 2003. Subject: rebuttal testimony on performance based regulation, total factor productivity measurement and benchmarking

42. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Boston Gas, 2003. Subject: performance based regulation, total factor productivity measurement and benchmarking

43. Before the US District Court for the Western District of Wisconsin, Trombetta, LLC vs. Dana Corporation and AEC, 2003. Subject: estimate damages in solenoid patent infringement case.

44. Before the Rhode Island Public Utilities Commission: evidence on behalf of New England Gas, 2003. Subject: direct testimony on alternative service quality regulation proposals.

45. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2001. Subject: reply to surrebuttal testimony in support of service quality incentive plan.

46. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2000. Subject: rebuttal testimony in support of service quality incentive plan.

47. Before the Supreme Court of Victoria, Australia; evidence on behalf of TXU Australia, 2000. Subject: Whether the regulator’s price determination complied with legal mandates to use price-based incentive regulation.

48. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2000. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

49. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Massachusetts gas and electric distribution companies, 2000. Subject: Service quality benchmarking.

50. Before the Hawaii Public Service Commission; evidence on behalf of Hawaiian Electric, 1999. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

51. Before the Oklahoma Corporation Commission; evidence on behalf of Oklahoma Gas and Electric, 1999. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

52. Before the Kentucky Public Service Commission; evidence on behalf of Louisville Gas and Electric and Kentucky Utilities, 1998. Subject: Rebuttal testimony in support of service quality incentive plan and benefits of companies’ regulatory proposal to low-income customers.

53. Before the Kentucky Public Service Commission; evidence on behalf of Louisville Gas and Electric and Kentucky Utilities, 1998. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

54. Before the Maine Public Utilities Commission, evidence on behalf of the Edison Electric Institute, 1998. Subject: Merits of allowing utility companies to use their brand names in competitive retail energy markets.

55. Before the California Public Utilities Commission, evidence on behalf of the Edison Electric Institute, 1997. Subject: Merits of allowing utility companies to use their brand names in competitive retail energy markets.

Publications:

1. *The Price Cap Designers Handbook* (with M. N. Lowry), Edison Electric Institute, 1995.
2. "The Treatment of Z Factors in Price Cap Plans" (with Mark Newton Lowry), *Applied Economics Letters*, 2: 1995.
3. "Forecasting Productivity Trends of Natural Gas Distributors" (with Mark Newton Lowry), *AGA Forecasting Review*, March 1996.
4. *Performance-Based Regulation for Electric Utilities: The State of the Art and Directions for Further Research* (with Mark Newton Lowry), Palo Alto: Electric Power Research Institute, 1996.
5. *Developing Unbundled Electric Power Service Offerings: Case Studies of Methods and Issues* (with Laurence Kirsch), Washington: Edison Electric Institute, 1996.
6. "A Theoretical Model of Spillovers Through Labor Recruitment", *International Economic Journal*, Autumn 1997.
7. *Branding Electric Utility Products: Analysis and Experience in Related Industries* (with Mark Newton Lowry and David Hovde), Washington: Edison Electric Institute, 1997.
8. "The Branding Benefit", *Electric Perspectives*, November 1997.
9. *Price Cap Regulation for Power Distribution* (with Mark Newton Lowry), Washington: Edison Electric Institute, 1998.
10. *Controlling for Cross-Subsidization in Electric Utility Regulation* (with Mark Meitzen and Mark Netwon Lowry), Washington: Edison Electric Institute, 1998.
11. "Price Caps for Distribution Service: Do They Make Sense?", *Edison Times*, December 1998 (with Eric Ackerman and Mark Newton Lowry).
12. *Economies of Scale and Scope in Power Distribution* (with Mark Newton Lowry), Washington: Edison Electric Institute, 1999.
13. *Competition for Metering, Billing and Information Services: The Experience in California So Far*, Edison Electric Institute, 1999.
14. *Third Party Metering, Billing and Information Services: Further Evidence from California*, Edison Electric Institute, 2000.
15. "Performance Based Regulation of Energy Utilities" (with Mark Newton Lowry), *Energy Law Journal*, 2002
16. "Performance Based Regulation and Business Strategy" (with Mark Newton Lowry), *Natural Gas*, 2003.

17. "Performance Based Regulation and Energy Utility Business Strategy" (with Mark Newton Lowry), *Natural Gas and Electric Power Industries Analysis 2003*, Financial Communications, Houston, 2003

18. "Price Control Regulation in North America: Role of Indexing and Benchmarking," (with M.N. Lowry and L. Getachew), *Proceedings of Market Design Conference*, Stockholm, Sweden, 2003.

19. "Performance Based Regulation Developments for Natural Gas Utilities" (with Mark Newton Lowry), *Natural Gas and Electricity*, 2004.

20. "Incentive Power and the Design of Regulatory Regimes," *Network*, December 2005.

21. "Alternative Regulation for Electric Utilities" (with Mark Newton Lowry), *Electricity Journal*, June 2006.

22. "Performance Indicators and Price Monitoring: Assessing Market Power," *Network*, March 2007.

23. "Incentive Regulation in North American Energy Markets" *Energy Law and Policy*, Carswell Publishing, Toronto, Canada, 2009.

24. "Regulatory Reform in Ontario: Successes, Shortcomings and Unfinished Business" *Public Utilities Fortnightly*, November 2009

25. "An Update to Keystone XL Development," *CERI Crude Oil Report*, September 2015

26. "Mexico Natural Gas Reform," *Geopolitics of Energy*, January-February 2016

27. "Clean Energy Policy in the U.S." *Geopolitics of Energy*, July 20616.

28. "The Energy Policy Outlook Under President Trump," *Geopolitics of Energy*, November-December 2016.

29. "Electricity Security, Renewables, and the South Australia Power Outages," *Geopolitics of Energy*, April-May 2017.

30. "Prospects for Nuclear Power in the U.S.," *Geopolitics of Energy,* August 2017.

31. "The Past and Future of the X Factor in Performance-Based Regulation," *Geopolitics of Energy*, February 2019

32. "The Past and Future of the X Factor in Performance-Based Regulation," *The Electricity Journal*, April 2019

Presentations at Seminars and Professional Meetings:

1. Department of Energy/NARUC, Orlando, FL, 1995.
2. Illinois Commerce Commission and the Center for Regulatory Studies, St. Charles, IL, 1995.
3. Regulatory Studies Program, NARUC/Michigan State University, East Lansing, MI, 1995.
4. Marketing Conference, Edison Electric Institute, Chicago, IL, 1997.
5. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 1997.
6. Code of Conduct Conference, Denver, CO, 1997.
7. Code of Conduct Conference, Denver, CO, 1998.

8. Forum on Price Cap Regulation for Power Distribution. Melbourne, Australia, 1998.
9. Conference on Competition and Regulatory Reform in Hawaii. Honolulu, HI, 1998
10. Alternative Approaches Towards Price Cap Regulation. Melbourne, Australia, 1998.
11. Economics Meetings, Edison Electric Institute. Charlotte, NC, 1998.
12. Metering, Billing and Information Services Policy Convention, EEI, Chicago, IL, 1999.
13. Electricity Deregulation Conference. Vail, CO, 1999.
14. PURC Regulatory Training Seminar for Natural Gas Policy, Buenos Aires, Argentina, 1999.
15. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2000.
16. Seminar on Theory and Practice of Economic Regulation, Sydney, Australia, 2000.
17. Power Delivery Reliability Conference. Denver, CO, 2000.
18. Performance-Based Regulation Conference. Chicago, IL, 2000.
19. Regulatory Studies Program, NARUC/Michigan State University, East Lansing, MI, 2000.
20. Performance-Based Ratemaking Conference, Denver, CO 2000.
21. Energy Forum, Institute of Public Affairs, Melbourne, Australia, 2000.
22. Chamber of Commerce and Industry, Perth, Australia, 2001.
23. Energy Regulation Conference, Melbourne, Australia, 2001.
24. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 2001.
25. PURC Regulatory Training Seminar, La Paz, Bolivia, 2001.
26. Performance-Based Regulation Conference, Denver, CO, 2001.
27. Cost Structure of Energy Networks, Sydney, Australia, 2002.
28. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 2002.
29. Performance-Based Ratemaking Conference, Denver, CO 2002.
30. How to Regulate Electricity Lines Companies?, New Zealand Institute for the Study of Competition and Regulation, Wellington, New Zealand, 2003
31. Public Utility Regulation Seminar: Tariff Design and Incentives, Acapulco, Mexico, 2003
32. Rates and Regulation Meeting: Southeastern Electric Exchange, Williamsburg, VA, 2003.
33. Workshop on Service Quality Regulation in Ontario, Toronto, ON 2003.
34. Joint Canadian Electricity Association Distribution Council and Customer Council Meeting, Halifax, Nova Scotia, 2004.
35. Asia-Pacific Productivity Conference, Brisbane, Australia, 2004. [invitation, paper submitted]
36. Workshop on Productivity Measurement, Melbourne Australia, 2005.
37. Utility Regulators Forum, Canberra Australia, 2005.
38. CAMPUT Energy Regulation Course, Kingston Canada, 2006.
39. Performance Based Regulation Seminar, Toronto Canada, 2006.
40. Performance Benchmarking for Energy Utilities, Arlington, Virginia, 2006.
41. Performance Benchmarking for Energy Utilities, Seattle, Washington, 2007.
42. Alternative Regulation Seminar, Boston, Massachusetts, 2007.
43. CAMPUT Energy Regulation Course, Kingston Canada, 2007.
44. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2008.
45. Performance Benchmarking for Energy Utilities, Denver, Colorado, 2008.
46. Alternative Regulation Seminar, Toronto, Canada, 2008.
47. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2008.
48. CAMPUT Energy Regulation Course, Kingston Canada, 2008.
49. Performance Benchmarking for Energy Utilities, Chicago, IL, 2008.
50. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2009.
51. Alternative Regulation Seminar, Boston, MA, 2009.
52. CAMPUT Energy Regulation Course, Kingston Canada, 2009.

53. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2010.
54. Alternative Regulation Seminar, Boston, MA, 2010.
55. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2010.
56. CAMPUT Energy Regulation Course, Kingston Canada, 2010.
57. Alternative Regulation Seminar, Toronto Canada 2010.
58. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2011.
59. Alternative Regulation Seminar, Philadelphia PA, 2011.
60. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2012.
61. Alternative Regulation Seminar, Chicago, IL, 2012.
62. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2013.
63. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2013.
64. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2014.
65. Alternative Regulation Seminar, Chicago, 2014.
66. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2014.
67. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2015.
68. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2015.
69. CERI Oil and Gas Conference, Calgary, Canada. 2015.
70. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2016.
71. Latin American Natural Gas Conference, Naturgas, Cartegena, Colombia, 2016.
72. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2016.
73. CERI Electricity Conference, Calgary, Canada, 2016.
74. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2017.
75. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2018.
76. Florida Infrastructure Conference, Gainesville, FL, 2018.
77. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2018.
78. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2019
79. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2019.
80. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2020.

A. Thomas Bozzo

RESUME

October 2022

Address:

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Academic Background:

PhD, University of Maryland–College Park, 1998, Economics
Complex Systems Summer School, Santa Fe Institute, Santa Fe, NM, 1994
BA, University of Delaware, 1990, Economics and English, *Magna cum laude*

Positions Held:

Vice President, Laurits R. Christensen Associates, Inc., 2003–present
Senior Economist, Laurits R. Christensen Associates, Inc., 1997–2002
Economist, Laurits R. Christensen Associates, Inc., 1996
Instructor, University of Maryland, College Park, MD, 1996
Instructor, University of Delaware, Newark, DE, 1995

Professional Experience:

My areas of expertise include economic cost measurement, litigation support, applied econometric and statistical analysis, productivity measurement, regulation of network industries, and geographical information systems. I was a principal author of the Christensen Associates reports on the state of freight railroad competition for the Surface Transportation Board, where my work focused on the analysis of rail pricing and markups by commodity using data from the Carload Waybill Sample. I also contributed analysis of the economic geography of rail shipments of major commodity groups (e.g., coal, grains, intermodal) and analysis of projections of rail freight flows.

My work for the U. S. Postal Service (USPS) has focused on applications of econometrics, statistics, and cost theory to the measurement of economic costs of mail products. I currently supervise production of clerk and mailhandler cost estimates by postal products for USPS's Cost and Revenue Analysis and the analysis of USPS operating data to develop productivity inputs for downstream engineering-economic models used to estimate costs below the regulatory product level. I have testified in four U.S. postal rate cases and assisted USPS with litigation support for the Postal Regulatory Commission's Annual Compliance Review process since FY 2007.

Since joining Christensen Associates, I have also been involved with numerous energy, litigation, and telecommunications projects. Recent energy work includes load research sample design and load estimation, econometric analysis of electricity distribution data for load impacts of volt/var control systems, and analysis of AMI and distribution data for phase prediction for service transformers and meters

Expert Testimony:

Regulatory Proceedings

Client: United States Postal Service (2020)
Proceeding: Postal Regulatory Commission, Docket No RM2017-3, Statutory Review of the System for Regulating Rates and Classes for Market Dominant Products.
Declaration of A. Thomas Bozzo and Mark E. Meitzen, regarding proposed price cap modifications.

Client: United States Postal Service (2006)
Proceeding: Postal Rate Commission, Docket No R2006-1, Postal Rate and Fee Changes.
Written direct testimony, USPS-T-12, regarding econometric methods for mail processing costs.
Written direct testimony, USPS-T-46, regarding In-Office Cost System redesign.
Written rebuttal testimony, USPS-RT-1, regarding cost measurement issues for Within-County Periodicals.
Written rebuttal testimony, USPS-RT-5, regarding econometric methods for mail processing costs.

Client: United States Postal Service (2005)
Proceeding: Postal Rate Commission, Docket No R2005-1, Postal Rate and Fee Changes.
Written direct testimony, USPS-T-12, regarding econometric methods for mail processing costs.

Client: United States Postal Service (2001)
Proceeding: Postal Rate Commission, Docket No R2001-1, Postal Rate and Fee Changes.
Written direct testimony, USPS-T-14, regarding econometric methods for mail processing costs.

Client: United States Postal Service (2000)
Proceeding: Postal Rate Commission, Docket No R2000-1, Postal Rate and Fee Changes.
Written direct testimony, USPS-T-15, regarding econometric methods for mail processing costs.
Written rebuttal testimony, USPS-RT-6, regarding econometric methods for mail processing costs.
Written rebuttal testimony, USPS-RT-18, regarding estimates of mail processing cost by weight increment.

Publications

“Is Demand for Market-Dominant Products of the United States Postal Service Becoming More Own-Price Elastic?” (with Kristen L. Capogrossi, B. Kelly Eakin, John Pickett, and Mithuna Srinivasan). In Michael A. Crew and Timothy J. Brennan (eds.), *The Role of the Postal and Delivery Sector in a Digital Age* (Edward Elgar, 2014), pp. 28-45.

"Railroad Performance Under the Staggers Act." (With B. Kelly Eakin, Mark E. Meitzen, and Philip E. Schoech). *Regulation* 33(4) (Winter 2010), pp. 32-38.

"Using Operating Data to Measure Labor Input Variability and Density Economies in U.S. Postal Service Mail Processing Operations." In Michael A. Crew and Paul R. Kleindorfer (eds.), *Progress in the Competitive Agenda in the Postal and Delivery Sector* (Edward Elgar, 2009), pp. 223-238.

Non-Confidential Consulting Reports:

"Analysis of Sacramento Municipal Utility District Conservation Voltage Reduction (CVR) Tests: June 2013-June 2014," prepared for EPRI, February 2015 (Christensen Associates Energy Consulting).

"Parallel Tracks? Lessons from the Railroad Industry," RARC-WP-12-014, prepared for the United States Postal Service Office of Inspector General, August 2012 (Christensen Associates).

"Meeting Commonwealth Edison's Distribution Allocation Requirements from Illinois Commerce Commission Order 10-0467," November 2011 (Christensen Associates Energy Consulting, with Michael O'Sheasy, Bruce Chapman, Daniel Hansen, Micheal Swan, and William Winnerling).

"Cost of Service Standards in the United States Postal Service," RARC-WP-11-008, prepared for the United States Postal Service Office of Inspector General, August 2011 (Christensen Associates).

"An Update to the Study of Competition in the U.S. Freight Railroad Industry," prepared for the U.S. Surface Transportation Board, January 2010 (Christensen Associates).

"Supplemental Report to the U.S. Surface Transportation Board on Capacity and Infrastructure Investment," prepared for the U.S. Surface Transportation Board, March 2009 (Christensen Associates).

"A Study of Competition in the U.S. Freight Railroad Industry and Analysis of Proposals that Might Enhance Competition," prepared for the U.S. Surface Transportation Board, November 2008 (Christensen Associates).

Conference Participation

Presenter, "Mail processing productivity, workload, and labor input variability in the PAEA era" (with Tim Huegerich), 38th Annual Eastern Conference (Rutgers University Center for Research in Regulated Industries), Shawnee-on-Delaware, Pennsylvania (2019)

Discussant, New Regulatory Framework for the Modern Grid panel, 35th Annual Eastern Conference (Center for Research in Regulated Industries), Shawnee-on-Delaware, Pennsylvania (2016).

"Methodologies for CVR Impact Measurement," Assessment Strategies and Benefits of Advanced Volt/Var Control panel presentation, IEEE Power & Energy Society Transmission & Distribution Conference, Chicago, Illinois (2014).

Presenter, Demand Elasticity panel, 21st Conference on Postal and Delivery Economics, Portmarnock, Ireland (2013).

Discussant, New Directions panel, 29th Annual Eastern Conference (Center for Research in Regulated Industries), Skytop, Pennsylvania (2010).

Discussant, USO and Contracting panel, 28th Annual Eastern Conference (Center for Research in Regulated Industries), Skytop, Pennsylvania (2009).

Presenter, "Using Operating Data to Measure Labor Input Variability and Density Economies in U.S. Postal Service Mail Processing Operations." 16th Conference on Postal and Delivery Economics, Abufeira, Portugal, and 27th Eastern Conference (Center for Research in Regulated Industries), Skytop, Pennsylvania (2008).

Discussant, Cost Measurement panel, 15th Conference on Postal and Delivery Economics, Semmering, Austria (2007).

Major Projects:

Postal and Delivery

Production of clerk and mailhandler cost estimates for the USPS Cost and Revenue Analysis and Annual Compliance Report.

Review and analysis of alternative price cap models for USPS market dominant products.

"Greenfield Costing" study of the use of census-based data in USPS product cost modeling.

Econometric modeling of trends in own-price demand elasticities for USPS market-dominant products (for USPS OIG, Risk Analysis Research Center).

Analysis of USPS costs associated with preferential products' service standards (for USPS OIG, Risk Analysis Research Center).

Productivity measurement for USPS mail processing operations using Management Operating Data System (MODS) data.

Cost modeling for USPS competitive product negotiated service agreements (NSAs).

Mail density survey for USPS Transportation Costing System (TRACS).

Written testimony before the Postal Regulatory Commission (PRC), Dockets No. R2006-1, R2005-1, R2001-1, and R2000-1. Oral testimony before the PRC in R2006-1 and R2000-1.

USPS In-Office Cost System (IOCS) survey instrument redesign and statistical analysis support. IOCS is an ongoing data collection system that classifies work activities and identifies postal products for several USPS labor categories with approximately 600,000 annual observations using a multi-stage stratified sample design.

Development of USPS Cost and Revenue Analysis (CRA) methodology for mail processing operations; CRA costs, revenues, and volumes by shape, weight increment, and function.

Econometric modeling of USPS mail processing operations for cost elasticity estimation.

Variance estimation methods for sample-based USPS mail processing and city carrier costs. These cost components employ non-linear estimators combining data from complex surveys as well as econometrically estimated inputs.

Joint USPS/Government Accountability Office/Postal Regulatory Commission Data Quality Study.

Energy

Econometric analysis of AMI meter and distribution data for transformer and meter-level phase prediction.

Statistical design and load profile estimation for Dayton Power and Light's load research program.

Econometric analysis of energy use impacts of conservation voltage reduction (CVR) systems.

Load research sample evaluation for Nova Scotia Power.

Statistical design for Commonwealth Edison distribution cost allocation studies.

Other Industries

Freight Railroad Competition Studies for the U.S. Surface Transportation Board (2007-2010).

Analysis of telephone cost proxy models for U.S. Federal and Minnesota universal service funds.

Bruce R. Chapman

RESUME

October 2022

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Academic Background:

All course work necessary for PhD, University of Wisconsin–Madison, 1981, Economics
MA, University of Wisconsin–Madison, 1979, Economics
BA, University of Pittsburgh, 1976, Economics

Positions Held:

Vice President, Christensen Associates Energy Consulting, LLC, 2015-present
Senior Economist, Christensen Associates Energy Consulting, LLC, 2005–2014
Senior Economist, Laurits R. Christensen Associates, Inc., 1992–2005
Economic Analysis Consultant, Laurits R. Christensen Associates, Inc., 1988–1992
Research Economist, Laurits R. Christensen Associates, Inc., 1986–1988
Associate Consultant, Coopers & Lybrand Consulting Group, Economics Practice, Toronto, Canada, 1985–1986
Research Assistant, University of Wisconsin-Madison, 1980–1981
Research Analyst, Woods Gordon (Economics Group), Toronto, Canada, 1979–1980

Professional Experience:

I assist clients in the electricity and natural gas industries to improve their costing and pricing capabilities. I advise clients in such areas of expertise as: cost-of-service analysis and rate design based upon established regulatory and market-based principles; innovative rate design including demand response products, renewables pricing, fixed billing, and other market-based retail pricing products; load forecasting and load research analysis. I supervise and conduct analysis of costing and pricing issues for utilities, regulators, customers and other industry stakeholders. Additionally, I have supervised the development of software required for the implementation and support of innovative retail products. Examples include cost-of service and rate design models to support rate applications, and models to predict customer tariff choice and price response. I regularly present costing and pricing issues and concepts at industry conferences and workshops.

Major Projects:

Reviewed rate design alternatives for very large customers served under marginal cost-based pricing.

Conducted a review of distributed energy resource pricing alternatives for a utility designing a DER pilot program with site storage capability.

Assisted a Canadian natural gas distributor to evaluate alternative rate structures.

Evaluated price response to a fixed billing program by customers with minimal prior data.

Reviewed cost recovery practices with respect to energy efficiency costs at North American utilities.

Contributed to an EPRI report on measurement of non-energy impacts of efficient electrification.

Acted as a cost-of-service expert for a western U.S. state's regulator reviewing a utility's rate application.

Reviewed alternative rate classification schemes for a Canadian natural gas utility.

Prepared a memorandum reviewing a government-owned utility's market overview of an RTO's wholesale pricing components and comparability with other jurisdictions.

Assisted a utility to prepare testimony on a proposed electric fixed-bill experiment.

Assisted a Canadian utility to develop time-varying pricing for large customers.

Supported the preparation of a rate application by a natural gas utility.

Evaluated the advisability of contracted rate administration services for a vertically integrated utility.

Prepared an analysis of demand-side management cost allocation practices for a Canadian utility.

Reviewed alternative corporate treatment non-utility services by a Canadian utility.

Prepared an analysis of non-utility service marginal costs for a Canadian utility.

Supported a Canadian utility's rate filing with testimony on cost-of-service issues.

Conducted a review of commercial rate designs and rate levels across a sample of American electric utilities.

Prepared a survey of wholesale electric contract structures for a southeastern utility.

Conducted a comprehensive review of the retail rates of a hydro-electric generation dominated Canadian utility.

Conducted a comprehensive review of the retail rates of a Canadian utility with a conventional generation mix.

Prepared a cost-of-service study for a Great Plains electric utility.

Reviewed economic development and load retention rates for a Canadian utility.

Evaluated behavior of fixed billing customers following instances of very high consumption.

Reviewed the retail rate portfolio of a Canadian utility with respect to industry standards.

Reviewed the cost causation underpinnings of a utility's residential rate design.

Collaborated in a review of standby rate structures for a Midwestern utility.

Provided pricing and revenue recovery guidance to a Caribbean utility.

Provided guidance to a Southeast Asian utility in the design of time-of-use rates. Guidance included instruction in simulation of price response.

Directed a cost-of-service study for a large distribution utility.

Assisted a utility to adjust its costing and pricing methods following addition of significant new generation and transmission assets.

Assisted a utility to merge rates of two separate service territories following a corporate merger.

Reviewed a natural gas distribution utility's proposal for a commodity hedging arrangement.

Assisted in developing an electric vehicle tariff for a Midwestern utility.

Assisted in an evaluation of economic development and load retention rates for a Midwestern utility.

Led an evaluation of a Midwest utility's residential time-of-use rate in comparison with other TOU designs and current marginal costs. Evaluated means by which participation could be increased.

Participated in an evaluation of the merits of a special contract for a large customer of an Eastern utility.

Conducted an analysis of the relative cost-of-service implications of creating a separate class for a specialized subset of customers from an existing large customer class.

Assisted a Great Plains utility to develop a renewable tariff for large industrial customers.

Managed a project that assisted a Great Plains public service commission staff to evaluate natural gas utility submissions for safety-related cost recovery via new riders.

Participated in a load research data development project for a Midwestern utility, including sample design and selection, and class interval load profile development.

Conducted an analysis of the cost implications for a Caribbean utility of introducing LED street lighting.

Developed generic cost-of-service and rate design models for use in client rate cases.

Customized company cost-of-service and rate design models for an Asian utility. The project also included support for marginal cost capability development.

Led a rate case preparation process for a Southeastern utility that included load and energy forecasting, development of revenue requirements, and support for cost of service and rate design.

Participated in a Midwest utility's rate case by reviewing current mass market time-of-use and other rate designs and recommending modifications.

Collaborated in a review of a large Canadian utility's cost-of-service methodology, including a public review process with stakeholders. Testified before regulator regarding recommendations.

Conducted an assessment of a Great Plains public power utility's plans for three pricing concepts: green power, economic development rates, and unbundled retail pricing to facilitate customer choice.

Assisted a distribution utility to review aspects of its distribution cost allocation methodologies by conducting a survey of methodologies across a number of electric utilities.

Assisted a state energy office to review ways in which the state could improve its record of energy efficiency program achievements, as recorded by the ACEEE Scorecard.

Collaborated in the development of rate redesign alternatives for a utility's real-time pricing program structure.

Collaborated in the review of the potential for a Canadian utility to introduce a fuel adjustment mechanism.

Conducted an analysis of probable migration of customers to new time-of-use electricity programs offered by a southeastern utility.

Evaluated the accuracy of an electric utility's fixed bill offer algorithm and recommended modifications.

Led a project which conducted a review of an electric utility's avoided cost calculation and the application of those costs in energy efficiency reviews.

Managed and participated in reviews of rate and gas cost adjustment applications for a Great Plains public service commission's gas division.

Conducted a cost-of-service and rate design study for a Caribbean utility in preparation for a rate submission.

Supported review for an industrial customer group of a large filing by a utility, focusing on non-bypassable riders.

Managed a gas cost review process for a Great Plains regulatory agency.

Analysis of smart grid pricing issues for a Great Plains public power utility.

Contributed to load research sample development for an investor-owned utility.

Managed a review of a large electric and gas utility's costing methodologies.

Managed a cost-of-service and rate design study for a Caribbean utility.

Conducted analysis of distribution costing practices at a large Midwestern investor-owned utility.

Development of a time-of-use rider for two electric utilities.

Management of a study of interruptible pricing program improvements for a large Midwestern utility.

Management of a comprehensive cost-of-service and rate design study for a Caribbean utility.

Strategic pricing for a large hydro-dominated utility.

Evaluation of the net economic benefits of alternative power supply strategies: coal vs. renewables and energy efficiency.

Load forecasting project for a medium-sized electric utility with significant industrial load.

Analysis of alternative means of net metering.

Evaluation of alternative demand response programs for a municipal utility.

Analysis of treatment of margins from real-time pricing.

Analysis of a natural gas energy conservation funding mechanism.

Design and pricing of a small customer Time-of-Use program.

Evaluation of cost of capital for a small Caribbean utility.

Risk pricing of a long-term customer choice retail contract.

Evaluation of response by small customers to fixed billing programs.

Evaluation of response by medium-sized customers to a banded fixed billing program.

Cost-of-service project including marginal cost and traditional cost basis.

Preparation of load research survey sample via stratified random sampling.

Design and pricing of a Critical Peak Pricing product

Evaluation of residential customers' propensity to adopt a voluntary Time-of-Use product

Pricing of a fixed bill product for a new service territory based on response elsewhere

Evaluation of peak period response to a fixed billing product

Development of an electric utility fuel forecast

Customization of fixed bill software for use at a utility site

Design and pricing of a Banded Fixed Billing product.

Long-term wholesale power procurement for an electric utility.

Report on Adoption of Variable Pricing contracts in deregulated retail electricity markets.

Development of Fixed Bill software to generate offers and monitor customer behavior.

Quantitative evaluation of net benefits of demand response programs.

Quantitative evaluations of customer response to fixed billing.

Design and pricing of several pilot and permanent fixed-bill programs.

Development of Efficient Tariff Prices via Marginal Costing.

Analysis of Market Data Available to Estimate Marginal Cost of Reliability.

Evaluation of Risk of Fixed Billing Based on Customer Response.

Cost Allocation Analysis for Rate Case Filing.

Analysis of Customer Response to Fixed Billing.

Fixed Bill Scoping for a Natural Gas Provider.

Analysis of Risk Implications of Fixed Billing for an Electric Utility.

Strategic Assessment of an Electric Utility's Retail Tariff Portfolio.

Guaranteed Bill Product Design and Risk Assessment.

White Paper on Interruptible/Curtailable Service.

Marginal Cost-Based Cost of Service Development.

Software Scoping for Self-Designed Products.

Flat Bill Offer Software Development.

Comprehensive Rate Repricing.

RTP Price Hedging Product Development.

Retail Pricing Under Competition Conference.

Rate Optimization Plan.

Fixed Bill Product Development.

Weather Hedge Evaluation.

Real-Time Pricing Product Development.

Workshop: Creating a Diversified Retail Pricing Portfolio.

Product Mix Business Plan.

Prepared material for testimony in Federal District Court on Real-Time Pricing.

Risk-Based Pricing Workshops.

Survey of New Electricity Market Players.

Analysis of Fixed Bill Products.

Strategic Pricing Plan for a Midwestern Utility.

Product Mix Analysis for Small Customers.

Real-Time Pricing Workshop.

Innovative Pricing and Marginal Costing for a Co-op.

Real-Time Pricing with Multiple Options.

Real-Time Pricing for a G&T and its Co-ops.

Product Mix Analysis for Large Customers.

Real-Time Pricing Service Design for Commercial Customers.

Advanced Service Design Workshop.

Real-Time Pricing Program for a Midwestern Utility.

Evaluation of Customer Response to Real-Time Pricing.

Real-Time Pricing Program Development for an Eastern Utility.

Two-Part Pricing Service Design.

Real-Time Pricing Regional Workshops.

Real-Time Billing Program Support and Revision.

Electricity Efficiency Programs.

Real-Time Pricing Program Redesign for an Eastern Utility.

Real-Time Pricing Implementation for a Canadian Utility.

Real-Time Pricing Practitioners' Workshop.

Real-Time Pricing for a Canadian Utility.

Customer Evaluation of Real-Time Pricing.

Review of Competitive Pricing Strategies.

Evaluation of Process of Marketing Real-Time Pricing.

Review of Methods for Distinguishing Customer Response to Rate Change.

Real-Time Pricing Rate for a Southern Utility.

Review of Accounting and Incentives for a Real-Time Pricing Rate.

Analysis of Load Impact of Priority Service Alternatives.

Benefit/Cost Analysis of an Integrated Energy Management System.

Benefit/Cost Analysis of Marginal Cost-Based Rates for DSM Integrated Resource Plan.

Impact Evaluation of Curtailable Electric Service.

Survey of Households Who Were Candidates for Voluntary Time of Use Rates.

Audit of Energy Management Software.

Real-Time Pricing Rate for a Large Northeastern Public Utility.

Software Design for Real-Time Pricing.

Improved Approaches to Estimating Benefits of DSM Programs.

Load Shapes Assessment Program.

Fuel Purchase Contract Study.

Evaluation of the Effects of Canadian Energy Policy.

Evaluation of Energy Conservation Programs.

Professional Papers:

"Pricing Distributed Generation: Challenges and Alternatives," *Natural Gas & Electricity*, March 2017.

"Pricing of Renewable Energy Made Difficult by Policy Challenges," *Natural Gas & Electricity*, January 2016.

"Room for Fixed Billing in the World of Conservation?," *Natural Gas & Electricity*, August 2008.

"Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, June 2001 (with Ahmad Faruqui, Dan Hansen, and Chris Holmes).

"A Survey of Real-Time Pricing Programs," *The Electricity Journal*, August–September 1993 (with Juliet Mak).

"Real-Time Pricing: DSM at Its Best?," *The Electricity Journal*, August 1990 (with Tom Tramutola).

Conference Presentations:

"Retail Pricing to Facilitate Efficient Electrification", pre-conference workshop at EUCI's Canadian Electric Rate Design Conference, Vancouver, BC, Sept 27, 2022.

"The Current Landscape of Standby Pricing", Southeastern Electricity Exchange Rates and Regulation Section Meeting, Louisville, KY, September 22, 2022.

"TOU and Demand Pricing: Lessons and Possibilities", EUCI's TOU and Residential Demand Charges Conference, web-based, May 2021.

"Pricing to Support Innovative Rate Design", EUCI's Canadian Rate Design Symposium, web-based workshop, September 2021.

"Rate Classification Issues for Business Customers", EUCI's Canadian Rate Design Symposium, web-based, September 2021.

"TOU and Demand Pricing: Lessons and Possibilities", EUCI's TOU and Residential Demand Charges Conference, web-based, May 2021.

"Pricing Distributed Energy Resources", EUCI's Rate Innovation for Electric Cooperatives Conference, web-based workshop, March 2021.

"Green Tariff Pricing Structures", EUCI's Utility Green Tariffs A-Z, on-line course, November 2020.

"Pricing Distributed Energy Resources: the Canadian Challenge", web-based workshop at EUCI's Canadian Rate Design Symposium, September 2020.

"Standby Rates in Canada", EUCI's Canadian Rate Design Symposium, web-based, September 2020.

"Extending the Retail Portfolio: Fixed Billing for Mass Market Customers", an EUCI web-based workshop with Seth Blocker, Georgia Power Company, June 2020.

"Green Tariff Pricing Structures", EUCI's Utility Green Tariff Conference, Denver, Colorado, September 2019.

"Cost Factors Inducing Change in the Pricing of Distributed Energy Resources", EUCI's NEM and Utility Solar Rates Summit, Denver, Colorado, September 2019.

"Whither Standby Rates", EUCI's Canadian Rate Design Symposium, Calgary, AB, June 2019.

"Retail Electricity: Costing and Pricing for Contemporary Challenges", pre-conference workshop at EUCI's Canadian Rate Design Symposium, Calgary, AB, June 2019.

"The Other Side of Residential Revenue Recovery: The Avoided Cost Controversy", post-conference workshop at EUCI's Residential Demand Charges Conference, Nashville, TN, May 2018.

"Attracting and Retaining Large-Customer Loads", EUCI's Canadian Rate Design Symposium, Vancouver, BC, April 2018.

"Basics of Retail Pricing: Traditional and Innovative", pre-conference workshop at EUCI's Canadian Rate Design Symposium, Vancouver, BC, April 2018.

"Retail Pricing to Support Electric Vehicle Charging", EUCI's 7th Annual Southeast Clean Power Summit, Nashville, TN, February 2018.

"Pricing Distributed Energy Resources: Issues and Approaches", pre-conference workshop at EUCI's 7th Annual Southeast Clean Power Summit, Nashville, TN, February 2018.

"The Other Side of Residential Revenue Recovery: the Avoided Cost Controversy", post-conference workshop at EUCI's Residential Demand Charges conference, Charleston, SC, July 2017.

"Net Metering and Solar Energy Pricing," pre-conference workshop at EUCI's Net Energy Metering and Utility Solar Rates Summit, Denver, CO, July 2016.

"Pricing the Purchase of Renewable Energy," post-conference workshop at EUCI's 4th Annual Southeast Clean Power Summit, Atlanta, GA, March 2015.

"Pricing Perspectives of Regulated Utilities on Solar Power," EUCI's Net Metering 2.0 and Utility Solar Rates Conference, Anaheim, CA, January 2015.

Cost of Service and Rate Design; Current Utility Costing and Pricing Challenges; Pricing Renewable Energy; Feed-in Tariffs and Demand Response Alternatives to Supply. Presentations to the Wisconsin Public Utility Institute's Energy Utility Basics Course, 2009–2017.

"The Bill Please," university course and public presentation within the "Decoding the Energy Industry" series; Wisconsin Public Utility Institute, 2014.

Electric Rate Design Principles and Designs (with Dr. Stephen Braithwait), and Pricing Renewable Resources; presentations to the Rate Design and Regulation Workshop, Wisconsin Public Utility Institute, Madison, Wisconsin, 2014.

"Customer Response to Dynamic Pricing: Who Responds and How?," EUCI's Smart Ratemaking Conference, Oct. 2009, Los Angeles; with Dr. Steven Braithwait.

Cost-of-Service, preconference workshop, EUCI's Smart Ratemaking Conference, Oct. 2009, Los Angeles.

Critical Peak Pricing: Valuation and Viability, presented at AESP's Innovations in Retail Pricing Conference, Chicago, IL, May 17, 2006.

Georgia Power's FlatBill Program, Risks and Returns, presented, with Monamee Adhikari, Georgia Power Company, at AESP's Innovations in Retail Pricing Conference, Chicago, IL, May 17, 2006.

Retail Pricing for Competitive Power Markets, six presentations on retail pricing and unbundling; Infocast conference February 28-March 2, 2001.

Retail Products and Pricing Under Competition, presented at the Canadian Electricity Association's seminar: Setting Up for New Energy Regulation, April 19, 1999.

Using Risk as the Maker of Prices: Risk-Based Pricing, presented at Infocast's conference: Power Industry Retail Pricing, June 23–25, 1999.

"Designing a Retail Pricing Product Mix for a Competitive Market: A C-VALU Case Study," presented at EPRI's Innovative Pricing Conference, Washington, DC, June 18, 1998, (with Kathleen King and David Kulha).

"Retail Products & Pricing in the Competitive Era," presented at IBC Conference: Successfully Implementing Retail Access, Washington, DC, April 27, 1998.

"Risk-Based Pricing: Making Money in Competitive Markets," EMACS Conference, Atlanta, Georgia, October 14, 1997, (with A. Faruqui, EPRI).

"Real-Time Pricing: Becoming Competitive Before Competition," presented at IBC Conference: Successfully Implementing Retail Profit Projects, Atlanta, Georgia, February 24, 1997, and Las Vegas, Nevada, July 17, 1997.

"Effective Retail Product Design for a Competitive Market," IBC Conference: Developing, Negotiating and Contracting Retail Electricity Prices, Atlanta, Georgia, February 24, 1997, (with Kathleen King).

"Innovative Pricing and Data Requirements," presented at the AEIC Load Research Conference, Washington, DC, August 4–6, 1995.

"Lessons Learned and the Path Forward," presented at EPRI's National Conference on Achieving Success in Evolving Electricity Markets, Atlanta, Georgia, October 10–12, 1995 (with Kathleen King).

"A Real-Time Pricing Primer: Service Design for a Competitive Market," presented at the Missouri Valley Electric Association Marketing Division Conference, Kansas City, Missouri, October 13, 1994.

"Real-Time Pricing: Service Design for a Competitive Market," presented at the American Public Power Association workshop, Scottsdale, Arizona, September 28, 1994.

"Customer Response to Real-Time Pricing: Results from Current Experiments," presented at the 6th National Demand-Side Management Conference, Miami Beach, Florida, March 25, 1993.

"Electricity Pricing Innovations for Retail Sales," presented at the Energy Utilities and Regulation Course, Wisconsin Public Utilities Institute, September 13, 1990; revised and presented again in 1992.

"Innovative Pricing in DSM: Recent Field Tests of Real-Time Pricing," presented at the Energy Demand-Side Research Seminar Series, University of Wisconsin-Madison, April 4, 1990 (with D. W. Caves).

Oral Testimony:

Docket DPU 22-22, rate application hearings of NSTAR Electric Company d/b/a Eversource Energy, regarding Eversource's cost-of-service study, September, 2022.

Docket 20-1651-EL-AIR (also 20-1652-EL-AAM and 20-1653-EL-ATA), rate application hearings of AES Ohio, dba Dayton Power & Light, regarding DPL's cost-of-service study, January 25, 2022.

Docket UT 20-035-04, rate application hearings of Rocky Mountain Power, on behalf of the Utah Division of Public Utilities, regarding RMP's cost-of-service study, November 17, 2020.

Panelist in Cost-of-Service Methodology review hearings on behalf of Nova Scotia Power, before the Nova Scotia Utilities and Review Board, proceeding NSUARB-NSPI-P-892, Matter No. M05473, December 2013.

Nick Crowley

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October 2022

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Academic Background:

Master of Science – University of Wisconsin-Madison, 2014, Economics
Bachelor of Arts – University of Wisconsin-Madison, 2012, Economics

Positions Held:

Senior Economist, Laurits R. Christensen Associates, Inc., Sept. 1, 2021-presernt
Economist, Laurits R. Christensen Associates, Inc., 2019-Aug. 31, 2021
Staff Economist, Laurits R. Christensen Associates, Inc., 2016-2018
Economist, Federal Energy Regulatory Commission, 2015-2016

Professional Experience:

I have extensive experience in matters of utility regulation, with an emphasis on rate design, regulatory finance, and productivity measurement. In my time as a consultant, I have testified on behalf of a major public utility in contentious rate proceedings, measured cost of capital and assembled corresponding reports, developed alternative rate designs, and forecasted electricity load for supply planning purposes. I have also performed extensive research for benchmarking purposes using publicly available data. My work includes marginal cost estimation and the development of marginal cost models for major electric utilities. On an ongoing basis, I manage a team to measure the price response by customers participating in leading demand response programs. My reports have been filed before regulatory authorities across North America. Prior to joining Christensen Associates Energy Consulting, I served as an Economist at the Federal Energy Regulatory Commission, where I assisted with energy industry benchmarking, market power studies, and the review and evaluation of natural gas pipeline rate cases. I have deep facility with Stata and Excel, in addition to other software packages used in quantitative analysis.

PUBLIC TESTIMONY

Massachusetts Department of Public Utilities. *Total Factor Productivity Study and X-Factor Calculation*. Docket 20-120. *Filed November 13, 2020.*

PUBLICATIONS

"Measuring the Price Impact of Price-Cap Regulation Among Canadian Electricity Distribution Utilities." *Utilities Policy.* Vol. 72, October 2021. (with Dr. Mark Meitzen.)

"2020 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Navya Kataria)

"2019 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark)

"2018 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark)

"2017 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report." (with Michael Ty Clark and Dan Hansen)

"2017 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Dan Hansen)

"2016 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-Based Pricing Programs: Ex-post and Ex-ante Report for Customers with Net Energy Metering." (with Michael Ty Clark and Dan Hansen)

"2016 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small, Medium, and Agricultural Non-residential Customers: Ex-post and Ex-ante Report." (with Michael Ty Clark and Dan Hansen)

CONFERENCE PRESENTATIONS

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Virtual. November 2021.

"Rate Design for Revenue Adequacy and Price Efficiency." Wisconsin Public Utility Institute. *Energy Utility Basics.* October 2, 2021.

"Rate Design and the Potential Impacts of Covid-19." EUCI Workshop. Virtual. November 17, 2020.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Atlanta, Georgia. March 9, 2020.

"Load Impact Evaluation: *Base Interruptible Program*." DRMEC Spring Workshop, California Public Utilities Commission. April 26, 2019.

"FERC Regulatory Policy and Relevant Environmental Issues, Focusing on the United States Natural Gas Grid" at the University of Wisconsin for the 2015 Energy Hub Conference.

REPORTS AND WORKING PAPERS

"Cost of Capital Study." For Grand Bahama Power Company, Ltd. April 15, 2021.

"Methodology and Cost Estimates for Generation and Transmission Services, 2021-2029." For Newfoundland and Labrador Hydro. November 15, 2018.

"Cost of Capital Study." For Grand Bahama Power Company, Ltd. October 17, 2018.

"Common Metrics Report: Performance Metrics for Regional Transmission Organizations, Independent System Operators, and Individual Utilities for the 2010-2014 Reporting Period." *Federal Energy Regulatory Commission Staff Report,* 2016.

COMPUTER/PROGRAMMING SKILLS: Deep knowledge of Excel and STATA for data analysis; some experience with R, SAS, and Python

APPENDIX A: RESUME OF JAMES M. COYNE

JAMES M. COYNE

Senior Vice President

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before federal, state and provincial jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

AREAS OF EXPERTISE

Energy Regulation

- Rate policy
- Cost of capital
- Incentive regulation
- Fuels and power markets

Management and Business Strategy

- Fuels and power market assessments
- Investment feasibility
- Corporate and business unit planning
- Benchmarking and productivity analysis

Financial and Economic Advisory

- Valuation analysis
- Due diligence
- Buy and sell-side advisory

Litigation Support and Expert Testimony

- Rate and regulatory policy
- Fuels and power markets
- Contract litigation
- Valuation and damages

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

University of New Hampshire
M.S., Resource Economics, *with honors*, 1981

Georgetown University
B.S., Business Administration and Economics, *cum laude*, 1975

DESIGNATIONS AND AFFILIATIONS

Community Rowing Inc., Board of Directors, 2015 - 2019

Georgetown University, Alumni Admissions Interviewer, 1988 – current

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001

American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996

National Petroleum Council, Regulatory and Policy Task Forces, 1992

President, International Association for Energy Economics, Dallas Chapter, 1995

Gas Research Institute, Economics Advisory Committee, 1990-1993

NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984

PUBLICATIONS AND RESEARCH

"Advancing FERC's Methodology for Determining Allowed ROEs for Electric Transmission Companies," submitted to FERC on behalf of EEI, James Coyne, Joshua Nowak and Julie Lieberman, May, 2020.

"Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation", James M. Coyne, Robert C. Yardley, Jr. and Jessalyn G. Pryciak, Energy Regulation Quarterly, Volume 6, Issue 3, 2018.

"Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May 2015.

"Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010

"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June 2007

"Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006

"Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004

"Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003

"The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001

Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992

"Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

"The Market Risk Premium: An In-Depth Review", Society of Utility and Regulatory Financial Analysts 53rd Financial Forum, Richmond, VA, April 28,2022

"Energy Sector in Transition", Ontario Energy Association, Toronto, ON, September 24, 2018.

"Understanding Regulated Utilities in Today's Capital Markets", NARUC Annual Meeting, La Quinta, CA, November 14, 2016.

"Rate of Return: Where the Regulatory Rubber Meets the Road," CAMPUT Annual Conference, Montreal, Quebec, May 17, 2016.

"Innovations in Utility Business Models and Regulation", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015

"M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010

"The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010

"A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008

"Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005

"The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005

"Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005

"The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005

"Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002

"Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001

"Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001

"Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999

"New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999

"Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998

"Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Alberta Beverage Container Management Board				
Alberta Beverage Container Management Board	2016 2019	Expert for the Board	N/A	Return Margin on Bottle Depots
Alberta Utilities Commission				
ATCO Utilities Group	2008 2009	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
Enmax Power Corporation	2017	Enmax	22570	Cost of Common Equity
Enmax Power Corporation	2020	Enmax	24110	2021 Generic Cost of Capital
American Arbitration Association				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
British Columbia Utilities Commission				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015 2016	FortisBC Utilities	G-129-16	Cost of Capital (Gas and Electric Distribution)
FortisBC	2022	FortisBC Utilities	G-217-22	Cost of Capital (Gas and Electric Distribution)
California Utilities Commission				
San Diego Gas & Electric Company	2019	San Diego Gas & Electric Company	A-19-04-014	Cost of Capital (Electric & Gas Distribution)
San Diego Gas & Electric Company	2021	San Diego Gas & Electric Company	A-21-08-014	Cost of Capital (Electric & Gas Distribution)
Southern California Gas Company	2022	Southern California Gas Company	A-22-04-011	Cost of Capital (Gas Distribution)
San Diego Gas & Electric Company	2022	San Diego Gas & Electric Company	A-22-04-012	Cost of Capital (Electric & Gas Distribution)
Canada Energy Regulator				
Enbridge Pipelines Inc.	2021	Enbridge Pipelines Inc.	RH-001-2020	Cost of Capital (Oil Pipeline)
Connecticut Department of Public Utility Control				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)
Federal Energy Regulatory Commission				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	Docket No. ER11-2909-000	Return on Equity (Electric)
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	Docket Nos. ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Startrans IO, LLC	2015	Startrans IO, LLC	ER-16-194-000 and EL16-25-000	Cost of Capital (Electric Transmission)
Northern States Power Company	2019	Northern States Power Company	ER20-26-000	Cost of Capital (Electric Transmission)
PPL Electric Utilities Corp.	2020	PP&l Industrial Customer Alliance v. PPL Electric	EL20-48-000	Answering Testimony in Response to a Section 206 ROE Complaint
Florida Public Service Commission				
Florida Power & Light Company	2021	Florida Power & Light Company	Docket No. 20210015-EI	Cost of Capital (Electric)
Georgia Public Service Commission				
Georgia Power Company	2022	Georgia Power Company	44280	Cost of Capital (Electric)
Hawaii Public Utility Commission				
The Gas Company	2017	The Gas Company	Docket No. 2017-0105	Cost of Capital (Gas Distribution)
Maine Public Utilities Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Enmax Corporation	2019	Enmax Corporation	2019-00097	Regulatory Approval of Emera Maine Acquisition
Versant Power	2021	Versant Power	MPUC Docket No. 2020-00316	Cost of Capital (Electric)
Versant Power	2022	Versant Power	2022-00XXX	Cost of Capital (Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Maryland State Board of Contract Appeals				
Green Planet Power Solutions	2018	Green Planet Power Solutions and Maryland Bio Energy LLC v. Maryland Department of General Services	MSBCA 3061	Contract Litigation, Power Purchase Agreement, Damages Analysis
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain
Minnesota Public Utilities Commission				
Northern States Power Company	2015 2016	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
Northern States Power Company	2017	Northern States Power Company	E002/M-17-797 G002/M-17-787 E002/M-17-818	Cost of Capital (Electric and Gas Rate Riders for Transmission, Renewable Generation and Gas Distribution)
New Brunswick Energy and Utilities Board				
Liberty Utilities (Gas New Brunswick) LP	2021	Liberty Utilities (Gas New Brunswick) LP	491	Cost of Capital (Gas)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2016	Newfoundland Power	2016 GRA	Cost of Capital (Electric)
Newfoundland Power	2018	Newfoundland Power	2018 GRA	Cost of Capital (Electric)
Newfoundland Power	2021	Newfoundland Power	2021 GRA	Cost of Capital (Electric)
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Nova Scotia Power Inc.	2022	Nova Scotia Power Inc.	2022 GRA	Return on Equity/Business Risk (Electric)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study
Ontario Power Generation	2016	Ontario Power Generation	EB-2016-0152	Cost of Capital (Electric Generation)
Ontario Power Generation	2020	Ontario Power Generation	EB-2020-0290	Cost of Capital (Electric Generation)
Prince Edward Island Regulatory and Appeals Commission				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
Maritime Electric Company	2022	Maritime Electric Company		Return on Capital (Electric)
Régie de l'énergie du Québec				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015-2017	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
South Carolina Public Service Commission				
Piedmont Natural Gas Company	2022	Piedmont Natural Gas Company	2022-89-G	Return on Equity (Gas Distribution)
South Dakota Public Service Commission				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
Texas Public Utility Commission				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
U.S. Department of Commerce				
Government of Québec	2017	Duty Investigation of Uncoated Groundwood Paper from Canada	PUC Docket No. 29206	Contracting for Renewable Resources, Market Analysis, Damages Analysis
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.	Docket No. 8698/8710	Return on Equity (Gas Distribution)
Green Mountain Power Corporation	2017	Green Mountain Power Corporation	Docket No. Tariff-8677	Return on Equity (Electric)
Green Mountain Power Corporation	2018	Green Mountain Power Corporation	18-0974	Return on Equity (Electric)
State Corporation of Virginia				
Dominion Energy Virginia	2021	Virginia Electric and Power Company	PUR-2021-00058	Cost of Capital (Electric)
Wisconsin Public Service Commission				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)
Northern States Power Company	2017 2019	Northern States Power Company	PSCW Docket No. 4220-UR-123, 4220-UR-124	Return on Equity (Gas & Electric)
Northern States Power Company	2021	Northern States Power Company	4220-UR-125	Cost of Capital (Electric, Affidavit)
Yukon Utilities Board				
ATCO Electric Yukon	2016	ATCO Electric Yukon	2016-2017 GRA	Return on Equity (Electric)

APPENDIX B: RESUME OF DANIEL S. DANE

DANIEL S. DANE, CPA
Senior Vice President

Daniel S. Dane has more than 20 years of experience in the energy, utility, and financial services industries providing advisory services to power companies, natural gas pipelines, and local gas distribution companies in the areas of regulation and ratemaking, litigation support, mergers and acquisitions, valuation, financial statement audits and analysis, and the examination of financial reporting systems and controls. Mr. Dane has testified and provided expert reports on regulated ratemaking and utility performance matters for investor- and provincially-owned utilities, including on the cost of capital and capital structure, merger impacts, earnings sharing mechanisms and rate adjustment mechanisms, revenue requirements, lead-lag studies/cash working capital, and utility productivity and benchmarking. That testimony includes assessments of Ontario Power Generation's equity thickness before the OEB in EB-2016-0152 and EB-2020-0290. Mr. Dane coauthored "A Comparative Analysis of Return on Equity of Natural Gas Utilities" with Mr. Coyne on behalf of the OEB. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2004 – Present)
CE Capital Advisors, Inc.
Senior Vice President (Concentric/CE Capital)
Financial and Operations Principal (CE Capital)

Ernst & Young (2000 – 2001, 2003 – 2004)
Staff Auditor and Database Management Associate

ZIA Information Analysis Group (1997 – 2000)

EDUCATION

Boston College
M.B.A., 2003

Colgate University
B.A., Economics, 1996

REPRESENTATIVE PROJECT EXPERIENCE

Ratemaking and Utility Regulation Assignments

Expert Testimony

- Submitted expert testimony on behalf of utilities and other stakeholders in state administrative rate setting and merger approval proceedings regarding merger impacts, revenue requirements, the cost of capital, capital structure, lead-lag studies/cash working capital, regulatory lag and rate base development.

Regulatory Support

- Provided financial modeling, development of expert reports, and preparation of multiple rounds of testimony on behalf of U.S. and Canadian investor-owned electric, natural gas, and water utilities related to multiple aspects of the ratemaking process, including: cost of capital; ring fencing; revenue requirements and lead-lag studies/cash working capital; decoupling; prudence and cost recovery; capital tracker tariff mechanisms; cost allocation and shared services; merger approval; regulatory lag; and ratemaking policy.
- Consulting assignments have included utility clients across the U.S. and Canada.

Financial Advisory Assignments

Competitive Solicitations & Asset Divestitures

- Sell-side support for approximately $2 billion in generating asset transactions, including nuclear, natural gas, and coal generating facilities.
- Buy-side due diligence support for U.S., Canadian, and international investors in electric and natural gas LDC utility operations, wind generation and natural gas pipeline facilities.
- Regulatory policy, ring-fencing, and merger impacts advisory services provided to U.S. and Canadian investor-owned utilities.

Valuation Services

- Developed Fairness Opinions issued by CE Capital Advisors, Inc. to Boards of Directors of companies entering into asset purchases and sales. Led valuation modeling on multiple energy-related valuation assignments using the Income Approach, Cost Approach, and Sales Comparison Approach.

Litigation Advisory Assignments

Prepared economic and valuation analyses and expert reports in proceedings related to contract disputes, takings claims, and bankruptcy proceedings. Clients include international diversified energy companies, regulated utilities, and bondholders.

Management and Operations Consulting Assignments

Performed prudence reviews, including contracting strategy reviews and assessments of project controls and oversight for developers of nuclear-generating capacity uprates and new nuclear facilities.

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant, 2004

Massachusetts Society of Certified Public Accountants, 2004

American Institute of Certified Public Accountants, 2011

CERTIFICATIONS

Licensed Securities Professional: NASD Series 7, 28, 63, 79 and 99 Licenses

PRESENTATIONS

"Regulatory Treatment of Timing Differences Related to Pension and OPEB Costs." Presented to the Ontario Energy Board, July 2016 (Docket No. EB-2015-0040).

"Financial Management and Capital Markets." University of Idaho Utility Executive Course, 2018.

"Increasing Shareholder Value through the Capital Markets." University of Idaho Utility Executive Course, 2015, 2016 and 2017.

"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Jim Coyne and Julie Lieberman), presented to the Ontario Energy Association, June 2007.

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Connecticut Public Utilities Regulatory Authority				
The United Illuminating Company	09/22	The United Illuminating Company	Docket No. 22-08-08	Revenue Requirements
SJW Group and Connecticut Water Service, Inc.	4/19	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 19-04-02	Merger Impacts
SJW Group and Connecticut Water Service, Inc.	12/18	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 18-07-10	Merger Impacts
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Lead-Lag Study Cash Working Capital
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Lead-Lag Study Cash Working Capital
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Lead-lag Study Cash Working Capital
Illinois Commerce Commission				
The Ameren Illinois Utilities	07/10	Central Illinois Light Company; Central Illinois Public Service Company; Illinois Power Company	Docket Nos. 09-0306 thru 09-0311 (cons.)	Rate Base Adjustments Earnings Attrition
Maine Public Utilities Commission				
The Maine Water Company	07/19	Application for Approval of Reorganization Pursuant to 35-A M.R.S. § 708	Docket No. 2019-00096	Merger Impacts, Customer Benefits, Public Interest
Massachusetts Department of Public Utilities				
National Grid	11/20	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 20-120	Revenue Requirement Lead-lag Study Cash Working Capital
The Berkshire Gas Company	05/18	The Berkshire Gas Company	D.P.U. 18-40	Revenue Requirement
National Grid	04/18	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Impact of the Tax Cuts and Jobs Act of 2017; Administrative and General Expense Allocations
National Grid	11/17	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Revenue Requirement Lead-lag Study Cash Working Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New Hampshire Public Utilities Commission				
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Temporary Rates
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Revenue Requirement
New Mexico Public Regulation Commission				
El Paso Electric Company	05/20	El Paso Electric Company	Case No. 20-00104-UT	Lead-lag Study Cash Working Capital
Oklahoma Corporate Commission				
Liberty Utilities Co.	02/22	Liberty-Empire	Cause No. PUD 202100163	Return on Equity Capital Structure
Liberty Utilities Co.	06/22	Liberty-Empire	Cause No. PUD 202100050	Winter Storm Funding and Cost Recovery
Public Utility Commission of Texas				
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Lead-lag Study Cash Working Capital
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Lead-lag Study Cash Working Capital
Regulatory Commission of Alaska				
Golden Heart Utilities, Inc. and College Utilities Corporation	08/21	Golden Heart Utilities, Inc. and College Utilities Corporation	U-21-070 U-21-071	Lead-lag Study Cash Working Capital
Rhode Island Division of Public Utilities and Carriers				
PPL Corp.	11/21	Petition of PPL Corporation, PPL Rhode Island Holdings, LLC, National Grid USA, and The Narragansett Electric Company for Authority to Transfer Ownership of The Narragansett Electric Company to PPL Rhode Island Holdings, LLC and Related Approvals	Docket No. 21-09	Merger Impacts Public Interest

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
South Dakota Public Service Commission				
Northern States Power Company-MN	06/11	Northern States Power Company-MN	EL 11-019	Return on Equity
Vermont Public Utility Commission				
Vermont Department of Public Service	08/17	Joint Petition of NorthStar Decommissioning Holdings, LLC, NorthStar Nuclear Decommissioning Company, LLC, NorthStar Group Services, Inc., LVI Parent Corp., NorthStar Group Holdings, LLC, Entergy Nuclear Vermont Investment Company, LLC, and Entergy Nuclear Operations, Inc., and any other necessary affiliates entities to transfer ownership of Entergy Nuclear Vermont Yankee, LLC, and for certain ancillary approvals, pursuant to 30 V.S.A. §§ 107, 231, and 232	Docket No. 8880	Nuclear Facility Transfer
Nova Scotia Utility and Review Board				
Nova Scotia Power, Inc.	01/22	Nova Scotia Power, Inc.	M10431	Earnings Sharing Mechanism and Regulatory Adjustment Mechanisms
Ontario Energy Board				
Hydro One Networks Inc.	08/21	Hydro One Networks Inc.	EB 2021-0110	Productivity Framework Review
Ontario Power Generation	12/20	Ontario Power Generation	EB 2020-0290	Cost of Capital: Equity Thickness
Ontario Power Generation	05/16	Ontario Power Generation	EB 2016-0152	Cost of Capital: Equity Thickness

LARRY E. KENNEDY, CDP
Senior Vice President

Mr. Kennedy has been in the pipeline, electric, gas utility and municipal infrastructure business for 40 years. As Senior Vice President, Concentric Advisors, ULC, Mr. Kennedy has provided professional consulting services to gas and electric utilities including generation facilities (including nuclear facilities), and high voltage transmission lines, large diameter transmission pipelines, railway systems and municipally owned utility systems. Previously, Mr. Kennedy was with Gannett Fleming Canada ULC, for over 17 years, where he was responsible for completing depreciation studies and provided advice related to large capital program spending and controls for many regulated North American utilities. Mr. Kennedy was also employed by Interprovincial Pipelines Limited (now Enbridge Pipelines) for 15 years in several plant accounting and regulatory positions and with Nova Gas Transmission Pipelines (now TC Energy) for three years as a Depreciation Specialist.

Mr. Kennedy has provided expert witness testimony related to depreciation, stranded costs, capital accounting issues, utility valuation, and property tax issues before several North American regulatory bodies. Mr. Kennedy has completed numerous seminars and all courses offered by Depreciation Programs, Inc. Mr. Kennedy is a member of the teaching faculty of the Society of Depreciation Professionals ("SDP") and has presented depreciation, stranded cost, and capital accounting related topics to the SDP, Canadian Electric Association, Canadian Gas Association, Canadian Property Taxpayers Association, Alberta Utilities Commission, British Columbia Utilities Commission and the Canadian Energy Pipeline Association. Mr. Kennedy is a past Society of Depreciation Professionals President.

PERSONAL INFORMATION

- Diploma, Applied Arts - Business Administration, Northern Alberta Institute of Technology, 1978
- Member, Society of Depreciation Professionals
- Certified Depreciation Professional

EXPERIENCE

Representative Project Experience

- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and in 2015 for submission to the FERC (Docket No. RP15-1022-000) to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.

- Viking Gas Transmission Company - The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the

Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons, including discussion related to the long demand of natural gas.

- Midwestern Gas Transmission Company: The assignment included development of a detailed depreciation study and Testimony to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons. The Direct Testimony included significant discussion related to the topics of Decarbonization and changing political climate towards removal of fossil fuel demand forecasts.
- Enbridge Lakehead System: A Technical Update to a 2016 full depreciation study was prepared and filed with the FERC in 2021 in support of updating depreciation rate and resultant depreciation expense. The technical update also included an analysis and recommendation of a 20-year Economic Planning Horizon (Economic Life).
- Consolidated Edison Company of New York, Inc.: Mr. Kennedy co-authored a study and report which presented the results of research focusing on prior periods of transformative change and more recent discussions of policy tools that could address the impacts of climate change on the Company's electric, steam, and natural gas businesses.
- Montana-Dakota Utilities Co.: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study and associated expert testimony were submitted to the Montana Public Service Commission in 2018 and to the North Dakota Public Service Commission in 2022. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of the retirement of generation facilities due to environmental legislation and estimation of net salvage requirements.
- Commonwealth Edison Company: Mr. Kennedy sponsored extensive Rebuttal Testimony related to the average service life, net salvage estimations, and appropriate depreciation practices in a 2020 rate proceeding.
- Great Plains Natural Gas Co.: Annual updates of depreciation rates and net salvage requirements were calculated and submitted to the Minnesota Department of Commerce annually since 2017.
- National Grid USA Service Company Limited: A depreciation study was completed in 2020 for the National Grid High Voltage Direct Current (HVDC) electric interstate transmission line. The study included consideration of the average service life of the system components, the level of components of the system and the compliance of the recommended componentization to the FERC Uniform System of Accounts. The resultant study was used by the company in filings with the Federal Energy and Regulatory Commission (FERC)

- Society of Depreciation Professionals (SDP): Mr. Kennedy has presented at the annual conferences on the topic of the erosion of the regulatory compact throughout North America, the Future of Energy transition and its impacts on recovery of investment. Additionally, Mr. Kennedy is a member of the SDP teaching faculty and has lead a number of workshops on various aspects of decarbonization and has co-instructed on the topic of the future of energy.

Other Representative Project Experience

- Alberta Departments of Energy and Forestry and Agriculture: Detailed toll comparison and valuation models were developed to provide a comparison of the toll fairness of each of the Provinces Rural Electrification Associations ("REA") to the comparable Investor Owned Utilities ("IOU") for the 32 REA's currently operating in Alberta. In addition to providing a toll comparison of the REA and IOU, a fair market valuation for each of the REA's was also prepared. The final report of the toll compatibility and specific valuations were submitted to the Alberta Department of Energy and the Alberta Department of Forestry and Agriculture. Mr. Kennedy was the Responsible Officer on this project.
- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.
- AltaGas Utilities Inc.: A number of depreciation studies have been completed, which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board ("Board"). Mr. Kennedy has appeared before the Alberta Utilities Commission on behalf of AltaGas on a number of occasions.
- AltaLink LP: An initial study was developed for submission to the Alberta Utilities Commission ("AUC") in 2002. The study included the estimation of service life characteristics, and the estimation of net salvage requirements for all electric transmission assets. A net salvage study and technical update was also filed with the Board in 2004. Since 2004, additional depreciation studies were filed in 2005, 2010 and 2012, 2016 and 2018. The 2010, 2012, 2016 and 2018 studies included a number of provisions in order to ensure compliance to Alberta's Minimum Filing Requirements for depreciation studies and for compliance to the International Financial Reporting Standards. These studies also specifically analyzed the pace of technical change in the Alberta Electric system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.

- ATCO Electric: Studies have included the development of annual and accrued depreciation rates for the electric transmission and distribution systems for the Alberta assets of ATCO Electric, in addition to the generation, transmission, and distribution assets of Northland Utilities Inc. (NWT) and the distribution assets of Northland Utilities (Yellowknife) Inc. The ATCO Electric studies were submitted to the AUC for review, while the NWT and Northland Utilities (Yellowknife) Inc. studies were submitted to the Northwest Territories Utilities Board and Yukon Electric Company Limited (YECL) was submitted to the Yukon Public Utilities Board. These studies also specifically analyzed the pace of technical and recently have specifically considered the impacts of early retirements caused by storms and forest fires.

- ATCO Gas: Studies were prepared in 2010 and 2018 which were the subject of a review by the AUC. Elements of all of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. These studies also specifically analyzed the pace of technical change in the Alberta Gas system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.

- Centra Gas Manitoba, Inc.: The study included development of annual and accrued depreciation rates for all gas plant in service. Elements of the study included a field inspection of metering and compression facilities, service buildings and other gas plant; service life analysis for all accounts using the retirement rate analysis on a combined database developed from actuarial data and data developed through the computed method; discussions with management regarding outlook; and the estimation of net salvage requirements. A similar study was completed in 2006, 2011, and 2015. The 2011 and 2015 studies were the subject of a review by the Manitoba Public Utilities Board in 2012 and 2016. Mr. Kennedy has also consulted on issues regarding International Financial Reporting Standards ("IFRS") compliance and required componentization.

- Enbridge Gas Distribution Inc.: Full and comprehensive depreciation studies have been completed in 2009 and 2011. The 2009 study also included review of the company's gas storage operations. Both studies included the development of annual and accrued depreciation rates for all depreciable natural gas distribution, transmission and general plant assets. Elements of the studies included the service life analysis for all accounts using the computed mortality method of analysis, discussion with management regarding outlook and the estimation of net salvage requirements. Studies were prepared for submission to the Ontario Energy Board.

- Mr. Kennedy has also completed an allocation of the accumulated depreciation accounts into the amounts related to the recovery of original cost and the amounts recovered in tolls for the future removal of assets currently in service. The allocations were determined as of December 31, 2009 and were deemed by the company's external auditors to be in conformance with proper accounting standards and procedures. In 2013, a review of the reserve required for the future removal of assets currently in service was undertaken by Mr. Kennedy. The results of the review were summarized in evidence presented by Mr. Kennedy to the Ontario Energy Board.

- ENMAX Power Corporation: Studies have included the development of annual and accrued depreciation rates for all depreciable electric transmission assets. Elements of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Alberta Department of Energy and more recently for submission to the Alberta Energy and Utilities Board. Similar studies have also been completed for submission for the ENMAX Electric Distribution assets for submission to the AUC. The ENMAX distribution asset assignments also included an extensive asset verification project where the plant accounting and operational asset records were verified to the field assets actually in service.

- Fortis Group of Companies: Studies have included the development of annual and accrued depreciation rates for the electric distribution assets in Alberta and for the generation, transmission, and distribution assets in British Columbia. The FortisBC Inc. studies were completed and filed with the British Columbia Utilities Commission ("BCUC") in 2005, 2010, 2011 and 2018 encompassing both the FortisBC electric and natural gas companies. FortisAlberta Inc. studies were completed in 2004 (updated in 2005), 2009 and 2010. Elements of the studies included the development of average service lives using the retirement rate method of analysis, development of net salvage estimates, compliance with IFRS, and the determination of appropriate annual accrual and accrued depreciation rates. The most recent studies also specifically analyzed the pace of technical change in the Electric systems, and specifically considered the impacts of retirements, system modernization and technical enchantments to the assets.

- International Financial Reporting Standards ("IFRS"): Mr. Kennedy has been retained by numerous clients encompassing most Canadian Provinces and Territories. The assignments included the review of company's assets and depreciation practices to provide opinion on the compliance to the IFRS. The assignments have also included the issuance of opinion to the External Auditors of Utilities to comment on the manner in which the Utilities can minimize differences in the regulatory ledgers and the accounting records used for financial disclosure purposes. Mr. Kennedy has also presented to the Canadian Electric Association, the Society of Depreciation Professionals, the Canadian Energy Pipeline Association and to the BCUC on this topic.

- Mackenzie Valley Pipeline Project: This assignment included the review of the proposed depreciation schedule for the proposed Mackenzie Valley Pipeline. The review included a discussion of the policies used by the company and the depreciation concepts to be included in a depreciation schedule for a Greenfield pipeline. The review was supported through appearance at the oral public hearings before the National Energy Board of Canada ("NEB").

- Manitoba Hydro: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study was submitted to the Manitoba Public Utilities Board. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of net salvage requirements. A similar study was also completed in 2006 and in 2011. The 2011 depreciation study was the subject of a review by the Manitoba Public Utilities Board in 2012. Mr. Kennedy has also consulted with Manitoba Hydro on issues regarding IFRS compliance and required componentization.

- New Brunswick Power: Mr. Kennedy completed a comprehensive depreciation review of the electric generation (including the nuclear facilities), transmission, distribution and general plant assets. The review, which was prepared for submission to the New Brunswick Public Utilities Board, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report.

- Newfoundland and Labrador Hydro (NALCOR): Mr. Kennedy developed comprehensive depreciation studies that included the development of depreciation policy and rates for NALCOR. The studies provided a significant review of the previous depreciation policy, which included use of a sinking fund depreciation method and provided justification for the conversation to the straight-line depreciation method. The study, which was prepared for submission to the Newfoundland and Labrador Utilities Commission, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report for submission in a General Tariff Application. Additional studies were also completed in 2008 and 2010. The 2010 and 2017 studies were the subject of Regulatory Review in 2012 and 2019.

- Ontario Power Generation: Assignments have included a review of the Depreciation Review Committee process completed in 2007. This review provided recommendations for enhanced internal processes and controls in order to ensure that the depreciation expense reflects the annual consumption of service value. Additionally, full assessments of the lives of the regulated assets of the company's electric generation hydro and nuclear plants were completed in 2011 and 2013 and were submitted to the Ontario Energy Board for review.

- TransCanada Pipelines Limited - Alberta Facilities: The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Alberta Energy and Utilities Board, incorporated the concepts of time-based depreciation for gas transmission accounts and unit-based depreciation for gathering facilities. The data was assembled from two different accounting systems and statistical analysis of service life and net salvage were performed. For gathering accounts, the assignment included the oversight of the development of appropriate gas production and ultimate gas potential studies for specific areas of gas supply. Field inspections of gas compression, metering and regulating, and service operations were conducted. Studies were completed in 2002 and 2004, 2007, 2009 and 2012, 2015, and 2018.

- TransCanada Pipelines Limited - Mainline Facilities: The study prepared for submission to the NEB included the development of annual and accrued depreciation rates for gas transmission plant east of the Alberta - Saskatchewan border. Elements of the study included a field inspection of compression and metering facilities, service life and net salvage analysis for all accounts. The study was completed in 2002 and was supported through an appearance before the NEB. Study updates have been completed in 2005, 2007, 2009 and an additional full and comprehensive study was completed in 2011, and 2017. The 2011 study was fully supported through an appearance before the NEB in 2012.

Designations and Professional Affiliations

- Society of Depreciation Professionals -Certified Depreciation Professional
- Society of Depreciation Professionals (former President)

EVIDENCE ENTERED INTO PROCEEDINGS IN THE UNITED STATES

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2015	Alliance Pipeline LP	Alliance Pipeline LP	Federal Energy and Regulatory Commission	Docket No. RP15-1022
2019	Viking Gas Transmission Company	Viking Gas Transmission Company	Federal Energy Regulatory Commission	RP19-1340
2020	National Grid USA Service Company Limited	National Grid USA Service Company Limited	Federal Energy Regulatory Commission	Settled through Negotiation
2018	Great Plains Natural Gas Co.	Great Plains Natural Gas Co.	Minnesota Department of Commerce	Annual Depreciation Filing
2018	Montana-Dakota Utilities	Montana-Dakota Utilities	Montana Public Service Commission	Docket D2019.9
2019	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Cascade Natural Gas Corporation	Cascade Natural Gas Corporation	Oregon Public Utility Commission	UM - 2073
2020	Missouri-American Water Company	Missouri-American Water Company	Missouri Public Service Commission	WR-2020-0344
2020	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Commonwealth Edison Company	Commonwealth Edison Company	State of Illinois – Illinois Commerce Commission	Docket 20-0393
2021	Intermountain Gas Company	Intermountain Gas Company	Idaho Public Utilities Commission	Case No. INT-21-01
2021	Midwestern Gas Transmission Company	Midwestern Gas Transmission Company	Federal Energy Regulatory Commission	RP21-525-000
2021	Enbridge Lakehead System	Enbridge Lakehead System	Federal Energy Regulatory Commission	DO21-15-000
2021	Consolidated Edison of New York	Consolidated Edison of New York	New York State Public Service Commission	19-G-0066
2022	Montana-Dakota Utilities	Montana-Dakota Utilities	North Dakota Utilities Commission	pending Montana-Dakota Utilities
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0130
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0155

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2022	Northern Natural Gas Company	Northern Natural Gas Company	Federal Energy Regulatory Commission	pending

EVIDENCE ENTERED INTO PROCEEDINGS IN CANADA

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
1999	ENMAX Power Corporation	Edmonton Power Corporation	Alberta Energy and Utilities Board	980550
2000	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	Decision 2002-43
2001	City of Calgary	ATCO Pipelines South	Alberta Energy and Utilities Board	2000-365
2001	City of Calgary	ATCO Gas South	Alberta Energy and Utilities Board	2000-350
2001	City of Calgary	ATCO Affiliate Proceeding	Alberta Energy and Utilities Board	1237673
2001	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2002	Centra Gas British Columbia	Centra Gas British Columbia	British Columbia Utilities Commission	N/A
2002	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2003	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1279345
2003	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2003	City of Calgary	ATCO Pipelines	Alberta Energy and Utilities Board	1292783
2003	City of Calgary	ATCO Electric-ISO Issues	Alberta Energy and Utilities Board	N/A
2003	City of Calgary	ATCO Gas	Alberta Energy and Utilities Board	1275466
2003	City of Calgary	ATCO Electric	Alberta Energy and Utilities Board	1275494
2003	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2003	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-1-2002
2004	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1305995
2004	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1336421
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2004	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	NOVA Gas Transmission Limited	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423
2004	Westridge Utilities Inc.	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2005	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	ATCO Electric	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	ATCO Power	ATCO Power	Municipal Government Board of Alberta	N/A
2005	British Columbia Transmission Corporation	British Columbia Transmission Corporation	British Columbia Utilities Commission	N/A
2005	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Transmission	Alberta Energy and Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Distribution Assets	Alberta Energy and Utilities Board	1380613
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	N/A
2005	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2005	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2005	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	New Brunswick Board of Commissioners of Public Utilities	N/A
2005	Northland Utilities (NWT) Inc.	Northland Utilities (NWT) Inc.	Northwest Territories Utilities Board	N/A
2005	Northland Utilities (Yellowknife) Inc.	Northland Utilities (Yellowknife) Inc.	Northwest Territories Utilities Board	N/A
2005	NOVA Gas Transmission Ltd.	NOVA Gas Transmission Ltd.	Alberta Energy and Utilities Board	1375375
2005	City of Red Deer	City of Red Deer Electric System	Alberta Energy and Utilities Board	1402729

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2005	Yukon Energy Corporation	Yukon Energy Corporation	Yukon Utilities Board	N/A
2006	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1456797
2006	BC Hydro	BC Hydro	British Columbia Utilities Commission	N/A
2006	Imperial Oil Resources Ventures Limited	McKenzie Valley Pipeline Project	National Energy Board of Canada	GH-1-2004
2007	Enbridge Pipelines Limited	Enbridge Pipelines Limited	National Energy Board of Canada	RH-2-2007
2007	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Energy and Utilities Board	1514140
2007	Kinder Morgan	Terasen (Jet fuel) Pipeline Limited	British Columbia Utilities Commission	N/A
2008	ATCO Electric	Yukon Electrical Company Limited	Yukon Utilities Board	N/A
2008	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1553052
2008	City of Lethbridge Electric System	City of Lethbridge	Alberta Utilities Commission	N/A
2008	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1512089
2008	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2009	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	N/A
2009	Fortis Alberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1605170
2010	ATCO Electric	ATCO Electric	Alberta Utilities Commission	1606228
2010	Enbridge Pipelines Limited· Line 9	Enbridge Pipelines Limited - Line 9	National Energy Board of Canada	N/A
2010	Gazifere	Gazifere	La Regie de L'Energie	R-3724-2010
2010	Kinder Morgan	Kinder Morgan	National Energy Board of Canada	N/A
2010	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	N/A
2011	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	1606694
2011	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1606895
2011	ATCO Electric	Northland Utilities (NWT) Inc.	Northwest Territories Utility Board	N/A
2011	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1606822

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2011	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Utilities Commission	1607159
2011	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	GazMetro	GazMetro	La Regie de L'Energie	R-3752-2011
2011	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2011	Qulliq	Qulliq	Utilities Rates Review Council	N/A
2011	SaskPower	SaskPower	Internal Review Committee	N/A
2011	TransAlta Utilities Corporation	TransAlta Utilities Corporation	Municipal Government Board of Alberta	N/A
2012	City of Red Deer	City of Red Deer	Alberta Utilities Commission	1608641
2012	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Ontario Energy Board	EB 2011-0345
2012	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2013/2013 GRA
2012	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2012	Northwest Territories Power Corporation	Northwest Territories Power Corporation	Northwest Territories Public Utilities Board	N/A
2012	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-003 -2011
2013	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1608711
2013	lntraGaz Incorporated	lntraGaz Incorporated	La Regie de L'Energie	R-3807-2012
2013	Yukon Electrical Company Limited (YECL)	Yukon Electrical Company Limited (YECL)	Yukon Utilities Board	2013-2015 GRA
2014	Enbridge Gas Distribution	Enbridge Gas Distribution	Ontario Energy Board	EB-2012-0459
2014	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1609674
2015	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 3524
2015	EPCOR Distribution & Transmission	EPCOR Distribution & Transmission	Alberta Utilities Commission	Proceeding 20407

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2015	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	N/A
2015	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2015	GazMetro	GazMetro	La Regie de L'Energie	N/A
2015	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2014/15 & 2015/16 GRA
2015	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2016	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 20272
2017	NALCOR	NALCOR	Newfoundland Public Utilities Board	Settled
2017	TransCanada Pipelines Limited – Mainline Facilities	TransCanada Pipelines Limited – Mainline Facilities	National Energy Board of Canada	RH-1-2018
2017	TransCanada Pipelines Limited – NGTL Facilities	TransCanada Pipelines Limited – NGTL Facilities	National Energy Board of Canada	RH-001-2019
2018	WestCoast Transmission System	WestCoast Transmission System	National Energy Board of Canada	Settled
2018	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 24195
2018	ATCO Gas	ATCO Gas	Alberta Utilities Commission	Proceeding 24188
2018	SaskEnergy Inc.	SaskEnergy Inc.	Saskatchewan Review Board	N/A
2018	SaskPower	SaskPower	Saskatchewan Review Board	N/A
2018	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	Proceeding 24161
2018	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 23848
2018	FortisBC Energy Inc.	FortisBC Energy Inc.	British Columbia Utilities Commission	N/A
2018	FortisBC Inc.	FortisBC Inc.	British Columbia Utilities Commission	N/A
2019	Capital Power Corporation	Capital Power Corporation	Municipal Government Board of Alberta	N/A
2019	TransAlta Corporation	TransAlta Corporation	Municipal Government Board of Alberta	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2019	Trans Mountain Pipeline ULC	Trans Mountain Pipeline ULC	Canadian Energy Regulator	T260-2019-04-01
2019	NB Power	NB Power	New Brunswick Energy Utility Regulator	Pending
2019	ATCO Electric	ATCO Electric Transmission	Alberta Utilities Commission	Proceeding 24964
2020	Enbridge Pipelines Inc.	Enbridge Pipelines Inc.	Canada Energy Regulator (CER)	RH-001-2020
2021	Ontario Power Generation	Ontario Power Generation	Ontario Energy Board	N/A
2021	AltaLink L.P	AltaLink L.P	Alberta Utilities Commission	Proceeding 26059
2022	IntraGaz LP	IntraGaz LP	La Regie de L'Energie	R-4189-2022
2022	BC Hydro	BC Hydro	British Columbia Utilities Commission	Project 1599243

AMANDA R. NORI

Senior Project Manager

Ms. Nori is a professional depreciation expert with over 13 years of experience completing comprehensive utility studies. Over this time, Ms. Nori has assisted in preparing over 50 detailed depreciation studies for clients across the regulated utility industry. She reviews and evaluates complex financial data, builds the studies, and prepares expert evidence required by Canadian and U.S. regulators. Ms. Nori is a recognized expert on these matters and an invited speaker on utility depreciation topics. Ms. Nori holds a Bachelor of Arts from the University of Calgary (2006), is a Certified Depreciation Professional (CDP) as awarded by the Society of Depreciation Professionals (SDP) (2020) and has completed the Advanced Regulatory Program offered by the University of Illinois—Springfield (2020). In addition, Ms. Nori has presented on current issues at the SDP annual conference and is a current member of the SDP Board of Directors.

AREAS OF EXPERTISE

- Data Processing
- Iowa Curve Estimation
- Cost of Removal
- Gross Salvage Estimation
- Statistical Analysis Depreciation Expense Analysis
- Testimony Preparation
- Post Filing Services
- Business Analysis
- Service Life Estimation
- Management Consulting
- Financial Analysis Actuarial Analysis
- Simulated Retirement Analysis
- Regulatory Compliance

EXPERIENCE

Representative Project Experience

- AltaGas Utilities Inc.: A number of depreciation studies have been completed, which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board (“Board”).

- AltaLink LP: A depreciation study was developed for submission to the Alberta Utilities Commission ("AUC") in 2010. The study included the estimation of service life characteristics, and the estimation of net salvage requirements for all electric transmission assets. Additional depreciation studies were filed in 2012, 2016 and 2018. All studies included a number of provisions in order to ensure compliance to Alberta's Minimum Filing Requirements for depreciation studies and for compliance to the International Financial Reporting Standards. These studies also specifically analyzed the pace of technical change in the Alberta Electric system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.

- ATCO Electric: Studies have included the development of annual and accrued depreciation rates for the electric transmission and distribution systems for the Alberta assets of ATCO Electric, in addition to the generation, transmission, and distribution assets of Northland Utilities Inc. (NWT) and the distribution assets of Northland Utilities (Yellowknife) Inc. The ATCO Electric studies were submitted to the AUC for review, while the NWT and Northland Utilities (Yellowknife) Inc. studies were submitted to the Northwest Territories Utilities Board and Yukon Electric Company Limited (YECL) was submitted to the Yukon Public Utilities Board. These studies also specifically analyzed the pace of technical and recently have specifically considered the impacts of early retirements caused by storms and forest fires.
- ATCO Gas: Studies were prepared in 2010 and 2018 which were the subject of a review by the AUC. Elements of all the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. These studies also specifically analyzed the pace of technical change in the Alberta Gas system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.
- ENMAX Power Corporation: This study included the development of annual and accrued depreciation rates for all depreciable electric transmission assets. Elements of the study included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Alberta Utilities Commission. The ENMAX distribution asset assignment also included an extensive asset verification project where the plant accounting and operational asset records were verified to the field assets actually in service.
- Fortis Group of Companies: Studies have included the development of annual and accrued depreciation rates for the electric distribution assets in Alberta and for the generation, transmission, and distribution assets in British Columbia. The FortisBC Inc. studies were completed and filed with the British Columbia Utilities Commission ("BCUC") in 2010, 2011 and 2018 encompassing both the FortisBC electric and natural gas companies. The FortisAlberta Inc. study was completed in 2010. Elements of the studies included the development of average service lives using the retirement rate method of analysis, development of net salvage estimates, compliance with IFRS, and the determination of appropriate annual accrual and accrued depreciation rates. The most recent studies also specifically analyzed the pace of technical change in the Electric systems, and specifically considered the impacts of retirements, system modernization and technical enchantments to the assets.

- Consolidated Edison Company of New York, Inc.: Ms. Nori co-authored a study and report which presented the results of research focusing on prior periods of transformative change and more recent discussions of policy tools that could address the impacts of climate change on the Company's electric, steam, and natural gas businesses.
- Commonwealth Edison Company: Ms. Nori prepared extensive Rebuttal Testimony related to the average service life, net salvage estimations, and appropriate depreciation practices in a 2020 rate proceeding.
- Viking Gas Transmission Company - The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons, including discussion related to the long demand of natural gas.
- Canadian Electricity Association: Ms. Nori presented at the CEA on the topic of current issues and trends in 2013.
- Society of Depreciation Professionals (SDP): Ms. Nori has presented at the annual conferences on the topic of current issues in depreciation studies in 2022. Additionally, Ms. Nori is a current member of the SDP Board of Directors.

PROJECTS COMPLETED, MANAGED OR TESTIFIED ON BY MS. NORI

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2010	Gazifere	Gazifere	La Regie de L'Energie	R-3724-2010
2011	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	1606694
2011	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1606895
2011	ATCO Electric	Northland Utilities (NWT) Inc.	Northwest Territories Utility Board	N/A
2011	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1606822
2011	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Utilities Commission	1607159
2011	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	GazMetro	GazMetro	La Regie de L'Energie	R-3752-2011
2012	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Ontario Energy Board	EB 2011-0345
2012	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2013/2013 GRA

2012	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2012	Northwest Territories Power Corporation	Northwest Territories Power Corporation	Northwest Territories Public Utilities Board	N/A
2012	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-003 -2011
2013	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1608711
2013	Yukon Electrical Company Limited (YECL)	Yukon Electrical Company Limited (YECL)	Yukon Utilities Board	2013-2015 GRA
2014	Enbridge Gas Distribution	Enbridge Gas Distribution	Ontario Energy Board	EB-2012-0459
2014	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1609674
2015	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 3524
2015	EPCOR Distribution & Transmission	EPCOR Distribution & Transmission	Alberta Utilities Commission	Proceeding 20407
2015	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	N/A
2015	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2015	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2014/15 & 2015/16 GRA
2016	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 20272
2017	NALCOR	NALCOR	Newfoundland Public Utilities Board	Settled
2017	TransCanada Pipelines Limited – Mainline Facilities	TransCanada Pipelines Limited – Mainline Facilities	National Energy Board of Canada	RH-1-2018
2017	TransCanada Pipelines Limited – NGTL Facilities	TransCanada Pipelines Limited – NGTL Facilities	National Energy Board of Canada	RH-001-2019
2018	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 24195
2018	ATCO Gas	ATCO Gas	Alberta Utilities Commission	Proceeding 24188
2018	SaskEnergy Inc.	SaskEnergy Inc.	Saskatchewan Review Board	N/A
2018	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	Proceeding 24161
2018	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 23848
2018	FortisBC Energy Inc.	FortisBC Energy Inc.	British Columbia Utilities Commission	N/A
2018	FortisBC Inc.	FortisBC Inc.	British Columbia Utilities Commission	N/A

2019	ATCO Electric	ATCO Electric Transmission	Alberta Utilities Commission	Proceeding 24964
2019	Viking Gas Transmission Company	Viking Gas Transmission Company	Federal Energy Regulatory Commission	RP19-1340
2019	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2020	Missouri-American Water Company	Missouri-American Water Company	Missouri Public Service Commission	WR-2020-0344
2020	Enbridge Pipelines Inc.	Enbridge Pipelines Inc.	Canada Energy Regulator (CER)	RH-001-2020
2020	Commonwealth Edison Company	Commonwealth Edison Company	State of Illinois – Illinois Commerce Commission	Docket 20-0393
2021	Ontario Power Generation	Ontario Power Generation	Ontario Energy Board	N/A
2021	Enbridge Lakehead System	Enbridge Lakehead System	Federal Energy Regulatory Commission	DO21-15-000
2021	Consolidated Edison of New York	Consolidated Edison of New York	New York State Public Service Commission	19-G-0066
2021	AltaLink L.P	AltaLink L.P	Alberta Utilities Commission	Proceeding 26059
2022	BC Hydro	BC Hydro	British Columbia Utilities Commission	Project 1599243
2022	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	Proceeding 27581
2022	Enbridge Gas Inc.	Enbridge Gas Inc.	Ontario Energy Board	EB-2022-0200
2023	United Illuminating Company	United Illuminating Company	State of Connecticut Public Utilities Regulatory Authority	22-08-08

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2023 – Present)
Senior Project Manager

Concentric Energy Advisors, Inc. (2021 – 2022)
Project Manager

Concentric Energy Advisors, Inc. (2017 – 2020)
Senior Consultant
Consultant

Gannett Fleming (2009-2017)
Depreciation Analyst

RealNet Canada, Ltd. (2007-2009)
Field Analyst

EDUCATION

University of Calgary, Alberta
Bachelor of Arts, European History, 2006

Society of Depreciation Professionals

Certified Depreciation Professional, 2018

University of Illinois Springfield, 2020

Graduate Certificate in Public Utility Management and Regulation

PROFESSIONAL ASSOCIATIONS/DESIGNATIONS

Certified Depreciation Professional (2018 – Present)

Society of Depreciation Professionals (2010 – Present)

Member of the Board, Society of Depreciation Professionals (2023 – Present)

Abbas Lakha, CPA, CA

Associate Partner
Consulting Services

Abbas.lakha@ca.ey.com
+1 416 943 3938

Career summary

Ernst & Young LLP
2009 – 2013
2015 – Present

Toronto Hydro
2013 – 2015

Industry Expertise

Energy services/ Power and Utilities

Education

Honours Bachelor of Business Administration, Schulich School of Business, York University

Certification(s)

CPA, CA

Community Activities(s)

Director, Canadian Charity
2017 - present

Summary

Abbas is an Associate Partner with the Consulting Services group in Toronto and has been with EY since 2009, with a gap of two years in industry within the Power and Utilities Sector. He has gained IFRS US GAAP, and regulatory accounting experience by working with public and private companies in a variety of industries, specifically in power and utilities.

Abbas has also been involved with advising companies on complex accounting issues, developing capex and depreciation policies, as well as assisting with regulatory filings and queries. Further, Abbas has significant experience in the regulatory landscape, assisting large utilities with amalgamations, process improvement, risk mitigation, harmonization of policies and processes and the understanding of regulatory implications.

Relevant Professional Experience

- **Consulting Services:**

  Various Gas, Water and Electricity Utilities:
  - Lead a team of individuals working with a large P&U client on a transformation initiative as part of an integration effort. This included a review accounting policy, harmonization of finance and business processes, documentation of processes and identification of automation and process improvement opportunities
  - Assisted management in identifying key areas of focus and priority for the customer care team in an effort to improve the customer experience
  - Conducted several process reviews across various areas of the business including the collections and customer process
  - Lead a team to assist the utility in harmonizing and aligning management reporting between legacy entities. This included the implementation of Power BI and an Azure data model in an effort to create a source of truth for the finance department
  - Assisted management in determining the regulatory impact of alignment decisions and providing a tracking mechanism
  - Assisted management in identifying efficiency opportunities including the use of automation in core finance processes
  - Assisted management in the review of cost allocations between their unregulated and regulated business. This included a formal study of costs allocation and the documentation of a harmonized approach for the amalgamated entity
  - Led a team of individuals to undertake an overhead capitalization study across serval clients resulting in a report documenting management's approach to overhead capitalization
  - Assisted management in understanding the implications to regulatory accounting of changes in various accounting policies and processes through the establishment of a deferral account
  - Assisted with the review of the business support team, including a process, FTE and technology review outlining key process gaps and improvements
  - Lead a team to understand and document legacy methodologies in relation to the unbilled revenue model and document observations with respect to variances, assumptions and gaps within the model
  - Provided recommendations to assist the large utility in better tracking its assets, and creating a formidable capex strategy
  - Assisting the company in understanding and applying reasonable depreciation policies in line with regulatory requirements
  - Lead a team of individuals in a review of the unbilled revenue methodology, including interactions and interviews with regulatory staff
  - Worked with the audit committee to update the COSO framework and the governance structure of the internal audit group
  - Responsible for assisting with segments of multi year regulatory filings and rate case approvals
  - Responsible for evaluating and determining process gaps in the RRR process and filing and providing relevant recommendations to leadership

		- Responding for providing reports relating to various business processes identifying opportunities to enhance the control environment and create efficiencies in serval processes.
		
		- **Shareholder owned Electricity Generator, Gas, Water and Electricity Utility**
		  - Led the audit of a large multi-billion-dollar power and utilities company, dealing with complex revenue transactions, business acquisitions and several other key accounting considerations
		  - Responsible for understanding and dealing with regulatory issues across several US states, including but not limited to: Georgia, Arizona, California and New Hampshire.

Andrew Grainger, FCPA, FCGA
Partner
Business Consulting

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Industry lines
Power and Utilities
Nuclear
Oil & Gas

Education
University of Calgary
Bachelor of Accounting Science

Certification(s)
Fellow Chartered Professional Accountant (FCPA), Fellow Certified General Accountant (FCGA)

Professional experience summary

Andrew Grainger is a Partner in the Business Consulting practice of EY LLP and is the Canadian Power & Utility Consulting leader. He is responsible for managing and developing a diverse and skilled group of business advisors as well as securing new business with a number of market leading companies across a Canada.

Andrew has 25 years of experience working with clients in the Power & Utilities industry and has extensive experience with strategic, system implementation and integration projects, project management, and business process transformation and reengineering initiatives across Finance, IT, Supply Chain, and other operations.

Engagement experience

- Andrew is the coordinating partner for a large natural gas utility client and oversees the delivery of numerous engagements throughout the utility's operations, including the development of target operating models in Operations, Customer Care, Engineering, Storage and Transmission, Distribution Operations, and Finance.
- Andrew is the Global Client Service Partner for a large Electric Transmission & Distribution Company, and responsible for the coordination of our work across multiple areas of the organization, including Strategy, Customer Experience, Finance, as well as working with the COO and his VP's to develop and execute on their overall strategy for the Energy Transition and the role their respective groups are responsible for in order to enable that transition.
- Andrew is the Global Client Service Partner for a large Electric Distribution Company, and responsible for the management of numerous engagement teams, including the large systems integration of the ERP systems from four legacy utilities joined through merger and acquisition, in to one system. He is working closely with senior management as part of the Executive Steering committee to identify project risks and opportunities to drive business value and efficiencies as a result of the ERP convergence and provide ongoing support to senior management throughout the project.
- Andrew is the lead partner working with a large P&U client on a Finance Transformation initiative as part of an integration effort. He is leading a team working with senior management to review accounting policies, business processes, and system needs to develop a roadmap toward an integrated solution, and then execute on that roadmap over the next ten months.
- For a large P&U client, Andrew is the engagement partner leading a team to provide an ongoing assessment as to the current and emerging issues and risks that may impede the on-time / on-budget / on-scope delivery of a custom development Customer Information System modernization project. The team is working alongside the PMO to provide recommendations and assist management with mitigating high-priority issues and risk identified, provide assessment, maintenance, scheduling and tracking of the Project Plan, including daily updates based on Service Provider and the client's progress. The team is also providing ongoing support to management in relation to business case realization.
- Andrew is the engagement partner for a large scale P&U client, leading a team to provide an ongoing assessment as to the current and emerging issues and risks that may impede the on-time / on-budget / on-scope delivery of a Maximo and ClickSoftware implementation project. The team is working with management to provide recommendations and assist management with mitigating high-priority issues and risk identified. Andrew sits on the Executive Steering Committee to provide ongoing support to senior management throughout the project.
- For a Multi-service utility in Ontario, serving 360,000 electric & water customers, Andy was the QA partner working with the team to provide oversight for the design, development and delivery of a role-based, blended curriculum for an Oracle CC&B, MTM, and MDMR

implementation. The program included: needs analysis, user task analysis, web-based and instructor-led curriculum design, train-the-trainer, learning management system set-up, and business process refinement and knowledge transfer planning.

- For the largest Nuclear Power Generation facility in North America, Andrew served as the lead partner to advise senior management on select strategic initiatives to streamline processes and reduce costs. The assessments to date have covered areas in finance, supply chain and commercial services, IT project management, application rationalization, and throughout operational functions of the company. This also included project reviews to provide senior management with an independent evaluation of selected critical projects.
- For a large natural gas utility, Andrew oversaw a team working with the finance and regulatory team to provide an assessment of the capitalization policies for indirect overheads. This engagement included the preparation of a report that was filed with the utilities regulator as evidence to support the reasonability of their approach.
- Andrew was the engagement partner for a procurement transformation program at a large nuclear power generation facility. Scope included integrated work management, maintenance and engineering, redesigning of procurement processes, and improving management of MRO and capital spares inventory
- For a large natural gas transmission, distribution and storage company, Andrew was the engagement partner advising the company on carving out business processes and functions for the regulated portion of their business, in order to address regulatory requirements. This involved an in-depth review of their current business process in order to determine and develop a roadmap for the necessary changes required to business process, management reporting and system requirements to enable them to capture the appropriate information in an efficient manner and produce the required information on an ongoing basis.
- Andrew led a review of the AP shared services function for a large P&U client. He led a team working with senior management to perform a current state assessment of the business processes, identified gaps, manual workarounds and compensating controls currently being used, to design a future state process that will enable them to take advantage of automation technology. The future state model streamlined the business processes, reducing the need for manual intervention and workarounds, as well as increasing control effectiveness and reducing the risk of manual error.
- For a large P&U company that was experiencing a period of unprecedented growth in its regulated business, Andrew was the engagement partner leading an assessment of the Plan, Budget, and Forecast process. As the company was undertaking some of the largest capital expansion projects in its history, Andrew led the project team to assist the organization with enhancing their PBF process to allow them to balance this growth with their regulatory requirements, implement changes to their process and tools to enable them to closely monitor their budgets, and prepare driver based forecasts to better support decision-making. The enhanced process provided increased the transparency in its budgeting and forecasting processes, as well as increased the value that the Planning and Forecasting team delivers to the organization.
- Andrew was the Partner that oversaw an Enterprise Resource Planning (ERP) Needs Assessment and Scoping for an LDC in Southwestern Ontario to identify opportunities to create business value based on their strategic and operational priorities, and on industry leading practices. Defined ERP solution architecture options based on the capabilities required by the LDC to execute on the benefits opportunities, including non-ERP components. Analyzed and compared the ERP solution architecture options based on the differential business value they enabled, and their corresponding one-time implementation costs, ongoing operating costs, execution risk and ongoing operating risk factors, a robust, rigorous process including scenario and sensitivity analyses and leveraging our understanding of cost and risk factors specifically in the LDC's environment and based on our industry-specific knowledge capital and fact bases.
- Power & Utilities company, Fleet policy integration - Led the team working with fleet management to review the fleet policies (incl. vehicle assignment and fit for purpose) and supported the development and implementation of a harmonized policy.
- Power & Utilities company, Garage strategy Led the team working with fleet management to perform a current state assessment of the garage operations in the two legacy companies and, through detailed financial analysis and productivity analysis, supported the design of the future state integrated operating model for the garage operations.

- Power & Utilities company, Fleet support strategy - Led the team working with fleet management to perform a current state assessment of the fleet support function in the two legacy companies and, through detailed financial analysis and productivity analysis, supported the design of the future state integrated operating model for the fleet support operations.
- Power & Utilities company, Auto Taxable Benefit -Led the team working with fleet management and HR / payroll to perform a current state assessment of the two legacy companies' auto taxable benefit processes and identified gaps against the CRA policy to design a future state integrated process with greater CRA compliance and an improved information flow to HR / payroll
- Power & Utilities company, Content Management - Leading a team to provide an ongoing assessment of the current and emerging issues and risks that may delay the delivery of the roll out of a content management program (storage and delivery). The team is working alongside the PMO to provide recommendations and assist management with mitigating high-priority issues and risks identified and provide assessment from an organizational change management, IT and operational perspective.
- Power & Utilities company, Engineering wavespace™ session- Conducted a virtual wavespace™ session designed to help the Engineering and Storage and Transmission team to obtain an overview of future industry trends, align and recalibrate near-term strategic priorities and craft a roadmap.
- Power & Utilities company, organizational design for Finance, and Customer Care & Sales functional areas - Supported and facilitated the design of the amalgamated Finance and Customer Care & Sales functions. The team developed high level design of the amalgamated organization for these functions. The engagement also included detailed organization design and talent selection, and development and execution of the people transition strategy and plan for Finance.
- Power & Utilities company, rapid synergy assessment - The engagement involved the high-level identification of synergies through executive leadership interviews, headcount and productivity benchmarking and examination of corporate reports.
- Power & Utilities company, Distribution Operations integration projects - Supported various engagements within Operations to design of the future state operating models for Field Execution, Planning and Dispatch and Customer Connection. EY facilitated several workshops with Operations Teams and Leadership, and developed a decision-making approach to evaluate current state operating models and supported detailed analysis.
- Natural gas company, Distribution Operations wavespace™ session - Conducted an interactive wavespace™ session to provide them with an overview of the global trends in the natural gas industry, deep dive and demonstrations on the innovations in the industry to develop the Distribution Operations long-term strategic roadmap
- Power & Utilities company, Customer Care & Sales operating model assessment - Supported the client with the design of the amalgamated future state operating model for the function. The team conducted site visit, analyzed key metrics data, performed costing analysis and evaluated business and financial benefits to develop recommendations on the operating model
- Power & Utilities company, Integration Management office advisory - Reviewed and assessed the reasonableness of identified synergies and overall targets. Advised the Integration Management Office ("IMO") on leading practices for interdependency management, performance measurement, key performance metrics and executive and operational dashboarding

Guidehouse

Andrea Roszell

Director

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Toronto, ON
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Professional Summary

Andrea is an experienced strategist and project manager. Through her work with clients across North America, Andrea has developed an intimate knowledge of the electricity industry and the challenges relating to the evolution of business models for utilities, energy service companies and system operators which will be required during the transition to a more dynamic, intelligent and distributed future. She has 10 years' experience in the energy industry covering a wide range of projects including energy strategy development, conservation and demand management program evaluations and providing research, analysis, and advice to clients on various emerging energy technologies. Her clients have included utilities, governments, and private sector companies. Andrea's areas of expertise include smart grid and grid modernization, micro grid and renewable energy project assessments, energy strategy development, conservation and demand management program evaluation, and business case development and market assessment of emerging energy technologies.

Areas of Expertise

- **Energy Cloud Transformation:** Assists clients in developing new policies, strategies and business models around the emerging Energy Cloud (e.g., renewables, distributed energy resources, grid modernization).
- **Smart Grid / Grid Modernization**: Assists clients in crafting their Smart Grid strategy, leveraging the integration of new and existing technologies to transform their business and organization, as well as in developing their energy vision. Involves quantifying costs and benefits associated with grid modernization and scoping Smart Grid projects which meet client reliability and cost effectiveness requirements.
- **Emerging Technology Assessment**: Performs research and cost effectiveness analysis to identify growth opportunities for emerging technologies in varying market conditions and make recommendations to clients about investment opportunities.
- **Conservation and Demand Management**: Leads residential evaluations for multiple program types. Involves both process and impact evaluation components. Andrea leverages her experience in the industry to identify best practices and program improvements. She has also been involved in upstream lighting evaluations including in-store intercept surveys, shelf surveys, general population surveys, residential focus groups and industry expert Delphi panels.

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Andrea Roszell

Director

Professional Experience

Smart Grid / Grid Modernization

- Acted as project manager for the development of a Grid Modernization roadmap for a utility in Western Canada. Identified Grid Modernization goals, prioritized technologies and aligned technology deployment initiatives with internal and external trigger points.
- Developed a grid transformation strategy for a utility in Western Canada. Developed strategic positions that nurture new opportunities and new business models for the utility, provided background on technology and policy trends that are transforming the electricity sector globally and link to the conditions likely to unfold in utility jurisdiction, Identified opportunities to evolve the utility business model to meet future customer needs, assessed and prioritize initiatives to protect corporate value and generate revenue and outlined growth strategy required to become utility of the future.
- Led the development of a microgrid business and financial model for a utility in the southern US. Included identifying value propositions, customers, channel strategy, key activities, revenue streams and costs. Developed financial proforma model to determine the viability of the project.
- Acted as project manager for the development of Smart Energy projects for 32 US Navy bases. Involves analysis of existing energy consumption patterns, existing building and utility control systems, and energy savings potential through integration and expansion of control systems. Projects include modernizing on-base electric distribution systems to improve system reliability and reduce operating costs. Available control strategies are presented to the Navy and facilitated workshops led to desired project outcomes. Projects were evaluated from an energy savings and economic perspective to establish most desirable projects
- Acted as project manager for a project to develop a regulatory strategy for a utility to support efforts to influence and guide policy and regulatory development and identify and prioritize opportunities for the utility in the future.
- Supported project to evaluate growth opportunities for microgrid-generated energy within the United States. Involved an initial financial screening assessment of the market through an individual financial examination of a representative selection of actual microgrid projects. This project investigated generation technologies, geographic locations, customers loads and financing options to support the customer’s market-entry decision.

Energy Sector Transformation

- Acted as project manager for the development of pathways to meet provincial GHG reduction targets. Included identifying initiatives to reduce GHG emissions, and quantifying the energy, GHG and cost impacts. Analysis involved completing technology and risk assessment as well as sensitivity analysis.

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Andrea Roszell
Director

- Acted as project manager for the development of a regulatory and policy roadmap to guide a utility client through the steps required in order to transform the regulatory and policy environment to one that supports the utilities involvement in the Energy Cloud.
- Supported a client in the development of a roadmap which identifies actionable recommendations to support the utilities transformation to offering products and services required in the Energy Cloud. The roadmap initiatives were prioritization, and interdependencies and timelines were identified.
- Assisted a client with the development of business unit growth strategies, and associated justification, for the regulated and unregulated businesses and developed an internal investment evaluation and approval framework to support evaluation of investments in new products and services which may be offered.
- Supported a client in understanding the potential roles of electricity sector participants (utilities, system operators, third parties) in a future with higher penetration of distributed energy resources. Identified potential future roles for the client and completed a gap analysis to identify the additional functionality required.
- Assisted a client in the development of an investment framework to clarify investment funding levels, governance, and overall process for requesting pilot, due diligence, and scaled-investment funding. Developed business case templates to support the framework and tested the template through development of four individual business cases.

Emerging Technology Assessment

- Contributed to a market study of the wind / hydro / solar markets across Canada in support of a proposed acquisition of a project developer. Analysis included electricity supply/demand dynamics in several Canadian provinces, the number of projects under contract, and supply chain availability.
- Acted as deputy project manager for a CHP and WER potential study through which the technical and market (achievable) potential for CHP and WER in Ontario was evaluated. The study involved characterizing facilities across Ontario, developing energy profiles, accounting for existing CHP/WER and district energy systems across Ontario, comparing CHP/WER economics to buy from grid and ultimately identifying the achievable potential for BMG across the province.
- For the U.S. Navy, Andrea led the team that developed a long-term thermal energy plan for eight Navy installations across the U.S. Andrea and her team performed a detailed analysis of the current and future steam requirements, calculated the distribution system heat losses, and developed fuel and electricity forecasts. By working with the installation’s stakeholders and Navy technical staff, Andrea and her team selected options and performed a comparative analysis that included detailed economic assessment of capital and operating costs as well as an evaluation of the impact on Navy-wide and regional energy goals. As an example, one of our recommendations to replace an old and inefficient boiler plant at Norfolk Naval Station with a 15 MW cogeneration system is currently moving through the funding approval process.

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Andrea Roszell

Director

Conservation and Demand Management

- Responsible for leading detailed upstream lighting program evaluation for Duquesne Light. Tasks included in-store intercept surveys, shelf surveys, general population surveys, residential focus groups and industry expert Delphi panels. Project outputs included quantifying NTG ratios and recommendations for future lighting program design.
- Responsible for leading process and impact evaluation of several EE/DSM programs including residential appliance recycling, residential energy efficiency rebates, low income energy efficiency programs and C&I programs for Duquesne Light. This multi-year evaluation involves providing the client with feedback on program improvements and best practices.
- Led evaluation of residential Appliance Recycling Program for DTE. Responsible for developing research questionnaires to survey participants to assess net-to-gross, realization rate, program awareness and program satisfaction. This three-year evaluation involved annual process and impact components. Evaluation components include savings verification, participant satisfaction surveys, trade ally interviews and net-to gross/ market effects research.

Work History

- Director, Guidehouse
- Process Engineer, Hatch
- Fuel Cell Researcher, Queen’s University

Education

- M.S., Chemical Engineering, Queen’s University
- B.S., Honours, Chemical Engineering, University of Waterloo

Craig Sabine

ASSOCIATE PARTNER

Toronto, ON

craig.sabine@ca.ey.com

Direct: 647-288-5227

EDUCATION

MBA Executive Program, Queen's School of Business, Kingston, ON, Canada (2012)

BES Environmental and Resource Studies. Minor, Biology University of Waterloo, ON, Canada (2004)

TESTIMONY EXPERIENCE

- Gazifere 2017 COS. April, 2016
- Coffin and Lowry v. Atlantic Power Corporation. March, 2015
- ENMAX General Rate Application Hearing, AUC. July, 2014
- Manitoba Hydro NFAT Hearing, MPUB. April, 2014
- Natural Gas Markets Review Consultative Hearing, OEB. 2010/14

Craig Sabine is an Associate Partner at EY, leads the firm's Energy Transition services in Canada. Previous Craig led the Energy Companies practice at Guidehouse Canada and is past Chair of Guidehouse's regulatory transformation initiative. Craig is a strategic partner and trusted advisor to Canadian utilities, energy sector organizations, the financial services sector in strategic planning, investment decision making, risk management, affiliate relationships and cost allocation, as well as other organizational transformation.

Working with executive management teams, Craig focuses on the strategic market opportunities and regulatory challenges within and across the energy value chain and has supported regulatory filings related to system planning, cost allocation, affiliates, working capital and rate design.

Craig is a recognized leader in the analysis of energy markets in Canada, including expertise in provincial regulatory and policy development. Notable impactful assignments have afforded Craig the opportunity to assess the gas supply risk management program of SaskPower, review the full cost risk in the Bruce Power refurbishment agreement, provide expert testimony regarding Manitoba Hydro's $25 billion capital investment plan and build an internal compliance program (ICP) for TransAlta related to NERC compliance.

Prior to Guidehouse Craig was a Senior Manager and Eastern Region Lead of MNP LLP's energy practice and a Manager at ICF Marbek.

Areas of expertise

- Portfolio assessment and business Planning
- Enterprise Risk
- Cost Allocation and affiliates
- Regulatory economics
- Integrated planning
- Generation procurement and divestiture
- Policy design
- Organizational Development
- Processes and efficiency

Project experience

Strategy, Decarbonisation and Energy Transition

- **Ontario BESS Analysis - (Jun 2021 to Sept 2021)** - Craig evaluated a large battery storage project in Ontario for an international conglomerate and supported the project in the IESO's unsolicited energy proposals process. The BESS asset was found to offer substantial system and local benefits for Ontario and investable revenue streams by improving the productivity of baseload and variable generation with positive impacts on wholesale energy prices.
- **TC Energy Pump storage – (Mar 2021 to Oct 2021)** Guidehouse performed an economic analysis of a proposed large-scale hydroelectric pumped storage power project in Ontario. The analysis focused on the economic viability of the project considering the forecasted market prices and used the EVM model to pump storage operation within the market. Guidehouse, is currently providing regulatory support in ongoing discussions with the IESO.
- **Crown Investments Corporation of Saskatchewan – Combined Cycle Project Support – (Mar 2016 to Dec 2016)** After serving as a member of the Evaluation Committee for the qualification of accepted generation developers, Craig supported the CIC with project risk and value for money analysis of project bids for development and operation of a 300 MW combined cycle facility required in

Saskatchewan by 2019. The project will result in a decision by the Saskatchewan government to proceed with the project under SaskPower or private sector lead

- **FortisBC Energy Vision 2050** – **(August 2019 to May 2020)**. Location: BC, Canada In support of FortisBC, Craig recently led an effort to develop GHG reduction scenarios that align with the provincial government's 2050 GHG targets. Guidehouse modelled scenarios that include extensive electrification, but also adopt smart low carbon fuel use and natural gas heatpumps to determine the costs and benefits of alternative policy pathways. A diverse scenario was found to offer robust optionality and generates equivalent emissions reductions to all electrification scenarios in BC. The assignment leveraged energy and economy optimization models to determine the most likely technical and economically reasonable pathways towards a 2050 GHG reduction across the BC economy, and studied the impacts of heatpumps, EVs, RNG, hydrogen, energy efficiency and industrial electrification.]
- **Ministry of Energy Ontario Fuels Sector Decarbonization Options – (May 2016 to Jan 2017. Location: ON, Canada)** Craig acted for the Ministry of Energy in 2016 as Director in charge for an assignment to develop a fuels sector decarbonization analysis as part of the initial phase of the Long-Term Energy Planning process. The report provided the Ministry and stakeholders with a detailed view of the state of Ontario's fuels markets, including natural gas, refined petroleum products, propane, bio fuels and alternative fuels. The analysis also provided a set of scenarios illustrating the impacts of different demand outlooks for fuels, the GHG outcomes that result from various energy end-use technologies shifts and studied different degrees of electrification of fuel switching. A number of demand factors were tested, including clean fuel standards, conservation and DSM scenarios, technology adoptions and fuel switching.
- **Ontario Teacher's Pension Plan, Low Carbon Economy Transition – (May 2017 to Oct 2017. Location: ON, Canada)** Craig led an expansive consulting engagement with one of the world's largest pension funds to develop, implement and embed a framework to monitor and assess the risks and opportunities presented to the organization of a low carbon economy transition. The assignment included multinational teams who developed benchmark scenarios of economic activity and a framework model to track energy use technologies and GHG metrics in the economy to measure and monitor the pace of energy systems transition. The organization was highly engaged through facilitated workshops to support change management and new business processes necessary to embed climate risk and low carbon transition in all aspects of the investment process.
- **Ontario EV Consortium Strategic Plan – (July 2018 to January 2019. Location: ON, Canada)** In a keystone project for a consortium of 4 electric distribution utilities in Ontario, representing more than 80% of the province's total end-use load, Craig project managed to examine the merits of a viable system / societal costs business case for utility ownership of electric vehicle (EV) charging infrastructure. Navigant's study developed EV adoption forecasting and charging infrastructure siting needs for light-, medium-, and heavy-duty vehicles at the forward sortation area level under 3 scenarios and identified the most attractive EV charging business options, such as public curbside, and fleets conversion, establish system impact estimates and siting requirements for ratepayer funding.
- **ENMAX EV Charging Pilot Program Design – (June 2019 to October 2019. Location: AB, Canada)** Craig led the engagement with ENMAX to develop strategy and design of Calgary's newest EV charging customer program by examining an array of utility sponsored charging incentive programs in the North American EV

market and produce core data to enhance system design needs and customer experience

- **BC Hydro Electric Vehicle Rate Design.(February 2019 to May 2019. Location: BC, Canada)** Led review of North American rate design best practices for electric vehicles in residential, workplace, and general service jurisdictions for Canadian utility
- **IESO Ontario Conservation Potential Study. (August 2018 to July 2019 Location: ON, Canada)** Supported development of an integrated natural gas and electricity conservation potential study, including top-down modelling of base year energy consumption, technology trends and load curves by sector, segment and end use. Assisted with developing saturation of baseline and efficient measures to determine scenarios for technical, economic and achievable potential. (Client: IESO)
- Efficiency Alberta Conservation Potential Study. Supported development of an integrated natural gas and electricity conservation potential study, including top-down modelling of base year energy consumption, technology trends and load curves by sector, segment and end use. Craig also led the task to quantify the GHG impacts of the various efficiency investment scenarios. [Client: Date: August 2017 to July 2018. Location: AB, Canada]

Energy and Utilities – Risk and Regulatory

- **Hydro One Cost Allocation and Rate Harmonization (June 2019 to July 2019).** In 2019, Craig co-led a project to determine the appropriate cost allocation methodology to harmonize rates across legacy Hydro One and acquired customer bases, needed to proceed through a re-basing COS application and in conformance to the affiliate relationship code. The filing is currently under review by the Ontario Energy Board.
- **Hydro One Transmission Total Cost Benchmarking (March 2018 to October 2021)**. Craig participated with a team in 2018/19 and in 2021 combining Guidehouse and First Quartile Consulting to benchmark the total cost and work practices of Hydro One Networks' transmission operations. The team collected cost and practice data from utilities across North America, conducted interviews with Hydro One Networks staff, and provided recommendations to improve overall performance. The report was filed with the regulator.
- **Hydro Quebec Transmission Provider Code of Conduct Review (Mar 2020 to October 2020)**. Craig led a team who reviewed the existing code of conduct and procedures to ensure independence of the transmission function from the energy marketing business in support of Hydro Quebec's ongoing performance improvement and reorganization. The assignment required alignment with FERC statute 358 focused on ensuring fairness of transmission access where the transmission provider is vertically integrated.
- **ENMAX Billing and Customer Care Costs Allocation Approach (Mar 2016 to Jul 2016)** – Recently, Craig led the development of an assignment to review, benchmark and optimize the procedure with which ENMAX allocates the costs of its Encompass customer care function, the organization's affiliate billing and customer care company. With several non-regulated customers and the utility EPC, Encompass incurs costs to serve all affiliate and contracted entities. Craig's team discovered several allocation factors that could be changed and compliant with Alberta's affiliates transactions regulations, while saving shareholders over $1.7 million in annual cost.

- **Gazifere Corporate IRM Review (Jun 2016 to Jan 2017)** - Craig supported the Gatineau and Outaouais region natural gas utility review its last five year IRM period and recommend changes to take before the regulator that may improve the value and success of IRM for rate payers and shareholders. The assignment includes an economic and demographic assessment to understand the driving forces of IRM performance given the current structure and set of performance factors.
- **Confidential Utility Client Underground Residential Service Cost Benchmarking (Mar 2014 to Jul 2019)**. In 2014 and 2019, Craig performed an analysis of underground electric (URD) service installation costs for residential connections. Desktop research and interviews were conducted to determine a fair cost range for material project elements and benchmark URD cost profiles across utility service territories and quantify an expected cost.
- **Gazifere Corporate Cost Allocation Model (Jun 2016 to Jan 2017)** – Craig was engaged to provide the Gatineau based subsidiary of Enbridge with a review of their current cost allocation methodology and determine next steps to develop an amended model reflective of regulatory best practices. Craig managed the assignment and constructed a full suite budgeting model to allocation corporate costs from Enbridge Inc. and EGD to Gazifere, considering the regulatory principles of prudence, cost-benefit and fair market value. Craig provided expert testimony before the Regie de Energie.
- **ENMAX Affiliates Transactions Program Review (Jun 2013 to Jan 2014)** – Craig recently testified during ENMAX's 2015 rates application before the AUC. Craig managed the third party review and fair market value assessment of ENMAX's 2011 and 2012 affiliate transactions in support of the firm's cost of service rate filing and forward approach for determining affiliate transactions. The goal of the assignment was to provide assurance of compliance with the AUC's Affiliates Code of Conduct and to provide opinion on the fair market value of affiliate transactions between ENMAX and for profit entities. Craig provided IR support and testimony before an AUC panel.
- **SaskPower, Large Customer Tx Connection Process Risk Review (Jun 2017 to Jul 2017)** – Craig led an optimization assignment for SaskPower to review and determine enhancements to the customer connection process for commercial and industrial connections. The review included examining the policies and process, risk management strategy and controls used to prepare for and invest in connecting new large customer loads and upstream system investments. The work included a current state assessment, identification of risks and gaps and jurisdictional scan for common and best practice in customer connection requirements.
- **Enbridge Shared Services Allocation Model (Jun 2012 to Jul 2013)** - At MNP, Craig participated on a team who assessed the shared services cost model of one of Ontario's largest natural gas distribution utilities, whose parent company provides shared services support in a number of operational functions. To approve the natural gas rates charged to Ontario consumers, Enbridge Gas Distribution must have its shared services cost allocation approved by the OEB after third party assessment. The analysis included benchmarking the shared costs of several functions to other cost of service and ratemaking submissions of gas and electric utilities.
- **Hydro Ottawa, Regulatory Compliance Review (Aug 2017 to Mar 2018)** – Craig is currently leading a project assess the client's current regulatory compliance

program against industry best practices and the principles of process improvement in order to develop a recommendation and roadmap for implementation an optimized program and set of policies. The engagement involves stakeholder facilitation, regulatory research and analysis and process mapping.

- **Northpoint Energy Gas Hedging Process Review (Jun 2018 to Oct 2018)** – Craig recently participated with a SWOT team to review, enhance and implement an improved set of parameters and procedures to ensure robust risk protection in gas purchasing at Northpoint Energy, who supplies SaskPower with natural gas needs and services.
- **OEB Regulatory Reporting Review and Enhancement (Jun 2014 to Mar 2015)** – Craig managed the first stage of a change initiative at the OEB, to review and perform a gap analysis of the processes, procedures and systems in place at the Board to execute its reporting and entity performance management needs. In support of the new Renewed Regulatory Framework and scorecard performance management approach, the OEB is ensuring its data and reporting structures are aligned with industry best practice to realize the full potential of information coming into its systems.
- **OPA Process Audit and Re-design (Jun 2014 to Sept 2014)** - Craig recently supported the OPA in efforts to reconstruct the review and assurance process of regulated price plan (RPP) claims submitted by Ontario electricity distributors as part of their settlement activities. Craig provided technical expertise on two field audits of the settlement claims and has been managing the development of a compliance and risk-based oriented certification program to replace annual audit.
- **OEB Internal Controls Review (Sept 2013 to Dec 2013)** – Craig participated as subject matter expert and reviewer on an assignment to evaluate the design and compliance of internal controls within the OEB's procurement, finance and IT departments. Subsequently the MNP evaluated and recommended on the need for and design of an internal audit function within the organization.
- **IESO (formerly OPA) – Audits of Bruce Power Refurbishment Implementation Agreement (Jun 2014 to Feb 2015)** – Craig managed three separate audits on behalf of the OPA over their long-term contract with Bruce Power – the Bruce Power Refurbishment Implementation Agreement (BPRIA). The audits provide assurance opinion over the costs associated with Units 1 and 2 refurbishment project, the O&M costs to date and the total fuel costs. These audits totalled over $5.6 billion in shared investment between Bruce Power and the Province of Ontario and will support accountability improvement over future contracts to supply Ontario electricity from the Bruce Nuclear Station.

NERC Standards Compliance – Reliability Standards

- **ATCO NERC Audit (Jun 2009 to Sept 2009)** - Craig and an expert team completed a gap analysis of ATCO's procedures to comply with AESO reliability standards, which are largely based upon NERC standards. ATCO will complete an audit with the AESO to achieve compliance with 9 GOP reliability standards and provided recommendations for improvement of evidence packaging, format and adherence to each requirement and sub-requirement. Craig, led management of the project, supported assessment of the standards and reviewed the resulting gap analysis report.
- **TransAlta NERC Compliance (Mar 2009 to Sept 2009)** - Mr. Sabine worked with a team of reliability, compliance and NERC standards experts to support TransAlta's development of corporate internal compliance program that will enable the firm

to build and support evidence of compliance with NERC and provincial reliability standards programs, in all of its operating jurisdictions. The project will position TransAlta as a premier Canadian utility in the reliability space and ensure internally consistent procedures are met within day to day operations and compliance efforts.

- **AESO NERC Audit (Mar 2008 to Sept 2008)** - For Alberta's electricity system operator, Craig's NERC team completed a mock audit process in conjunction with the internal audit of the AESO's reliability standards compliance program. The gap analysis portion assessed the AESO's level of compliance with NERC reliability standards with the project lead, while supporting the preparation of SMEs for an upcoming WECC audit, to which the AESO is responsible for bulk electricity system reliability compliance. Craig participated in mock auditing activities and managed the administration and scheduling of the project.
- **EnCana NERC and CIP Compliance (Feb 2008 to May 2008)** – Craig was assigned to verify compliance with NERC reliability standards, EnCana commissioned a team of consultants led by Craig to assess the firm's position leading into an AESO post self-certification compliance audit. The expert compliance and data quality team assessed CIP-001, EOP-004, PRC-001, PRC-004, TOP-005 and related requirements for EnCana's Cavalier Cogen facility using a gap analysis tool.
- **Hydro One CIP Mock Audit (Jun 2007 to Dec 2007)** - This assignment, for Ontario's largest electricity transmitter, focused on preparing the firm for compliance with the critical infrastructure protection and IT security related requirements of the NERC Reliability Standards. A team consisting of electricity systems and IT infrastructure experts performed mock audit activities with a variety of SMEs from across Hydro One to assess the readiness of the firm for audit, the level of rigor available in the firm's evidence and the internal compliance procedures that are in place to adhere to the NERC and IESO standards.

Energy and Utilities – Strategy and Regulatory

- **ATCO Electric, Regulatory Reform Strategy (Jun 2018 to Sept 2018)** – As advisor to ATCO's management team, Craig has been developing regulatory strategies to support ATCO's transformation objectives as pressures continue to mount for utility businesses reform and innovation. Particularly, Craig has helped to identify technologies, business models and rate structures that could support ATCO investment in grid modernization, distributed energy and non-wires alternatives and platform initiatives.
- **Ontario Energy Board, Gas Markets Advisory (Jun 2010 to Sept 2020)** – Craig continues to support the OEB to assess North American natural gas markets, supply, storage and transportation, a role he has been fulfilling in some form since 2010. Facilitating market price outlooks, updated quarterly, Craig supports the processes to review utility natural gas supply plans, QRAM filings and other strategic and policy initiatives.
- **SaskPower Integrated Planning Process Support (Jun 2018 to Sept 2018)** – Craig and a Guidehouse team are currently supporting SaskPower through a complete

improvement program of their supply planning process. Modelled after integrated resource planning (IRP), Guidehouse has conducted workshops and interviews to better understand the departmental inputs and touch points to analyse and report a 20 year future strategy for the SaskPower's resources. The assignment involves full support, process design and training to conduct an IRP for the first time and moving away from a 20 year supply option-only planning approach.

- **Manitoba Public Utilities Board Expert Witness (Jun 2013 to Mar 2014)** - Craig acted as an independent expert on behalf of the Manitoba PUB, evaluating the costs and benefits of Manitoba Hydro's current capital development strategy. Craig and a team of other experts provided key insight and analysis to the PUB to evaluate the potential benefits of the preferred plan and set of alternatives in the Needs for and Alternatives to process that will ultimately provide recommendations for approvals of the Keeyask and Conawapa large hydro projects, their risk adjusted net present value to the rate payers of Manitoba and an assessment of the key risks that must be considered to support the 20 year capital plan. Craig provided expert testimony before the Board in 2014.
- **Koskie Minsky Expert Witness Support (Mar 2014 to Mar 2015)** – For a law firm representing plaintiffs in a class action vs. Atlantic Power Corporation, Craig provided expert witness testimony regarding economic and market-based impacts on the financial position of the IPP. Craig's testimony includes evaluation of the Florida and Ontario electricity markets and the impacts of PPA negotiations on Atlantic's share value and ability to service dividends.
- **ENMAX Fibre Optics Business Valuation (Jun 2013 to Sept 2013)** – In support of the potential for regulatory hearings associated with the sale of a non-regulated business, Craig managed the development of a valuation of fibre optics assets for a Canadian utility. The assignment developed a full model of equipment, construction, labour and operating costs associated with an urban fibre optic network.
- **Ontario Energy Board Cap and Trade Regulatory Framework (Jun 2016 to Sept 2016)** – Craig recently served as the special advisor to the OEB as the Ontario Government developed its Cap and Trade program. Supporting development of the cap and trade regulatory framework, Craig was responsible for assisting the OEB to develop an aligned regulatory framework for natural gas utilities who will be covered entities and ensure that the OEB's jurisdiction supports the utilities' compliance with the program at reasonable and prudent costs for rate payers.
- **Kinder Morgan General Rate Application (Jun 2014 to Sept 2014)** – Currently, Craig is working closely with an internal team of operations, project management and finance experts at a major Canadian pipelines company to prepare the rate base for their 2013 rates application to the National Energy Board. Craig is managing all aspects of development and verification of the rate base and capital project accounts to develop one of three key sections of the GRA cost of service.
- **Greater Sudbury Hydro Business Process Improvement (Jun 2014 to Sept 2015)** – Craig was a manager as part of a broad spectrum utilities' process improvement team assigned to support a complete BPI of all of Sudbury Hydro's processes. The assignment will result in full current state and future state process maps, with key recommendations and change management and training for Sudbury Hydro employees.
- **Modeling and Strategic Advice, National Round Table on the Environment and Economy (Mar 2007 to Sept 2008)** - Mr. Sabine worked with a team on this year

long modeling and analysis effort investigating scenarios that Canada might use to achieve reductions in its Green House Gas (GHG) emissions by 50-60% as part of an effort to attain sustainable levels of CO2 emissions worldwide. Craig has worked with project managers to help develop, model and assess the level of success that a variety of policy and structural scenarios might have on Canada's next generation of climate change responses. NRTEE's goal for this program is to identify the strategic directions for energy and climate policy the government must pursue to put the country on a course for a 60 percent reduction in greenhouse gas emissions by 2050 in a manner that will contribute to Canada's economic prosperity and competitiveness. The team employed a full-cycle energy, economic-demand and supply model to simulate GHG emissions simultaneously across all economic sectors. This model called Energy 20/20 was used to develop and analyze the reductions that could.

- **Environment Canada Production Cost Model (August 2006 to July 2008)** - Mr. Sabine managed the development of a costing model for Environment Canada to support their policy modeling efforts in the electricity generation sector. The costing model relies on standard industry approaches to capital costs and operations and maintenance costs, while building on financial, market, costs of capital and other parametric assumptions to analyse macroeconomic impacts on the current and future costs of power plants and emissions reduction equipment in Canada. The tool will be used to set the basis for capital and lifetime costs of power plant options and emissions abatement technologies, which can be fed into simulation and optimization models supporting policy and market analysis.
- **Environment Canada , Natural Resources Canada Hydrogen Production Pathways (August 2003 to July 2004)** – Craig acquired and analyzed a wide variety of data on the Canadian Electric Power Sector to determine the capacity of the power generation sector to support a hydrogen economy in transportation. Craig was part of the IPM team that modelled nine Canadian provinces to aid in this three-phase project.

Other Strategy and Electricity Sector

- **EPCOR RECs Verification (Jun 2006 to Sept 2006)** - Electricity generation from renewable sources is eligible for "Eco-Logo" certification where it is deemed to offset fossil fuel generation. In Alberta, electricity is predominantly generated from coal and natural gas. Craig managed a project to develop a methodology and analysis of the greenhouse gases deemed to be offset from two renewable generators in Alberta for the period of 2003 through 2006. This quantification was used to provide an expert opinion on the actual offsets attributable to the RECs associated with these generators.
- **Dupont GHG Reduction Verification (Jun 2007 to Sept 2007)** - Mr. Sabine was lead of an audit team that performed a verification of the DuPont Louisville Freon plant; to verify HFC-23 emission reductions for 2008, 2009 and 2010. The facilities managers have implemented several programs leading to GHG equivalent reductions of over 1 million tonnes. More recently, a change to the quantification protocol was also reviewed that added a new portion to the amount of HFC-23 reduced through project level reductions. The data sources and data were QA/QC'ed and calculations verified. The focus of this assignment was the issuance of a letter of verification for the emission reductions achieved by way of Dupont's efficiency optimization program and F-23 destruction abater.
- **Epcor Greentags Review (Jun 2005 to Sept 2005)** - For one of Alberta's premiere electricity generators and marketers, Craig completed a verification of the methodology and quantification of the environmental attributes associated with

renewable generation from Ecologo certified facilities. Opinion letters were drafted for several large commercial customers who have entered into contract with Epcor, for "Greentag" energy to be used voluntarily for a percentage of their load.

- **JP Morgan Cabon Assets Risk Evaluation (Jun 2008 to Sept 2008)** - In early 2008, Mr. Sabine was the technical lead on developing a risk evaluation tool for a large New York investment banking arm. JP Morgan required expert carbon reduction project risk evaluation, on the likelihood of its portfolio of projects completing approvals, keeping construction deadlines and producing registered emission reductions and becoming optimally transactable. The resulting tool was based on ICF's proprietary KPRISM CDM risk evaluation tool, but was tailored for JP Morgan's portfolio of voluntary market projects. The excel-based tool is also flexible in design to be transferable to other portfolio's adaptable to any number of current carbon registries. Craig helped design and implement the programming, while acting as liaison with the client to incorporate specific inputs. Mr. Sabine also presented the final tool and first short training seminar.
- **Natsource Carbon Reduction Projects Portfolio Valuation (Jun 2004 to Sept 2004)** - Mr. Sabine is engaged a large asset management and carbon investment firm in valuing a portfolio of CDM projects. Using ICF's proprietary CDM project evaluation tool, KPRISM, Craig worked with a team to adapt the tool to evaluate a portfolio of CDM and JI projects that are part of a carbon hedge fund developed by Natsource. The risk assessment will enable Natsource to analyse their carbon price risk and risk of delivery from a portfolio and project level perspective. The KPRISM tool and other techniques employed by ICF have been developed through many years of project experience in valuing emissions reduction projects and assessing their risks to investors.
- **Canadian Electricity Association Scenario Analysis Air Emissions Under the Canadian Regulatory Framework (Jun 2008 to Sept 2008)** - Mr. Sabine led a team employed by the CEA and its members, including all major generating utilities across Canada, to aggregate and analyze electricity sector futures outlooks. While managing the project and facilitating sessions aimed at developing an analysis and approach to lobby the federal government, Craig was challenged to address a broad range of sensitivities affecting different power companies across the country. The project was taken on to develop a comprehensive database of current and forecasted electric generating fleet operations and inform the development of alternative approaches to regulating the sector in terms of GHGs and air pollutants. The analysis assessed the changes in compliance flexibility, fuel switching, new and emerging technology development and credit purchasing across a broad range of regulatory scenarios. The analysis investigated the opportunities and barriers for capital stock turnover, culminating in a lower emitting national power sector and the relevant and realistic timeframes in which this may be feasible.
- **Conservation Potential and Market Capability Assessment for System Constrained Area (Jun 2007 to Mar 2008)** - For the OPA, Craig managed an extensive study of the West GTA market's capacity and capability to deliver conservation measures, including energy efficiency, demand response and fuel switching in the residential, commercial and industrial sectors. The analysis included an estimation of the technical, economic and achievable potential for conservation and energy efficiency over a 10 year timeframe, under a set of incentive scenarios. Market capability was also assessed with several barriers to uptake of conservation measures being identified. Mr. Sabine managed an ICF

team made up of Ontario market experts and building-technology experts to produce a report and set of implementation recommendations that could be used by the OPA and relevant local distribution companies in their design and implementation of conservation programs and incentives.

- **Energy Markets – WindVision Canada Wide Energy Target 2025 (Sept 2006 to Mar 2007)** - Mr. Sabine headed up an effort to support CANWEA's new target setting process. The study involved surveying the best available provincial-level electricity demand data and planned power plant new-build information to assess what the future of Canada's electricity supply-demand balance might be. Assumptions on the amount of projected wind uptake were layered over each province's supply-demand outlook to determine a reasonable wind target for the industry. Niche markets and cost competitiveness of different generating technologies were also explored during the process. An accompanying phase investigated in detail, the impacts of different scenarios of economic and policy conditions on cost competitiveness of wind versus other generating technologies.
- **Energy Markets (Sept 2005 to Mar 2006)** – Analysis of Intensity Based and Cap & Trade GHG Regulation in Canada - While with ICF Mr. Sabine directed a study for the CHA designed to assess the impacts of different GHG regulation frameworks on the Canadian power sector and the role that hydro developers and operators could play. Mr. Sabine managed the modelling effort using the IPM® to assess hydro's potential role in meeting GHG reduction targets or becoming part of a Canadian system of GHG offsets. The study forecasted carbon price, sector compliance costs and energy prices.
- **Lehman Brothers Alberta Electricity Market Review (Jun 2007 to Sept 2007)** - Large investment bank, a detailed assessment of the Alberta power market, including 20 year wholesale electricity price forecast was provided. Mr. Sabine supported expert council to the IPM® modeling team on Alberta market structure and helped to analyze results and produce the final report. The project supported the potential financing and acquisition of an Alberta renewable developer/operator. The study included overview of Alberta market history and deregulation, summarization of the sector's challenges and system of Power Purchase Arrangements. These assessments were coupled with a detailed look at the generating fleet and power price forecast using the IPM®, which included a forward REC price expectation.

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Professional Summary

Peter Steele-Mosey is an Associate Director in Guidehouse's Canadian Energy segment. He is an econometrician with fourteen years' experience in: evaluating the impact of demand response and energy efficiency programs, quantifying the impact of alternative electricity rate structures on demand, researching and developing alternative electricity rates, forecasting electricity and combustible fuel demand, and adjusting such forecasts for structural load modifiers (EVs, DERs, etc.)

Peter has, since 2012, developed load forecasts for utilities or assisted them with evolving their existing load forecasting procedures. Peter recently completed a 10-year roadmap for LUMA, laying out the long-term transition plan for its regulatory system load forecasting function in a Systems Operations Principles (SOP) report filed with its regulator, PREB. Peter is currently finalizing an engagement with the Abu Dhabi and Al Ain Distribution Companies to help these distribution utilities evolve their existing water and electricity demand forecasting techniques to meet future needs (i.e., greater intra-day granularity, modeling structural shifts in load drivers).

Peter is also currently engaged in supporting the 2022/2023 CPUC's Potential and Goals study, specifically by expanding on the work he led as part of the 2020/2021 study cycle in developing a "top-down" projection of energy efficiency potential for the commercial sector. In 2019 Peter completed work on an integrated (gas and electricity) achievable potential study for the Independent Electricity System Operator (IESO) and Ontario Energy Board (OEB), projecting the potential for energy conservation under four different scenarios across a 20-year period.

Areas of Expertise

- **Forecasting, Scenarios, and Energy Efficiency Potential**: Develops demand and emissions scenario projections based on client inputs, engineering calculations and empirical examinations of historical patterns. Advises clients on forecast evaluation and design and estimates econometric forecasts of long-term and short-term system loads based on historical observables and potential future structural changes.
- **Electricity Pricing and Price Responsiveness**: Delivers expert advice on energy retail pricing and potential consumer response based on prior empirical work with consumer electricity price-response and close familiarity with the different types of electricity pricing regimes deployed across North America.
- **Econometric Impact Evaluation (EE & DR)**: Provides robust and regulator-accepted empirical evaluations of demand response and energy efficiency programs. Combines rigorous quantitative techniques with advanced graphical outputs to provide evaluation transparency for experts and non-specialists alike.

Professional Experience

Forecasting and Scenario Projection

- California Public Utilities Commission, *Energy Efficiency Top-Down Potential Analysis*, 2022 – 2023. A key outcome of the prototype top-down analysis developed by Peter in 2020 through 2022 was the request by the CPUC to expand this effort for the current potential study cycle from 2022 through 2023.
- LUMA, *Load Forecast Review and Future-State Recommendations for Process and Governance*, 2021 – 2022. Peter is the workstream lead for an effort to map out a long-term process for evolving LUMA's existing load forecasting approaches, as well as identifying (and executing) highly targeted near-term improvements (remediation) of existing approaches and workflows.
- California Public Utilities Commission, *Energy Efficiency Top-Down Potential Prototype Analysis*, 2020 – 2022. Peter developed a prototype top-down approach to estimating and projecting energy efficiency potential[1] for a sub-set of commercial segments. This analysis compared the average energy intensities of two sets of buildings to develop an estimated unit improvement in efficiency that could be scaled out to the population. Costs of such improvements were based on the historic estimated levelized cost of energy (LCOE) by segment and end-use.
- Al Ain Distribution Company and Abu Dhabi Distribution Company, *Load Forecast Review, Recommendations, and Implementation*, 2021 - 2022. Peter was the technical lead for this project, overseeing the development of an end-state model architecture intended to allow for long-term hourly forecasting of water and electricity demand and the integration of major structural changes to load drivers (DSM, EVs, DERs, etc.).
- Enbridge Gas, Inc. *Load Forecasting Benchmarking and Development*, 2021. Peter was the lead SME and project manager for this effort, undertaking an extensive review and documentation of existing EGI load forecasting approaches (across both legacy service territories) and comparing these to approximately 10 comparator natural gas distribution utilities from across Ontario.
- FortisBC, *Scenario Forecast of the Load Impacts of Disruptive Load Drivers*, 2019 - 2020. Peter managed this effort to support the efforts of FortisBC's electricity forecasting group to understand the potential effect on their existing long-term forecast of load drivers for which few historical observations existed (e.g., widespread deployment of electric vehicles, solar PV supported by energy storage, etc.). Peter led this work in 2016, with an extensive update (to support the new Long Term Electricity Resource Plan) completed in October of 2020

[1] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/cpuc-top-down-potential-final-2022-1-18.pdf

- Independent Electricity System Operator, *2019 Conservation Achievable Potential Study*, 2018 - 2019*.* Peter acted as project manager for this 13-month engagement. The goal of this study was to provide a 20-year projection of the Technical, Economic and Achievable (under four scenarios) conservation potential for natural gas and electricity in Ontario. In addition to managing the project, Peter lead all major stakeholder sessions. Stakeholder presentations and other deliverables are available on the engagement webpage.[2]
- Toronto Hydro-Electric System Ltd., *Spatial Peak Demand Forecast*, 2017 - 2018*.* Peter was the project manager and subject matter expert leading the development of a spatial peak demand forecast for Toronto Hydro. The key deliverables for the this project were the development of a "gross" (DSM and distributed generation frozen at current levels) 8,760 (hourly) peak demand forecast at the Region, station and bus-level, and the development of a set of Outlooks that quantify the potential impact of a number of structural changes in major load drivers (e.g., solar PV, electric vehicles, energy storage, etc.)
- Ontario Ministry of Energy, Northern Development, and Mines (formerly Ontario Ministry of Energy), *Fuels Technical Report (FTR)*[3], 2017 - 2018. Peter managed this effort to support the Ontario Ministry of Energy's development of the Long-Term Energy Plan (LTEP). The two key inputs to the LTEP are the Independent Electricity System Operator (IESO)'s Ontario Planning Outlook (OPO), and the corresponding document covering the fuels sector, the FTR. The FTR developed five Outlooks, potential future scenarios of fuels use under different assumptions regarding major structural changes (e.g., EV uptake, changes to fuel blending standards, etc.)
- BC Hydro and FortisBC, *Projection of Total Thermal Demand in British Columbia,* 2017*.* As part of Navigant's broader engagement with four B.C. utilities to develop a provincial (and utility-specific) estimate of achievable conservation potential, Peter led the development of a forecast of total thermal demand (gas, propane, fuel oil, etc.) in the province across the forecast period.
- P3 Group (PJM Power Providers), *Review of PJM Peak Demand Forecasting Approach and Outputs*, 2015. Peter was part of the team engaged by the P3 group of utilities to review new inputs included by the PJM forecasting staff in the demand forecast (in particular indices capturing changes in the efficiency of space-cooling equipment) as well as the forecast outputs and conceptual approach to ensure that the likelihood of omitted variable bias was being minimized.

[2] 2019 Conservation Achievable Potential Study, http://www.ieso.ca/2019-conservation-achievable-potential-study
[3] Available online: https://www.ontario.ca/document/fuels-technical-report

- Toronto Hydro-Electric System Ltd., *Development of an Advanced Load Forecast Methodology.* Peter was the lead econometrician in this effort to develop a methodologically transparent and regulatorily robust approach to forecasting station bus peak demand. This engagement involved a detailed examination of the current state approach used by THESL as well as a benchmarking exercise, which included a literature review and interviews with nine peer utilities/organizations' forecasting staff. In addition to recommending a specific modelling approach, Peter was responsible for the design of forecasting testing regime.
- Toronto Hydro-Electric System Ltd., *Spatial Peak Demand Forecast*, 2012 - 2013*.* Peter developed a system-wide 25 year forecast of peak demand for THESL, based on the approach favored by Ontario's Independent Electricity System Operator (IESO) but calibrated to take into account historical demand side management (DSM) and distributed generation (DG) and to allow for alternative future forecasts of DSM and DG.
- Impacts of Alternative TOU Structures. Peter is the lead author of a report for the Ontario Energy Board (OEB) forecasting the impact on a variety of metrics (principally system peak demand) of four alternative time-of-use (TOU) price structures. Ontario is currently the only jurisdiction in North America with mandatory TOU rates for all residential customers. Estimated impacts were based on own- and cross-price elasticities estimated using four years' worth of hourly historical data for 15,000 customers (see below for more details).

Electricity Pricing and Price Responsiveness

- Xcel Energy, *TOU Pilot Evaluation*.[4] Peter is the lead analyst and project manager for the multi-year evaluation of Xcel Energy Minnesota's opt-out TOU pilot. Interim results for this evaluation were reported in February 2022, with final results due by the end of 2022.
- Abu Dhabi Distribution Company, *TOU Pilot Deployment & Evaluation*, 2022. Peter has been engaged as an SME to support the deployment of this large C&I TOU pilot being deployed by ADDC.
- Ontario Energy Board, *Overnight Pilot Rate Review*.[5] In early 2022, Peter acted as SME for an in-depth review and re-examination of results from the OEB's pilot rate targeting EV customers, including providing ad hoc expert review of Board staff rate designs and supporting evidence.

[4] Guidehouse, prepared for Xcel Energy, *Xcel Energy Minnesota Time-of-Use Pilot Evaluation – Interim Report: Impact and Process* Evaluation, February 2022
See PDF page 52/217
https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={D0CA327F-0000-C130-B92D-0CF55C38B2F4}&documentTitle=20222-183193-02

[5] Guidehouse, prepared for the Ontario Energy Board, *Additional Investigation of the Benefits of an Overnight Pricing Plan*, March 2022
https://www.oeb.ca/sites/default/files/Supplemental-Report-Benefits-of-an-Overnight-Pricing-Plan-20220331.pdf

- Salt River Project, *Audit of Price Comparison Screen*, Peter was the technical lead undertaking a review of SRP's residential and commercial price/rate comparison screen, an online resource that allows customers to compare different rates and select the one that's best for them.
- Evergy, *TOU Pilot Evaluation*. Peter acted as SME for the multi-year evaluation of Evergy's opt-in TOU pilot. Interim results for this evaluation were delivered in late 2020, and final results were reported at the end of 2021.
- Abu Dhabi Distribution Company, *TOU Pilot Design*, 2021. Peter led the development of the experimental and evaluation design of ADDC's TOU pilot, adapting insight from evaluations of North American pilots to the unique constraints of the UAE.
- Duquesne Light, *Alternative Rates: Community Development Rates*, 2021. Peter developed a community development rate discount on the basis of that utility's existing allocated cost of service (ACOS) study intended to support the location of high load factor customers to locations with existing (under-utilized) distribution infrastructure.
- Alectra Utilities, *Evaluation of the Alectra @Home and @Work pilots,* 2019 - 2022. Peter is the project manager and lead analyst for the evaluation of two of Alectra's electric vehicle (EV) charging pilots designed to motivate shifts in behaviour changes through electricity pricing and enabling technologies. The @Work pilot has a commercial focus, emphasizing "smart charging" and demand response as a service to larger commercial consumers to help them avoid peak energy and monthly peak demand charges. The @Home pilot targets residential consumers and includes multiple treatments for shaping behaviour: direct TOU pricing, incentive payments for non-use in certain windows, etc.
- Ontario Energy Board, *Meta-Analysis of the RPP Pilots* 2019 - 2020.[6] Peter was the project manager lead author of a meta-analysis of nine alternative commodity pricing pilots commissioned by Ontario Energy Board as part of its Regulated Price Plan (RPP) Roadmap[7] effort to evolve the RPP to deliver greater ratepayer value. The final report associated with this work will be published on the OEB website in the near future.

[6] Guidehouse, prepared for the Ontario Energy Board, *Regulated Price Plan Meta-Analysis*, December 2020 https://www.oeb.ca/sites/default/files/report-RPP-Pilot-Meta-Analysis-20211110.pdf

[7] Ontario Energy Board, *RPP Roadmap*, Case Number EB-2016-0201 https://www.oeb.ca/industry/policy-initiatives-and-consultations/rpp-roadmap

- London Hydro, *Evaluation of the London Hydro RPP Pilot,* 2017 - 2019. Peter was the project manager and lead analyst for the evaluation of London Hydro's RPP pilot. This pilot tested the impact of real-time information on participant consumption as well as the impact of a critical peak price on consumer demand. The interim[8] and final[9] evaluation reports are available online.
- Ontario Energy Board, *Regulated Price Plan (RPP) Pilot Rate Development*, 2017. Peter developed the prices applied to the suite of RPP pilots deployed by the Ontario Energy Board in 2017. Prices were developed based on the principal of revenue neutrality, leveraging hourly residential demand data from a representative sample of Ontario local distribution companies (LDCs). Rate structures included alternative scheduled rates (i.e., alternative time-of-use – TOU – rate structures) as well as rates with unscheduled elements, including a critical peak pricing and variable peak pricing rate structures.
- Hydro One Networks, *Assessment of Alternative Transmission Rates*, 2017. Guidehouse (then Navigant) helped Hydro One understand the trade-offs inherent in a number of different styles of retail transmission rate structure, with respect to network, line, and transformation charges. Guidehouse began by considering six different rate structures, narrowed down to three, based on internal stakeholder feedback and regulatory research: revenue decoupling, full connection-based tariff, and a hybrid tariff (aka a straight-fixed variable rate). Guidehouse conducted a jurisdictional review for examples of such rates offered by other utilities, and then evaluated the competing alternatives (using historical customer demand and consumption data) for: revenue stability, equity and fairness (cost causation), customer bill stability, customer comprehensibility, economic efficiency, and implementation considerations.
- Ontario Energy Board, *Alternative Commercial Rate Analysis,* 2016 - 2017. Peter has worked with the Ontario Energy Board to quantify the distribution charge impacts to non-residential rate classes of alternative rate structures in Ontario. This work has involved quantifying the impacts of a change to a fully fixed distribution charge and of rates that collect revenue based on coincident system peak demand rather than energy.
- Alectra Utilities (formerly PowerStream) *Evaluation and Design of Advantage Power Pricing (APP),* 2014 - 2017. PowerStream's APP pilot was a variable peak pricing pilot with enabling technology (a price-responsive smart thermostat) currently in its second year of operation. Peter provided the principal analytic support for the program design and managed the evaluation of the first summer of deployment, which estimated that this program has delivered an average coincident peak demand impact of more than 1 kW per participant.

[8] Navigant Consulting, Prepared for London Hydro*, Regulated Price Plan Roadmap Pilot Program Interim Impact Evaluation: Summer 2018*, 2019-05-24
https://www.oeb.ca/sites/default/files/rpp-roadmap-interim-results-londonhydro-20190524.pdf

[9] Navigant Consulting, Prepared for London Hydro*, Regulated Price Plan Roadmap Pilot Program Final Impact Evaluation*, 2020-04-21
https://www.oeb.ca/sites/default/files/LondonHydro-RPP-Pilot-Final-Evaluation-Report-20200421.pdf

- Ontario Energy Board, *Evaluation of the Impact of Ontario's Transition from Tiered to TOU Rates,* 2013 - 2014. Peter was the lead author and analyst of this study commissioned by the OEB. Impacts were estimated in two ways: using a conventional dummy-variable fixed-effects set of regressions and using a Rotterdam system of demand equations. The second approach delivered own- and cross-price elasticities required for a forecast of the impact of alternative TOU structures (see above). The results of the first approach were used to validate the more sophisticated elasticity approach.[10]
- Enercare Connections, *Evaluation of the Impact of Suite Sub-Metering,* 2012. Estimated the impact on energy conservation of the implementation of suite-metering (as opposed to flat fee) of multi-residential building units for EnerCare Connections.[11]
- Ontario Ministry of Energy and Infrastructure, *Time of Use Rate Analysis*, 2010. Peter was the lead analyst in helping Ministry staff understand the potential impacts on bills, demand, and overall system costs of a set of alternative TOU rate structures to the default rate in place at that time. A key outcome of this analysis was a Ministry request to the OEB to change the length of the evening Off-Peak period.
- Newmarket Hydro, *Evaluation of the Impact of TOU Rates,* 2009 - 2010. Peter was the lead author and analyst of this engagement to estimate the impact of TOU rates on consumption patterns in Newmarket Hydro's service territory. In addition to estimating average impacts, Peter combined survey and hourly consumption data to estimate the impact of TOU rates on the consumption of the best-informed customers. Navigant found that the impact for these customers was more than three times the average impact per customer.[12]
- Ameren Illinois and ComEd, *Evaluation of Residential Real Time Pricing,* 2009 - 2010. Peter contributed extensively to the PY2009 and PY2010 evaluations of Ameren's Power Smart Pricing program and ComEd's Real Time Pricing program. Peter estimated the own-price elasticity of demand and the conservation impact for both programs.

Econometric Impact Evaluation (EE & DR)

- Duke Energy Progress (formerly Progress Energy), *EnergyWise Home Impact Evaluation (DEP)* 2011 - 2024. Peter estimated the impacts of Duke Energy Progress' (DEP, formerly Progress Energy Carolinas) summer (A/C) and winter (heat strips and water heaters) load control program for program years 2011 through 2021.
- Duke Energy, *EnergyWise Business and PowerManager Impact Evaluation (DEI, DEP, DEC)*, 2019 - 2024. Peter is key technical advisor on the evaluation of these C&I thermostat and load switch direct load control programs in multiple Duke territories for program year 2019.

[10] Report: http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/Navigant_report_TOU_Rates_in_Ontario_Part_1_201312.pdf
[11] Report: https://www.enercare.ca/sites/default/files/submetering-conservation-report.pdf
[12] Report: http://www.nmhydro.ca/pdf/NMH_TOU_FINAL.PDF

- Duke Energy Progress, *Commercial, Industrial and Governmental Demand Response Automation (CIG DRA) Program Evaluation*, 2010 - 2024. Peter is the lead author and analyst of the evaluation of DEP's CIG DRA program, for program years 2010 through 2018. As part of this analysis, Peter confirms DEP's calculation of settlement baselines used for participant payment and uses participant-specific regressions to estimate verified program impacts. Peter will continue in his role as lead evaluator and project manager through 2023.
- PECO, *Evaluation of Act 129 Demand Response Portfolio,* 2017 - 2018. Peter was the impact lead for the evaluation of PECO's Act 129 demand response programs (residential, small commercial, and large power users) for the summer of 2018, developing the detail approach to cross-validation used to select individual customer baselines.
- Evergy (formerly Weststar), *Evaluation of A/C Cycling Program*, 2018 - 2020. Peter was the lead evaluator for Westar's WattSaver A/C cycling program for the evaluation of impacts in the summers of 2017 and 2018.
- Duquesne Light, *Evaluation of Large Curtailable Load Program (Act 129)*, 2016 - 2018. Peter was the project manager for Navigant's multi-year evaluation of Duquesne's large C&I Act 129 DR program for the summers of 2017 and 2018.
- Duke Energy Florida, *EnergyWise Home Impact Evaluation (DEF)*, 2017 - 2018. Peter was the project manager and lead evaluator of Duke Energy Florida's EnergyWise home demand response program. This was a 14-month evaluation of the demand response capabilities of water heaters, heat pumps, and pool pumps. Peter was responsible for the experimental design of the program (currently still in the field), the sampling, and, when loggers are collected in March 2018, the evaluation.
- HECO, *Evaluation of Behavioural Demand Response,* 2017 - 2018. Peter was the lead evaluator for HECO's ActionDR behavioural DR program implemented by Bidgely. Peter was responsible for estimating the demand response impacts of the program.
- Alectra Utilities (formerly PowerStream), *Evaluation of Residential Energy Management Pilot*, 2015 - 2016. Peter has been the project manager and lead analyst for the evaluation of Alectra (formerly PowerStream)'s REM pilot. Peter was responsible for estimating energy (gas and electric) savings and DR impacts.
- DTE, *EM&V 2.0 Pilot,* 2015 - 2017. Peter is the econometric lead for DTE's EM&V 2.0 pilot. The purpose of this pilot is to compare the accuracy and cost-effectiveness of two different evaluation approaches using interval data: custom econometric impact evaluation and the use of a proprietary third-party software package (EnergySavvy).
- Duke Energy, *Impact Evaluation of PowerShare Commercial DR*, 2016 - 2017. Peter is the lead evaluator and project manager for the evaluation of Duke Energy's PowerShare commercial and industrial DR program in all Duke's Indiana, Ohio, Kentucky and Carolinas jurisdictions for program years 2016 through 2019.

- Newfoundland Labrador Hydro, *NLH RTM Pilot Evaluation*, 2015 - 2016.[13] Peter was the project manager for Navigant's evaluation of the impact of the deployment of a real-time monitor (for viewing electricity consumption)
- Duke Energy Ohio, *HōM Energy Manager,* 2014 - 2015. Peter was the project manager and impact lead for the evaluation of Duke Energy Ohio's smart thermostat demand response program. In exchange for allowing their A/C units to be cycled, participants in the program were provided with smart thermostats that can be controlled via web portal.
- PSE&G, *Whole House (WH) and Programmable Thermostat (PT) Sub-Programs*, 2015 - 2016. Peter was the impact lead for the evaluation of these PSE&G sub-programs that ran from 2008 through 2013. The WH program deploys energy conservation measures of increasing cost by tier of participation – measures deployed range from CFLs (Tier 1) to major insulation retrofits or furnace replacement (Tier 3). The PT sub-program deployed packs of CFLs and direct-installed programmable thermostat. Both programs were deployed exclusively in "urban enterprise zones". Both gas and electricity impacts were estimated.
- Southern California Edison, *Impact Evaluation of Commercial and Industrial Energy Efficiency Projects*, 2014 - 2015. Peter led the econometric evaluation of the impact of energy efficiency retrofit projects undertaken by large commercial and industrial customers for SCE as part of its preferred resources pilot (PRP).
- Southern California Edison, *Impact Evaluation of Summer Discount Plan*, 2014 - 2015. Peter led the PY2013 and PY2014 evaluations of Southern California Edison's (SCE) DLC program, estimating the ex post and ex ante impacts of the approximately 300,000 residential and 10,000 commercial participants. Peter is currently leading the PY2014 evaluation.
- APS, *HEI Pilot Evaluation,* 2013 - 2015. Peter lead the evaluation of three APS pilot programs: a direct load control program (thermostat set-back), a technology-enabled critical peak pricing program and a information-based home energy management program.
- DTE, *Net-to-Gross Estimation*, 2013. Peter acted as the senior econometric advisor in an effort to estimate the net-to-gross ratio for an upstream lighting efficiency program for DTE.
- Puget Sound Energy, *Winter DLC Pilot Evaluation*, 2011 - 2012. Peter estimated the impact of water heater, heat pump, electric furnace and baseboard heating curtailment on household demand for a pilot program implemented by Puget Sound Energy. An article based on this research was published in Public Utilities Fortnightly (PUF).[14]

[13] Report: https://www.gov.nl.ca/eccm/files/publications-rtm-complete-rpt-f-mar31-2016.pdf

[14] http://www.fortnightly.com/fortnightly/2012/08/directly-controlling-winter-peak

- Independent Electricity System Operator (previously the Ontario Power Authority), *Evaluation of Ontario Power Authority-Funded DLC Pilot*, 2010 - 2011. As lead econometric analyst on this engagement, Peter estimated the impact of a suite of different control technologies on average household hourly electricity consumption. Technologies deployed included fridge, freezer, pool pump, water heater and A/C control devices. Peter provided a thorough analysis of the pilot program design and made recommendations for future pilot design protocols.

Work History

• Associate Director	2016 - present
• Managing Consultant, Navigant	2012 – 2016
• Senior Consultant, Navigant	2010 – 2012
• Consultant, Navigant	2008 – 2010

Thought Leadership

- "*Quick-Ramp, Customer Engagement: Price-Motivated Residential DR with 15 Minutes' Notice*", Presented at the 40th PLMA Conference in collaboration with Carlos Lopez, London Hydro, 2019. https://plma.memberclicks.net/assets/40thConf/6.Lopez%20&%20Steele-Mosey-Quick-Ramp%20Pilot%202019-10-31.pdf
- "*Evolving Variety: How Price Response Varies by Enabling Technology*", Presented at the 36th PLMA Conference in collaboration with Daniel Carr, Alectra Utilities, 2017. https://www.peakload.org/assets/36thConf/C1.Carr&Steele-Mosey-Alectra%20Evolving%20Variety%20Final.pdf
- Association of Energy Service Professionals, Strategies Monthly Member eMagazine, "*Win-Win: PowerStream's Advantage Power Pricing Empowers Customers to Deliver Voluntary DR and Reduce Their Bills*", November 2016
- *Empowering Voluntary DR with Rates and Technology* Peak Load Management Alliance, 34th PLMA Conference, , Del Ray Beach Florida, November 9th, 2016 http://www.peakload.org/?page=2016FallAgenda
- Peak Load Management Alliance, PLMA Interest Group Discussions: Women in DR Update, *Winter Residential Direct Load Control: Findings and Lessons Learned from Two Programs*, April 13th, 2016
- SmartGrid Canada, SmartGrid Canada Conference 2015: SmartGrid Roadshow, *Advantage Power Pricing Pilot*, October 2015
- Association of Energy Service Professionals, Winter 2013 Conference, *Moving Residential Load Control from One-Way to Two-Way: Challenges and Opportunities*, Orlando Florida, January 2013

- Public Utilities Fortnightly, Directly Controlling the Winter Peak: Learning Lessons from PSE's residential demand response pilot, August 2012
  https://www.fortnightly.com/fortnightly/2012/08/directly-controlling-winter-peak

Education

- Master of Arts, Economics — University of Guelph
- Bachelor of Arts (Honours) — Queen's University, Kingston

Andrew Griffith

Energy Markets Manager

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Years of Experience
Professional start date: March 2012

ICF start date: July 2016

Education
M.A., International Economics and Energy, Resources & Environment, Johns Hopkins School of Advanced International Studies, 2016

B.A., International Studies and Psychology, Johns Hopkins University, 2011

Andrew Griffith is an energy markets manager in ICF's natural gas and utilities advisory services group. He has more than six years or experience in the energy field.

Mr. Griffith provides in-depth analytical and regulatory support for natural gas and joint utilities on issues related to policy-driven electrification and decarbonization policy, commodity supply planning, peak day infrastructure requirements, and storage utilization. Mr. Griffith has participated in numerous studies forecasting natural gas market developments in North America, analyzing emissions and decarbonization trends, analyzing sector resilience and capacity, and projecting long-term natural gas infrastructure spending. Mr. Griffith has presented in both public and private forums on these topics.

Mr. Griffith also provides assessments of the value of new natural gas pipeline and storage assets to utilities and ratepayers. He has worked extensively on Canadian natural gas market and regulatory issues.

Mr. Griffith holds an M.A. in International Economics and Energy, Resources & Environment from the Johns Hopkins School of Advanced International Studies and a B.A. in International Studies and Psychology from Johns Hopkins University.

Mr. Griffith has assisted on testimony in regulatory and legal proceedings related to natural gas distribution company pipeline contracting, infrastructure capacity requirements, natural gas storage economics, and pipeline facility expansion economics.

Project Experience

Natural gas storage valuation for asset owner, 2019 & 2022. For a confidential client, Mr. Griffith valued a portfolio of natural gas assets in two different regional gas markets for the owner of the assets. Implemented changes to the ICF gas storage model to add more realistic daily price volatility into the model.

Natural gas supply portfolio analysis, 2019-2021, Summit Natural Gas of Maine. For Summit Natural Gas of Maine, Mr. Griffith was a consultant who quantitatively and qualitatively compared pipeline supply and LNG import supply options for Summit Utilities during a regulatory proceeding to determine the prudence of contracting for pipeline capacity on the Algonquin Gas Transmission Atlantic Bridge project. Provided regulatory approval and legal testimony support for the resulting supply contracting.

Filed as an expert report by Michael Sloan: *Request for Approvals and Findings Related to Atlantic Bridge Project.* Summit Natural Gas of Maine, Inc. Maine Public Utilities Commission. Docket No. 2019-00185.

New York Natural Gas Planning Study, 2019-2021. For a confidential client, Mr. Griffith was the lead analyst assessing the current state of New York natural gas markets. Provided an assessment of regions in New York with constrained infrastructure and expected demand growth after gathering information from New York's gas utilities, interstate pipelines, and other sources. Modelled the cost of various policy scenarios for achieving New York's emissions goals under the CLCPA.

Natural gas storage buy-side review, 2021. For a confidential client, Mr. Griffith led a study that valued a portfolio of U.S. Gulf Coast natural gas assets. Assessed the physical characteristics, competitive landscape, market growth opportunities, and provided rate forecast scenarios.

IRP Jurisdictional Review, Enbridge, 2020. For Enbridge, Mr. Griffith compared the regulatory environments in Ontario and New York to assess the differences in non-pipeline solutions, demand side management, infrastructure requirements planning, and other natural gas market planning.

Natural gas storage valuation for asset owner, 2020. For a confidential client, Mr. Griffith led a study to value a portfolio of natural gas assets in four different North American gas markets for the owner of the assets. Assessed all aspects of each market that effect gas prices and access to natural gas production and demand sources including infrastructure constraints and project development.

Climate Change Risk Assessment Report, 2021, 2020 & 2018, Devon Energy. For Devon Energy, Mr. Griffith led an analysis of expected commodity prices, demand levels, and production potential in two reference scenarios and two sustainable development scenarios in order to assess the resilience and profitability of Devon's production portfolio. The results were published in public reports for Devon's investors.

North American Midstream Infrastructure - A Near Term Update Through 2025, INGAA, ICF, 2020. For INGAA, Mr. Griffith was a consultant who reported on the amount of oil & gas infrastructure development and demand growth expected through 2025 in light of the COVID-19 pandemic.

Impact of Changing Supply Dynamics on the Ontario Natural Gas Market, Enbridge, 2019. Mr. Griffith was a consultant contributing to the analysis in the expert report, "Impact of Changing Supply Dynamics on the Ontario Natural Gas Market", which was authored by Michael Sloan and Srirama Palagummi and submitted on behalf of Enbridge Gas Limited, before the Ontario Energy Board in Case EB-2019-0159 in July 2019.

South Carolina natural gas transportation and supply cost guidance, 2019, South Carolina State House. For the South Carolina State House, Mr. Griffith was the lead natural gas consultant on a study that researched, summarized, and evaluated gas source costs and transportation costs for future gas-fired power generation for the state of South Carolina. Assessed pipeline constraints and idenitfied pipeline supply options by communicating with the interstate pipelines that serve South Carolina and conducting an independent assessment.

Natural gas storage valuation for a utility, 2019, Heritage Natural Gas. For Heritage Natural Gas, Mr. Griffith valued natural gas storage capacity and varying levels of deliverability for a gas utility. Accounted for the client's projected demand and portfolio of supply and transportation contracts in order to determine their optimal level of storage capacity.

Development of a methane emissions calculator, 2019, NYC Office of Sustainability. For the New York City Office of Sustainablity, Mr. Griffith designed and built a tool for calculating lifecycle methane emissions for use by cities and local distribution companies.

North American Midstream Infrastructure Investment through 2035, INGAA, ICF, 2018. For the Interestate Natural Gas Association of America, Mr. Griffith was a consultant who analyzed the amount of oil & gas infrastructure development possible in North America through 2035 for two different scenarios using ICF's Midstream Infrastructure Report (MIR) and other modeling tools. The study assessed capital expenditures in base case and rising cost scenarios and the resulting economic consequences of oil and gas infrastructure development.

Natural gas supply and demand forecast, ISO-NE, 2018. For the Independent System Operator of New England, Mr. Griffith was a consultant on a study that reported on the expected annual, winter, summer, and peak demand for natural gas in New England along with potential sources of gas supply.

Impact of Dawn LTFP Service on Western Canadian Markets, Union Gas Limited (now Enbridge), 2017. For Union Gas Limited, Mr. Griffith was a consultant who analyzed the impact of the TC Energy Dawn Long-Term Fixed Price service on Western Canadian producers and Ontario markets by projecting the change in prices at Dawn hub.

U.S. Oil and Gas Infrastructure Investment through 2035, API, ICF, 2017. For the American Petroleum Institute, Mr. Griffith was a constulant who analyzed the amount of oil & gas infrastructure development possible in U.S. through 2035 for two different scenarios using ICF's Midstream Infrastructure Report (MIR) and other modeling tools. The study assessed capital expenditures and the resulting economic consequences of oil and gas infrastructure development.

Supply Curve Development, Environmental Proctection Agency, 2017. For the U.S. Environmental Protection Agency, Mr. Griffith was a consultant who developed supply curves for an EPA project using the EIA Annual Energy Outlook and ICF's Gas Market Model.

Gas Market Constraint Modeling, Exelon, 2017. For Exelon, Mr. Griffith was a consultant who researched and modelled the power and gas market capacity in a specific geogprahic region under various supply and weather scenarios. The modelling included forecasting design day natural gas demand natural gas infrastructure requirements.

Gas Supply Cost Assessment, AECI, 2017. For AECI, Mr. Griffith was a consultant who assessed the cost of supplies of natural gas under various scenarios and calculated the cost of transporting gas along various pipeline routes. Helped determine the value of new pipeline capacity between the Rockies Express Pipeline and the St. Louis, Missouri area.

Decarbonization Risk Modelling, Union Gas Limited (now Enbridge), 2017. For Union Gas Limited, Mr. Griffith was a consultant who modelled the risk to natural gas assets by decarbonization efforts until the year 2050.

Natural Gas Storage Valuation, Union Gas Limited (now Enbridge), 2017. For Union Gas Liminted, Mr. Griffith was a consultant who modelled the value of geogprahic region's natural gas storage using basis differentials and other key variables.

Regional and North American Market Analysis, Enbridge, 2016. For Enbridge, Mr. Griffith was a consultant who analyzed the current and future market for natural gas, focusing on specific regions of interest.

Economic Impacts of the Port Arthur Liquefaction Project, Sempra, 2016. For Sempra, Mr. Griffith was an analyst that assisted in writing a report on the economic effects of the proposed Port Arthur LNG export facility as part of a U.S. Department of Energy permit application.

Demand Elasticity Determination, Environmental Proctection Agency, 2016. For the U.S. Environmental Protection Agency, Mr. Griffith was a consultant who used projected demand and price levels to determine the future elasticity of demand for multiple regions, seasons, and years in the future.

Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short- and Near-Term Electric Generation Needs, ISO New England, 2016. For the Indepdent System Operator of New England, Mr. Griffith was an analyst who assisted in providing a summary of the current natural gas pipeline infrastructure in New England and an assessment of the potential future development of additional pipelines in the region.

Market Analysis, Propane Education and Research Council (PERC), 2016. For the Propane Education and Research Council, Mr. Griffith was an analyst who assisted in developing a state-by-state analysis of the markets for propane in all sectors. Compared internal propane import volume data with external sources in order to find disparities.

Market and Infrastructure Reliability Analysis, DTE Energy, 2016. For DTE Energy, Mr. Griffith was an analyst who assessed the ability of the current natural gas infrastructure to meet demand and analyzed potential vulnerabilities in the infrastructure.

Infrastructure Vulerability Analysis, U.S. Department of Energy (DOE), 2016. For the U.S. Department of Energy, Mr. Griffith was an analyst who collaborated on a report on areas of vulnerability in the natural gas infrastructure in the U.S. with the office of Energy Policy and Systems Analysis (EPSA).

Subscription Projects

Gas Market Compass, Numerous Clients. Assists in the production of ICF's quarterly-produced base cases for the North American natural gas markets.

Detailed Production Report, Numerous Clients. Assists in the production of this service that provides ICF's projection of gas, oil, and natural gas liquid production over time.

Midstream Infrastructure Report, Numerous Clients. Assists in the production of this product that assesses the amount of midstream infrastructure, including gas pipeline capacity that is likely to be built in markets throughout North America over the next 20 years.

Select Publications and Presentations

Griffith, A. & Milligan, P. (2021) Presented to the Association of Energy Engineers – Oklahoma. *ERCOT February 2021 Blackout: Overview and Open Questions*. Fairfax, VA: ICF.

Petak, K., Manik, J., A., Griffith, A. (2018) American Petroleum Institute and ICF. *North America Midstream Infrastructure through 2035: Significant Development Continues*. Fairfax, VA: The INGAA Foundation, Inc.

Petak, K., Vidas, H. Manik, J., Palagummi, S., Ciatto, A., Griffith, A. (2017) American Petroleum Institute and ICF. *U.S. Oil and Gas Infrastructure Investment Through 2035*. Washington, DC: American Petroleum Institute.

International Trade Administration (2015). *2015 Top Markets Report – Renewable Fuels: A Market Assessment Tool for U.S. Exporters*. Washington, DC: U.S. Department of Commerce.

Employment History

ICF. Senior Energy Markets Consultant. Fairfax, VA. 2016 – Present.
Swiss Re. Climate Consultant. Washington, DC. 2014-2015.
U.S. International Trade Administration. Intern. Washington, DC. 2014.
Accenture. Senior Analyst. Washington, DC. 2012-2014.
U.S. Department of State. Intern. Brussels, Belgium. 2011.
RBI Strategies and Research. Intern. Denver, CO. 2008-2009.

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EXPERIENCE OVERVIEW

Michael Sloan is the Managing Director for ICF's Natural Gas and Liquids Advisory Services Group. He has more than 40 years of experience in the energy field.

Mr. Sloan provides in-depth analytical and regulatory support for natural gas utilities on issues related to policy-driven electrification and decarbonization policy, the potential for non-pipeline solutions to meet natural gas demand growth, natural gas utility avoided costs, and the value of natural gas demand side management (DSM). He also provides assessments of the value of new natural gas pipeline and storage assets to utilities and ratepayers. Mr. Sloan has worked extensively on Canadian natural gas market and regulatory issues.

Mr. Sloan has also provided market analytics and regulatory support for the propane industry since 2004. In addition to his work evaluating propane market trends and the economic impacts of the propane industry, he is currently focusing on the potential impacts of climate change policies on the industry.

Mr. Sloan is a frequent speaker at natural gas and propane conferences and association board meetings, and has submitted testimony in more than 40 regulatory and legal proceedings related to natural gas distribution company non-pipeline solutions, natural gas avoided costs, natural gas storage market power, natural gas storage economics, natural gas storage land owner issues, pipeline facility expansion economics, propane pricing power and other issues.

Years of Experience

- 40 years of experience in natural gas and liquids market and policy analysis

Education

- B.A., Economics, Policy Studies/Operations Research, Dartmouth College, Hanover, NH.

PROJECT EXPERIENCE

Selected Natural Gas Industry Analysis and Regulatory Support Projects

Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals", March 2020. For Washington Gas and AltaGas Mr. Sloan led a major study to evaluate the potential for a major natural gas distribution company to reach net zero carbon emissions by 2050.

2018 Potential for Infrastructure IRP to Avoid Natural Gas Distribution Facilities Investments. March 2018. For Union Gas and Enbridge Gas in Ontario, Mr. Sloan led a major study to evaluate the potential for an integrated planning process to reduce the need for new distribution company infrastructure by implementing targeted DSM programs.

2018 American Gas Association Study on the Implications of Policy-Driven Residential Electrification. July 2018. For AGA, Mr. Sloan led a study to determine the cost implications of AGA residential electrification scenarios.

2015 Ontario Natural Gas Market Review: Assessing Ontario Natural Gas Market Requirements. January 2016. Mr. Sloan completed a detailed assessment of Ontario natural gas market requirements for Union Gas Limited, and presented the conclusions of the assessment to the Ontario Energy Board ("OEB") during the OEB 2016 Natural Gas Market Review.

Analysis of the Value of Nexus Pipeline Capacity to DTE Gas Customers. December 2015. Mr. Sloan completed a detailed assessment of the value of holding Nexus pipeline capacity on DTE Gas customers for DTE Gas. The assessment concluded that holding Nexus Pipeline capacity would provide long term benefits to DTE Gas customers.

Analysis of the Value of Nexus Pipeline Capacity on Michigan Energy Markets. November 2015. Mr. Sloan completed a detailed assessment of the value of holding Nexus pipeline capacity on Michigan Energy Markets for DTE Electric. The assessment concluded that holding Nexus Pipeline capacity would provide long term benefits to DTE Electric customers.

Analysis of Union Gas Avoided Costs 2016, 2018. For Union Gas, Mr. Sloan prepared an assessment of the Union Gas estimates of avoided costs used to evaluate DSM programs. The assessment included recommendations for revisions to the avoided cost estimation methodology.

Analysis of Impact of Changing North American Supply and Demand on Union Gas Pipeline Facilities. September 2014. For Union Gas, Mr. Sloan prepared an assessment of the impact of natural gas market changes on planned Union gas facilities. The assessment concluded that new Union Gas facilities would continue to be used and useful for the foreseeable future.

Analysis of the Impact of Changing Natural Gas Market Conditions on ATCO Pipelines Market Risk. January 2014. On behalf of ATCO Pipelines, Mr. Michael D. Sloan completed an assessment of the impact of recent natural gas market changes on ATCO Pipeline market risk. The assessment reviewed the changes in natural gas supply and transportation on market risks for shippers and customers in Alberta.

Analysis of Natural Gas Market Outlook and Options for Gaz Metro, Quebec, Canada, 2013. Mr. Sloan completed an assessment of natural gas market conditions including expected pipeline flows and constraints impacting the Gaz Metro supply planning.

Analysis of Value of Proposed Natural Gas Storage Facilities 2013: Mr. Sloan used his storage valuation model to evaluate the potential value of contracting for capacity on a proposed storage facility for Heritage Gas, Nova Scotia Canada.

Analysis of Natural Gas Supply Options, Centra Manitoba Gas Company – a Division of Manitoba Hydro, 2006-2007 and 2010 -2012: Mr. Sloan prepared a detailed assessment of natural gas supply options for Centra Manitoba Natural Gas. The review included detailed assessment of customer demand patterns relative to industry standards, availability and likely costs of alternative supply strategies capable of meeting demand. The assessment also included evaluation of the clients' current facility contracts, and recommendations for future natural gas facility development and contracting practices. The review includes an assessment of likely pipeline flows and tariffs on the TransCanada Pipeline system.

Storage Market Concentration, Union Gas Limited, 2005 – 2006: On behalf of Union Gas, Mr. Sloan evaluated natural gas storage market concentration and natural gas storage market power in Ontario and the Great Lakes Basin. His report included an assessment of the workably competitive market region for Union Gas storage based on an analysis of market liquidity, connectivity, and market concentration. Mr. Sloan also testified before the Ontario Energy Board on behalf of Union Gas Limited on these issues. At the conclusion to this proceeding the Ontario Energy Board deregulated more than 50 Bcf of Union Gas Storage.

Analysis of Optimum Storage Utilization, MichCon Gas, 2006, 2008, 2011: Mr. Sloan has prepared a series of analyses of the optimum storage utilization for the MichCon Gas local distribution company business to support MichCon regulatory proceedings related gas supply costs and storage utilization. The analyses evaluated the value of existing MichCon gas storage to LDC customers based on different weather patterns and usage scenarios.

Analysis of Value of Proposed Natural Gas Storage Facilities to Nova Scotia Power and Light (NSPI) – 2008: Mr. Sloan used his storage valuation model to evaluate the potential value of contracting for capacity on a proposed storage facility to NSPI.

Analysis of the Impact of LNG on Natural Gas Markets in Quebec, Rabaska Limited, 2005 – 2006: Mr. Sloan prepared a detailed analysis and forecast of the likely impacts of an LNG import facility located in Quebec on local, regional, and US and Canadian natural gas markets. The analysis concluded that the facility would substantially reduce natural gas prices in the region, and increase supply options and supply reliability. The report was filed with the Canadian Environmental Assessment Agency by Rabaska Limited as part of the facility approval process.

Analysis of Natural Gas Market Liquidity at Points Affecting New York State LDC's, Northeast Gas Association, 2003: Mr. Sloan co-authored a major study of natural gas market liquidity for the Northeast Gas Association to identify liquid markets for natural gas commodity purchases. The study included development of new approaches to evaluating market liquidity in the Northeastern U.S., and identified market centers that could be considered sufficiently liquid to provide a reliable source of natural gas.

Analysis of Natural Gas and Energy Price Volatility, for the American Gas Foundation and the Oak Ridge National Laboratory, 2003: Mr. Sloan managed a major study and co-authored a report on natural gas and energy price volatility for the American Gas Foundation.

Multi-Client Study, American Gas Association and Interstate Natural Gas Association of America: Mr. Sloan conducted the analysis, and co-authored the report "Short-term Natural Gas Markets" which was widely cited in FERC Order 637. The analysis was used by FERC to provide quantitative support for the removal of price caps in the short-term capacity release market

Propane Market Analysis

Annual Retail Propane Sales Report: U.S. Odorized Propane Sales by State and End-Use Sector: 2018 – 2020: Mr. Sloan has managed a major project to collect and analyze annual propane sales data for the Propane Education and Research Council (PERC). This effort represents the only currently available data source on state-by-state retail propane sales and includes the collection and processing of survey responses from more than 2000 propane marketers.

Propane Market Forecast Model Development: Mr. Sloan managed the development and implementation of two major propane demand forecasting models for the PERC. The models provide the only publicly available forecasting capability at the State and County levels. The Propane Database and Forecasting Model (PDFM) provides State by State assessments of the total odorized propane market by end-use, including residential, commercial, on-road vehicle, industrial, and portable cylinder markets. The County Residential Propane Model (CRPM) provided propane markets with a customizable forecasting tool capable of evaluating residential demand on a county-by-county basis.

Regulatory and Market Support, National Propane Gas Association, 2008 – 2019. Mr. Sloan provides market and regulatory analysis of issues influencing the propane industry for the National Propane Gas Association.

Assessment of the EIA Regional Residential Propane Model and Regional Residential Distillate Model, U.S. Energy Information Administration, 2006/2007. Mr. Sloan was asked by the EIA to peer review the EIA

Residential Short Term Energy Model residential propane and distillate modules. The review included an in-depth review of the two modules, and recommendations to the EIA for model improvements.

EXPERT TESTIMONY

1. Written evidence of Dr. Michael O Lerner and Michael D. Sloan, *Long term natural gas transmission expansion economics,* 1995. Mr. Sloan submitted written evidence and testified on behalf of Union Gas Limited before the Ontario Energy Board in EBRO 486. Mr. Sloan's evidence concerned the long-term economics of pipeline expansion on the Union Gas system.
2. Written evidence of Dr. Michael O Lerner and Michael D. Sloan, *Long term natural gas transmission expansion economics,* 1996. Mr. Sloan submitted written evidence and testified on behalf of Union Gas Limited before the Ontario Energy Board in EBLO 251. Mr. Sloan's evidence concerned the long-term economics of pipeline expansion on the Union Gas system.
3. "Written Evidence of Bruce B. Henning and Michael D. Sloan", TransCanada PipeLines Limited, Hearing Order RH-1-2002 (dated May 2002). Mr. Sloan submitted written evidence before the National Energy Board on behalf of Enbridge Gas Distribution Inc., Societe En Commandite Gaz Metro, and Union Gas Limited. Mr. Sloan's written evidence concerned the proposed establishment of the Southwest Zone and its impact on market liquidity.
4. "Analysis of FERC Staff Report Investigating California Natural Gas and Electricity Prices", San Diego Gas & Electric Co., Docket Nos. EL00-95-045 and EL00-98-42, prepared by Bruce B. Henning and Michael Sloan, (dated October 15, 2002) and submitted on behalf of Energy and Environmental Analysis, Inc. ("EEA") before the Federal Energy Regulatory Commission ("FERC"). Mr. Sloan's report concerned issues related to FERC's investigation of natural gas and electricity prices.
5. "Written Evidence of Bruce B. Henning and Michael D. Sloan on Behalf of Union Gas Limited", Hearing Order RP-2000-0005 (dated October 29, 2003). Mr. Sloan submitted written evidence on behalf of Union Gas Limited before the Ontario Energy Board. Mr. Sloan's written evidence addressed issues related to the compensation of landowners for the use of natural gas storage pools located on their property.
6. "Written Evidence of Bruce B. Henning and Michael D. Sloan", TransCanada PipeLines Limited, Hearing Order RH-3-2004 (dated June 21, 2004). Mr. Sloan submitted written evidence and testified before the National Energy Board on behalf of Enbridge Gas Distribution Inc., Societe En Commandite Gaz Metro, and Union Gas Limited.
7. Report "The Impact of Rabaska LNG Imports on Quebec and Ontario Natural Gas Markets", authored by Bruce B. Henning and Michael Sloan (dated November 2005) and submitted on behalf of Rabaska Limited Partnership before the Canadian Environmental Assessment Agency.
8. Report "Analysis of Competition in Natural Gas Storage Markets For Union Gas Limited." 2006. Authored by Bruce B. Henning, Michael D. Sloan, and Richard Schwindt and submitted before the Ontario Energy Board Natural Gas Electricity Interface Review EB-2005-0551. 2006. Mr. Sloan testified on behalf of Union Gas Limited before the Ontario Energy Board of Canada.
9. Report "Storage Planning and Optimization for MichCon GCR Customers", December 2007. Authored by Bruce B. Henning and Michael D. Sloan and submitted on behalf of MichCon before the Michigan Public Service Commission U-15451.
10. Report "Assessment of Natural Gas Commodity Options for Centra Gas Manitoba". February 2009. Authored by Bruce B. Henning and Michael D. Sloan and submitted on behalf of Centra Gas Manitoba before the Manitoba Public Utilities Board.
11. Report "Dawn Gateway Pipeline Expansion Project: Market Fundamentals and Market Impact of Project Construction". Authored by Bruce B. Henning and Michael D. Sloan and submitted on behalf of Union Gas before the Canada National Energy Board.

12. Expert witness report "Opinions and Report on Propane Markets and Prices in Minnesota Related to Minnesota Attorney General Counterclaim and Answer". February 2011. Authored by Mr. Michael D. Sloan and submitted on behalf of Ferrellgas, L.P. before the State of Minnesota District Court, Second Judicial District.
13. Report "ICF 2011 Addendum to the 2007 ICF Report: Storage Planning and Optimization for MichCon GCR Customers", December 2011. Authored by Bruce B. Henning and Michael D. Sloan and submitted on behalf of MichCon before the Michigan Public Service Commission U-16921.
14. Report "Impact of Changing Supply Dynamics on the Ontario Natural Gas Market", January 30, 2013. Authored by Mr. Bruce B. Henning, Mr. Michael D. Sloan, and Ms. Briana Adams, and submitted on behalf of Union Gas Limited before the Ontario Energy Board in EB-2013-0074.
15. Report "Review of Natural Gas Pipeline Market Activity around the Dawn Hub". May 2013. Authored by Mr. Bruce B. Henning and Mr. Michael D. Sloan and submitted on behalf of Gaz Métro before the Quebec Public Utilities Board.
16. Expert Witness Report and Testimony "Impact of Changing Natural Gas Market Conditions on ATCO Pipelines Market Risk". January 2014. Authored by Mr. Michael D. Sloan and submitted on behalf of ATCO Pipeline before the Alberta Utilities Board. Mr. Sloan testified on behalf of ATCO Pipelines before the Alberta Utilities Board.
17. Expert Witness Report and Testimony "Updated Assessment of Alton Natural Gas Storage", July 2014, Authored by Mr. Leonard Crook and Mr. Michael Sloan and submitted on behalf of Heritage Gas Limited before the Nova Scotia Utility and Review Board. Mr. Sloan testified on behalf of Heritage Gas before the Nova Scotia Utility and Review Board.
18. Expert Witness Report and Testimony "Impact of Changing North American Supply and Demand on Union Gas Pipeline Facilities", September 2014. Authored by Mr. Michael D. Sloan and submitted on behalf of Union Gas Limited before the Ontario Energy Board.
19. Expert Witness Report "Evaluation of Union Gas Avoided Costs", December 2014, Authored by Michael D. Sloan and submitted on behalf of Union Gas Limited before the Ontario Energy Board in Case No. EB-2015-0029. Mr. Sloan testified on behalf of Union Gas Limited before the Ontario Energy Board.
20. Expert Witness Report and Testimony "The Value of Nexus Pipeline Capacity to DTE Gas Customers", December 2014, Authored by Michael D. Sloan and submitted on behalf of DTE Gas before the Michigan Public Service Commission in Case No. U-17691. Mr. Sloan testified on behalf of DTE Gas before the Michigan Public Service Commission.
21. Expert Witness Report "Impact of Natural Gas Market Trends on Utilization of the Union Gas Dawn Parkway System", June 30, 2015. Authored by Mr. Michael D. Sloan and submitted on behalf of Union Gas Limited before the Ontario Energy Board.
22. Expert Witness Report and Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", November 2015, Authored by Michael D. Sloan and Maria Scheller and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-17920. Mr. Sloan testified on behalf of DTE Gas before the Michigan Public Service Commission.
23. Expert Witness Report and Testimony "The Value of Nexus Pipeline Capacity to DTE Gas Customers", December 2015, Authored by Michael D. Sloan and submitted on behalf of DTE Gas before the Michigan Public Service Commission in Case No. U-17941. Mr. Sloan testified on behalf of DTE Gas before the Michigan Public Service Commission.
24. Expert Witness Report "2015 Ontario Natural Gas Market Review: Assessing Ontario Natural Gas Market Requirements", January 2016. Authored by Mr. Michael D. Sloan and submitted on behalf of Union Gas Limited before the Ontario Energy Board. Mr. Sloan presented the results of the analysis to the Ontario Energy Board on behalf of Union Gas Limited.

25. Expert Witness Report and Testimony "Propane Market Trends in the Northeastern U.S. and Atlantic Canada", January 2016, Authored by Michael D. Sloan and submitted on behalf of Heritage Gas before the Nova Scotia Utility and Review Board. Mr. Sloan testified on behalf of Heritage Gas before the Nova Scotia Utility and Review Board.
26. Expert Witness Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", October 2016, Authored by Michael D. Sloan and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-18143.
27. Expert Witness Testimony "The Value of Nexus Pipeline Capacity to DTE Gas Customers", December 2016. Authored by Michael D. Sloan and submitted on behalf of DTE Gas before the Michigan Public Service Commission in Case No. U-18243.
28. Expert Report "ICF Review of MNP Proposal for Irving Oil Load Retention Service". Authored by Michael D. Sloan and submitted on behalf of Nova Scotia Power before the Canada National Energy Board in Case RHW-001-2017.
29. Expert Report "Assessment of the Impact of the TransCanada Dawn LTFP Service Proposal on Natural Gas Markets", Authored by Michael D. Sloan and submitted on behalf of Union Gas Limited before the Canada National Energy Board in Case RH-003-2017.
30. Confidential Expert Report "Analysis of Merchant Natural Gas Storage Competition in Ontario", January 2017. Authored by Michael D. Sloan and submitted on behalf of Enbridge, Inc. and Spectra Energy Corporation to the Competition Bureau Canada.
31. Expert Witness Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", October 2017, Authored by Michael D. Sloan and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-18403.
32. Expert Report "Rebuttal to Evidence of James Grevatt on 2017 FortisBC LTGRP Testimony" addressing non-pipeline solutions. Authored by Michael Sloan and John Dikeos and submitted on behalf of FortisBC to the British Columbia Utilities Commission in Project No. 1598946.
33. Expert Report "Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment", January 2018. Authored by Michael D. Sloan and John Dikeos and submitted on behalf of Union Gas Limited and Enbridge Gas Limited, before the Ontario Energy Board in Case EB-2017-0128.
34. Expert Witness Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", September 2018, Authored by Michael D. Sloan and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-18412.
35. Expert Witness Testimony "The Value of Nexus Pipeline Capacity to DTE Gas Customers", April 2018. Authored by Michael D. Sloan and submitted on behalf of DTE Gas before the Michigan Public Service Commission in Case No. U-18412.
36. Expert Witness Testimony "Impact of the Nexus Pipeline on Michigan Energy Markets", September 2018, Authored by Michael D. Sloan and submitted on behalf of DTE Electric before the Michigan Public Service Commission in Case No. U-20221.
37. Expert Report "Impact of Changing Supply Dynamics on the Ontario Natural Gas Market", July 2019. Authored by Michael Sloan and Srirama Palagummi and submitted on behalf of Enbridge Gas Limited, before the Ontario Energy Board in Case EB-2019-0159.
38. Expert Report "Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals", March 2020. Authored by Michael Sloan and Peter Narbaitz and submitted on behalf of AltaGas to the Public Service Commission of the District of Columbia, Formal Case No. 1142.

39. Expert Witness Testimony on behalf of Summit Utilities before the Maine Public Utilities Commission regarding the value of contracted pipeline capacity on the Atlantic Bridge Pipeline to natural gas consumers in the Summit Utilities Maine service territory. June 2020. MPUC Docket No. 2019-00185.
40. Expert Witness Testimony report and deposition, "Opinions and Report on Propane Markets and Prices in Michigan Related to Michigan Attorney General Complaint June 27, 2018". Authored by Mr. Michael D. Sloan and submitted on behalf of AmeriGas before the State of Michigan Circuit Court for the 38th Judicial Circuit, Monroe County. June 2020.
41. Expert Report, "IRP Jurisdictional Review", September 2020. Submitted on behalf of Enbridge Gas Limited before the Ontario Energy Board in Case EB-2020-0091.
42. Expert Witness Rebuttal Testimony on behalf of Summit Utilities before the Maine Public Utilities Commission regarding the value of contracted pipeline capacity on the Atlantic Bridge Pipeline to natural gas consumers in the Summit Utilities Maine service territory. July 2021. MPUC Docket No. 2019-00185.
43. Expert Report "Assessment of the Value of the Enbridge Gas Dawn to Corunna Storage Project: Potential Value of Incremental Storage Capacity and Market-Based Alternatives to Enbridge Gas", February 2022. Authored by Michael Sloan and Andrew Griffith and submitted on behalf of Enbridge Gas Limited, before the Ontario Energy Board in Case EB-2022-0086.

SELECTED PUBLICATIONS AND PRESENTATIONS

Harry Vidas, Michael Sloan. "Pipeline Markets in Transition: Cost Impacts of FERC Order 636." *Gas Research Institute*, March 1998.

Michael Sloan, Paul Friley. "Natural Gas Storage Overview in a Changing Market Environment." *Gas Research Institute,* GRI-99/0200, February 2000.

Michael Sloan, Paul Friley, Bruce Henning. "Restructuring Activity of Natural Gas Local Distribution Companies." *Gas Research Institute,* GR00/0018, June 2000.

Bruce Henning, Michael Sloan, Maria deLeon. "Natural Gas and Energy Price Volatility." *Prepared for the Oak Ridge National Laboratory by the American Gas Foundation*, October 2003.

Michael Sloan, Bruce Henning, Sol deLeon, David Clayton. "Propane Industry Issues and Trends." *Propane Education and Research Council*, June 2004.

Michael Sloan, Bruce Henning, Sol deLeon, David Clayton. "Propane Industry Issues and Trends II." *Propane Education and Research Council*, January 2005

Michael Sloan, Bruce Henning. "Propane Industry Issues and Trends III." *Propane Education and Research Council*, August 2005.

Michael Sloan. "Propane Market Growth: A Review of Propane Market Trends and the Role of the PERC Market Metrics Initiative", Prepared for the National Propane Gas Association, January 30, 2006.

Michael Sloan, Bruce Henning. "Propane Industry Issues and Trends IV", *Propane Education and Research Council*, August 2006.

Michael Sloan. "Natural Gas Supply and Demand in an Uncertain Environment". Canadian Institute Conference on Natural Gas Storage, September 2008.

Michael Sloan, Richard Meyer. "2009 Propane Market Outlook – Assessment of Key Market Trends, Threats, and Opportunities Facing the Propane Industry Through 2020." *Propane Education and Research Council*, September 2009.

Michael Sloan. “What Keeps You Up at Night? Natural Gas Market Planning in an Uncertain Environment”. Canadian Institute Conference on Natural gas Storage, February 2009.

Michael Sloan. “Back to the Future? Impact of Market Volatility and Uncertainty on Natural Gas Supply and Infrastructure”. Canadian Institute Conference on Natural Gas Infrastructure and Supply, November 2009.

Michael Sloan, Richard Meyer. “2010 Propane Market Outlook – Assessment of Key Market Trends, Threats, and Opportunities Facing the Propane Industry Through 2020. ” *Propane Education and Research Council*, June 2010.

Michael Sloan, Bruce Hedman, et al., “Strategic Market Assessment for Commercial Sector Propane Sales” *Propane Education and Research Council*, February 2011.

Michael Sloan, K.G. Duleep, et al. “Economic Impact of the Propane Green Autogas Solutions Act of 2011 (H.R. 2014)”, *National Propane Gas Association*, October 2011.

Michael Sloan. “Industry at a Crossroads”, *Propane Education and Research Council*, May 2012.

Michael Sloan, Warren Wilczewski. “2013 Propane Market Outlook – Assessment of Key Market Trends, Threats, and Opportunities Facing the Propane Industry Through 2020. ” *Propane Education and Research Council*, April 2013.

Michael Sloan. “Implications of U.S. natural gas liquids (NGL) market developments on European petrochemical and NGL markets”, Platt’s European Petrochemicals Conference, Düsseldorf, Germany. March 2014.

Michael Sloan. “A Detailed Look at the Impact of Cochin Pipeline Reversal on Propane Markets in the Midwest”, presented to the Midwest Governors Association Propane Supply Chain Working Group Meeting June 4, 2014, Madison Wisconsin.

Michael Sloan, Warren Wilczewski. “Impact of the Cochin Pipeline Reversal on Consumer Propane Markets in the Midwest”, *Propane Education and Research Council*, August 2014.

Michael Sloan, “NGL Production Outlook in the Utica and Marcellus”, NGL Gold Rush Executive Briefing, Cleveland, Ohio. September 2014.

Michael Sloan, “NGL Production, Economics, and Pricing in the Utica and Marcellus”, NGL Gold Rush Summit, Cleveland, Ohio. September 2014.

Michael Sloan. “North American Propane and Butane Demand, Markets and Pricing”, Platt’s 4th Annual NGL’s Conference, Houston, Texas, September 2014.

Michael Sloan, Warren Wilczewski. “Impact of the U.S. Consumer Propane Industry on U.S. and State Economies in 2012”, *Propane Education and Research Council*, November 2014.

Michael Sloan. “Future Trends: Assessing Ontario Natural Gas Market Requirements Through 2020”, December 2014. Submitted on behalf of Union Gas Limited before the Ontario Energy Board, and presented to the Ontario Energy Board Stakeholder Conference, December 2014.

Michael Sloan. “NGL Market Outlook in a Dynamic Oil Price Environment”, *2014 NGL Forum*, San Antonio, Texas, December 2014.

Michael Sloan. “Consumer Propane Markets in a Changing Oil Price Environment”, 2015 NPGA Southeaster Convention, Atlanta, Georgia, April 2015.

ICF Consulting Canada, *“Impact of Energy East on Ontario Natural Gas Prices”,* April 8, 2015, Prepared for the Ontario Energy Board by Michael Sloan, with Kevin Petak, Hua Fang, Leonard Crook.

Michael Sloan. “Outlook for Natural Gas Demand Growth in the Industrial Sector”, 2015 ARGUS Natural Gas Markets Conference, Houston, Texas, May 2015.

Michael Sloan. “The Market for Global Petrochemical Feedstocks in a Changing Oil Price Environment – Current and Future Trends”, 2015 Platt’s Asian Petrochemical Markets Conference, Shanghai, China, August 2015.

Michael Sloan. “Global LPG Markets: The Outlook for Propane and Butane”, Platt’s 5th Annual NGL’s Conference, Houston, Texas, September 2015.

Michael Sloan. “2016 Propane Market Outlook – Key Market Trends, Opportunities and Threats Facing the Propane Industry Through 2025. ” *Propane Education and Research Council*, November 2015.

Michael Sloan. “Evaluating the End Game: The Outlook for the NGL Industry in a Low Oil Price Environment”, *2015 NGL Forum*, San Antonio, Texas, December 2015.

Michael Sloan. “2015 Ontario Natural Gas Market Review: Assessing Ontario Natural Gas Market Requirements”, January 2016. Submitted on behalf of Union Gas Limited before the Ontario Energy Board, and presented to the Ontario Energy Board Stakeholder Conference, January 2016.

Michael Sloan. “Is Demand Back?? Keeping up with Supply?? Things are not always as they seem – The Big Picture”, 2017 NGL Forum, Atlanta, April 2017.

Michael Sloan. “2017 Propane Market Outlook: Current Market Conditions and the Outlook Through 2025”, NPGA Southeast Convention, Nashville, April 2017.

Michael Sloan. “Business Risk: Implications of a Low Carbon World for Natural Gas LDC’s”, 2017 NGL Forum, Boston, June 2017.

Michael Sloan. “The Impact of Infrastructure Development Trends on Midwest Natural Gas Markets”, 2017 NGL Forum, September 2017.

Michael Sloan and John Dikeos. “Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment for Ontario”, Prepared for Union Gas and Enbridge Gas, March 2018.

Michael Sloan. “2018 Propane Market Outlook: Coping with Changing Markets”, NPGA Southeast Convention, Atlanta, April 2018.

Michael Sloan, Joel Bluestein, Eric Kuhle. “Implications of Policy-Driven Residential Electrification – An American Gas Association Study prepared by ICF”, July 2018.

Michael Sloan. “2019 Propane Market Outlook: Warning Signs in a Changing Market 2025”, NPGA Southeast Convention, Atlanta, April 2019.

Eric Kuhle and Michael Sloan, “2018 Propane Industry’s Economic Impact Report; Impact of the U.S. Consumer Propane Industry on U.S. and State Economies in 2018”, Propane Education and Research Council, April 2020.

Statement to the Michigan State Senate and House Committees on the impact of a potential shutdown of Enbridge Line 5 on behalf of the Michigan Propane Gas Association. March 2021.

Michael Sloan. “2021 Propane Market Outlook: Adapting to Change – Electrification and Decarbonization”, NPGA Southeast Convention, Atlanta, October 2021.

EMPLOYMENT HISTORY

ICF	Managing Director	2016 - Present
ICF International	Project Manager to Principal	2007 – 2016
Energy and Environmental Analysis, an ICF International Company	RA to Project Manager	1981-2006

Greg Lyle
President
Innovative Research Group Inc.

Greg Lyle is the founder of Innovative Research Group Inc. (INNOVATIVE), a national public opinion research and consultation firm with offices in Toronto and Vancouver. With over 30 years opinion research experience, Greg uses a full range of research tools for a variety of government and corporate clients.

INNOVATIVE has a strong track record of experience in Canada's energy sector. Greg has worked such as the BC Utilities Commission, the Independent Electricity System Operator, the Association of Major Power Consumers, the Canadian Gas Association, Canadian Electricity Association, the Canadian Nuclear Association, and many natural gas and electricity distributors, electricity transmission companies and generators as well as oil and gas pipelines.

INNOVATIVE conducts both consultations and traditional market research on topics including rate applications, customers satisfaction, utility brands, integrated regional resource plans, infrastructure siting, public and trades safety, low volume consumer behaviour, pricing and policy preferences.

Greg's research has been highlighted in media across the country. He has been featured in many media outlets including Macleans' Magazine, the Globe and Mail, the Toronto Star, the Hill Times, and the National Post.

Work Experience

1998 - Present

Innovative Research Group Inc. – Vancouver, BC and Toronto, ON
President

- In 1998, Mr. Lyle incorporated his strategic counsel and research practice. Initially incorporated as Lyle Public Affairs Corporation, Innovative was re-branded in the summer of 2004 to better reflect the collegial nature of the firm and the goal of being at the cutting edge of research development.
- Through Innovative, Mr. Lyle has expanded the research and strategic counsel practice he established in B.C. in 1994. While remaining active in the BC market place, Mr. Lyle has expanded to a national focus with a second office launched in Toronto in 2004.
- While managing a team of full-time and associated consultants, Mr. Lyle remains active in client services. Since rebranding as Innovative, Mr. Lyle has been involved in a wide array of projects over the past 14 years utilizing the full range of his consulting tools in projects ranging from a handful of omnibus questions to designing and tracking multi-media communications campaigns.

2000 - 2004

Navigator Ltd. – Toronto, ON
President

- In the winter of 2000, Lyle Public Affairs Corporation formed a joint venture with two other consultants to form Navigator Ltd, a strategic communications practice based in Toronto.
- Mr. Lyle was the founding President of Navigator and focused on a research-based issue management practice working with the federal and provincial governments, industry associations and major corporations.
- Navigator grew from the initial group of three principals to a team of more than a dozen senior consultants during the four years Mr. Lyle served as President.

1994 - 1998	***Agincourt Research and Communications/Lyle Risk Management Strategies*** *– Roberts Creek, BC* **Sole Proprietor** ▪ In January 2004, Mr. Lyle left Decima and Hill Knowlton to start his own strategic counsel practice. For the first year and a half, Mr. Lyle worked in partnership with ***Angus Reid Group*** and then operated on his own.
1991 – 1993	***Hill and Knowlton and Decima Research*** *– Vancouver, BC* **Concurrent Vice Presidencies** ▪ Mr. Lyle was the first Decima employee in Western Canada, and was responsible for establishing a new business unit. During this period, Mr. Lyle began conducting his own focus groups and public opinion surveys over a wide range of topics in both marketing and public affairs. Mr. Lyle also provided strategic communications counsel as part of the Hill and Knowlton team.
1988 – 1991	***Office of the Premier*** *– Winnipeg, Manitoba* **Principal Secretary** ▪ At 25 years old, Mr. Lyle was the youngest Principal Secretary in Canada. Mr. Lyle was a key architect of the government's strategy in a minority government which led to its election to a majority in 1990. Mr. Lyle managed the Premier's Office, participated at a senior level in the Meech Lake round of constitutional negotiations, served as a Cabinet Officer acting as Cabinet Secretary in the absence of the Clerk of Executive Council and as lead drafter of the government's Throne Speeches. Mr. Lyle served as the principal client contact for most government opinion research and all research conducted for the Manitoba PC Party.
1987 - 1988	***Leader of the Opposition*** *– Winnipeg, Manitoba* **Special Assistant** ▪ Sole Political staffer to the Leader of the Opposition, handled a variety of tasks including question period preparations, policy development and leader's representative on party executive and campaign committee.

Education

June 2008	**York University** (Institute for Social Research) – Toronto, ON ▪ Summer Program in Data Analysis: Structural Equation Modeling and Mixed Models Hierarchical and Longitudinal Data.
April 2002	**Harvard University** (Executive Education Program) ▪ Leading a Professional Service Firm
August 2001	**Essex University (**Summer School in Social Science Data Analysis and Collection) – Essex, UK ▪ Sorting, Q Methodology and Multidimensional Scaling
July 1997	**Essex University** (School In Social Science Data Analysis and Collection) – Essex, UK ▪ Time Series Analysis
1997-98	**University of British Columbia** (Political Science Graduate Course Work) – Vancouver, BC
1989	**University of British Columbia** (Bachelor of Arts, Political Science) – Vancouver, BC

Awards

June 2016	**Public Affairs Association of Canada Award of Distinction**

Mercer

welcome to brighter

Qualifications

At the request of Enbridge Gas Inc. (the "Company"), Mercer prepared a report and supplementary letter to present actuarial estimates of pension and benefit accrual costs in accordance with US GAAP and the cash funding requirements for 2022 to 2024 for the plans in which the Company participates. We understand the report and letter may be provided to the Ontario Energy Board (the "OEB") in conjunction with the Company's application for recovery of pension and benefit costs from ratepayers.

To comply with the OEB's rules of practice and procedure section 13A.03(b), this document includes a summary of the qualifications, relevant educational experience and professional experience for the Mercer actuaries that prepared the report and supplementary letter.

Ken Chin

Ken is the actuary responsible for the work related to the Company's benefit plans.

Ken is a Principal in Mercer's Benefits business, and is based in Montreal. He joined Mercer in 1987 and has 35 years of experience working in the pension and benefits industry.

Ken is the lead non-pension benefits actuary for a number of Mercer's clients across Canada. His work includes the valuation, design/re-design and funding of such plans. Ken also provides peer review on several of his colleague's non-pension valuation and accounting work. He has extensive knowledge of accounting standards (US GAAP, IAS 19, CPA 3462, CPA 3463, PS 3250 and PS 3255) applicable to non-pension benefits, and is a member of the Canadian accounting specialist network. Prior to his current role, Ken was a Wealth consultant at Mercer from 1987 to 1999. He transitioned into his current role to lead the non-pension benefits practice in Montreal, when CICA 3461 became newly applicable to non-pension benefits.

Ken is a Fellow of the Canadian Institute of Actuaries (FCIA) and a Fellow of the Society of Actuaries (FSA). He earned a Bachelor of Science with specialization in Actuarial Mathematics in 1988, under the Co-Op program from Concordia University.

Jesse Little

Jesse is one of the actuaries jointly responsible for work related to the Company's pension plans.

Jesse is a Senior Associate in Mercer's Wealth business, and is based in Edmonton. He joined Mercer in 2018 and has over eight years of experience working in the pension industry.

Jesse is the lead actuary or co-actuary for a number of Mercer's Canadian clients in the quasi-public and private sectors. He advises on the design, funding, investments and administration of both registered and non-registered pension plans. Jesse has acted as either the lead actuary or co-actuary for the preparation of actuarial funding valuations for large private-sector registered pension plans in Western

Canada, as well as asset allocation studies. In addition to his client work, Jesse has presented a number of pension and investment seminars to clients and plan stakeholders, and sits on the Northern Alberta Canadian Pension and Benefits Institute council.

Jesse is a subject matter expert on risk management strategies for pension plans and is a member of Mercer's Financial Strategy Group ("FSG"). The FSG helps clients achieve their unique risk management objectives, by delivering advice on pension risk assessment, management and reduction. He also helps his clients integrate the pension solutions within their overall financial strategy.

Jesse is a Fellow of the Canadian Institute of Actuaries (FCIA) and a Fellow of the Society of Actuaries (FSA). He is also a CFA Charterholder. He earned a Bachelor of Science with distinction in statistics in 2012 and an MBA in 2018, both from the University of Alberta.

Edith Samuels

Edith is one of the actuaries jointly responsible for work related to the Company's pension plans.

Edith is a Principal in Mercer's Wealth business, and is based in Winnipeg. She joined Mercer in 1995 and has over 27 years of experience working in the pension industry.

As a pension consultant and qualified actuary, Edith works with a variety of clients and their pension plans assisting with the design, funding and accounting for pension commitments. She has experience simultaneously leading a number of consulting teams for Canadian clients in the quasi-public and private sectors. She is knowledgeable in the full lifecycle of both defined benefit and defined contribution plans, including designing, amending, funding, converting and winding up pension plans. She is comfortable with complex technical and legal concepts and is capable of communicating this knowledge to a broader audience, including employees and employee groups. She is a pension accounting subject matter expert, leading Mercer's network of accounting specialists and acting as a mentor and advisor to colleagues.

Edith is a Fellow of the Canadian Institute of Actuaries (FCIA) and a Fellow of the Society of Actuaries (FSA). She graduated from the University of Manitoba in the pre-Master's program in Actuarial and Management Sciences, and Brandon University with a Bachelor of Science in Mathematics.

Scott Thompson

Scott is one of the actuaries jointly responsible for work related to the Company's pension plans.

Scott is a Principal in Mercer's Wealth business, and is based in Calgary. He joined Mercer in 2007 and has over 15 years of experience working with defined benefit and defined contribution pension plans.

Scott is currently the relationship manager, retirement consultant, and actuary for several prominent western Canadian companies. He is experienced working with plans registered in British Columbia, Alberta, Federal, Ontario and Saskatchewan, including several multi-jurisdictional plans. He is responsible for all aspects of registered and non-registered retirement plan management, including governance, risk strategy, mergers & acquisitions, design, union negotiations, wind-up, funding, accounting, executive disclosure, and pension administration services for a variety of Canadian, North American, and international companies in the private and quasi-public sectors. He has gained international experience working in Mercer's São Paulo and Tokyo offices.

Scott is a Fellow of the Canadian Institute of Actuaries (FCIA) and a Fellow of the Society of Actuaries (FSA). He graduated from the University of Calgary with a Bachelor of Arts, majoring in both actuarial science and economics.

Mercer welcome to brighter

Kenneth Yung

WORK EXPERIENCE

Partner, Career
Mercer (Canada) Limited Oct 2004 – Present

Role and Responsibilities
- Partner and Career Practices Leader, providing strategic oversight across all consulting practices
- Leader of Mercer's Executive Rewards business in Canada
- Member of Mercer's Global and Canadian Energy Vertical
- Lead consultant for a significant number of energy companies in Canada
- Regular presenter at client seminars on compensation and governance topics
- Expert witness on compensation matters at a number of rate cases

Typical Consulting Assignments
- Lead consulting engagements with Board of Directors and/or management of upstream, midstream, energy services and utilities organizations, including a number of publicly-traded S&P/TSX60 issuers and private companies
- Evaluate total remuneration packages, including base salaries, incentive compensation and benefits provided to executive and non-executive employees to ensure alignment with approved compensation philosophy
- Design effective short-, mid- and long-term incentive programs using a fact-based and collaborative approach to support business and human capital strategies and to create shareholder value
- Provide guidance and support on proxy disclosure and corporate governance matters for publicly-traded companies to ensure they meet regulatory requirements and emerging best practice

EDUCATION

Chartered Financial Analyst Oct 2008
CFA Institute

Bachelor of Commerce, Finance with Distinction 2000 – 2004
Haskayne School of Business, University of Calgary

Erika Aruja, M.A (Economics)

Consultant

EXPERIENCE OVERVIEW

Erika provides an economic perspective to analyzing environmental and energy issues. As a Consultant with Posterity Group, Erika has conducted research and analysis to identify energy savings potential and GHG reduction opportunities under various economic conditions and policy interventions. She has advised utilities, federal departments, and provincial agencies on a variety of climate change and energy policies. As a Project Manager, Erika has successfully managed complex projects and designed stakeholder engagement activities for several clients.

Prior to joining Posterity Group, Erika worked as an Economist with Environment and Climate Change Canada and a Researcher for the University of Ottawa and Sustainable Prosperity. Erika has master's degree in Economics with a focus on environmental and natural resource economics and competed the ISO 14064 courses on GHG emissions accounting.

PROJECT EXPERIENCE

Energy Forecasting, Scenario Analysis & Resource Planning

Resource Planning Support: Southern California (SoCal) Gas (April 2022-ongoing): Posterity Group is developing an end use model to support SoCal Gas with ongoing long term planning activities in both SoCal Gas' and SDG&E's service territories. PG's model will enable SoCal to conduct scenario analysis including estimating the impacts of policies, climate change, and energy efficiency potential. Erika is the Project Manager and Analyst for the project.

2022 Long Term Resource Plan (LTGRP) Information Request Support: FortisBC (August 2022 -ongoing): After successful completion of the load forecast and scenario analysis for the 2022 LTGRP, Posterity Group is again working with FortisBC Energy Inc (FEI) to support the information request (IR) process for the LTGRP filing. PG will help respond to IRs from the BCUC and intervenors and conduct project management support to FEI for this IR process. Erika is the project management and analyst for the project which requires coordinating with the regulatory team at FEI to ensure PG provides timely and robust content for IR responses.

2022 Long Term Resource Plan Load Forecast Additional Analysis: FortisBC (March-August 2022): Posterity Group is continuing to work with FortisBC Energy Inc (FEI's) to support the 2022 Long-term Gas Resource Plan (LTGRP) filing and conduct additional analysis related to the load forecast and scenario analysis. PG is providing additional analysis of demand-side management options with FEI's Diversified Energy Planning scenario, reviewing calculation methods for the provincial GHG reduction requirements, and modelling impacts of FEI's system from BC Hydro's resource planning scenarios. Erika is the project manager and an analyst for this project. She worked closely with the FEI client team, BC Hydro and their consultants, and PG's project team to execute the analysis on the tight schedule.

Renewable Gas Program Review – Cost Recovery Analysis: FortisBC (July-October 2021). FortisBC Energy Inc (FEI) assessed the pricing scheme of their voluntary renewable gas (RG) program, including how to recover supply costs from customers who did not volunteer to pay a premium for RG. Posterity Group estimated how non-participants may respond to changes in their annual gas bill from RG-related costs by changing demand or defecting from the gas system. The results of this project will help inform FEI's proposed design of the RG program to minimize impact on customers. Erika was the lead analyst and project manager.

2022 Long Term Resource Plan Load Forecast: FortisBC (December 2019-March 2022). Following a successful engagement in 2017, FortisBC again engaged Posterity Group to generate a natural gas end-use forecast in support of their 2022 Long Term Gas Resource Plan (LTGRP) filing. The analysis uses baseline end-use energy intensities for over 40 customer segments across 5 provincial regions developed by Posterity Group through the 2021 Conservation Potential Review. Forecasting analysis incorporates multiple data sources including customer end-use surveys, customer energy use data, and price and commodity forecasts. In addition to the reference case forecast, Posterity Group is conducting scenario analysis that estimates the impact on gas demand from several policy drivers including anticipated federal, provincial, and municipal codes and standards, carbon pricing, natural gas transportation, and supply of low carbon gasses. Erika was the Project Manager and an Analyst for the project, leading regular project management responsibilities, client liaison and supporting stakeholder engagement.

Energy Transition Scenario Analysis: Enbridge Energy Inc (July 2020-September 2022). Enbridge retained Posterity Group to conduct the Energy Transition Scenario Analysis (ETSA) project to consider the operations impacts from a range of municipal, provincial and federal policies that Enbridge could face in the future. The project involved modelling future load at the granular level of energy end uses, different building types, rate classes, and regions, and model several scenarios that consider possible economic and policy environments. The scenarios assess impacts on natural gas demand, GHG emissions and peak load. Posterity Group will also provide Enbridge with an online visualization platform to enable Enbridge staff to interact with the outputs of the analysis to support decision making. Erika was the Project Manager and Analyst for the study.

2021 Conservation Potential Review: FortisBC (January 2020-June 2021). FortisBC has entrusted its 2021 Conservation Potential Review Study (CPR) to Posterity Group. The CPR will support two of FortisBC's major regulatory filings in 2022: the long-term gas resource plan (LTGRP) and the demand side management plan. Posterity Group will estimate BC's technical, economic and market potential savings over a 20-year period for natural gas. Erika was an Advisor for the study and coordinated with the LTGRP project.

Greenhouse Energy Profile Study: IESO (January-October 2019). Posterity Group worked with the IESO and an Advisory Committee of stakeholders to develop an energy profile for Ontario's covered agriculture sector (including vegetables, flowers, cannabis and vertical farming). The project team developed a five-year forecast of energy and water consumption, estimated savings potential and local generation capacity, and developed concepts for demand response and incentive programs. As the Lead Analyst, Erika conducted research, modelling and analysis to develop the reference case and estimate savings potential. She also presented the results to the client group and stakeholders. As Deputy Project Manager, Erika was responsible for ongoing management of the project schedule, budget, and communications with subcontractors and the clients.

Long-Term Gas Resource Plan Interrogatory Support: FortisBC (March 2018-November 2018). Posterity Group (PG) supported FortisBC in responding to BC Utilities Commission and intervener Information Requests (IRs) regarding its 2017 Long Term Gas Resource Plan (LTGRP). PG provided FortisBC with information in support of such inquiries related to the load forecast and subsequent scenario analysis conducted by PG for inclusion in FortisBC's LTGRP. Erika was Project Manager and a Support Consultant.

Natural Gas Demand Scenarios: FortisBC (2017). Posterity Group provided demand scenario analysis to support FortisBC demand forecasting, with Erika focusing on the industrial sector. This work involves analysis of six scenarios that built on the core end-use forecast completed in June 2017. The results will help FortisBC assess the impact of various policies on demand for fuels, including the City of Vancouver zero emissions plan and the BC Step Code. As part of this project, Posterity Group added additional modelling features to the processing software at the heart of the forecasting model. These features will allow users to dynamically select the municipalities that are expected to opt into new energy efficiency requirements.

2017 Long Term Resource Plan Load Forecast: FortisBC (2016-2017). Erika helped develop reference case forecasts and scenario analysis for the residential and industrial sectors over a twenty-year period. Projections in the consumption of natural gas by end-use was conducted for multiple scenarios based on changes to in natural gas and carbon prices, economic growth, and building codes and standards. Analysis was also conducted on fuel-switching and the supply and demand of renewable natural gas. Erika also lead documenting the project method to communicate the scenarios to stakeholders.

Research & Policy Advice

Energy Label Research: Natural Resources Canada (January– April 2022). Posterity Group was tasked by Natural Resources Canada (NRCan) to conduct marketplace research on stakeholder experience with, and perception of, energy and sustainability labels and designations for buildings. The goal of the research is to help improve NRCan's understanding of the market so they can enhance marketing efforts for its ENERGY STAR Portfolio Manager and ENERGY STAR scoring programming. Erika was the Project Manager.

Study on the Roles, Challenges and Opportunities for Utilities in Supporting Jurisdictions with Benchmarking, Labelling and Disclosure of Energy Use: Natural Resources Canada (NRCan) (December 2019-March 2020). Posterity Group worked with NRCan's Office of Energy Efficiency to study the challenges, barriers and opportunities to utilities to participate in commercial sector energy benchmarking initiatives in Canada. Posterity Group interviewed gas, electric and efficiency utilities from across Canada to collect information on their experience with energy benchmarking initiatives, including technical considerations for data transfer to ENERGY STAR Portfolio Manager. The findings of the research are meant to help NRCan identify opportunities to support utility participation in energy benchmarking programs. Erika is the project's Lead Analyst and Project Manager.

Analysis of Funding Programs to Support Market Transformation: Natural Resources Canada (NRCan) (July-September 2019). Posterity Group helped NRCan identify federal, provincial and territorial funding programs that support the uptake of high efficiency equipment, specifically residential windows, space heating equipment and water heating equipment. Posterity Group assessed what technologies and project types are funded across Canada, where gaps exist, and how NRCan can leverage existing programs to support the implementation of the "Paving the Road to 2030 and Beyond: Market transformation roadmap for energy efficient equipment in the building sector". Erika was the Lead Analyst and Project Manager.

Adaption of US E-Training on EE and GHG Reduction for Canadian Federal Buildings Year 3: Natural Resources Canada (NRCan) (March 2019-March 2020). Posterity Group is helping NRCan's Greening Government Support Services to adapt the U.S. Federal Energy Management Program's webinars for the Canadian federal market. These training webinars are intended to help build capacity within federal organizations to identify and implement energy savings projects and practices; capacity that will be instrumental in helping organization work toward achieving the GHG reduction target outlined in the Federal Sustainable Development Strategy. Erika is an Analyst and Project Manager for Year 3 of the multi-year project.

Clean Technology and Environmental Outcomes: A Review of Approaches in other Jurisdictions, The Clean Growth Hub (February-May 2019). Posterity Group supported the federal Clean Growth Hub to identify international best practices in tracking, collecting and reporting environmental outcomes from funding clean technology projects. This project will support the inter-departmental "Clean Growth Hub" initiative to enhance federal capacity to track clean technology outcomes from various programs that fund clean technology across Canada. The scope includes GHG and environmental outcomes such as pollution to air, water and soil and effects on biodiversity. Erika was a Subject Matter Expert and Deputy Project Manager for the project.

Low Carbon Economy Fund Applicant Guidance and Templates, Environment and Climate Change Canada (January-December 2018). Posterity Group provided guidance and advisory support to ECCC as they develop templates and supporting material for the Challenge under the Low Carbon Economy Fund (LCEF). The LCEF is a $2 billion fund established under the Pan-Canada Framework on Clean Growth and Climate Change, which will provide $0.6 billion to support GHG reduction projects through a merit-based process. Challenge proponents will be required to report on energy savings and GHG reductions and may submit proposals for individual projects or for provincial programs. Posterity Group supported ECCC to ensure the templates and guidance material provided to Challenge proponents is clear and comprehensive, and that it is flexible enough to accommodate proponents from different sectors. Erika as an Advisor focusing on GHG quantification methodology and was Project Manager for the second half of the project.

Needs Assessment for Provincial-Territorial Labelling and Disclosure Measure for Commercial and Institutional Buildings: Natural Resources Canada (September 2017-March 2018). Since April 2017, NRCan has facilitated a Federal-Provincial-Territorial Labelling and Disclosure Working Group (LADWG), whose mandate includes establishing a national framework for energy labelling and disclosure for commercial/institutional buildings as per the Pan Canadian Framework on Clean Growth and Climate Change. As Lead Analyst, Erika organized and conducted consultations with stakeholders including provincial, territorial and municipal governments, utilities, and industry associations from across Canada. Using this research and consultation information, Erika drafted a Model National Framework that policy makers across Canada can use to develop and implement building energy benchmarking, labelling and disclosure programs. As Deputy Project Manager, Erika liaised with the client on project status, managed the schedule and invoicing, and led client meetings.

Federal Programming Strategies to Achieve Energy Savings: Natural Resources Canada (November 2016-April 2017). Through in-person interviews with senior leadership and research on NRCan's programs, Erika prepared a program activity map of the Departments initiatives related to energy efficiency in the built environment. A gap analysis was conducted by comparing NRCan's initiatives with those run by the U.S Department of Energy's Buildings Technology Office. Based on this research and analysis, recommendations were provided to NRCan on how to design and deliver federal energy efficiency programming such that resources and outcomes are maximized.

Energy Savings and Greenhouse Gas Emissions Reductions Analysis & Modelling

Energy Management Best Practices for Cannabis Greenhouses and Warehouses: CEATI International (November 2019-April 2021). Posterity Group, in partnership with Cultivate Energy Optimization and D+R International, assessed best practices of energy management for cannabis production in both greenhouse and warehouse facilities. The study provided a five-year forecast of energy use in five regions (Ontario, British Columbia, Colorado, Oregon and Washington) for the sector and identified energy saving opportunities. This work contributes to an important base of industry knowledge from which future conservation activities might be developed. Erika was the Project Manager and an Analyst for the project.

District Energy System GHG Accounting and Reporting Methodology Guidance: Public Service and Procurement Canada (September 2019 -May 2020). Stratos, in partnership with Posterity Group, supported Public Services and Procurement Canada (PSPC) to develop a greenhouse gas (GHG) accounting and reporting guidance document for their Energy Services Acquisition Program (ESAP). One of ESAP's main objectives is to reduce the GHG intensity of the district energy system (DES) currently serving a portfolio of buildings in the national capital region. As GHG reductions are a key metric for ESAP to measure and report on, Stratos and Posterity Group are helping to design corporate- and project-level GHG accounting and reporting methodologies that align with existing federal policies on GHG accounting and reporting requirements. Erika is a Technical Advisor for the project.

Greenhouse Benchmarking Analysis: Ontario Greenhouse Vegetable Growers (OGVG) (May-September 2019). Posterity Group helped OGVG develop a data collection strategy and analysis approach to develop a benchmark model for Ontario vegetable greenhouses. Posterity Group drafted a data collection survey, solicited energy use and production data from OGVG members, and analyzed the data to develop a percentile ranking of energy use. This work will help OGVG inform their benchmarking development strategy. The project operated in parallel to the Greenhouse Energy Profile study, which OGVG supported. Erika was an Analyst and Project Manager for the project.

Market Characterization and Conservation Potential for Ontario's Drinking Water and Wastewater Treatment Plants in Ontario: Independent Electricity System Operator (May-December 2018). Posterity Group was retained by the Independent Electricity System Operator to assess energy use, GHG emissions and opportunities for improved energy management in Ontario's water and wastewater treatment sector. As an Analyst for the study, Erika conducted interviews with market actors and reported on the study's findings. As Deputy Project Manager, Erika conducted day-to-day project management responsibilities and prepared weekly project status reports for the client.

Market Characterization and Conservation Potential for Ontario's Drinking Water and Wastewater Treatment Plants on Ontario First Nations Communities: Independent Electricity System Operator (August-December 2018). For the Independent Electricity System Operator, Posterity Group assessed energy use, GHG emissions and opportunities for improved energy management in Ontario's water and wastewater treatment sector. The project included a sub-study on First Nations communities, including connected and remote communities. For the project, the study team estimated baseline energy use from Ontario First Nations communities, identified opportunities to save energy, reduce energy costs, and reduce GHG emissions, highlighted case studies from communities across the province, and recommended opportunities to save energy and achieve non-energy benefits associated with retrofitting water treatment facilities. As an Analyst for the project, Erika conducted research, modelled energy use and savings measures, and communicated the results. She was also Deputy Project Manager.

Low-Carbon Heating Technologies for Ontario: Ontario Ministry of Environment and Climate Change (November 2017-June 2018). Posterity Group helped the Ontario Ministry of the Environment and Climate Change to identify and study the GHG reduction impact potential of low carbon space, water and process heating technologies and fuels in Ontario's residential, commercial and industrial sectors. In order to estimate emission reduction potential of various measures, Erika provided the team with emission factors and quantification methodology for the necessary fuels, technologies and industries. Erika also estimated the job impacts from spending on energy efficiency measures. Erika was Project Manager for the second half of the project.

EDUCATION & TRAINING

GHG Inventory, Accounting and Reporting (ISO 14064-1), University of Toronto, 2017
GHG Project Quantification, Monitoring and Reporting (ISO 14064-2), University of Toronto, 2017
GHG Validation and Verification (ISO 14064-3), University of Toronto, 2017

Master of Arts, Economics, University of Ottawa, 2013-2014
Honours Bachelor of Arts, Political Science and Economics, Wilfrid Laurier University, 2006-2010

EMPLOYMENT HISTORY

Posterity Group	Consultant	2016-present
Environment and Climate Change Canada	Economist	2015-2016
Sustainable Prosperity	Junior Research Associate	2014-2015
University of Ottawa	Research Assistant	2014-2015
The Natural Step Canada	Learning Programs Coordinator	2011-2013
Canadian Embassy to the United States of America	Intern	2010

REFERENCES

- Enbridge
  Cora Carriveau, Specialist Carbon, Energy Transition Planning
  Cora.Carriveau@enbridge.com, 519-436-4600 x 5002149 or 519-567-2910
- FortisBC Energy Inc
  Diana Aguilar, Integrated Resource Planning Manager
  diana.aguilar@fortisbc.com, 604.209.1260
- IESO
  Vicki Gagnon, Business Manager, Public Sector Conservation
  Vicki.Gagnon@ieso.ca, 416-969-6428

David F. Shipley

Senior Consultant

Experience Overview

David Shipley has over 25 years of experience as an energy engineer. His areas of expertise include: stock-and-flow models for energy efficient buildings and technologies, load forecasting, CDM potential estimates, building energy modelling, building commissioning, building energy systems, energy efficiency, renewable energy, energy and environmental systems modelling, and demand-side management. Mr. Shipley recently served on the expert panel for the 2019 Ontario Achievable Potential Study, as a recognized national expert on these studies.

In recent years, Mr. Shipley has coordinated the residential sector analysis for conservation potential studies for electric and gas utilities in six provinces, and has developed modeling tools used for analysis by the commercial and industrial teams in these studies. This has led to the development of Posterity Group's Navigator™ suite of energy and emissions simulation tools. He has also conducted market studies on building commissioning, HVAC and lighting technologies for commercial buildings, and efficient equipment for industry. Before joining Posterity Group, Mr. Shipley was a Senior Consultant in energy efficiency with ICF/Marbek, and Project Manager with the Energy Center of Wisconsin.

Select Project Experience

Conservation Potential and High Efficiency Buildings

Potential Study Meta-Analysis: NRCan (August 2022 – ongoing). The Canada's Green Building Strategy Secretariat within the Office of Energy Efficiency (OEE) will act as the "gatekeeper" for the 2023 budget submission to the Department of Finance for the Canada's Green Building Strategy which will be underpinned by various policy measures, programs, codes, regulations. As OEE is developing the first phase of the Canada's Green Building Strategy, they are tasked with assessing the impact of the programs administered by various departments in preparation of the 2023 budget process.

This task requires estimates of energy efficiency and GHG emission mitigation potential in the built environment but lacks suitable information of this type. In the short term, NRCan has hired Posterity Group to address this gap by collecting and summarizing the results of past energy efficiency potential studies conducted in Canada. This meta-analysis will serve as a high-level estimate of technical and economic potential until more detailed modelling and analysis is conducted.

Conservation Potential Study: Pacific Northern Gas (August 2021-November 2021). Posterity Group developed a Conservation Potential Review study for Pacific Northern Gas. This analysis built on resource planning and conservation potential work Posterity Group has recently completed in BC, including FortisBC's 2021 CPR. It has been used to support adjustments to PNG's current portfolio of DSM programs and PNG's 2023 DSM Plan and Resource Plan filing. Dave was Technical Lead and Residential Advisor.

2021 Conservation Potential Review: FortisBC Energy Inc. (January 2020-September 2021). FortisBC's 2021 Conservation Potential Review Study (CPR) supported two of FortisBC's major regulatory filings in 2022: the long-term gas resource plan (LTGRP) and the demand side management plan. Posterity Group estimated BC's technical, economic and market potential savings over a 20-year period for natural gas using its Navigator Energy and Emissions Simulations Suite™, which enables complex, multi-variable modelling, detailed scenario exploration and solution optimization. The CPR is an important guiding document for ongoing conservation and energy management program development and support at FortisBC. Posterity Group proposed a transparent, well-documented approach to develop the CPR and facilitated the engagement of internal and external stakeholders. Posterity Group completed end-use modelling and scenario development for FortisBC's 2022 Long Term Gas Resource Plan (LTGRP) in parallel with the CPR, to ensure technical consistency across the projects. Dave was Technical Director and Residential Sector Lead.

2022 Long Term Gas Resource Plan Demand Forecast and Resource Planning: FortisBC Energy Inc. (February 2020-July 2021). Following a successful engagement in 2017, FortisBC again engaged Posterity Group to generate a natural gas end-use forecast in support of their 2022 Long Term Gas Resource Plan (LTGRP) filing. The analysis uses baseline end-use energy intensities for over 40 customer segments across 5 provincial regions developed by Posterity Group through the 2021 Conservation Potential Review. Forecasting analysis incorporates multiple data sources including customer end-use surveys, customer energy use data, and price and commodity forecasts. In addition to the reference case forecast, Posterity Group conducted scenario analysis to estimate the impact on gas demand from a number of policy drivers including anticipated federal, provincial and municipal codes and standards, carbon pricing, efficiency activity, natural gas transportation, liquefied natural gas production, renewable natural gas production, and availability of district energy. Dave was Technical Director for the project.

Integrated Resource Planning and Achievable Potential Study Support: Enbridge (2019-Present). Technical lead on modeling and analysis to support Enbridge Gas in their planning and DSM activities. Building on the results of the provincial Achievable Potential Study (APS), used the Navigator™ Energy and Emissions Simulation Suite to construct a model of Enbridge's service territory to estimate DSM potential and peak demand impacts. The detailed model will permit the client-consultant team to better understand the outputs from the 2019 APS, identify limitations in the underlying dataset, and integrate additional data to estimate program potential and budgets. The Navigator™ Energy and Emissions Simulation Suite enables complex, multi-variable modelling, detailed scenario exploration and solution optimization. It also has an 8760 peak analysis module, which we are using to develop full annual load shape profiles for the gas end uses relevant to Enbridge's service territory.

Greenhouse Energy Profile Study: Ontario IESO (2018-2019). Technical lead on modeling and analysis of economic and achievable potential for energy conservation in covered agricultural facilities in Ontario, including greenhouses and indoor agriculture. Developed the stock-and-flow model for three different scenarios of sector expansion, for technical, economic, and achievable energy savings potential, and for peak demand reduction. Provided full 8760-hour profiles of demand before and after the application of energy and demand reduction measures.

2019 Ontario Achievable Potential Study Technical Advisory Panel: IESO (2018-2019). Acted as an Expert Panel Member to the Independent Electricity System Operator (IESO) and the Ontario Energy Board (OEB) for the 2019 Ontario Achievable Potential Study (APS). Provided advice on the integrated electricity and natural gas APS, which will seek to identify and quantify energy savings, GHG emission reductions, and associated costs from demand side resources for 2019-2038. Helped the IESO and OEB ensure that the APS is conducted using industry best practices. Reviewed and provided guidance on all aspects of the APS including the methodology and workplan, base case and reference forecast, energy efficiency and conservation measures, technical and economic potential analysis, achievable potential analysis, and final report.

Conservation Potential Study: Ontario Energy Board (2015-2016). Technical lead on modeling and analysis of economic and achievable potential for energy conservation in Ontario, covering the service territories of both natural gas companies. Led the residential analysis and was principal model developer, including development of stock-and-flow models, economic screening models, and achievable adoption models.

Conservation and Demand Management Study: Newfoundland Power and Newfoundland Labrador Hydro (2014-2015). Technical lead on modeling and analysis of economic and achievable potential for conservation and demand management in Newfoundland and Labrador. Led the residential analysis and was principal model developer.

Tailored Achievable Potential Studies for Ontario LDCs: Hydro One Networks, NPEI, Powerstream, Horizon Utilities, Thunder Bay Hydro, Waterloo North Hydro, Entegrus, Canadian Niagara Power, Algoma Power, Brantford Power, Milton Hydro, Oakville Hydro, Oshawa PUC, Haldimand County Power, Halton Hills Hydro, Burlington Hydro, Brant County Power (2014-2015). Developed tailored versions of the OPA achievable potential model (see the project immediately below), to provide detailed conservation potential estimates for the service territories of several Ontario LDCs.

Achievable Potential Study: Ontario Power Authority (2013). Led the analysis of conservation potential for all sectors, deriving much of the economic potential from outputs of OPA's End Use Forecaster model, but applying data from ICF Marbek's internal databases to estimate achievable potential. After a market characterization phase targeting the application of measures in Ontario, produced a fine-tuned estimate of achievable potential.

Conservation Potential Study for Yukon Government: YEC, and YECL (2011-2012). Led residential analysis of conservation potential, including developing detailed end-use baseline profiles calibrated to utility data, deriving economic potential for cost-effective actions in the residential sector, and forecasting 20-year economic and achievable savings.

Conservation Potential Study: SaskPower (2010-2011). Led residential analysis of conservation potential, including developing detailed end-use baseline profiles calibrated to utility data, deriving economic potential for cost-effective actions in the residential sector, and forecasting 20-year economic and achievable savings.

Conservation Potential Study: Terasen Gas (2010-2011). Led residential analysis of conservation potential, including developing detailed end-use baseline profiles calibrated to utility data, deriving economic potential for cost-effective actions in the residential sector, and forecasting 20-year economic and achievable savings.

DSM Potential Study: Enbridge Gas (2008). Led residential analysis of conservation potential, as part of a major update to the DSM study Marbek did in 2004. Developed detailed end-use baseline profiles calibrated to utility data, derived economic potential for cost-effective actions in the residential sector, and forecast 10-year economic and achievable savings.

DSM Potential Study: Enbridge Gas Inc. (formerly Union Gas) (2008). Led residential analysis of conservation potential for Union Gas, as part of a project similar to Enbridge project above.

CPR 2007: BC Hydro (2007). Led analysis of residential savings potential for BC Hydro, as part of a project to estimate potential for all sectors. Derived detailed end-use baseline profiles calibrated to utility data, derived economic potential for cost-effective actions in the residential sector, and forecast 20-year savings. This was an update to an earlier CPR Marbek performed for BC Hydro in 2002.

CPR: Newfoundland Power and Newfoundland and Labrador Hydro (2007). Led analysis of residential savings potential for Newfoundland and Labrador, as part of a project to estimate potential for all sectors. Project included same elements as the BC Hydro study.

Fuel Switching Potential: Ontario Power Authority (2006). Developed the residential fuel switching potential estimate as part of a full fuel switching potential study for Ontario.

DSM Potential Study: Terasen Gas (2005). Developed the residential energy savings and fuel switching potential estimate as part of a full DSM potential study for the Terasen service territory. Conducted part of the commercial energy savings and fuel switching potential analysis.

DSM Potential Study: Enbridge Gas (2004). Developed the residential energy savings potential estimate as part of a full DSM potential study for the Enbridge service territory.

DSM Study: Manitoba Hydro (2003). Led residential analysis for DSM study.

Statewide Technical and Economic Potential: Consortium of Wisconsin Utilities (1993). While at Energy Center of Wisconsin, managed the completion phase of the estimate of conservation, fuel switching and load management potential, as part of IRP filing.

End-Use Energy Efficiency and GHG Mitigation Modelling & Load Forecasting

Resource Planning Support: SoCal Gas (April 2022-ongoing): Posterity Group is developing an end use model to support SoCal Gas with ongoing long term planning activities in both SoCal Gas' and SDG&E's service territories. PG will build a model that "mirrors" the results from the current End Use Forecaster (EUF) model and then add enhanced capability allowing users to accomplish modeling tasks that are either not currently possible (e.g., scenario analysis) or completed outside of the EUF model (e.g., policy impact analysis or electrification analysis). Dave is the Technical Director for the project.

2022 Long Term Resource Plan Load Forecast Additional Analysis: FortisBC (March 2022-ongoing): Posterity Group is continuing to work with FortisBC Energy Inc (FEI's) to support the 2022 Long-term Gas Resource Plan (LTGRP) filing and conduct additional analysis related to the load forecast and scenario analysis. PG is providing additional analysis of demand-side management options with FEI's Diversified Energy Planning scenario, reviewing calculation methods for the provincial GHG reduction requirements, and modelling impacts of FEI's system from BC Hydro's resource planning scenarios. Dave is the technical director for this project.

Renewable Gas Program Review – Cost Recovery: FortisBC Energy Inc. (July 2021-October 2021). FortisBC Energy Inc (FEI) reassessed the pricing scheme of their voluntary renewable gas (RG) program, including how to recover supply costs from customers who did not volunteer to pay a premium for RNG. Posterity Group (PG) focused on assessing how non-participants may respond to changes in their annual gas bill from RG-related costs. Posterity Group estimated impacts to annual demand and customer defection from price signals. The results of this project helped inform FEI's proposed design of the RG program to minimize impact on customers. Dave acted as Advisor.

DSM Planning Support: Enbridge Gas Inc. (January 2021-January 2022). In 2019 and 2020, Posterity Group worked with EGI to develop a Navigator end-use energy model to support DSM planning. The model aligns closely to the Ontario Energy Board's 2019 Achievable Potential Study but includes adjustments that better reflect Enbridge's input and experience, and to correct for identified limitations. Model outputs are housed within Power BI to provide an interactive means to support future EGI planning efforts. In 2021, Posterity Group worked with EGI to update and enhance the end-use model dataset to support its next multi-year DSM plan submission. Priorities include: Developing evidence to position the APS in a context that more accurately reflects EGI's knowledge and experience; Make further adjustments to the APS dataset to address deficiencies and enable sensitivity analysis; and Interrogatory and Witness Support. Dave was Technical Director and Lead Analyst.

Load Forecasts for the Southwest Ontario Greenhouse Sector: IESO (February 2021-August 2021). Greenhouse energy demand continues to expand in the Windsor-Essex and Chatham-Kent regions. To support planning efforts in these regions, the IESO developed three load forecast scenarios (a low growth, reference case, and high growth scenario) for greenhouse non-coincident winter-peak load. Posterity Group was hired to review the information and assumptions used by the IESO and provide additional information to validate the IESO's forecast scenarios or identify possible areas for adjustment. The main activities included in this project were data collection, review and analysis, scenario development, modelling, and a comparison of the data and model results to the IESO's assumptions and models. Dave acted as Expert Advisor.

Energy Transition Scenario Analysis: Enbridge (July 2020-March 2021). Posterity Group supported Enbridge's Energy Transition Planning team to conduct scenario analysis of the consider the financial and operational impacts of the range of climate policy related impacts Enbridge could face over the next 30 years. Posterity Group modeled future load at the granular level of energy end uses, different building types, rate classes, and regions, and undertaking scenario analysis to explore several possible economic and policy scenarios under which Enbridge may operate in the future. The goal of the project was for Posterity Group to provide Enbridge with a comprehensive end-use level dataset that reflects several possible futures and a user-interface tool that allows decision makers to explore this dataset and distill quantitative impacts (e.g., how gas use and GHG emissions will change) under different forecast scenarios. Dave was Technical Director and Residential Sector Lead.

Energy Management Best Practices for Cannabis Greenhouses and Warehouses: CEATI International Inc. (November 2019-May 2020). Posterity Group, in partnership with Cultivate Energy Optimization and D+R International, assessed and documented best practices of energy management for cannabis production in both greenhouse and warehouse facilities. The study developed a five-year forecast of energy use in three regions (Ontario, British Columbia and the Pacific Northwest) for the sector and assessed energy saving opportunities. The outcome of this work formed an important base of industry knowledge and bridge the gap to provide current and comprehensive information regarding energy use in cannabis facilities, from which future conservation activities might be developed. Dave acted as Senior Analyst.

Long Term Resource Plan Model Enhancement: FortisBC Gas (November 2018-February 2020). Posterity Group added several new features to the Long Term Resource Plan model used to support FortisBC's regulatory filings. New features included the ability to output avoided cost and customer cost of energy, ability to vary short-term and long-term elasticity of energy demand based on the latest research, and the ability to run hundreds of stochastically-generated scenarios with inputs varying probabilistically.

Long Term Resource Plan Regulatory Support: FortisBC Gas (March 2018-November 2018). Posterity Group supported FortisBC in responding to BC Utilities Commission and intervener Information Requests (IRs) regarding its 2017 Long Term Gas Resource Plan (LTGRP). Posterity Group provided FortisBC with information and analysis in support of such inquiries related to the load forecast and subsequent scenario analysis conducted by Posterity Group for inclusion in FortisBC's LTGRP.

Analysis of Fenestration Products in Support of Canadian Market Transformation Activities: NRCan (July 2017-June 2018). Posterity Group provided analysis of the current market for low-rise residential fenestration products, including windows, doors, and skylights and developed estimates of the energy savings potential from changing performance levels in ENERGY STAR or introducing national performance standards. Dave was the technical lead on this project. To produce the estimate, he developed a detailed model of HVAC consumption in different types and vintages of low-rise housing in 22 regions, and modeled the application of several different fenestration energy performance improvements. Developed from publicly available data, this model can be applied for other future projects.

Low Carbon Heating Options for Ontario: Ontario Ministry of the Environment and Climate Change (November 2017-June 2018). Posterity Group estimated the GHG reduction impact potential of strategies targeting low carbon space, water and process heating technologies and fuels in Ontario's residential, commercial and industrial sectors. The project included four main activities: Development of energy and GHG Inventory and accompanying business as usual forecast for Ontario's thermal end-uses by fuel, sector/subsector, and end use; Development of a long list of fuels and technologies with abatement potential, and an evaluation matrix to build a short list of the 10 preferred, most promising technologies and fuels for detailed analysis; Detailed analysis of the short list of fuels and technologies to understand their current market structure, barriers, and applicability; and, development of illustrative deployment scenarios to estimate the potential impacts of the shortlisted fuels. Dave developed the inventory model and the illustrative deployment scenario models.

Natural Gas Demand Scenarios: FortisBC (July 2017-November 2017). Posterity Group provided demand scenario analysis to support FortisBC demand forecasting, with Dave acting as Technical Director and Residential sector lead. This work involved analysis of six scenarios that built on the core end-use forecast completed in June 2017. The project results helped FortisBC assess the impact of various policies, including the City of Vancouver zero emissions plan and the BC Step Code. As part of this work, Posterity Group added new features to the processing software at the heart of the forecasting model. These features allow users to dynamically select the municipalities that are expected to opt into new energy efficiency requirements.

Long Term Resource Plan Model and Forecast: FortisBC Gas (October 2016-June 2017). FortisBC turned to Posterity Group to develop a new end-use forecasting model to enhance their current end-use resource forecasting approach, and to generate a new 2017 forecast. The model provides value to the load forecasting, integrated resource planning, system planning, and conservation potential teams at FortisBC. Enhancements include: a full integration of energy efficiency impacts at the individual measure level, improved transparency of the model; features to allow casual users to vary parameters and review the effects on the results; outputs for every year in the forecast period (rather than milestone years); closer linkage between the annual demand and peak demand forecasting approaches; the ability to analyze the impact of changes such as municipal policy activity, ability to analyze the impact of liquefied natural gas and natural gas transportation initiatives. Dave was technical director and lead model developer.

End Use Load Forecast: FortisBC (2012-2014). Developed an end-use based load forecasting system for FortisBC, using detailed customer data and models built for an earlier conservation potential study. The model could forecast account growth and consumption of five fuels under five economic scenarios, over a twenty-year period, for three sectors, six regions, 33 rate classes, 36 building types, and 29 end uses. The model also estimated potential for conservation programs and reported on the sensitivity of the potential to different economic scenarios.

Integrated Resource Plan: NB Power (2009). Led residential analysis as part of a project to provide input data to NB Power's integrated resource planning process.

Conservation Potential Review and 20 Year Load Forecast: Ontario Power Authority (2009-2010). Led residential analysis of conservation potential for OPA, as part of project to develop a model combining forecasting and DSM potential.

Market Characterization of the Commercial/Institutional and Residential Sectors in Yukon: YEC and YECL (2012). Prepared initial program focus assessment documents, based on results from the Conservation Potential Study. Assisted in planning and preparing interview guides for market research, and conducted interviews. Provided input to program concept documents, which will lead to commercial and residential programs offered by the Yukon utilities.

Residential Market Segmentation Study: Enbridge Gas Inc. (formerly Union Gas) (2010). Led this analysis to assess the potential for DSM technologies in specific niche markets. In a mature market for DSM activities such as Union's service territory, many measures no longer pass the TRC test in a typical or average application, but often will pass in niche applications. We provided a strategic assessment of potential niche markets, to target DSM program activities.

EDUCATION

M.Sc., Energy Studies, University of Sussex - Brighton, Sussex, United Kingdom, 1987

B.A.Sc., Mechanical Engineering, Minor: Management Science, University of Waterloo – Waterloo, Ontario, Canada, 1986

CERTIFICATIONS

Licensed Professional Engineer (Ontario)

PROFESSIONAL AFFILIATIONS

American Society of Heating, Refrigeration, and Air-conditioning Engineers

EMPLOYMENT HISTORY

Posterity Group	Senior Consultant	2016-Present
ICF International	Senior Technical Specialist	2011-2016
Marbek Resource Consultants	Senior Consultant	2000-2010
Energy Center of Wisconsin	Project Manager	1993-2000
Resource Management Associates	Energy Engineer	1991-1993
University of Waterloo	WATSUN Engineer	1987-1991

Alex Tiessen, P.Eng., CMVP, PMP

Principal

EXPERIENCE OVERVIEW

Alex brings 17 years of experience helping utilities and governments understand end-use energy within their jurisdictions to make informed energy resource planning, demand side management and policy decisions. As a founding partner of Posterity Group, he has the privilege of co-leading a team of talented professionals and supporting our progressive clients throughout North America.

Alex's career has focused on characterizing energy use in the built environment through end-use modelling. He has developed sectoral models to support clients in assessing demand side management potential and has led geo-targeted analysis to underpin resource planning activities. Alex relishes the challenge of helping clients forecast different possible futures through scenario modelling, curating complex data to distill insights, and improving organizational efficiencies by connecting planning groups with a common end-use dataset.

The supply and use of energy are evolving due to climate change, policy changes, and technology innovation. Alex is driven to help our clients navigate this changing energy landscape by providing flexible, granular, and transparent information on energy end-uses.

He holds a B.Sc. in Mechanical Engineering from Queen's University, is a Licensed Professional Engineer in the province of Ontario, a Project Management Professional, and a Certified Measurement and Verification Professional.

PROJECT EXPERIENCE

EV and Mining Market Studies: IESO (September 2022-ongoing). Electricity demand in both the mining sector and electric vehicle (EVs) sector continues to expand and represents an area of increasing importance to provincial and certain regional load forecasting. The IESO has developed load forecast scenarios for both mining and EVs to support planning efforts: low growth, reference case, and high growth scenarios (collectively the Forecast Scenarios) for the 2023-2050 period. Posterity Group's three main study objectives are to review and validate the IESO's current forecast modelling assumptions, provide recommendations for modelling moving forward and to provide load forecasts under high, medium, low scenarios for the 2023-2050 period.

Commercial Prefeasibility Studies: Enbridge (June 2022-October 2022). Posterity Group is conducting prefeasibility studies on six commercial technologies to assess their technical and market opportunities in Enbridge's jurisdictions in Ontario. Enbridge is interested in finding out the potential energy and GHG emission savings from these technologies and their possible inclusion into the utility's DSM activities. The six commercial sector measures being explored and characterized in these studies are Rooftop Units (RTUs), Domestic Hot Water Demand Control, Building Recommissioning (RCx), Building Envelope Improvements, Adaptive HVAC Controls, and Boiler System Optimization.

Resource Planning Support: Southern California Gas (April 2022-August 2023). Posterity Group is developing an end use model to support SoCal Gas with ongoing long term planning activities in both SoCal Gas' and SDG&E's service territories. PG will build a model that "mirrors" the results from the current End Use Forecaster (EUF) model and then add enhanced capability allowing users to accomplish modeling tasks that are either not currently possible (e.g., scenario analysis) or completed outside of the EUF model (e.g., policy impact analysis or electrification analysis).

Integrated Resource Planning Analysis Support: Enbridge Gas Inc. (July 2019-Dec 2022). Starting in 2019, Posterity Group supported Enbridge to create the foundation of an integrated resource planning alternative (IRPA) dataset and modelling approach (prior to the IRP Framework being developed) using our Navigator end-use model. Posterity Group worked with Enbridge to develop load shapes and apply these profiles to a modified version its conservation potential study dataset and reference case - effectively converting its conservation potential study dataset into an IRP planning tool. These updates allowed our team to estimate peak demand reduction potential from enhanced targeted energy efficiency (ETEE) measures, including peak hour and peak day impacts. Enbridge and Posterity Group have continued to work together to develop an approach to align its facility expansion and reinforcement planning activities with the 2021 IRP Framework. This involves incorporating IRPA screening into its asset management planning (AMP) process and performing IRPA analysis for ongoing leave to construct (LTC) applications. This work includes developing scaled versions of the full end-use model to assess the potential for targeted efficiency activities as a strategy to defer infrastructure investment in constrained areas of the gas distribution system. To date, this analysis has been completed for four constrained system areas.

Energy Label Research: Natural Resources Canada (2021-2022). Posterity Group has been tasked by Natural Resources Canada (NRCan) to conduct marketplace research on stakeholder experience with, and perception of, energy and sustainability labels and designations for buildings. This initiative is intended to improve the Building and Industry Division (BID)'s understanding of the market with the goal of improving marketing efforts for its ENERGY STAR Portfolio Manager and ENERGY STAR scoring programming.

DSM Plan: FortisBC (September 2021-May 2022). Posterity Group has been hired to develop the DSM Expenditure Plan for the 2023-2027 program implementation period for FortisBC's natural gas and electric utilities. The scope of work involves program and portfolio development, cost effectiveness modelling and reporting.

Assessment of Additional Energy Savings from DSM Measures: FortisBC (June 2021-September 2021). Calculating the impact of building level energy and emissions reductions can be subjective. At a project level, the value can be subject the baseline, early replacement considerations, calculation methodology, spillover attributions, and free ridership attributions. The subjectivity of these factors ultimately impacts the way the FortisBC can communicate the impact of their DSM program as part of their emissions reductions efforts and tracking for their 30 By 30 targets. To assist FortisBC, Posterity Group is investigating FortisBC's current DSM programs, the provincial CleanBC Funds, and other DSM jurisdictions for new methodologies and best practices on building level emissions reductions calculations.

DSM Planning Support: Enbridge Gas Inc. (July 2019 -April 2022). In 2019 and 2020, Posterity Group worked with EGI to develop a Navigator end-use energy model to support DSM planning. The model aligns closely to the Ontario Energy Board's 2019 Achievable Potential Study but includes adjustments that better reflect Enbridge's input and experience, and to correct for identified limitations. Model outputs are housed within Power BI to provide an interactive means to support future EGI planning efforts. In 2021, Posterity Group is working with EGI to update and enhance the end-use model dataset to support its next multi-year DSM plan submission. Priorities include: Developing evidence to position the APS in a context that more accurately reflects EGI's knowledge and experience; Make further adjustments to the APS dataset to address deficiencies and enable sensitivity analysis; and Interrogatory and Witness Support.

Load Forecast, Southwestern Ontario Greenhouse Sector: Independent Electricity System Operator. (February 2021-May 2022). Posterity Group supported the IESO's resource planners by reviewing and assessing energy profile and load forecast assumptions for Ontario's high-growth greenhouse sector. This involved undertaking market research and analysis to develop electric demand forecast scenarios in support of supply planning efforts. Our approach leveraged Posterity Group's previous experience undertaking greenhouse sector research in Ontario and our ability to develop load forecast scenarios using our end-use based modelling platform.

Energy Transition Scenario Analysis: Enbridge (July 2020-June 2021). To consider the financial and operational impacts of the range of climate policy related impacts Enbridge could face over the next 30 years, Enbridge retained Posterity Group to conduct the Energy Transition Scenario Analysis (ETSA) project. The purpose of this project is for Posterity Group to support Enbridge's Energy Transition Planning (ETP) project by modeling future load at the granular level of energy end uses, different building types, rate classes, and regions, and undertaking scenario analysis to explore several possible economic and policy scenarios under which Enbridge may operate in the future. In close collaboration with Enbridge, Posterity Group is developing several critical drivers that may impact Enbridge's system, modelling how each driver effects natural gas demand, and then models several scenarios of possible futures.

Prefeasibility Study and M&V Best Practices: Gas Heat Pumps and Dual-Fuel Heat Pumps: Con Edison via CEATI International Inc. (May 2020-December 2020). Posterity Group is conducting a technical, economic and market potential study for natural gas heat pumps (GHP) and dual-fuel heat pumps (Dual-Fuel HP) in Con Edison's and Orange and Rockland's residential, multi-family and commercial sectors for both retrofit and new construction applications. Technologies will be compared to two reference cases: electric air source heat pumps, and most efficient in-kind replacement. Phase 2 of the project involves developing Measurement and Verification (M&V) best practices for natural gas heat pumps technologies.

Prescriptive Lighting Measure Review: Ontario IESO (April 2020-July 2020). Posterity Group conducted a study to update the IESO's prescriptive lighting technology list to reflect current regional incremental costs and cover technologies that accurately reflect Ontario's lighting market baseline. As part of the project, Posterity Group also updated the IESO's incentive setting strategy to ensure that incentives continue to be used cost-effectively to address the achievable potential in Ontario's non-residential lighting market.

2022 Long Term Gas Resource Plan Demand Forecast and Resource Planning: FortisBC Energy Inc. (February 2020-July 2021). Following a successful engagement in 2017, FortisBC again engaged Posterity Group to generate a natural gas end-use forecast in support of their 2022 Long Term Gas Resource Plan (LTGRP) filing. The analysis uses baseline end-use energy intensities for over 40 customer segments across 5 provincial regions developed by Posterity Group through the 2021 Conservation Potential Review. Forecasting analysis incorporates multiple data sources including customer end-use surveys, customer energy use data, and price and commodity forecasts. In addition to the reference case forecast, Posterity Group will conduct scenario analysis that estimates the impact on gas demand from a number of policy drivers including anticipated federal, provincial and municipal codes and standards, carbon pricing, efficiency activity, natural gas transportation, liquefied natural gas production, renewable natural gas production, and availability of district energy.

2021 Conservation Potential Review: FortisBC Energy Inc. (January 2020-September 2021). FortisBC has entrusted its 2021 Conservation Potential Review Study (CPR) to Posterity Group. The CPR will support two of FortisBC's major regulatory filings in 2022: the long-term gas resource plan (LTGRP) and the demand side management plan. Posterity Group will estimate BC's technical, economic and market potential savings over a 20-year period for natural gas using its Navigator Energy and Emissions Simulations Suite™, which enables complex, multi-variable modelling, detailed scenario exploration and solution optimization. The CPR is an important guiding document for ongoing conservation and energy management program development and support at FortisBC. Posterity Group has proposed a transparent, well-documented approach to develop the CPR and will facilitate the engagement of internal and external stakeholders. Posterity Group will complete FortisBC's 2022 LTGRP in parallel with the CPR, which will ensure smooth handoffs and technical consistency across the projects.

Energy Management Best Practices for Cannabis Greenhouses and Warehouses: BC Hydo, FortisBC, Ontario IESO, Enbridge and National Rural Electric Cooperative Association via CEATI International (November 2019-August 2020). Posterity Group, in partnership with Cultivate Energy Optimization and D+R International, will assess and document best practices of energy management for cannabis production in both greenhouse and warehouse facilities. The study will develop a five-year forecast of energy use in three regions (Ontario, British Columbia and the Pacific Northwest) for the sector and assess energy saving opportunities. The outcome of this work will form an important base of industry knowledge and bridge the gap to provide current and comprehensive information regarding energy use in cannabis facilities, from which future conservation activities might be developed.

Study on the Roles, Challenges and Opportunities for Utilities in Supporting Jurisdictions with Benchmarking, Labelling and Disclosure of Energy Use: Natural Resources Canada, Office of Energy Efficiency (December 2019-March 2020). Posterity Group is working with NRCan's Office of Energy Efficiency to study the challenges, barriers and opportunities to utilities to participate in commercial sector energy benchmarking initiatives in Canada. Posterity Group will survey utilities across Canada to collect information on their experience with benchmarking initiatives, including technical considerations for data transfer to ENERGY STAR Portfolio Manager. The findings of the research will help NRCan identify opportunities to support utility participation in energy benchmarking programs.

Greenhouse Energy Profile Study: Independent Electricity System Operator (January 2019-October 2019). Posterity Group is working with the Independent Electricity System Operator and an Advisory Committee to develop an energy profile for Ontario's greenhouse sector. Teaming up with Wood, Posterity Group will help study this important sector – one that is expected to grow, particularly in regions with forecasted grid constraints. The study will: Define a baseline energy consumption in the greenhouse sector; Define a "reference case" energy use for the sector over the next 5 years; and Estimate savings potential for energy and water, demand response, local generation, and programs. Currently, there is no dataset profiling the energy footprint of the greenhouse sector, the outcomes of this study will be valuable to several stakeholders and provincial planning groups

Clean Technology and Environmental Outcomes – A Review of Approaches in other Jurisdictions: Canada's Clean Growth Hub (February 2019-May 2019). Posterity Group provided the Clean Growth Hub with a report examining administrative data in the context of how clean technology and innovation programs in other jurisdictions in Canada and abroad report on environmental outcomes. This project will support the inter-departmental initiative to enhance federal capacity to track clean technology outcomes from various programs. Posterity Group advised the Clean Growth Hub on data collected and methodologies used to assess or track environmental outcomes during all three phases of project implementation (1) application; (2) project implementation; (3) project completion. The scope included GHG and environmental outcomes such as pollution to air, water and soil and effects on biodiversity.

High-Efficiency Buildings: Case Studies: NRCan Office of Energy Research and Development (February 2019-July 2019). Posterity Group worked with NRCan to undertake literature review, interviews, and technical case-study development for the purpose of gathering information about high efficiency buildings in Canada and to better quantify the costs, energy usage, and ensuing greenhouse gas emissions of high efficiency buildings. This work combined two of Posterity Group's core competencies: The assessment of markets for energy efficient and low carbon technologies and services; and technical assessment of energy performance in the built environment. Our team developed an inventory of high performing Canadian buildings, undertook market research and interviews with leading builders and developers, assessed and developed building energy simulation models and Class D estimates of incremental costing for high performance buildings, and developed a series of case studies covering both technical and market-related aspects of high-performance building development.

Zonal Pricing Review: Independent Electricity System Operator (November 2018). Posterity Group undertook a review of Independent Electricity System zonal pricing data analysis in support of a response to a provincial stakeholder inquiry on the impact proposed changes to Ontario's wholesale electricity market. Specifically, the inquiry related to the planned changes to transition the Ontario wholesale market from the current two-schedule uniform pricing system to a single-schedule system with zonal and nodal prices; a change being proposed as part of the Market Renewal effort launched in the spring of 2016 by the IESO.

Market Characterization and Conservation Potential for Ontario's Drinking Water Treatment and Waste Water Treatment Plants: Independent Electricity System Operator (May 2018-December 2018). This project provided a detailed inventory of drinking water treatment plants and wastewater treatment plants facilities in the province; assessed baseline energy use in these facilities, including end-use level estimates of in plant energy-use and collection/distribution system pumping energy use; provided a characterization of the existing equipment stock; provided an estimate of the energy/GHG savings potential (economic) and; provided a detailed analysis of methane mitigation, demand response, and peak reduction opportunities through Combined Heat and Power and other means.

Market Characterization and Conservation Potential for Ontario First Nation Communities' Drinking Water Treatment and Waste Water Treatment Plants: Independent Electricity System Operator (July 2018-January 2019). The study involved: Developing baseline energy use in facilities on First Nations communities; Identifying opportunities to save energy, both from equipment upgrades and process improvement; Highlighting case studies from communities across the province; and Providing recommendations on how to achieve energy savings and the non-energy benefits associated with the measures.

Food Services Challenge Case Studies: Independent Electricity System Operator (July 2018-April 2020). Restaurants Canada, NRCan, and IESO are administering a program called the Food Services Challenge in which restaurants and food service organizations are invited to improve their energy use through equipment upgrades and energy management best practices. Four participants will be shortlisted to receive energy audits of their facilities, recommendations on equipment upgrades and energy efficiency measures, and will be given around a year to implement the measures. Case studies will then be developed on the four food service facilities to help other similar organizations follow suit. Posterity Group is providing the program administrators with candidate selection support, Level 1 and Level 2

ASHRAE energy audits, development of measurement and verification plans for each candidate, post-retrofit assessments, and will be responsible for developing the final reports and case studies.

Industrial Optimization Program Evaluation: FortisBC (September 2018-May 2019). Posterity Group helped FortisBC evaluate its Industrial Optimization Program and provided recommendations on how to improve the Program moving forward by focusing on four evaluation objectives: Obtaining Program feedback from participants and consultants; Verifying Program enabled savings; Comparing the Program M&V structure to similar programs in other jurisdictions; and Assessing free-ridership and participant spillover. FortisBC used the outcomes from this evaluation to report on program enabled impact savings and establish a Program net-to-gross ratio, while at the same time drawing insights from program feedback, M&V structure research and free-ridership and spillover findings to inform future program enhancements.

Environmental Sustainability Plan Development: La Cite Collegiale (April 2018-July 2018). Posterity Group, in partnership with CDM Energy Solutions, developed a comprehensive Environmental Sustainability Plan for La Cite Collegiale's Ottawa campus. The development of the plan was informed by a review of existing and planned energy audit results, analysis of renewable energy opportunities and other campus-wide initiatives, stakeholder meetings, and the vision and leadership of La Cite. The plan provides the business case and action plan for the implementation of energy management opportunities including energy-efficiency and greenhouse gas reduction measures, renewable energy, and water-efficiency upgrades.

Analysis of Fenestration Products in Support of Canadian Market Transformation Activities: NRCan (July 2017-June 2018). NRCan engaged Posterity Group to analyze the residential low-rise fenestration market (windows, doors and skylights) in Canada as part of a broader strategy to decrease their impact on low-rise building energy use. This assignment includes technical and market analysis of proposed changes to ENERGY STAR criteria and proposed incoming Minimum Energy Performance Standards. With the support of subcontractors Arborus Consulting and David Petersen, Posterity staff will examine the impact of these proposed standards on energy use and GHG emissions; and market actors including manufacturers, consumers, dealers and homebuilders. We will also develop a stakeholder database, and critique proposed standards, suggesting modifications as needed.

Design and Implementation of an Industrial Pay-for-Performance Pilot: Independent Electricity System Operator (November 2017-April 2019). Posterity Group providing technical support for the design and delivery of the IESO's industrial pay-for-performance pilot program. Posterity Group developed a business case for the pilot program which involved iterative modelling to evaluate the impact of different incentive rates, incentive structures, cost assumptions and energy and demand savings assumptions on cost-effectiveness. Posterity Group also created facility screening criteria for participation in the pilot and a participant M&V approach for inclusion in the business case. After the pilot was launched in 2018, Posterity Group supported the IESO in its delivery the pilot program by applying their M&V expertise and knowledge of working with large industrial clients. Delivery activities involved: completing M&V feasibility assessments for potential pilot participants and providing recommendations on whether to accept each facility into the pilot; and developing M&V plans and assisting with energy management plans for participants accepted into the pilot.

Operational Improvement Study: Enbridge Gas Distribution (September 2017-November 2017). Posterity Group, in association with TdS Dixon, completed a research study about Operational Improvement measures for hospital and university subsectors in Ontario, on behalf of Enbridge Gas. Posterity Group identified operational improvement programs offered to hospitals and universities in other jurisdictions to assess program classification type, typical implemented measures, and measure life assumptions for these measures. Posterity Group also collected input from key Ontario industry association stakeholders regarding Ontario-specific market barriers, and to identify and discuss opportunities for tying into existing or planned interventions. Enbridge will use the results of the research study to inform program design activities, including whether or not to include operational improvement measures in their custom program, and how to assess savings for the measures should they be included.

Energy Performance Contract Support Services: Defence Construction Canada (August 2017-August 2020). Defense Construction Canada has entrusted Posterity Group to provide third party review and technical services in support of their energy performance contracts to reduce energy use and cost in military installations across Canada, and to provide for capital renewal. Under this standing offer arrangement, Posterity Group is called on to support Defence Construction Canada in several ways: to provide energy audit and energy savings measure development support; to provide third party technical review of the feasibility studies undertaken as part of energy performance contracts; to provide construction-phase support during measure installation; and to provide energy measurement and verification support.

Adaption of US E-Training on EE and GHG Reduction for Canadian Federal Buildings: Natural Resources Canada (August 2017-March 2020). Posterity Group is helping NRCan's Greening Government Support Services to adapt the U.S. Federal Energy Management Program's (FEMP) webinars for the Canadian federal market. These training webinars are intended to help build capacity within federal organizations to identify and implement energy savings projects and practices; capacity that will be instrumental in helping organization work toward achieving the GHG reduction target outlined in the Federal Sustainable Development Strategy. The scope includes adaption of ten specific U.S. FEMP courses; work that will include content adaptation, translation, recording in English and French, and ongoing stakeholder consultations with NRCan and the U.S. FEMP contact person. The Posterity Group team is uniquely positioned to provide these services; in addition to established training qualifications, we are providing built environment energy management expertise, as well as Canadian energy efficiency policy expertise.

Develop Prescriptive New Construction & Retrofit Lighting Incentives: FortisBC Electric (February 2017-April 2017). Posterity Group helped FortisBC develop a prescriptive lighting offering that covered both retrofit and new construction projects. The project's primary tasks included a jurisdictional scan to evaluate the applicability prescriptive lighting programs and measures offered by other utilities, and the development of input assumptions and eligibility criteria for each measure. Posterity Group contacted local lighting distributors and mined existing FortisBC program data to create region-specific cost assumptions.

Conservation Plan and Program Process Audit: Independent Electricity System Operator (March 2017-November 2017). Deloitte, with advisory support from Posterity Group, helped the IESO to ensure there are effective risk management controls in place to review and approve the LDC Conservation Plans and Programs.

Custom and Large Volume Program Review: Factors Influencing and Mitigating Free Ridership: Enbridge Gas Inc. (formerly Union Gas) (March 2017-May 2017). Union Gas hired Posterity Group to assist in the preparation of evidence for its mid-term review submission to the Ontario Energy Board. Specifically, Posterity Group was tasked with exploring and assessing Union Gas' efforts to reduce the free ridership rate for their Custom Commercial-Industrial (CI) and Large Volume offerings under the 2015-2020 DSM Framework as compared to the previous DSM framework. These work products will allow Union Gas to identify efforts undertaken under the new framework to date, to qualitatively assess the extent of these efforts per the OEB's Decision and Orders relative to the programs, and to identify major internal and market barriers to lowering the free ridership rate for these program offerings. The work involved a literature review and jurisdictional scan of program design and implementation factors that can influence free ridership; a review of Union Gas's program documentation for both framework periods; interviews with staff; and a gap analysis exercise leading to the reporting recommendations.

Greenhouse Construction Industry Standard Practice Study: Enbridge Gas Inc. (formerly Union Gas) (August 2016-June 2017). Posterity Group in partnership with Wood helped Union Gas establish a defensible energy performance base case for greenhouse new construction and expansion projects in Union Gas' service territory by employing a study methodology that aligns with the California Public Utilities Commission's Industry Standard Practice Guide. The study findings will allow Union program staff, the Ontario Energy Board and their evaluation contractor to accurately assess impacts resulting from DSM program activities targeting the greenhouse subsector.

Study of Federal Programming Strategies to Achieve Energy Savings: Natural Resources Canada (December 2016-March 2017). NRCan's Assistant Deputy Ministers of the Office of Energy Efficiency (OEE) and Innovative Energy Technology Services (IETS) needed to explore an approach to planning and prioritizing national energy efficiency programming and research investments that leverages lessons learned from "Ecosystem" approach that the US Department of Energy's Buildings Technology Office (BTO) has deployed, which allows for greater coordination of activities, leveraging of respective outcomes, and more efficient use of resources. Together with our partners Industrial Economics, Incorporated (IEc) and Optimal Energy, Posterity Group led the Canadian effort to assist NRCan to develop a comprehensive, data-driven approach to energy efficiency programming focused on the built environment, and informed by the experience of the BTO. This arrangement took advantage of IEc and Optimal's deep knowledge of the BTO, and Posterity Group's history of working with NRCan. Posterity Group worked to provide NRCan with recommendations on how best to design, deliver, and coordinate federal energy efficiency programming and R&D investments that similar to the approach taken by the U.S., This study also equipped NRCan with the tools necessary to adapt its existing programs to maximize their positive impacts on the energy efficiency of the built environment.

Upstream Program Development Support: Enbridge Gas Inc. (June 2016-January 2017). Enbridge Gas is relying on Posterity Group to provide strategic guidance on how and where employing an upstream program approach may improve the effectiveness of its commercial program offerings. In this project, Posterity Group will: Evaluate candidate measures regarding their suitability for an upstream program delivery approach, in consultation with EGD staff; Characterize the Ontario market for two selected measures in order to determine market size, market structure, barriers to increased uptake, market actor support for an upstream delivery approach, and consistency with EGD's overarching DSM strategy. Provide support to EGD staff in the design of an upstream program.

Upstream/Midstream Commercial Program Design: Independent Electricity System Operator (September 2015-February 2016). A working group of Local Distribution Companies in Ontario contracted Posterity Group through the IESO to undertake three upstream program designs for the commercial sector. The programs under design included three technology areas, compressed-air, unitary packaged air conditioning units (rooftop units), and variable frequency drives. The methodology for the study included a detailed market characterization of each technology area, including a literature review, program administrator interviews, and market actor interviews to determine barriers that an upstream program approach could overcome. The market characterization informed the program design phase which undertook to establish the proper intervention point for the program in the supply chain, to establish technology eligibility and program economics. The project work plan included a very aggressive timetable and a highly parallel process workflow that leveraged the contributions of a broader LDC steering committee representing four Ontario LDCs (Toronto Hydro, Hydro One, Horizon Utilities, and Entregrus).

Contractual and Technical Reviews: Independent Electricity System Operator (October 2015-September 2016). Compliance audits representing over $26 million in aggregate incentive payments were undertaken for retrofit, high performance new construction, energy audit and existing building commissioning program applications to ensure that energy savings were accurately quantified and reported.

Industrial Energy Efficiency Program Evaluation: Independent Electricity System Operator (February 2015-April 2016). Posterity Group, in partnership with Econoler and Cadmus, recently helped the IESO meet its program reporting requirements for the Industrial Energy Efficiency Program. Posterity Group supported the gross impact savings analysis by conducting desk-top reviews, site visits and telephone interviews to validate project savings for sample projects.

Run-it-Right M&V Methodology: Enbridge Gas Inc. (August 2015-May 2016). Posterity Group, with TdS Dixon, helped Enbridge define an approach to verify savings for its Run-it-Right program. An M&V method was developed that embodied three guiding principles: the M&V approach needed to be flexible, scalable and logical; substantiated; and balanced with regard to cost versus accuracy. Our project team also advised Enbridge on how customers should be engaged to improve the chances that RiR program savings will be realized, that they can be measured, and that they will persist.

IEI Technical Consultant: Independent Electricity System Operator (May 2014-October 2015). Posterity Group, in partnership M.A. Comeau Consultant Inc., helped the IESO by providing technical review support for applications received under its Industrial Electricity Incentive Program. Among other elements, industrial participants were required to submit metering plans with their application packages. Our team reviewed these metering plans and provided recommendations for corrective action to ensure metering plans were compliant with program requirements.

Development of Major Energy Retrofit Guidelines: Natural Resources Canada (February 2014-March 2016). Posterity Group, in partnership with Arborus Consulting and TdS Dixon, developed guidelines for the Office of Energy Efficiency's Buildings Division to support building sector initiatives, including the National Energy Code of Canada for Buildings and ENERGY STAR Portfolio Manager. The guidelines target decision makers in small to medium-sized commercial and institutional facilities and outline an approach to identifying and undertaking major retrofits. They include seven building –specific companion modules which present opportunities unique to office buildings, K-12 schools, hospitals, non-food retail, hotel, supermarket and food store facilities.

High Efficiency Natural Gas Laundry Dryers Pre-feasibility Study: FortisBC (June 2014-December 2014). Posterity Group assisted Fortis BC's Innovative Technologies Group to understand the opportunity for energy efficiency within the stock of residential and commercial laundry drying equipment in BC. Posterity Group developed methodologies to assess high efficiency laundry drying equipment as a potential DSM measure; undertook interviews and secondary research including interviewing researchers and performing patent searches to characterize emerging technologies; and is led modelling activities to estimate conservation potential within FortisBC's residential and commercial customer base.

Combination Units Pre-feasibility Study: FortisBC (December 2013-May 2014). Posterity Group assisted Fortis BC's Innovative Technologies Group to understand the opportunity for energy savings through the use of combination space and water heating equipment within BC's residential sector. Posterity Group developed methodologies to assess combination space and water heating equipment as a potential DSM measure; undertook interviews and secondary research to characterize the BC market and supply chain for combination units; and led modelling activities to estimate conservation potential within FortisBC's residential customer base. Posterity Group conducted in-depth modelling of natural gas savings potential for numerous baseline and upgrade scenarios including end-of-life and early replacement, new construction and retrofit applications, and across various service regions.

Development of an Energy Management Best Practices Guide: Natural Resources Canada (February 2013-July 2013). Posterity Group developed an Energy Management Best Practices Guide, updated the Office of Energy Efficiency Building Division's Energy Management Action Plan, and provided a framework for website content on managing and retrofitting existing buildings.

Study to Determine EnerGuide Fuel Consumption Label Compliance: Natural Resources Canada - Office of Energy Efficiency (December 2012-March 2013). Posterity Group supported the OEE's Transportation Division in their evaluation of the EnerGuide Fuel Consumption Labeling program - a voluntary agreement between NRCan and the vehicle industry to label new vehicles with the EnerGuide Fuel Consumption Label. The project involved conducting market research at 580 sites in 33 cities across Canada, performing compliance analyses, and presenting aggregate findings.

Evaluation, Measurement and Verification (EM&V) Planning Services: Enbridge Gas Inc. (formerly Union Gas) (January 2015-September 2015). Posterity Group's program evaluation expertise was instrumental in helping Union Gas prepare its submission packages to the Ontario Energy Board for the 2015-2020 DSM program framework. EM&V plans were developed for eleven programs, including market transformation, low-income, resource acquisition, performance based and behavioural offerings.

Post-retrofit audits for NRCan's ecoEnergy Retrofit and Energy Retrofit Assistance Programs: Natural Resources Canada – Office of Energy Efficiency (December 2007-March 2011). Alex was responsible for managing a team of auditors and conducting post-retrofit audit work for over 70 projects, representing over 250 facilities. This project involved on-site project implementation verification, and M&V of savings using Option C of the International Performance Measurement and Verification Protocol (IPMVP).

SaskPower Industrial Energy Optimization Program Implementation: SaskPower (2012). Alex provided technical support to industrial participants. Through this role, Alex managed the development of baselines for Cargill Prairie Malt and Devon Energy, which involved working with their historical interval meter data, identifying key production, environmental, and operational drivers, and making adjustments.

Northern Industrial Electricity Rate Program – Energy Management Plan Review Services: Ontario Ministry of Northern Development and Mines (2011-2012). Alex provided training and ongoing technical support to the review team on energy baseline development best practices and measurement and verification (M&V) planning. Alex also reviewed quarterly reviewed quarterly reports submitted by participants and provided feedback on the nature of the progress being made towards their energy management plans. The reviews focused on baseline development, updates on capital projects and M&V planning and reporting.

Market Transformation Evaluation Plan: Natural Resources Canada (2012). Alex developed a methodology to evaluate the impacts of contributions made by Natural Resources Canada (NRCan) to light emitting diode (LED) roadway initiatives. Since the objective of NRCan's funding was to accelerate the adoption of LED roadway technology in Canada, the recommended approach was founded on principals discussed in the California Emerging Technologies evaluation protocol, as well as the principals of Rogers' Diffusion of Innovations Theory.

Third-Party Review of the Home Energy Savings Program and Ontario Solar Thermal Heating Incentive: Ontario Ministry of Energy (2012). Alex reviewed the methodology used by the Ministry of Energy to evaluate the impact of the Home Energy Savings Program (HESP) and Ontario Solar Thermal Heating Incentive Program (OSTHI). The work focused on assessing the calculation methods used to derive the benefits generated by the Ontario government's participation in these two programs.

Evaluation, Measurement and Verification (EM&V) Plan Development: Enbridge Gas Inc. (formerly Union Gas) (August 2011-August 2012). Alex managed the development of seven EM&V plans for Union Gas in accordance with the Ontario Power Authority (OPA) EM&V Protocols and Requirements. These plans were prepared to accompany Union Gas' submission packages to the Ontario Energy Board for their new program portfolio.

Multi-family Buildings Program Evaluation: Ontario Power Authority (April 2009-July 2011). Alex was responsible for leading the gross impact analysis for the OPA's Multifamily Buildings Program evaluation. This was a three-year evaluation project where Alex managed and conducted desk-top and post-retrofit site visit evaluation activities. Alex also contributed to the process evaluation activities by conducting interviews with building owners, property managers, and building operators.

EcoNova Scotia's Clean Air and Climate Change Program Evaluation: Nova Scotia Environment (2010-2011). The Clean Air and Climate Change Program leveraged federal Trust Fund dollars to reduce environmental impacts in Nova Scotia as well as develop future capacity to stimulate ongoing impact reduction. Alex led the development of the evaluation framework and was responsible for managing the review of the GHG and air emissions impact claims for over 140 projects transcending Nova Scotia's transportation, commercial/institutional, municipal infrastructure, and renewable energy sectors.

Efficiency New Brunswick's Large Industry Program M&V Support: Efficiency New Brunswick (2008-2010). Alex provided measurement and verification plan review and support services for Efficiency New Brunswick's Large Industry program. This involved conducting site visits at industrial facilities in New Brunswick, undertaking technology research activities and providing M&V expertise.

Measurement and Verification Consultant – Ontario Power Authority's Demand Response (DR) 1 Program: St. Marys Paper Corp. (2007-2009). Alex provided M&V consulting services for St. Marys Paper Corp. in support of their participation in the OPA's DR1 Program. On a monthly basis, Alex reviewed and certified St. Marys Paper Corp.'s baseline energy use and curtailed MWh calculations.

EDUCATION

Bachelor of Science (Mechanical Engineering), Queen's University – Kingston, Ontario, Canada, 2005

CERTIFICATIONS & TRAINING

Project Management Professional (PMP)
Certified Measurement and Verification Professional (CMVP)
LEED Accredited Professional (LEED Canada NC version 1)
GHG Inventory, Accounting and Reporting (ISO 14064-1, ISO 14064-2), University of Toronto

PUBLICATIONS

Tiessen, Alex. (2014). "Chapter 14: Chiller Evaluation Protocol. The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures". Prepared for the U.S. Department of Energy's National Renewable Energy Laboratory.

Tiessen, Alex. (2014). "Chapter 16: Retrocommissioning Evaluation Protocol. The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures". Prepared for the U.S. Department of Energy's National Renewable Energy Laboratory.

PROFESSIONAL AFFILIATIONS

Professional Engineers of Ontario
Efficiency Valuation Organization
Association of Energy Services Professionals
Project Management Institute
American Society of Heating, Refrigerating and Air-Conditioning Engineers

EMPLOYMENT HISTORY

Posterity Group	Principal	2012 - present
ICF Marbek	Manager	2011-2012
Marbek Resource Consultants	Consultant	2007-2011
Stantec Consulting	EIT	2006-2007

W. Randy Colbert, BSc, FSA, FCIA

Background:

- Has worked for Willis Towers Watson for 35 years, mostly in Toronto with two years in Europe.
- WTW is a leading global professional services company that helps organizations improve performance through effective people, risk and financial management.
- Client facing role as a consulting actuary. In that role, was an expert in the financing, operation and administration of pension plans.
- Consulted to management and boards of many large employers in Canada. Clients included private sector, public sector, broader public sector, and unions. Also conducted many retirement planning sessions for employees of clients.
- Served as the Canadian Supplemental Executive Retirement Plan (SERP) Issue Leader for Towers Watson for 10 years.
- Served as Towers Watson's Canadian Professional Excellence leader. In that role, championed working with clients in a way that promotes integrity and professionalism.
- Served as Chair of the Towers Watson Canada Pension Committee which oversees the administration and investments for the Canadian pension plans.

Litigation support:

Has assisted numerous clients in various negotiations, disputes, litigation and arbitrations; examples include:

- Calculating value of lifetime pension in wrongful dismissal lawsuits
- Determining value of executive pension benefits
- Review and comment on assumptions used in determining present values of annuities & pensions
- Appropriate use of asset returns, mortality and expected lifetime in retirement planning

Education:

- B.Sc. in Actuarial Science and Economics from the University of Toronto
- Fellow of the Canadian Institute of Actuaries and Society of Actuaries since 1992.

Decker Ringo

Associate Director, 2050 Partners

deckerringo@gmail.com
Washington, DC

Professional Summary

Decker's areas of expertise include evaluation of energy efficiency and fuel switching measures, technical cost modeling, and engineering analysis. As an Associate Director with 2050 Partners, Decker Ringo studies the energy and cost savings that could be available from future improvements to California's Title 24 building codes. Decker's key responsibilities at Guidehouse included supporting utility-based incentive programs and the development of federal energy efficiency standards. He helped refine Guidehouse's cost modeling methodology and he has reverse engineered modeled the costs of over 100 products, including heat pumps, air conditioners, boilers, cooktops, dishwashers, furnaces, heating equipment, icemakers, pool heaters, vending machines, and water heaters.

Professional Experience

- Characterized the incremental installation costs, energy cost savings, and GHG reductions associated with 30 residential energy optimization measures including oil-to-gas measures and early replacement of fossil fuel home heating and water heater products with electric heat pumps.
- Evaluated over 200 energy efficiency measures for residential and commercial sectors to determine their energy savings, consumer costs, and other factors needed to estimate the achievable potential for a utility in New England.
- Managed three separate cost studies on behalf of Massachusetts utility program administrators to estimate the incremental costs of increasing efficiency in residential heating and cooling products. Led two separate surveys of HVAC contractors to gather information about residential heating equipment installations.
- Led the development of a gas futures model that allows users to set emissions reduction targets, adjust various interventions (e.g., electrification, efficiency improvements), and observe the forecast of primary fuel needs, GHG emissions, and investment costs through the year 2050.
- Led the engineering analysis for U.S. Dept. of Energy rulemakings regarding Packaged Terminal Air Conditioner (PTAC) and Dedicated Purpose Pool Pump (DPPP) equipment. Characterized markets, investigated technology options, conducted product testing, and tore down products to assess the incremental costs associated with high-efficiency technologies.

Work History

- Associate Director, 2050 Partners
- Associate Director, Guidehouse
- Senior Consultant, SRI International
- Materials Research Engineer, Lexmark International

Decker Ringo
Associate Director, 2050 Partners

Education

- MS, Technology and Policy and Mechanical Engineering, Massachusetts Institute of Technology
- BS, Chemical Engineering and Mechanical Engineering, University of Michigan

welcome to brighter

Benedict O. Ukonga, FSA, FCIA, CFA

Mercer (Canada) Ltd

Ben Ukonga is a Principal and actuary in Mercer's Wealth business in Calgary. He is also the leader of Mercer's Wealth business in Calgary.

Ben works with many large and mid-size Canadian companies as well as multi-national organizations and provides strategic advice on the design, funding, risk management, financial reporting and administration of pension arrangements. He also advices his clients in special situations such as union negotiations, plan mergers and conversions, and in mergers, acquisitions and divestitures. Ben has also worked with different foreign Governments and provided advice on the design, funding and administration of the public sector pension arrangements in those countries.

Ben has over 22 years of consulting experience, including 6 years with a competitor and 2 years consulting in the US. Ben is a faculty member of Mercer's HR Knowledge Series of client education seminars, and the School of Pension Investment Management, sponsored by Mercer and The Schulich School of Business, York University where he presents sessions on pension funding and accounting.

Ben is an active member of the actuarial profession and the pension industry. He was previously a member of the Canadian Institute of Actuaries (CIA) Pension Plan Financial Reporting Committee, and currently sits on the Alberta Regional Council of the Association of Canadian Pension Management (ACPM). He was also a member of the Financial Services Regulatory Authority of Ontario's (FSRAO) Technical Advisory Committee on Asset Transfers, and acts as one of Mercer's media contacts on pension issues.

Ben graduated from the University of Windsor with a Bachelor's degree in Mathematics and Statistics, and was the recipient of the Board of Governors' award for his graduating class. He is a Fellow of the Society of Actuaries, a Fellow of the Canadian Institute of Actuaries and a CFA Charterholder.

FORM A

Proceeding: EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Greg Lyle (*name*). I live at Gibsons (*city*), in the British Columbia (*province/state*) of Canada .

2. I have been engaged by or on behalf of Enbridge Gas Inc. (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date August 9, 2022

Signature

FORM A

Proceeding:...EB-2022-0200...

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ...John Decker Ringo...*(name)*. I live at ...Burke... *(city)*, in the ...State... *(province/state)* of ...Virginia, U.S.A.

2. I have been engaged by or on behalf of ...Enbridge... *(name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

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4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ...Sep. 7, 2022...

John Decker Ringo

Signature

FORM A

Proceeding: EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is A. Thomas Bozzo (*name*). I live at Madison (*city*), in the State (*province/state*) of Wisconsin .

2. I have been engaged by or on behalf of Enbridge Gas (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date August 9, 2022

A. Thomas Bozzo
Digitally signed by A. Thomas Bozzo
Date: 2022.08.09 14:40:36 -05'00'

Signature

FORM A

Proceeding: EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is David Shipley (*name*). I live at Ottawa (*city*), in the province (*province/state*) of Ontario .

2. I have been engaged by or on behalf of Enbridge Gas Inc. (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

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   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date 6 September 2022

Signature

FORM A

Proceeding: EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ......Erika Aruja......(*name)*. I live at ......Ottawa...... (*city)*, in the ...Province... (*province/state*) of ...Ontario... .

2. I have been engaged by or on behalf of ...Enbridge Gas Inc.... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

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Date ...6 September 2022...

Signature

FORM A

Proceeding:……EB-2022-0200………

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Abbas Lakha (*name)*. I live at Richmond Hill (*city)*, in the Province (*province/state*) of Ontario .

2. I have been engaged by or on behalf of Enbridge Gas, as an employee of EY (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date September 27, 2022

Signature

FORM A

Proceeding:……EB-2022-0200………

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ....Andy Grainger............(*name)*. I live at ...Komoka.................... (*city)*, in the ..Province........... (*province/state*) of ..Ontario.................... .

2. I have been engaged by or on behalf of Enbridge Gas, as an employee of EY (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

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(b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

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4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date .September 28, 2022.......

Andy Grainger

Signature

FORM A

Proceeding:EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Peter Steele-Mosey (*name)*. I live at Toronto (*city)*, in the province (*province/state*) of Canada.

2. I have been engaged by or on behalf of Enbridge Gas, Inc. (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

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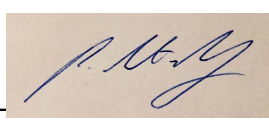
Date ....2022-08-22..........



Signature

FORM A

Proceeding: 2024 Rebasing

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Andrew Griffith. I live in Denver in the state of Colorado.

2. I have been engaged by or on behalf of Enbridge Gas Inc. to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date September 29, 2022

Andrew Griffith

Signature

FORM A

Proceeding: EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ......Michael Sloan......(*name*). I live at ......Great Falls...... (*city*), in the ....State.......... (*province/state*) of ......Virginia...... .

2. I have been engaged by or on behalf of ......Enbridge...... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

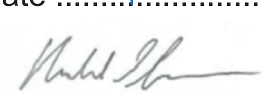
   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ......September 29, 2022......



Signature

FORM A

EB-2022-0200

Proceeding: Rate Basing Proceeding

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Andrea Roszell (*name*). I live at Whitby (*city*), in the Province (*province/state*) of Ontario.

2. I have been engaged by or on behalf of Enbridge (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date Sept. 5. 2022

Signature

FORM A

Proceeding: EB-2022-0200 EGI 2024 Rebasing

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Edith Samuels (*name*). I live at Winnipeg (*city*), in the province (*province/state*) of Manitoba.

2. I have been engaged by or on behalf of Enbridge Gas Inc. (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date August 15, 2022

Edith Samuels

Signature

FORM A

Proceeding:..EB-2022-0200 EGI 2024 Rebasing.........................

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ....Jesse Little......................................(*name*). I live at ..Edmonton...................... (*city*), in the ..province......... (*province/state*) of ....Alberta................ .

2. I have been engaged by or on behalf of ..Enbridge Gas Inc............. (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ...August 15, 2022...................................

____
Signature

FORM A

Proceeding: EB-2022-0200 EGI 2024 REBASING

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is KEN CHIN (*name*). I live at MONTREAL (*city*), in the PROVINCE (*province/state*) of QUEBEC.

2. I have been engaged by or on behalf of ENBRIDGE GAS INC (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date AUGUST 17, 2022

Signature

FORM A

Proceeding: EB-2022-0200 EGI Rebasing

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Scott Thompson (*name*). I live at Calgary (*city*), in the province (*province/state*) of Alberta.

2. I have been engaged by or on behalf of Enbridge Gas Inc. (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date August 11, 2022

Signature

FORM A

Proceeding: EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ....Kenneth Yung..............(*name)*. I live at ....Oakville....... (*city)*, in the ....Ontario....... (*province/state*) of ....Canada....... .

2. I have been engaged by or on behalf of ....Enbridge Gas Inc....... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

(a) to provide opinion evidence that is fair, objective and non-partisan;

(b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

(c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ....August 8, 2022.......

Kenneth Yung

Signature

Type text here

FORM A

Proceeding: EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Randy Colbert (*name)*. I live at Toronto (*city)*, in the Ontario (*province/state*) of Canada .

2. I have been engaged by or on behalf of Enbridge Gas Inc. (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date August 5, 2022

W. R. Colbert

Signature

FORM A

Proceeding:......EB-2022-0200......

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ......Craig Sabine......(*name)*. I live at ....Bowmanville.... (*city)*, in the ....Ontario.... (*province/state*) of ....Canada.... .

2. I have been engaged by or on behalf of ....Enbridge Gas Inc.... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

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   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ....September 19, 2022....

Cg Sabine

Signature

FORM A

Proceeding: EB-2022-0200 EGI 2024 Rebasing

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Larrry E. Kennedy...............(*name*). I live at ...Calgary........ (*city*), in the ...Province.......... (*province/state*) of .....Alberta.............. .

2. I have been engaged by or on behalf of ..Enbridge Gas Inc.... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
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   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date August 9, 2022

Signature

FORM A

Proceeding:……EB-2022-0200…

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ...Daniel S. Dane.....................(*name)*. I live at Northborough... (*city)*, in the ...State.................. (*province/state*) of .Massachusetts.......... .

2. I have been engaged by or on behalf of ......Enbridge Gas Inc.. (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ...August 10, 2022................

Daniel Dane

Signature

FORM A

Proceeding:……EB-2022-0200………

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ....James Coyne....(*name)*. I live at ....Concord.... (*city)*, in the ....Massachusetts.... (*province/state*) of ....United States.... .

2. I have been engaged by or on behalf of ....Enbridge Gas Inc..... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ....September 21, 2022....

JM Coyne
Signature

FORM A

Proceeding: EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is A. Thomas Bozzo (*name*). I live at Madison (*city*), in the State (*province/state*) of Wisconsin .

2. I have been engaged by or on behalf of Enbridge Gas (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date August 9, 2022

A. Thomas Bozzo Digitally signed by A. Thomas Bozzo Date: 2022.08.09 14:40:36 -05'00'

Signature

FORM A

Proceeding: EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Bruce R. Chapman (*name)*. I live at Madison (*city)*, in the state (*province/state*) of Wisconsin.

2. I have been engaged by or on behalf of Enbridge Gas Inc. (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date August 8, 2022

Bruce R. Chapman

Signature

FORM A

Proceeding: EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Nicholas Crowley (*name*). I live at Madison (*city*), in the State (*province/state*) of Wisconsin.

2. I have been engaged by or on behalf of Enbridge Gas, Inc (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date 8/9/2022

Nicholas Crowley

Signature

FORM A

Proceeding: # EB-2022-0200, EGI 2024 Rebasing

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Larry Kaufmann (*name*). I live at Austin (*city*), in the State (*province/state*) of Texas :

2. I have been engaged by or on behalf of EGI (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date August 9, 2022

Larry Kaufmann

Signature

FORM A

Proceeding: EB-2022-0200

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Benedict Ukonga (*name*). I live at Calgary (*city*), in the province (*province/state*) of Alberta .

2. I have been engaged by or on behalf of Enbridge Gas Inc. (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

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   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date June 26, 2023

Signature

EXECUTIVE SUMMARY

1. Overview

1. Enbridge Gas and its predecessor organizations have been meeting Ontario's energy needs for 175 years through an extensive storage, transmission and distribution network. In 2019, Enbridge Gas began its latest evolution—the province's largest utility integration to date.

2. Today, the Company serves over 3.8 million residential, commercial, and industrial customers across more than 300 municipalities and more than 20 First Nations. As the province's largest utility, Enbridge Gas reaches into more than three-quarters of the province's homes, as well as the majority of Ontario's economy-driving industries and businesses, and its critical public services.

3. Ontario's natural gas system provides unparalleled value to energy consumers. Natural gas meets 30 percent of Ontario's energy needs, almost twice that of the electricity system, at less than a third of the cost, with no additional provincial funding.[1] On a peak basis, the natural gas system provides three to five times as much energy as the electricity system.

[1] According to the Canada Energy Regulator, in 2019, natural gas accounted for 30% of total end-use demand and electricity accounted for 16% (Canada Energy Regulator. (2022 July, 28). Provincial and Territorial Energy Profiles – Ontario. https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html Figure 6). According to the Canadian Centre for Energy Information, in 2019, natural gas represented 32% of total energy use in Ontario and electricity represented 17.5%. In 2020, natural gas represented 34% of total energy use in Ontario and electricity represented 19%. (Government of Canada. (2022, August 30). Energy use. https://energy-information.canada.ca/en/subjects/energy-use). In 2021, the total gas distributor revenues from delivering natural gas in Ontario was $4.9 billion, and the total revenue for electricity distributors was $18 billion, with an estimated $3.1 billion transferred to the tax base through the provincially funded Renewable Cost Shift program.

4. The depth and breadth of Enbridge Gas's connection to Ontario's energy consumers make the Company both uniquely attuned to what customers need today and what they expect tomorrow, and uniquely positioned to meet those expectations. Delivering value to customers has been the main goal of Enbridge Gas's integration, and customers remain at the heart of its ongoing mission to provide safe, reliable, resilient, cost-effective and sustainable energy solutions.

5. Given this customer-centered focus, customers are an integral part of Enbridge Gas's business planning and decision-making processes, and their feedback, gathered through extensive engagement, directly informs this rate rebasing application, which covers the 2024 to 2028 period and is the Company's first as an integrated company.

6. An explicit customer focus is one of the four outcomes that utilities are expected to deliver under the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF). This Application describes how Enbridge Gas plans, strategizes, prioritizes and optimizes expenditures to produce those outcomes, and it meets the requirements outlined in the OEB's Filing Requirements for Natural Gas Applications.

7. Reflecting what customers told the Company is most important to them, the proposed rates in this Application will support a system that can continue to meet their needs safely and reliably in a cost-effective way, while at the same time helping them prudently prepare for the energy transition that is underway in the communities where they live, driven by existing and planned federal and provincial policies. Given the role the Enbridge Gas system plays today and its importance in a diversified energy future, it is in Ontarians' best interest that its assets be

maintained, and investments made, ensuring a strong backbone for transitioning energy systems.

8. Enbridge Gas's values of integrity, safety, respect and inclusion, along with its strategic priorities, guide its decision-making. The evidence that makes up this Application is Enbridge Gas's business plan and demonstrates how the Company intends to support customers through continued safe, reliable, cost-effective operations while prudently incorporating new energy solutions. The plan is specifically underpinned by the 2024 to 2028 Utility System Plan (USP) and the 2023 to 2032 Asset Management Plan (AMP), provided at Exhibit 2, Tab 6, Schedule 1 and Exhibit 2, Tab 6, Schedule 2, respectively. Enbridge Gas's strategic priorities and alignment with the RRF are provided in Table 1 of the USP.

9. At a high level, a distinct majority of customers who were engaged during the planning process supported Enbridge Gas's 2024 to 2028 business plan objectives, including those that would introduce higher costs. Customers told the Company clearly that their priorities include affordability, reliability, and minimizing environmental impacts. The design, methodology, process and results of Enbridge Gas's customer engagement are provided at Exhibit 1, Tab 6, and discussed in more detail below.

10. Following a comprehensive review of all regulated revenues, costs and policies, Enbridge Gas proposes that from 2024 to 2028, its current and future customers continue to be served through regulated distribution, transportation, and storage rates set through a price-cap incentive regulation structure very similar to the one used to set the Company's rates during its deferred rebasing term from 2019 to 2023. This involves determining just and reasonable cost of service rates for 2024, and then adjusting rates for the following four years using a formula specific to each

year. Details of the multi-year incentive rate-setting mechanism Enbridge Gas is proposing are provided at Exhibit 10, Tab 1, Schedule 1, and discussed in more detail later in this summary.

11. Overall, Enbridge Gas is requesting a 5% increase in revenues in 2024. Rate impacts for individual customers will vary by rate zone and rate class. For typical general service customers, Enbridge Gas is proposing rates that would result in an annual bill increase for 2024 (relative to 2023) of up to 3% for customers in the EGD rate zone, an increase of up to 8% for customers in the Union South rate zone and a decrease of 3-13% for customers in the Union North rate zone.

12. These impacts are driven by two main factors: 1) recovery of a forecast total revenue deficiency of $294.1 million, and 2) proposed harmonization of rate zones /u and the recovery of gas costs. The total revenue deficiency arises primarily from an increase in depreciation expense, adjustments to the Company's capital structure to reflect energy transition risks and the increasing cost of providing service to customers and is partially offset by $121.2 million in annual integration and productivity savings realized during the 2019 to 2023 deferred rebasing term.

13. As provided at Exhibit 4, Tab 4, and discussed in further detail below, integration savings, together with productivity savings, have mitigated the operations & maintenance (O&M) cost pressures experienced over the past few years as a result of the COVID-19 pandemic and the period of rapid inflation that has followed.

14. As integration costs wind down, integration savings will continue to mitigate costs, which are expected to continue rising as a result of: continued inflation and labour market challenges, legislative impacts on locates, cyber security threats to the energy industry, changes in the technology industry and global insurance market,

and inclusion in utility O&M and rates of amounts previously recovered separately though deferral accounts.

15. To deliver integration savings, Enbridge Gas undertook a complex business transformation with the aim of delivering value and a consistent and improved experience to customers. Following the amalgamation of Enbridge Gas Distribution (EGD) and Union Gas Limited (Union) on January 1, 2019[2], the Company has vigorously pursued synergies—many of them amidst the challenges of a global pandemic—through aligned systems and programs that delivered qualitative improvements for the same, or lower, cost to customers.

16. The Company accomplished this by making significant investments throughout the deferred rebasing term to deliver the highest level of sustainable savings. As provided at Exhibit 1, Tab 9, and discussed in further detail below, current and future customers are better off than they otherwise would have been had the predecessor utilities continued to operate as separate companies. This Application also responds to additional specific directives set out in the Mergers, Acquisitions, Amalgamations and Divestitures (MAADs) Decision[3], including a rate harmonization proposal.

17. In subsequent years, proposed rates also reflect the harmonization plan provided at Exhibit 8, Tab 2, Schedule 1. The plan proposes to align, simplify and enhance rates and services to meet customer needs and is underpinned by the service harmonization proposals provided at Exhibit 8, Tab 4. Both the proposed rate and service harmonization plans are discussed in more detail later in this summary.

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[2] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.
[3] Ibid.

18. Enbridge Gas is proposing to phase in harmonized services and rates to allow time to implement system changes, inform customers and mitigate bill impacts. A mitigation plan is provided at Exhibit 8, Tab 2, Schedule 6, and discussed in more detail later in this summary.

19. To further reflect the operations and services of a single utility, Enbridge Gas is also proposing to harmonize a number of other processes, procedures and methodologies.

20. Finally, this Application addresses the broader evolution that has been taking place in the energy sector since Enbridge Gas's predecessor utilities last submitted rate rebasing applications. Around the world, political leaders, policy makers, and energy consumers themselves have signaled they are looking for substantive changes to the way energy is developed and used to help mitigate the impact of climate change.

21. This transition in energy development and use is complex and ever-evolving, and it is widely expected to intensify over the next two decades. As provided in Exhibit 1, Tab 10, the governments of Canada and Ontario have set targets to reduce greenhouse gas (GHG) emissions, and many municipalities have also set their own targets.

22. Although there continues to be a great deal of uncertainty about the pace and precise nature of Ontario's energy transition, it is clear that one is underway. It is also clear that a successful transition will help lower GHG emissions while preserving consumers' access to secure and cost-effective energy. Enbridge Gas is confident about the role it can and will play in providing the next generation meaningful solutions, as well as helping to facilitate an orderly transition. Enbridge

Gas's Energy Transition Plan (ETP) provided at Exhibit 1, Tab 10, Schedule 6, outlines how the Company is proposing to balance customers' need for continued access to a secure, cost-effective supply of energy with "safe bet" actions that support Ontario's near-term GHG reduction goals. Exhibit 1, Tab 10, Schedule 4 explains how the Company is incorporating energy transition assumptions into its forecasting and planning processes, and what impact that is having on the AMP, finance and regulatory approaches.

23. Investing in the system to keep it healthy and robust is critical to ensuring it can continue to deliver value to customers by meeting their energy needs today, and in the future. Enbridge Gas's commitment to supporting customers with a safe, secure and reliable system that can grow and evolve is reflected in its capital expenditures, provided at Exhibit 2, Tab 5.

24. As illustrated throughout this Application, the rates Enbridge Gas is proposing are reasonable and necessary to support the kind of energy solutions customers have told the Company they expect, to provide a consistent and improved customer experience, and to buttress government goals addressing climate change. A strong majority of customers themselves say they are willing to invest in the long-term health of the system, as well as low-carbon options and solutions to reduce impacts on the environment, through reasonable rate increases.

2. The Value of The Enbridge Gas System

25. Enbridge Gas is Ontario's largest natural gas distributor. It serves over 3.8 million residential, commercial, and industrial customers across the province, from Kenora to Ottawa in the north, and from Windsor to Kingston and communities beyond in the south. It does this through 153,000 km of natural gas transmission and distribution pipelines (enough to circle the Earth more than three times), as well as

through the delivery of extensive energy conservation programs. Based on its 2024 Rebasing proposal, Enbridge Gas's residential customers will pay approximately $45 a month in charges to receive energy from a highly dependable and resilient underground delivery system.

26. Enbridge Gas's dependable and resilient system also includes its storage and transmission assets: 199 PJ of regulated integrated underground natural gas storage at the Dawn Hub and throughout Ontario, and the Dawn Parkway Transmission System, which runs from near Sarnia to the western edge of the Greater Toronto Area, where it connects with other downstream pipelines serving eastern Canada and the northeast U.S. The Dawn Hub is connected to most of North America's major natural gas basins, which gives customers access to abundant and affordable supplies from western Canada and the northeastern U.S. These assets provide Ontarians with a resilient system and a secure supply, and shield customers from large price fluctuations in the market, unlike other large metropolitan regions like New York. The importance of resiliency and secure supply, provided at Exhibit 1, Tab 10, Schedule 2, has been underscored most recently by the deepening energy crisis in Europe.

27. Thanks to Enbridge Gas's robust system, natural gas is a safe, reliable, resilient, cost-effective source of energy for Ontario today, generating lower emissions than alternatives such as oil, and propane, and meeting 30% of the province's energy needs on an annual basis, almost double that of electricity.

28. Enbridge Gas supports Ontario's growth and prosperity by delivering energy solutions to critical economic sectors, including customers in automotive, chemical, food & beverage, greenhouse–agricultural, manufacturing, mining, pulp & paper, refining and steel. It also supports critical public services, such as hospitals, long-

term care facilities, schools and community centres.

29. The system keeps Ontarians warm in the winter and cool in the summer. On a peak winter day, the natural gas system provides three to five times as much energy as the electricity system. On hot summer days, natural gas helps meet peak demand[4] as an important part of the electricity system, where it makes up more than a quarter of installed generation capacity.[5] Currently, the IESO is forecasting an increase in electricity demand for Ontario out to 2042, and it expects to use natural gas-fired generation to meet those increased demands.[6]

30. As discussed throughout this Application, regardless of the direction of Ontario's energy transition, the natural gas system will be critical to providing Ontarians with resilient, reliable, cost-effective energy solutions, including by working in a more integrated way with the electricity system.[7]

31. The increasing frequency and severity of extreme weather events underscores the need to maintain and build more resilience into Ontario's energy systems. For example, according to the Insurance Bureau of Canada, eight of the largest insurance payouts in Canadian history relate to extreme weather events that have occurred since 2011.[8] The inherent resiliency of a system with the majority of its

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[4] Top Ten Ontario Demand Peaks from May 1, 2021, to April 30, 2022, https://www.ieso.ca/-/media/Files/IESO/settlements/Top-Ten-Ontario-Demand-Peaks-Archive.ashx.
[5] Generator Output by Fuel Type Hourly Report, January 1, 2021, http://reports.ieso.ca/public/GenOutputbyFuelHourly/PUB_GenOutputbyFuelHourly_2021_v365.xml.
[6] Annual Planning Outlook: Ontario's electricity system needs: 2023-2042, December 2021, p.74 https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/2021-Annual-Planning-Outlook.ashx.
[7] This is consistent with the October 21, 2022 Letter of Direction from the Minister of Energy to the Chair of the OEB, https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf.
[8] Insurance Board of Canada. (2022, June 15). Derecho Storm Ranks 6th Largest Insured Loss Event in Canadian History, http://www.ibc.ca/on/resources/media-centre/media-releases/derecho-storm-ranks-6th-largest-insured-loss-event-in-canadian-history.

assets underground will only become more valuable in the future, as severe weather events are expected to become more frequent and intense.

32. Enbridge Gas delivers more than natural gas. The Company also has a proven track record when it comes to helping customers lower their energy use, as well as lowering the emissions intensity of the energy they are using.

33. For example, between 1995 and 2021, its demand side management (DSM) programs have reduced customer consumption by 30.9 billion cubic metres of natural gas, a cumulative reduction of 57.8 million tonnes of carbon dioxide equivalent (tCO2e).[9] Natural gas played an important role in the replacement of coal-fired electricity in Ontario, which is considered the single largest GHG reduction action in North America.[10] Enbridge Gas has also introduced pilot programs that have begun to green its gas supply, such as a voluntary renewable natural gas (RNG) program and by blending hydrogen into the gas supply of 3,600 customers in Markham (through the Low-Carbon Energy Project (LCEP)).[11] Based on the project's early successes, Enbridge Gas is moving ahead more quickly than originally planned to the project's second phase, which will add an additional 12,400 customers. To understand the implications of system-wide blending in

[9] Enbridge 2021 Sustainability Report, p.26. https://www.enbridge.com/~/media/Enb/Documents/Reports/Sustainability%20Report%202021/Enbridge-SR-2021.pdf.
[10] The addition of 5,500 MW of natural gas-fired generation supported the province in completely eliminating coal-fired electricity generation, which is considered the single largest GHG emission reduction action in North America. https://www.ontario.ca/page/end-coal. GHG emissions from electricity generation were 32 MT lower in 2020 as compared to 2005, a 90% reduction. (Source: National Inventory Report 1990-2020: Greenhouse Gas Sources and Sinks in Canada, Part 3, Table A11-12).
[11] See EB-2020-0066 for the Voluntary RNG program. The Voluntary RNG program was launched in April 2021 and has reduced CO2e emissions by approximately 49 tonnes as of March 2022. Further details on this program are included in Section 6.5. Please see EB-2019-0294, Exhibit 2, Tab 2, Schedule 6 page 13 for the LCEP program. Phase 1 of the LCEP, which began blending hydrogen into the natural gas distribution system in October 2021, reduced CO2e emissions by approximately 57 tonnes between October 2021 and March 2022.

Ontario, Enbridge Gas also plans to undertake a full evaluation of its natural gas grid in Ontario. The Enbridge Gas hydrogen strategy is provided in further detail at Exhibit 4, Tab 2, Schedule 6.

3. How Customers Informed Enbridge Gas's Business Planning

34. Building on existing market research and previous consultations, Enbridge Gas conducted extensive customer engagement throughout 2021 and early 2022 in support of this Application. The objective was to integrate customer feedback into the business planning process, ensuring the Application adequately reflects and is responsive to customer needs and preferences. In total, more than 12,000 customers participated in the process through three distinct phases, which included various forms of engagement, such as focus groups, in-depth interviews, telephone surveys, and online workbooks.

35. This multi-phased approach followed the Enbridge Gas planning process. Business planners refined their plans as customer engagement results from each phase became available. As plans evolved, so too did the engagement, with each phase containing more detailed background information and more specific trade-offs for participants to consider, culminating in the third phase, which gauged customer support for specific investment choices. In this phase, customers were able to review and change their choices to view the cumulative impact on their distribution rates, based on preliminary estimates. The engagement phases were completed before final planning decisions were made.

36. As part of the engagement, all customers were asked to consider a list of outcomes. Across all customer groups, reliably and safely delivering natural gas emerged as two top priorities, followed closely by providing affordable pricing and minimizing any environmental impacts. Generally, customers said they preferred

Enbridge Gas focus on maintaining current levels of safety, reliability, and customer service, and that they wanted the Company to look at the long-term health of the system, spreading costs out evenly over time even if this approach would have an impact on rates.

37. At a high level, respondents had the opportunity to provide feedback on the Company's business plan objectives, climate change goals, and efforts to reduce GHG emissions from natural gas, all of which could introduce higher costs that would be passed on to customers. Across all customer segments, a clear majority of customers indicated they believe Enbridge Gas is taking the right approach.

38. At least two thirds of customers (general service and contract) supported the draft rate increase included in the workbook as a result of the draft plan. Generally, customers chose to spend more now to improve Enbridge Gas assets, such as replacing aging compressor stations and vintage steel pipelines, rather than delay, even though this would have an impact on their bills. Customers were also supportive of energy transition initiatives, agreeing the Company should actively invest in low-carbon solutions including energy efficiency technologies, hydrogen gas, RNG and carbon capture, utilization and sequestration (CCUS), as well as advancing research, development, and commercialization of low-carbon technologies.

39. Further detail on customer engagement is provided at Exhibit 1, Tab 6.

4. The Current Energy Transition Landscape

40. Over the past several decades, global governments have recognized that climate change is a shared problem that requires global action. Through the Kyoto Protocol and the Paris Agreement, countries have agreed to reduce GHG emissions

entering the atmosphere.

41. As provided at Exhibit 1, Tab 10, Schedule 3, the Government of Canada has committed to reducing GHG emissions by 40% below 2005 levels by 2030, and to net-zero emissions by 2050. Federal policies to achieve these targets have been developed and implemented, with the development of further policies underway.

42. The Government of Ontario has committed to reducing GHG emissions by 30% below 2005 levels by 2030 and provincial climate policy development and implementation is underway, with some policies already in place. A provincial panel has also been struck[12] to advise the Ministry of Energy on long-term energy planning in the context of this transition. The panel's goal is to keep energy rates low and provide market signals for the long-term development of Ontario's energy sector.[13]

43. To date, the provincial government has not set any GHG reduction targets beyond 2030, however, as Canada's second-largest emitting province, Ontario will need to achieve further GHG reductions if the federal government's ambitious net-zero target is to be achieved by 2050.[14]

44. Municipalities across Ontario are also increasingly taking action to address climate change within their boundaries. Primarily, this includes establishing plans to achieve municipally set targets and/or measures to mitigate climate change, while

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[12] Government of Ontario. (2022, March 24). Order in Council 698/2022 https://www.ontario.ca/orders-in-council/oc-6982022.
[13] This is consistent with the October 21, 2022 Letter of Direction from the Minister of Energy to the Chair of the OEB, https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf.
[14] Government of Canada. (2022, May 26). Greenhouse Gas Emissions https://www.canada.ca/en/environment-climate-change/services/environmental-indicators/greenhouse-gas-emissions.html.

continuing to meet local energy needs.

45. It is clear that climate and energy transition targets and plans in Canada have progressed significantly over the past several years at the federal, provincial, and municipal levels; however, there remains a considerable lack of specificity around how these targets will be met and funded, and the development of detailed policies is still in progress. Despite this longer-term uncertainty, the planning activities of the province's Independent Electricity System Operator (IESO) clearly demonstrate that the natural gas system will continue to be needed over the 2024 to 2028 timeframe. Further detail on the IESO planning and procurement outlooks is provided at Exhibit 1, Tab 10, Schedule 2.

4.1. Enbridge Gas's Energy Transition Plan

46. While planning for and implementing an energy transition, both government[15] and energy consumers (as discussed in the previous section on customer engagement) agree it is a key priority to ensure that future energy systems are reliable, resilient, and cost-effective.

47. As outlined in the Company's ETP, Enbridge Gas believes Ontario can achieve this balance through an orderly transition to a diversified low-carbon system in which the gas and electricity systems work together, while incorporating new energies and technologies over time. Hybrid heating systems in particular would allow customers to reduce emissions by pairing increasing amounts of non-emitting electricity with natural gas, while transitioning to lower carbon fuels over time. Much like Ontario's electricity system has transitioned away from coal, Enbridge Gas envisions the gas system evolving into one that delivers RNG and hydrogen, and any other low and

[15] October 21, 2022 Letter of Direction from the Minister of Energy to the Chair of the OEB, https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf.

zero-carbon gas solutions that may become available.

48. This diversified approach would allow Ontarians to continue deriving value from the resilient, reliable infrastructure they have been investing in for decades, as well as mitigating their overall energy costs as they lower their GHG emissions. As demonstrated in an independent study commissioned by Enbridge Gas, provided at Exhibit 1, Tab 10, Schedule 5, a diversified approach can achieve net zero at a much lower cost, saving as much as $50 billion over deep electrification. /u

49. The ETP has been informed by Enbridge Gas's understanding of current energy transition and climate policies, stakeholder input and a review of research and studies, both external and commissioned by the Company. Energy transition has been incorporated into Enbridge Gas's forecasting and planning processes by including energy transition assumptions in forecasting, in the efforts to include Integrated Resource Planning (IRP) in the AMP, and by accounting for energy transition in the Company's finance and regulatory approaches and stakeholder engagement.

50. While governments and stakeholders work to determine how best to achieve net-zero, there are actions that are a "safe bet" and should be taken now. These actions include: further reducing natural gas demand by maximizing energy efficiency through Enbridge Gas's DSM programs; leveraging the Company's distribution system to deliver low and zero-carbon energy such as RNG and hydrogen; displacing higher-carbon fuels used in the industrial sectors with natural gas and in the transportation sector with compressed natural gas (CNG) and compressed renewable natural gas (C-RNG); integrating gas and electric system planning; and developing new low and zero-carbon technologies.

51. Reflecting customers' support for specific energy transition initiatives that it received during the engagement process, Enbridge Gas is proposing investments in specific "safe bet" actions as provided at Exhibit 1, Tab 10, Schedule 6, Table 1.

52. Among the proposals is the creation of a $25 million Energy Transition Technology Fund (ETTF) to advance and accelerate the research, development, and commercialization of low-carbon technologies to help customers cost-effectively achieve their carbon reduction goals. More detail on the proposed fund is provided at Exhibit 1, Tab 10, Schedule 7.

53. Energy transition planning is not only reflected in the Company's "safe bet" actions, but also in the way Enbridge Gas is forecasting growth, managing risk and allocating capital.

54. By implementing the actions in this ETP, Enbridge Gas is taking steps to support an orderly energy transition to net-zero in Ontario. To further contribute to achieving the provincial and federal GHG reduction targets, Enbridge Gas intends to continue to evolve its ETP over time and may bring future updates to the OEB.

4.2. Energy Transition and Capital Structure

55. Uncertainty about the pace and direction of the energy transition is having a significant impact on Enbridge Gas's risk profile. As noted in a detailed risk analysis study performed by Concentric Energy Advisors (Concentric) that followed the OEB's preferred approach to assessing capital structure for the utilities, there have been significant changes in the market in which Enbridge Gas operates since the

OEB last approved equity thickness levels for EGD[16] and Union[17].

56. The study, provided at Exhibit 5, Tab 3, Schedule 1, Attachment 1, identifies energy transition as representing “a radical transformation[18]” in the long-term risk for Enbridge Gas. The study noted that not only are investors perceiving the transition as transforming the long-term risk environment for natural gas distributors such as the Company [19], but that their concerns are already affecting capital markets[20] and that further, Enbridge’s access to capital is becoming increasingly intertwined with its ability to meet its environmental, social and governance (ESG) goals.[21] The study also noted evolutions in other aspects of the Company’s profile over the past decade, including volumetric, financial and operational risk.

57. The study found that Enbridge Gas has the lowest deemed equity ratio of any investor-owned gas utility in North America despite falling towards the middle of the spectrum of risk profiles established by the proxy companies used.[22] “In addition, in recent years the OEB’s adjustment formula has provided returns on equity (ROE) that are among the lowest of any investor-owned electric or gas utility in Canada or the U.S. The combination of the lowest deemed equity ratio and the low authorized ROEs in recent years places Enbridge Gas at a competitive disadvantage in terms of attracting capital and compensating existing shareholders,” the study concludes.[23]

[16] EB-2011-0354.
[17] EB-2011-0210.
[18] Exhibit 5, Tab 3, Schedule 1, Attachment 1, p. 44.
[19] Ibid, p. 1.
[20] Ibid, p. 21-22.
[21] Ibid, p. 27.
[22] Ibid, p. 123.
[23] Exhibit 5, Tab 3, Schedule 1, Attachment 1, p. 121.

58. Based on the study's recommendations, Enbridge Gas is asking the OEB to approve an increase in its deemed equity ratio from 36% to 42% to maintain financial strength and continued access to capital at a reasonable cost, and to manage the energy transition under a variety of economic and capital market conditions, while providing safe and reliable service to customers.

59. To manage the revenue requirement impact, the Company is proposing a phased-in transition to the proposed higher equity level, where equity would be increased to 38% in 2024, and then a further 1% per year increase during the remainder of the price cap term, ultimately reaching 42% in 2028. The proposed 2024 change comprises $26.3 million of the forecast 2024 revenue deficiency of $294.1 million. /u
Please see Exhibit 5, Tab 3, Schedule 1 for details of this proposal. Overall rate mitigation is discussed further below and is provided at Exhibit 8, Tab 2, Schedule 6.

5. <u>Building on a Record of Sound Capital Management</u>

60. As provided at Exhibit 2, Tab 5, Enbridge Gas (and EGD and Union before it) has prudently prioritized capital spend over the 2013 to 2024 period to ensure a safe and reliable system that is meeting customer needs today and can evolve to meet their needs tomorrow as the energy transition continues to take shape.

61. While the level of capital expenditures varies year-over-year—largely due to sizeable replacement or reinforcement projects and the timing of the execution of these projects—the underlying base spend has been stable over both the 2014 to 2018 period for EGD and Union as well as over the deferred rebasing term for Enbridge Gas. Exhibit 2, Tab 5, Schedule 3 summarizes the historical spend for EGD and Union under their individual IRM terms and details the year-over-year variances for Enbridge Gas under the deferred rebasing term. As each project is

completed, it has been included in rate base for the purposes of earnings sharing, and becomes part of the safe, reliable system that currently serves millions of Enbridge Gas customers.

62. Enbridge Gas's commitment to supporting customers is reflected in its capital investment plan for 2024 to 2028. In 2024, the plan's main focus is on ensuring a safe, healthy, and robust system that can continue to deliver value to customers by meeting their energy needs today, and supporting them through an orderly energy transition, with Enbridge Gas continuing to consider non-pipe alternatives through IRP.[24]

63. The Company believes it is striking a fair and reasonable balance for customers by remaining focused on safety and reliability, while also incorporating energy transition considerations into its capital plan. This balance will ensure customers continue to have access to secure and cost-effective energy, while providing a resilient backbone from which to shape the system of the future.

64. The forecast capital expenditure for the 2024 Test Year is $1,491.3 million. This /u
investment represents the needs identified and prioritized in the AMP to ensure the safety and reliability of the Enbridge Gas system. This includes supporting the demand for customer and system growth, maintaining pipeline integrity of the distribution and transmission systems, ensuring compliance with regulations, investing in Enbridge Gas facilities and expenditures related to system changes as a result of implementing rebasing proposals, and technology investments to ensure continued reliability and security. To support an orderly energy transition, Enbridge

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[24] This is consistent with the October 21, 2022 Letter of Direction from the Minister of Energy to the Chair of the OEB, https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf.

Gas is also investing in low-carbon strategies to reduce greenhouse gas emissions and renewable energy opportunities to “green the grid”.

65. Enbridge Gas ensures its investments are efficient and effective through a capital budget process, which is itself underpinned by applying Enbridge Gas’s asset management decision-making strategies and framework to balance risk, cost, and performance throughout the life cycle of its assets. Please refer to the USP provided at Exhibit 2, Tab 6, Schedule 1 for further detail on the budget process, and the AMP provided at Exhibit 2, Tab 6, Schedule 2, which details a 10-year plan to manage the Company’s assets and identifies most of its capital requirements. There are other elements of the capital plan that are not part of the AMP, including community expansion projects and regulated RNG and CNG projects. Further detail on capital expenditures is provided at Exhibit 2, Tab 5.

66. Enbridge Gas has always had a strong focus on evaluating whether its existing distribution and transmission assets can meet the current and future needs of its customers, safely and reliably. In July 2021, the OEB issued the IRP Framework[25] which gives direction to Enbridge Gas on how to compare and consider alternatives in its long-term pipeline and facility planning systematically and consistently and allows it to be compensated appropriately for delivering these alternatives. The framework seeks to ensure that chosen alternatives are in the best interest of Enbridge Gas’s customers by considering reliability and safety, cost-effectiveness, public policy and risk management.

67. IRP represents a change to the facility planning that Enbridge Gas has performed in the past, and the Company is taking steps to integrate these new requirements

[25] EB-2020-0091.

into its approach, which aligns with the expectations expressed by most Enbridge Gas customers involved in the rebasing engagement process. They are looking to Enbridge Gas to help develop offerings and new solutions to help reduce natural gas usage.

68. For example, to address growing demand in a community, under the IRP Framework the Company explores alternatives such as delivering more energy without adding new pipeline through the use of liquefied or compressed natural gas or using energy efficiency programs to lower demand.

69. Enbridge Gas is incorporating IRP into its evaluation of a wide range of projects including system reinforcement; projects related to the maintenance and replacement or renewal of distribution and transmission assets; distribution station investments; integrity projects required to maintain storage assets and growth-related reinforcement projects. Further information on Enbridge Gas's IRP Framework is provided at Exhibit 2, Tab 6, Schedule 2, Appendix B – IRP.

70. Energy transition is evolving, which means investment decisions will be based on the best information available at the time. Enbridge Gas recognizes that Ontario's energy transition will lead to changes in customer behaviours and the use of natural gas over time, however the Company does not expect those impacts to be significant immediately and is projecting it will continue adding new natural gas customers in the near term. For example, Enbridge Gas is expecting it will add approximately 40,000 new customers in 2024, in line with growth in recent years. The long-range forecast that underpins Enbridge Gas's customer connection forecast does reflect a gradual decline in the number of new customers that are connected over the AMP's 10-year planning period, as a wider variety of energy solutions become available. As the impacts of the energy transition become clearer,

capital requirements for customer connections will be assessed and reflected in future year rate applications.

71. Enbridge Gas is also connecting communities that have not had access to natural gas in the past. Through phase 1 and phase 2 of the Natural Gas Expansion Program, the Company has helped residents in nine community expansion project areas switch from higher emitting fuels to natural gas since 2019. An additional 22 community expansion projects are slated to start construction by the end of 2025.

6. How Customers Benefit from Integration

72. After 15 years of operating under successive IR frameworks, there were reduced opportunities for EGD and Union to continue finding efficiencies to deliver incremental benefits to customers. The OEB's approval for the two utilities to integrate opened the door to a new opportunity: delivering quantitative and qualitative benefits by aligning systems and processes, rationalizing costs, and streamlining organizational structures, and passing along those benefits to current and future customers in Ontario at rebasing.

73. During the five-year deferred rebasing term, Enbridge Gas was committed to prioritizing integration investments to deliver the highest level of sustained benefit to customers, despite the challenges of operating in a global pandemic for much of that period. The Company has over-achieved on that commitment[26], delivering $86 million in sustained annual savings to be passed on to customers at rebasing. As provided at Exhibit 1, Tab 9, customers are better off today than they otherwise

[26] When comparing synergies achieved during the actual 5-year deferred rebasing term to the estimated first 5 years included in the 10-year submission in the MAADs Application. EB-2017-0306/EB-2017-0307, Exhibit 1, Tab 9, Schedule 1, p.1.

would have been had the utilities continued to operate as separate entities.

74. Customers are benefitting from more than cost savings. Today, they are being served by a more effective utility with aligned systems and programs that enable improvements for the same or lower cost. Together, the quantitative and qualitative benefits of integration further safe, reliable, and efficient business operations and strengthen Enbridge Gas's ability to respond to customer needs and market evolution.

75. Enbridge Gas set the foundation for successful integration by restructuring the organization layer by layer across all departments to reduce duplication and align and clarify accountabilities before introducing integrated technology system solutions and process initiatives. The reorganization was completed by the end of Q1 2019. In 2020, to respond to the global drop in energy demand early in the pandemic, Enbridge offered an enterprise-wide Voluntary Workforce Options (VWO) Program to incent employees to retire early, take leave or voluntarily exit. At Enbridge Gas, the program advanced reductions that were expected over the integration period leading up to rebasing.

76. Among the technology system solutions and process initiatives that are delivering customer benefit, as well as supporting safe, reliable, and effective operations:
   a) A consolidated Customer Information System (CIS) that aligns billing processes and delivers enhancements on a unified platform. This involved migrating 1.6 million customers who were previously on Union's CIS. The project also consolidated customers into one MyAccount system, one interactive voice response (IVR) system, and a consolidated website. Beyond realizing savings, the project provides consistent processes and procedures for employees and customers, an enhanced user experience

through efficient access to information, and a single integrated system to connect stakeholders across the organization.

b) Consistent and efficient distribution work management practices across the utility, including the planning, scheduling, compliance, work management systems (WMS), WMS support, asset management, and support for overall work to maintain Enbridge Gas's assets. The work management initiative consolidated work management centres across EGD and Union service territories from twelve centres to three. To enable this, Enbridge Gas undertook a multi-year, phased project to bring the asset and work management system (AWS) onto a common platform, creating a common system and processes for planning work, and harmonized policies, processes, and procedures for distribution maintenance operations. At the same time, more than 1,000 Distribution Operations field technicians and supporting staff moved to a single technology solution for field work.

c) Centralized Gas Control and Nominations teams, along with the Supervisory Control and Data Acquisition (SCADA) system. EGD's control centre operations were moved from Edmonton to a consolidated control centre in Chatham and the EGD assets into the SCADA system.

d) Consolidated separate meter shops and harmonizing accreditation audits, streamlining the way Enbridge Gas's metering asset life cycles are managed. As well, harmonizing storage and transmission operations at Dawn and Tecumseh created the opportunity to repurpose roles, allowing some activities previously conducted by external service providers to be insourced.

e) Eliminated duplicated shared services and systems to streamline and simplify the technology portfolio.

f) Consolidated office spaces reduce the need for leased locations. Following a review of regional operating boundaries for field operations, decisions were made for a new Greater Toronto Area (GTA) East location to service the combined Peterborough and Cobourg areas and a new GTA West location consolidating Burlington, Milton, and Brampton service areas.

7. How Customers Benefit from Productivity Gains

77. In addition to synergies, other initiatives that did not require integration resulted in productivity savings over the deferred rebasing term.

78. Enbridge Gas delivered sustainable productivity savings across all operating areas during the deferred rebasing term, the most significant of which occurred through higher e-bill adoption. Through active conversion strategies and an improved sign-up process through the web interface, 62% of Enbridge Gas customers are on e-bill. This is recognized to be a best-in-class benchmark, suggesting there will be limited take-up beyond the current adoption rate. Other initiatives include IVR automation which allows customers to self-serve, reducing call volumes. Combining emergency call handling with the dispatch function enabled contractor savings. Prioritizing land management of contaminated sites according to risk effectively reduced the scope of work. Other savings were achieved in areas where services were scaled back or no longer needed, processes and procedures were streamlined, and where modes of operational interaction were modified. For example, pandemic-related travel restrictions led Enbridge Gas teams to rely more on virtual interactions in 2020 and 2021, and even with the lifting of restrictions, travel budgets have been reduced.

79. Together, integration synergies and productivity initiatives will have delivered sustained annual savings of $121.2 million in the 2024 Test Year.

80. Productivity savings have been embedded prospectively in the form of labour and non-labour efficiencies. In 2023 and 2024, salaries and wages, as well as contract services costs, have been reduced to reflect committed savings the Company will strive to manage through vacancies, reallocation of work, automation, and other means. Further detail on productivity savings is provided at Exhibit 4, Tab 4, Schedule 2.

8. Operating and Managing Costs in a More Complex Environment

81. The cost performance of Enbridge Gas—and EGD and Union before it—has been below inflationary trends, balancing rising costs with efficiencies while supporting customer growth and maintaining the commitment to safety, reliability, and customer service over the past decade. Further detail of historical O&M increases is provided at Exhibit 4, Tab 4, Schedule 1.

82. The COVID-19 pandemic has had a substantial impact on the Company’s operations and costs since 2020. Early in the pandemic, public health restrictions limited site and asset access resulting in a significant curtailment of field work. In addition, travel was limited due to reduced work volumes and labour shortages were driven by worker and contractor illness. Also in 2020, Enbridge’s VWO Program, as provided at Exhibit 1, Tab 9, Schedule 1, further reduced compensation costs, effectively delivering sustainable integration savings earlier than planned.

83. The pandemic also affected Enbridge Gas’s ability to meet certain service quality requirements (SQRs) stipulated by the OEB due to public health restrictions limiting site access and staffing challenges due to higher levels of illness. While the Company continues to consistently exceed a number of standards, beginning in 2020, performance measures have not achieved the threshold targets for call

answering performance, call abandon rate and meter reading.

84. In 2021, as provincial restrictions lifted, field work began to gradually increase while the Company continued to face staffing challenges due to attrition, turnover and illness. At the same time, the Company's operations and costs were impacted by rising inflation and materials shortages. Performance against certain SQRs continued to be impacted by the same challenges. Call answering and call abandon rates were also affected by the CIS consolidation project, which migrated 1.6 million customers to the new system at the same time that the IVR automated system was put in place. While IVR and digital adoption has enabled customers to self-serve issues that are relatively easy to resolve, more complex issues continue to be handled through calls. This has increased the time needed to resolve issues and has affected call answering performance. Meter readings also continued to be affected by staffing challenges and access issues. Further details of Enbridge Gas's performance measurement through its OEB scorecard, an exemption request and proposed mitigation plans are provided at Exhibit 1, Tab 7, Schedule 1 and Attachments.

85. The lifting of pandemic restrictions has led to increased activity as the Company returns to normal operations. Increasing costs in 2022 are driven not only by a return to pre-COVID-19 work volumes, but also by higher inflation, managing deferred work, increasing compliance requirements and the Company's continued efforts to enhance safety and reliability. Even with elevated levels of inflation, Enbridge Gas's increase in O&M costs in 2022 are estimated to be lower than expected inflation, measured by GDP IPI, as a result of the savings from integration initiatives and productivity gains.

86. In 2023 and 2024, safety, reliability, compliance and technology costs are expected to continue to increase. Integrity program inspections have resulted in increased costs due to enhanced risk modelling driving improved safety and reliability. Compliance with Bill 93 (Getting Ontario Connected Act) has resulted in higher locates costs due to the timing required for completion of locates. Technology costs have also increased as a result of the technology industry shift to 'as a service' models and cyber security to meet regulatory requirements and protect information and operational technology including customer data. 2024 O&M will be further impacted by the inclusion of costs previously recovered separately through deferral accounts, while still remaining in line with inflation.

87. Apart from growth initiatives which, although part of the Company's mandate, are subject to the Company's planning and discretion, all other expected cost pressures are non-discretionary. Legislative changes, cyber security requirements, safety and reliability performance thresholds are all necessary obligations that cannot be deferred.

88. As noted above, Enbridge Gas is mitigating the cost pressures of this complex operating environment and escalating inflation with the substantial cost savings delivered through integration and productivity improvements. Effective cost management has led to the Company's O&M costs growing at a rate lower than inflation since the last time EGD or Union rebased.

9. Harmonizing Internal Practices, Process and Procedures

89. Enbridge Gas is proposing a number of harmonization efforts within this rebasing application to further support the operations and services of a single utility. Some proposals are also intended to fulfil OEB directives and filing requirements.

Noteworthy examples include depreciation, deferral and variance accounts and gas cost recovery.

9.1. Depreciation

90. Following integration, Enbridge Gas undertook a depreciation study conducted by Concentric, provided at Exhibit 4, Tab 5, Schedule 1, Attachment 1. As a result of the study, Enbridge Gas is proposing to align its EGD and Union rate zone asset groups and plant accounts, depreciation methodologies and net salvage approaches for site restoration costs in 2024. This alignment will allow the Company to introduce and uniformly apply common depreciation practices. These practices will: enhance generational equity for rate payers; better match the depreciation expense to life cycle of the assets providing service to customers; and more accurately reflect the actual useful life of the assets used.

91. The proposed alignment would increase depreciation expense, comprising $160.4 million of the forecast 2024 revenue deficiency of $294.1 million. More detail on the proposed changes is provided at Exhibit 4, Tab 5, Schedule 1. /u

92. In reviewing the treatment of depreciation, the potential impact that energy transition could have on the economic life of Enbridge Gas's system was examined. An 'Economic Planning Horizon' (EPH) that would shorten the expected service life of assets was considered.

93. While there remains much uncertainty around the pace and direction of energy transition, the Company believes its safe, reliable and cost-effective system is critical to Ontario's ability to achieve net-zero, as provided at Exhibit 1, Tab 10, Schedule 1. Enbridge Gas does not currently expect that large sections of its system will be retired in the foreseeable future. As such, the Company has

concluded that introducing an EPH is not appropriate at this time. While Enbridge Gas has been collecting amounts for future abandonment within the net salvage component of depreciation rates for some time, the Company has concluded establishing a segregated fund is not in the best interest of customers at this time, as it would unnecessarily increase rates.

9.2. *Deferral and Variance Accounts*

94. As stand-alone deferral and variance accounts are no longer required for the EGD and Union rate zones, Enbridge Gas is requesting OEB approval for the harmonization of and other proposed changes to deferral and variance accounts (D&VAs). Further detail is provided at Exhibit 9, Tab 1, Schedule 2, and a summary list of the D&VA harmonization and other proposed changes is provided at Exhibit 9, Tab 1, Schedule 1, Attachment 2, and proposed accounting orders are provided at Exhibit 9, Tab 1, Schedule 1, Attachment 3.

9.3. *Gas Cost Recovery Harmonization*

95. Enbridge Gas is proposing a common reference price based on the forecast weighted average price for natural gas supply. Implementation is proposed for January 1, 2024, to align rates with the common reference price, gas supply plan and harmonized gas cost deferral and variance accounts. Further detail is provided at Exhibit 4, Tab 2, Schedule 2.

10. Continuing to Harmonize the Customer Experience

96. In its 2018 MAADs Decision[27], the OEB directed Enbridge Gas to file a proposal to harmonize rates for the EGD and Union rate zones. To support this directive, the Company began examining how to harmonize the services that underpin rate

[27] EB-2017-0306/EB-2017-0207, OEB Decision and Order, August 30, 2018.

design.

97. Enbridge Gas is proposing to harmonize the services currently offered in the EGD and Union rate zones to provide a common suite of services for customers. Simplifying services will make it easier for customers to do business with Enbridge Gas, as the Company will be able to align and update multiple business applications, and harmonize business processes, delivering efficiencies over time by eliminating duplication.

98. In keeping with Enbridge Gas's customer-centric focus, the needs and preferences of customers informed the design of the proposed harmonized services. A subset of customers was identified and engaged early in the harmonization process, and they were asked to provide input on the existing service parameters and overall service designs and to share any thoughts for improvements.

99. Customers indicated that they were satisfied with the services they receive today and, as a result, Enbridge Gas incorporated elements from the existing services into the proposed harmonized services when possible.

100. The proposed harmonized services for contract customers are planned to be effective April 1, 2026, unless otherwise noted in evidence. This will provide the time needed to implement changes to internal and customer-facing business applications, processes, and to notify customers of changes to their services. Some service proposals, such as the elimination of unused services, can be implemented on January 1, 2024, as these proposals do not require system changes.

101. Further detail of the service harmonization plan is provided at Exhibit 8, Tab 4.

102. Building on its proposed service harmonization, Enbridge Gas is proposing to harmonize its three rate zones (EGD, Union North and Union South) into one rate zone and establish new harmonized rate classes. Harmonizing rate zones and rate classes will allow Enbridge Gas to align, simplify and enhance rates and services to meet customer needs. It will give the Company the ability to treat customers across the province of Ontario similarly, applying the same rates for the same service to customers in the same rate class, regardless of where they are located. Customer communication will no longer need to be tailored for different rate zones, and the Company's regulatory applications and reporting to the OEB could be simplified when only providing information regarding one rate zone. During the engagement process for this Application, customers themselves also showed support in moving to a single rate zone as a matter of fairness.

103. Enbridge Gas is proposing to phase in implementation of harmonized services and rates between 2024 and 2026 to allow time to implement system changes, inform customers and mitigate bill impacts. Harmonized general service rate classes are forecast to be implemented April 1, 2025 and harmonized contract rate classes are forecast to be implemented April 1, 2026. Further detail of the rate harmonization plan is provided at Exhibit 8, Tab 2, Schedule 1, including the implementation plan.

11. How Enbridge Gas Proposes Rates Be Set for 2025 to 2028

104. As provided at Exhibit 10, Tab 1, Schedule 1, Enbridge Gas is requesting a multi-year incentive rate-setting mechanism (IRM) be used to set regulated distribution, transportation, and storage rates for the period January 1, 2025, to December 31, 2028 (IR term), and that rates during that term be set based on a price cap incentive rate-setting (Price Cap IR) mechanism and associated parameters. The first year of the IR term will apply the Price Cap IR parameters to rates set through cost of service for 2024. This is similar to the mechanism that has been in place

over Enbridge Gas's deferred rebasing term from 2019 to 2023.

105. A Price Cap IR is the approach the OEB notes in its Renewed Regulatory Framework as being appropriate for most distributors[28]. It is also in line with customer expectations, as reflected in Enbridge Gas's customer engagement study conducted for this rebasing proposal and referenced earlier in this study.

106. Enbridge Gas's IRM proposals, summarized below and provided in more detail at Exhibit 10, Tab 1, Schedule 1, are supported by research conducted by a consultant retained to make recommendations on reasonable productivity and stretch factors, as well as an inflation factor. The resulting study from Black & Veatch Management Consulting (Black & Veatch) is provided at Exhibit 10, Tab 1, Schedule 1, Attachment 1.

107. Enbridge Gas is proposing to move to a two-factor inflation factor[29], consistent with the OEB's 4th Generation IRM Report of the Board, calculated as the weighted sum of 75% for the non-labour component and 25% for the labour component, based on average hourly earnings. These weights broadly reflect the share of non-labor and labor costs for Enbridge Gas and other gas distributors and are also similar to recent inflation factor precedents in Ontario.

108. Based on the recommendations from Black & Veatch, Enbridge Gas proposes a productivity factor of -1.35% and a stretch factor of zero. This reflects what the study has identified as a long-term productivity trend throughout the gas distribution

[28] Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, p.14.
[29] Ibid, pp.15-16.

industry of slowing output growth and increasing input growth.

109. The study has demonstrated that a productivity factor of -1.35% is generally consistent with the productivity offsets that have been approved for U.S. gas distributors in recent regulatory proceedings. Please see Section 6.2 of the Black & Veatch study provided at Exhibit 10, Tab 1, Schedule 1, Attachment 1 for more detail.

110. Supporting the proposed zero stretch factor are cost benchmarking results from the Black & Veatch study, which demonstrate that Enbridge Gas is a good cost performer and therefore, has less potential to achieve incremental productivity gains than the rest of the industry. Over the last few IR terms, EGD and Union (prior to 2019) and Enbridge Gas (since integration) have been able to realize considerable sustainable efficiencies and synergies through aggressive integration efforts. Those benefits are being passed on to customers at rebasing in 2024 and are expected to be sustained in the next IR period. Please see Exhibit 1, Tab 9, Schedule 1 for total synergies achieved and Exhibit 4, Tab 4, Schedule 2 for details on productivity savings.

111. In conclusion, as illustrated throughout this Application, Enbridge Gas's proposals are reasonable and necessary to support the safe, reliable, resilient, secure and affordable energy system customers have told the Company they expect.

ADMINISTRATION

1. Primary Contact Info

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3. Website and Social Media

Link to the location on the Enbridge Gas Inc. website where the application and related documents will be accessible:

https://www.enbridgegas.com/about-enbridge-gas/regulatory

Social Media accounts used by Enbridge Gas Inc. to communicate with its customers:

https://twitter.com/enbridgegas

https://www.facebook.com/enbridgegas

https://www.youtube.com/user/EnbridgeGas

https://www.linkedin.com/company/enbridgegas/

4. Customer Email Addresses

Table 1
Customer Email Addresses Retained by Enbridge Gas by Customer Class

Line No.	Particulars	Number of Customer Email Addresses	% of Total
		(a)	(b)
	General Service		
	EGD Rate Zone		
1	Rate 1	1,587,735	74%
2	Rate 6	137,586	78%
	Union North Rate Zone		
3	Rate 1	238,347	66%
4	Rate 10	1749	79%
	Union South Rate Zone		
5	Rate M1	783,688	66%
6	Rate M2	6,427	81%
7	Total General Service	2,755,532	71%
	Distribution Contract		
	EGD Rate Zone		
8	Rate 125	4	100%
9	Rate 200	1	100%
10	Rate 300	1	100%
11	Rate 315	1	100%
12	Rate 100	16	100%
13	Rate 110	424	100%
14	Rate 110/ Rate 145	6	100%
15	Rate 110/ Rate 170	1	100%
16	Rate 115	7	100%
17	Rate 115/ Rate 145	5	100%
18	Rate 115/ Rate 170	9	100%
19	Rate 135	42	100%
20	Rate 145	5	100%
21	Rate 170	11	100%

Table 1 (Continued)

Customer Email Addresses Retained by Enbridge Gas by Customer Class

Line No.	Particulars	Number of Customer Email Addresses	% of Total
		(a)	(b)
	Distribution Contract (Continued)		
	Union North Rate Zone		
22	R100	1	100%
23	R100/R25	12	100%
24	R20	6	100%
25	R20/R25	53	100%
26	R25	2	100%
	Union South Rate Zone		
27	Rate M10	3	100%
28	Rate M4	226	100%
29	Rate M5A	38	100%
30	Rate M7	63	100%
31	Rate M9	4	100%
32	Rate T1	40	100%
33	Rate T2	25	100%
34	Rate T3	1	100%
35	Total Distribution Contract	1007	100%
	Storage and Transportation Contract		
36	Rate M12/M12-X	199	100%
37	Rate C1	19	100%
38	Rate M16	2	100%
39	Rate M13	5	100%
40	Rate M17	1	100%
41	Rate 331	1	100%
42	Rate 332	1	100%
43	Total Storage and Transportation Contract	228	100%
44	Total	2,756,767	71%

5. On-Bill or Bill Insert Information Date Requirement

Enbridge Gas requires 60 days lead time for bill inserts and 45 days for bill message information to be included in the bill cycle.

6. Community Meeting Locations

Community meetings will not be held for this Application.

7. Notice of Hearing Publication

Enbridge Gas serves much of Ontario as such, the notice of this Application should be published in publications that provide wide circulation in Ontario. Suggestions include The Toronto Star, Sudbury Star, Thunder Bay Chronicle-Journal, Ottawa Citizen, Hamilton Spectator and Windsor Star.

8. Bill Impacts

Enbridge Gas is proposing the following total bill impacts for a typical residential and small commercial sales service customer in each rate zone. Total 2024 bill impacts are relative to Enbridge Gas's proposed 2023 Rates (EB-2022-0133) at April 2022 QRAM gas costs. Total 2024 bill impacts are inclusive of the proposed deferral and variance account disposition in 2024 and the proposed Energy Transition Technology Fund rider.

Table 2
2024 Typical Bill Impacts

Rate Class	Annual Consumption (m^3)	2024 Total Bill Impact ($; %)	Rate Class/Design Harmonization Total Bill Impact (%)	
EGD Rate Zone				
Rate 1	2,400	$36; 3%	0%	/u
Rate 6	22,606	$91; 1%	1%	/u
Union North Rate Zone				
Rate 01 North West	2,200	($64); (5%)	0%	/u
Rate 01 North East	2,200	($193); (13%)	0%	/u
Rate 10 North West	93,000	($1,212); (3%)	0%	/u
Rate 10 North East	93,000	($5,937); (13%)	0%	/u
Union South Rate Zone				
Rate M1	2,200	$98; 9%	0%	/u
Rate M2	73,000	$1,293; 5%	1%	/u

9. Proposals

This Application contains many proposals that constitute a change to the status quo to harmonize the policies, methodologies and services of the EGD and Union rate zones. Please see below for a list of those methodologies and approvals requested.

10. Hearing Preference

This is the first Cost of Service and Incentive Rate (IR) mechanism Application Enbridge Gas has filed as an amalgamated utility. At the time of filing Enbridge Gas prefers an oral hearing for this Application. The view of Enbridge Gas regarding an oral or written hearing will depend on the outcome of any settlement.

11. Price Cap IR

Enbridge Gas is proposing rates during the IR term be set based on a Price Cap Incentive Rate-setting (Price Cap IR) mechanism and associated parameters. Under the proposed Price Cap IR, rates will be set through this Application for the first year

(2024 Test Year) and then adjusted in years two to five (2025 to 2028) using an Annual Rate Adjustment Formula calculated as (I - X) ± Y ± Z + ICM, where:

a) I = inflation factor
b) X = productivity factor of -1.35% and stretch factor of zero
c) Y = costs that are incremental to the costs subject to Price Cap escalation (i.e. pass-through items or costs approved in other proceedings and implemented as part of the annual rate application)
d) Z = change in costs associated with unforeseen events outside of management control
e) ICM = Incremental Capital Module

In addition to the formulaic changes to rates, Enbridge Gas is proposing rate adjustments for a phased-in equity thickness increase and rate adjustments for rate mitigation. This IRM proposal also includes an Off-Ramp and an Earning Sharing Mechanism.

More detail on the proposed Price Cap IR is provided at Exhibit 10, Tab 1, Schedule 1.

12. Requested Effective Date

Enbridge Gas is requesting the 2024 rates resulting from this Application be effective January 1, 2024. There are specific proposals that have different effective dates. Those are stated within the Application.

13. Deviations

Enbridge Gas has complied with the OEB's policies and guidelines set out in the Handbook[1] and Filing Requirements[2]. Where modifications were necessary, they are noted in the checklists provided at Exhibit 1, Tab 1, Schedule 4.

14. Changes to Methodologies

This Application is the first Cost of Service application filed as an amalgamated entity, as such it includes many changes to methodologies to harmonize the two pre-amalgamated utilities. These are outlined in detail in evidence and include:

a) harmonized unregulated storage cost allocation methodology
b) harmonized indirect overhead capitalization methodology
c) harmonized heating degree days methodology
d) harmonized average use forecast methodology
e) harmonized heat value calculation methodology
f) harmonized customer additions and the average number of general service customers forecast methodology
g) harmonized distribution contract market forecasting methodology
h) harmonized normalization methodology for general service volumes
i) harmonized design criteria methodology and process for determining design demands
j) harmonized reference price methodology to set gas costs
k) harmonized methodology for forecasting unaccounted for gas
l) harmonized and specific cost allocation methodologies
m) harmonized and specific rate design methodologies

[1] Handbook for Utility Rate Applications, October 13, 2016.
[2] Filing Requirements For Natural Gas Rate Applications, February 16, 2017.

15. Directive Response Summary

A directive response summary is provided at Exhibit 1, Tab 13, Schedule 1.

16. Conditions of Service and Customer-related policies and regulations

Enbridge Gas's Conditions of Service and a description of the changes that have been made are provided at Exhibit 8, Tab 5, Schedule 1. Some customer-related policies have been included at Exhibit 1, Tab 15, Schedule 1. The rest can be found at enbridgegas.com.

17. Rate Confirmation

Enbridge Gas has ensured that all rates or charges listed in its Conditions of Service or other policies and regulations are included in the Rate Handbooks provided at Exhibit 8, Tab 2, Schedule 7.

18. Utility and Corporate Structure

18.1.Corporate Organizational Structure

Enbridge Gas Inc. (Enbridge Gas) is the result of an amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union) on January 1, 2019, pursuant to the provisions of the *Business Corporations Act* (Ontario) (the OBCA). Enbridge Energy Distribution Inc. (EEDI) and Great Lakes Basin Energy L.P. (GLBE), both indirect wholly owned subsidiaries of Enbridge Inc. (Enbridge), own all the issued and outstanding common shares of Enbridge Gas, which continues to have all of the assets, rights, contracts, liabilities and obligations of each of EGD and Union, including licenses and permits. Enbridge Gas's registered office is located at 500 Consumers Road, North York, Ontario, M2J 1P8.

EGD was incorporated in 1848 by *Special Act, II Victoria Cap. XIV*, of the Province of Canada. By letters patent dated September 30, 1954, EGD was continued under the *Corporations Act, 1953* (Ontario). EGD changed its name from The Consumers' Gas Company Ltd. to Enbridge Gas Distribution Inc. on July 25, 2002.

Union was incorporated under the laws of the Province of Ontario by letters patent dated December 19, 1911. Pursuant to a certificate of amalgamation dated January 1, 1998, Union amalgamated with Centra Gas Ontario Inc.

The Company did not have any other subsidiaries whose assets or revenues individually exceed 10%, or in the aggregate exceed 20%, of the total consolidated assets or total consolidated revenues of Enbridge Gas as at December 31, 2021. Enbridge Gas's corporate entities relationship chart is provided at Attachment 1.

18.2. Utility Organizational Structure

Enbridge Gas's utility organizational structure is provided at Attachment 2.

18.3. Board of Directors

Enbridge Gas's board of directors is provided at Attachment 3.

18.4. Planned changes

There are no planned changes in the corporate or utility structure or in the legal organization and control.

19. Requested Approvals and Accounting Orders

19.1 Requested Approvals

Exhibit 1 – Administrative Documents

Approval of Enbridge Gas's proposals in the Administrative binder including approvals of:

- Partial exemption request for certain performance metrics
- Energy Transition Technology Fund (ETTF)
- Harmonized customer connection policies
- Harmonized unregulated storage allocation methodology
- Regulatory treatment of the Natural Gas Vehicle (NGV) Program
- Regulatory treatment of the Distributor Consolidated Billing (DCB) Program
- Extension of existing financial terms of the Opening Billing Access (OBA) Program for 10 months until October 31, 2024

Exhibit 2 – Rate Base

Approval of Enbridge Gas's 2024 Test Year Rate Base including approvals of:

- 2024 Test Year net property, plant and equipment
- 2024 Test Year allowance for working capital
- 2021 Lead-Lag Study
- Harmonized capitalization policy
- Harmonized indirect overhead capitalization methodology
- 2024 Test Year capitalized overhead amounts
- 2024 Test Year capital expenditures

Exhibit 3 – Operating Revenue

Approval of Enbridge Gas's 2024 Test Year Operating Revenue including approvals of:

- 2024 Test Year general service market revenue forecast
- 2024 Test Year general service market volume forecast
- 2024 Test Year distribution contract market revenue forecast
- 2024 Test Year distribution contract market customer and volume forecast
- 2024 Test Year storage and transportation revenue / upstream transportation optimization forecast
- 2024 Test Year other revenue forecast
- Harmonized heating degree days forecasting methodology
- 2024 Test Year heating degree days forecast
- Harmonized average use forecast methodology
- Harmonized weather normalization methodology
- 2024 Test Year customer additions and the average number of general service customers forecast
- General Service customer additions forecasting methodology
- Harmonized heat value calculation methodology

Exhibit 4 – Operating Expenses

Approval of Enbridge Gas's 2024 Test Year Operating Expenses including approvals of:

- 2024 Test Year gas cost forecast
- Procurement of additional 10 PJ of market-based storage not included in 2024 Test Year gas cost forecast
- A common reference price methodology to set gas costs
- Harmonized design criteria and process for determining its design demands

  - Using the coldest observed heating degree day on record
  - Harmonized process for determining design demands
- Operational contingency space
- Low Carbon Energy
  - Implementation of a proposed new Low Carbon Voluntary Program in 2025, at which time the existing pilot VRNG program would be discontinued
  - Procuring low-carbon energy as part of Enbridge Gas's gas supply commodity portfolio and recovering the associated incremental costs through the proposed cost recovery mechanism
- Harmonized methodology for forecasting unaccounted for gas
- 2024 Test Year unaccounted for gas forecast
- 2024 Test Year O&M forecast
- 2024 depreciation rates and expense
- 2024 Test Year income tax forecast
- 2024 Test Year property tax forecast
- Updated Parkway Delivery Obligation (PDO) framework
- 2024 Test Year Parkway Delivery Commitment Incentive (PDCI) forecast

Exhibit 5 – Cost of Capital and Capital Structure

Approval of Enbridge Gas's 2024 Test Year Cost of Capital and Capital Structure including approvals of:

- 2024 forecast financing plan and the associated cost of capital
- A change to the deemed equity thickness component of Enbridge Gas's capital structure
- Approach to phase in the proposed change to equity thickness

Exhibit 6 – Revenue Deficiency/Sufficiency

No approvals requested.

Exhibit 7 – Cost Allocation

Approval of Enbridge Gas's 2024 Test Year Cost Allocation Study including approvals of:

- Harmonized cost allocation study to support the current rate classes
- Harmonized cost allocation study to support the harmonized service and rate class proposals for implementation post 2024

Exhibit 8 – Rate Design

Approval of Enbridge Gas's 2024 rate design including approvals of:

- Recovery of the 2024 revenue requirement from proposed rates
- Rate harmonization plan, including rate zone harmonization and implementation plan
- Rate design for the gas supply commodity charge and gas supply transportation charges
- Rate design for general service rate classes
- Rate design for the in-franchise contract rate classes
- Rate design for the ex-franchise rate classes
- Rate mitigation plan
- Combined rate handbook for the 2024 Test Year
- Changes to miscellaneous and direct purchase service charges

Approval of Enbridge Gas's post 2024 harmonized rate design including approvals of:

- Recovery of the 2024 revenue requirement from proposed harmonized rates

- Rate harmonization plan, including rate class harmonization and implementation plan
- Rate design for harmonized general service rate classes
- Rate design for the harmonized in-franchise contract rate classes
- Rate design for the harmonized ex-franchise rate classes
- Rate handbook for the harmonized rate classes

Approval of Enbridge Gas's harmonized services and related charges including approvals of the:

- Distribution services
- Bundled direct purchase service
- Semi-unbundled direct purchase service
- Unbundled direct purchase service
- Ex-franchise services
- Ex-franchise contract general terms and conditions

Exhibit 9 – Deferral and Variance Accounts

Approval of Enbridge Gas's deferral and variance accounts harmonization and other changes, including approvals of the following deferral and variance accounts:

- Purchase Gas Variance Account
- Third-Party Transportation Variance Account
- Load Balancing Variance Account
- Inventory Revaluation Variance Account
- Upstream Transportation Optimization Variance Account
- Transportation from Dawn Service Deferral Account
- Unaccounted for Gas Variance Account

- Market-Based Storage Variance Account
- Gas Distribution Access Rule Deferral Account
- Deferral Clearing Variance Account
- Parkway Delivery Obligation Variance Account
- Unauthorized Overrun Non-Compliance Deferral Account
- Pension and Other Post Employment Benefits Variance Account
- Incremental Capital Module Deferral Account
- Facility Carbon Charge Variance Account
- Customer Carbon Charge Variance Account
- Greenhouse Gas Emissions Administration Variance Account
- Volume Variance Account
- Earnings Sharing Mechanism Deferral Account
- Tax Variance Account

Approval of Enbridge Gas's establishment of new deferral and variance accounts including approvals of the following deferral and variance accounts:

- Energy Transition Technology Fund Variance Account
- Rate Harmonization Variance Account
- Dawn Parkway Surplus Capacity Deferral Account
- Locate Delivery Services Variance Account
- Open Bill Access Extension Deferral Account
- Enhanced Distribution Integrity Management Deferral Account /u
- Post-Retirement True-Up Variance Account /u

Approval of the closure of certain deferral and variance accounts:

- Transition Impact of Accounting Changes Deferral Account
- Ex-Franchise Third Party Billing Services Deferral Account

- Renewable Natural Gas Injection Service Deferral Account
- Dawn Access Cost Deferral Account
- Open Bill Revenue Variance Account
- OEB Cost Assessment Variance Accounts (EGD rate zone and Union rate zones)
- Short-term Storage and Other Balancing Deferral Account
- Unbundled Services Unauthorized Storage Overrun Deferral Account
- Capital Pass-through Deferral Accounts
    - Parkway West Project Costs
    - Brantford-Kirkwall Parkway D Project Costs
    - Lobo C Compressor/Hamilton-Milton Pipeline Project Costs
    - Dawn H/Lobo D/Bright C Compressor Project Costs
    - Burlington-Oakville Project Costs
    - Panhandle Reinforcement Project Costs
    - Sudbury Replacement Project
- Accounting Policy Change Deferral Account
- Impacts Arising from the COVID-19 Emergency Deferral Account

Approval to dispose of the forecast balance, including the allocation and disposition methodology, of the following deferral and variance account balances:

- Accounting Policy Changes Deferral Account
- Tax Variance Deferral Account
- Incremental Capital Module Deferral Accounts
- Impacts Arising from the COVID-19 Emergency Deferral Account
- Transition Impact of Accounting Changes Deferral Account
- Transitional Pension Balance

Exhibit 10 – Incentive Rate-setting Proposal

Approval of Enbridge Gas's Incentive Rate Mechanism including approvals of:

- A multi-year price cap incentive rate-setting mechanism

19.2 Accounting Orders

Enbridge Gas's proposed Accounting Orders are provided at Exhibit 9, Tab 1, Schedule 1, Attachment 3.

20. Draft Issues List

1. 2024 Approvals (Phase 1)

A. Overall

1) Is the overall 2024 revenue requirement reasonable?

2) How should the OEB take Energy Transition factors into account for the determination of Enbridge Gas's new rates that will be effective January 1, 2024, considering the current policies of the Government of Ontario?

3) Are the economic and business planning assumptions used by Enbridge Gas for the 2024 Test Year appropriate?

4) Has Enbridge Gas responded appropriately to all relevant OEB directions from previous proceedings?

B. Rate Base (Exhibit 2)

5) Is Enbridge Gas's 2024 Utility Rate Base appropriate, including:
   a) The forecast level of 2024 net property, plant and equipment.
   b) 2024 allowance for working capital.

6) Is Enbridge Gas's forecast of 2024 Test Year capital expenditures, supported by the Asset Management Plan, appropriate?

7) Is Enbridge Gas's proposed harmonized indirect overhead capitalization methodology appropriate?
   a) Are the 2024 Test Year capitalized overhead amounts appropriate?

C. Load Forecast and Revenue Forecast (Exhibit 3)

8) Is Enbridge Gas's 2024 Test Year Operating Revenue forecast appropriate, including:
   a) 2024 Test Year general service market revenue forecast.
   b) 2024 Test Year general service market volume forecast.
   c) 2024 Test Year contract market revenue forecast.
   d) 2024 Test Year contract market customer and volume forecast.
   e) 2024 Test Year storage and transportation revenue upstream transportation optimization forecast.
   f) 2024 Test Year other revenue forecast.

9) Are Enbridge Gas's proposals for harmonized load forecasting methodologies and the 2024 Test Year results from those harmonized methodologies appropriate, including:
   a) Heating degree days methodology and 2024 Test Year heating degree days forecast.
   b) Harmonized average use forecast methodology and 2024 Test Year Forecast.
   c) Harmonized weather normalization methodology.
   d) Harmonized heat value methodology and 2024 Test Year calculation.
   e) Harmonized customer additions forecast methodology and 2024 Test Year customer additions.

f) Harmonized average number of general service customers forecast methodology and 2024 Test Year customer average number of general service customers forecast.

D. Operating Expenses (Exhibit 4)

10) Are Enbridge Gas's proposed 2024 Test Year Operating Expenses appropriate, including:
   a) 2024 Test Year gas costs.
   b) 2024 Test Year O&M costs.
   c) 2024 Test Year depreciation expense.
   d) 2024 Test Year other financing expense.
   e) 2024 Test Year income tax expense.
   f) 2024 Test Year property tax expense.

11) In relation to the 2024 Test Year gas cost forecast,
   a) Is Enbridge Gas's 2024 Test Year gas supply plan, including the forecast of gas, transportation and storage costs, appropriate?
   b) Is the proposal for a common reference price methodology to set gas costs for Enbridge Gas appropriate?
   c) Is the proposed harmonized design criteria and process for determining design demands appropriate?
   d) Is the proposal for a harmonized approach to determine operational contingency space to support storage and transmission appropriate?
   e) Is the proposal for a harmonized methodology for forecasting unaccounted for gas appropriate?
   f) Is the 2024 Test Year Forecast volume of unaccounted for gas appropriate?
   g) Is the proposal for an updated harmonized Parkway Delivery Obligation (PDO) Framework appropriate?

h) Is the 2024 Test Year Parkway Delivery Commitment Incentive (PDCI) Forecast appropriate?

12) Is the proposal for implementation of the 2024 Gas Supply Plan after OEB approval is obtained, and for reflecting cost variances in gas cost deferral and variance accounts, appropriate?

13) Is the proposal for Enbridge Gas to add 10 PJ of market-based storage not included in the 2024 Test Year gas cost forecast appropriate?

14) In relation to the 2024 Test Year depreciation expense, are the proposed harmonized depreciation rates appropriate?

E. Cost of Capital (Exhibit 5)

15) Is Enbridge Gas's proposed 2024 Capital Structure appropriate, including:

a) Long and medium term debt.
b) Short term debt.
c) Common equity.

16) Is Enbridge Gas's proposed change to the deemed equity thickness component of its capital structure from 36% to 42% appropriate?

17) Is Enbridge Gas's proposed phase-in of increases to equity thickness over the 2024 to 2028 term appropriate?

18) Is Enbridge Gas's proposed 2024 Test Year Cost of Capital appropriate, including:

a) Cost of short-term debt.
b) Cost of long-term debt.

c) Cost of common equity, applying the OEB's formula to calculate ROE.

F. Revenue Deficiency/Sufficiency (Exhibit 6)

19) Is Enbridge Gas's 2024 Test Year Revenue Deficiency calculated correctly, including:
   a) 2024 Test Year revenue requirement and the resulting delivery and gas supply revenue deficiency.

G. Cost Allocation (Exhibit 7)

20) Is Enbridge Gas's 2024 Test Year Cost Allocation Study, including the methodologies and judgements used and the proposed application of that study to the current rate class design, appropriate?

H. Rate Design (Exhibit 8)

21) Is Enbridge Gas's proposal to set 2024 rates using current rate classes and an updated harmonized cost allocation study appropriate?

22) Is Enbridge Gas's rate design proposal for the gas supply commodity charge and gas supply transportation charges appropriate?

23) Are Enbridge Gas's proposed 2024 rates just and reasonable?

24) Is Enbridge Gas's proposed implementation and mitigation plan for 2024 rates appropriate?

25) Are Enbridge Gas's proposed changes to the terms and conditions applicable on January 1, 2024, to existing rate classes appropriate?

26) Are Enbridge Gas's proposed miscellaneous service charges in Rider G appropriate?

27) Are Enbridge Gas's proposed Direct Purchase Administration Charge (DPAC) and Distributor Consolidated Billing (DCB) charges appropriate?

28) Is Enbridge Gas's combined Rate Handbook for 2024 appropriate?

29) Are Enbridge Gas's proposed changes to services and related charges for 2024 appropriate?

I. Deferral & Variance Accounts (Exhibit 9)

30) Is Enbridge Gas's proposal for harmonization and continuation of certain existing deferral and variance accounts appropriate?

31) Is Enbridge Gas's proposal for the establishment of certain new deferral and variance accounts appropriate?

32) Is Enbridge Gas's proposal to close certain existing deferral and variance accounts appropriate?

33) Is Enbridge Gas's proposal to dispose of the forecast balances in certain deferral and variance accounts appropriate?

J. Incentive Rate Mechanism (Exhibit 10)

34) Is Enbridge Gas's proposed Price Cap Incentive Rate-Setting Mechanism, using an Annual Rate Adjustment Formula calculated as (I - X) ± Y ± Z + ICM, appropriate, including:

a) Inflation Factor (I) calculated using two factors.
b) Productivity Factor and Stretch Factor (X), using a productivity factor of -1.35% and a stretch factor of zero.
c) Y Factor for costs that are incremental to the costs subject to Price Cap escalation (i.e., pass-through items or costs approved in other proceedings and implemented as part of the annual rate application).
d) Z Factor for changes in costs associated with unforeseen events outside of management control.
e) Incremental Capital Module (ICM) using the OEB's ICM policy.
f) Earnings Sharing Mechanism (ESM).
g) Off-ramp.

35) Is Enbridge Gas's proposal for the process to follow for annual rate adjustment applications for 2025-2028 appropriate?

36) Is Enbridge Gas's proposal for annual proceedings for clearance of deferral and variance accounts and presentation of utility results (and any ESM amounts) and scorecard results appropriate?

K. Other

37) Is Enbridge Gas's proposed regulatory treatment of the Natural Gas Vehicle (NGV) Program appropriate?

38) Is Enbridge Gas's proposed regulatory treatment of the Distributor Consolidated Billing (DCB) Program appropriate?

39) Is Enbridge Gas's proposal for the extension of the existing financial terms of the Open Billing Access (OBA) Program for ten months until October 31, 2024 appropriate?

40) Is the proposed harmonized unregulated storage allocation appropriate?
    a) Is the proposed allocation of costs in the 2024 Test Year between regulated and unregulated storage appropriate?

41) Should the OEB grant Enbridge Gas's request for a partial exemption from the Call Answering Service Level, Time to Reschedule a Missed Appointment and Meter Reading Performance Measurement targets set out in GDAR?

42) Should the OEB Commissioners make a recommendation to the Chief Executive Officer of the OEB for a review of GDAR's SQR measures based on customer experience and expectations, and current industry and technical standards?

L. Rate Implementation

43) How should the OEB implement the 2024 rates relevant to this proceeding if they cannot be implemented on or before January 1, 2024?

2. Post 2024 Approvals (Phase 2)

A. Energy Transition

44) Is Enbridge Gas's proposal for an Energy Transition Technology Fund and associated rate rider appropriate?

45) Is Enbridge Gas's proposal to amend the Voluntary RNG Program, and to procure low-carbon energy as part of Enbridge Gas's gas supply commodity portfolio, appropriate?

B. Harmonized Rate Classes

46) Is Enbridge Gas's proposed design of harmonized rate classes appropriate, including:
   a) Rate design for the general service rate classes.
   b) Rate design for the in-franchise contract rate classes.
   c) Rate design for the ex-franchise rate classes.

47) Is Enbridge Gas's 2024 Test Year Cost Allocation Study, including the methodologies and judgements used and the proposed application of that study to the proposed harmonized rate classes, appropriate?

48) Are Enbridge Gas's proposed harmonized rates and related charges, based on the 2024 Test Year Cost Allocation Study, just and reasonable?

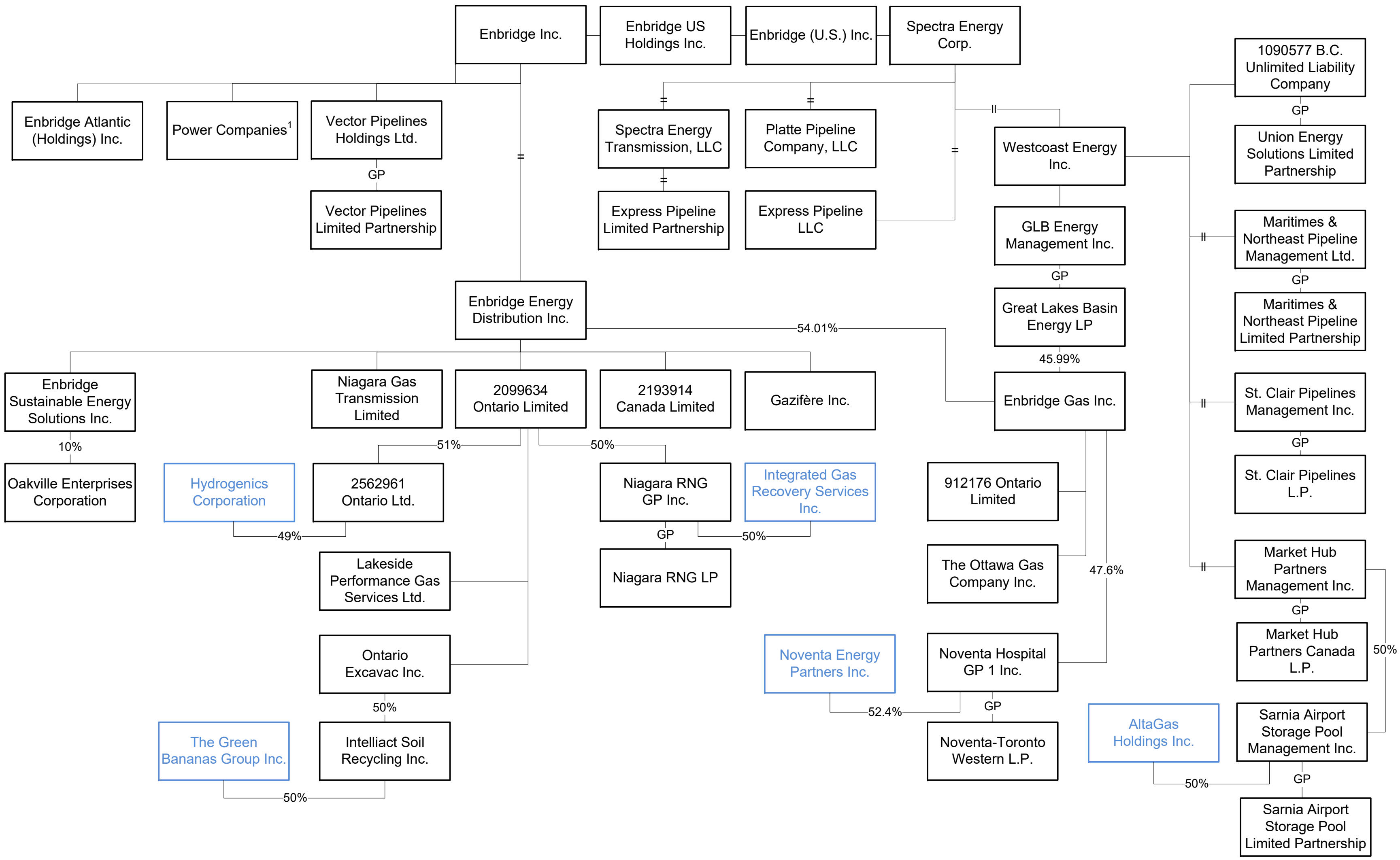
49) Is Enbridge Gas's proposed implementation and mitigation plan for harmonized rate classes appropriate?

50) Is Enbridge Gas's Rate Handbook for harmonized rate classes appropriate?

51) Is Enbridge Gas's proposed rate harmonization implementation and mitigation plan appropriate?

52) Are Enbridge Gas's proposed changes to services and related charges post 2024 appropriate?

GAS DISTRIBUTION & STORAGE GROUP OF ENTITIES
ORGANIZATIONAL CHART



Notes:
Ownership is 100%, unless otherwise noted
[1]These are various entities with renewable electricity generation assets (wind and solar) to whom EGI provides services
Blue font indicates a third party shareholder (non-Enbridge entity)

The information contained on this organization chart is strictly confidential and intended for internal company use only.

workday

Al Monaco

President & CEO

SVP & President Gas Distribution and Storage

Al Monaco

Michele Harradence

SVP & President Gas Distribution and Storage

- Director Product Development
- VP Energy Services
- SVP Operations
- Director Public Affairs & Ombudsman
- VP Business Development & Regulatory
- Director Business Development
- VP Customer Care
- Vice President, Engineering & STO

workday.

Al Monaco
Michele Harradence
Jim Sanders

SVP Operations

- Director Toronto Region Ops
- VP, Distribution Operations Services & Governance
- Director Eastern Region Operations & Gazifere
- Director EAM Program
- Director GTA West
- Director, Enterprise Work Management
- Director Southeast Region Ops
- Director Northern Region Ops
- Director GTA East Ops
- Director Southwest Region Operations

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Michele Harradence
Jim Sanders
Dean Dalpe

VP, Distribution Operations Services & Governance

- Director, Operations Services and EGI Sync
- Director Field Services and Growth

Al Monaco
Michele Harradence
Jim Redford

VP Energy Services

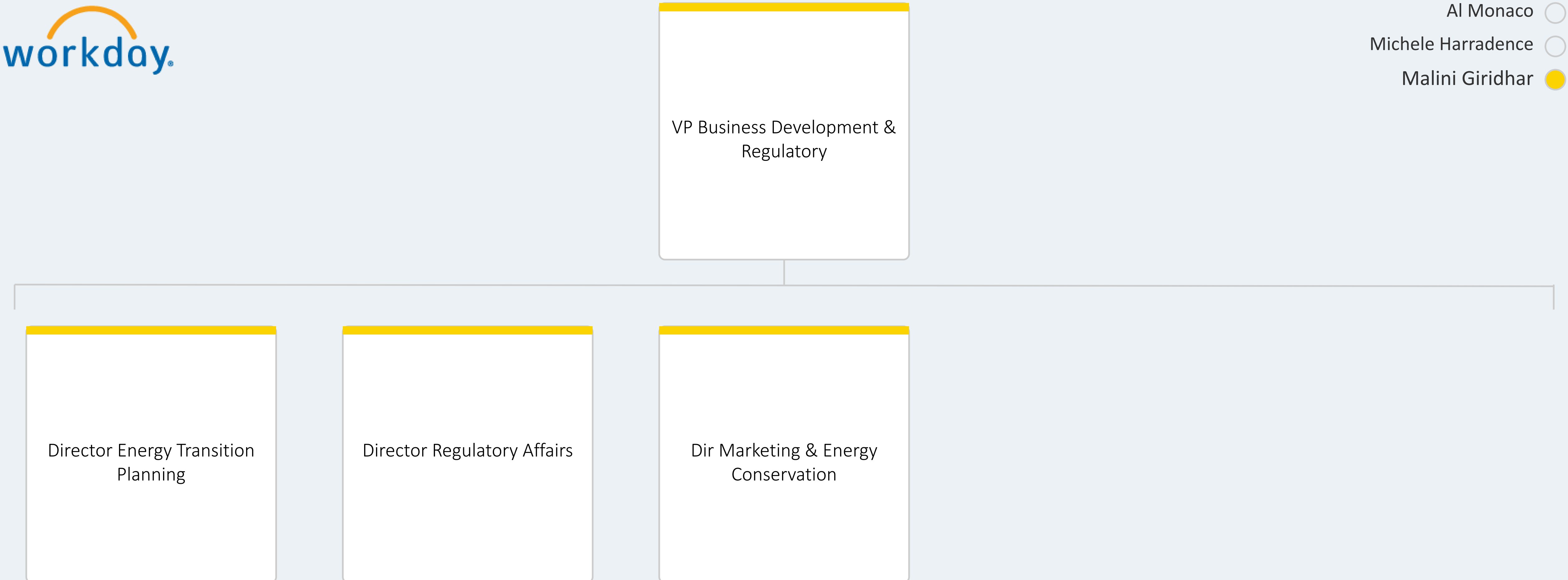
Chatham Corp 50 Keil

Director S&T Sales

Dir Gas Control & Management

Director S&T Business Development

Director Gas Supply


Al Monaco
Michele Harradence
Malini Giridhar
VP Business Development & Regulatory
Director Energy Transition Planning
Director Regulatory Affairs
Dir Marketing & Energy Conservation

workday

Al Monaco
Michele Harradence
Tanya Mushynski

VP Customer Care

- Director Distribution In Franchise Sales
- Director, Large Volume Contracting & Policy
- Dir Customer Care Operations

Al Monaco
Michele Harradence
Wes Armstrong

Vice President, Engineering & STO

- Director Engineering Services & IMS
- Director System Improvement
- Director Transmission Compression & LNG Operations
- Director, Integrity and Asset Management
- Engineering Director

Enbridge Gas Inc.

as at March 1, 2022

DIRECTORS

Michele E. Harradence

James E. Sanders

David G. Unruh

OFFICERS

Michele E. Harradence - President

James E. Sanders - Senior Vice President, Operations

Mark R. Boyce - Vice President, Law

Dean P. Dalpe - Vice President, Operations Services and Governance

Tanya M. Ferguson - Vice President, Finance

Malini Giridhar - Vice President, Business Development & Regulatory

Tanya C. Mushynski - Vice President, Customer Care

James G. Redford - Vice President, Energy Services

Rebecca M. Schriver - Vice President, Technology & Services

Jonathan E. Gould - Treasurer

Christopher J. Johnston - Controller

David Taniguchi - Corporate Secretary

Business Activity:	Natural gas distribution. Pipeline assets include: Ojibway and Detroit River Crossing.
Incorporation Date:	January 01, 2019
Jurisdiction:	Ontario
Corporate No.	5008296
Act:	Business Corporations Act (Ontario) - Amalgamation
Financial Year End:	December 31
Registered Office:	500 Consumers Road, North York, Ontario, Canada, M2J 1P8
Business Names:	Enbridge Gas – Ontario Enbridge Gas Distribution – Ontario Ottawa Gas – Ontario Provincial Gas – Ontario Tecumseh Gas Storage – Ontario Union Gas – Ontario
Shareholder(s):	Enbridge Energy Distribution Inc. - Class A Common – 281,881,334 Great Lakes Basin Energy L.P. - Class B Common – 240,020,243
Extra-Provincial Registration(s):	Alberta Quebec
Regulator:	Canada Energy Regulator Ontario Energy Board

SYSTEM OVERVIEW

1. General Description

1. Enbridge Gas has over $14 billion in regulated assets and serves over 3.8 million residential, commercial, and industrial customers in Ontario delivering heating to more than 75% of Ontario's homes. Enbridge Gas's service area is divided into the following seven operating regions:
   a) Northern Region covers the Northwest and Northeast districts stretching from Kenora to Orillia.
   b) Eastern Region covers Ottawa and Eastern district stretching from Belleville to Ottawa.
   c) Southwest Region covers the Windsor/Chatham and the Sarnia/London districts.
   d) Southeast Region covers the Niagara, Waterloo/Brantford, and Hamilton districts.
   e) Greater Toronto Area (GTA) West and Halton Region covers the western GTA and Halton districts.
   f) GTA East Region covers the eastern GTA.
   g) Toronto Region covers the City of Toronto.

2. Enbridge Gas has storage and transmission assets that serve to receive, store, and transport natural gas for markets in Ontario, Quebec, the Maritimes, and major United States (U.S.) natural gas-consuming areas. Enbridge Gas's Dawn Hub in Southwestern Ontario is connected to most of North America's major natural gas basins, including abundant and affordable gas supplies in the Western Canadian Sedimentary Basin and the Utica and Marcellus-producing regions in the U.S. It is similarly connected to the major demand markets, more than half a dozen major

pipelines connect at Dawn. Enbridge Gas's transmission assets link the extensive network of underground storage pools at the Dawn Hub to major Canadian and U.S markets and forms an important link in transporting gas from the Dawn Hub to the GTA through its West, Central, and East transmission operations areas.

3. Enbridge Gas owns and operates approximately 153,000 km of main and service pipelines for the transportation and distribution of gas. In addition, Enbridge Gas owns and operates approximately 311 petajoules (PJ) of underground gas storage facilities (199 PJ regulated and 112 PJ unregulated), has more than 800,000 horsepower of compression and one liquified natural gas facility. Enbridge Gas's supporting assets include service facilities, fleet, and information technology assets. The fleet assets include 1,895 fleet vehicles, plus heavy equipment, and tools. Enbridge Gas has 84 buildings across Ontario including administration sites, and operations depots to support functional business needs and activities. The information technology assets include over 300 applications plus associated software and hardware that provide critical functionality to effectively run the business.

<u>2. Map of Assets, Operations and Franchise</u>

4. Please see Attachment 1 for a map that shows Enbridge Gas assets and operations, as well as where the utility operates in the province, and the communities it services. This map identifies the location of gas transportation assets, compressor stations and interconnects, underground storage facilities, Liquefied Natural Gas facilities, and any other assets.


Enbridge Gas Inc. System Map
Ontario
Québec
Manitoba
MINNESOTA
MICHIGAN
WISCONSIN
ILLINOIS
OHIO
NEW YORK
PENNSYLVANIA
Lake Superior
Lake Michigan
Lake Huron
Georgian Bay
Lake Ontario
Lake Erie
Thunder Bay
Sault Ste. Marie
Sudbury
North Bay
Timmins
Ottawa
Kingston
Belleville
Toronto
Hamilton
London
Waterloo
Sarnia
Windsor
Chatham
Cornwall
Corporate Profile North America
CANADA
UNITED STATES OF AMERICA
UNITED KINGDOM
Liquids Pipelines
Natural Gas Transmission Pipelines
Natural Gas Gathering Pipelines
Gas Processing Plants
Enbridge Gas Distribution and Affiliates Service Territory
Union Gas Service Territory
Crude Storage and Terminals
Gas Storage Facility
NGL Storage
Propane Terminals
LNG US
Rail
Trucking Facility
Power transmission
Waste Heat Recovery
Geothermal Power
Wind Assets
Solar Assets
Hydroelectric Power Assets
Storage Facilities
Legend
Pools_Union
STO Pipelines
EGI Tecumseh Storage Pipelines
Pipelines Operating Above 3450 kPa
Transmission Pipelines
Distribution High Pressure Pipelines
Vector Pipeline
TransCanada Pipeline
CER Interconnecting Pipelines
Roads
Urban Areas
First Nation Boundaries
Kilometers
Legend
Towns
Compressor Station Sites
Interconnect CER Pipelines
STO Pipelines
EGI XHP Pipelines
30% SMYS Pipelines
Transmission Pipelines
Distribution High Pressure Pipelines
Tecumseh Storage pipelines
Trans CANADA Pipelines
Vector Pipeline
Other U.S. Pipelines
First Nation Boundaries
CUSTOMER
Enbridge Gas Inc.
ENBRIDGE
TITLE
EGI SYSTEM MAP
DIVISION
Franchise
DRAWN BY
F. Seguin
CHECKED BY
F. Seguin
STATUS
APPROVED
DATE
10/08/2022
SYSTEM
GeoMedia Pro 2020
SCALE
1:1,455,000
PROJECTION
Universal Transverse Mercator Zone 17
DATUM
North America 1983 - CANADA
DRAWING
MA2789 K1
VERSION
5.0
DATA SOURCE
Enbridge Gas Carrying Facility from GIS System 2022
Base Mapping from DMTI SPATIAL 2022 and MNR LIO 2018-21
US Pipeline from Penwell MAPSearch 2007
TransCanada Pipeline data 2004
DISCLAIMER
The location of Enbridge Gas facilities on the following drawing is approximate and is to be used for information purposes only. Enbridge Gas re-affirms that this drawing should not be relied upon to determine the location of any Enbridge Gas' facilities, exact locates can be determined by calling Ontario One Call 1-800-400-2255
This document is to be used for viewing purposes only. It shall not guarantee gas supply or availability for a specific project. It is for demonstration purposes only indicating Natural Gas infrastructure.
FILE
X:\Mapping_serv\GeoMedia_Projects\MA2789 K - EGD System Map RegionsAUG 2022.gws
REVISIONS
Superseed July 2021
0 60 120 180 240 300
Kilometers
MA2789 K1

APPLICATION SUMMARY

Filing Requirement	Details	Schedule Reference	
	Revenue Requirement		
Revenue requirement requested for the test year	$6,310.4 million	Exhibit 6 Tab 1 Schedule 1	/u
Increase/decrease ($ and %) from previously approved revenue requirement	$2,332.2 million, 58.6%	Exhibit 6 Tab 1 Schedule 1 and Attachment 1 and 2	/u
Revenue (deficiency) or sufficiency	($294.1) million	Exhibit 6 Tab 1 Schedule 1	/u
Schedule of main drivers of revenue requirement	Drivers of delivery deficiency of $270.9 million (sufficiency/(deficiency)): • Net sustainable synergies and productivity, $67.2 million • Changes in accounting policy and methodologies, $25.6 million • Impact related to ICM and Capital Pass Through, ($42.0) million • Cost pressures, ($135.0) million • Higher depreciation resulting from new depreciation study, ($160.4) million • Increase equity thickness from 36% to 38% in 2024 ($26.3) million Drivers of gas supply deficiency of $23.2 million (sufficiency/(deficiency)): • Unaccounted for Gas, ($11.5) million • Other gas supply plan changes ($11.2) million • Peaking and load balancing ($5.8) million • Compressor fuel $0.5 million • Market-based storage $4.8 million	Exhibit 6 Tab 1 Schedule 2	/u

Filing Requirement	Details	Schedule Reference
Budgeting and Accounting Assumptions		
Economic overview (such as growth and inflation)	• Inflation (CPI): 3.9% (2022), 2.4% (2023), 2.2% (2024) • Real GDP: 3.8% (2022), 3.1% (2023), 1.8% (2024) • GDP-IPI (FDD): CPI forecast used as a proxy since there is no consensus GDP IPI FDD forecast available. Canadian CPI rose approximately 24% since 2013 (from August 2013 to August 2022).	Exhibit 3 Tab 2 Schedule 4
Identification of accounting standard used for each year and brief explanation of impacts resulting from any change in accounting standard	Enbridge Gas uses United States Generally Accepted Accounting Principles (US GAAP) as its basis of accounting for all years included in this Application.	Exhibit 1 Tab 8 Schedule 2
Throughput Forecast		
Throughput for the test year	27,922,873 10^3m^3	Exhibit 3 Tab 3 Schedule 1 Attachment 7
Throughput growth for the test year (percentage change from last OEB-approved)	2,035,018 10^3m^3, 7.9%	Exhibit 3 Tab 3 Schedule 1 Attachment 7
Customer numbers (average)	3,914,712	Exhibit 3 Tab 3 Schedule 1 Attachment 5
Change in customer count (average) from last OEB-approved (# and %)	493,359, 14.4%	Exhibit 3 Tab 3 Schedule 1 Attachment 1

Filing Requirement	Details	Schedule Reference
Customer numbers (year-end)	3,937,007	n/a Annual average count used
Changes in customer count (year-end) from last OEB-approved (# and %)	515,654, 15.1%	n/a Annual average count used
Brief description of forecasting method(s) used	The general service market forecast is derived using the forecast number of customers and the respective average use forecast. The base forecast for general service is adjusted for other factors that cannot be captured through the forecasting methodology, such as Demand Side Management (DSM). The distribution contract market forecast is derived through a customer-specific bottom-up forecast for existing and forecast new customers. The base forecast for distribution contract market is adjusted for other non-customer specific adjustments, such as DSM.	Exhibit 3 Tab 2 Schedule 3 to Schedule 8
Rate Base and Utility System Plan		
Rate base requested for the test year	$16,281.1 million	Exhibit 2 Tab 1 Schedule 1 /u
Change in rate base from last OEB approved ($ and %)	$8,384.6 million, 106%	Exhibit 2 Tab 1 Schedule 1 /u
Capital expenditures requested for the test year	$1,491.3 million	Exhibit 2 Tab 1 Schedule 1 /u
Change in capital expenditures from last OEB-approved ($ and %)	$693.7 million, 87%	Exhibit 2 Tab 1 Schedule 1 /u
Summary, key elements, and main drivers of the applicant's capital investment plan	The 2024 Test Year capital expenditure budget is based on an established process underpinned by the Asset Management Plan (AMP). The Asset Management Framework is used to balance risk, cost and	Exhibit 2 Tab 6 Schedule 1 and Schedule 2

Filing Requirement	Details	Schedule Reference
	performance through the entire asset life cycle. The capital expenditure forecast is adjusted for the timing of market or externally driven in-service projects in order to inform the rate base forecast. The expenditures are required to meet the needs of approximately 3.8 million customers and maintain Enbridge Gas's assets. Capital expenditures are prioritized based on the safety and reliability needs of the system and the requirement to economically attach new customers to the system.	
Operations, Maintenance and Administration (OM&A) Expense		
OM&A for the test year	$1,046.0 million	Exhibit 4 Tab 1 Schedule 1
Change from last OEB-approved ($ and %)	$248.1 million, 31.1%	Exhibit 4 Tab 4 Schedule 1
Summary of overall drivers and cost trends	Enbridge Gas's O&M costs are projected to grow at an average annual rate of 2.6% from 2013 to the 2024 Test Year. Through this period, the Company has managed the global pandemic and the resulting provincial restrictions which delayed the completion of work and led to resourcing challenges, in both labour and materials. The Company has also been able to mitigate the impact of significant inflation and cost pressures by focusing on driving integration synergies and productivity savings to pass on to customers at rebasing. Throughout the deferred rebasing term, the Company continued to support customer growth and maintained its commitment to safety and reliability.	Exhibit 4 Tab 4 Schedule 1

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Filing Requirement	Details	Schedule Reference	
Inflation rates used for OM&A forecasts	2.4% (2023), 2.2% (2024)	Exhibit 4 Tab 4 Schedule 2	
Total compensation for the test year	$428.4 million	Exhibit 4 Tab 4 Schedule 3	/u
Change from last OEB-approved ($ and %)	($119.5) million, (21.8%)	Exhibit 4 Tab 4 Schedule 3	/u
Summary of any proposed gas supply, transportation and storage costs	• Supply: $2,670.8 million • Transport: $527.6 million • Other Gas Costs (including Storage): $29.6 million • Total Utility Gas Costs: $3,228.0 million • 10 PJ of market-based storage not included in gas costs. The costs for this storage are proposed to be recovered in a variance account.	Exhibit 4 Schedule 2 Tab 1 Attachment 1	
Summary of any changes in depreciation rates	Enbridge Gas is filing a depreciation study to harmonize depreciation methodologies, net salvage methodologies, asset useful lives and assets within plant accounts. The depreciation study was conducted by Concentric Advisors and is the first study since the 2013 Cost of Service applications for EGD and Union. The proposed depreciation expense for 2024 is $892 million	Exhibit 4 Schedule 5 Tab 1	/u

Filing Requirement	Details	Schedule Reference
Cost of Capital		
A statement as to the use of the OEB's cost of capital parameters	Enbridge Gas's investment in rate base is financed on a combination of short-term debt, long-term debt, and common equity. The current OEB-approved capital structure is based on a deemed 36% common equity component (equity thickness), with the remaining 64% financed through short and long-term debt. Enbridge Gas is proposing an increase to the common equity component of its capital structure to 42%. However in consideration of the revenue requirement impacts of an increase to 42%, Enbridge Gas is proposing a phased-in transition to the proposed higher equity level, where equity would be increased to 38% in 2024, and then a further 1% per year increase during the remainder of the IR term, ultimately reaching a 42% equity component in 2028.	Exhibit 5 Tab 3 Schedule 1
Summary and rationale for any deviations from the OEB's cost of capital methodology	Enbridge Gas believes that significant changes in the market in which it operates have occurred since the time of 2013 Cost of Service Applications for EGD and Union, which was the last time the OEB reviewed equity thickness for each utility. In order to determine if the risk profile has changed significantly since 2013, Enbridge Gas retained Concentric Energy Advisors Inc. to prepare an independent report on the reasonableness of the capital structure currently approved by the OEB.	Exhibit 5

Filing Requirement	Details	Schedule Reference	
The weighted average cost of capital (WACC) proposed in the application, and a summary breakdown of the proposed rates for each component of capital financing: • Return on equity, • Return on preferred shares • Weighted average cost of long-term debt • Cost of short-debt debt	WACC: 5.87% Cost of Capital: $955.7 million	Exhibit 5 Tab 1 Schedule 1	
	Return On Equity: 8.66%, $535.8 million		/u
	Weighted Average Cost of Long/Medium Term Debt: 4.17%, $418.0 million	Exhibit 5 Tab 2 Schedule 1 Attachment 6	/u
	Cost of Short Term Debt: 3.00%, $2.0 million		
Cost Allocation and Rate Design			
Summary of any deviations from OEB-approved cost allocation and rate design methodologies, including any changes to miscellaneous service charges.	The cost allocation study for the 2024 Test Year is the first study prepared by Enbridge Gas since the MAADs Decision. The 2024 cost allocation study is a fully integrated and comprehensive study that includes all current approved rate classes in the EGD and Union rate zones. A detailed review of the OEB approved cost allocation studies for EGD and Union was undertaken and to the extent possible, Enbridge Gas has incorporated one of the approved cost allocation methodologies of either the EGD or Union rate zone in the 2024 proposed cost allocation study.	Exhibit 7 Tab 1 Schedule 2 Exhibit 7 Tab 1 Schedule 3	

Filing Requirement	Details	Schedule Reference
Summary of any deviations from OEB-approved cost allocation and rate design methodologies, including any changes to miscellaneous service charges. (Continued)	Enbridge Gas has prepared a detailed explanation of proposed changes to existing cost allocation methodologies in response to prior OEB directives as well as other proposals for the allocation of Dawn Parkway demand costs and the DSM budget.	Exhibit 7 Tab 1 Schedule 4
	Enbridge Gas is proposing to eliminate certain rate classes that have limited or no use.	Exhibit 8 Tab 1 Schedule 2
	Enbridge Gas is proposing a change to the rate design for the gas supply commodity charge and gas supply transportation charges for the current rate classes, which aligns with the proposal for a common reference price for setting of gas costs.	Exhibit 8 Tab 2 Schedule 2
	Enbridge Gas is proposing a straight fixed variable rate design for current in-franchise contract rate classes where customer and demand-related costs are recovered in monthly fixed charges and demand rates and commodity costs are recovered in commodity rates. The level of monthly customer charge and demand charge for each rate class is proposed. Enbridge Gas is proposing a rate design methodology for Rate 300 based on Rate 125 due to there being no Rate 300 customers forecast in 2024.	Exhibit 8 Tab 2 Schedule 4
	Enbridge Gas is proposing a change to the rate design for Rate M12/C1 transportation demand charges on the Dawn Parkway System to recover Dawn Station, Kirkwall Station and Parkway Station demand costs based on the use of the assets required to provide each service option.	Exhibit 8 Tab 2 Schedule 5

Filing Requirement	Details	Schedule Reference
Summary of any deviations from OEB-approved cost allocation and rate design methodologies, including any changes to miscellaneous service charges. (Continued)	Enbridge Gas is proposing a change to the rate design for Rate C1 firm transportation from St. Clair, Bluewater, and Ojibway to Dawn to recognize the gas on these paths flows counter to the direction of flow on a peak day. Enbridge Gas is proposing to introduce two monthly fixed charges for Rate M13 producers to recognize differences in cost for stations that have a remote terminal unit. Enbridge Gas is proposing to charge producers under a Gas Purchase Agreement one of the Rate M13 monthly fixed charge based on the nature of the station. Enbridge Gas is proposing a change to the derivation of the Rate M13 and Rate M16 transmission commodity charge.	Exhibit 8 Tab 2 Schedule 5
	Enbridge Gas is proposing to harmonize, eliminate, and establish new miscellaneous service charges to reflect the operations and services of the amalgamated utility.	Exhibit 8 Tab 3 Schedule 1
	Enbridge Gas is proposing to harmonize the direct purchase charges, including the direct purchase administration charge and the distributor consolidated billing charge. Enbridge Gas is also proposing to harmonize other balancing charges and non-compliance charges.	Exhibit 8 Tab 3 Schedule 2 Exhibit 8 Tab 4 Schedule 2 to Schedule 5

Filing Requirement	Details	Schedule Reference
Summary of any deviations from OEB-approved cost allocation and rate design methodologies, including any changes to miscellaneous service charges. (Continued)	Enbridge Gas is proposing to eliminate the Union Supplied Fuel (USF) option available to certain in-franchise and ex-franchise transportation customers to simplify the service as there are no customers who take the service option. Consistent with this proposal, Enbridge Gas also proposes to eliminate the formula for the Yearly Commodity Revenue Requirement for Rate M12, applicable to the USF option. Enbridge Gas proposes to eliminate the charges for the name change service to align with similar services in the industry.	Exhibit 8 Tab 4 Schedule 6
Summary of any new proposals	Enbridge Gas is proposing to introduce two new rate riders as part of this Application: • Rider N - Energy Transition Technology Fund Rider Enbridge Gas proposes to recover the Energy Transition Technology Fund from customers as a fixed monthly amount through a rate rider to the monthly customer charge. • Rider L – Low-Carbon Voluntary Program Rider Enbridge Gas is proposing to charge customers who elect for the Low-Carbon Voluntary Program through a new rate rider and discontinue the existing Rider L for the voluntary Renewable Natural Gas program, effective January 1, 2025.	Exhibit 8 Tab 1 Schedule 2

Filing Requirement	Details	Schedule Reference
	Enbridge Gas has prepared a proposal to harmonize rates across its three rate zones into one rate zone and establish new harmonized rate classes. The implementation plan provides the timing of the rate harmonization plan. The implementation of harmonized general service rate classes is planned for April 1, 2025 and the implementation of harmonized contract rate classes is planned for April 1, 2026. Enbridge Gas is proposing to introduce service areas as geographic regions within the Enbridge Gas franchise area where the availability of services may be limited and/or where additional charges for service may apply.	Exhibit 8 Tab 2 Schedule 1
	Enbridge Gas is proposing a straight fixed variable with demand rate design for the harmonized general service rate classes including the level of proposed monthly customer charge.	Exhibit 8 Tab 2 Schedule 3
Summary of any new proposals (Continued)	Enbridge Gas is proposing a rate design for the proposed harmonized rate classes which includes straight fixed variable rate design where customer and demand-related costs in monthly fixed charges and demand rates and commodity costs in commodity rates. Other rate design proposals for the harmonized rate classes have been summarized in the evidence. Enbridge Gas proposes to limit the applicability of Rate 200 to existing distributors.	Exhibit 8 Tab 2 Schedule 4

Filing Requirement	Details	Schedule Reference
Summary of any new proposals (Continued)	Enbridge Gas is proposing to harmonize ex-franchise contract rate classes and rate design for producer services. Enbridge Gas is proposing to limit the applicability of the current Rate 401 RNG producer service to existing producers in the EGD rate zone. The proposed harmonized producer service would be applicable to new RNG producers. Enbridge Gas is proposing to introduce an RNG sampling charge for RNG producers, excluding producers under Rate 401, to recognize the incremental cost of RNG sampling. Enbridge Gas is proposing a non-utility cross charge associated with the Dow Moore and Black Creek storage pools for costs that were previously invoiced by EGD to Union and allocated to the unregulated operations. Enbridge Gas is proposing to maintain the non-utility cross charge associated with the Hagar Liquefaction Service of $1.59/GJ for 2024 and the IR term.	Exhibit 8 Tab 2 Schedule 5 Exhibit 8 Tab 2 Schedule 5
	Enbridge Gas proposes to harmonize the services currently offered in the EGD and Union rate zones to provide a common suite of services for Enbridge Gas customers.	Exhibit 8 Tab 4 Schedule 1 to Schedule 6

Filing Requirement	Details	Schedule Reference
Summary of any significant changes proposed to revenue-to-cost ratios and fixed/variable splits	A comparison of proposed revenue-to-cost ratios to the last OEB-approved ratios is provided in the Application. Changes are a result of the implementation of the rate harmonization plan and assessed against bill impacts. A comparison of fixed and variable rate recovery is also provided.	Exhibit 8 Tab 1 Schedule 3
Summary of any proposed mitigation plans to address rate impacts on specific customer classes or overall rate impact	A rate mitigation plan is proposed as a means to minimize volatility of rate impacts throughout the multi-year implementation of the rate harmonization plan.	Exhibit 8 Tab 2 Schedule 6
	Performance and Reporting	
Scorecard proposal and a brief explanation of the performance results and drivers for the last five years for measures that contain historical data	Enbridge Gas's scorecard was implemented as part of the MAADs proceeding. The Company is reporting on the 20 established measures that are divided into four driver categories: customer focus, operational effectiveness, public policy responsiveness, and financial performance. For each measure, Enbridge Gas is providing in evidence, five years of scorecard results (2017 to 2021), with 2017 and 2018 presented separately for the pre-amalgamated utilities.	Exhibit 1 Tab 7 Schedule 1
Summary of any reporting requirements proposed	Enbridge Gas is proposing to continue reporting on the scorecard annually in the earnings sharing and deferral and variance account (D&VA) proceedings.	Exhibit 10 Tab 1 Schedule 1
Description of how the applicant has addressed the Service Quality Performance (SQR) and Measurement requirements as outlined in the OEB's Gas Distribution Access Rule (GDAR).	Enbridge Gas is proposing to continue using the scorecard established in the MAADs proceeding and which includes the Service Quality Requirements measures that are outlined in the OEB's GDAR.	Exhibit 1 Tab 7 Schedule 1

Filing Requirement	Details	Schedule Reference
Discussion of any outstanding areas of non-compliance and the effect they have had on the application, including any relief sought	For the reporting period, Enbridge Gas was unable to meet the performance standard for four SQR measures. All reasonable steps have been taken to ensure compliance with the GDAR, with details provided in evidence and in the mitigation plans that are also being provided. Contributing factors in not reaching the SQR measures include the COVID-19 pandemic, staffing issues, and extreme weather events. Enbridge Gas is seeking partial exemption from the current GDAR targets for Call Answer Service Level (to a target of 65%), Time to Reschedule a Missed Appointment (to a target of 98%), and Meter Reading Performance (to a target of 2%).	Exhibit 1 Tab 7 Schedule 1
Bill Impacts		
Summary of total bill impacts ($ and %) for typical or average customers in all customer classes	Typical customer total bill impacts for 2024 have been prepared for a sales service customer for the general service rate classes and for a direct purchase customer for the contract service rate classes. Total 2024 bill impacts are relative to Enbridge Gas's proposed 2023 Rates[1] at April 2022 QRAM[2] gas costs. Total 2024 bill impacts are inclusive of the proposed deferral and variance account disposition in 2024 and the proposed Energy Transition Technology Fund rider. EGD Rate Zone • Rate 1 – $36; 3% • Rate 6 – $91; 1% • Rate 100 – $3,100; 3% • Rate 110 – $2,100; 1% • Rate 115 – ($7,300); 0% • Rate 125 – ($524,900); 0% • Rate 135 – $10,000; 5% • Rate 145 – ($21,400); (15%)	Exhibit 8 Tab 2 Schedule 6 /u

[1] EB-2022-0133.
[2] EB-2022-0089.

Filing Requirement	Details	Schedule Reference

Summary of total bill impacts ($ and %) for typical or average customers in all customer classes (Continued)	• Rate 170 – $468,000; 3%
	• Rate 200 – ($80,400); 0%
	<u>Union North Rate Zone</u>
	• Rate 01 North West – ($64); (5%)
	• Rate 01 North East – ($193); (13%)
	• Rate 10 North West – ($1,212); (3%)
	• Rate 10 North East – ($5,937); (13%)
	• Rate 20 – ($21,000); (1%)
	• Rate 25 – ($38,300); (4%)
	• Rate 100 – ($149,200); (1%)
	<u>Union South Rate Zone</u>
	• Rate M1 – $98; 9%
	• Rate M2 – $1,293; 5%
	• Rate M4 – $56,200; 2%
	• Rate M5 – ($39,300); (1%)
	• Rate M7 – $1,230,000; 7%
	• Rate M9 – $312,900; 7%
	• Rate T1 – ($129,200); (1%)
	• Rate T2 – $135,800; 1%
	• Rate T3 – $1,146,000; 2%
	<u>Ex-Franchise</u>
	• Rate 332 – 14%
	• Rate M12/C1 Dawn-Parkway
	    • Dawn to Parkway – (9%)
	    • Dawn to Kirkwall – -23%
	    • Kirkwall to Parkway – 152%
	    • Parkway to Kirkwall/Dawn – 6%
	    • Kirkwall to Dawn – (12%)
	    • M12-X – (6%)
	• Rate M13 – 5%
	• Rate M16 – (3%)
	• Rate M17 – 0%
	• Rate C1 – (50%)
		Exhibit 8
		Tab 2
		Schedule 6

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Filing Requirement	Details	Schedule Reference
Summary of total bill impacts ($ and %) for typical or average customers in all customer classes (Continued)	Approximate total bill impact percentages representing typical customers transition to the proposed rate classes and rate design have been prepared for a sales service customer for the general service rate classes and a direct purchase customer for the contract service rate classes. Harmonized total bill impacts are relative to 2024 proposed rates at April 2022 QRAM gas costs. The total bill impacts for harmonized general service rate classes are proposed to be effective April 1, 2025 and harmonized contract rate classes are proposed to be effective April 1, 2026. <u>EGD Rate Zone</u> • Rate 1 – 0% • Rate 6 – 1% • Rate 100 – 5% • Rate 110 – 3% • Rate 115 – 5% • Rate 125 – 0% • Rate 135 – (3%) • Rate 145 – 3% • Rate 170 – 1% • Rate 200 – 1% <u>Union North Rate Zone</u> • Rate 01 – 0% • Rate 10 – 0% • Rate 20 – 2% • Rate 25 – (2%) • Rate 100 – 1%	Exhibit 8 Tab 2 Schedule 6

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Filing Requirement	Details	Schedule Reference
Summary of total bill impacts ($ and %) for typical or average customers in all customer classes (Continued)	<u>Union South Rate Zone</u> • Rate M1 – 0% • Rate M2 – 1% • Rate M4 – 0% • Rate M5 – -2% • Rate M7 – 1% • Rate M9 – 3% • Rate T1 – 1% • Rate T2 – 1% • Rate T3 – 0%	Exhibit 8 Tab 2 Schedule 6
Deferral and Variance Accounts		
Accounts requested for disposition including account balances, disposition methodology and timing	Accounts and balances for disposition include: • Accounting Policy Changes Deferral Account, $142.2 million • Tax Variance Deferral Account, ($5.0) million • Incremental Capital Module Deferral Accounts, ($25.6) million • Impacts Arising from the COVID-19 Emergency Deferral Account, $1.5 million • Transition Impact of Accounting Changes Deferral Account, $39.9 million • Transitional Pension Balance, ($254.6) million The total balance to be cleared is a credit to customers of approximately ($101.6) million inclusive of interest forecast to December 31, 2023. Enbridge Gas is proposing interim disposition based on forecast balances at December 31, 2023, for the listed D&VA with final balances not known at this time. Enbridge Gas will clear the final account balances as part of Enbridge	Exhibit 9 Tab 2 Schedule 1 and Schedule 2

Filing Requirement	Details	Schedule Reference
Accounts requested for disposition including account balances, disposition methodology and timing (Continued)	Gas's 2023 annual earnings sharing and deferral disposition proceeding for these accounts, as required. Enbridge Gas proposes to dispose of the combined balance as a net credit to all customers in 2024 as a mitigation effort that can offset other impacts of rate proposals made as part of this Application. If approved, the combined balance, a net payable of ($101.6) million, will be disposed of to customers effective January 1, 2024, over a 12-month period. Enbridge Gas is proposing a harmonized approach to the allocation and disposition of the D&VA balances, consistent with the proposed 2024 cost allocation study.	Exhibit 9 Tab 2 Schedule 1 and Schedule 2
Any new deferral and variance accounts requested and any request for the discontinuation of existing accounts	New D&VAs requested include: • Energy Transition Technology Fund Variance Account (Account No. 179-321) • Rate Harmonization Variance Account (Account No. 179-322) • Dawn Parkway Surplus Capacity Deferral Account (Account No. 179-323) • Locate Delivery Services Variance Account (Account No. 179-324) • Open Bill Extension Deferral Account (Account No. 179-325) • Enhanced Distribution Integrity Management Program Deferral Account (Account No. 179-326) • Post-Retirement True-Up Variance Account (Account No. 179-328) Discontinuation of existing EGD rate zone D&VAs: • Transition Impact of Accounting Changes Deferral Account (Account No. 179-02_) • Ex-Franchise Third Party Billing Services Deferral Account (Account No. 179-08_)	Exhibit 9 Tab 1 Schedule 1 to Schedule 4

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Filing Requirement	Details	Schedule Reference
Any new deferral and variance accounts requested and any request for the discontinuation of existing accounts (Continued)	• Renewable Natural Gas Injection Service Deferral Account (Account No. 179-12_) • Dawn Access Cost Deferral Account (Account No. 179-40_) • Open Bill Revenue Variance Account (Account No. 179-48_) • OEB Cost Assessment Variance Account (Account No. 179-94_) Discontinuation of the following Union rate zones D&VAs: • OEB Cost Assessment Variance Account (Account No. 179-151) • Short-term Storage and Other Balancing Services (Account No. 179-70) • Unbundled Services Unauthorized Storage Overrun (Account No. 179-103) • Parkway West Project Costs (Account No. 179-136) • Brantford-Kirkwall/Parkway D Project Costs (Account No. 179-137) • Lobo C Compressor/Hamilton-Milton Pipeline Project Costs (Account No. 179-142) • Dawn H/Lobo D/Bright C Compressor Project Costs (Account No. 179-144) • Burlington-Oakville Project Costs (Account No. 149) • Panhandle Reinforcement Project Costs (Account No. 179-156) • Sudbury Replacement Project (Account No. 179-162) Discontinuation of the following Enbridge Gas D&VAs: • Accounting Policy Changes Deferral Account (Account No. 179-120)	Exhibit 9 Tab 1 Schedule 1 to Schedule 4

Filing Requirement	Details	Schedule Reference
Any new deferral and variance accounts requested and any request for the discontinuation of existing accounts (Continued)	• Impacts Arising from the Covid-19 Emergency Deferral Account (Account No. 179-384) Enbridge Gas is also proposing harmonization and other changes to the D&VAs, not listed above. Enbridge Gas is proposing to harmonize various D&VAs, as the accounts are no longer required for the EGD and Union rate zones on a stand-alone basis.	Exhibit 9 Tab 1 Schedule 1 to Schedule 4
Rate Schedules		
Summary of any other changes to the current OEB-approved rate schedules that are being proposed in the new rate schedules, which are filed and provided at Exhibit 8.	Enbridge Gas is proposing one combined rate handbook for Enbridge Gas that incorporates the EGD and Union rate zones rate classes. In order to provide consistency and a standard presentation between EGD and Union rate schedules, formatting and content changes have been proposed. The more significant changes involve updates to the description of services and terms and conditions, the consistent inclusion of gas supply charges on rate schedules, and the consistent use of rate riders across rate zones. The rate schedules have also been updated to reflect other proposals as appropriate.	Exhibit 8 Tab 2 Schedule 7

Filing Requirement	Details	Schedule Reference
Incentive Rate Setting		
Summary of the key components proposed for the Price Cap IR method for the incentive rate-setting period	Enbridge Gas is proposing rates during the IR term be set based on a Price Cap Incentive Rate-setting (Price Cap IR) mechanism and associated parameters. Under the proposed Price Cap IR, rates will be set through this Cost of Service Application for the first year (2024 Test Year) and then adjusted in years two to five years (2025-2028) using an Annual Rate Adjustment Formula calculated as (I - X) ± Y ± Z + ICM, where: • I = inflation factor, calculated as a weighted average of growth in the Canadian GDP Implicit Price Index for Final Domestic Demand (GDP IPI FDD) and the Ontario Average Hourly Earnings (AHE) indexes • X = productivity factor of -1.35% and stretch factor of zero • Y = costs that are incremental to the costs subject to Price Cap escalation (i.e. strict pass-through items or costs approved in other proceedings and implemented as part of the annual rate application) • Z = change in costs associated with unforeseen events outside of management control • ICM = Incremental Capital Module In addition to the formulaic changes to rates, Enbridge Gas is proposing rate adjustments for a phased-in equity thickness increase as provided in Exhibit 5, Tab 3, Schedule 1 and rate adjustments for rate mitigation as provided at Exhibit 8, Tab 2, Schedule 6. This IRM proposal also includes an Off-Ramp (in the event actual utility earnings are outside of +/- 300 basis points from the OEB approved ROE, and an Earning Sharing Mechanism (utility earnings in excess of 150 basis points above the OEB-approved ROE to be shared on a 50/50 basis with ratepayers) during the IR term.	Exhibit 10 Tab 1 Schedule 1

Filing Requirement	Details	Schedule Reference

Notes:

- This Application is the first rebasing application filed after the amalgamation of EGD and Union.
- The OEB-approved figures are based on the 2013 Cost of Service Applications for EGD[3] and Union[4].
- Historical details have been provided for 2013 to 2018, historical details and variance analysis have been provided for 2019 to 2023.
- The 2022 Estimate is based on the 2 months of actuals and 10 months of forecast.
- The 2022 Estimate was prepared and finalized at the end of March 2022 and the 2023 Bridge Year and 2024 Test Year were prepared in early 2022 and finalized at the end of September 2022.
- The deficiency was developed using proposed 2023 rates at April 2022 QRAM[5] prices.
- Enbridge Gas as an amalgamated utility does not have OEB-approved figures to compare the 2024 Test Year results. In the absence of this, Enbridge Gas has combined the 2013 OEB-approved figures from EGD and Union for comparison and illustrative purposes.
- Minor differences may exist in the presentation of tables and numbers due to rounding.

[3] EB-2011-0354.
[4] EB-2011-0210.
[5] EB-2022-0089.

CUSTOMER ENGAGEMENT

KAREN SWEET, SUPERVISOR CUSTOMER AND MARKET INSIGHTS

1. The purpose of this evidence is to address customer engagement requirements as outlined in Section 5.0 of the Handbook for Utility Rate Applications (Handbook)[1]. Specifically, this evidence provides an overview of the customer engagement (design, methodology, and process), results showing customer preferences and needs, and details regarding how the analysis of the results informed Enbridge Gas's business planning and decision-making processes. A detailed customer engagement report produced by Innovative Research Group (Innovative) is provided at Attachment 1. A detailed customer engagement report produced by Enbridge Gas for transportation customers and Ontario producers is provided at Attachment 2. These reports are referenced throughout this schedule.

2. This evidence provides an overview of the customer engagement process and a summary of key themes from the customer engagement results. Further discussion and analysis of the results is found in the various exhibits of this Application, with specific references summarized in Table 4.

3. This evidence is organized as follows:
    1. Customer Engagement Design
    2. Overall Results
    3. Summary

[1] Handbook for Utility Rate Applications, October 13, 2016.

1. Customer Engagement Design

4. Enbridge Gas conducted an extensive customer engagement process throughout 2021 and early 2022 in support of this Application. In total, over 12,000 customers participated in the customer engagement process through three distinct phases which included various forms of engagement, such as focus groups, in-depth interviews, telephone surveys, and online workbooks. The paragraphs below describe the forms of engagement used and also characterize the quality of the customer engagement, detailing considerations of its timing, methodology, scope across all customer segments, and how the learnings from previous engagements and the expertise of market research professionals were leveraged in its development.

5. The objective of the customer engagement was to integrate customer feedback into the business planning process, thereby ensuring the Application adequately reflects and is responsive to customer needs and preferences. To provide the various Enbridge Gas teams with results at key stages in their business planning processes, the customer engagement was designed to evolve over three distinct phases with each phase building upon the last. The first phase used qualitative research to provide directional input regarding customer needs and priority outcomes before detailed business planning was fully underway. The second phase quantified these findings using random sample surveys and started to explore high level investment and rate design choices. The third phase gauged customer support for specific investment choices. All three phases were completed before final decisions were made by Enbridge Gas teams. The timing for the three phases is included in Table 1.

Table 1

Three Phase Approach to Customer Engagement

#	Phase	Description	Engagement Activity	Timing of Fieldwork
1	Phase One (Development)	Exploring the range of views – this phase focused on an initial understanding of perceptions, opinions, or beliefs and attitudes of various customer groups	Focus groups and in-depth interviews	May – June 2021
2	Phase Two (Refinement)	Drawing broader conclusions – initial evaluation of investment and rate design choices and concepts to provide an opportunity to enhance and refine them	Telephone and online surveys	August 2021
3	Phase Three (Validation)	Reacting to the plan – evaluate draft investment and rate design choices	Online workbook	December 2021 – January 2022

6. Enbridge Gas's Customer & Market Insights (CMI) team took the lead in the process by designing the customer engagement for each phase. It leveraged the experience of Innovative to finalize all surveys/workbooks and discussion/interview guides. Innovative executed the fieldwork for each phase and ultimately produced a report with the results. Oversight of each phase by the CMI team ensured the customer engagement process took advantage of Enbridge Gas's existing research such as the customer satisfaction tracking program. In addition, the engagement was designed to build upon previous consultations including customer engagement conducted for the 2019 Asset Management Plan.[2]

[2] EB-2020-0181, Exhibit C, Tab 3, Schedule 1.

7. In addition to ensuring the customer engagement benefited from past and ongoing research, guiding principles for the design of the engagement included:
    a) Ensuring a positive customer experience. Keeping surveys a reasonable length, limiting the number of times the same customers were solicited for feedback, and putting information into terms and concepts customers could understand without having prior knowledge of Enbridge Gas operations.
    b) Ensuring representation for all types of customers in all rate zones.
    c) Balancing timing considerations. Ensuring customer feedback was available in early stages of the business planning process, while also giving customers details needed to make informed choices (such as cost impacts).
    d) Being open to customer-driven priorities. Providing opportunities for customers to make suggestions or introduce topics not covered in the survey/workbook questions and discussion/interview guides.
    e) Incorporating opportunities to learn and evolve Enbridge Gas's approach to customer engagement. Testing and diagnostic questions were included in the engagement to monitor and collect feedback for the benefit of later phases and future engagement processes.

8. Additional information on the design of the customer engagement is included in the Designing this Engagement section in the Innovative report provided at Attachment 1, pages 34-38.

1.1. Complementary Engagement

9. Enbridge Gas has a robust customer satisfaction tracking program that monitors the customer experience at major touchpoints via ongoing surveys for the general service market, as well as periodic customer satisfaction studies for contract and transportation customers. Enbridge Gas also conducts daily and monthly surveys

with randomly selected general service customers to gauge their level of satisfaction with Enbridge Gas and provide opportunities for open-ended comments with feedback and suggestions.

10. Customer feedback and other insights collected through research guides Enbridge Gas business decisions on an ongoing basis, with customer satisfaction scores, insights, and customer comments received through surveys being regularly reviewed and addressed by the Company. Customer research is also commonly completed prior to launching new offerings or services and integrated into projects that will impact customer touchpoints. For example, customers were recruited to formally test and comment on the new enbridgegas.com website in 2020 at multiple points in the development process.

11. In addition to formal research, customer feedback is collected and addressed in various ways. Examples are summarized by customer grouping below.

12. General Service Customers:
    a) Ombuds Office: Enbridge Gas's Ombuds Office regularly compiles information summarizing the reasons customers contacted or were forwarded to the Ombuds Office. This information is made available to relevant departments across the Company and is a driver for process and policy changes as well as incremental improvements to the customer experience at various touch points.
    b) Social Media: Enbridge Gas monitors customer comments posted to its social media accounts on an ongoing basis. Feedback received through these channels is forwarded to the appropriate teams within Enbridge Gas to review and address accordingly. This feedback results in adjustments to

communications and is an input into policy and process changes. Enbridge Gas also produces ad-hoc summary reports of social media comments to inform Enbridge Gas's response to specific issues. For example, reports were regularly produced summarizing customer comments and concerns related to the COVID-19 pandemic and shared with the employees responsible for pandemic-related policies and communications.

13. Contract and Transportation Customers:
    a) Ongoing interactions with frontline staff: Regular interactions between customers, Enbridge Gas account representatives, and other frontline staff are a rich source for customer insights. Customer feedback and concerns regularly prompt follow-up work that includes identifying the nature of the issue, what additional information is needed, what could be done to address the issue, and which areas of the Company need to be involved. For example, if feedback indicates that Enbridge Gas should pursue a new service, policy change or other remedy, a task team may be assembled accordingly.
    b) Customer meetings: Enbridge Gas holds formal one-on-one and group meetings/webinars with contract and transportation customers on a regular basis and provide another opportunity to collect customer feedback both in general and related to specific topics.

14. Enbridge Gas also built upon past customer engagements, including those completed by EGD and Union. Specifically, past consultations helped inform an initial list of customer outcomes that were brought forward as a starting point for this customer engagement. Past customer engagements and the priority outcomes identified by each are provided in Table 2.

Table 2

Previous Customer Engagement Processes

#	Engagement	Vendor	Fieldwork Timing	Top Outcomes Identified
1	EGI 2019 Asset Management Plan Customer Engagement[3]	Ipsos Public Affairs	December 2019 – January 2020	• Safety, reliability, and affordability were rated as being highly important customer outcomes by business and residential customers. • When asked to rank the importance of various aspects of their natural gas service, providing stable and predictable pricing was ranked within the top four categories among all customers, while minimizing the impact on the environment was ranked third among residential customers.
2	Union 2019 Rate Application Customer Engagement[4]	Innovative	February 2017 – March 2017	• In both the qualitative and quantitative research, and across all rate classes, customers consistently ranked price, reliability and safety as the outcomes that mattered most to them.
3	EGD 2019 Rate Application Customer Engagement[5]	Ipsos Public Affairs	December 2016 – May 2017	• Customer outcomes were not ranked in this engagement, but across all metrics and customer segments, most customers felt that Enbridge Gas should invest in maintaining current levels of reliability, safety, and customer service.

1.2. Methodology

15. The customer engagement was built into the schedule of the broader business planning process, such that results would be available before decisions on the business plan were made and was customized for each customer group. The first

[3] EB-2020-0181, Exhibit C, Tab 3, Schedule 1.
[4] EB-2018-0305, Exhibit D1, Tab 2, Schedule 1.
[5] EB-2018-0305, Exhibit D2, Tab 1, Schedule 1.

phase of the customer engagement process used qualitative tools and Phase Two and Phase Three used quantitative tools. With each progressive phase, questions and background information became more detailed as more information became available from Enbridge Gas teams, and also with learnings from pretest results and customer feedback from the previous phases. Table 3 shows customer engagement activities by customer group.

Table 3
Customer Engagement Activity by Customer Group

#	Customer Group	Timing	Engagement Activity	Definition of Customer Group
1	General Service Residential (Rate Class - 1, R01, M1)	May 2021, August 2021, December 2021 – January 2022	Phase One focus groups, Phase Two surveys, Phase Three online workbook	Those in the residential account class who typically use less than 50,000 m3 of natural gas per year
2	General Service Business (Rate Class - 6, R01, R10, M1, M2)	June 2021, August 2021, December 2021 – January 2022	Phase One in-depth interviews, Phase Two surveys, Phase Three online workbook	Non-contract business customers who use less than 50,000 m3 (small) and more than 50,000 m3 (medium-large) of natural gas per year
3	Contract (Rate Class - 100, 110, 115, 125, 135, 145, 170, 300, 315, M10, M2, M4, M5A, M7, M9, R10, R100, R20, R25, T1, T2, T3)	February – March 2022	Phase One in-depth interviews, Phase Three online workbook	Commercial and industrial customers who have a signed contract for natural gas delivery with Enbridge Gas.
4	Transportation customers (Rate Class - M12, C1)	December 2021 – January 2022	Online workbook, validation interviews	Ex-franchise customers who transport natural gas between interconnects on the system

#	Customer Group	Timing	Engagement Activity	Definition of Customer Group
5	Ontario Producers (Rate Class - M13, 401)	December 2021 – January 2022	Online workbook, validation interviews	Customers who produce conventional and renewable natural gas in the Enbridge Gas franchise area

16. The methodology for the activities conducted by Innovative are further described in the Innovative report provided at Attachment 1. This report also includes a copy of each discussion guide, survey, and workbook used by Innovative. These materials were tailored for each customer group to reflect the topics affecting them.

17. The voluntary residential workbook was accessible to all Enbridge Gas residential customers and publicized via social media and the Enbridge Gas website. A total of 303 Enbridge Gas customers completed this voluntary version of the workbook between December 13, 2021, and January 16, 2022. Results from this survey are summarized in the Phase Three Report: Voluntary Residential Report. Please see the Innovative report provided at Attachment 1, pages 507-515. Results from the voluntary group were consistent with results from the representative group, and where references are made to the residential customer results, Enbridge Gas uses results from the Phase Three: Residential Representative Report.

18. In addition to the customer activities conducted by Innovative, Enbridge Gas completed some components of the customer engagement without the use of its third-party vendor, Innovative. This included engagement with contract customers for some phases, and engagement with transportation customers and Ontario producers (M13). These are sophisticated customers with individualized needs and preferences, so it was agreed that individual meetings with Enbridge Gas staff who

have relationships with them would be more suitable than the use of focus groups. The methodology for these groups is described in the following paragraphs.

19. Contract Customers:

a) Enbridge Gas invited a subset of contract customers and energy marketers across rate zones and segments to participate in one-on-one meetings. to gauge their satisfaction with existing services, understand areas for potential improvements, and to validate assumptions related to service harmonization. Initial invitations were extended to the customers most impacted by any potential changes and those with unique services. As the process continued, additional customers were invited as they expressed interest as part of regular interactions with Enbridge Gas staff. Enbridge Gas also held sessions with customer associations that represent contract rate customers to inform them of the customer engagement process and to receive input. Results from this phase of customer engagement informed the draft service harmonization proposals and planning work. Phase Two of the customer engagement was not applicable to contract rate customers. In Phase Three, Enbridge Gas prepared a series of videos for customers explaining the draft proposals for service harmonization. In addition, all contract customers were invited to provide feedback on those draft proposals by completing an online workbook. Energy marketers and associations were given the opportunity to complete the same online workbook as contract customers. No association results are included in the report to maintain anonymity due to the small number of these completions. Both contract customer and energy marketer results are combined and included in the report. Please see the Innovative report provided at Attachment 1, pages 393-506.

b) Upon review of the results from the customer engagement workbook, Enbridge Gas held another round of meetings with relevant customer associations that represent contract rate customers, (and customers who are members of those associations), to explain the draft proposals in more detail and to field any questions that customers or the associations had. These meetings resulted in subsequent one-on-one meetings with customers who had follow-up questions or who wanted to clarify how the proposed services would work in practice. These meetings informed further refinement of some of the proposed services.

20. Transportation customers and Ontario producers:
   a) In late 2020, Enbridge Gas representatives engaged a group of larger Transportation customers of varying types who would be most impacted by any potential changes and asked questions about service harmonization of M12 and C1 transportation rates. Questions covered topics such as a change to the renewal rights language, the removal of Utility Supplied Fuel, and options regarding transportation fuel rates.
   b) In late 2021 and early 2022, Transportation customers and Ontario producers were invited to complete a survey workbook that was available online. An invitation was sent to a representative of each customer to participate in the customer engagement and offered the opportunity to complete the workbook online or to meet with an Enbridge Gas representative to discuss the questions in the workbook and complete the workbook together. Since the invitation to complete the workbook also included a copy of the workbook, some customers completed the survey on paper. All responses received were combined. Innovative completed validation interviews with customers who were willing to be contacted for this purpose. Please see the Innovative report provided at Attachment 1, pages 516-522 for results from these interviews.

1.3. Phase One Process Overview

21. Phase One was exploratory in nature and included opportunities for customers to bring forward outcomes of importance for Enbridge Gas to consider. The discussion guide was developed through various meetings with business planners from different parts of the organization. Enbridge Gas then developed a preliminary list of topics that would benefit from customer input, which was gradually narrowed down through discussion and prioritization. Where applicable, results from previous customer engagements were shared. Prioritization was based on some general principles, which included whether recent customer feedback on the topic existed, whether Enbridge Gas would be able to genuinely consider customer feedback in its decision-making process, and whether the topic of consideration would have a meaningful impact on customers. Key sections of the discussion guide included customer needs, customer outcomes, rate issues, use reserves or borrow, the future of natural gas, and energy transition.

22. The Phase One report was prepared by Innovative and shared with all relevant Enbridge Gas teams for their review and consideration. Follow-up meetings were held to answer any questions arising from the report.

1.4. Phase Two Process Overview

23. By the time Phase One fieldwork was complete, development work for Phase Two was already underway. Enbridge Gas shared preliminary results from the Phase One focus groups with Enbridge Gas teams to help facilitate discussion of the Phase Two questionnaire, which allowed feedback from Phase One to be a consideration.

24. Phase Two, or the refinement phase, was a step towards evaluating initial proposals and concepts to allow Enbridge Gas the opportunity to enhance and refine its draft business plans. Key areas of questions included overall satisfaction, customer outcomes, asset management, rates, new or harmonized programs and policies, and energy transition. The results from Phase One, as well as previous customer engagement work guided areas of questioning. This phase helped Enbridge Gas to narrow down the areas of discovery, as well as gauge some initial customer reactions to some of its early proposals.

25. Initial testing of the Phase Two questionnaire determined which questions could be asked on the telephone and the online version, ensuring the questions were being asked effectively ahead of the full launch of the survey.

26. Innovative prepared the Phase Two reports (one for Residential, and one for Business customers) and they were shared with relevant Enbridge Gas teams. Follow-up meetings were held to share topic-specific results with the teams, as well as to discuss customer needs and preferences, including the outcomes.

1.5. Phase Three Process Overview

27. Investment and rate design choices in Phase Three of the customer engagement were developed through discussions with the various Enbridge Gas teams responsible for those areas. These meetings were held to better understand the topics and options to include and to determine whether it should be included in the customer engagement (regardless of whether or not it was included in Phase One or Phase Two). This was to ensure that the required background was available to allow customers to make an informed choice. This also included discussions about

the overall rate impacts, to ensure that the most current information could be included in the final workbook.

28. Previously identified concerns related to customer engagement, such as the ability for customers to review the cumulative impact of their choices on overall rates, were addressed in this workbook by allowing customers to review and change their choices based on the preliminary estimates of cumulative impact on their distribution rates.[6]

29. To ensure that customers understood the workbook content, four focus groups were conducted with residential customers ahead of the launch of the workbook.

30. Phase Three reports prepared by Innovative were shared with all Enbridge Gas teams as soon as they were available. For the Residential Representative Report an interim report was made available to all project stakeholders in mid-December (December 17, 2021), with final reports being shared in early 2022. All these reports, both the Innovative report and the Transportation report were available to the complete group of project stakeholders for reference throughout their planning process.

31. Customers participating in the customer engagement were given the option to receive follow-up information from Enbridge Gas about how customer feedback was used and the overall outcomes of the customer engagement. Communication to this group began after the conclusion of Phase Three.

[6] EB-2018-0305 Exhibit I.STAFF.80.

1.6. Customer Engagement Diagnostics

32. Diagnostic questions designed to assess the effectiveness of the customer engagement and to identify ways to improve future consultations were included in Phase Three workbooks. Across all customer segments, 73% or more of the respondents had a favourable impression of the workbook they completed, and a clear majority stated that the workbook contained "just the right amount" of information. Full results of the diagnostic questions can be found in each of the Phase Three Customer Engagement reports, as well as in the Key Findings section. Please see the Innovative report provided at Attachment 1, pages 33, 296-300, 386-391, 500-505 and the Transportation report provided at Attachment 2, pages 18, 22 and 44.

1.7. Additional Customer Engagement

33. To ensure a thorough understanding of general service customer preferences related to rate design and bill presentment, Enbridge Gas commissioned Innovative to complete a series of focus groups and in-depth interviews focusing on these specific topics. This work was completed in June and July of 2022. This additional customer engagement used a similar approach to Phase One of the main customer engagement, and a total of 10 focus groups with residential customers, and 20 in-depth interviews with business customers were completed. The final report was prepared by Innovative and distributed to key stakeholders across the Company. Please see Exhibit 8, Tab 2, Schedule 3 for further discussion.

2. Overall Results

34. Customer engagement results were important inputs into Enbridge Gas's business planning activities. Please see the Innovative report provided at Attachment 1 and the Transportation report provided at Attachment 2 for more detailed customer

engagement results. Specific topics from the Phase Three results are discussed in the various exhibits of this Application. Their main locations are outlined in Table 4. Key themes from the results are addressed in the paragraphs below.

Table 4
Summary of Investment Choices and Location in the Evidence (order according to Phase Three General Service Residential Customer Workbook)

#	Area	Choices Topic	Location in the Application
1	Distribution	Compression Station	Within the Asset Management Plan in Exhibit 2, Tab 6, Schedule 2
2		Vintage Steel Pipeline Replacement Program	Within the Asset Management Plan in Exhibit 2, Tab 6, Schedule 2
3		Hydrogen Gas	Within the Asset Management Plan in Exhibit 2, Tab 6, Schedule 2 and the Hydrogen evidence Exhibit 4, Tab 2, Schedule 6
4		Innovation and Technology Fund	Exhibit 1, Tab 10, Schedule 7
5		Cutoff at Main (residential only)	Exhibit 8, Tab 3, Schedule 1
6		Cross Bores	Within the Asset Management Plan in Exhibit 2, Tab 6, Schedule 2
7		Advanced Meter Infrastructure[7]	Exhibit 2, Tab 7, Schedule 2
8	Fuel	Responsibly Sourced Gas (RSG)	Included in the 2022 Annual Gas Supply Plan Update, EB-2022-0072
9		Renewable Natural Gas (RNG)	Exhibit 4, Tab 2, Schedule 7
10	Harmonization (General Service)	Infill Policy	Exhibit 8, Tab 3, Schedule 1
11		Rate Zones	Exhibit 8, Tab 2, Schedule 1
12		Rate Design – Cost of being connected to the system	Exhibit 8, Tab 2, Schedule 3
13		Rate Design – Cost of accessing portion of the system	Exhibit 8, Tab 2, Schedule 3
14	Contract Customer Service Harmonization	Various topics	Exhibit 8, Tab 4, Schedules 1 through 6

[7] Advanced Meter Infrastructure was covered in the customer engagement but is no longer requesting approval in this Application. For more detail, please see Exhibit 2, Schedule 7, Tab 2.

#	Area	Choices Topic	Location in the Application
15	Transportation Service Harmonization	Parkway Station Rate Design Considerations	Exhibit 7, Tab 1, Schedule 4

2.1. Customer Needs and Preferences

35. Customers are generally satisfied with the utility service experience received from Enbridge Gas and have few unmet needs. Across customer groups, including transportation customers and Ontario producers, satisfaction was strong across the various phases. In Phase Three, overall satisfaction was measured at 80% among residential customers, 74% among non-contract business customers, and 84% among contract customers. Similarly, the majority of transportation customers (14/15 customers) and Ontario producers (6/6 customers) expressed satisfaction with Enbridge Gas.

2.2. Outcome Priorities

36. All customers were asked to consider a list of outcomes as part of this customer engagement. Reliably and safely delivering natural gas are two top priorities in terms of importance across all customer groups, followed closely by providing affordable pricing. A second tier of priorities included providing dependable customer service, making good use of the money customers pay and minimizing any environmental impacts. Providing predictable pricing was also among this list of second tier priorities for transportation customers and Ontario producers. Following these priorities were being socially responsible and supporting economic growth.

37. When asked to rank priorities, general service customers placed affordable pricing at the top of the list, while it was rated second or third among other customer groups. Reliably and safely delivering natural gas were also key priorities, followed closely by minimizing any impacts on the environment.

2.3. High-level Investment Trade Offs

38. When asked if Enbridge Gas should invest in improving or maintaining levels of natural gas safety, reliability and customer service, most customers would prefer that it focus on maintaining current levels.

39. Generally, customers prefer that Enbridge Gas look at the long-term health of the system and spread costs out evenly over time even if there is an impact to rates.

40. At a high level, respondents had the opportunity to provide feedback on the Enbridge Gas business plan objectives, climate change goals, and efforts to reduce GHG emissions from natural gas, all of which may introduce higher costs that would be passed on to customers. A clear majority of general service and contract customers indicated this to be the right approach.

41. Furthermore, at least two thirds of customers (general service and contract) supported the draft rate increase included in the workbook as a result of the draft plan. Generally, customers chose to spend more now to improve Enbridge Gas assets rather than delay. Customers were also supportive of initiatives related to Hydrogen gas and the Innovation and Technology Fund, named the Energy Transition Technology Fund in this Application.

2.4. Results for Harmonization Topics

42. The customer engagement also covered various rate and service harmonization topics. Among general service customers, this included questions about rate zones, rate design, as well as the infill policy for residential customers. Among contract customers a large number of service harmonization topics were included, covering both contract rate distribution services and direct purchase services. Please see the

Innovative report provided at Attachment 1, pages 453-499 for these topics and results. Please see Exhibit 8, Tab 4, Schedules 1 – 6 for a discussion of the results.

43. Similarly, a series of rate design questions for transportation customers and Ontario producers were included in their respective workbooks. Please see the Transportation report provided at Attachment 2, pages 12-15, 30-33.

44. Please see Table 5 for a summary of the overall results of customer reactions to various investment choices.

Table 5
Customer Engagement Results of Investment Choices (Phase Three)

#		Choices Topic	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Results
1	Distribution	Compression Station	Replace as planned	Defer beyond period			Customers clearly preferred the plan to replace
2		Vintage Steel Pipeline Replacement Program	Increase its spending	Defer proactive replacement			Customers support the proactive replacement of vintage steel pipelines
3		Hydrogen Gas	Implement plans to invest more (expand pilot project and complete a feasibility study)	Not implement these plans for further investments			Customers support plans for Hydrogen
5		Innovation and Technology Fund	Spend $1M/year	Spend $5M/year	Spend $10M/year	No fund	Customers support a fund but are fairly evenly divided over the amount
6		Cutoff at Main (residential only)	Charge homeowners the full cost	Charge homeowners some ($750)	Not charge homeowners		Customer feedback is mixed -some prefer homeowners be charged full cost, others none

Table 5
Customer Engagement Results of Investment Choices (Phase Three)

#		Choices Topic	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Results
7		Cross Bores	Proactive program (inspections and prevention)	Leave processes as they are			Customer feedback is mixed – slightly more businesses prefer the implementation of proactive programs, while slightly more residential customers prefer leaving processes as they are
8		Advanced Meter Infrastructure	As soon as it is feasible	Moderate pace	Slower pace	Replace meters only as required	Residential and business customers agree that proceeding with advanced meter infrastructure at a moderate pace is the way to go, followed by the option to proceed at a slower pace
9	Fuel (General Service customers only)	Responsibly Sourced Gas (RSG)	Commit to 10% RSG in the gas supply	Commit to 25% RSG in the gas supply	Commit to 50% RSG in the gas supply	Not add any RSG if there is added costs	Customers prefer some investment in RSG, but there is no strong consensus on the amount
10		Renewable Natural Gas (RNG)	Increasing RNG to 8% of gas supply	Increasing RNG to 5% of gas supply	Increasing RNG to 2% of gas supply	Not add any RNG if there is added costs	Customers prefer some investment in RNG, but there is no strong consensus on the amount

Table 5
Customer Engagement Results of Investment Choices (Phase Three)

#		Choices Topic	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Results
11	Harmonization (General Service customers only)	Infill Policy (residential only)	Offer 15 metres at no cost to the homeowner and charge $75/m for the remainder	Offer 20 metres at no cost to the homeowner and charge $100/m for the remainder	Offer 25 metres at no cost to the homeowner and charge $140/m for the remainder		Of the choices, customers generally preferred 15 metres at no cost to the homeowner and a charge of $75/m for the remainder
12		Rate Zones	Implement a single rate zone and make the rates for natural gas service the same across Ontario	Leave the rate zones as they are where customers pay different rates for natural gas service			Customer results varied by rate zone, with customers who benefitted from the changes generally supporting one rate zone, while those who did not benefit preferring to leave it as is
13		Rate Design – Cost of being connected to the system	Each customer should pay a portion based on the amount of natural gas they use	The cost should be paid equally by customers of the same type regardless of how much natural gas they use			Customers tend to prefer for each customer to pay a portion based on their usage

Table 5
Customer Engagement Results of Investment Choices (Phase Three)

#		Choices Topic	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Results
14		Rate Design – Cost of accessing portion of the system	Each customer should pay a portion based on the amount of natural gas they use	The cost should be paid equally by customers of the same type regardless of how much natural gas they use			Customers tend to prefer for each customer to pay a portion based on their usage

2.5. Final proposals as a result of Customer Engagement responses

45. In the Phase Three workbook customers were shown draft proposals of Enbridge Gas's business plan and asked to share their preferred approach of the choices offered and provide additional comments if needed. Enbridge Gas teams then reviewed the results of Phase Three to produce a final business plan for this Application. Phase Three results are discussed in relation to the final business plan in the various exhibits of this Application. Their main locations are outlined in Table 4.

3. Summary

46. Using a three-phase approach designed to provide feedback to Enbridge Gas at key stages in the development of the Application, the customer engagement process identified customer expectations, the outcomes of greatest value to them, and solicited feedback on specific investment and rate design options. The results of the customer engagement directly informed the final Application, with adjustments made to proposed business plans to reflect customer needs and preferences. Diagnostic questions included within Phase Three workbooks confirm the quality of the customer engagement. Phase Three results also show support for 2024-2028 business plan objectives, climate change goals, and reducing GHG emissions from natural gas, with a clear majority across all customer segments indicating that Enbridge Gas is taking the right approach.

47. Customer engagement and all other market research conducted by Enbridge Gas is an integral part of Enbridge Gas's business planning process to ensure customer needs and preferences are being kept at the forefront. Enbridge Gas will continue to engage with customers through all the various channels it currently has in place and address customer feedback as necessary.

Enbridge Gas 2024 Rate Rebasing Customer Engagement

March 2022

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INNOVATIVE RESEARCH GROUP

Customer Engagement Report

March 2022

Confidentiality

This report and all of the information and data contained within may not be released, shared, or otherwise disclosed to any other party, without the prior, written consent of Enbridge Gas Inc.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Enbridge Gas. The conclusions drawn and opinions expressed are those of the authors.

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Table of Contents

Table of Appendices

Introduction

Innovative Research Group Inc. (INNOVATIVE) was engaged in the Spring of 2021 to help design, execute, and document the results of Enbridge Gas Inc.'s customer engagement, as part of their 2024 Rate Rebasing Application to the Ontario Energy Board (OEB) for the years 2024 to 2028.

Early in 2017, the OEB's *Handbook for Utility Rate Applications (Handbook)*[1] was supplemented with amended filing requirements for natural gas rate applications, which make the following stipulations regarding customer engagement:

- *"…utilities are expected to demonstrate value for money by delivering genuine benefits to customers and providing services in a manner which is responsive to customer preferences. Customer engagement is expected to inform the development of utility plans, and utilities are expected to demonstrate in their proposals how customer expectations have been integrated into their plans, including the trade-offs between outcomes and costs.*
- *The OEB expects natural gas utilities to provide an overview of customer engagement activities undertaken and how their customer's* ***needs***, ***preferences*** *and expectations have been reflected in the elements of the application."*[2]

Needs questions focus on understanding the gap between the services and experience customers want, and the services and experience customers are receiving.

Preferences questions focus on customer views about the outcomes the utility should focus on, priorities among those outcomes, and trade-offs illustrated by choices on specific programs or the pacing and prioritization of investments.

This engagement was completed in three phases. Phase One took place in June of 2021 and focused on identifying customers' perceptions of the key issues they would like the Enbridge Gas rate application to address. In July 2021, customer feedback and key findings from this phase were provided to Enbridge Gas planners to provide initial customer input into the development of draft investment plans.

Data collection for Phase Two was carried out in August of 2021, with the objective of understanding customer opinions on their needs and key outcomes. Phase One collected the range of views in these areas, while Phase Two used surveys to draw generalized conclusions. In addition to overall satisfaction, the survey touched on asset management, rate design, customer care, new or harmonized programs and policies, and energy transition. A final open-ended question allowed respondents to provide any additional comments they felt Enbridge Gas should take into account when developing their investment plan. Customer feedback from Phase Two was provided to Enbridge Gas planners in September 2021 in advance of the preparation of the draft investment plan.

Following Phase Two, Enbridge Gas developed a draft plan that built on the findings of the first two phases of the customer engagement as well as other business objectives. The Phase Three survey was then designed to provide feedback that could be used by Enbridge Gas as it finalized its plan and its submission to the Ontario

[1] Handbook for Utility Rate Applications (October 13, 2016)

[2] OEB Filing Requirements for Natural Gas Rate Applications, Section 2.1.6.

Energy Board (OEB). Data collection for Phase Three took place started in December 2021 and carried over into early January of 2022. Most of the reports were provided to Enbridge Gas in January 2022 except for Contract Customers, which was provided in February 2022.

This document provides an overview of the Enbridge Gas 2024 Rate Rebasing customer engagement process and a summary of the generalizable results from the representative surveys.

- A detailed description of the methodology can be found in the section ("Designing This Engagement")
- Detailed results can be found in the attached customer engagement Appendices.

Executive Summary

Enbridge Gas took a three-phase approach to identify customer needs and preferences:

- **Phase One** used qualitative tools to identify key customers' needs and outcomes.
- **Phase Two** used random sample surveys of customers to draw generalizable conclusions regarding customer needs and outcomes as well as exploring some initial trade-offs and rate design issues.
- **Phase Three** used a workbook approach to further explore key planning trade-offs, the overall rate impact of the draft plan, and rate design issues.

The engagement found the following key findings:

Enbridge Gas customers are generally satisfied and have few unmet needs.

Overall satisfaction with Enbridge Gas was included in all three waves. In the survey waves business satisfaction ranged from 74% to 85% while residential satisfaction was at 78% to 86%. When asked what else Enbridge Gas could do to improve their service, most customers had no suggestions for improvement. Lower rates was the most common comment among those who had a suggestion. Consistent with these findings, when customers in the Phase Two engagement were asked whether Enbridge Gas should aim to maintain or improve safety, reliability and customer service, customers consistently chose maintain rather than improve.

Reliable and Safe Delivery and Affordable Pricing Top Outcomes

When customers are asked how they know if Enbridge Gas is doing a good job, the top mention by far is consistent service with few or no interruptions.

When in Phase Two, customers were asked to rate the importance of a list of nine outcomes generated from input in Phase One, reliably and safely delivering natural gas were the top two, with affordable prices either tied or slightly behind, depending on the survey. A second tier of priorities included providing dependable customer service, providing predictable pricing, making good use of the money customers pay, and minimizing environmental impacts. Being socially responsible was rated below those items, and supporting economic growth was the least important of the outcomes.

Customers were then asked to rank their top three outcomes. Providing affordable pricing topped the list this time. Safely and reliably delivering natural gas formed a second tier along with minimizing environmental impacts. Providing dependable customer service, making good use of the money customers pay, and providing predictable pricing was a third tier. Again, being socially responsible and supporting economic growth had the lowest levels of support.

At Least Two Thirds in Each Customer Segment Support the Draft Rate Increase

Most customers are willing to accept the average 1.9% price increase resulting from Enbridge Gas draft plan. Looking at the specific initiatives prior to the rate increase question, customers chose to spend more now to improve Enbridge Gas' assets than delay. This was demonstrated in the pacing question in Phase Two and with investment choices in Phase Three. These choices included programs such as compressor stations and vintage steel pipeline replacement and expanding its hydrogen gas program.

Customers Prefer to Pay by Volume, Mixed Views on Single Rate Zone

Reaction to a Single Rate Zone tended for follow the regional benefits. In Union South, which would see an increase, customers generally opposed moving to a single rate zone. In the Northern rate zones which see rate decreases, customers support the move to a single rate zone by wide margins. The EGD rate zone is also more likely to support than oppose a single rate zone, but by smaller margins.

Customers strongly prefer to pay based on use whether customers were asked about the cost of connecting to the system or the cost of accessing system capacity. Even high-volume residential customers agree.

Customers Would Like to See Some Effort Made Towards Cleaner, More Responsible Fuel Choices

Majorities of both business and residential customers are prepared to pay more for more responsibly sourced natural gas, but there is no consensus on how much more they are willing to pay.

Similarly, majorities of both business and residential customers are prepared to pay more for more Renewable Natural Gas, but there is no consensus on how much more they are willing to pay.

Key Findings

Phase One: Exploring the Range of Views

Methodology: Focus groups with residential customers and one-on-one interviews with small and med-large business customers

Customer Needs

Most residential and business participants are satisfied with their overall experience with Enbridge Gas. They don't have to think about their natural gas supply and that is the way they like it. For most participants, the most frequent interaction comes when they receive their bills. And, for most participants, bills are seen as predictable and relatively affordable.

Good things customers identified for Enbridge Gas to keep doing:

- Uninterrupted service
- Good customer service
- Transparent billing
- Reasonable price

Primary areas where customers feel there is room for improvement:

- Price
- Onsite service calls
- Billing issues

Customer Outcomes

Typically, participants were slow to engage on this topic until a list of possible outcomes was shared. Participants tended to take natural gas service for granted and didn't enter the conversation with a lot of pre-existing thoughts. However, once the list was shared, participants quickly became more focused in their comments.

Priority outcomes for customers:

- Reliability and safety (table stakes)
- Pricing
- Customer service
- Minimizing environmental impacts

Rate Design

- When discussing how bills should be calculated, there was a strong consensus that customers should pay the variable cost of the natural gas they themselves use. It was also clear that most participants believe that fixed costs related to how much natural gas customers use should also be allocated based on use.
- For infrequent transactions, such as account openings, meter tests and meter turn offs, both residential and business customers generally lean to a user pay approach.
- There was strong interest in moving to a single rate zone. Most supported a single rate zone for fairness. They felt all customers get the same natural gas, so they should pay the same rate.
- When asked whether Enbridge Gas should have the flexibility to use money in reserves to avoid having to borrow money, participants expressed considerable interest in giving Enbridge Gas flexibility if it means potential savings for customers.

Energy Transition

- Most participants in both customer segments feel customers like them will use the same or less natural gas in the future.
- Many participants were not familiar with any options available to Enbridge Gas to reduce greenhouse gases. Only a few participants were aware of biogas and other approaches to replace traditional natural gas from fossil fuels with renewable natural gas or similar alternatives such as hydrogen.
- Enbridge Gas is seen – by both residential and business participants – as having a potential role in funding research or in informing customers about available options.
- Most participants are not willing to accept less reliability to improve environmental impacts. There are two core concerns:
    - Loss of natural gas supply in winter
    - Business interruption
- Most participants in both customer segments were willing to pay more for natural gas if that will reduce negative environmental impacts.
- While most participants seemed open to paying for a research fund, residential participants, in particular, seemed less likely to support research than paying more for greener natural gas.

Phase Two: Drawing Broader Conclusions

Methodology: Online and telephone surveys with residential and small to med-large business customers

Overall Satisfaction

Overall, most residential and general service business customers are satisfied with the service provided by Enbridge Gas. Most of the business surveys were completed online, and the level of satisfaction among them and the online residential survey respondents is virtually identical.

Customer Outcomes

INNOVATIVE explores customer outcome priorities in three ways:

1. Customers are asked to rate outcomes to identify how much importance customers place on each outcome.
2. Customers are asked to rank outcomes to give planners some sense of how to resolve conflicts between outcomes of similar importance in the rating section.
3. Finally, customers are asked to choose between outcomes in specific program choices later in the Phase Two survey and in the Phase Three survey.

The ratings and rankings provide general guidance, particularly at the early stage of planning when investment options still need to be developed.

Using a list based on participant feedback garnered in Phase One and research with customers conducted by Enbridge Gas prior to this customer engagement, survey respondents were asked to indicate which specific outcomes or goals are most important to them. The list and results are presented in the table below:

% Extremely Important (9-10 on 0-10 scale)	**Residential [online] (n=2,400)**	**Residential [telephone] (n=600)**	**Small Business (n=400)**	**Med-Large Business (n=169)**
Safely delivering natural gas	88%	85%	89%	88%
Reliably delivering natural gas	87%	79%	89%	87%
Providing affordable pricing	86%	71%	89%	82%
Providing dependable customer service	81%	68%	83%	84%
Making good use of the money customers pay	80%	64%	81%	74%
Providing predictable pricing	76%	57%	78%	71%
Minimizing any impacts on the environment	69%	62%	68%	66%
Being socially responsible	57%	51%	60%	50%
Supporting the growth of Ontario’s economy	49%	40%	57%	49%

All customers agree that safely and reliably delivering natural gas are the two most important outcomes for Enbridge Gas to consider. Providing affordable pricing is as important as reliable delivery among online residential and small business respondents, while being slightly less important among telephone residential and medium-large business respondents. Across all surveys, there is a consensus that being socially responsible and supporting the growth of Ontario's economy are the least important outcomes.

When asked to indicate which outcome was MOST important to them, a slightly different picture emerges, with all customer segments putting providing affordable pricing at the top of the list, and safely delivering natural gas dropping to a distant second for residential customers and even lower among the business customers. Once again, being socially responsible and supporting the growth of Ontario's economy are at the bottom of the list.

% Saying Outcome is MOST Important	Residential [online] (n=2,400)	Residential [telephone] (n=600)	Small Business (n=400)	Med-Large Business (n=169)
Providing affordable pricing	41%	29%	43%	35%
Safely delivering natural gas	15%	18%	13%	13%
Minimizing any impacts on the environment	15%	18%	10%	6%
Reliably delivering natural gas	14%	13%	15%	23%
Providing dependable customer service	5%	3%	5%	4%
Making good use of the money customers pay	3%	2%	4%	2%
Providing predictable pricing	3%	5%	7%	10%
Being socially responsible	1%	2%	1%	1%
Supporting the growth of Ontario's economy	1%	2%	1%	4%
Don't know	1%	8%	2%	3%

***NOTE**: Outcomes are shown in ranked order according to online residential survey results.*

Asset Management

When it comes to the level of safety, reliability and customer service they receive from Enbridge Gas, most general service residential and business customers would like the utility to invest in maintaining rather than improving the current level.

Of the three metrics included in the survey, residential customers are most likely to want Enbridge Gas to invest in improving the current level of safety, whereas general service business customers would prefer investment in improving the level of customer service.

Presented with a trade-off between a long-term approach to asset health versus a more immediate approach, along with the accompanying impact on rates, a majority of both residential and general service business customers feel Enbridge Gas should take a long-term approach, spreading costs out evenly over time, even it means higher rates now. Most strongly in favour of this approach are the medium-large business customer segment.

	Residential [online] (n=2,400)	Residential [telephone] (n=600)	Small Business (n=400)	Med-Large Business (n=169)
Enbridge Gas should look at the long-term health of the system and spread costs out evenly over time even if that means higher rates now	58%	59%	54%	64%
Enbridge Gas should focus on the immediate impact on rates and only spend what it takes to keep the system in good order now to keep rates low, even if that means an increase in rates later that may end up being more expensive for customers overall	21%	15%	25%	20%
I don't have an opinion on this	14%	15%	14%	12%
Don't know	7%	11%	7%	4%

Rates

Network Connection

All survey respondents were provided with the following preamble and then asked how they feel customers should be billed for these costs:

> *One type of fixed cost is that of being connected to the network. This includes the cost of the pipeline, the pressure regulator, the natural gas meter, meter reading, billing, the contact centre and operations support. These costs are fixed for Enbridge Gas, and are similar for each customer and do not change based on the size of the customer.*

While the opinion of medium-large business respondents is a bit more tentative, all general service customers feel that each customer should pay a portion of network connection costs based on the amount of natural gas they use.

	Residential [online] (n=2,400)	Residential [telephone]	Small Business (n=400)	Med-Large Business (n=118)*
Each customer should pay a portion based on the amount of natural gas they use	61%	n/a	65%	50%
The cost should be paid equally by customers of the same type (i.e. residential or business)	30%		25%	33%
I don't have an opinion on this	5%		5%	11%
Don't know	4%		5%	6%

** As this question was only asked online, the weighted sample size for medium-large business customers is n=118 rather than the N=169 when telephone and online are combined.*

Network Capacity

All survey respondents were provided with the following preamble and then asked how they feel customers should be billed for these costs:

> *One type of fixed cost is that of the network capacity. This includes the cost of the network infrastructure, its operation, maintenance, and natural gas storage to meet the peak demand of customers on the coldest days of the year. These costs are fixed for Enbridge Gas but may vary for each customer based on their individual level of peak demand.*

Similar to network connection costs, all general service customers feel each customer should pay a portion of network capacity costs based on the amount of natural gas they use (on the coldest days of the year).

	Residential [online] (n=2,400)	Residential [telephone]	Small Business (n=400)	Med-Large Business (n=118)*
Each customer should pay a portion based on the amount of natural gas they use on the coldest days of the year	62%	n/a	62%	58%
The cost should be paid equally by customers of the same type (i.e. residential or business)	26%		25%	26%
I don't have an opinion on this	7%		8%	13%
Don't know	6%		5%	3%

** As this question was only asked online, the weighted sample size for medium-large business customers is n=118*

Rate Zones

All survey respondents were provided with a preamble to provide background based on the current rate zones and regions. They were then given some idea of the financial impact of Enbridge Gas moving forward with a single rate zone across Ontario. The financial impact was specific to the customer segment (ie. residential vs business).

Residential customers:

- *Approximately 60% of customers will see very little change to the amount they pay today.*
- *Approximately 30% of customers will see an increase of roughly 5% (or roughly $5 per month).*
- *Approximately 10% of customers will see a decrease of roughly 10% (or roughly $10 per month).*

Business customers:

> *The impact is dependent on the amount of natural gas you use but could range from +5% to -10% of the amount you pay today.*

Residential and business customers alike feel Enbridge Gas should implement a single rate zone for natural gas service across the province. However, opinion among medium-large business customers specifically is much more evenly divided than small business, with only a marginal two-point difference between those who prefer a single rate zone over maintaining different rate zones.

	Residential [online] (n=2,400)	Residential [telephone]	Small Business (n=400)	Med-Large Business (n=118)*
Enbridge Gas should implement a single rate zone and make the rates for natural gas service the same across Ontario	47%	n/a	45%	40%
Enbridge Gas should leave the rate zones as they are where customers pay different rates for natural gas service based on where they [live/operate]	34%		33%	38%
I don't have an opinion on this	11%		15%	14%
Don't know	7%		7%	8%

** As this question was only asked online, the weighted sample size for medium-large business customers is n=118*

Customer Care

While general service customers do not feel it is terribly important for Enbridge Gas to offer customers the option to pay their bills by credit card, they do feel strongly that the fees for credit card payments should be paid for only by those who choose that method of payment.

Importance of providing the option to pay by credit card	Residential [online] (n=2,400)	Residential [telephone] (n=600)	Small Business (n=400)	Med-Large Business (n=169)
Important	47%	46%	52%	39%
Not Important	51%	51%	45%	56%
Don't know	3%	3%	3%	6%

	Residential [online] (n=2,400)	Residential [telephone] (n=600)	Small Business (n=400)	Med-Large Business (n=169)
Spread out among all customers	10%	10%	12%	10%
Paid by the customer choosing to pay by credit card	81%	67%	78%	77%
I don't have an opinion on this	7%	16%	8%	11%
Don't know	3%	7%	2%	2%

New or Harmonized Programs and Policies

Cross Bores

After reading a description of utility cross bores, survey respondents were asked the following question:

> *These programs to proactively inspect and resolve existing cross bores and to prevent the creation of cross bores during the completion of new installations combined would cost customers $0.50 per year for 5 years. Which of the following is closest to your view?*

A strong majority of all general service customers feel Enbridge Gas should proceed with the more costly proactive program rather than an approach that may increase safety risk.

	Residential [online] (n=2,400)	Residential [telephone]	Small Business (n=400)	Med-Large Business (n=118)*
Enbridge Gas should implement the proactive program and continue with the preventative program to eliminate existing cross bores and prevent any new cross bores to maintain safety, even though it costs more.	63%	n/a	58%	59%
Enbridge Gas should leave its processes of trenchless drilling as is and only resolve those that come up as an issue arises, even though this may create additional cross bores which increases safety risk.	13%		13%	21%
I don't have an opinion on this	17%		20%	18%
Don't know	7%		9%	1%

** As this question was only asked online, the weighted sample size for medium-large business customers is n=118*

Automated Meter Infrastructure

Survey respondents were asked how important specific features of automated meters are to them.

All general service customers agree that enabling Enbridge Gas to better detect and respond to possible leaks is the most important feature. Residential and small business customers feel remote shut-off is the next most important feature, but for medium-large business customers, the elimination of estimated meter reads is more important. Eliminating the need for Enbridge Gas to access their property is considered the least important feature by all general service customer segments.

% Very or Somewhat Important	Residential [online] (n=2,400)	Residential [telephone] (n=600)	Small Business (n=400)	Med-Large Business (n=169)
Enable Enbridge Gas to better detect and respond to possible gas leaks	94%	95%	91%	90%
Enable Enbridge Gas to remotely and automatically shutoff gas supply if needed in the event of an emergency	90%	89%	89%	82%
Lower GHG emissions by reducing meter reader vehicles on the road	67%	68%	71%	71%
Eliminate the need for estimated meter reads (where your usage and bill are estimated and adjusted in a following month)	67%	59%	70%	84%
Enable access to more accurate, hourly updates to better understand and manage your natural gas use	66%	57%	66%	72%
Eliminate Enbridge Gas' need to regularly access your property to conduct a meter reading	53%	48%	57%	58%

NOTE*: Features are shown in ranked order according to online residential survey results.*

Energy Transition

Compared to today, most general service customers anticipate that customers like them will be using about the same amount of natural gas in 10 years, ranging from 44% of medium-large business customers to 58% of online residential respondents. At 27%, medium-large business respondents are more likely than others to anticipate customers like them using more natural gas in 10 years.

Thinking further ahead, a plurality of residential and small business customers anticipate customers like them will be using less natural gas in 30 years than they do today. Opinion among medium-large business customers is divided, with 29% saying less, 28% saying more and 25% saying about the same.

Considering options and solutions to reduce impacts on the environment, all general service customers responded similarly, with the highest level of agreement that Enbridge Gas should actively be investing in low-carbon options and solutions that would help reduce impacts on the environment. Across the board, the lowest level of agreement was that Enbridge Gas is well-positioned to support the development of low-carbon options and solutions – though it is worth noting that a majority in all customer segments agree with this statement.

% Completely or Somewhat Agree	Residential [online] (n=2,400)	Residential [telephone] (n=600)	Small Business (n=400)	Med-Large Business (n=169)
Enbridge Gas should actively be investing in low-carbon options and solutions that would help reduce impacts on the environment	81%	87%	81%	77%
I look to Enbridge Gas to help develop offerings and new solutions that will help me reduce my natural gas usage	75%	75%	77%	71%
Given its experience, Enbridge Gas is well positioned to support the development of low-carbon options and solutions	56%	61%	56%	55%

***NOTE**: Results are shown in ranked order according to online residential survey.*

Reduce Demand/Avoid New Infrastructure (IRP)

Following a preamble about finding options to reduce demand or avoid new infrastructure projects altogether, survey respondents were asked the following question:

> *How much, if anything, would [you/your organization] be willing to pay per year for Enbridge Gas to develop solutions in natural gas conservation and other non-pipeline alternatives instead of new pipeline or capacity projects?*

Across all general service customer segments, at least a plurality said they would not be willing to pay anything extra.

	Residential [online] (n=2,400)	Residential [telephone]	Small Business (n=400)	Med-Large Business (n=118)*
RES: $1.00/month or $12.00 extra per year BUS: 2% added to the delivery portion of your bill	19%	n/a	17%	21%
RES: $2.00/month or $24.00 extra per year BUS: 4% added to the delivery portion of your bill	13%		8%	3%
RES: $4.00/month or $48.00 extra per year BUS: 8% added to the delivery portion of your bill	8%		1%	0%
RES: $10.00/month or $120.00 extra per year BUS: 10% added to the delivery portion of your bill	4%		3%	2%
Some other amount	0%		1%	2%
I would not be willing to pay anything extra	42%		52%	52%
Don't know	14%		17%	19%

** As this question was only asked online, the weighted sample size for medium-large business customers is n=118*

Low-Carbon Options/Greening the Gas

Respondents were also given examples of how Enbridge Gas might reduce the amount of greenhouse gas emissions, such as blending traditional natural gas with renewable natural gas.

Almost half of business customers said they would not be willing to pay anything extra to "green the gas", which is a significantly larger proportion than among residential customers (35%). Across all general service segments, about one-in-four said they would be willing to pay the lowest amount.

	Residential [online] (n=2,400)	Residential [telephone]	Small Business (n=400)	Med-Large Business (n=118)*
RES: $1.00/month or $12.00 extra per year BUS: 2% added to the delivery portion of your bill	23%	n/a	22%	26%
RES: $2.00/month or $24.00 extra per year BUS: 4% added to the delivery portion of your bill	14%		12%	5%
RES: $4.00/month or $48.00 extra per year BUS: 8% added to the delivery portion of your bill	11%		1%	0%
RES: $10.00/month or $120.00 extra per year BUS: 10% added to the delivery portion of your bill	6%		3%	3%
Some other amount	1%		1%	3%
I would not be willing to pay anything extra	35%		47%	48%
Don't know	11%		14%	16%

** As this question was only asked online, the weighted sample size for medium-large business customers is n=118*

New Technologies

Asked if they would be willing to pay anything extra for Enbridge Gas to develop solutions in developing and advancing new low-carbon and energy efficient technologies, the proportion not willing to pay anything extra ranges from 37% among residential customers to 52% of medium-large business customers. About one-in-five across all segments said they would be willing to pay the lowest amount.

	Residential [online] (n=2,400)	Residential [telephone]	Small Business (n=400)	Med-Large Business (n=118)*
RES: $1.00/month or $12.00 extra per year BUS: 2% added to the delivery portion of your bill	23%	n/a	20%	23%
RES: $2.00/month or $24.00 extra per year BUS: 4% added to the delivery portion of your bill	13%		10%	5%
RES: $4.00/month or $48.00 extra per year BUS: 8% added to the delivery portion of your bill	10%		2%	0%
RES: $10.00/month or $120.00 extra per year BUS: 10% added to the delivery portion of your bill	4%		3%	1%
Some other amount	1%		1%	4%
I would not be willing to pay anything extra	37%		48%	52%
Don't know	12%		15%	14%

** As this question was only asked online, the weighted sample size for medium-large business customers is n=118*

Certified Natural Gas

Respondents were provided the following preamble and then asked if they would support Enbridge Gas sourcing this type of natural gas, even if it comes at a small premium.

> *Enbridge Gas is looking at options to ensure that the natural gas it purchases is responsibly sourced. This means the companies who produce the natural gas adhere to higher standards than the minimum government standards. This relates to areas such as minimizing impacts to air and water quality, lowering carbon emissions during production, and stronger engagement with Indigenous communities, etc. While it may not always cost more, it is possible that this responsibly sourced natural gas comes at a small premium and would cost customers a little bit more.*

At least half of all general service customers support this initiative, ranging from 50% among small business customers to 55% among residential customers.

	Residential [online] (n=2,400)	Residential [telephone]	Small Business (n=400)	Med-Large Business (n=118)*
Support	55%	n/a	50%	51%
Neutral	19%		19%	27%
Oppose	20%		21%	17%
Don't know	7%		10%	5%

** As this question was only asked online, the weighted sample size for medium-large business customers is n=118*

Final Comments

At the end of the surveys, respondents were asked a final open-ended question:

Is there anything that you would like to share with Enbridge Gas as it works on building its investment plan for the future?

All responses were coded. The full range of comments are provided in the separate detailed reports for residential and business customers, but the following table summarizes the most common themes across the general service customer base.

Most online residential and small business respondents said there was nothing they wanted to share, as did a plurality of telephone residential and medium-large business respondents.

Small numbers mentioned things like rates, the environment, that Enbridge Gas should fund research and development rather than customers, and billing issues.

	Residential [online] (n=2,400)	Residential [telephone] (n=600)	Small Business (n=400)	Med-Large Business (n=169)
Nothing	**60%**	**38%**	**61%**	**46%**
No response	**2%**	**13%**	**4%**	**14%**
Keep cost low/reasonable pricing/No rate increases	7%	7%	5%	3%
Doing a great job/keep up the good work	3%	7%	1%	2%
Prioritize the environment/Reduce carbon footprint/GHG/emissions	3%	3%	3%	2%
Cost of R&D/business/improvements should be paid by Enbridge (profits) not the customer	3%	0%	3%	3%
Resolve billing issues/Inaccurate meter readings/equalized payments	1%	4%	3%	3%

Phase Three: Reacting to the Plan

Methodology: Online workbook surveys with residential, small to med-large business customers, and contract customers

NOTE: Due to the small sample of Contract customers, results in this section are shown as frequencies to remind readers the sample is limited as well as percentages to facilitate at least a directional comparison to the residential and business customer segments.

Satisfaction with Enbridge Gas

Consistent with Phase Two, a solid majority of customers across all customer segments are satisfied with the service they receive from Enbridge Gas. Satisfaction among residential customers is higher than among business customers.

Satisfaction with Enbridge Gas' Performance	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)	Contract (n=89)
Satisfied	80%	74%	80%	73%	84% (75)
Dissatisfied	5%	8%	7%	8%	9% (8)
Neutral/Don't know	15%	18%	14%	19%	7% (6)

Making Choices

Customers were presented with background information to help them give an informed opinion on how Enbridge Gas should address a variety of planning issues. After reviewing the background information, customers were asked to choose between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down. It should be noted that not all customer segments were asked the same questions, as reflected in the results reported in this section.

Compression Stations

Preferred Approach to Compression Stations	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)	Contract (n=81)
Replace the compressor stations	70%	61%	65%	60%	77% (62)
Defer the compression station project	9%	10%	6%	10%	2% (2)
I don't have an opinion on this	15%	23%	23%	23%	16% (13)
Don't know	6%	7%	6%	7%	5% (4)

A strong majority of customers in every customer segment wants Enbridge Gas to replace compressor stations as it currently plans. Contract and residential customers tend to favour the replacement option more than business customers, whereas business customers are significantly more likely to indicate they don't have an opinion on this issue.

Vintage Steel Pipeline Replacement Program

Preferred Approach to Vintage Steel	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)	Contract (n=81)
Increase its spending	64%	58%	59%	58%	70% (57)
Defer proactive replacement	12%	12%	11%	12%	6% (5)
I don't have an opinion on this	16%	22%	20%	22%	19% (15)
Don't know	7%	8%	10%	8%	5% (4)

Across the customer segments, majorities support increasing the spending in order to replace vintage steel pipelines in order to help prepare the system for the future. Residential customers are significantly more likely to prefer an increase in spending, while business customers are less likely to have an opinion on this issue.

Hydrogen Gas

Preferred Approach to Hydrogen Gas	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)	Contract (n=81)
Should implement these plans	63%	51%	54%	51%	65% (57)
Should not implement these plans	19%	22%	21%	22%	11% (5)
I don't have an opinion on this	12%	19%	17%	19%	21% (15)
Don't know	6%	8%	7%	8%	2% (4)

Among residential and contract customers, majorities support Enbridge Gas implementing its draft plan for blending more hydrogen gas into the natural gas it delivers, even with a rate increase. Business customers are less convinced, but still half prefer this option as well.

Innovation and Technology Fund

Preferred Approach to Innovation & Technology Fund	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)	Contract (n=81)
Spending $1M/year	24%	26%	21%	26%	16% (13)
Spending $5M/year	23%	22%	24%	21%	23% (19)
Spending $10M/year	23%	15%	13%	15%	25% (20)
Should not develop a fund to invest	12%	13%	14%	12%	17% (14)
I don't have an opinion on this	12%	17%	17%	17%	14% (11)
Don't know	6%	8%	12%	7%	5% (4)

Well over half of the customers in all customer segments are willing to pay something towards a technology fund. Equal proportions of residential customers prefer spending $1M, $5M, or $10M/year to develop an innovation and technology fund (along with rate increases that rise with the level of investment). Business customers tend to prefer a lower level of investment (and rate increase), while contract customers are the opposite in favouring a higher level of investment (and rate increase). The higher level of support for this program in Phase Three compared to Phase Two is likely due to providing options with lower monthly costs.

Cut Off at Main

Preferred Approach to Cut Off at Main	Residential (n=5,400)
Charge homeowners the full cost	30%
Charge homeowners $750	18%
Should not charge homeowners	33%
I don't have an opinion on this	13%
Don't know	7%

Residential customers are almost evenly divided on charging homeowners the full cost of a cut off at main and not charging homeowners at all (and sharing these costs among all residential customers). About one-in-five prefer charging homeowners a portion and sharing the rest, while a similar proportion did not indicate a preference.

Cross Bores

Preferred Approach to Cross Bores	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)
Should implement the proactive program	33%	38%	36%	38%
Should leave its processes of trenchless drilling as is	37%	32%	32%	32%
I don't have an opinion on this	21%	22%	26%	22%
Don't know	9%	9%	6%	9%

While there is no clear consensus among either customer segment, residential customers lean in favour of Enbridge Gas staying with their current process of trenchless drilling over implementing a proactive program (along with a rate increase). Among business customers, the reverse is true. The change in the cost of this program between Phase Two and Phase Three is the likely reason for lower support in this phase compared to Phase Two.

Advanced Meter Infrastructure

Preferred Approach to Advanced Meter Infrastructure	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)
As soon as is feasible	18%	18%	25%	18%
Moderate pace	28%	30%	27%	30%
Slower pace	24%	20%	18%	20%
Replace meters only as required	18%	15%	14%	15%
I don't have an opinion on this	8%	11%	11%	11%
Don't know	5%	6%	5%	6%

Residential and business customers are in agreement that proceeding with advanced meter infrastructure at a moderate pace is the way to go, followed by the option to proceed at a slower pace. Less popular options are to proceed as soon as is feasible or to replace meters only as required. Residential customers are split on these two approaches, while business customers lean toward the former.

Social Permission for Draft Rate Increase

At this point in the workbook, respondents were given an opportunity to review all the planning choices they had made, along with their associated rate impacts (if any). The total rate impact was calculated for each individual respondent based on the choices they had made. Respondents were invited to review all of their responses and make changes until they felt they had reached a balance they were comfortable with. Each time they changed a response, their total rate impact was recalculated.

Following a review of their own preferences, customers were then asked to react to the cost of Enbridge Gas' draft plan. This amount was the same for all respondents in a given customer segment. Respondents were asked to indicate whether Enbridge Gas should increase, maintain, or reduce the draft increase.

Social Permission	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)	Contract (n=81)
Should increase its investments	17%	18%	17%	18%	19% (15)
Should maintain the draft increase	54%	49%	55%	49%	62% (50)
Should reduce the draft increase	10%	10%	6%	11%	7% (6)
Other	3%	3%	3%	3%	1% (1)
Don't know	16%	19%	19%	19%	11% (9)
Social Permission (Increase + Maintain)	**71%**	**67%**	**72%**	**67%**	**80% (65)**

Across all customer segments, there is a clear preference for maintaining the draft increase, and an additional one-in-five would like Enbridge Gas to increase its investments, arriving at a level of social permission of 67% among business customers, 71% among residential customers, and 80% (or 65 out of 81) among contract customers.

Service and Rate Harmonization

Respondents were also asked to indicate their preference on several other items that may affect customers, including an infill policy and issues related to how rates are determined.

Infill Policy

Preferred Approach to Infill Policy	Residential (n=5,400)
Offer 15 metres at no cost to the homeowner and $75/m for the remainder	32%
Offer 20 metres at no cost to the homeowner and $100/m for the remainder	22%
Offer 25 metres at no cost to the homeowner and $149/m for the remainder	13%
I don't have an opinion on this	21%
Don't know	11%

When it comes to the infill policy, residential customers prefer the approach of offering 15 metres at no cost to the homeowners with the remaining connection provided at $75 per metre. Customers appear to give priority to avoiding a few really large bills over providing more people with free connections. Almost one-third did not choose any of the options presented to them.

Rate Zones

Preferred Approach to Rate Zones	Residential (n=5,400)	EGD	Union North East	Union North West	Union South
Should implement a single rate zone	40%	43%	63%	50%	29%
Should leave the rate zones as they are	42%	38%	25%	31%	56%
I don't have an opinion on this	11%	12%	7%	11%	9%
Don't know	6%	6%	5%	8%	6%

The Phase Three version of this question was different from the Phase Two question. In Phase Three, the question specifically reminded customers which rate zone they are in. The level and pattern of support shifted when customers more clearly understood the direct impact on their own bills.

Overall, residential customers are divided on whether or not to implement a single rate zone. However, in the three rate zones where implementing a single rate zone would decrease current rates (EGD, Union North), support for a single rate zone ranges from 43% to 63%. In Union South, where a single rate zone would increase current rates, a majority would prefer to leave the rate zones as they are.

Preferred Approach to Rate Zones	Business (n=3,500)	EGD	Union North East	Union North West	Union South
Should implement a single rate zone	41%	42%	48%	48%	34%
Should leave the rate zones as they are	37%	33%	37%	34%	46%
I don't have an opinion on this	15%	17%	10%	11%	13%
Don't know	7%	8%	5%	7%	7%

There is no standout preference among business customers overall, though they do lean toward implementing a single rate zone. But, similar to residential customers, when we look at the different rates zones, those who would benefit from a single rate zone with a decrease in rates tend to prefer that option, while those in Union South – whose rates would rise – would prefer to leave things as they are. Interestingly, among business customers, there isn't a single rate zone where support for either approach reaches the level of a majority.

Rate Design – Cost of Being Connected to the System

Cost of Being Connected to the System	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)
Customers should pay a portion based on use	64%	64%	58%	65%
The cost should be paid equally	24%	22%	25%	21%
I don't have an opinion on this	8%	8%	7%	9%
Don't know	5%	6%	9%	5%

Rate Design – Cost of Accessing System Capacity

Cost of Accessing System Capacity	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)
Customers should pay a portion based on use	70%	68%	62%	68%
The cost should be paid equally	18%	17%	20%	17%
I don't have an opinion on this	7%	9%	10%	9%
Don't know	5%	6%	8%	5%

For both the costs of being connected to the system and of accessing system capacity, a solid majority of residential and business customers feel that customers should pay a portion based on use.

Fuel Choices

Responsibly Sourced Gas

Preferred Approach to Responsibly Sourced Gas	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)
Commit to 10% of responsibly sourced gas	18%	22%	25%	21%
Commit to 25% of responsibly sourced gas	18%	14%	12%	14%
Commit to 50% of responsibly sourced gas	25%	15%	13%	15%
Not add any responsibly sourced gas	21%	24%	27%	24%
I don’t have an opinion on this	11%	17%	16%	18%
Don’t know	8%	8%	6%	8%

Customers were given options to increase the amount of responsibly sourced natural gas that included the proportion of responsibly sourced natural gas and the annual cost of reaching that level. Full details are provided in the Phase Three reports.

A majority of customers would like to see some investment made in sourcing more responsible gas, but there is no consensus among customers on the level of commitment they feel Enbridge Gas should make.

A quarter (25%) would like to see a commitment to 50% responsibly sourced gas, but only four percentage points fewer do not want any responsibly sourced gas if it means an increase in rates. The opinion among all other residential respondents is evenly divided among a commitment of 10%, a commitment of 25%, or not making a choice.

Business customers are less in favour of committing to responsibly sourced gas. They are almost evenly divided between not adding any (24%) and committing to only 10% (22%). One-quarter of business customers did not indicate a preference.

Renewable Natural Gas

Preferred Approach to Renewable Natural Gas	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)
Increasing the amount of RNG in its gas supply to 8%	15%	13%	14%	13%
Increasing the amount of RNG in its gas supply to 5%	17%	14%	14%	15%
Increasing the amount of RNG in its gas supply to 2%	22%	25%	21%	25%
Should not add any RNG to its gas supply	25%	23%	25%	23%
I don't have an opinion on this	13%	16%	20%	16%
Don't know	8%	8%	7%	9%

Customers were given options to increase the amount of Renewable Natural Gas (RNG) that included the proportion of RNG and the annual cost of reaching that level. Full details are provided in the Phase Three reports.

A majority of residential and business customers are willing to pay more to increase the amount of RNG in the system. The two most popular choices are increasing the amount of RNG to only 2% or not adding any at all, but neither option gets more than 25% of the vote in either customer segment. Another 17% of business customers and 32% of residential customers chose to increase the amount of RNG to 5% or 8%.

Customer Engagement Diagnostics

Approach

Respondents had the opportunity to provide feedback on Enbridge Gas' 2024-2028 business plan objectives, their climate change goals, and reducing GHG emissions from natural gas – all of which may introduce higher costs that would be passed on to customers. When asked if the stated objectives seemed like the right approach or the wrong approach, a clear majority across all customer segments felt that it was the *right approach*.

Feedback on Customer Engagement Approach	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)	Contract (n=81)
Right approach	70%	67%	68%	67%	80% (65)
Wrong approach	8%	8%	8%	8%	5% (4)
Don't know	23%	25%	24%	25%	15% (12)

Overall Impression

Respondents were asked for their overall impression of the workbook they had completed. Across all customer segments, 73% or more had a favourable impression.

Overall Impression of the Workbook	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)	Contract (n=63)
Favourable	74%	73%	74%	73%	79% (50)
Unfavourable	18%	18%	16%	18%	10% (6)
Don't know	8%	9%	10%	9%	11% (7)

Volume of Information

The workbook also found the right balance of information. A clear majority of customers in all segments stated that the workbook contained "just the right amount" of information.

Volume of Information	Residential (n=5,400)	Business (n=3,500)	Med-Large (n=217)	Small (n=3,283)	Contract (n=63)
Too little information	9%	9%	11%	9%	13% (8)
Just the right amount	69%	71%	71%	71%	62% (39)
Too much information	22%	20%	18%	20%	25% (16)

Designing This Engagement

Introduction

The OEB requires Enbridge Gas to consider the views of customers while developing the plans that underpin its rate application. This is no small challenge as many customers begin with limited knowledge of the natural gas distribution system.

This engagement was designed with four key factors in mind:

- Timing
- Openness to customer-driven priorities
- Giving customers the opportunity to provide informed opinions
- A strong representation of the view of all the types of customers in all rate zones

Timing: This engagement was scheduled around the planning process. The first two phases were intended to provide Enbridge Gas planners with input on needs and outcomes before detailed planning was fully underway. The third phase was intended to provide input on the draft plan before final decisions were made.

Openness: This engagement is about finding out what matters to customers. As such, the Phase One focus groups and interviews began each topic with an open-ended question to capture what was on customers' minds. For customer needs, participants were asked what Enbridge Gas could do to improve its service to them. For outcomes, customers were asked how do you know if Enbridge Gas is doing a good job for you or not? Since Phase Three did not include a qualitative component, the workbook included multiple opportunities for comments on specific issues. Finally, each survey or workbook included diagnostic questions at the end to create an opportunity for participants to add comments or raise concerns.

Informed Opinions: Customers know very little about how natural gas gets to their homes. But the OEB requires natural gas utilities to ask them to make choices about quite technical matters. Our approach builds on established opinion research literature that includes "deliberative democracy" pioneered by researchers such as Fishkin and Luskin and "public judgement" by Yankelovich. The essence of their argument is that people may not know much, but they can learn. The goal in the engagement is not to turn customers into engineers, but to give them enough basic background that they can make an informed decision on whether they are willing to pay X to secure A or prefer to pay Y to secure B.

INNOVATIVE's approach is to develop workbooks that share the basic information necessary to ask the more detailed project or program choices, particularly in the second and third phases.

Representativeness: A key question in any engagement is whether all types of customers have had an opportunity to be heard. In the general service survey work in Phase Two and Phase Three, quotas were established by rate zone, customer segment, and volume to ensure all types of customers had an equal chance of participation. These same quotas were then used to weight the final data to ensure the sample fully reflected the full range of customers. Contract Customers had a number of specific issues, so an expanded workbook was created for them. As a result, it was decided to survey them only in Phase Three to ensure we received the best possible response to the longer workbook.

One key issue in conducting surveys is coverage. Using workbooks requires email addresses for invitations and not all Enbridge Gas customers have provided their emails to the utility. The gap is largest among residential customers. If customers who provide emails are different in some unknown way from customers who do not, that could impact the workbook results.

To guard against that issue, Enbridge Gas commissioned INNOVATIVE to conduct a short form of the Phase Two online survey as a telephone survey among residential customers. While there are some small differences shown in the report, the fact that the telephone and online results are very similar indicated there is no coverage issue.

The following sections provide a detailed overview of the various activities carried out during each phase of the Enbridge Gas 2024 Rate Rebasing customer engagement program.

Phase One: Exploring the Range of Views

The objective of this initial phase of the customer engagement was to give customers an opportunity to identify key issues for the Enbridge Gas rate application to address. Having these types of guided yet exploratory conversations with customers ensures that outcomes that matter to customers are included in the utility's planning process.

Each section of the guide gave customers a chance to respond to open-ended questions to allow customers to frame the initial discussion. Subsequent probes and stimulus were based on previous customer research conducted by Enbridge Gas.

The discussion guide was developed by Enbridge Gas and finalized with input from INNOVATIVE.

This qualitative phase, including focus groups (among residential customers) and in-depth interviews (among small and med-large business customers), provided customers an opportunity to "colour outside the lines" through qualitative feedback. It was designed to provide customers with some education about the Enbridge Gas system and to gather customer feedback on needs and outcomes, rate design considerations, and energy transition. The interviews and focus groups followed structured discussion guides and were led by professional interviewers/moderators. The feedback gathered from these activities helped inform the subsequent phases of the customer engagement, including the telephone surveys and online workbooks.

Phase Two: Drawing Broader Conclusions

A key objective of Phase Two was to understand customer opinions on their needs and key outcomes. Phase One collected the range of views in these areas. Phase Two used surveys to draw generalized conclusions.

In addition to overall satisfaction, the survey touched on asset management, rate design, customer care, new or harmonized programs and policies, and energy transition. A final open-ended question allowed respondents to provide any additional comments they felt Enbridge Gas should take into account when developing their investment plan.

Phase Two included complementary telephone and online surveys. Both versions included key demographics, needs, and outcomes questions, and satisfaction with Enbridge Gas. The telephone survey included some of the simpler questions on planning preferences while the online version added additional preference questions.

Running both a telephone survey with a random sample of all customers at the same time as the complementary online survey allowed for an assessment of any potential coverage issues in the online sample.

The surveys were developed by Enbridge Gas and finalized with input from INNOVATIVE. The residential and business versions were different only where wording adjustments were needed to tailor the question or response options for a residential vs business customer.

Telephone Surveys

The telephone survey was finalized after a set of pretests to assess the length and viability of the survey instrument. In order to keep the survey length under 15 minutes, a number of complex questions that were better suited to an online approach were removed from the telephone survey.

The residential* telephone survey followed a stratified random sampling methodology. This is a method of sampling that involves the division of a "population" (in this case, Enbridge Gas' customer base) into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or known characteristics (in this case, consumption quartile and region). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

** A telephone survey was also made available to small and med-large business customers who did not respond to the invitation to the online survey, or for whom email addresses were not available. Because this subset of business customers did not have a defined set of characteristics upon which to develop sampling strata, the 44 completes obtained with this methodology were added to the online survey dataset.*

Online Survey

The online survey sampling approach mirrored the stratified random sampling methodology used in the telephone survey, but while residential customer strata were defined by consumption quartiles, business customers were classified as either "Low" or "High" volume due to the much smaller target sample size.

The advantage of the online survey is that it lends itself to longer surveys than are feasible with a telephone methodology. As such, questions that were identified as being core to this phase of the engagement were included in both the telephone and online surveys, but the online version included additional questions about outcome priorities, preference for investing in service quality, the pace of spending on system health, allocation of fixed costs, implementing a single rate zone, investment in dealing with cross bores, automated meter infrastructure, and options for reducing environmental impacts.

Phase Three: Reacting to the Plan

There were four key objectives for Phase Three:

1. To acquire feedback on key choices in the development of Enbridge Gas' business plan that involve trade-offs between customer outcomes.
2. To secure customer reaction to the potential rate impacts of the draft plan.
3. To obtain customer input on rate design choices.

4. **[For residential and business customers:]** To assess customer interest in improving Environmental, Social and Governance outcomes by pursuing responsible gas sourcing and renewable gas sourcing.

4. **[For contract customers:]** The workbook also included questions on service and rate harmonization for both contract rate distribution services and direct purchase services.

Online Workbook

INNOVATIVE used a "workbook-style" survey to ensure the opinions collected on these issues were informed opinions. Through the workbook, customers were provided key background information on Enbridge Gas and its network as well as background relevant to key business planning, rate design, and sourcing choices. The workbook was tested to ensure the material and questions were understandable for customers with limited knowledge of the Enbridge Gas system as well as to assess whether the workbook found the right balance between too much and too little information. Specific design features included:

- Providing both background information and an estimate of rate impact (wherever available), for capital planning choices about compression stations, vintage steel pipeline replacement, hydrogen gas, an innovation, and technology fund, cutting off service at the main pipeline, cross bores, and advanced meter infrastructure.
- Comment boxes were provided for all trade-off questions.
- A review page to give respondents an option to change their responses based on the total estimated rate impact of their original choices. They could change their responses as many times as they liked.
- **[For residential and business customers:]** Additional questions touched on issues around service and rate harmonization, as well as fuel choices that would reduce GHGs and improve ESG outcomes.
- **[For contract customers:]** Additional questions touched on issues around service and rate harmonization with regard to both contract rate distribution services and direct purchase services. Embedded in the survey were links to videos that provided respondents with background information specific to these issues.
- A final set of diagnostic questions allowed respondents to give feedback on the customer engagement survey itself, including overall favourability, amount of information provided and any missing content or questions they would still like answered.

The surveys were developed by Enbridge Gas and finalized with input from INNOVATIVE. All survey participants were sent an invitation from Enbridge Gas containing a unique survey URL.

The sample stratified sample design utilized in Phase Two was also used in Phase Three for residential and small and med-large business customers (although, due to the much larger sample size in this phase, small business customers were classified by consumption quartile according to usage volume, with the additional category of med-large business customers).

In keeping with the practice of allowing all those who want to be heard to be given an opportunity to provide input, a voluntary, open-link version of the workbook was also publicized to Enbridge Gas residential customers.

The table below demonstrates the scope of the customer engagement and provides an overview of the number and types of customers engaged in different activities throughout all phases of the engagement.

2024 Rate Rebasing Customer Engagement

Activity	Residential	Small & Med-Large Business	Contract	Timeframe
Phase One: Development				
Focus Groups	53			Jun 2021
In-depth Interviews		20		Jun-Jul 2021
Phase Two: Refinement				
Telephone Surveys	600	525		Aug 2021
Online Surveys	2,400	44		Aug 2021
Phase Three: Validation*				
Online Workbook: Representative	5,400	3,500		Dec 2021-Jan 2022
Online Workbook: Voluntary	303			Dec 2021-Jan 2022
Online Workbook: All Customers Invited			89	Feb 2022
Customers Engaged	**8,756**	**4,089**	**89**	**Jun 2021-Feb 2022**

* As a part of Phase Three, INNOVATIVE also conducted validation telephone interviews with 7 Transportation (M12/C1) and Ontario Producers (M13) customers, after they were consulted by Enbridge Gas on its 2024 Rate Rebasing plan.

2024 Rate Rebasing Customer Engagement

Phase One Report

August 2021

Table of Contents

INNOVATIVE RESEARCH GROUP

Project Overview

Enbridge Gas 2024 Rate Rebasing Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Enbridge Gas to assist in meeting its customer engagement commitments for its 2024 Rate Rebasing requirements. This report summarises the findings of Phase One: a qualitative research engagement that included a series of 10 focus groups with residential customers and 20 one-on-one interviews conducted with small and medium-sized business customers. Qualitative research is used to identify the range of views on topics of interests. Surveys in subsequent phases will establish the incidence of those views among the broader customer base.

Research Objectives

- The objective of this initial phase of the customer engagement was to give customers an opportunity to identify key issues for the Enbridge Gas rate application to address. Having these types of guided yet exploratory conversations with customers ensures that outcomes that matter to customers are included in the utility's planning process.

- Each section of the guide gave customers a chance to respond to open-ended questions to allow customers to frame the initial discussion. Subsequent probes and stimulus were based on previous customer research conducted by Enbridge Gas.

- The discussion guide was developed by Enbridge Gas and finalized with input from INNOVATIVE. After the first two nights of focus groups, visual stimuli were created to allow participants to view and respond to lists of potential outcomes (see slides 63 and 64), and to illustrate the types of costs Enbridge Gas incurs to serve its customers (slide 40).

All 10 focus groups were moderated by Greg Lyle (President at INNOVATIVE). Susan Oakes (Vice President) conducted 4 of the business IDIs, and the remaining interviews were conducted by Greg Lyle.

About Qualitative Research:

The value of in-depth interview and focus group research lies in the depth and range of information provided by the participants, rather than in the number of individuals holding each view.

Qualitative research is an exploratory research technique and does not hold the statistical reliability of quantitative research.

Methodology | Focus Groups

- A total of 10 online focus groups with a total of 53 Enbridge Gas residential customers were held between June 16th and June 23rd, 2021. The groups lasted two hours and were conducted on Zoom.
- As Enbridge Gas has email addresses for 60% of its residential customers, potential participants were recruited using a mixed methodology of online and telephone recruiting to arrive at a final participant pool that was reflective of the 60%/40% email vs no-email status of this customer segment.
- All participants were paid a $100 honorarium in appreciation of their time.

The break down of the focus groups is shown below.

Date	Rate Zone	Region	# of Participants
June 16, 2021	Enbridge Gas	GTA	Group One: 6 / Group Two: 5
June 17, 2021	Enbridge Gas	Non-GTA	Group One: 6 / Group Two: 6
June 21, 2021	Union Gas	South/West	Group One: 6 / Group Two: 6
June 22, 2021	Union Gas	Central	Group One: 5 / Group Two: 5
June 23, 2021	Union Gas	North/East	Group One: 4 / Group Two: 4

Methodology | In-depth Interviews

- A total of 20 in-depth interviews were held with small and medium-large business (billed) customers of Enbridge Gas between June 24th and July 15th, 2021. Interviews lasted an average of 45 minutes and were conducted using Zoom or some other online meeting platform.
- Potential participants were being recruited via an email invitation from INNOVATIVE, as well as by telephone. This allowed recruitment agents to give background about the interviews and to ask to be referred to the most appropriate person to participate – that is, a person in the organization who makes decisions regarding the use of natural gas.
- In appreciation of their time, a $100 donation was made to the charity of the participants' choosing.

The break down of In-depth Interviews is shown below.

Rate Zone	Size	# of Participants
Enbridge Gas	Small	5
Enbridge Gas	Medium-Large	5
Union Gas	Small	5
Union Gas	Medium-Large	5

Key Findings | Customer Needs [1/2]

Right at the start of the groups and interviews, participants were asked whether they were satisfied or not with their overall experience in order to launch a discussion of good things Enbridge Gas should keep doing as well as things they could be doing better.

Most residential and business participants are satisfied with their overall experience with Enbridge Gas. They don't have to think about their natural gas supply and that is the way they like it. For most participants, the most frequent interaction comes when they receive their bills. And, for most participants, bills are seen as predictable and relatively affordable.

Whether participants were satisfied or dissatisfied, all participants were asked to help build a list of good things Enbridge Gas should continue to do as well as things Enbridge Gas could do better.

Good Things to Keep Doing

While **uninterrupted service** was almost an assumption for most participants, it was clearly seen as a good outcome participants would like to see sustained. This was more commonly mentioned among residential participants than among business.

Good customer service was another common mention. Business mentions included being helpful during construction or when meters need replacement, just keeping appointments on a timely basis and good communications while issues were being resolved. Residential comments focused on the lack of need to interact with the company at all, positive website features, as well as punctuality.

Good or transparent billing was also a regular mention by both types of customers. Some participants mentioned they like that natural gas bills usually have no surprises. Other participants mentioned they found online billing and payment convenient and easy. Some participants, particularly residential customers, like the transparency of the bill. They like knowing how much goes to the carbon charge and other items. A number of participants also liked being shown their monthly usage over time, both the comparison to the same month a year ago and month-to-month.

Key Findings | Customer Needs [2/2]

Reasonable price was a less common comment but was still mentioned regularly, particularly among residential participants. Participants who made this comment often compared natural gas to electricity. In keeping with the billing transparency comments, participants would also mention no big jumps as something they like about the price of natural gas.

Things to Do Better

Many participants struggled to identify an area for improvement. Comments were quite fragmented.

Price concerns came from both residential and business participants. Business participants were more likely to focus on costs being too high. Residential participants had more varied concerns including affordability and paying significant amounts when natural gas usage is very low.

Onsite service calls for equipment maintenance and installations were occasionally mentioned by business participants, although many of these concerns appears to be out-of-scope activities of Energy Service providers. Participants did not appear to understand the “Open Bill” concept and appear to feel that any activities associated with activities on their gas bills must be Enbridge Gas activities. Comments included lack of responsiveness, poor punctuality, scheduling challenges and problems with application processes.

Billing issues were also raised occasionally. Business participants in particular raised concerns about estimated meter reads which were seen as a cause of sudden spikes in the amount owed. Both types also occasionally expressed frustration with the number of charges on their bill. Participants felt these charges are not well explained and left them with a feeling that they were being “nickeled and dimed”.

There were a handful of **environmental** comments looking for Enbridge Gas to reduce environmental impacts or to find offsets.

Finally, there was a comment from each customer type related to **social responsibility.** Participants looked to Enbridge Gas to act in a way that more broadly benefits society and to be accountable.

Key Findings | Customer Outcomes [1/3]

Following the discussion of direct experience, participants were asked to think more broadly about the Enbridge Gas plan and the outcomes it should focus on. Initially this discussion started with an open-ended question. The moderator then followed up with a broad category list of possible outcomes based on earlier research with Enbridge Gas customers.

Typically, participants were slow to engage on this topic until the list was shared. Participants tended to take natural gas service for granted and didn't enter the conversation with a lot of pre-existing thoughts. However, once the list was shared, participants quickly became more focused in their comments. Almost all participants liked the stimulus list as shown and didn't want to add or remove any items.

Reliable and **safe** delivery are table stakes to most participants. These items came up very infrequently in the open-ended discussion but were definitely seen as priorities when the list was shared.

- Some participants, particularly residential customers, questioned whether there was a secure, long-term supply of natural gas.
- Safety occasionally came up as a mention when discussing social responsibility and leaks often came up as a concern when discussing environmental impacts. Proper monitoring and maintenance came up as a safety priority. There were also mentions regarding security against threats such as a cyber attack as seen with Colonial Pipeline in the US.

Pricing came up in discussions with both customer types.

- The emphasis among business participants was on affordable pricing. They welcome anything that can keep their costs down to help them to be more competitive, or even simply survive in difficult times.
- Some residential participants also expressed affordability concerns, while others were looking for predictable pricing or for support programs for more vulnerable customers.
- Residential participants were also more interested in stable pricing, including positive comments regarding equal billing programs.
- Some business clients, particularly those in smaller organisations, also expressed interest in equal billing programs.

Key Findings | Customer Outcomes [2/3]

The importance of **customer service** was already established in the "needs" discussion. However, the moderator also shared a list of seven (7) potential customer service outcomes. As with the overall list of potential outcomes, participants in both segments felt the customer service outcome list was comprehensive in terms of categories.

- Dependable customer service was well canvassed with business participants during the "needs" discussion, but residential participants also expressed a desire for prompt and responsive service once the area was raised through the stimulus list.
- Customer contact options were raised both in terms of ease of reaching someone who can help with the customer's specific issue as well as being able to manage bills through online and email access.
- Business participants were more interested in reducing estimated meter reads although some residential participants also expressed an interest in "smart meters" to avoid estimates.
- Residential participants tended to be more interested in becoming more informed.
- Both groups like the idea of tools to manage consumption, including being able to identify unusual usage patterns, potential leaks and options to reduce natural gas consumption.

Minimizing environmental impacts came up on its own in the open-ended discussion of objectives and was strongly accepted, even by those who generally view natural gas as environmentally friendly.

- The impact of the natural gas system's physical footprint was a common concern among both types of customers. Participants frequently referenced controversies related to spills and habitat damage from other pipelines they had seen in the news when talking about the potential environmental impact of Enbridge Gas. Some participants raised natural gas pipeline leaks as a specific concern.
- Greenhouse gases were also a common concern, although not all participants were aware that natural gas creates those emissions. Some respondents referred to biogas as an alternative.
- In the open-ended discussion, both customer types occasionally raised the idea of Enbridge Gas developing new energy sources as well as improvements in energy efficiency and conservation.

Key Findings | Customer Outcomes [3/3]

Being socially responsible only came up occasionally in the open-ended discussion but was well accepted when participants reacted to the stimulus list. Only a few of the business participants suggested this item wasn't really necessary.

- Some of the comments regarding social responsibility overlap with other categories, particularly minimizing environmental impacts and safety.
- Being open and transparent came up quite strongly in the residential customer groups.
- There were also unprompted comments regarding being respectful of Indigenous groups, particularly considering pipeline projects, and being supportive of local communities within which Enbridge Gas operates.
- A diverse and inclusive workforce did not come up in the open-ended discussion but was strongly supported when raised by the moderator.

As with social responsibility, there were relatively few mentions of **supporting the growth of Ontario's economy** in the open-ended discussion but strong support when the stimulus list was shared.

- In the open-ended discussion, residential participants raised increased service for rural and remote communities currently without natural gas. Business participants supported that idea when it was raised by the moderator. There were a few participants in each segment who did not agree, but they appear to be a minority.
- Both residential and business participants generally supported the idea of investing in renewable energy projects as a means of growing Ontario's economy.
- Residential participants also raised the role of affordable natural gas prices in supporting the economy. Business participants did not raise affordability in this context but had raised the issue earlier in the price discussion.
- A few participants of both customer types also raised the idea of Enbridge Gas employing locals and keeping services within Ontario (i.e. call centres).

Residential participants were most likely to discuss **making good use of the money customers pay**. They were focused on cost efficiency as a means of keeping costs down.

Key Findings | Rate Design [1/3]

How Should Bills be Calculated?

Initially, this discussion began with a verbal introduction that left participants struggling to answer. However, when a stimulus diagram was added, participants found it easier to respond.

There is a strong consensus that customers should pay the variable cost of the natural gas they themselves use.

It is also clear that most participants believe that fixed costs related to how much natural gas customers use should also be allocated based on use.

Participants were more divided on how to treat fixed costs that are shared by all customers in a rate class. It is not clear from the qualitative phase whether more participants prefer having those costs split equally among customers or whether they should be allocated based on use.

Finally, insofar as fixed costs should be allocated based on use, it is not clear whether participants prefer paying those costs as natural gas is used (more in the winter, less in the summer) or whether participants prefer to have that cost split into equal monthly charges.

These findings were consistent across both customer types.

Both residential and smaller volume business participants expressed an interest in having an “equal payment” option for the part of their bill that varies by use.

Key Findings | Rate Design [2/3]

Who Should Pay for Infrequent Customer Transactions?

Participants were asked who should pay for the costs of specific transactions such as account openings, meter tests and meter turn offs.

Participants in both customer segments generally lean to a user pay approach. They generally like the idea that if you need a service, you pay for it. However, there are some hedges.

A few participants, mostly residential, do not like the idea of a charge for setting up an account. They feel they are being “nickel and dimed”.

Some residential participants felt it would be wrong to charge customers a specific charge for any issues that are not their own fault. One example given was a meter repair.

It appears that the general principle applied by most participants is that users should pay for things that are specific to an individual customer. The answer for specific charges is likely to vary depending on the details of the actual service.

One Rate Zone or Three?

There is strong interest across customer types in moving to a single rate zone.

Most participants initially supported a single rate zone for fairness. They felt all customers get the same natural gas, so they should pay the same rate.

When probed on whether they would continue to support a single rate zone if their own rates increases, many said they would continue to support a single rate zone. However, some said they would not continue to support the idea and others said it would depend on the cost.

There is a minority who prefer to leave the legacy rate zones in place. Those participants tend to feel that if it costs more to deliver natural gas in some areas compared to others, the customers in higher costs should pay for those costs.

Key Findings | Rate Design [3/3]

Should Enbridge Gas Have the Flexibility to Use Reserves?

When asked whether Enbridge Gas should have the flexibility to use money in reserves to avoid having to borrow money, participants expressed considerable interest in giving Enbridge Gas flexibility if it means potential savings for customers.

Participants have two key concerns in providing flexibility. First, because interest rates are currently low, some participants felt there is not enough benefit for customers at the moment to make this change worthwhile. Second, some people wanted to understand better what would be done to restore the funding for those long-term commitments. When would the money be paid back? How strong is the commitment to pay the money back?

Participants who were not interested in providing flexibility felt if money was put aside for a specific purpose, it should only be used for that purpose.

Key Findings | Energy Transition [1/5]

What Does the Future Look Like for Natural Gas?

Participants were asked whether customers in the same situation they are in today would likely use more, less or the same amount of natural gas 30 years from now.

Most participants in both customer segments feel customers like them will use the same or less natural gas in the future.

Participants who said "the same" felt natural gas would continue to be the most affordable and efficient energy option to meet their needs.

Participants who said "less" had several reasons:

- Many believe technology will reduce needs because 1) natural gas appliances will be more efficient and 2) homes and buildings will have better insulation and other improvements that will lead to reduced energy demands.
- Others believe new, renewable energy sources will be developed to replace natural gas.
- A few believe we will soon run out of natural gas and will be forced to adopt energy alternatives due to scarcity.

A few participants said "more", but those participants generally misunderstood the question and interpreted as related to their own home or business in the future and assumed they would have a bigger business or home or other life changes that would impact their natural gas use.

Do You Have Options to Reduce Greenhouse Gases?

Some participants simply did not have the energy literacy to answer this question. Those who did tended to focus on energy conservation and efficiency changes rather than energy changes, regardless of customer type. Specific conservation mentions included adding insulation and weatherstripping, upgrading to more energy efficient appliances and behavioural changes such as changing the thermostat, driving less and eating fewer meat products. Energy changes included installing solar panel or buying an electric vehicle. Participants appeared interested in learning more about available options.

Key Findings | Energy Transition [2/5]

Does Enbridge Gas Have Options to Reduce Greenhouse Gases?

Many participants were not familiar with any options available to Enbridge Gas to reduce greenhouse gases. Some participants were aware of biogas and other approaches to replace traditional natural gas from fossil fuels with renewable natural gas or similar alternatives such as hydrogen. There were also suggestions that Enbridge Gas could use more efficient equipment, could use energy alternatives such as solar power and electric vehicles in its own operations, and maybe find ways to improve the initial extraction process.

Where Does Enbridge Gas Fit When It Comes to Developing and Offering Low-Carbon Options?

Enbridge Gas was mentioned almost as frequently as government when participants were asked who should lead in developing and offering low-carbon options. Scientists and engineers were also identified as leaders in this area. Frequently these groups were mentioned in combination.

Participants were not as clear about what exactly Enbridge Gas could do. Suggestions included leading by example, sharing information, and bringing solutions to governments.

Responses were consistent across customer types.

Where Does Enbridge Gas Fit When It Comes to Developing and Offering Natural Gas Conservation Options?

Manufacturers are seen to have the leading role in this area. Enbridge Gas is seen – by both residential and business participants – as having a potential role in funding research or in informing customers about available options. Some participants see a conflict for Enbridge Gas on this topic since they feel Enbridge Gas benefits when customers use more natural gas.

Key Findings | Energy Transition [3/5]

Are Customers Willing to Accept Less Reliability to Improve Environmental Impacts?

Most participants are not willing to accept less reliability to improve environmental impacts. There are two core concerns.

Both residential and business participants are concerned about losing their natural gas supply in winter. Especially in the North, participants view loss of heating in the winter as a health and safety threat with the potential for loss of life. There are also concerns about physical damage as pipes could freeze and burst. Some participants noted they could accept short outages but not longer ones, for the reasons noted above.

Some business participants are also concerned about business interruption. Not only does loss of natural gas impact heating for businesses, for some it is a critical component of their production process whether that be supplying ovens, industrial dryers or forges. Losing natural gas means shutting the business down.

There is a minority of participants, mostly from Southern Ontario, who are willing to accept less reliability. Generally, they either appeared to have heating alternatives or did not actively consider the impact of any extended winter outages.

Key Findings | Energy Transition [4/5]

Are Customers Willing to Pay Higher Prices to Improve Environmental Impacts?

Most participants in both customer segments appear willing to pay more for natural gas if that will reduce negative environmental impacts. Most of this support seemed related to a desire to do something for future generations.

A key consideration for participants is what will they get for the increase. They are looking for clear targets and transparent reporting.

In terms of actual amounts, participants provided a wide range from 2% or 3% to 20% or 30%. There were more participants at the lower end of the range.

Those who are not willing to contribute typically were focused on keeping total costs down, felt they were already paying through the carbon tax, or felt it was a gesture that would not make any real difference.

Are Customers Willing to Pay More for a Research Fund?

While most participants seem open to paying for a research fund, residential participants in particular seemed less likely to support research than paying more for greener natural gas.

Supporters offer the same reason as why they would pay more. That is, their desire to be responsible environmental stewards.

Similarly, supporters would still like to see accountability and transparency measures.

Those who support a fund are generally willing to pay something in the 2% to 5% range. A few are willing to pay up to 10%. No one suggested more.

Both business and residential opponents to a research fund tend to focus on affordability - there are some people who just don't feel they can afford to pay more for natural gas.

Some residential participants felt research is an activity Enbridge Gas should be funding on its own out of its own profits.

Key Findings | Energy Transition [5/5]

Are Government or Consumers Best to Make Energy Choices?

Participants in both customer segments tended to indicate that consumers should be able to make choices about the energy options available to them over government, although some suggested both governments and consumers should work together.

Participants who preferred consumer choice tended to break into two groups. One group felt consumers were closer to the choices and better able to make faster and smarter choices. The second group distrusted government. That distrust itself was split between those who distrust governments as inefficient bureaucrats and those who distrust the particular party in power.

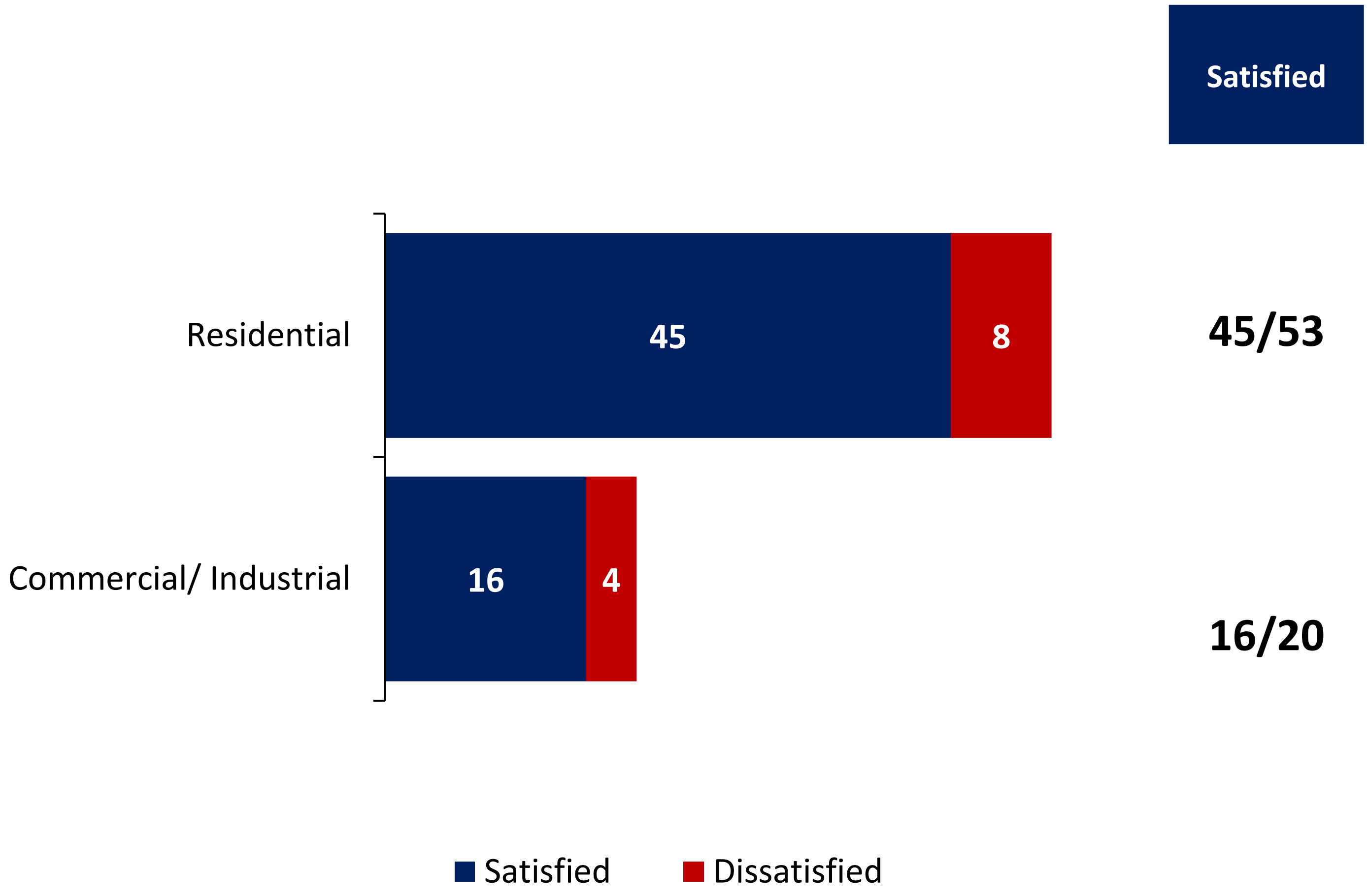
Participants who prefer government think governments are better able to drive widespread social change quickly and/or feel consumers are too emotional or do not have enough information to make good choices.

Customer Needs

Exploring Customer Needs

Customer Satisfaction

The groups and interviews began by asking whether customers were satisfied or not with their overall experience in order to launch a discussion of needs. Most residential and business clients are satisfied with their overall experience with Enbridge Gas. They don't have to think about their natural gas supply and that is the way they like it.



Note: The value of in-depth interviews and focus groups lies in the depth and range of information provided by the participants, rather than in the number of individuals holding each view. Therefore, the results of these qualitative research methods are directional and not generalizable.

Needs: Things that Enbridge Gas Does Well

Uninterrupted Service

"My supply's never been interrupted in all the years I've had it." - EGD Non-GTA Residential

"I've lived here over 30 years, and never had any issues with the gas company, so yeah, very reliable." – Union Central Residential

Good / Transparent Billing

"They provide you a graph that shows your usage, month by month, it's quite visual and so the format of their bill is excellent." – EGD GTA Residential

"I don't have any hiccups with billing. We've had hiccups with other suppliers but their billing seems to be ok." – EGD Med/Large Business

Reasonable Pricing

"It's a what appears to be a reasonably priced utility for me." – Union Central Residential

"It's more economical than any other type of heat." – Union North/East Residential

"Natural gas has been our most economical energy. I've always been pro gas." – EGD Med/Large Business

"I like that they keep the price consistent, there's not a huge jump or anything."– Union Small Business

Good Customer Service

"I've called them for help a few times, and they've been very punctual. Very straightforward" – Union South/West Residential

"The platform is good. I'm someone that goes online, so it works well." – Union Central Residential

"When you call, they're very nice, I've never had any issues with customer service." – Union Small Business

"In our new project, they've been very helpful. We've had to do a lot of meter changes in the last few years because we have 22 buildings here." – EGD Small Business

"Somebody had parked in front of the meter, so they read the meter for 2 to 3 periods. Our bill came in very high because they were estimating. I called them up and gave them the readings. They credited properly. So yeah, they were very responsive." - EGD Med/Large Business

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Needs:
Things Enbridge Gas Needs to do Better

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 60 of 550

Onsite Service Calls

"There was a malfunctioning valve and they [Enbridge] said it was fine. It was faulty. They [Enbridge] didn't even want to look into it." EGD Med/Large Business

"We've been dissatisfied when it comes to booking installations. Having one of their guys on the site at the same time as our guys can be a gigantic pain." – Union Small Business

Environment

"I'd like to see, if there's any way we can look at the impact that natural gas has on our environment." – Union Central Residential

"I don't know how companies can go over and above except for the environmental piece. Just making sure that they are protecting the environment." – EGD Med/Large Business

Billing Issues

"We have had some issues with understanding billing, because we have 22 different bills we've been trying to reconcile." – EGD Small Business

"I don't know, what costs are involved, whether it's legitimate." – EGD Medium/Large Business

"My gas is $53 but there's roughly eight other charges on here. If you're going to sell me gas call it gas, why have all these charges?" – Union North/East Residential

"They never really been clear. It's like your gas supply is really only $22, but everything adds up and the bill ends up being $80." – EGD GTA Residential

Price

"It would be nice if they could bring down their costs in advance, especially with small businesses trying to make ends meet" – Union Small Business

"From what I've seen so far it [the price] was pretty high. It's cheaper than electricity but its still high compared to anything else" – EGD Small Business

"In summer I don't use heater, but I still have to pay 50-70 $ per month." – EGD GTA Residential

Social Responsibility

"Ensure that society is benefiting from their participation, and that is not simply about profits, but they do see the value in contributing to society." – Union Central Residential

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Customer Outcomes

Reliably Delivering Natural Gas

Overview: Reliability was important for both customer types. Residential participants seemed to question the future supply of natural gas, while the business participants mentioned the constant supply of natural gas as an important factor in running their businesses smoothly.

Essential for Business Performance

"It's critical to our business to have the gas be consistent. If we can't get reliable gas we'd lose a lot of money." – EGD Med/Large Business

"Just guaranteeing a consistent supply of gas, priced at a reasonable rate so we can stay competitive" – Union Med/Large Business

Sustainable Supply of Natural Gas for the Future

"I'm thinking our natural resources are finite, and let's move in that direction." – EGD Non-GTA Residential

"They should focus on maintaining an abundant supply of natural gas well into the future." – Union South/West Residential

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Safely Delivering Natural Gas

Overview: While both customer types indicated the importance of proper monitoring and inspection as part of safely delivering natural gas, concerns for leaks and security threats were more prevalent among residential participants.

Proper Monitoring and Maintenance

"The delivery of the gas into the building, make sure that everything is safe there, check meters, all that kind of things." – EGD Med/large Business

"Making sure the equipment that's out in the market and the structures protecting that equipment are intact, up to date." – EGD Med/Large Business

"They should inspect houses regularly" – EGD GTA Residential

"I would like to see them come around, about every three years and check our appliances over with the gas purposes" – EGD South/West Residential

Prevent Leaks

"Taking whatever precautions possible to avoid gas leaks. That's huge. Like that's number one. Not cutting corners" – Union South/West Residential

"I would hope that there's some sort of monitoring going on underneath without digging up the whole ground [to check the] erosion with any of the buried pipes." – Union Central Residential

Security Against Threats

"How well they could deal with some sort of a catastrophic event like an earthquake or a terrorist attack or cyber attack" – Union North/East Residential

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Making Good Use of Customers' Money

Overview: Issues related to good use of money were more frequently brought up among residential participants where they discussed ways for Enbridge Gas to be more cost efficient in order to lower the overall natural gas cost for customers.

Cost Efficiency to Keep Costs Down

"The equipment that they use to deliver gas for my house or repair that should be used properly. If they have to upgrade from a steel pipe to a PVC pipe that should makes sense. They're not just sort of doing it for no reason" – Union Central Residential

"Union Gas used to trade in trucks like two or three years old and I always thought those trucks are good for five to 10 years. I don't know if Enbridge is doing that from a cost point of view." – Union South/West Residential

Providing Affordable Pricing [1/2]

Overview: Affordability was mentioned in both customer types but mostly among business participants, so they can keep their costs down to help them be more competitive, or even simply survive in difficult times. Residential participants had split views on predictable vs. stable pricing. Some favoured predictable pricing because it gave them more certainty and less surprises. Others expressed interest in stable pricing including positive comments regarding equal billing programs.

Affordable Pricing

"I will say the most important thing is to keep the costs to a minimum for all the users for your businesses and homeowners." – EGD Med/Large Business

"We're a true non-profit organization. Obviously, costs are a concern for us. I have another building not far from me, their electric heated, and they are just going bankrupt trying to heat the place." – EGD Med/Large Business

"We use a lot of gas and maybe a rebate once or twice a year would be nice. Gas in Canada is outrageous compared to other parts of the world" – Union Small Business

"New ways to distribute [gas] it to help the customers price wise" – Union Central Residential

Predictable Pricing

"Knowing that there would be a steady increase. I think that just gives me more certainty." – EGD Non-GTA Residential

"Predicted today, and tomorrow, it's going to be the same all the time. It should be there and not have any surprises" – Union South/West Residential

"[Predictable is something that] I would expect to be in line with inflation, not spiking to extremes." – Union Central Residential

Providing Affordable Pricing [2/2]

Stable Pricing (Equal Pricing)

"To be stable is, you know, is what I think concerns me most, I would like to have the prices stable, not fluctuating going extremely high." – Union South/West Residential

"Stability is very important where there's a necessity, without question. We live we live in a in a climate where we need your product, and not just for that for cooking, for drying our clothes as well." – Union South/West Residential

"I want my bill to be essentially similar, month after month, they offer a equitable billing plan where you can fill out essentially the same amount every month. So it's easy to plan for you prepay it" – Union Central Residential

"I just want my bill to be the same way. I don't know if my cost is fluctuating because of usage or if it's fluctuating because rates have went up." – Union Central Residential

"In terms of the billing process, even the equal billing, I would say is a plus." – Union North/East Residential

"I've got a fixed budget numbers. That's what I work from. So, make it equal every month." – Union Med/Large Business

Providing Dependable Customer Service [1/3]

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 67 of 550

Overview: Both groups of participants expressed a desire for prompt and responsive service, ease of contacting Enbridge Gas for specific issues, and using tools to manage their consumption. The business participants were more interested in reducing estimated meter reads although some residential participants also expressed an interest in "smart meters" to avoid estimates. There was also a tendency in residential participants to want to be better informed by Enbridge Gas.

Prompt and Responsive Service

"When I call I want someone to be there to answer quickly" – Union South/West Residential

"I want to be responded to and treated fairly. I want to be able to follow them and so I'm not getting a recording or I'm not getting a run around" – Union North/East Residential

"Always being there and being able to respond, whether it's by text message, online, phone call, and not being passed around from one person to another." – EGD Med/Large Business

"More accessibility, communication, when we call the lines, we just want to get a quick answer sorted out and move on because time is valuable." - EGD Small Business

Ease of Contacting Customer Service for Help

"You have somebody right at your fingertips all the time. So a long time ago they used to do inspections. All you had to do is call and somebody came out and checked it " – Union South/West Residential

"I know exactly who I need to call if we have a billing concern. Or if we have an outage, I know exactly who to call, who to go to. Should our needs change, or if you have something coming down, that's going to affect our usage. So that is key for us customer service, you know, who to call is super important." – EGD Med/Large Business

Providing Dependable Customer Service [2/3]

Reducing Estimated Meter Reads

"I think there should be some kind of electronic meter reading that you don't need to actually use a person to come out in different weather and somehow I know we can report our own" – EGD Non-GTA Residential

"[Billing based on estimated meter reads] has happened in the past with various utilities, like water, Hydro and gas, where it's not necessarily as accurate. Then sometimes you get money back because you've overpaid. But sometimes you don't." – Union North/East Residential

"It'd be nice to actually pay for what you actually use versus an estimate. But I mean, the system is pretty smart. It gets pretty close. I haven't had any issues, except when I'm moving like or, or to the to the point I made earlier is when I'm increasing in size and consumption." – EGD Med/Large Business

"I don't like the estimated readings because one month is less and the next is way higher. If they actually went and read the meter then it will be more normal and you know what your bills will be." – Union Small Business

Becoming More Informed

"I was looking for Enbridge Energy Information and really I couldn't find the information I was looking for [on their website]. Well, I got my information from a neighbor. I just I found it a little bit frustrating." – Union Central Residential

"It's not very often that you need to contact them, but I'd like to be more informed like, are there ways you could opt to buy your gas from a private provider?" – EGD Med/Large Business

Providing Dependable Customer Service [3/3]

Using Tools to Manage Consumption

"I kind of feel like putting more information out just like how the hydro companies put in terms of like, off peak, and different rates, explaining like how you can like, save on your gas bill." – EGD Non-GTA Residential

"If [providing tools to manage gas consumption] helps bring your bill down, that'd be good" – Union North/East Residential

"Some kind of energy assessment, where they can analyze your system. Start with where you can save money" – EGD Med/Large Business

"I actually really like that point about providing the client with tools to manage their usage." – EGD Small Business

Note: A few residential participants are concerned that Enbridge Gas might outsource its customer service and made the following comments:

"Enbridge should have stopped the outsourcing. I mean, it's a company in Canada, and they should employ Canadians. They should do that here." – EGD Non-GTA Residential

"I would like them to never offshore customer service" – Union South/West Residential

"When you finally get somebody on the phone, they're in Bangladesh, and they don't even know where North Bay is so that's irritating. I think they lose a lot of goodwill. I'm not saying Enbridge does that but I'm very tired of that." – Union North/East Residential

Minimizing Impact on the Environment [1/2]

Overview: The impact of the natural gas system's physical footprint was the most common concern. Controversies related to spills and habitat damage from other pipelines seen in the news were frequently referenced. Greenhouse gases were also a common concern, although not everyone was aware that natural gas creates those emissions. In the open-ended discussion, both customer types occasionally raised the idea of Enbridge Gas developing new energy sources as well as improvements in energy efficiency. Issues related to the sources of natural gas such as fracking was also mentioned in a couple of focus groups.

Concern About the Physical Footprint of Natural Gas

"I'm hoping that Enbridge is looking at where they're putting their pipelines, that they're actually making sure that the animals are not affected, and that they're trying to regrow trees, if they have to take down trees and things like that, all adding to lessen the carbon footprint" – Union Central Residential

"If their plan required building new gas pipelines or transporting other kinds of energy through populated areas or environmentally sensitive areas, [they should keep in mind] the risks of any sort of accidents, like an explosion or a leak" – Union North/East Residential

"Keeping their lines maintained, not having leaks, making sure they do their due diligence that lines are checked. I'm no tree-hugger but we all need a healthy environment." – Union Med/Large Business

"Enbridge should make sure there's no gas leaks anywhere that could cause harm and catch fire, like remote places in the wilderness." – Union Med/Large Business

Minimizing Impact on the Environment [2/2]

Concern About Greenhouse Gases

"Fossil fuels and how it's being burned and affecting the environment. I hope that they come up with something that that doesn't impact our environment at all." – Union Central Residential

"I think they should raise awareness on greenhouse gases and on renewable resources, because that's the field they're in." – Union Small Business

"For them [Enbridge] to be able to minimize their impacts on the environment would probably be more on how they're producing natural gas, transporting it, storing it, stuff like that." – Union Small Business

New Energy Sources

"Thinking about the environment in terms of alternatives to gas, or petroleum, maybe types of green energy or renewable energies, that could be potentially viable alternatives in the future" – Union North/East Residential

"I'm all in favor of composting to get natural gas and all that type of stuff. I know that big dairy farmers get lots of waste that they can produce their own gases from and that stuff to me is all very important" – Union Med/Large Business

Sources of Natural Gas

"Undertaking more sustainable ways to get the gas out of the ground. I'm not very knowledgeable on fracking. But I know that there are some serious environmental impacts." – Union North/East Residential

"Cleaning up old abandoned wells, tapping that natural methane and any possible methane leaks." – Union South/West Residential

"If Enbridge was really behind a lot of fracking that was going on, that would be disturbing. I want to believe that they're extracting the gas or their suppliers are extracting it in a way that isn't permanently damaging the environment." – Union North/East Residential

Being Socially Responsible [1/3]

Overview: Some of the comments regarding social responsibility overlapped with other categories, particularly minimizing environmental impacts and safety. Being open and transparent came up quite often in the residential customer groups. There were also unprompted comments regarding being respectful of Indigenous groups, particularly when installing pipelines, and being supportive of the local communities within which Enbridge Gas operates. A diverse and inclusive workforce was another theme that was strongly supported when raised by the moderator.

Environment and Safety Related

"Not running new pipelines through environmentally sensitive lands. I think they [Enbridge] should be lobbying government to improve our land protection, water protection acts that have been degraded so badly." – EGD Non-GTA Residential

"It will be connected to having greener gases and make sure that everybody in the future, okay, and that will be their social responsibility." – EGD Small Business

"I think the number one [is to be] socially responsible with respect to building the environment" – EGD Med/Large Business

"An inspector comes in to do a whole household check. Wondering if that's something that Enbridge could offer their customers, as you know come in and tell you're not paying the government for somebody else here, you're actually, you know, calling Enbridge and they have a fee for that." – Union Central Residential

Being Socially Responsible [2/3]

Being Open and Transparent

"I think they need to be have total disclosure on everything they're doing. So they don't hide some of the actions and cover up." – Union South/West Residential

"More open communication. We need to make sure that there's no spills happening. When they're happening, they should be reported." – EGD Non-GTA Residential

"For me, it would just be honest, when things happen. If you do have a gas line explosion, explain, okay, why it happened, own up to what happened if something went catastrophic." – Union Small Business

Respectful of Indigenous People

"Having good connections with Indigenous people, if they do end up crossing paths within Indigenous land." – EGD Non-GTA Residential

"There's often issues with getting pipelines across Canada, because of hereditary chiefs and indigenous communities not wanting it to disrupt the land. But possibly if Enbridge would work as partners to provide very reduced rates to these communities." – Union Central Residential

"There's definitely a need to get a bigger presence in some first nation communities, if the pipelines are on their lands, the company should stay on their good side and offer jobs." – Union Med/Large Business

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Being Socially Responsible [3/3]

Supportive of Local Communities

"They should obviously do a lot of consulting with the local municipality, rather than the province, rather than just go into the Ontario Energy Board. Maybe concentrate a little bit more locally, and get ideas and input from local issues" – Union Central Residential

"Consider any type of charitable work in the local communities that they service." – Union North/East Residential

"Enbridge needs to support communities, and be proactive when there's fundraisers or community events, they should be donating to certain things, pick some priorities, whether it's hospitals or things like that." – Union Med/Large Business

"If they're helping out with the community that we're in, that would be a blessing to make sure that they're giving some of their profits to help the people" – Union Small Business

Diverse and Inclusive Workforce

"Equal employment and making sure that they're ensuring that their employees match the people that live in the communities they serve" – Union GTA Residential

"Making sure that you are honoring workers rights, so that your workers are treated fairly and equitably, and that you're working towards diversity within your workforce" – Union Central Residential

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Supporting the Growth of Ontario's Economy [1/2]

Overview: Both customer types mentioned providing service for communities without natural gas, investing in renewable energy, affordable natural gas prices, and employing local people as ways that Enbridge Gas could support Ontario's economy.

More Service for Communities Without Natural Gas

"Keep going into those rural or remote communities and giving them natural gas." – Union North/East Residential

"Investing in bringing the pipelines into those communities would encourage maybe certain companies or factories to set up there to help support the growth of rather than just have it localized in the big cities." – Union Central Residential

"Expansions into outlying areas, which produces jobs and income for other companies." – Union Small Business

"I would like to see the growth of natural gas to communities and developments because I believe they have a good product." – EGD Med/Large Business

Investing in Renewable Energy Projects

"We need the people in the labs with the test tubes to find out new sources of energy, new efficient ways to deliver it and everything like that." – Union Central Residential

"The more greener it [energy] is, the better it is for us, for our kids in the future. So that is important to me." – EGD Small Business

"I could see them maybe on the producing side, producing natural gas a little bit more efficiently. Less impact on the environment." – EGD Small Business

Supporting the Growth of Ontario's Economy [2/2]

Affordable Natural Gas Prices

"Keeping gas at a decent price and making it affordable so that prices of everything else can come back down to a much more reasonable level for people that are either trying to buy their first new home or are moving from the big house into something smaller." – Union South/West Residential

"Enbridge didn't have such a support plan for people with low income or no income, maybe they should focus on that part of their plan." – EGD Non-GTA Residential

"They should look at how the economy's doing and adjust their prices accordingly. To make sure that their not stocking money in their pockets too much." – Union Small Business

Employing Local People

"Try to employ people locally within the communities that you serve, provide job opportunities for individuals would be a good thing" – Union North/East Residential

"They do have a responsibility that comes from being regulated by Ontario and they have a monopoly so I think that they have a responsibility to create jobs within reach." – EGD GTA Residential

"Getting jobs for people and that's a big thing because more jobs and more employment is good for the Ontario economy." – EGD Small Business

"The only way that they [Enbridge] could be supporting the growth of Ontario's economy is just making sure they hire people within Ontario that run Enbridge Gas." – EGD Med/Large Business

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Rate Issues

Fixed & Variable Costs

The following stimulus was used to illustrate the fixed costs and variable costs involved in calculating natural gas rates.

Rate Issues: *How Should Enbridge Calculate What You Pay?*

A new rate application is a fresh opportunity to consider how your rates are calculated. Starting from scratch, how would you like your bill to be calculated? Much of your bill is based on 3 types of costs.

Costs that have to be paid no matter how much gas is used

Variable costs (the cost of the gas customers use).

Fixed costs that create capacity to deliver gas (such as the pipes and compressors) that are related to how much gas customers use.

Fixed costs for services that are shared by all the customers in a rate class (customer support, programs like energy conservation and low-income assistance programs, and operations like the fleet of service technicians)

Costs that are related to how much customers use

How would you like Enbridge Gas to calculate what you pay?

Fixed & Variable Costs

Overview: Many participants from both customer types had difficulty understanding the concept. Business participants seemed to default to "everything variable", and residential participants had more nuanced responses split evenly between "Gas cost variable & overhead costs fixed" and "Gas cost and pipe cost variable, customer support costs fixed".

Business

Business participants typically preferred variable costs for everything.

"If you use more you should pay more" – EGD Med/Large Business

"I'd like to see it broken down by usage, that's the number one thing. I'd like to have one rate that covers all the costs and comes to me as I use more gas"– Union Small Business

"I'd like it to be linked to the volume of fuel. Because that sounds more fair. If someone is using a lot of fuel then they're getting more from the infrastructure" – EGD Med/Large Business

Residential

Participants were split between having fixed costs for overhead only or for pipes as well.

"With the fixed costs [related to creating capacity to deliver gas], you could try and do like a weighted average to split that a little bit more fairly" – Union North/East Residential

"I think it would be too confusing to break it down any further, I think we all share that fixed cost." – Union North/East Residential

"I like the idea of putting it on the individual consumer. So that everyone has a stake in making sure they do their part" – Union Central Residential

Specific Transactions

Overview: Both customer types were split between user fees and making specific transactions part of everyone's bill. Reactions varied based on the details of the actual service. However, the user fee approach was generally more favoured.

Paid by Everyone

"It's probably better buried in the overall cost of operations, easier to swallow for everybody" – EGD Med/Large Business

"It should be shared across the customer base evenly" – EGD Small Business

"It should be included in the overall cost. I don't like to feel like I'm being nickel and dimed with charges" – EGD Small Business

"It's something that should be absorbed across the board by everyone" – EGD GTA Residential

User Fees

"To me it's a pay per use sort of thing" – Union Central Residential

"They should be separate because I want to see if they have extra charges"– EGD GTA Residential

"I think the customer should pay their fair share. Customers should be paying for new service fees directly" – EGD Med/Large Business

"Why should I pay for someone else?" – Union Med/Large Business

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Rate Zones

Rate Zones

Overview: Both customer types largely preferred harmonized rates for equity, regardless if they pay more. However, a minority tended to prefer different rates for fairness and concerns about their costs increasing.

Different Rates

"Just in terms of fairness, it seems it should be based on how much you're using" – EGD GTA Residential

"The costs are different depending on where you live, the cost differences come down to differing fixed costs" – EGD GTA Residential

"I will say they should pay different rates depending on the cost in each area. Leave things the way they are." – EGD Med/Large Business

"It should depend on how long the pipeline takes to get to you" – EGD Med/Large Business

Harmonized Rate

"Everybody should be paying the same rate. It's not fair that some place in Kingston can't get the same rate" – EGD Small Business

"I think balancing it out is more fair" – EGD Med/Large Business

"We all live in Ontario, we're all getting the same gas. I think all zones should have the same rate" – Union Med/Large Business

"I think it should be a uniform price across the board" – Union South/West Residential

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Use Reserves or Borrow

Use Reserves or Borrow

Overview: Many participants were interested in Enbridge having the flexibility to use reserves if it means potential savings for customers.

Flexibility

Some participants simply like the idea of flexibility.

"I want them to be able to be flexible with their finances and use them where they're most needed" – Union Med/Large Business

"Flexibility for sure. It's tough to see money sitting there when it's not being used" – EGD Small Business

"They should have the flexibility to use it as needed because there may be priorities they can direct it to." – EGD Non-GTA Residential

Some are looking for clarity on when and how the reserves would be replenished.

"If they're going to replenish it then borrowing is ok." – Union Central Residential

"Yeah. If they're going to replenish the savings, I say use the savings. It's there. But you know, they have to have some sort of repayment plan where they're going to put that money back for its intended purpose." – Debbie (Union Central residential)

Don't Use Reserves

"Leave it as is, not accessible for company use. It's put aside for a reason" – Union South/West Residential

"If the money was set aside for a purpose, I think it should stay there. I don't think it should be fungible." – Union North/East Residential

"Again, I'm more conservative. I would put them aside and hold it for that specific purpose." – EGD Small Business

Future of Natural Gas

Role of Natural Gas in Your Future

Overview: Most participants of both customer types expected to use equal or less natural gas in the future due to other energy sources and technology. A few participants expect to use more because of the growth of their business or due to aging residential infrastructure.

Same/Less

Most expect to use same/less natural gas due to technology/energy advances.

"Technology and efficiency will advance, like furnaces and water tanks, which should cut down on consumption." – Union South/West Residential

"I'm hoping to start using less, as technology gets better we'll need less and things will still be efficient and safe." – Union South/West Residential

"We won't consume more, and with better equipment our efficiency will go up so we'll be using less in 30 years" – EGD Med/Large Business

"I'm going to say less, I just think there's going to be more renewable resources in 30 years than gas." – Union Med/Large Business

"Our ovens will be using the same, so we we'll be using the same too." – Union Med/Large Business

More

A few participants, mostly business, felt they will be using more.

"If we're around in 30 years I would expect we'll be using slightly more." – Union Med/Large Business

"More because we will keep growing" – EGD Small Business

"More because aging homes and insulation won't be effective." – EGD Non-GTA Residential

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Energy Source Choices (Consumers or Government)

Overview: Participants from both customer types were divided over whether consumers should lead because they make better choices, or government because it's a major decision that requires expertise and institutional might. Generally, both customer types preferred the consumer option. For "both government and consumers" responses see next slide.

Consumers

"Consumers, because governments always incur more costs and we have better leaders among the consumers." – EGD Non-GTA Residential

"I like to make my own decisions. Government takes a long time to adopt new technology." – EGD Central Residential

"Consumers because it would be more of what the consumer wants, not what the government thinks we want." – EGD Small Business

"We use the gas, so we should do it." – Union Small Business

Government

"If consumers make the choices it'll never get resolved. Government needs to set the parameters." – EGD Med/Large Business

"The government should make decisions on energy choices because they follow other protocols while the customer only thinks of price." – Union Small Business

"I don't want to sound elitist but you have more intelligent people running the government." – Union South/West Residential

Energy Source Choices (Consumers or Government)

Overview: A minority of participants in both customer types indicated they wanted a hybrid model where consumers and government work together.

Both

"Government should definitely be involved, but it's going to come down to individuals' choices." – EGD GTA Residential

"Definitely needs to be a collaboration."– EGD GTA Residential

"Consumer driven with government oversight. If the government can establish parameters (taxes, feeds, offsets) then consumers can drive the price within those parameters."– Union South/West Residential

"I'm a 20th century guy and I still have faith that government can help us make large scale social transitions. But consumers have to understand what's going on. It can't just be the CRA dictating stuff to us and sucking money out." – Union North/East Residential

"Both, I think one pushes the other. I think government regulation could actually be a benefit. And consumers can vote to influence government." – Union Central Residential

"Both, right? I think both working together would make it more possible. Government makes it and then consumers can decide whether it's good for them or not." – EGD Small Business

"Everyone is responsible. Authorities but everybody else too. They can encourage people and give subsidies." – EGD Small Business

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Energy Transition

What Low Carbon Options Do Customers Have?

Overview: Participants from both customer types offered examples of low carbon options. Residential participants offered many examples. However, one-on-one business participants offered fewer options, possibly because they were thinking about actually implementing these solutions in their businesses as opposed to theoretically using the options like residential participants.

Business

Business participants had ideas, but seemed constrained by the realities of their businesses. There was no clear pattern in the mentions so the order of the items below is not meant to suggest either priority or frequency of mentions.

(1) Capital projects to reduce energy usage, (2) Keep units colder in winter, (3) Better insulation, (4) Reduce equipment inefficiencies, (5) Maintaining boiler systems, (6) Running of battery power, (7) Turning lights off, (8) Sending less garbage to landfills, (9) Battery operated tools, (10) Solar power.

Residential

Residential participants suggested a wide variety of options with no clear pattern. The order of the items below is not meant to suggest either priority or frequency of mentions.

(1) Smart meters, (2) Right sizing vehicles, (3) Less driving, (4) Conservation, (5) Upgrade insulation, (6) Reduce garbage, (7) Solar power, (8) Geothermal, (9) Recycling, (10) Plant trees, (11) LED lights, (12) Maintain appliances, (13) Energy efficient appliances, (14) programmable thermostat, (15) shift energy consumption to non-peak times, (16) electric vehicles, (17) biking, (18) renewable energy, (19) educating people to use less energy.

Options for Enbridge Gas to Reduce Green House Gases

Overview: Participants from both customer types struggled to answer this question. Participants mentioned new more efficient technologies, alternative fuel sources like biogas and hydrogen, and developments in the direct operations of Enbridge Gas such as solar power, electric vehicles, and an improved extraction process.

Business

Business participants focused on "greener" equipment, "greener" extraction, and "greening" the Enbridge Gas direct operations.

"Natural gas powered vehicles for all their service vehicles would help. They have a big fleet, so that would make a difference." – EGD Small Business

"For Enbridge, it starts with bringing it to the surface, how it's processed and delivered. The whole extraction process" – EGD Med/Large Business

"They can go paperless, or make all their vehicles electric, better waste management, renewable resources like solar power." – Union Small Business

Residential

When able to answer the question, residential participants suggested similar options to the business participants.

- *Reduce the carbon emitted at the production stage*
- *Energy efficiency (natural gas powered vehicles)*
- *Biogas*
- *Use incentives to encourage less natural gas consumption*

Responsibility for Developing Low Carbon Solutions

Overview: Participants in both customer types tended to see the responsibility for developing low carbon solutions as the purview of industry and government.

Government

Government or regulators were common choices because of their expertise and perceived power in the space.

"First of all, government. They need to follow up with research. We may have hit a plateau with that…we may need more research into emissions, filtration systems and the like." – Union Med/Large Business

"Ultimately, I hold the government responsible for developing options and leading conservation, by having stricter protocols for companies around emissions." – Union Small Business

"Government can do a lot of public/private cooperation or research type activities" – EGD Small Business

**Government mentioned six times among residential participants.*

Industry

Companies like Enbridge Gas were also common choices due to their perceived responsibility/culpability and domain expertise.

"Enbridge can use their chemical engineers to produce natural gas which is more environmentally positive than what it is now." – Union Med/Large Business

"Enbridge has the expertise, training, and knowledge." – EGD Med/Large Business

"It would have to be manufacturers. We have our ovens, they build and service them. So if they can find a more environmentally safe way then that's up to them." – Union Med/Large Business

**Industry, incl. Enbridge mentioned ten times among residential participants.*

The role of Enbridge Gas in Low Carbon Solutions

Overview: Some participants across customer types suggested that Enbridge Gas should collaborate with the government, take a leading role in promoting less GHG intensive alternatives, and develop new technologies.

Enbridge Gas + Gov't

Some participants want Enbridge Gas to collaborate with government regulators and also take a leading role in the effort.

"I think Enbridge should take the initiative themselves and set an example for the government and others."– Union South/West Residential

"Enbridge can figure out something that is cost effective and then bring those solutions to the government."– Union North/East Residential

"That should be on Enbridge. It shouldn't be on consumers to pay for that…it should be a government and Enbridge discussion."– EGD Med/Large Business

Enbridge Gas Innovations

Some participants also want Enbridge Gas to pioneer new low carbon technologies and lead outreach on solutions for consumers.

"Yes, they can install and develop low carbon things which will be cheaper and better for the environment." – EGD Small Business

"Enbridge could help get the message out, with ads on radio and TV, trying to show people ways to be green, and they can market themselves as that." – Union Med/Large Business

"Enbridge could have a part in developing new technology for sure…they could fund the companies to develop things for them."– EGD Small Business

Responsibility for Developing Efficiency/Conservation

Overview: Participants in both customer types suggested that Enbridge Gas should collaborate with the government on conservation efforts, and that the manufacturing sector more broadly has an important role as well.

Enbridge Gas + Gov't

Participants want Enbridge Gas to collaborate with government regulators on conservation.

"I think that a company who's selling natural gas has it in their best interest to conserve it." – Union South/West Residential

"That would fall to Enbridge and the Ontario Energy Board, I would think."– EGD Small Business

"Enbridge and the government can work together on this one. Government can lead with funding research and incentivising new conservation technology."– Union South/West Residential

Other Industry

Participants also see the responsibility with manufacturing/industry more broadly.

"Responsibility for energy efficient devices is with the producers of the devices. If they have a social conscience then they will make them more efficient if they could." – Union Med/Large Business

"Supplier and appliance manufacturers, if they have the technology they can develop more efficient products." – Union Small Business

"You hope every industry is going to do it themselves, but obviously some are going to do less if it costs them money. But companies are going to feel the pressure from social media and customers." – Union Med/Large Business

Trade-Off: Outages for Lower Carbon Options

Overview: Participants from both customer types were split on whether they would accept outages for lower carbon energies, but most were unwilling. Residential participants were less willing to accept outages than business participants due to outage concerns and skepticism that it would really be benefitting the environment. Business participants were most concerned about business interruptions.

Accept Outages

Some participants accept outages because they perceived them as a temporary inconvenience and worth the trade.

"As long as it was just a short period of time, a couple hours is one thing but we don't want burst pipes." – Union Central Residential

"I'd be ok with the outage if it would help reduce environmental impacts – as long as there's a backup and it doesn't last too long." – Union Small Business

"I could accept them to a point, for lower carbon options. But I don't want my gas bill to double." – Union Med/Large Business

Don't Accept

Some participants did not accept the outage trade off because heating is critical to their business/home, and skepticism over the real benefit.

"Businessly, I can't accept it. We'd have a big problem if we can't heat our place" – EGD Med/Large Business

"Our welding plants would not be ok with power outages, we already get them from Hydro." – Union Med/Large Business

"I'd have to understand the trade off. If it was 1% better environmentally for unreliable service I'd say 'no'. But if they're reducing the carbon footprint by 50% I'd be able to live with that" – EGD Non-GTA Residential

Trade-Off: Pay More for Lower Carbon Options

Overview: Participants in both customer types were generally willing to pay more for lower GHG natural gas options, mostly from a desire to help future generations. The biggest variation was in the percentage amount they were willing to pay, with some saying 1-2% and some as high as 25%.

Under 10%

"Yes, top 5-10% might be something you could digest, I can accept that." – Union North/East Residential

"Yes, but only $5-10 per month." – Union North/East Residential

"5% per year wouldn't be so bad, if they're doing their part to help the planet." – EGD Small Business

"I guess it depends on the impacts they're expecting, but maybe upwards of 5%?"– EGD Med/Large Business

Over 10%

"If it's going to go down by double digits, then I'd be willing to pay upwards of 10% on my bill – Union North/East Residential

"I'm a small business, but I'd say that 10-15% more, as long as everybody at Enbridge does their part as well." – EGD Med/Large Business

"I'd accept a 10-15% increase in our bill as a trade for greener gas."– Union Non-GTA Residential

"25%" – EGD Med/Large Business

Funding Research & Development (R&D)

Overview: Participants in both customer types were open to paying for R&D but were less motivated, particularly residential participants, compared to their willingness to pay more for lower carbon solutions. In some cases this was because some felt it was the responsibility of Enbridge Gas. These responses are also possibly due to the ordering of the questions, with this prompt coming just after a question asking about a rate hike for lower carbon energy options.

Would Pay

Participants who were willing to pay for R&D found the idea generally appealing.

"Same for R&D, if there's specific goals upfront, I'd be willing to pay 5% more per month." – Union Small Business

"As far as R&D, we'd accept an extra $100-200 per month for something like that." – Union Med/Large Business

"I know everyone has to pay into research. I would understand a 2-5% additional cost for that." – Union Med/Large Business

"I'd be willing to pay a little bit, 5-10%."– Union North/East Residential

Would Not Pay

Participants who were not willing to pay for R&D often perceived that activity as the responsibility of Enbridge Gas, or simply felt they could not pay more.

"It should happen from Enbridge, they should be putting their profits into R&D. Take some from their own pocket." – Union Central Residential

"No, my taxes are going up so companies should be responsible for their footprints on our province." – Union South/West Residential

"No, I mean, I would love to, but at the same time, I couldn't pay more for that. I can't responsibly justify it." – EGD Small Business

"No, because we're paying so much already." – Union Small Business

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Out-of-Scope Issues

Third Party Service Providers

Note: The OEB mandates an open bill for utilities, including companies that rent appliances. However, some participants appear to believe that if there is a charge on their natural gas bill, that it must be an Enbridge Gas service. As noted earlier, this misperception often arose in the context of customer services for rental equipment.

"Some of the partners that Enbridge has had, specifically the water heater companies, have been the worst companies I've ever dealt with. They were on the on the verge of being fraudulent, I would say. And I thought it was shameful that Enbridge was actually endorsing them by you know, co billing with them" – Union North/East Residential

"We wanted to get a tankless system. We called Enbridge and when the guy eventually did come out, he then advised us that they don't rent the tankless systems unless you have a water softener system. If we're gonna rent a tankless system in our area, they would have known that they don't rent it without a water softener." – EGD Non-GTA Residential

Stimuli

Stimuli Used to Prompt Discussion 1/2

Possible Outcomes for Plan

Reliably delivering natural gas

Safely delivering natural gas

Making good use of the money customers pay

Providing affordable pricing

Providing dependable customer service

Minimizing any impacts on the environment

Being socially responsible

Supporting the growth of Ontario's economy

Possible Customer Service Outcomes for Plan

Providing dependable customer service

Offering the customer service contact options that you need

Ensuring that billing does not rely on estimated meter reads

Helping you become a more informed customer

Providing tools to help you manage your natural gas usage

Minimizing the need to access your property

Treating customers fairly and openly

Stimuli Used to Prompt Discussion 2/2

Possible Customer Service Outcomes for Plan

Providing dependable customer service

Offering the customer service contact options that you need

Ensuring that billing does not rely on estimated meter reads

Helping you become a more informed customer

Providing tools to help you manage your natural gas usage

Minimizing the need to access your property

Treating customers fairly and openly

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2024 Rate Rebasing Customer Engagement

ENBRIDGE

Phase Two Report – Residential

September 2021

Table of Contents

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Project Overview & Methodology

Enbridge Gas 2024 Rate Rebasing Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Enbridge Gas to assist in meeting its customer engagement commitments for its 2024 Rate Rebasing requirements. This report summarises the findings of Phase Two: online and telephone surveys with residential customers. A separate report summarises the findings of the Phase Two surveys with small and medium-large business customers.

Research Objectives & Survey Development

- A key objective of this phase is to understand customer opinions on their needs and key outcomes. Phase One collected the range of views in these areas. Phase Two uses surveys to draw generalized conclusions.
- In addition to overall satisfaction, the survey touched on asset management, rate design, customer care, new or harmonized programs and policies, and energy transition. A final open-ended question allowed respondents to provide any additional comments they felt Enbridge Gas should take into account when developing their investment plan.
- Phase Two included complementary telephone and online surveys. Both versions included key demographics, needs and outcomes questions, and satisfaction with Enbridge Gas. The telephone survey included some of the simpler questions on planning preferences while the online version added additional preference questions.
- Running both a telephone survey with a random sample of all customers at the same time as the complementary online survey allowed for an assessment of any potential coverage issues in the online sample.
- The surveys were developed by Enbridge Gas and finalized with input from INNOVATIVE. The residential and business versions were different only where wording adjustments were needed to tailor the question or response options for a residential vs business customer.

Project Overview & Methodology

Methodological Notes

- All data was collected between August 11th and 23rd, 2021. Details on sample design, weighting and validation can be found on the following pages.

- The telephone survey was finalized after a set of pretests to assess the length and viability of the survey instrument. In order to keep the survey length under 15 minutes, a number of complex questions that are better suited to an online approach were removed from the telephone survey. Throughout this report, it is clearly indicated which questions were asked only online vs which were asked in both the online and telephone versions.

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Sample Design

Sample Validation

Email Coverage and Consumption Analysis

The goal of the Phase Two surveys is to draw conclusions about the broader customer base. To achieve that goal, the surveys need a representative sample.

Since virtually all Enbridge Gas customers have phone numbers, the telephone sample allows us to apply a standard margin of error when projecting results to the broader customer base.

General population surveys normally rely upon StatsCan data to set quotas and weights, but in the case of Enbridge Gas customers. What is known is usage, region and rate class. Based on that, usage quotas were established for residential customers to ensure the telephone random sample was representative on known variables.

For the online sample, data provided by Enbridge Gas shows that they have email addresses for 64% of their residential customers.

Customer Segment	Full Population	Email Coverage	
Residential	3,410,649 records	2,167,285 records	**64%**

Comparing the overall population to the sample of that population with email addresses across known variables, we can see that the email sample is largely representative of the overall population of customers.

Customer Segment	Full Population	Those with email addresses	Difference
Residential	2,300m^3	2,279m^3	**-1%**

The average consumption of Enbridge Gas customers who have email addresses on file is almost identical to the total population of residential customers.

Knowing this, we set quotas based on region and consumption, as well as having an email address for the telephone survey. These sample quotas are set out on the following page.

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Sample Design

Sample Design and Methodology

Both the residential telephone reference survey and representative online survey samples were stratified based on known variables, including region, consumption and (in the case of the telephone survey) whether or not the customer had an email address on file. The target completes for each sample strata are shown below.

Residential Telephone Survey

E-mail (Y/N) & Consumption Quartile	Target Completes					
	EGD Region		Union Region			
	GTA	Other	South/ West	Central	North/ East	Total
Low – Y	36	33	13	15	7	104
Low – N	10	9	10	10	5	45
Med Low – Y	36	24	11	15	8	95
Med Low – N	15	9	10	13	6	53
Med High – Y	44	19	9	15	8	95
Med High – N	21	7	8	12	7	55
High – Y	54	15	8	14	7	99
High – N	25	6	7	11	6	55
Total	**240**	**123**	**76**	**106**	**55**	**600**

Residential Online Survey

Consumption Quartile	Target Completes					
	EGD Region		Union Region			
	GTA	Other	South/ West	Central	North/ East	Total
Low	183	167	90	103	51	594
Med Low	205	131	87	111	57	591
Med High	258	108	70	108	57	601
High	315	85	58	102	54	614
Total	**961**	**491**	**305**	**424**	**219**	**2400**

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Sample Validation

Age and Satisfaction

There is a possibility that the 36% who have not provided Enbridge Gas with an email could respond differently than the 64% who have shared their email. Using the random sample telephone survey as a reference survey provides a means of determining whether differences exist between the email sample and the broader customer base on basic demographics and satisfaction with Enbridge Gas that impact preferences. Insights gained from this can be used to develop weights to mitigate these differences if necessary. A comparison of the telephone and online survey samples is provided below and on the following page. In summary:

1. The telephone sample has a larger proportion of 45 to 64 year-olds, while the online sample are less willing to provide their age.
2. The level of satisfaction with Enbridge Gas is marginally higher among the telephone sample, while the online sample is more likely to have a neutral opinion.
3. While there are some differences in household size and income, there is virtually no differences when it comes to LEAP Qualification.

Age	Telephone	Online	Difference
18-24	2%	0%	2
25-44	9%	10%	-2
45-64	47%	39%	8
65-74	26%	21%	4
75+	5%	8%	-3
Prefer not to say	12%	22%	-10

	Telephone	Online	Difference
Very satisfied	55%	50%	-3
Somewhat satisfied	31%	27%	-4
Neither satisfied or dissatisfied	9%	17%	8
Somewhat dissatisfied	2%	3%	1
Very dissatisfied	2%	2%	-2

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

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Sample Validation

Household Size, Income & LEAP Qualification

Household Size	Telephone	Online	Difference
1 person	19%	11%	7
2 people	39%	42%	-3
3 people	15%	14%	1
4 or more	25%	19%	6
Prefer not to say	2%	13%	-11

Household Income	Telephone	Online	Difference
Less than $28,000	6%	4%	2
Just over $28,000 to $39,000	6%	5%	1
Just over $39,000 to $48,000	8%	5%	4
Just over $48,000 to $52,000	5%	5%	0
More than $52,000	54%	45%	9
Prefer not to say	21%	35%	-14

LEAP Qualification	Telephone	Online	Difference
LEAP Qualified	10%	9%	1
Not Qualified (<$52k)	21%	20%	1
Not Qualified (>$52k)	69%	72%	-3

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

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Final Sample

Weighting the Data

Having compared the telephone data to the online data, we found that any differences based on demographics were not consistently correlated with differences in preferences. We verified this by applying weights based on demographics, but this approach did not remove any substantive differences.

The final data for both residential surveys were therefore weighted to be proportionate based on the actual distribution of residential customers in each region, as well as by consumption quartile. *Weighted and unweighted sample sizes are outlined below. Minimal weighting was required to arrive at a representative sample.* The margin of error for the telephone survey is ± 4%, 19 times out of 20.

Residential Telephone Survey

E-mail (Y/N) & Consumption Quartile	Unweighted N						Weighted N					
	EGD Region		Union Region				EGD Region		Union Region			
	GTA	Other	South/ West	Central	North/ East	Total	GTA	Other	South/ West	Central	North/ East	Total
Low – Y	35	34	14	17	11	111	36	33	13	15	7	104
Low – N	9	5	10	11	9	44	11	10	10	10	5	46
Med Low – Y	35	24	16	15	11	101	36	24	11	15	8	94
Med Low – N	14	9	10	14	10	57	15	9	10	13	6	53
Med High – Y	42	18	13	15	14	102	44	19	9	15	8	95
Med High – N	17	8	10	12	15	62	21	7	8	12	7	55
High – Y	53	17	12	16	11	109	54	15	8	14	7	98
High – N	26	6	8	12	8	60	25	6	7	11	6	55
Total	**231**	**121**	**93**	**112**	**89**	**646**	**242**	**123**	**76**	**105**	**54**	**600**

Residential Online Survey

Consumption Quartile	Unweighted N						Weighted N					
	EGD Region		Union Region				EGD Region		Union Region			
	GTA	Other	South/ West	Central	North/ East	Total	GTA	Other	South/ West	Central	North/ East	Total
Low	226	292	195	208	151	1072	183	167	90	103	51	594
Med Low	231	186	171	220	142	950	204	131	87	112	57	591
Med High	238	176	114	201	107	836	259	107	70	108	57	601
High	289	131	74	150	96	740	315	85	58	102	54	614
Total	**984**	**785**	**554**	**779**	**496**	**3598**	**961**	**490**	**305**	**425**	**219**	**2400**

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Overall Satisfaction

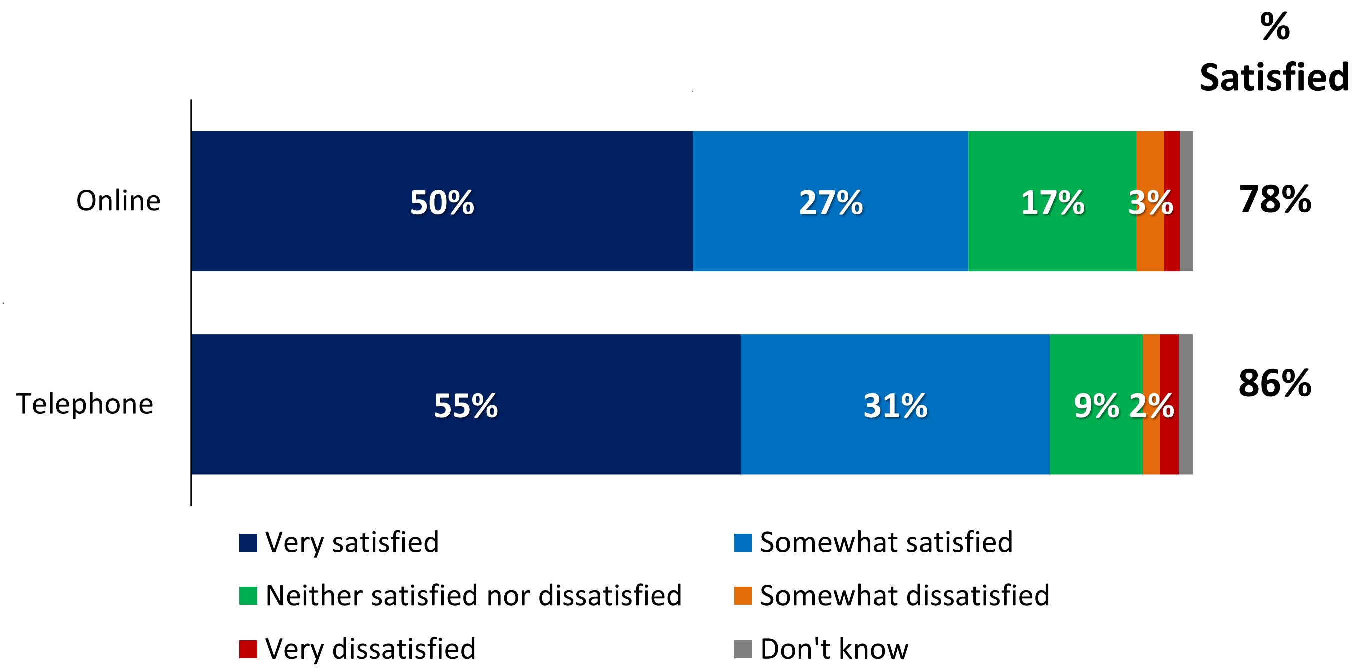
Satisfaction

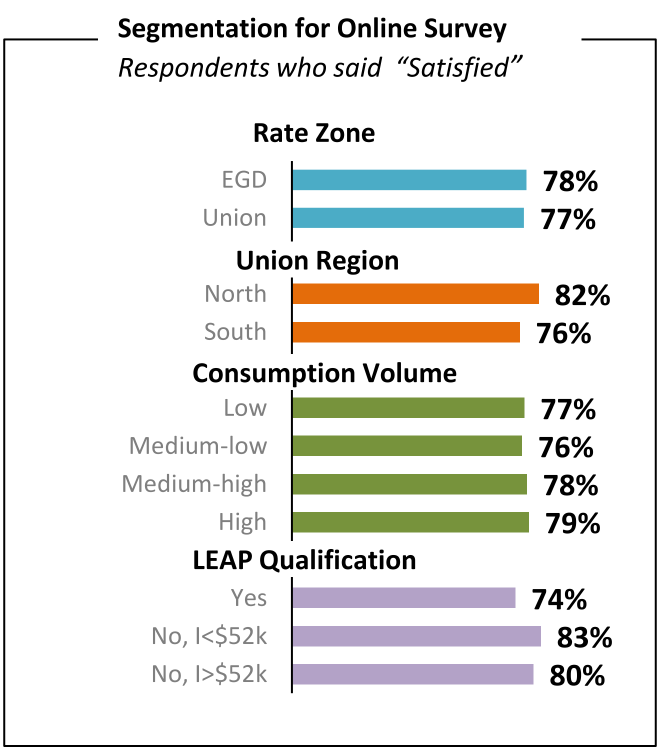
Telephone and Online Surveys

Q

Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

[asked of all respondents; telephone n= 600; online n= 2,400]





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Customer Outcomes

Importance of Outcomes

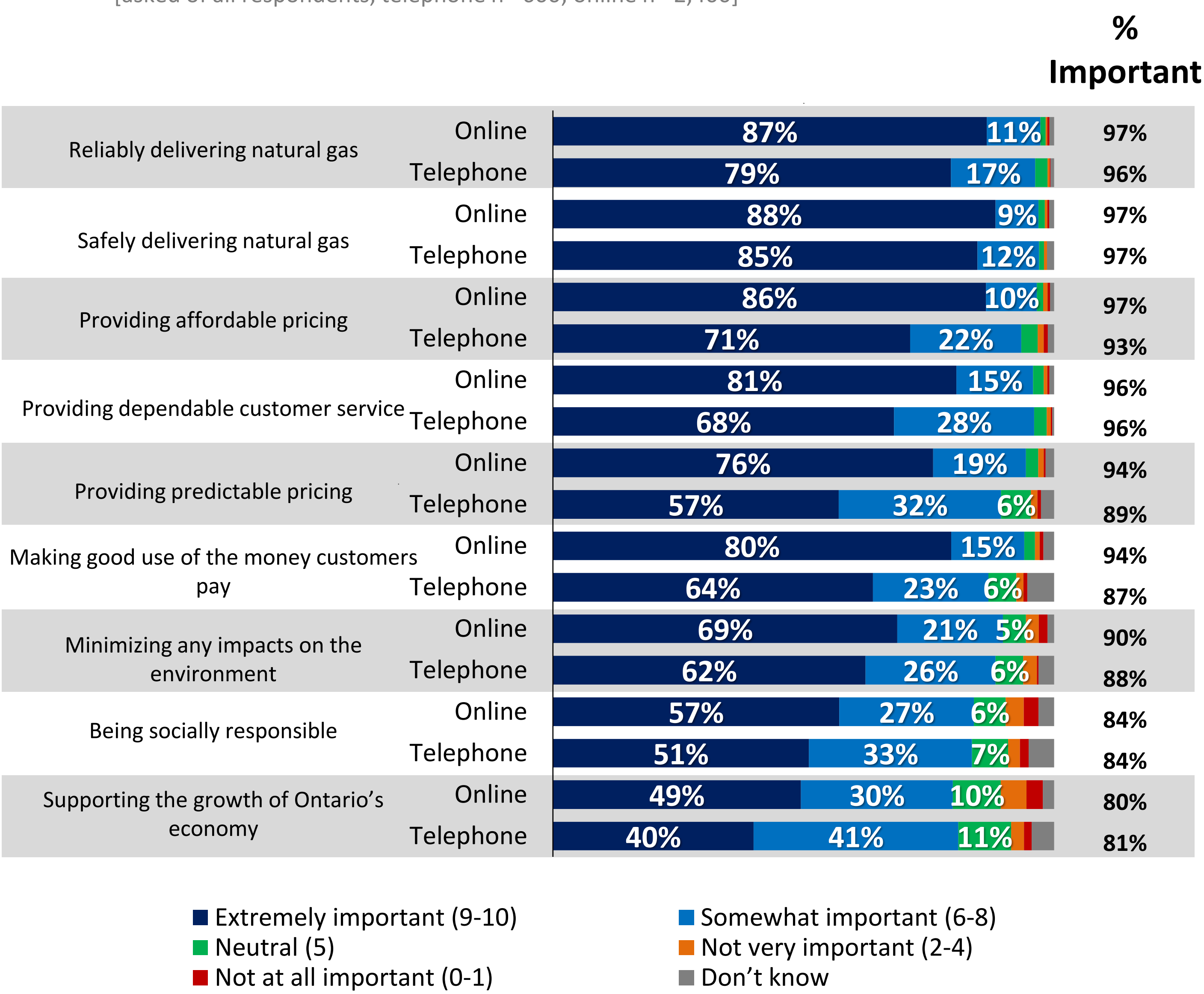
Telephone and Online Surveys

Q

In considering its business plan to be implemented starting in 2024, Enbridge Gas must make many decisions. We would like your feedback on the outcomes you would like Enbridge Gas to focus on in its plan. Outcomes are the goals and priorities that matter to you.

There is a list of broad outcomes that Enbridge Gas will need to consider. Using a scale from 0 to 10, where 0 means "not at all important" and 10 means "extremely important", please tell us how important each one is to you. Be sure to save a rating of 10 for those items that are most important to you.

[asked of all respondents; telephone n= 600; online n= 2,400]



NOTE: Data labels are removed where 3% or less

Importance of Outcomes

Telephone and Online Surveys

Q There is a list of broad outcomes that Enbridge Gas will need to consider. Please indicate how important each of the following outcomes is to you.

[asked of all respondents; telephone n=600; online n= 2,400]

Segmentation for Online Survey

% Total Importance (6 to 10)		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium-low	Medium-high	High	Yes	NO <$52K	NO >$52K
Reliably delivering natural gas	97%	97%	97%	97%	97%	97%	97%	98%	98%	95%	97%	98%
Safely delivering natural gas	97%	97%	97%	97%	97%	97%	97%	97%	97%	96%	96%	97%
Providing affordable pricing	97%	96%	97%	98%	97%	97%	98%	96%	97%	96%	96%	97%
Providing dependable customer service	96%	95%	97%	97%	96%	96%	96%	96%	95%	94%	97%	97%
Providing predictable pricing	94%	94%	95%	95%	95%	94%	94%	95%	96%	93%	94%	95%
Making good use of the money customers pay	94%	94%	94%	95%	94%	94%	95%	95%	92%	91%	94%	94%
Minimizing any impacts on the environment	90%	90%	90%	92%	89%	90%	91%	89%	90%	90%	90%	90%
Being socially responsible	84%	84%	84%	84%	84%	83%	85%	85%	83%	85%	85%	84%
Supporting the growth of Ontario's economy	80%	78%	82%	83%	82%	80%	82%	78%	79%	86%	84%	79%

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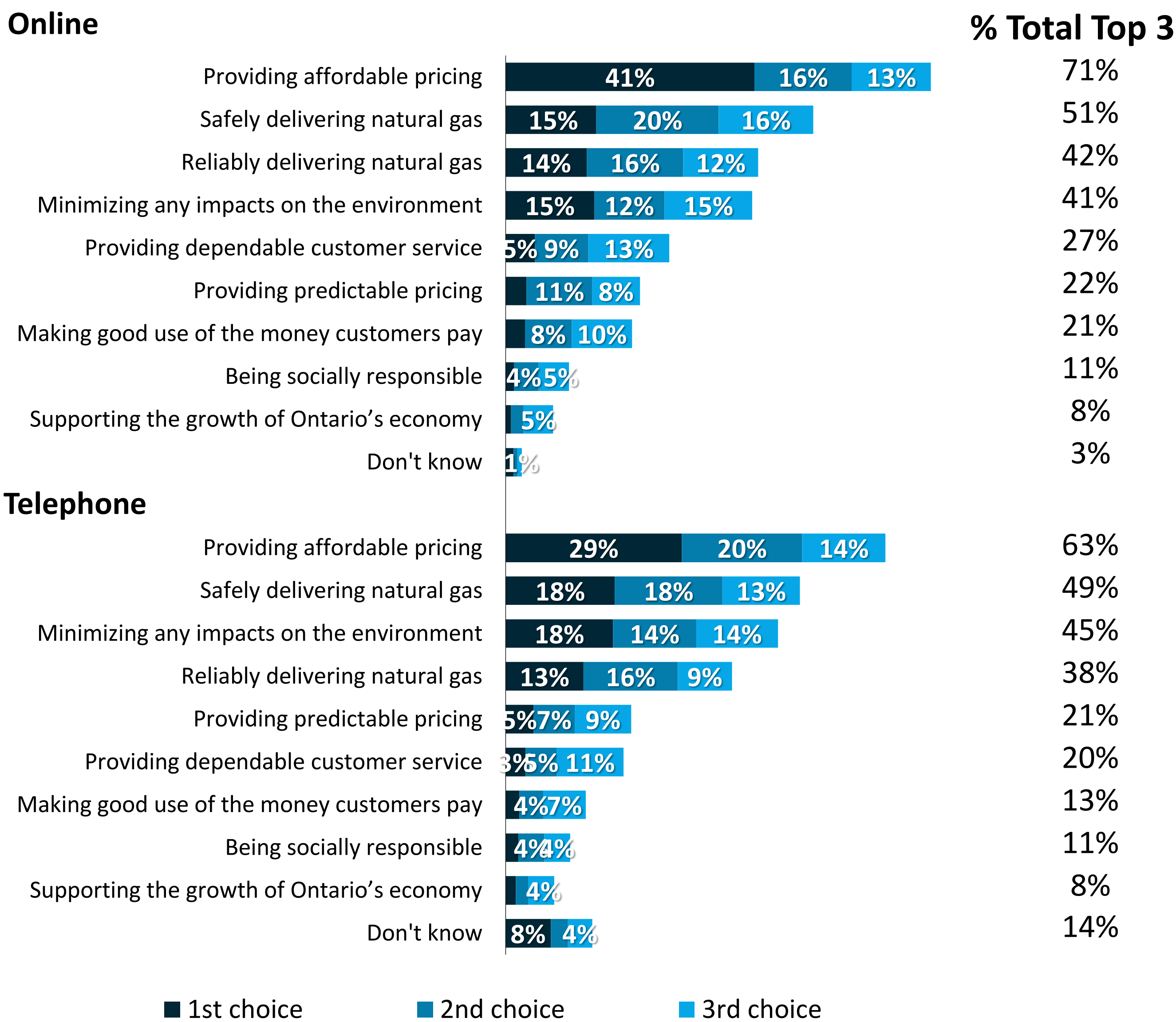
Priority of Outcomes

Telephone and Online Surveys

Q Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which one would you say is most important to you as a customer? And which one is second most important to you? And, finally, which one is third most important to you?

[asked of all respondents; telephone n= 600; online n= 2,400]



Note: 'No response' not shown. Respondents who say 'Don't know' do not get asked for further priorities.

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Priority of Outcomes

Telephone and Online Surveys

Q Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which one would you say is most important to you as a customer? And which one is second most important to you? And, finally, which one is third most important to you?
[asked of all respondents; telephone n= 600; online n= 2,400]

Segmentation for Online Survey

% Total Top 3 Choices		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium -low	Medium-high	High	Yes	NO <$52K	NO >$52K
Providing affordable pricing	71%	69%	73%	77%	72%	72%	72%	69%	70%	83%	76%	66%
Safely delivering natural gas	51%	53%	48%	44%	49%	53%	51%	49%	52%	41%	47%	54%
Reliably delivering natural gas	42%	41%	44%	38%	45%	40%	39%	41%	47%	30%	40%	46%
Minimizing any impacts on the environment	41%	42%	40%	40%	40%	41%	41%	45%	37%	30%	42%	44%
Providing dependable customer service	27%	27%	27%	28%	27%	27%	26%	27%	29%	33%	27%	26%
Providing predictable pricing	22%	22%	23%	27%	21%	22%	23%	23%	21%	29%	23%	21%
Making good use of the money customers pay	21%	21%	21%	19%	22%	19%	22%	22%	21%	23%	21%	20%
Being socially responsible	11%	11%	10%	11%	10%	11%	11%	11%	9%	9%	12%	11%
Supporting the growth of Ontario's economy	8%	8%	8%	7%	8%	8%	8%	7%	8%	10%	7%	9%

Note: 'No response' not shown. Respondents who say 'Don't know' do not get asked for further priorities.

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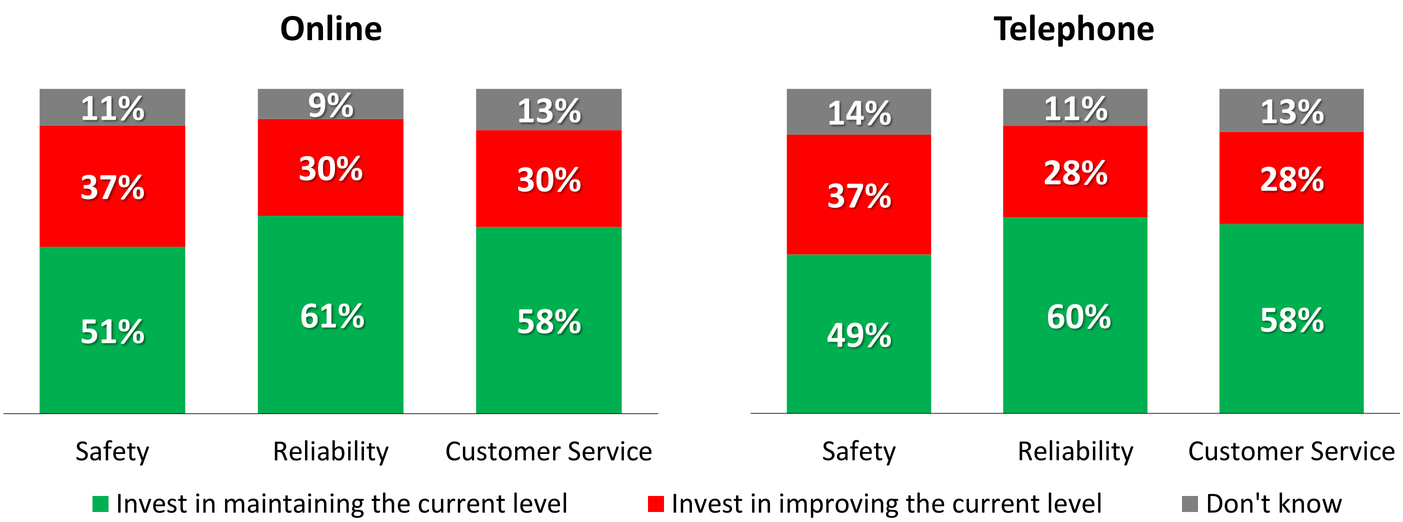
Asset Management

Investing in Service Quality

Telephone and Online Surveys

Q Thinking about the level of safety, reliability, and customer service you receive from Enbridge Gas would you like to see the company invest in maintaining or invest in improving upon the current level?

[asked of all respondents; telephone n= 600; online n= 2,400]



Segmentation for Online Survey

Safety	Total	Rate Zone: EGD	Rate Zone: Union	Union Region: North	Union Region: South	Consumption: Low	Consumption: Medium-low	Consumption: Medium-high	Consumption: High	LEAP Qualification: Yes	LEAP Qualification: NO <$52K	LEAP Qualification: NO >$52K
Maintaining current level	51%	50%	53%	53%	53%	49%	50%	52%	55%	45%	51%	55%
Improving current level	37%	38%	36%	35%	37%	40%	38%	39%	34%	40%	39%	35%

Reliability	Total	Rate Zone: EGD	Rate Zone: Union	Union Region: North	Union Region: South	Consumption: Low	Consumption: Medium-low	Consumption: Medium-high	Consumption: High	LEAP Qualification: Yes	LEAP Qualification: NO <$52K	LEAP Qualification: NO >$52K
Maintaining current level	61%	60%	62%	57%	64%	60%	59%	61%	64%	44%	63%	67%
Improving current level	30%	30%	29%	33%	28%	31%	30%	30%	28%	43%	27%	27%

Customer Service	Total	Rate Zone: EGD	Rate Zone: Union	Union Region: North	Union Region: South	Consumption: Low	Consumption: Medium-low	Consumption: Medium-high	Consumption: High	LEAP Qualification: Yes	LEAP Qualification: NO <$52K	LEAP Qualification: NO >$52K
Maintaining current level	58%	56%	60%	61%	60%	56%	57%	57%	59%	48%	61%	63%
Improving current level	30%	31%	28%	28%	28%	30%	30%	32%	28%	39%	27%	27%

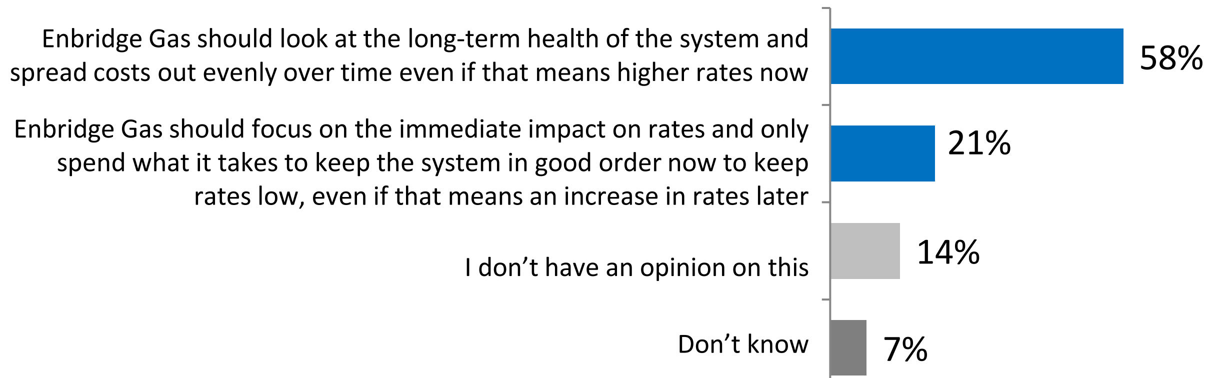
Budget Allocation

Telephone and Online Surveys

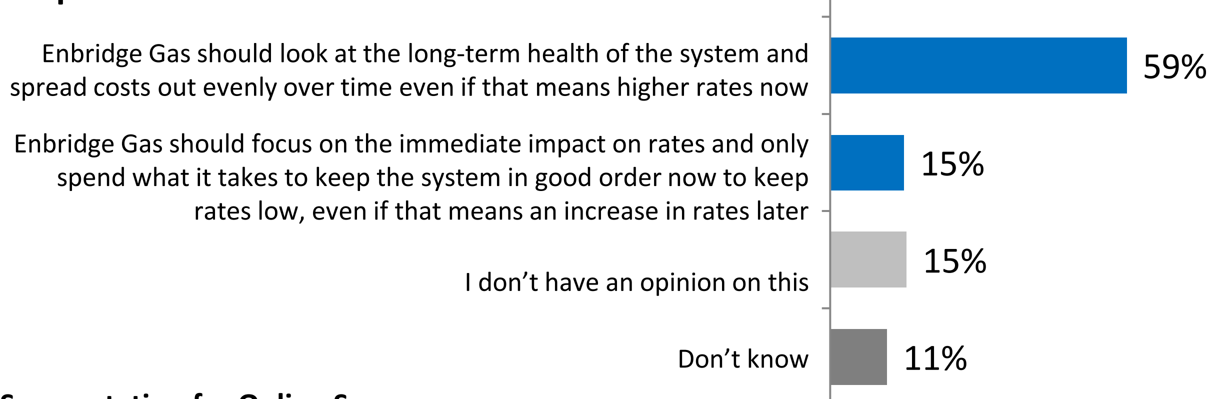
Q Thinking generally about Enbridge Gas' budget for replacing pipelines and equipment that deliver gas to your home, which of the following statements best represents your point of view?

[asked of all respondents; telephone n= 600; online n= 2,400]

Online



Telephone



Segmentation for Online Survey

		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium-low	Medium-high	High	Yes	NO <$52K	NO >$52K
Spread costs out evenly over time even if that means higher rates now	58%	57%	60%	54%	61%	58%	57%	60%	58%	40%	56%	67%
Spend what it takes to keep the system in good order now to keep rates low, even if that means an increase in rates later	21%	23%	18%	18%	18%	19%	20%	21%	23%	28%	22%	19%

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Rates

Fixed Cost – PREAMBLE

Online Survey

PREAMBLE:

Enbridge Gas is the only distributor of natural gas service in your area and there is not a competitive market in which rates are determined. For this reason, the Ontario Energy Board (OEB) reviews and approves all Enbridge Gas costs (that is, the costs to operate), and also reviews and approves how customer rates should be calculated.

Enbridge Gas incurs two types of costs in delivering natural gas to your home, those that are variable and those that are fixed.

One of these is the cost of the natural gas that customers use. This cost is determined by the market and will be passed on to you based on your measured consumption of natural gas.

The fixed costs that Enbridge Gas incurs can be divided into two groups.

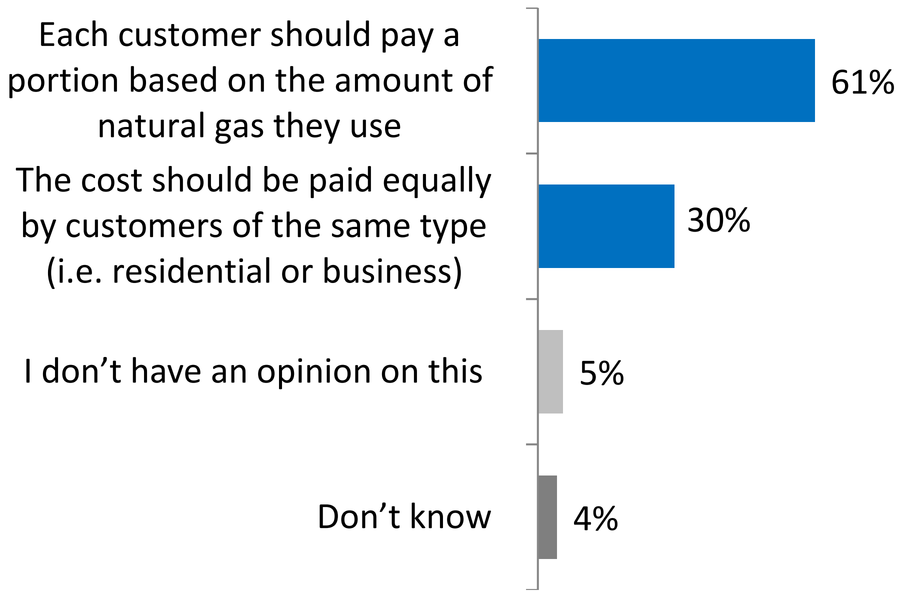
Fixed Cost – Network Connection

Online Survey

Q

The fixed costs that Enbridge Gas incurs can be divided into two groups.
One type of fixed cost is that of being connected to the network. This includes the cost of the pipeline, the pressure regulator, the natural gas meter, meter reading, billing, the contact centre and operations support. These costs are fixed for Enbridge Gas, and are similar for each customer and do not change based on the size of the customer.

How do you feel residential customers like you should be billed for these costs of being connected to the network?
[asked only of online respondents, n= 2,400]



Segmentation for Online Survey

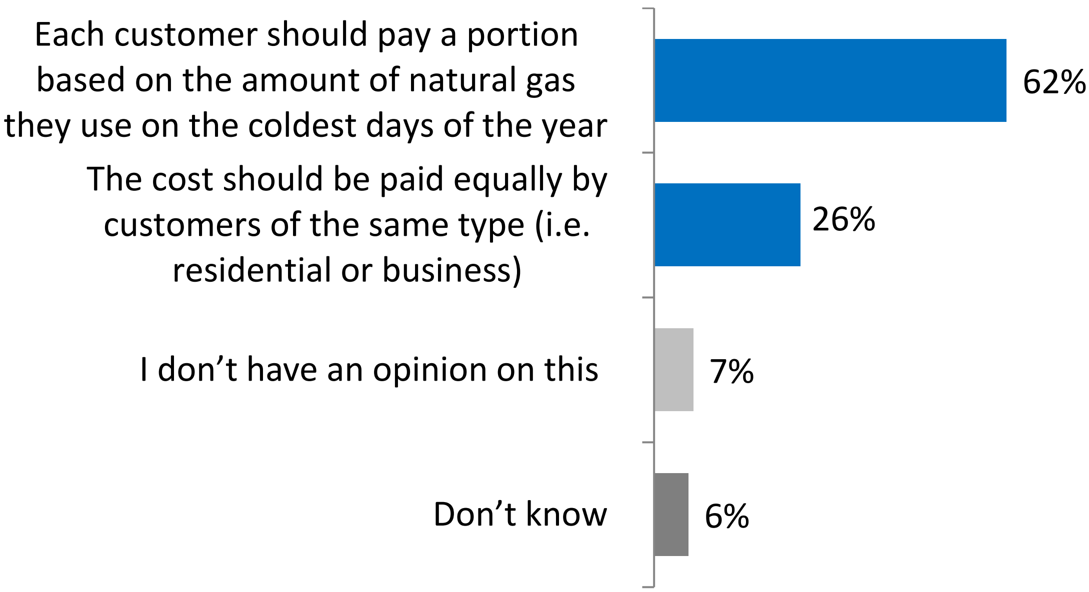
		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium -low	Medium-high	High	Yes	NO <$52K	NO >$52K
Pay a portion based on the amount of natural gas used	61%	62%	59%	58%	59%	66%	62%	59%	55%	64%	65%	60%
Paid equally by customers of the same type	30%	29%	31%	30%	31%	25%	29%	31%	34%	20%	25%	34%
I don't have an opinion on this	5%	5%	6%	6%	6%	5%	5%	5%	6%	11%	6%	3%
Don't know	4%	4%	4%	5%	4%	4%	5%	4%	4%	5%	3%	3%

Fixed Cost – Network Capacity

Online Survey

Q The fixed costs that Enbridge Gas incurs can be divided into two groups.
One type of fixed cost is that of the network capacity. This includes the cost of the network infrastructure, its operation, maintenance, and natural gas storage to meet the peak demand of customers on the coldest days of the year. These costs are fixed for Enbridge Gas, but may vary for each customer based on their individual level of peak demand.

How do you feel residential customers like you should be billed for these costs of accessing network capacity?
[asked only of online respondents, n= 2,400]



Segmentation for Online Survey

		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	**EGD**	**Union**	**North**	**South**	**Low**	**Medium -low**	**Medium-high**	**High**	**Yes**	**NO <$52K**	**NO >$52K**
Pay a portion based on the amount of natural gas used on the coldest day of the year	62%	63%	60%	57%	60%	66%	66%	60%	55%	61%	65%	63%
Paid equally by customers of the same type	26%	25%	27%	29%	26%	19%	22%	28%	33%	19%	21%	29%
I don't have an opinion on this	7%	7%	7%	8%	7%	8%	6%	6%	7%	11%	8%	4%
Don't know	6%	6%	6%	6%	6%	7%	6%	6%	5%	9%	6%	4%

Rate Zones

Online Survey

PREAMBLE:

Enbridge Gas, today, is a combination of Legacy Union Gas and Legacy Enbridge Gas Distribution. Currently there are three rate zones which result in customers paying different rates depending on where you are located in the province and which company you were served by prior to the merger. Enbridge Gas is considering the option of offering one rate zone for its different types of customers, regardless of location within Ontario. There are many benefits of one rate zone including similar charges for similar customers, a consistent customer experience, and reduced administrative costs.

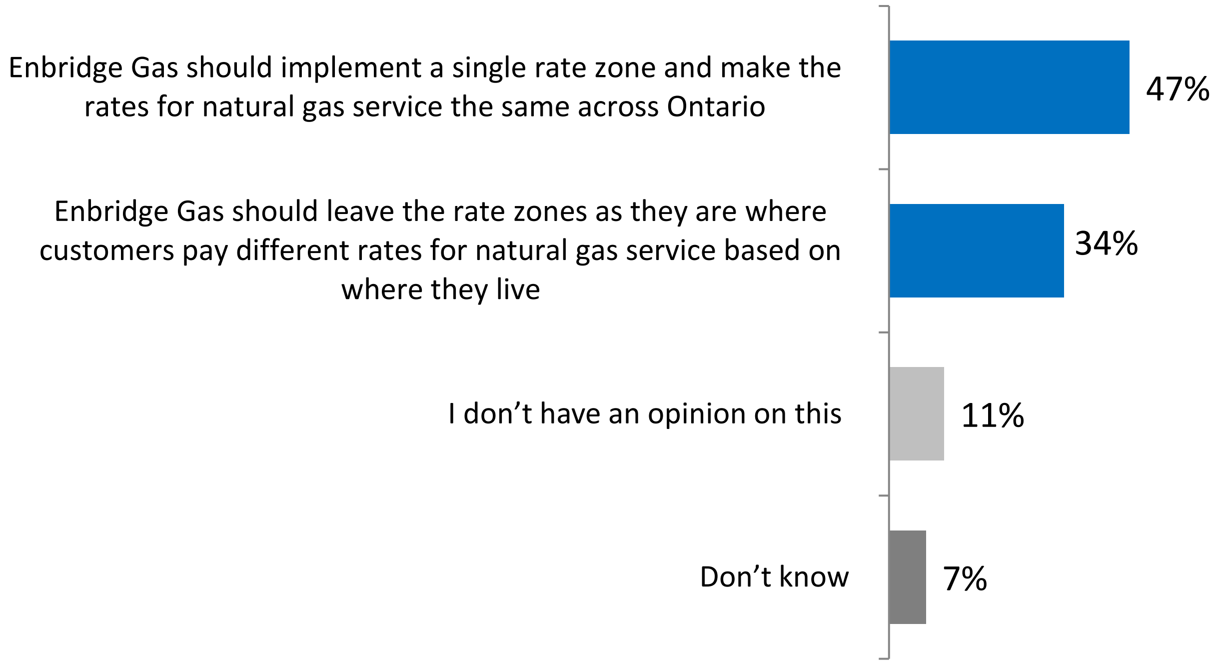
One rate zone could result in a change to the amount you pay today for your natural gas service.
Approximately 60% of customers will see very little change to the amount they pay today.
Approximately 30% of customers will see an increase of roughly 5% (or roughly $5 per month).
Approximately 10% of customers will see a decrease of roughly 10% (or roughly $10 per month).

Rate Zones

Online Survey

Q Considering this, which of the following is closest to your view?

[asked only of online respondents, n= 2,400]



Segmentation for Online Survey

		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium-low	Medium-high	High	Yes	NO <$52K	NO >$52K
Implement a single rate zone	47%	49%	45%	48%	44%	45%	44%	51%	50%	43%	45%	54%
Customers pay different rates for natural gas based on where they live	34%	34%	36%	33%	37%	36%	34%	34%	34%	36%	39%	32%
I don't have an opinion on this	11%	11%	11%	10%	11%	11%	12%	10%	10%	13%	9%	9%
Don't know	7%	7%	8%	9%	8%	8%	9%	6%	6%	9%	8%	5%

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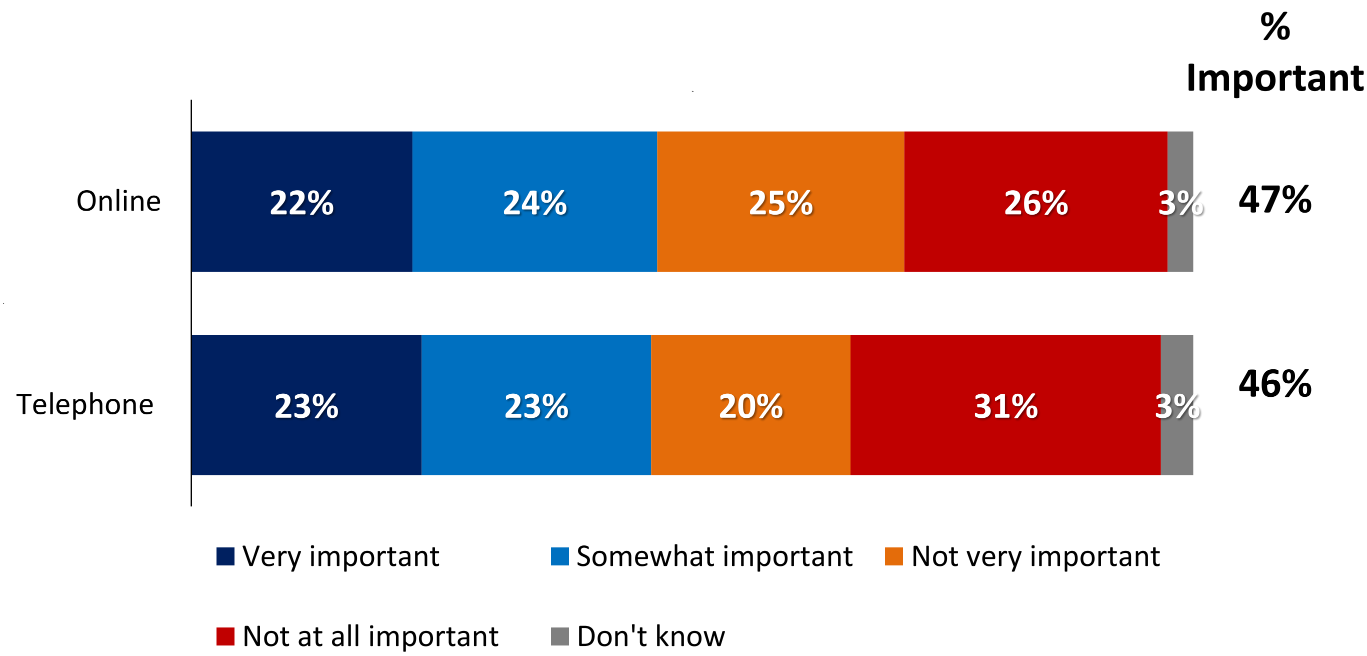
Customer Care

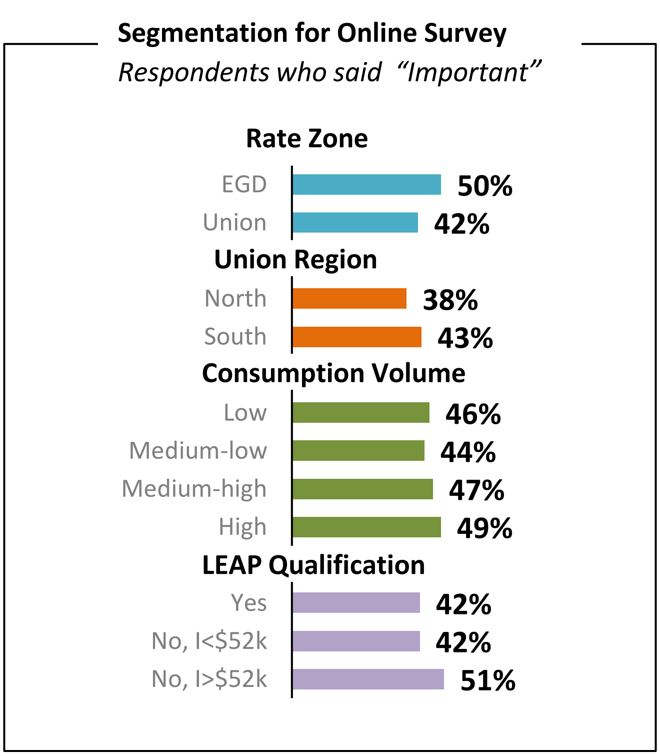
Credit Card Payment

Telephone and Online Survey

Q When you consider options for paying your bill, how important is it to you that Enbridge Gas provides customers the option to pay their bills by credit card?

[asked of all respondents; telephone n= 600; online n= 2,400]





Credit Card Charges

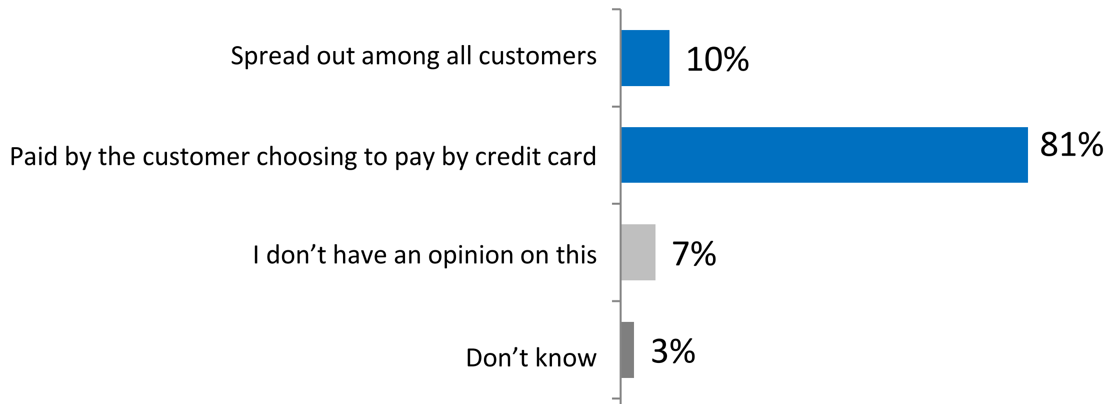
Telephone and Online Survey

Q

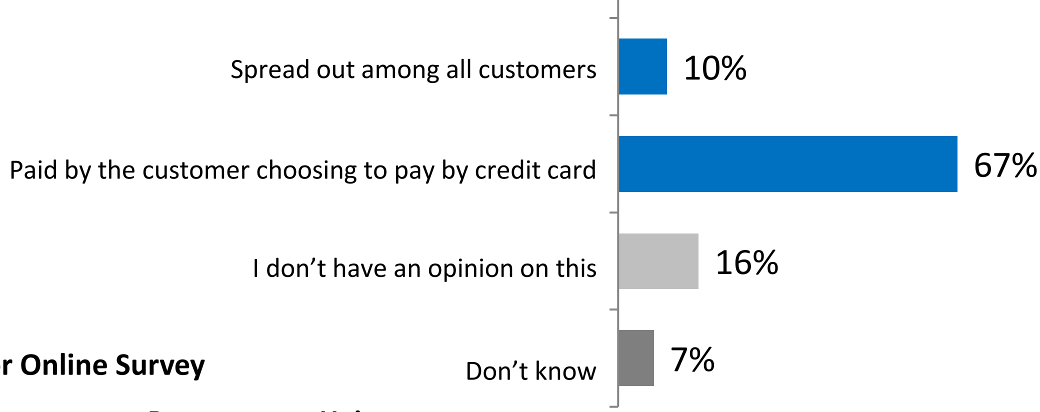
Credit card companies charge Enbridge Gas a fee for any payments that customers make by credit card. Do you believe that the costs of those credit card charges should be spread out among all customers, or should customers who choose to pay by credit card pay for these charges?

[asked of all respondents; telephone n= 600; online n= 2,400]

Online



Telephone



Segmentation for Online Survey

		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium -low	Medium-high	High	Yes	NO <$52K	NO >$52K
Spread out among all customers	10%	11%	8%	7%	9%	7%	9%	11%	11%	5%	6%	12%
Paid by the customer choosing to pay by credit card	81%	79%	83%	86%	82%	83%	80%	81%	79%	82%	84%	82%
I don't have an opinion on this	7%	7%	6%	4%	7%	7%	6%	7%	7%	9%	8%	5%
Don't know	3%	3%	3%	3%	3%	3%	4%	1%	2%	4%	3%	2%

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New or Harmonized Programs & Policies

Cross Bore

PREAMBLE:

While rare, it is possible that a natural gas line may intersect with a sewer line. When this happens, it is called a utility cross bore. This is unintentionally created when a natural gas line is installed through a process of trenchless drilling. Trenchless drilling is used to avoid creating open trenches that can disturb roads, driveways, and gardens, but it relies on locates of existing utilities which may not always be accurate for various reasons. While a utility cross bore may not pose an immediate risk, it may become an issue if a sewer line needs to be cleared in the case of a blockage.

Enbridge Gas intends to implement a program to proactively inspect and resolve any utility cross bores that may have been installed in the past. Also, a program has been implemented to prevent new installations from creating new cross bores even though that will increase the cost of the installation and require additional restoration work.

Cross Bore

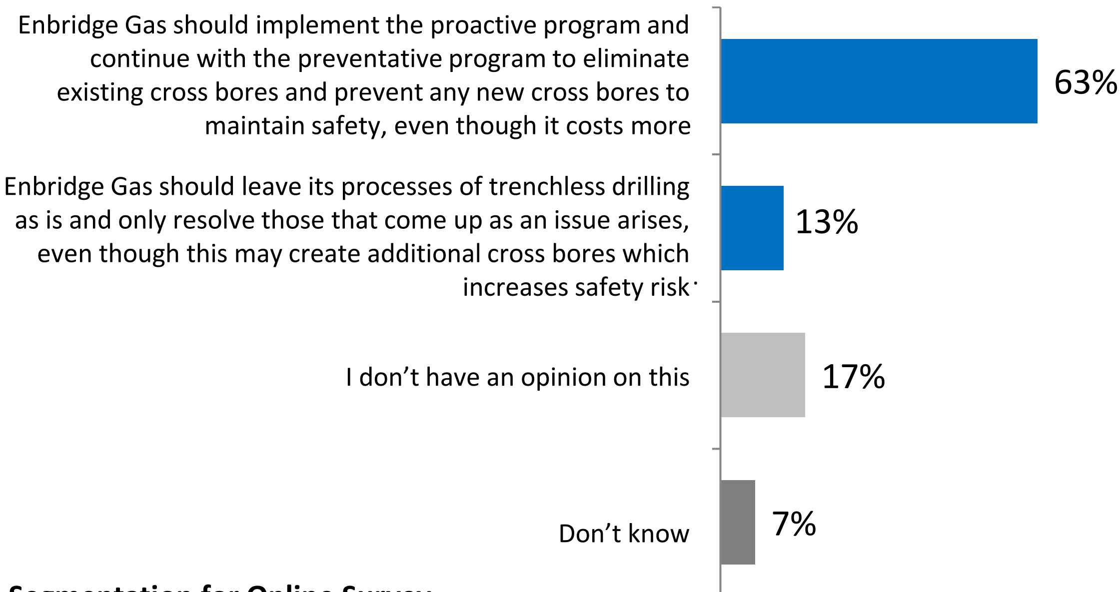
Online Survey

Q

These programs to proactively inspect and resolve existing cross bores and to prevent the creation of cross bores during the completion of new installations combined would cost customers $0.50 per year for 5 years.

Which of the following is closest to your view?

[asked only of online respondents, n= 2,400]



Segmentation for Online Survey

		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium -low	Medium-high	High	Yes	NO <$52K	NO >$52K
Implement the proactive program and continue with the preventative program	63%	65%	62%	55%	64%	63%	63%	66%	62%	52%	63%	72%
Leave its processes of trenchless drilling as is and only resolve those that come up as an issue arises	13%	12%	14%	15%	14%	12%	12%	12%	15%	17%	12%	12%
I don't have an opinion on this	17%	17%	16%	20%	15%	18%	17%	15%	18%	21%	18%	12%
Don't know	7%	6%	8%	11%	7%	8%	8%	6%	6%	9%	7%	4%

Infill Policy

Online Survey

PREAMBLE:

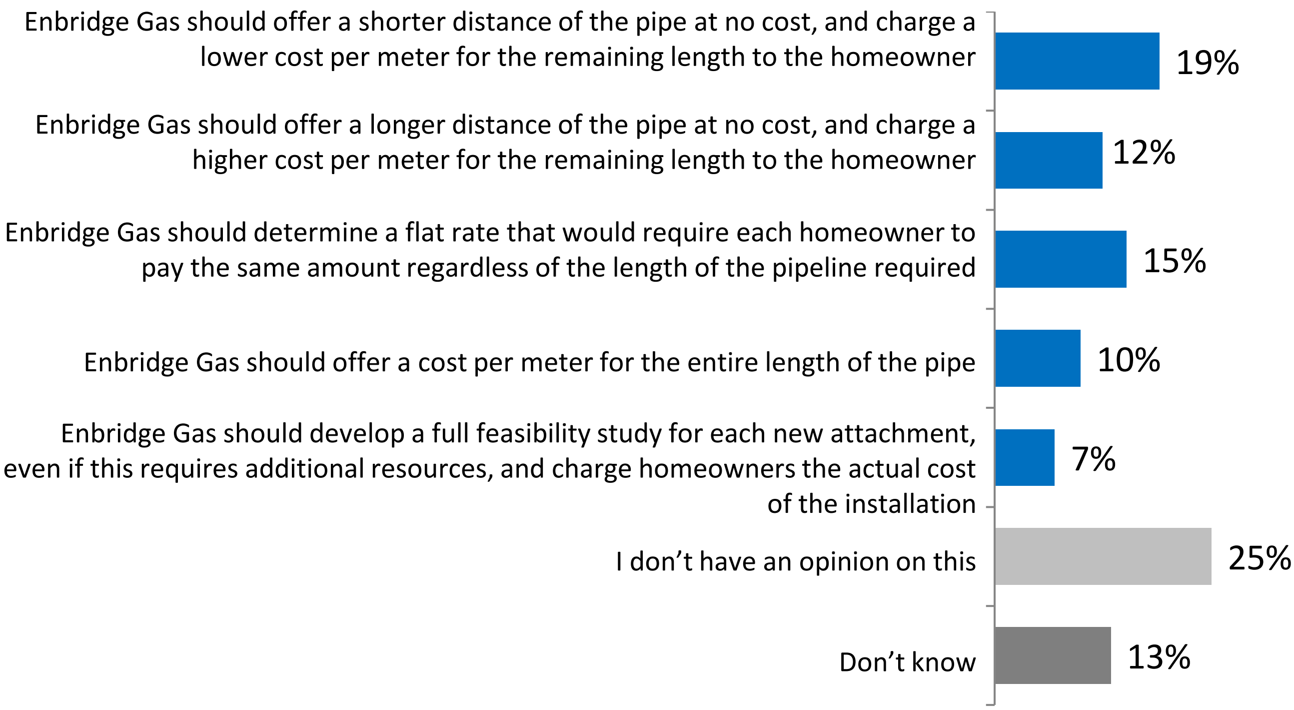
When an existing home is located near a main line, it may receive a natural gas connection through the residential infill policy. Under regulations, existing customers cannot be charged for any of these expenses.

According to the policy, connections are provided to homeowners at no cost (because forecasted revenues cover a portion of the cost to connect) up to a certain distance from the home to the main line. The cost for any extra distance must be paid by the homeowner. These costs can be structured in a number of different ways, and currently vary depending on whether someone is in the Legacy Enbridge Gas or Legacy Union Gas area.

Infill Policy

Online Survey

Q Enbridge Gas would like to create a policy that is the same across the entire territory and would like to ask you for your opinion.
Thinking about general principles, which of the following approaches is closest to your view?
[asked only of online respondents, n= 2,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	**EGD**	**Union**	**North**	**South**	**Low**	**Medium -low**	**Medium-high**	**High**	**Yes**	**NO <$52K**	**NO >$52K**
Offer a shorter distance of the pipe at no cost	19%	19%	19%	18%	19%	21%	18%	18%	18%	21%	20%	19%
Offer a longer distance of the pipe at no cost	12%	12%	13%	13%	13%	11%	11%	11%	15%	7%	11%	14%
Determine a flat rate	15%	15%	14%	16%	14%	13%	16%	15%	16%	20%	17%	15%
Offer a cost per meter for the entire length of the pipe	10%	10%	10%	8%	10%	9%	10%	10%	11%	6%	7%	13%
Develop a full feasibility study	7%	7%	7%	5%	7%	5%	8%	8%	6%	8%	6%	8%

Cut off at Main

Online Survey

PREAMBLE:

When a customer wants to cut off the natural gas service, for example, when a home is being demolished, when there has been a fire, or when a customer no longer wishes to receive natural gas service, the service is cut off at the main pipeline. This work is performed by a maintenance and construction crew. After that, in many cases a new home can be attached again at the same location. Not doing this work creates abandoned natural gas lines and meters, which may pose a safety risk.

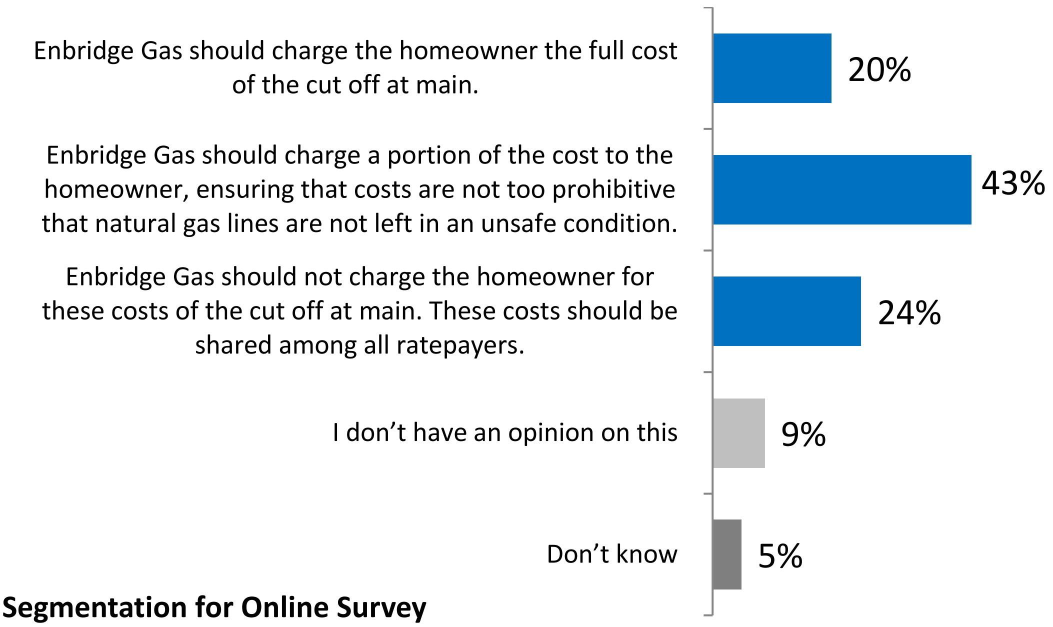
Any costs not charged to the homeowner are covered by Enbridge Gas, which means all ratepayers contribute to these costs through their rates.

Cut off at Main

Online Survey

Q

Enbridge Gas would like to create a policy that is the same across the entire territory and would like to ask you for your opinion.
Which of the following is closest to your view?
[asked only of online respondents, n= 2,400]



Segmentation for Online Survey

		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium -low	Medium-high	High	Yes	NO <$52K	NO >$52K
Charge the homeowner the full cost of the cut off at main	20%	20%	19%	15%	21%	19%	21%	18%	20%	12%	19%	20%
Charge a portion of the cost to the homeowner	43%	41%	44%	44%	45%	43%	43%	46%	39%	32%	43%	47%
Not charge the homeowner for these cost	24%	26%	22%	25%	21%	21%	23%	25%	29%	28%	23%	25%
I don't have an opinion on this	9%	8%	9%	9%	9%	11%	8%	6%	9%	17%	11%	5%
Don't know	5%	4%	5%	7%	5%	5%	6%	5%	3%	12%	4%	3%

Automatic Meter Infrastructure

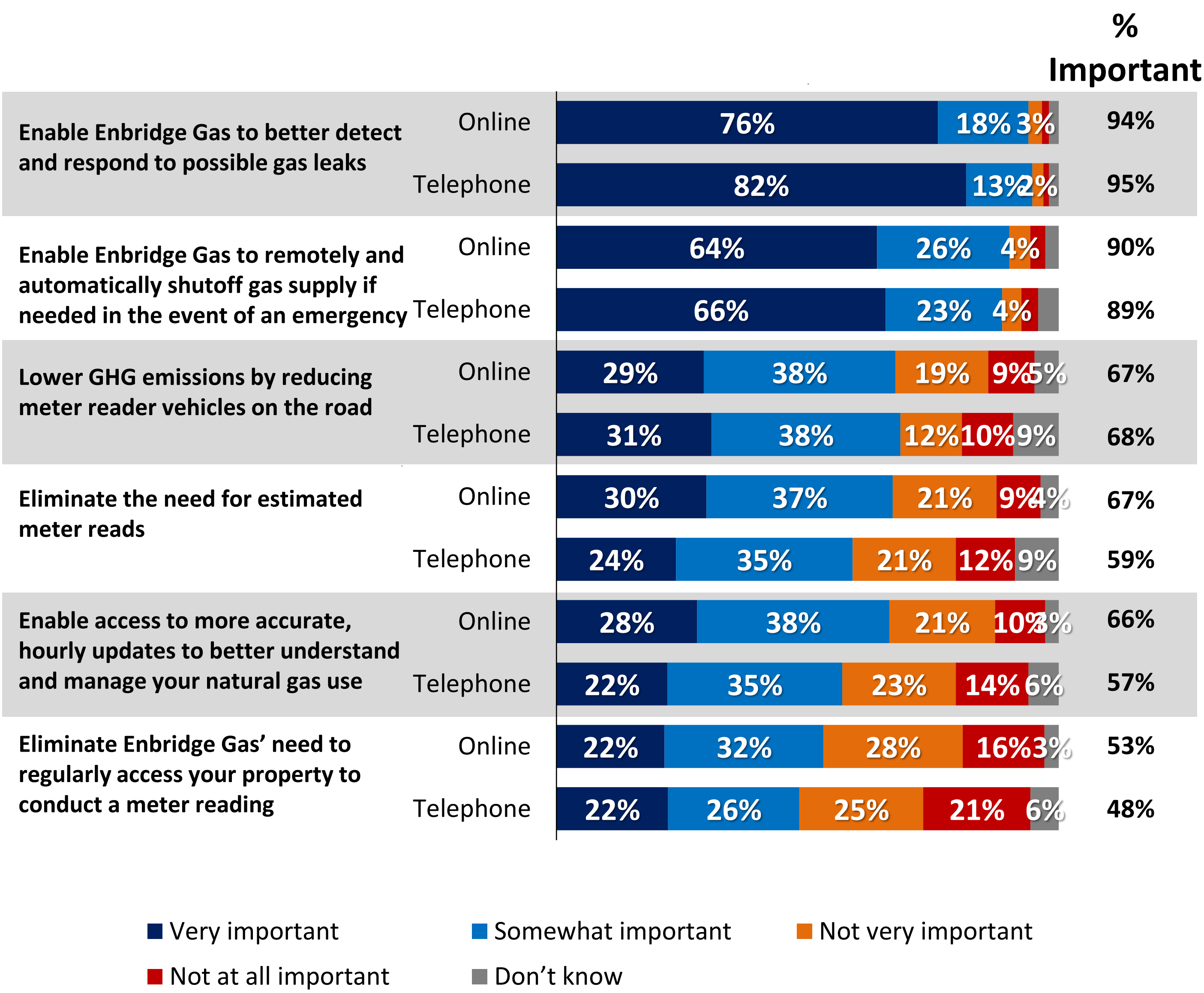
Telephone and Online Survey

Q

The gas meter technology currently used by Enbridge Gas has not changed in many years. There are new, advanced, meters available that would send the usage information to Enbridge Gas through a wireless network, similar to your electricity or water usage meters.

Please indicate how important each of the following features is to you.

[asked of all respondents; telephone n= 600; online n= 2,400]



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Automatic Meter Infrastructure

Telephone and Online Survey

Q The gas meter technology currently used by Enbridge Gas has not changed in many years. There are new, advanced, meters available that would send the usage information to Enbridge Gas through a wireless network, similar to your electricity or water usage meters.
Please indicate how important each of the following features is to you.
[asked of all respondents; telephone n= 600; online n= 2,400]

Segmentation for Online Survey

% Important		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium-low	Medium-high	High	Yes	NO <$52K	NO >$52K
Enable Enbridge Gas to better detect and respond to possible gas leaks	94%	94%	94%	94%	93%	96%	94%	93%	93%	92%	95%	95%
Enable Enbridge Gas to remotely and automatically shutoff gas supply if needed in the event of an emergency	90%	90%	90%	90%	90%	91%	89%	91%	89%	91%	91%	92%
Lower GHG emissions by reducing meter reader vehicles on the road	67%	69%	65%	65%	65%	69%	68%	68%	64%	64%	68%	72%
Eliminate the need for estimated meter reads	67%	67%	66%	67%	66%	68%	66%	65%	68%	71%	68%	68%
Enable access to more accurate, hourly updates to better understand and manage your natural gas use	66%	67%	65%	65%	64%	66%	66%	65%	68%	73%	67%	68%
Eliminate Enbridge Gas' need to regularly access your property to conduct a meter reading	53%	55%	50%	48%	51%	54%	54%	51%	55%	57%	52%	54%

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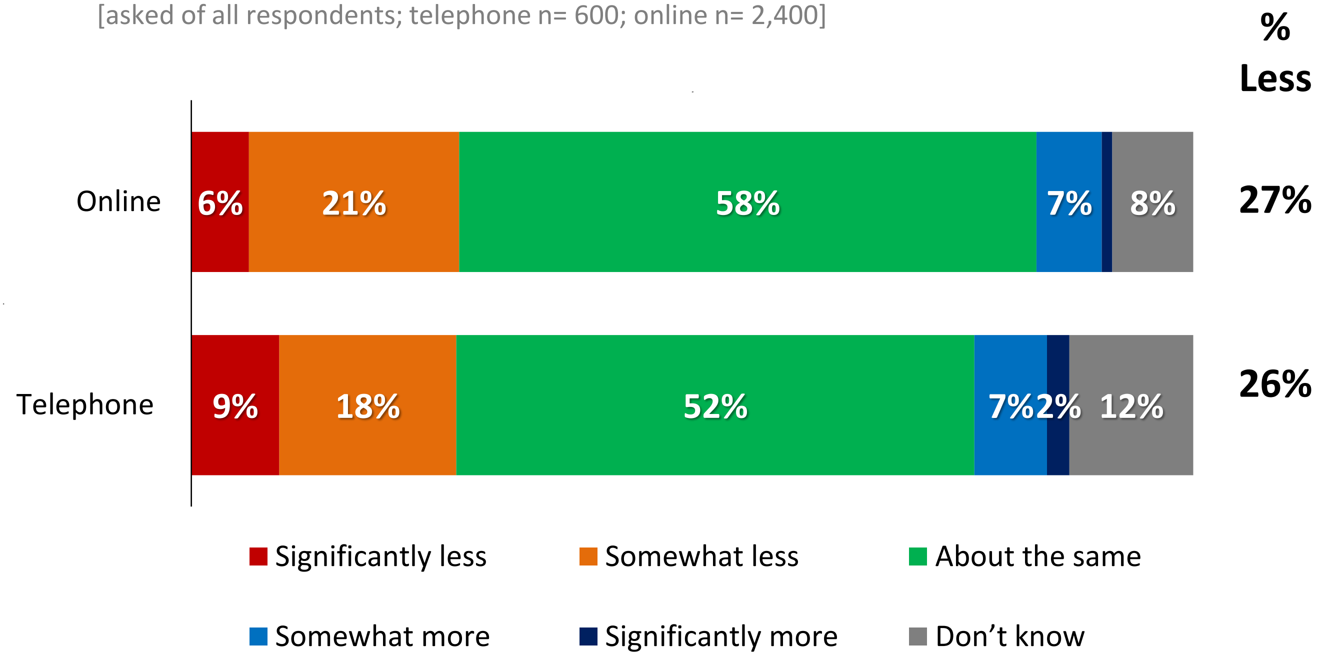
Energy Transition

Natural Gas Consumption in 10 Years

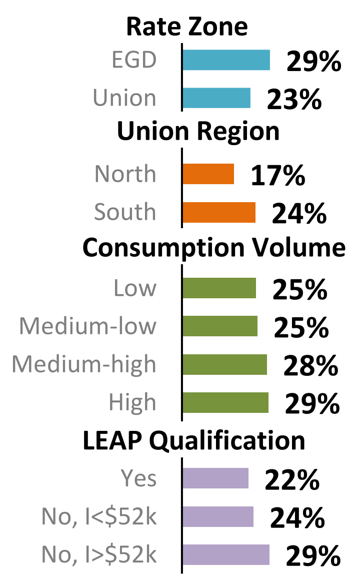
Telephone and Online Survey

Q Thinking about everything you know today, and considering any changes that you might expect in the future as it relates to all the energy choices available to you, how much natural gas do you think someone like you will be using in 10 years compared to today?

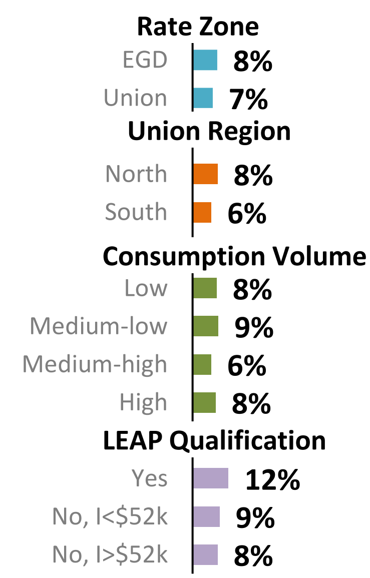
[asked of all respondents; telephone n= 600; online n= 2,400]



Segmentation for Online Survey
Respondents who said “Less”



Segmentation for Online Survey
Respondents who said “More”

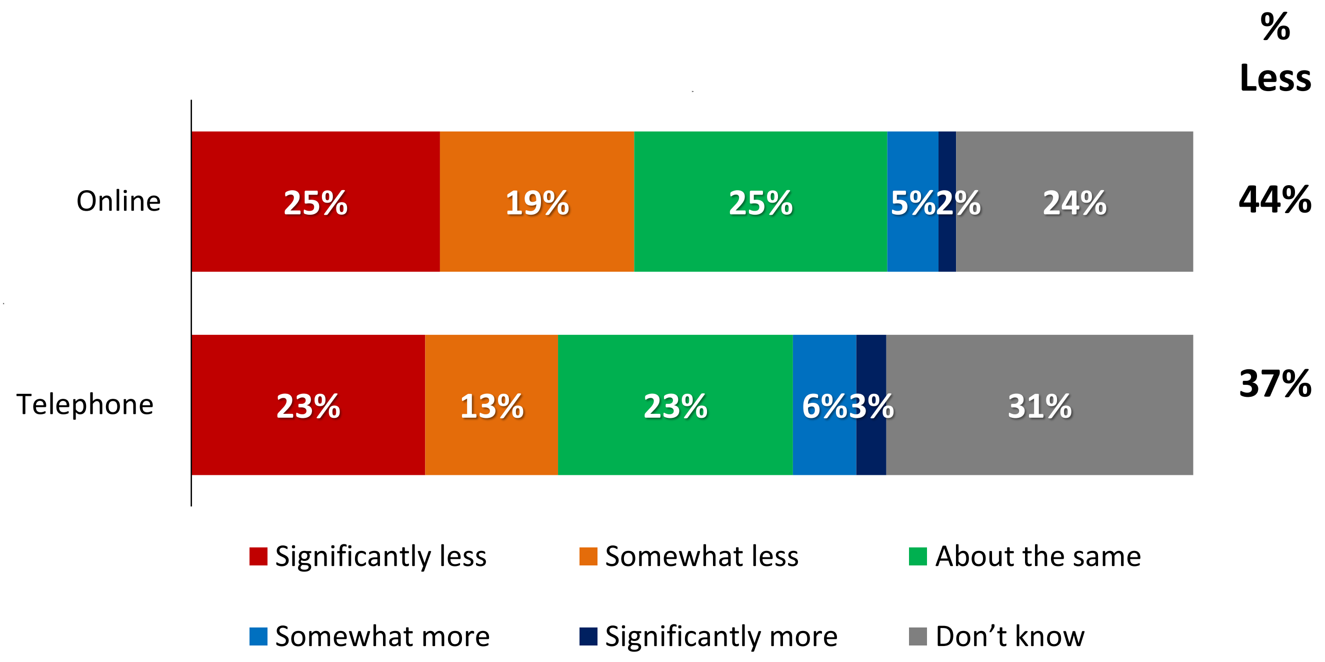


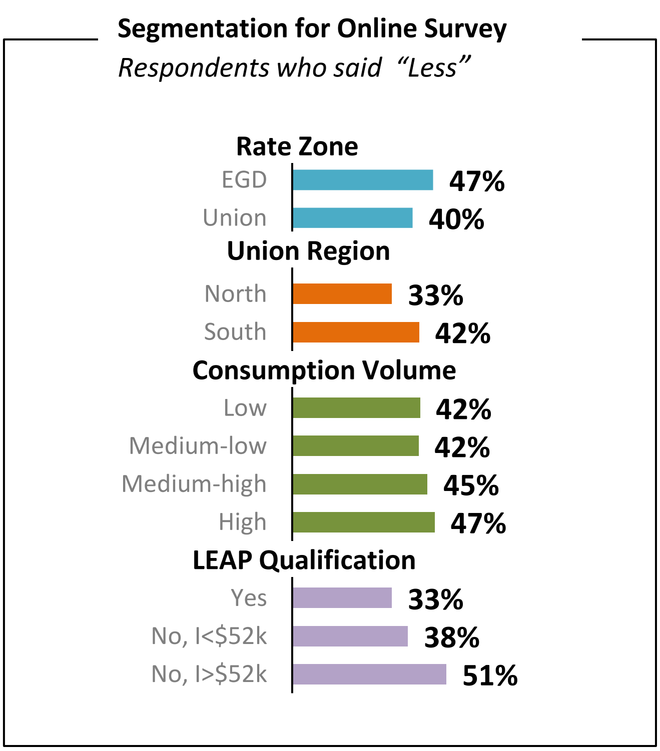
Natural Gas Consumption in 30 Years

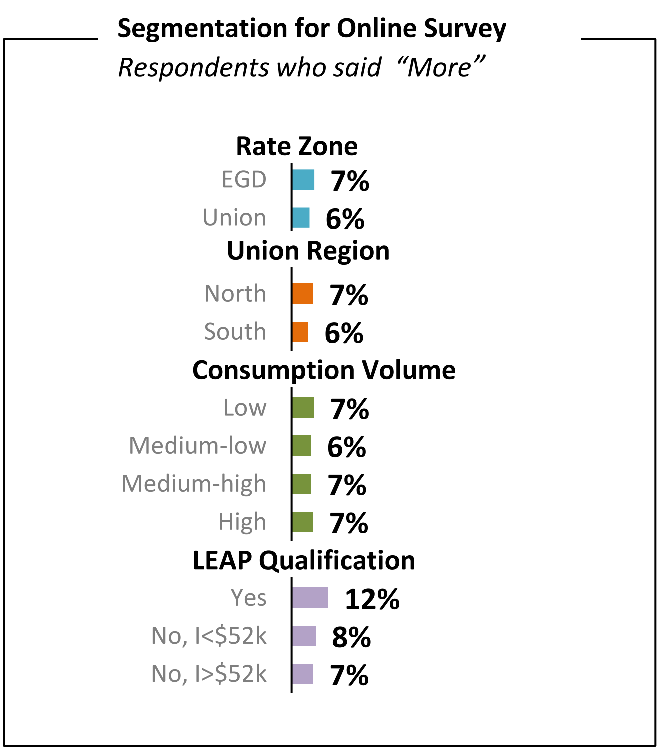
Telephone and Online Survey

Q How about in 30 years?

[asked of all respondents; telephone n= 600; online n= 2,400]







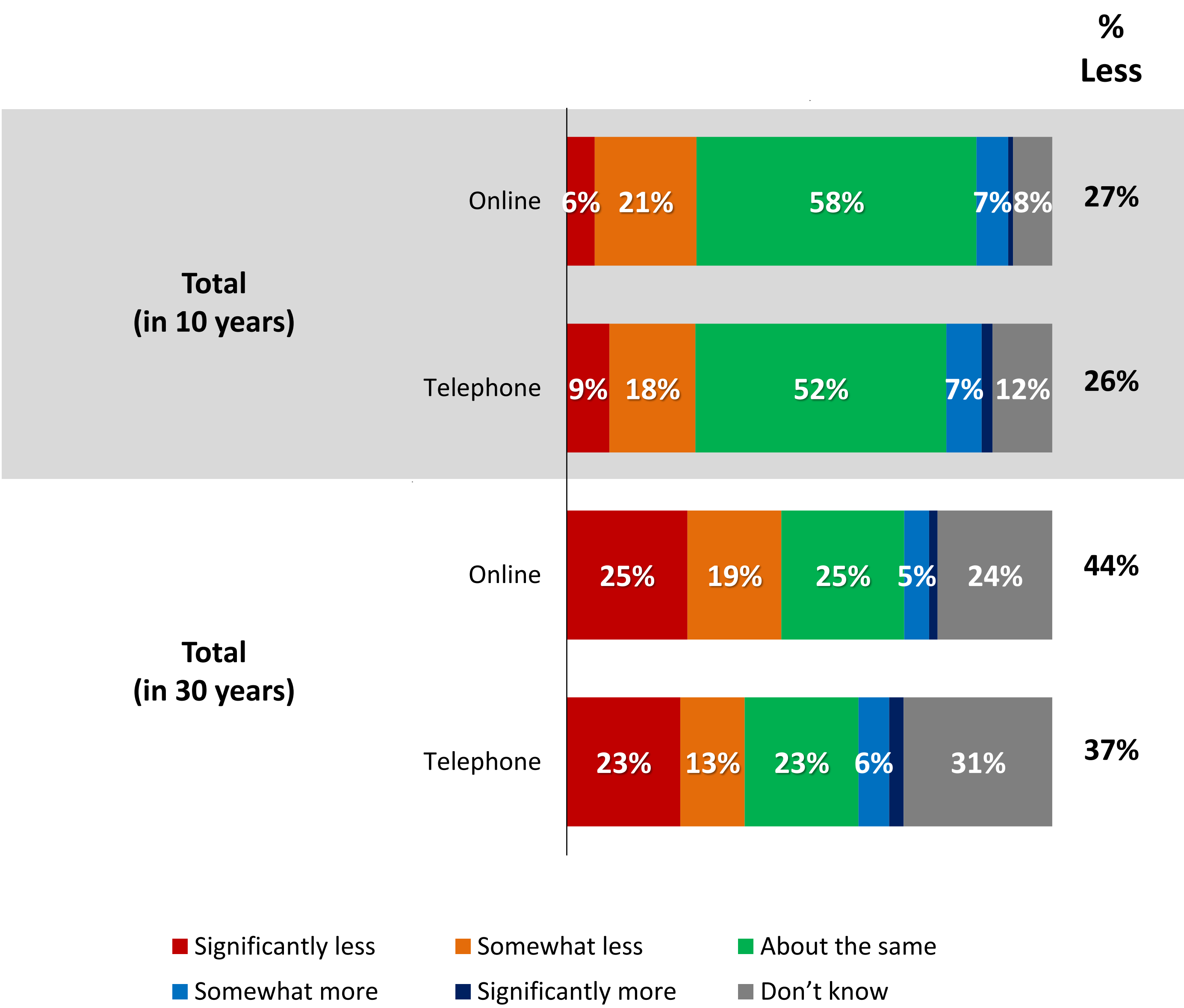
Natural Gas Consumption in 10 vs 30 Years

Telephone and Online Survey

Q

Thinking about everything you know today, and considering any changes that you might expect in the future as it relates to all the energy choices available to you, how much natural gas do you think someone like you will be using in 10 years compared to today? How about in 30 years?

[asked of all respondents; telephone n= 600; online n= 2,400]



NOTE: Data labels are removed where 3% or less

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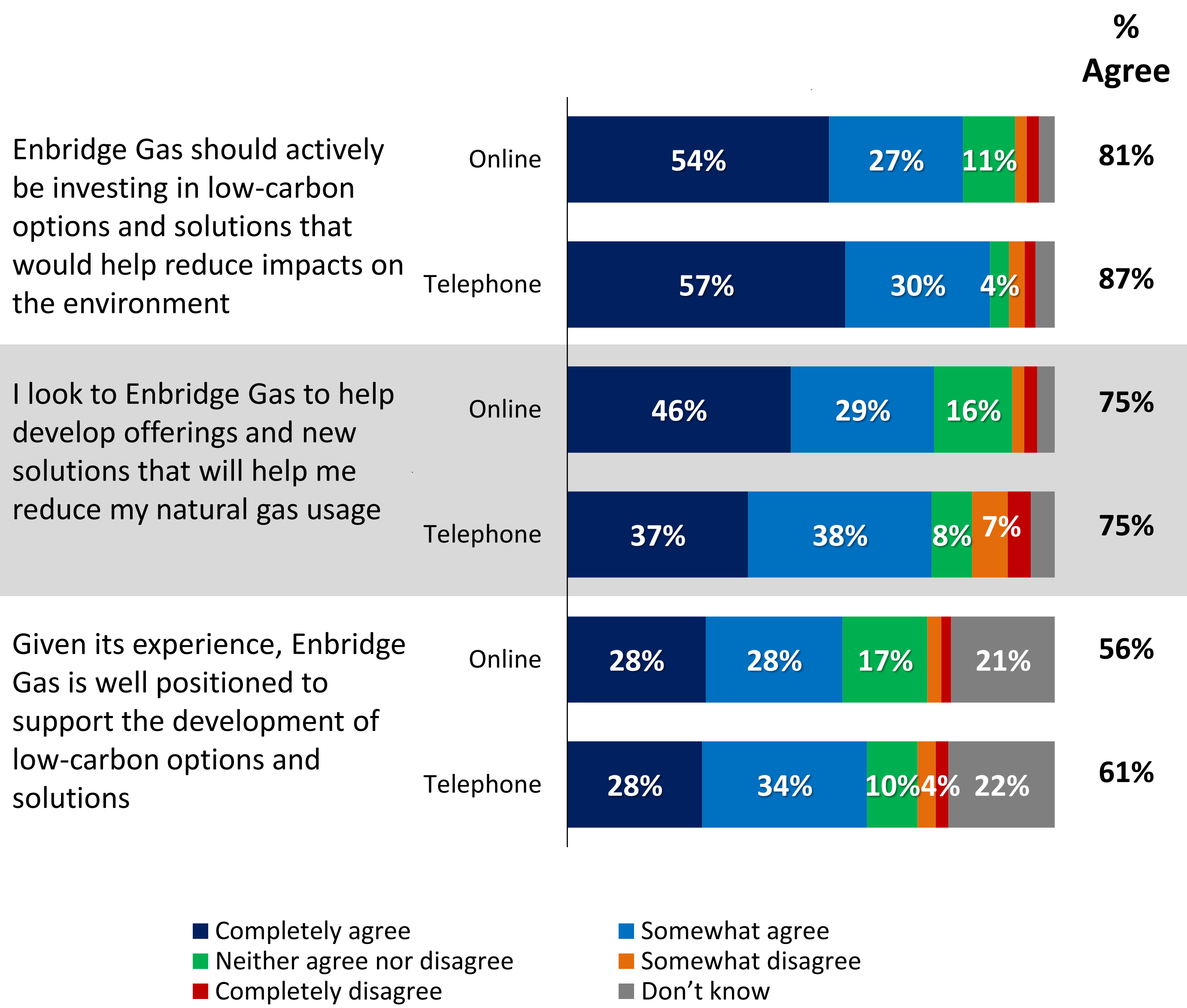
Reducing Environmental Impacts

Telephone and Online Survey

Q When you consider options and solutions to reduce impacts on the environment, please indicate whether you agree or disagree with the following statements.

[asked of all respondents; telephone n= 600; online n= 2,400]



NOTE: Data labels are removed where 3% or less

Reducing Environmental Impacts

Telephone and Online Survey

Q When you consider options and solutions to reduce impacts on the environment, please indicate whether you agree or disagree with the following statements.

[asked of all respondents; telephone n= 600; online n= 2,400]

Segmentation for Online Survey

Enbridge Gas should actively be investing in low-carbon options and solutions that would help reduce impacts on the environment.

		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium-low	Medium-high	High	Yes	NO <$52K	NO >$52K
Total agree	81%	82%	80%	81%	80%	81%	80%	82%	82%	78%	82%	84%
Total disagree	5%	5%	5%	3%	5%	5%	5%	5%	5%	7%	3%	5%

I look to Enbridge Gas to help develop offerings and new solutions that will help me reduce my natural gas usage.

		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium-low	Medium-high	High	Yes	NO <$52K	NO >$52K
Total agree	75%	76%	75%	73%	75%	72%	74%	77%	77%	78%	78%	77%
Total disagree	5%	6%	5%	4%	5%	5%	5%	5%	5%	6%	3%	5%

Given its experience, Enbridge Gas is well positioned to support the development of low-carbon options and solutions.

		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium-low	Medium-high	High	Yes	NO <$52K	NO >$52K
Total agree	56%	57%	55%	56%	55%	56%	57%	58%	56%	67%	61%	58%
Total disagree	5%	6%	4%	3%	4%	5%	5%	4%	5%	3%	2%	5%

Reduced Demand

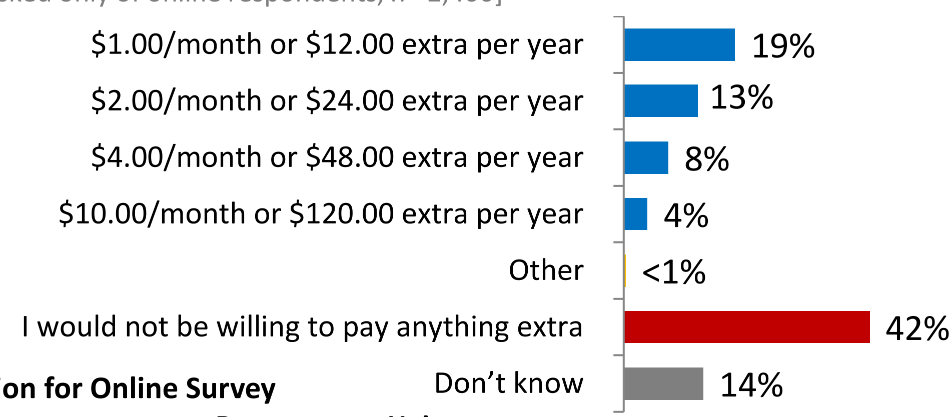
Online Survey

Q

When considering new or expanded pipeline projects, Enbridge Gas is required to evaluate whether alternatives are available that would eliminate the need for the project altogether. This would mean looking for ways to help 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, adding insulation, or upgrading your furnace or water heater. It could also include delivering compressed natural gas by truck or train to locations where pipelines do not exist. Other alternatives that reduce the need for natural gas might include geothermal heating and cooling, or air source heat pumps.

How much, if anything, would you be willing to pay per year for Enbridge Gas to develop solutions in natural gas conservation and other non-pipeline alternatives instead of new pipeline or capacity projects?

[asked only of online respondents, n= 2,400]



Segmentation for Online Survey

		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium-low	Medium-high	High	Yes	NO <$52K	NO >$52K
$1.00/month or $12.00 extra per year	19%	19%	19%	20%	18%	19%	19%	20%	19%	22%	21%	20%
$2.00/month or $24.00 extra per year	13%	14%	11%	11%	11%	12%	13%	14%	12%	12%	13%	16%
$4.00/month or $48.00 extra per year	8%	7%	9%	6%	9%	8%	7%	8%	8%	2%	7%	11%
$10.00/month or $120.00 extra per year	4%	5%	3%	2%	3%	4%	3%	4%	5%	2%	5%	6%
I would not be willing to pay anything extra	42%	41%	44%	45%	44%	41%	43%	42%	43%	49%	38%	36%

Low-Carbon Options

Online Survey

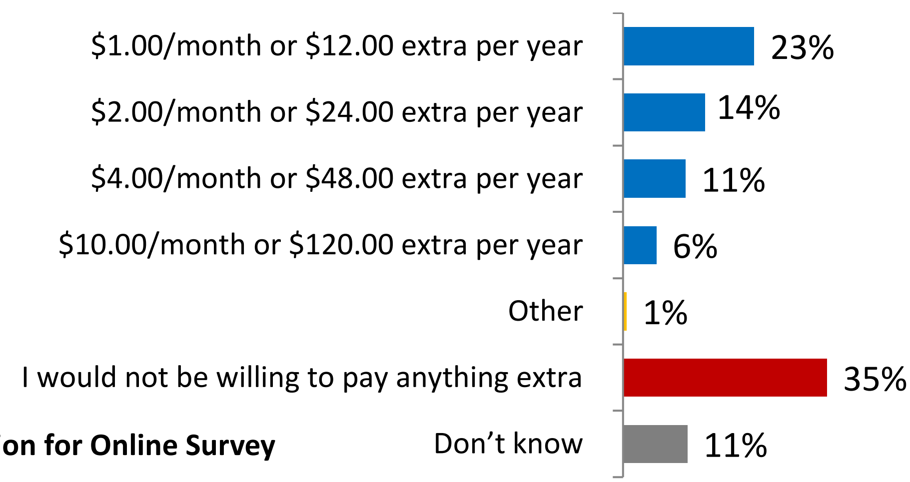
Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 149 of 550

Q

Other options Enbridge Gas may invest in that focus on reducing the amount of greenhouse gas emissions can include options that "green the gas." An example of this would be blending traditional natural gas with greener sources of gas, such as renewable natural gas derived from organic waste from farms, landfills, and water treatment plants, or hydrogen gas derived from using surplus electrical energy that is converted to hydrogen gas through electrolysis technology.

How much, if anything, would you be willing to pay per year for Enbridge Gas to develop solutions in greening the gas to reduce the greenhouse gas emissions from the use of natural gas?

[asked only of online respondents, n= 2,400]



Segmentation for Online Survey

		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium-low	Medium-high	High	Yes	NO <$52K	NO >$52K
$1.00/month or $12.00 extra per year	23%	23%	23%	23%	23%	23%	22%	22%	24%	25%	24%	23%
$2.00/month or $24.00 extra per year	14%	14%	14%	13%	14%	14%	14%	15%	14%	12%	15%	18%
$4.00/month or $48.00 extra per year	11%	11%	10%	9%	11%	11%	10%	12%	10%	5%	10%	15%
$10.00/month or $120.00 extra per year	6%	6%	5%	3%	6%	6%	5%	6%	7%	2%	7%	8%
I would not be willing to pay anything extra	35%	34%	36%	39%	35%	34%	37%	34%	35%	46%	32%	28%

New Technologies

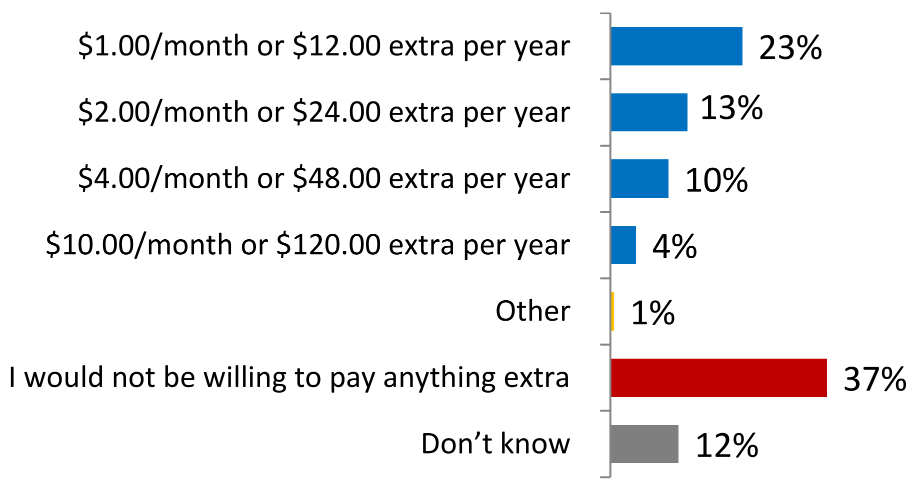
Online Survey

Q

Enbridge Gas can also support the advancement of various new low-carbon or energy efficient technologies that may not exist today. This would include participating in new research, development and supporting various pilot projects.

How much, if anything, would you be willing to pay per year for Enbridge Gas to develop solutions in developing and advancing new low-carbon and energy efficient technologies?

[asked only of online respondents, n= 2,400]



Segmentation for Online Survey

		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Medium -low	Medium-high	High	Yes	NO <$52K	NO >$52K
$1.00/month or $12.00 extra per year	23%	23%	23%	24%	22%	23%	22%	22%	25%	23%	24%	23%
$2.00/month or $24.00 extra per year	13%	14%	13%	12%	13%	13%	12%	14%	14%	11%	15%	17%
$4.00/month or $48.00 extra per year	10%	10%	9%	7%	10%	10%	10%	11%	9%	3%	9%	14%
$10.00/month or $120.00 extra per year	4%	5%	4%	2%	4%	5%	4%	4%	5%	2%	3%	7%
I would not be willing to pay anything extra	37%	37%	38%	39%	37%	37%	38%	38%	36%	51%	33%	31%

Paying More to Reduce Environmental Impact

Online Survey

	Natural gas conservation and other non-pipeline alternatives instead of new pipeline or capacity projects	Greening the gas to reduce the greenhouse gas emissions from the use of natural gas	Developing and advancing new low-carbon and energy efficient technologies
$1.00/month or $12.00 extra per year	19%	23%	23%
$2.00/month or $24.00 extra per year	13%	14%	13%
$4.00/month or $48.00 extra per year	8%	11%	10%
$10.00/month or $120.00 extra per year	4%	6%	4%
I would not be willing to pay anything extra	42%	35%	37%

Certified Natural Gas

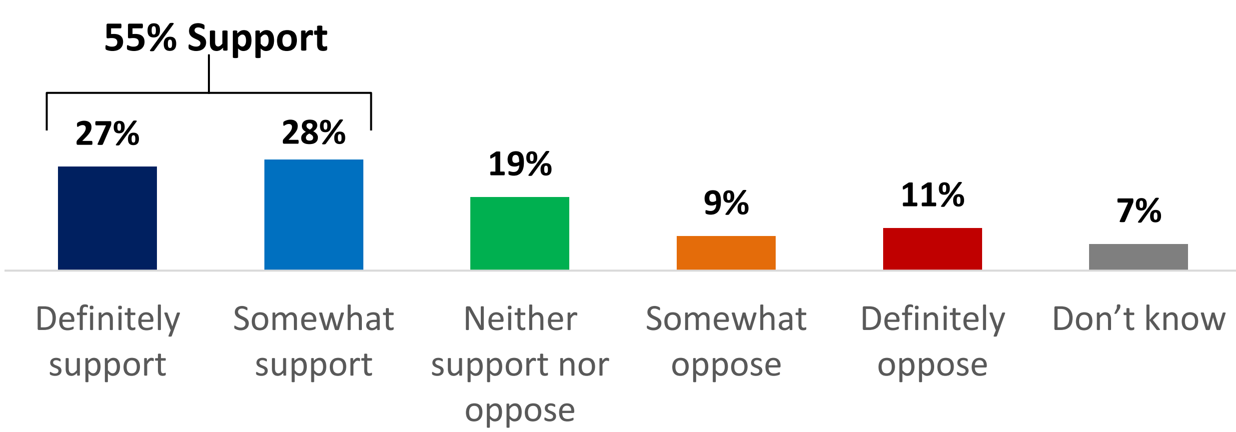
Online Survey

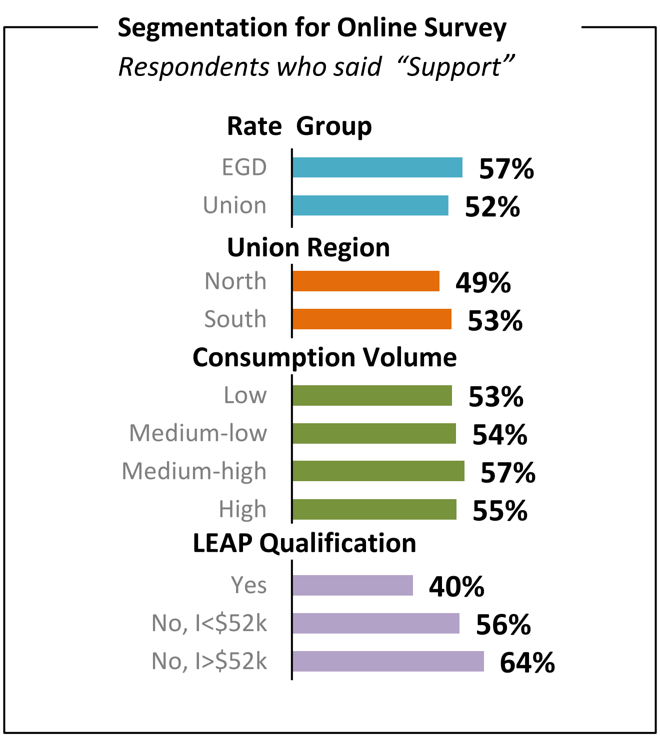
Q

Enbridge Gas is looking at options to ensure that the natural gas it purchases is responsibly sourced. This means the companies who produce the natural gas adhere to higher standards than the minimum government standards. This relates to areas such as minimizing impacts to air and water quality, lowering carbon emissions during production, and stronger engagement with Indigenous communities, etc. While it may not always cost more, it is possible that this responsibly sourced natural gas comes at a small premium and would cost customers a little bit more.

Considering this, would you support Enbridge Gas sourcing this type of natural gas to deliver to you, even if it comes at a small premium?

[asked only of online respondents, n= 2,400]





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Additional Comments

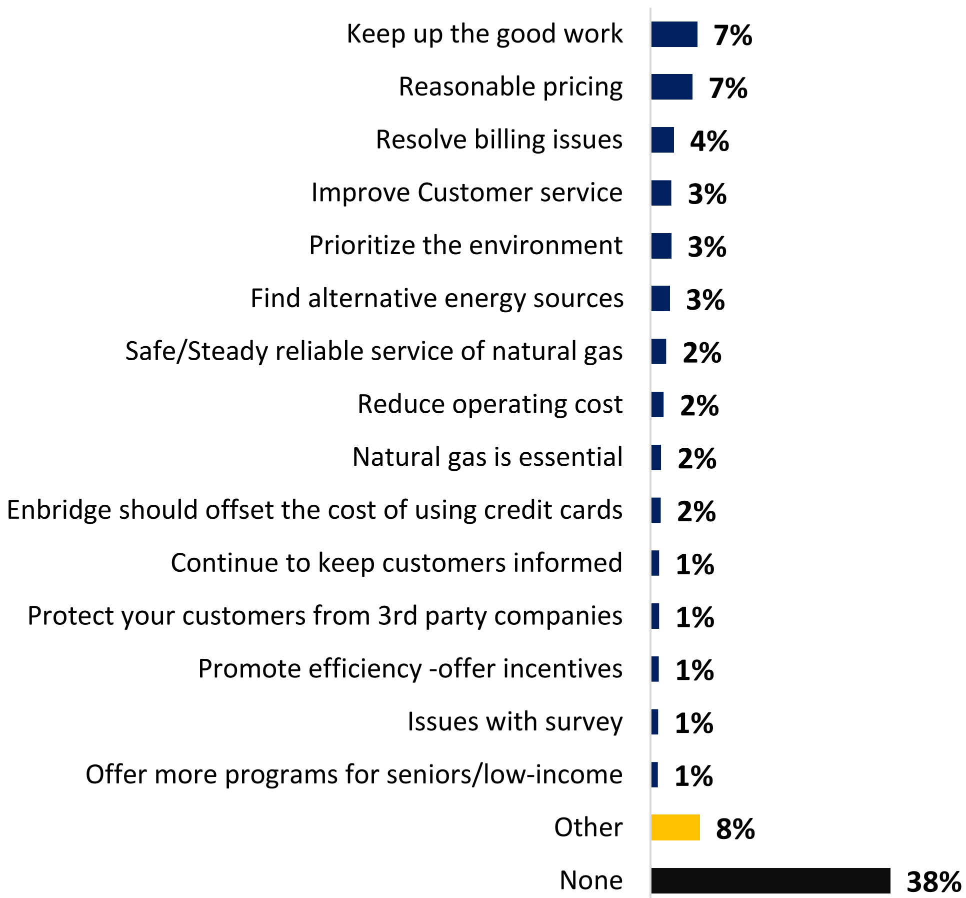
Additional Comments

Telephone and Online Surveys

Q Is there anything that you would like to share with Enbridge Gas as it works on building its investment plan for the future?

[asked of all respondents; telephone n= 600; online n= 2,400]

Telephone



‘Don’t know’ (<1%) not shown
‘No response’ (13%) not shown
Note: anything mentioned by fewer than 1% is included in "Other".

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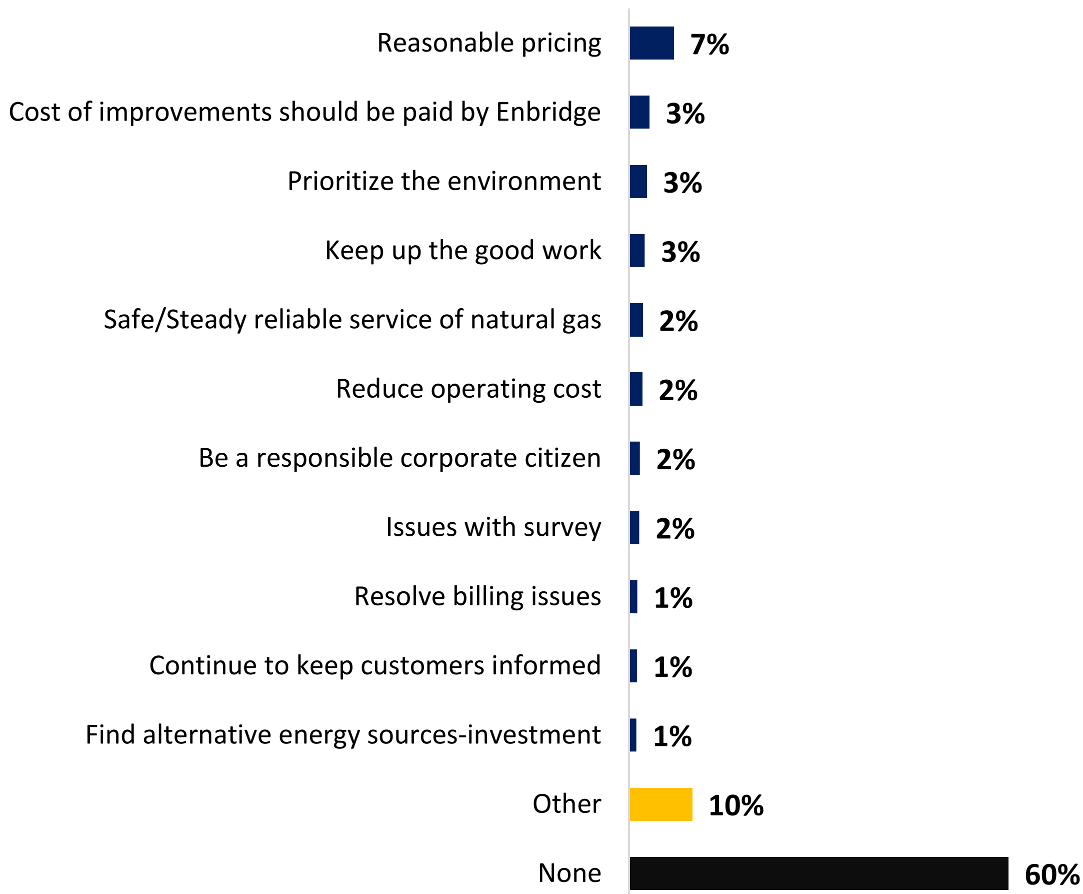
Additional Comments

Telephone and Online Surveys

Q Is there anything that you would like to share with Enbridge Gas as it works on building its investment plan for the future?

[asked of all respondents; telephone n= 600; online n= 2,400]

Online



'Don't know' (<1%) not shown
'No response' (2%) not shown
Note: anything mentioned by fewer than 1% is included in "Other".

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2024 Rate Rebasing Customer Engagement

ENBRIDGE

Phase Two Report – Business

September 2021

Table of Contents

Project Overview & Methodology

Enbridge Gas 2024 Rate Rebasing Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Enbridge Gas to assist in meeting its customer engagement commitments for its 2024 Rate Rebasing requirements. This report summarises the findings of Phase Two: surveys with small and medium-large business customers. A separate report summarises the findings of the Phase Two surveys with residential customers

Research Objectives & Survey Development

- A key objective of this phase is to understand customer opinions on their needs and key outcomes. Phase One collected the range of views in these areas. Phase Two uses surveys to draw generalized conclusions.

- In addition to overall satisfaction, the survey touched on asset management, rate design, customer care, new or harmonized programs and policies, and energy transition. A final open-ended question allowed respondents to provide any additional comments they felt Enbridge Gas should take into account when developing their investment plan.

- Phase Two included a multi-mode survey, allowing customers to complete either a telephone or online survey. The goal was to obtain as many online completes as possible, and then supplementing as needed with telephone interviews. Both versions included key firmographics, needs and outcomes questions, and satisfaction with Enbridge Gas. The telephone survey included some of the simpler questions on planning preferences while the online version added additional preference questions.

- The surveys were developed by Enbridge Gas and finalized with input from INNOVATIVE. The residential and business versions were different only where wording adjustments were needed to tailor the question or response options for a residential vs business customer.

Project Overview & Methodology

Methodological Notes

- All data was collected between August 11th and 23rd, 2021. Details on sample design, weighting and validation can be found on the following pages.
- Due to the smaller number of medium-large customers and lower response rates in previous engagements with Enbridge Gas, respondents in this group were entered into a prize draw for one of two cash prizes of $500 upon completion of either version of the survey. Respondents had the option of opting out of the prize draw at their discretion.
- The telephone survey was finalized after a set of pretests to assess the length and viability of the survey instrument. In order to keep the survey length under 15 minutes, a number of complex questions that are better suited to an online approach were removed from the telephone survey. Throughout this report, it is clearly indicated which questions were asked only online vs which were asked in both the online and telephone versions.

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Sample Design

Sample Validation

Consumption Analysis

Comparing the overall population to the sample of that population with email addresses across known variables, we can see that the email sample is largely representative of the overall population of lower volume business customers.

Median Consumption

The median consumption of Enbridge Gas business customers who have email addresses on file is somewhat lower than the median consumption of the total population of small and medium-large business customers,. Differences ranging from -15% to -10%.

Customer Segment	Full Population	Those with email addresses	Difference
Small Business	3,582m^3	3,067m^3	**-15%**
Medium-Large Business	104,731m^3	94,079m^3	**-10%**

Knowing this, we set quotas based on region and consumption. These sample quotas are set out on the following page.

Sample Design

Sample Design and Methodology

The survey samples were stratified based on the known variables: region and consumption. Furthermore, the final datasets were weighted based on these variables to ensure the final data accurately reflects the regional and consumption profile of the Enbridge Gas small and medium-large business customer segments. *Weighted and unweighted sample size are outlined below.*

Small Business Customers

Due to a good response rate among small business customers, all data collection was conducted online. All sample quotas were exceeded, resulting in a larger final weighted data set, which allowed for greater analysis among various segments.

Consumption Volume	Unweighted N						Weighted N					
	EGD Region		Union Region				EGD Region		Union Region			
	GTA	Other	South/ West	Central	North/ East	Total	GTA	Other	South/ West	Central	North/ East	Total
Low	61	27	68	60	43	259	63	24	38	50	24	200
High	81	21	28	28	20	178	80	31	27	37	25	200
Total	**142**	**48**	**96**	**88**	**63**	**437**	**143**	**56**	**65**	**87**	**49**	**400**

Medium-Large Business Customers

The response rate among medium-large business customers was lower than among small business customers. To boost responses, not only were invitations emailed to this customer segment to complete an online version of the survey (n=125), phone calls were also made to invite non-responders and those without an email address to invite them to complete a shorter telephone version (n=44). The final, combined, data was carefully reviewed to ensure no single customer had completed both versions of the survey.

Consumption Volume	Unweighted N						Weighted N					
	EGD Region		Union Region				EGD Region		Union Region			
	GTA	Other	South/ West	Central	North/ East	Total	GTA	Other	South/ West	Central	North/ East	Total
Low	34	13	16	19	9	91	40	12	10	15	7	84
High	29	6	14	20	9	78	47	12	7	13	5	84
Total	**63**	**19**	**30**	**39**	**18**	**169**	**87**	**24**	**17**	**28**	**12**	**169**

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

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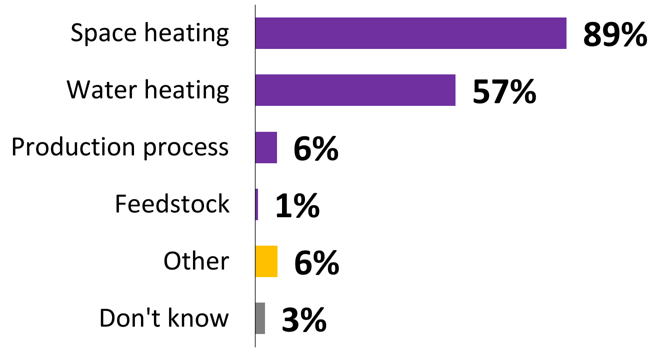
Firmographics: Small Business

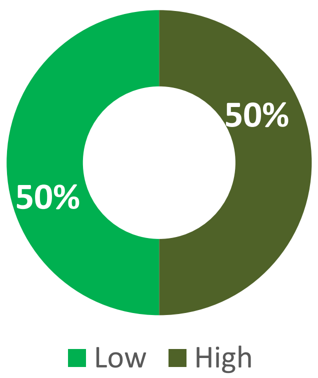
Online Surveys

Natural Gas Use

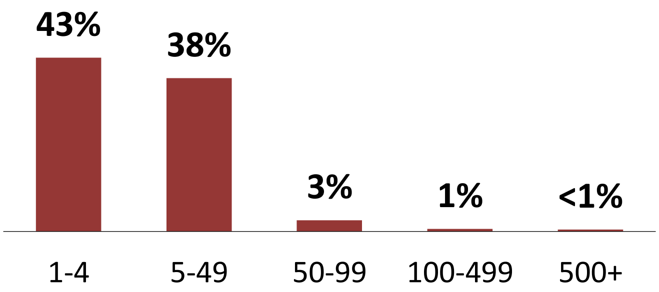


Multiple selection allowed

Consumption Volume

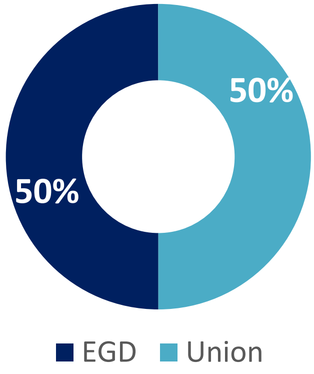


Number of Employees

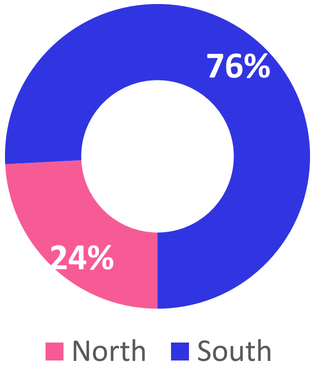


Don't know: 15%

Rate Zone



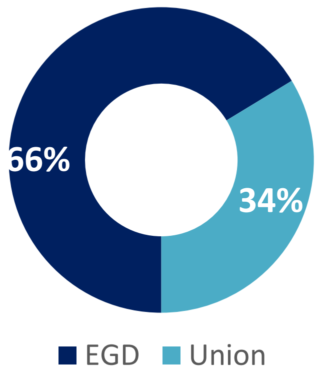
Union Region



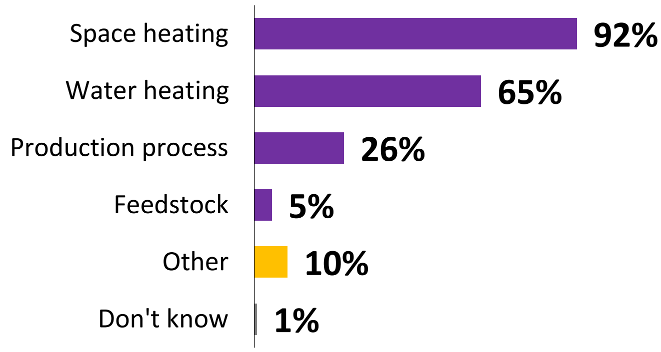
Firmographics: Med/Large Business

Telephone and Online Surveys

Rate Zone

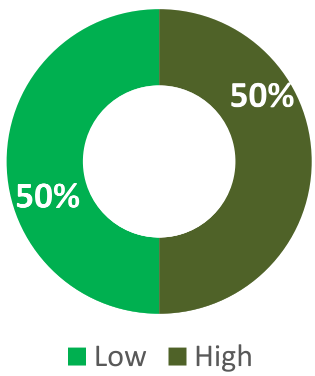


Natural Gas Use

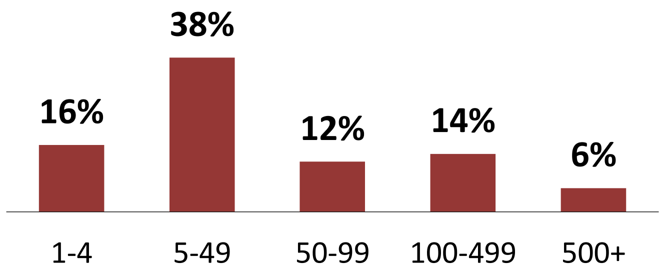


Multiple selection allowed

Consumption Volume



Number of Employees



Don't know: 13%

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Overall Satisfaction

Satisfaction

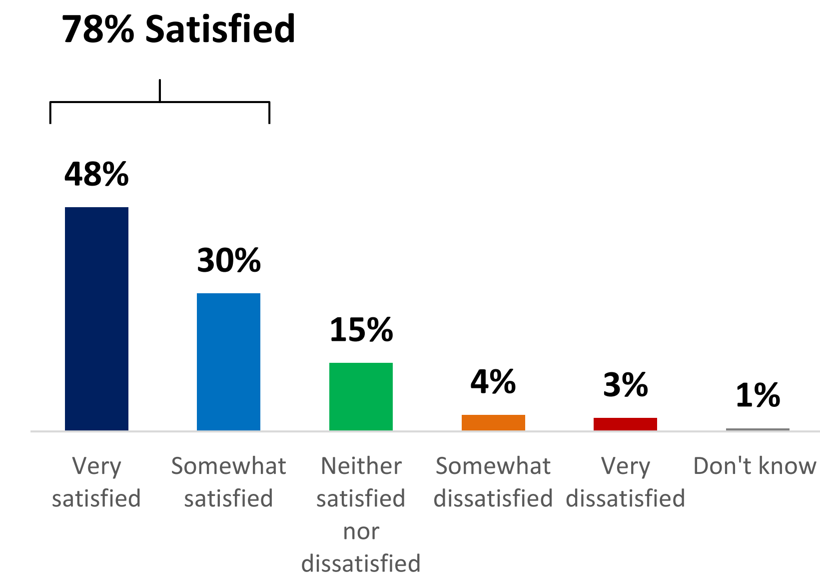
Telephone and Online Surveys

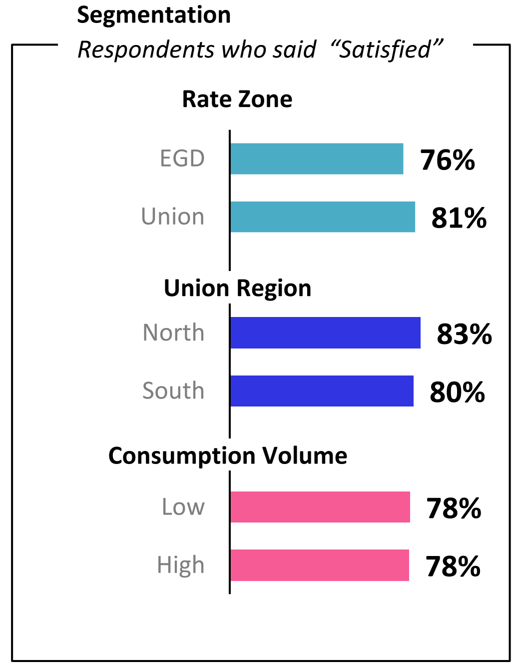
Q

Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

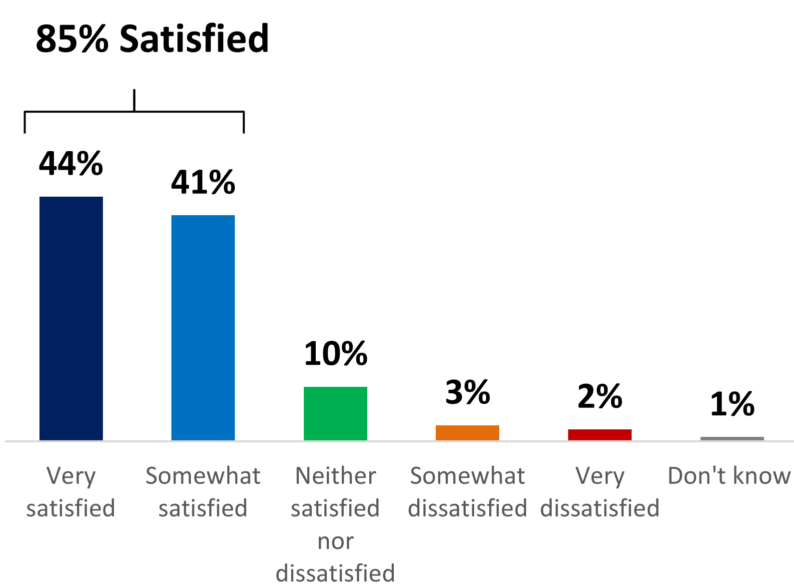
[asked of all respondents]

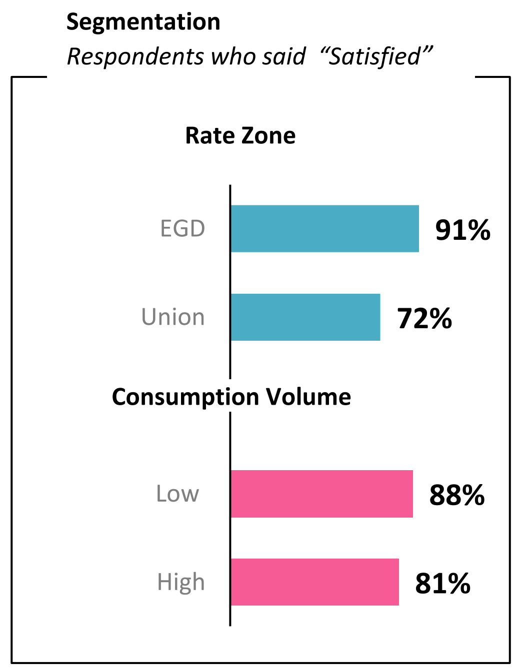
Small (n=400)





Med/Large (n=169)





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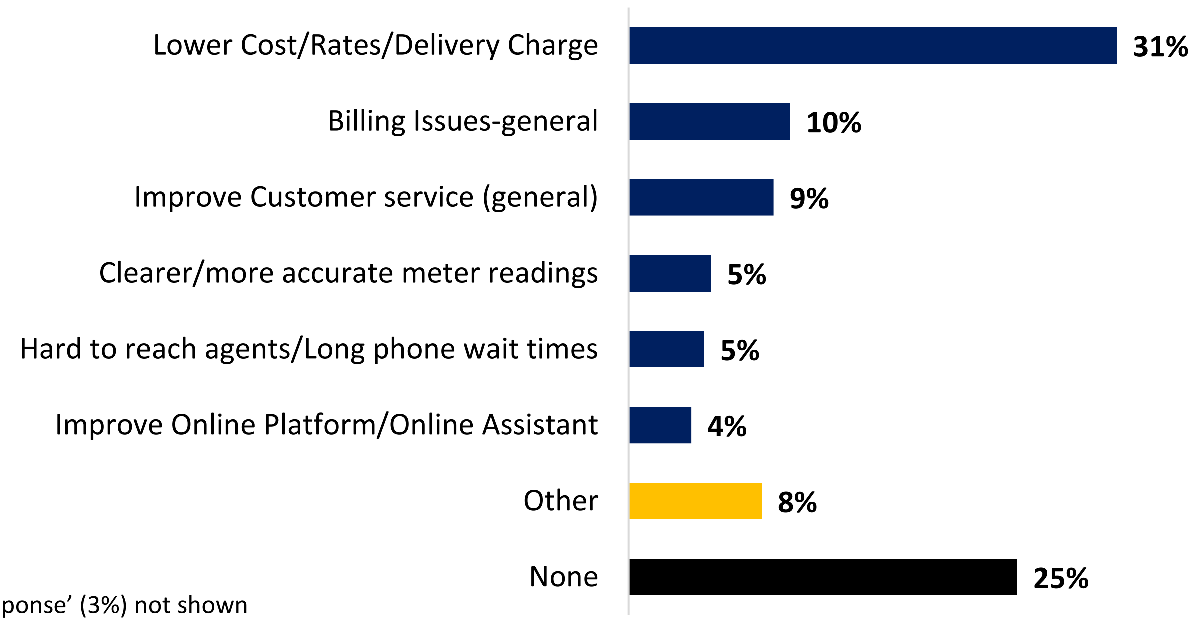
Service Improvement

Telephone and Online Surveys

Q Is there anything in particular Enbridge Gas can do to improve their service?

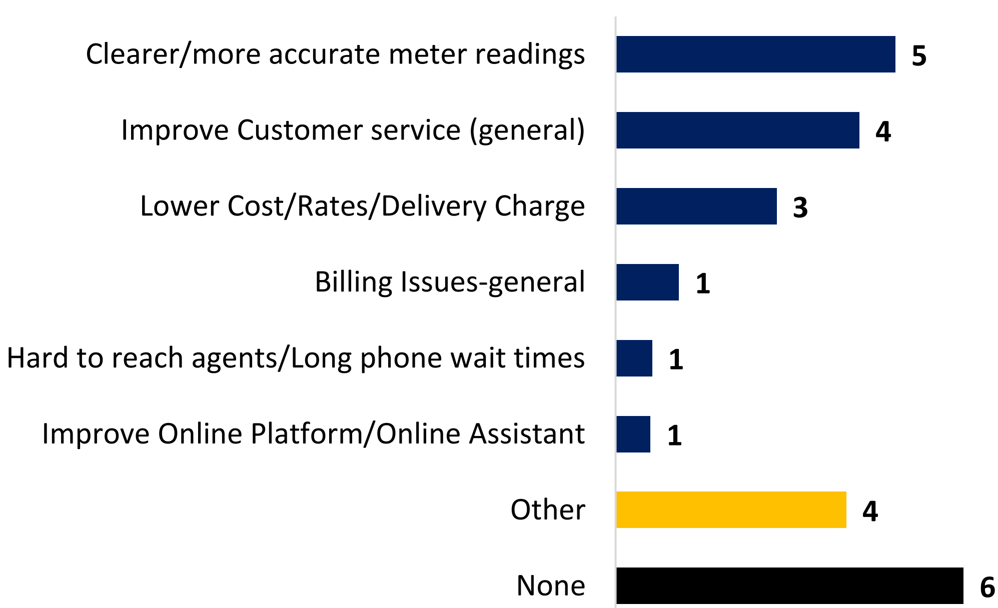
[asked only of those respondents who were not satisfied with Enbridge Gas service]

Small (n=85)



'No response' (3%) not shown

Med/Large (n=25)



'No response' (1 person) not shown

NOTE: Due to small n-sizes, chart shows number of mentions rather than percentages

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Customer Outcomes

Importance of Outcomes

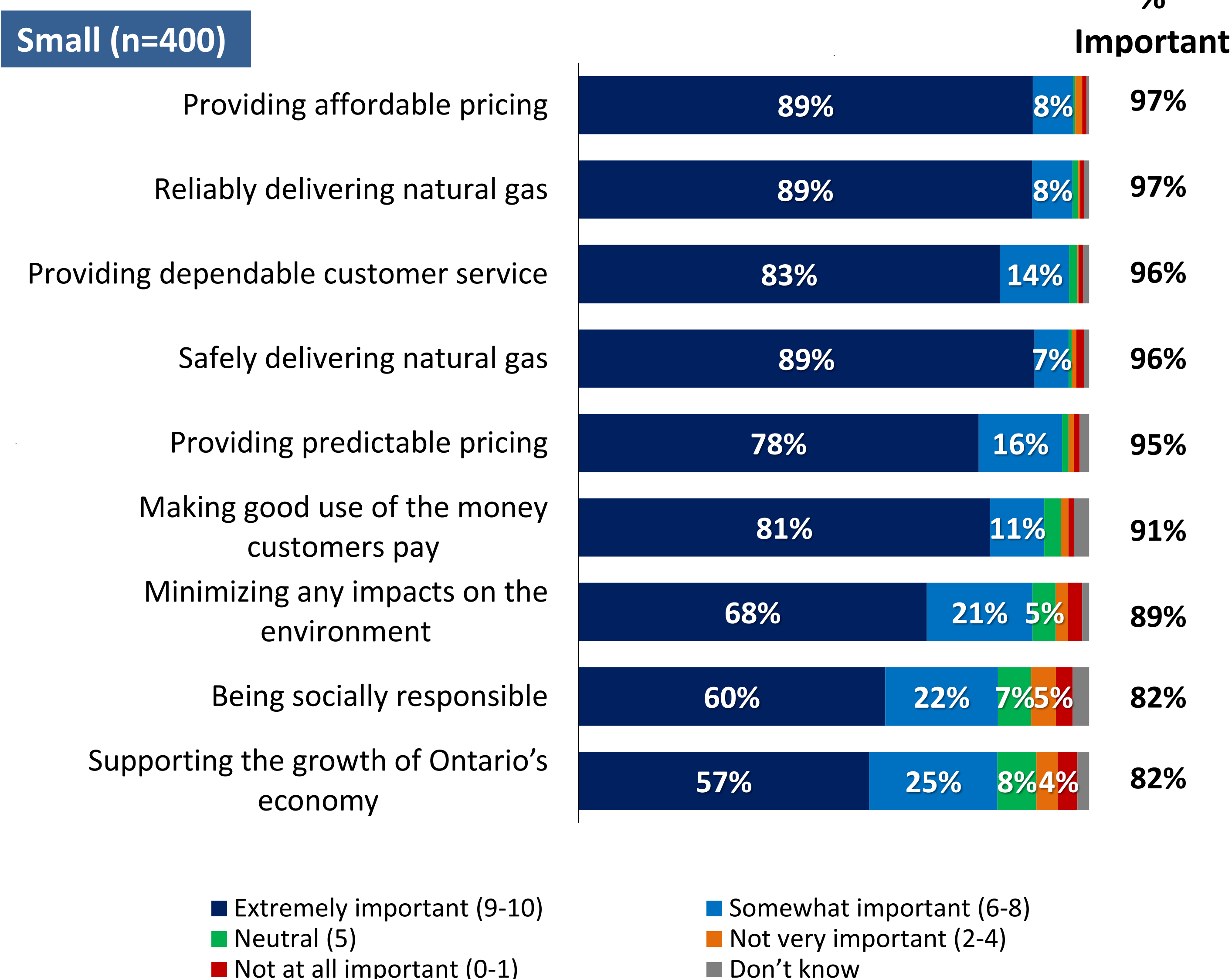
Online Survey

Q

In considering its business plan to be implemented starting in 2024, Enbridge Gas must make many decisions. We would like your feedback on the outcomes you would like Enbridge Gas to focus on in its plan. Outcomes are the goals and priorities that matter to you.

There is a list of broad outcomes that Enbridge Gas will need to consider. Using a scale from 0 to 10, where 0 means "not at all important" and 10 means "extremely important", please tell us how important each one is to you. Be sure to save a rating of 10 for those items that are most important to you.

[asked of all respondents]



NOTE: Data labels are removed where 3% or less

Importance of Outcomes

Online Survey

Q There is a list of broad outcomes that Enbridge Gas will need to consider. Please indicate how important each of the following outcomes is to you.
[asked of all respondents]

Small (n=400)

% Total Importance (6 to 10)		Rate Zone		Union Region		Consumption	
	Total	EGD	Union	North	South	Low	High
Providing affordable pricing	97%	97%	97%	96%	97%	96%	97%
Reliably delivering natural gas	97%	95%	98%	99%	98%	96%	98%
Providing dependable customer service	96%	94%	98%	100%	97%	95%	97%
Safely delivering natural gas	96%	95%	97%	98%	97%	95%	97%
Providing predictable pricing	95%	95%	94%	96%	94%	94%	95%
Making good use of the money customers pay	91%	90%	92%	91%	92%	91%	92%
Minimizing impacts on the environment	89%	85%	93%	92%	93%	87%	91%
Being socially responsible	82%	81%	83%	85%	82%	81%	84%
Supporting the growth of Ontario's economy	82%	78%	86%	89%	84%	80%	84%

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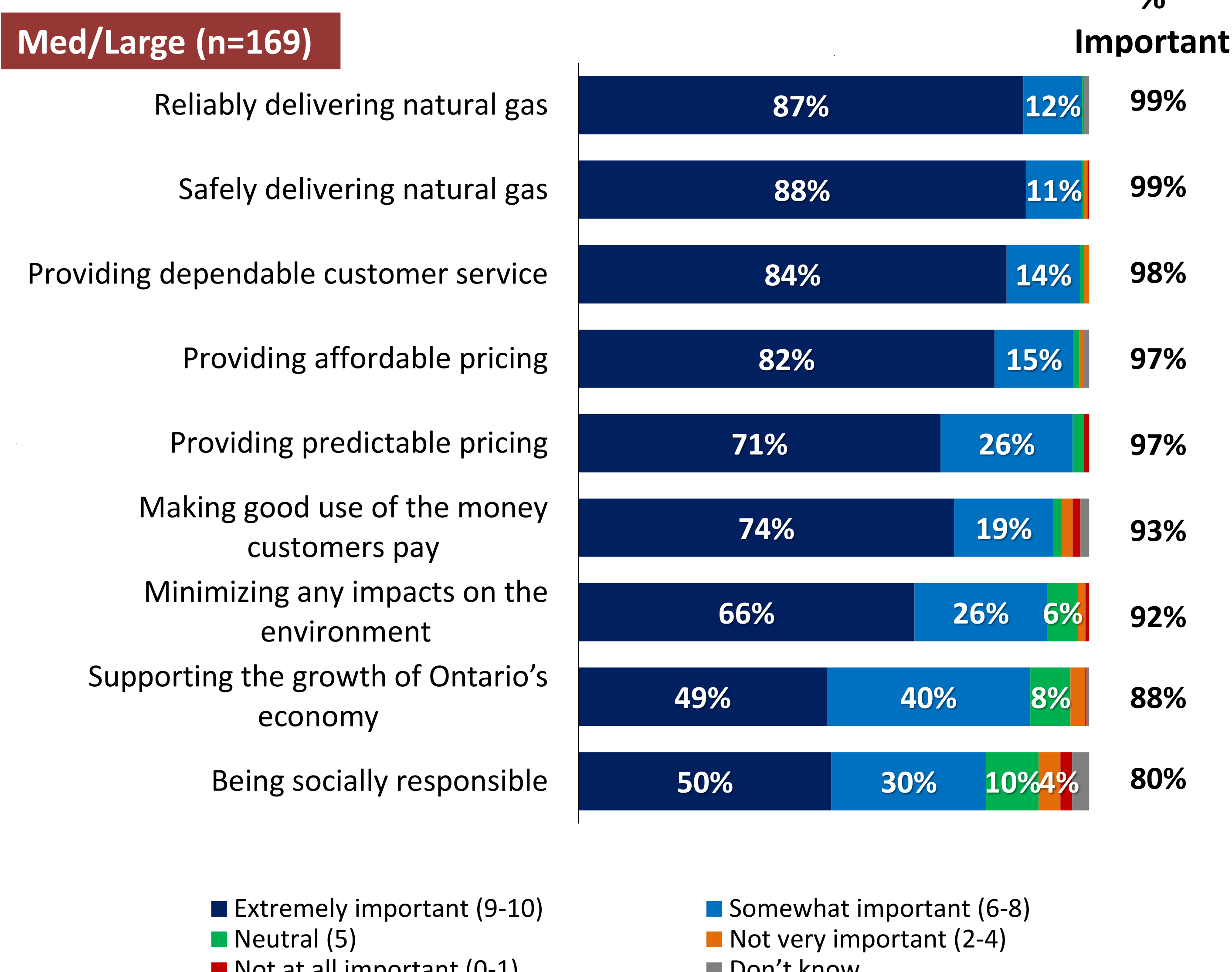
Importance of Outcomes

Telephone and Online Surveys

Q In considering its business plan to be implemented starting in 2024, Enbridge Gas must make many decisions. We would like your feedback on the outcomes you would like Enbridge Gas to focus on in its plan. Outcomes are the goals and priorities that matter to you.

There is a list of broad outcomes that Enbridge Gas will need to consider. Using a scale from 0 to 10, where 0 means "not at all important" and 10 means "extremely important", please tell us how important each one is to you. Be sure to save a rating of 10 for those items that are most important to you.

[asked of all respondents]



NOTE: Data labels are removed where 3% or less

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Importance of Outcomes

Telephone and Online Surveys

Q There is a list of broad outcomes that Enbridge Gas will need to consider. Please indicate how important each of the following outcomes is to you.
[asked of all respondents]

Med/Large (n=169)

% Total Importance (6 to 10)		Rate Zone		Consumption	
	Total	EGD	Union	Low	High
Reliably delivering natural gas	99%	99%	99%	100%	97%
Safely delivering natural gas	99%	99%	98%	99%	99%
Providing dependable customer service	98%	99%	98%	99%	97%
Providing affordable pricing	97%	97%	96%	99%	95%
Providing predictable pricing	97%	97%	95%	97%	97%
Making good use of the money customers pay	93%	90%	98%	97%	88%
Minimizing impacts on the environment	92%	94%	88%	95%	89%
Supporting the growth of Ontario's economy	88%	87%	91%	96%	81%
Being socially responsible	80%	82%	77%	82%	77%

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Priority of Outcomes

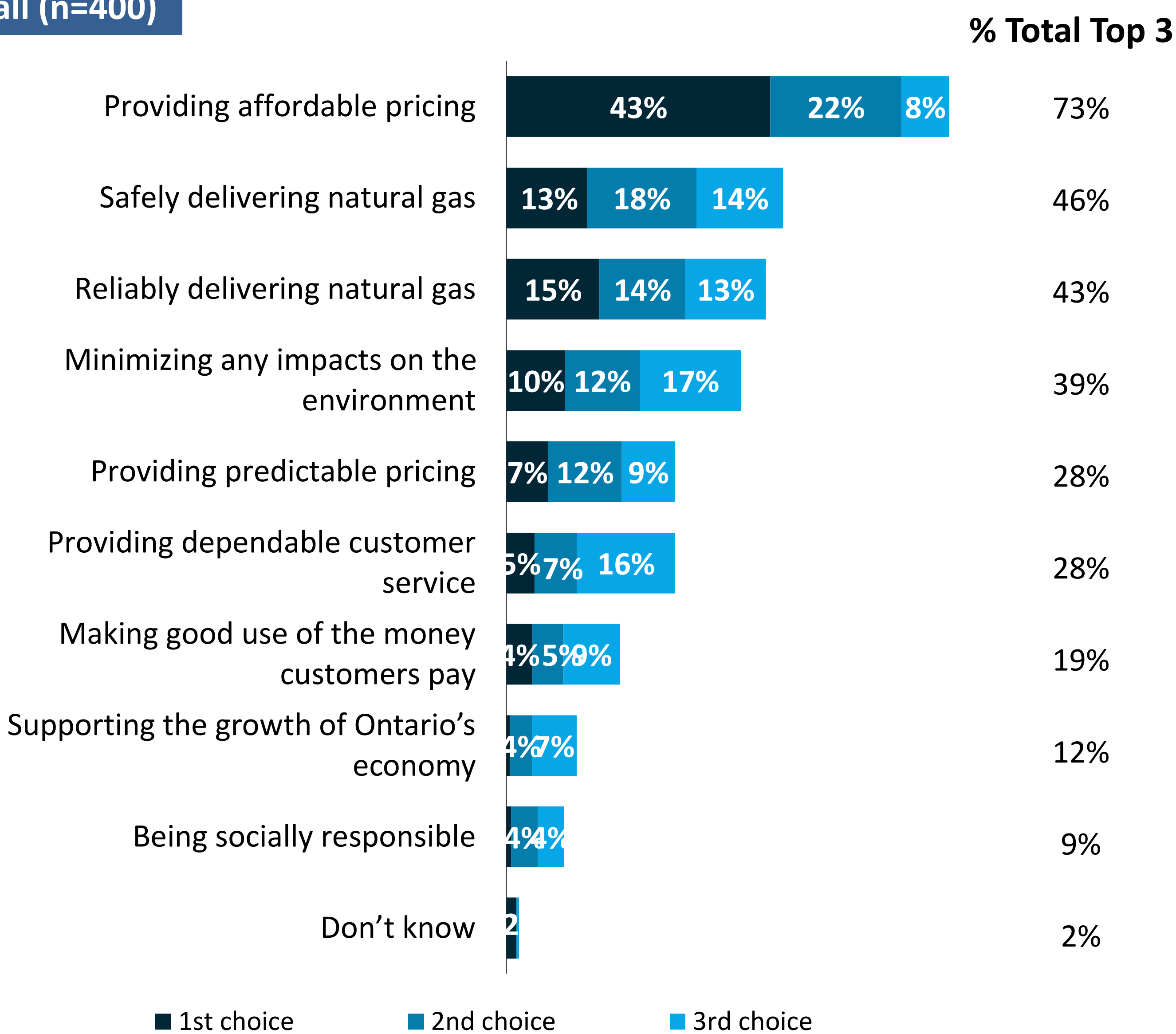
Online Survey

Q

Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which one would you say is most important to you as a customer? And which one is second most important to you? And, finally, which one is third most important to you?

[asked of all respondents]

Small (n=400)



Note: 'No response' not shown. Respondents who say 'Don't know' do not get asked for further priorities.

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Priority of Outcomes

Online Survey

Q

Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which one would you say is most important to you as a customer? And which one is second most important to you? And, finally, which one is third most important to you?

[asked of all respondents]

Small (n=400)

% Total Top 3 Choices		Rate Zone		Union Region		Consumption	
	Total	EGD	Union	North	South	Low	High
Providing affordable pricing	73%	75%	70%	70%	71%	73%	73%
Safely delivering natural gas	46%	49%	42%	36%	44%	46%	45%
Reliably delivering natural gas	43%	46%	40%	40%	40%	43%	43%
Minimizing any impacts on the environment	39%	34%	43%	44%	43%	35%	42%
Providing predictable pricing	28%	26%	29%	35%	27%	27%	29%
Providing dependable customer service	28%	26%	29%	36%	27%	28%	27%
Making good use of the money customers pay	19%	19%	19%	20%	18%	21%	17%
Supporting the growth of Ontario's economy	12%	10%	13%	9%	14%	11%	12%
Being socially responsible	9%	10%	9%	10%	9%	10%	9%

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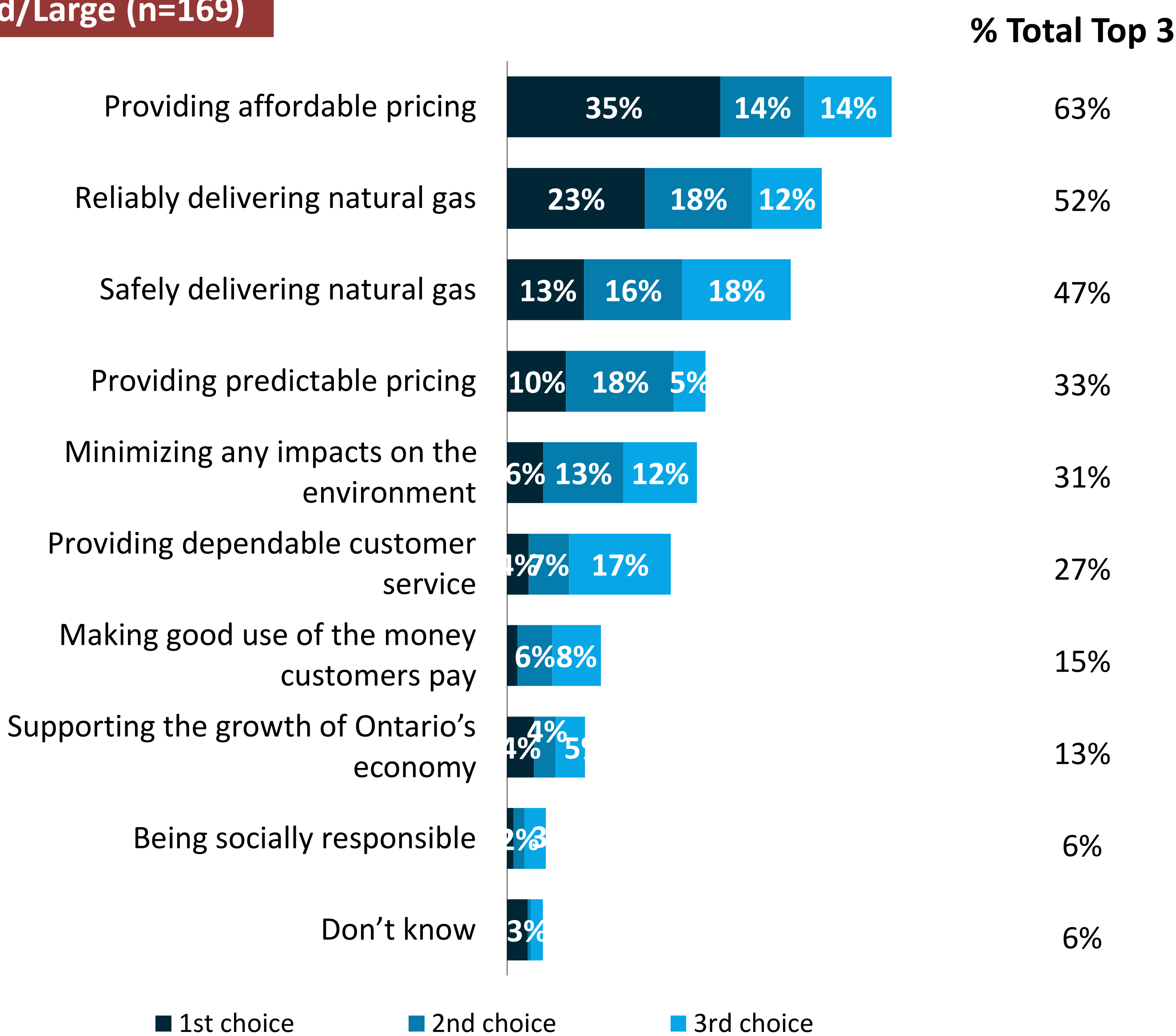
Priority of Outcomes

Telephone and Online Surveys

Q Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which one would you say is most important to you as a customer? And which one is second most important to you? And, finally, which one is third most important to you?

[asked of all respondents]

Med/Large (n=169)



Note: 'No response' not shown. Respondents who say 'Don't know' do not get asked for further priorities.

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Priority of Outcomes

Telephone and Online Surveys

Q

Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which one would you say is most important to you as a customer? And which one is second most important to you? And, finally, which one is third most important to you?

[asked of all respondents]

Med/Large (n=169)

% Total Top 3 Choices		Rate Zone		Consumption	
	Total	EGD	Union	Low	High
Providing affordable pricing	63%	58%	74%	66%	61%
Reliably delivering natural gas	52%	51%	54%	49%	55%
Safely delivering natural gas	47%	49%	42%	47%	46%
Providing predictable pricing	33%	33%	32%	34%	31%
Minimizing any impacts on the environment	31%	38%	18%	30%	32%
Providing dependable customer service	27%	23%	35%	29%	25%
Making good use of the money customers pay	15%	14%	18%	19%	12%
Supporting the growth of Ontario's economy	13%	14%	9%	10%	15%
Being socially responsible	6%	6%	7%	6%	7%

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Asset Management

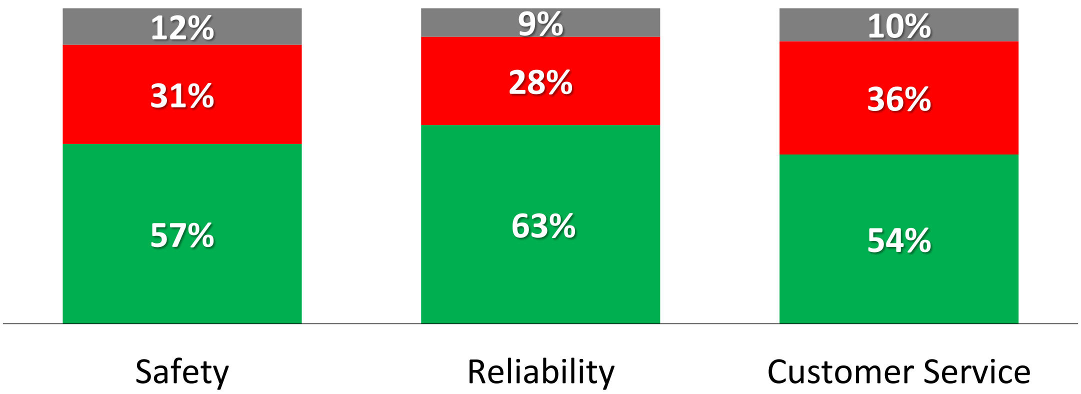
Investing in Service Quality

Online Survey

Q Thinking about the level of safety, reliability, and customer service you receive from Enbridge Gas would you like to see the company invest in maintaining or invest in improving upon the current level?

[asked of all respondents]

Small (n=400)



Safety	Total	Rate Zone: EGD	Rate Zone: Union	Union Region: North	Union Region: South	Consumption: Low	Consumption: High
Maintaining current level	57%	56%	58%	60%	57%	56%	58%
Improving current level	31%	33%	30%	28%	31%	33%	30%

Reliability	Total	Rate Zone: EGD	Rate Zone: Union	Union Region: North	Union Region: South	Consumption: Low	Consumption: High
Maintaining current level	63%	61%	65%	64%	65%	62%	64%
Improving current level	28%	30%	27%	27%	27%	28%	28%

Customer Service	Total	Rate Zone: EGD	Rate Zone: Union	Union Region: North	Union Region: South	Consumption: Low	Consumption: High
Maintaining current level	54%	54%	53%	57%	52%	57%	50%
Improving current level	36%	36%	36%	32%	37%	30%	42%

Investing in Service Quality

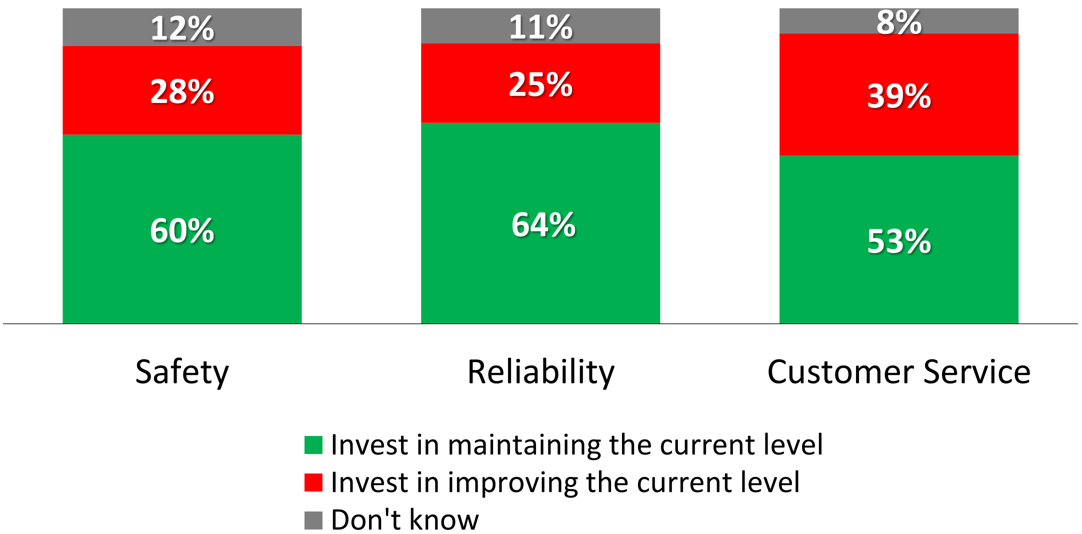
Telephone and Online Surveys

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 180 of 550

Q Thinking about the level of safety, reliability, and customer service you receive from Enbridge Gas would you like to see the company invest in maintaining or invest in improving upon the current level?

[asked of all respondents]

Med/Large (n=169)



Safety	Total	Rate Zone: EGD	Rate Zone: Union	Consumption: Low	Consumption: High
Maintaining current level	60%	60%	60%	61%	59%
Improving current level	28%	29%	26%	27%	29%

Reliability	Total	Rate Zone: EGD	Rate Zone: Union	Consumption: Low	Consumption: High
Maintaining current level	64%	66%	60%	59%	68%
Improving current level	25%	23%	30%	28%	23%

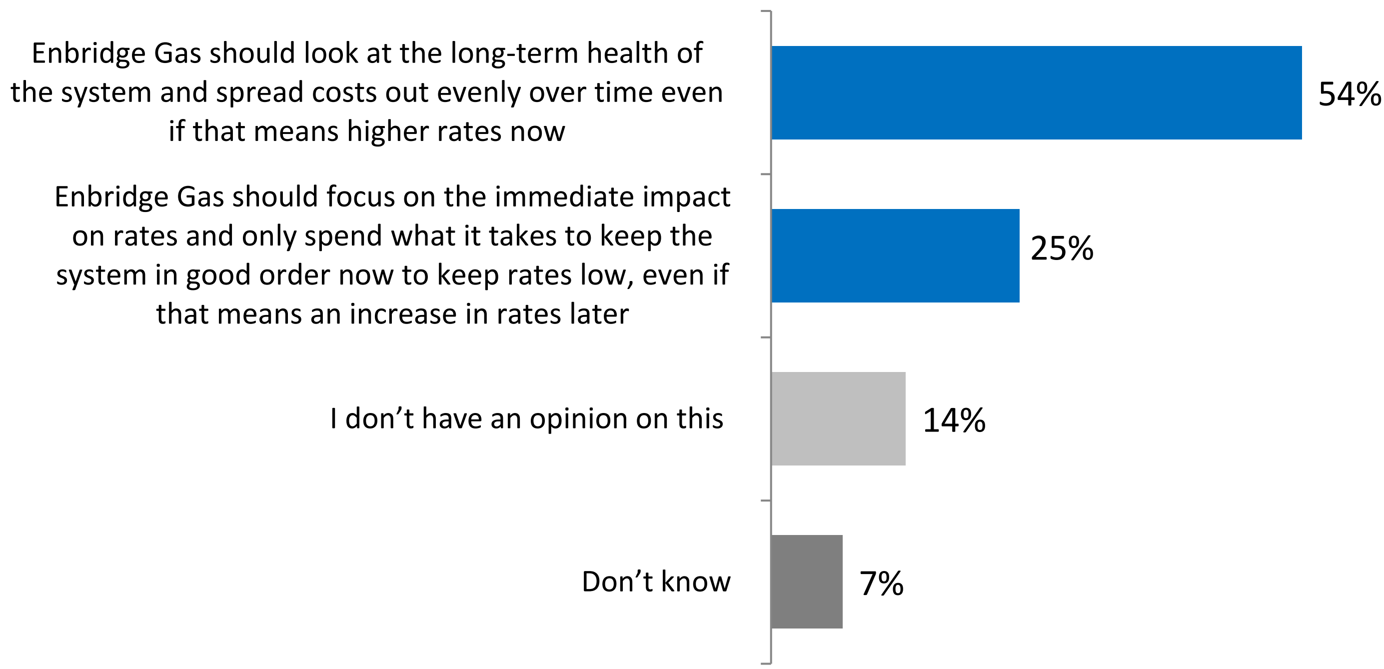
Customer Service	Total	Rate Zone: EGD	Rate Zone: Union	Consumption: Low	Consumption: High
Maintaining current level	53%	54%	52%	58%	48%
Improving current level	39%	37%	42%	33%	45%

Budget Allocation

Online Survey

Q Thinking generally about Enbridge Gas' budget for replacing pipelines and equipment that deliver gas to your organization, which of the following statements best represents your point of view?
[asked of all respondents]

Small (n=400)



		Rate Zone		Union Region		Consumption	
	Total	EGD	Union	North	South	Low	High
Spread costs out evenly over time even if that means higher rates now	54%	49%	59%	56%	60%	54%	53%
Spend what it takes to keep the system in good order now to keep rates low, even if that means an increase in rates later	25%	31%	19%	29%	16%	24%	27%

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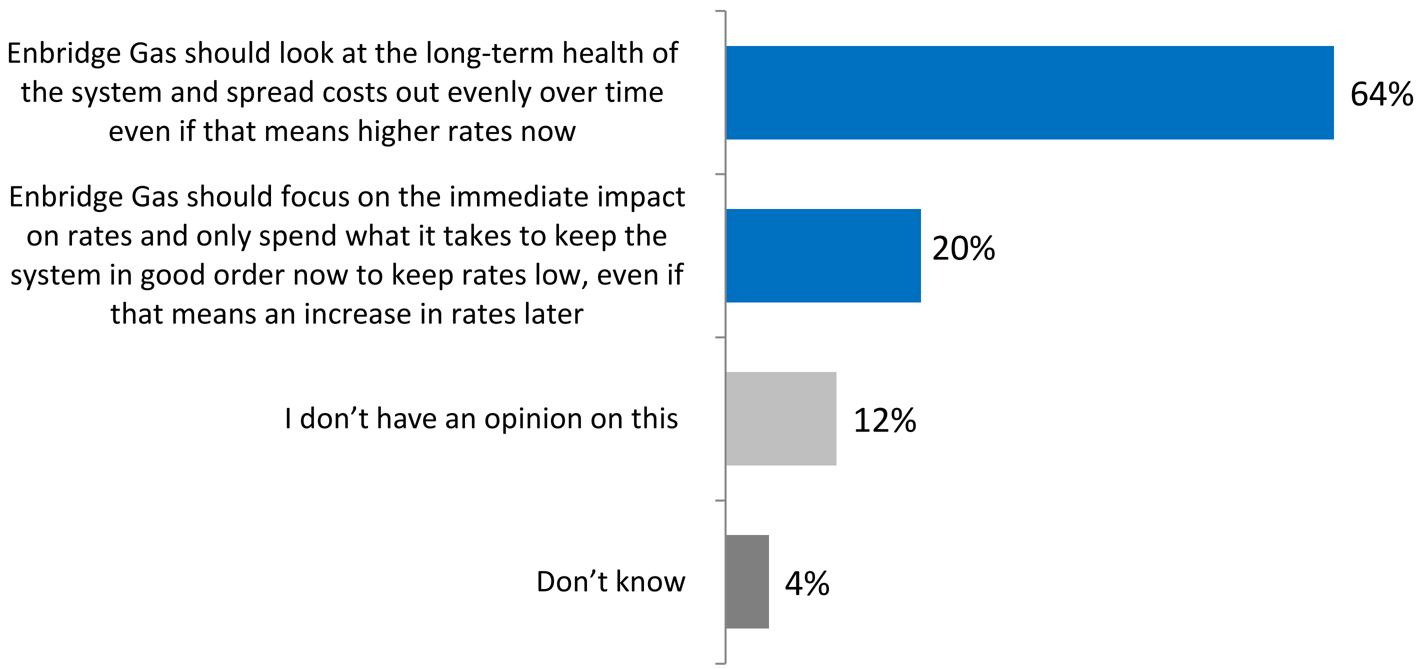
Budget Allocation

Telephone and Online Surveys

Q Thinking generally about Enbridge Gas' budget for replacing pipelines and equipment that deliver gas to your organization, which of the following statements best represents your point of view?
[asked of all respondents]

Med/Large (n=169)



		Rate Zone		Consumption	
	Total	EGD	Union	Low	High
Spread costs out evenly over time even if that means higher rates now	64%	65%	60%	56%	71%
Spend what it takes to keep the system in good order now to keep rates low, even if that means an increase in rates later	20%	21%	20%	24%	17%

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Rates

Fixed Cost – PREAMBLE

Online Survey

PREAMBLE:

Enbridge Gas is the only distributor of natural gas service in your area and there is not a competitive market in which rates are determined. For this reason, the Ontario Energy Board (OEB) reviews and approves all Enbridge Gas costs (that is, the costs to operate), and also reviews and approves how customer rates should be calculated.

Enbridge Gas incurs two types of costs in delivering natural gas to your organization, those that are variable and those that are fixed.

One of these is the cost of the natural gas that customers use. This cost is determined by the market and will be passed on to you based on your measured consumption of natural gas.

The fixed costs that Enbridge Gas incurs can be divided into two groups.

Fixed Cost – Network Connection

Online Survey

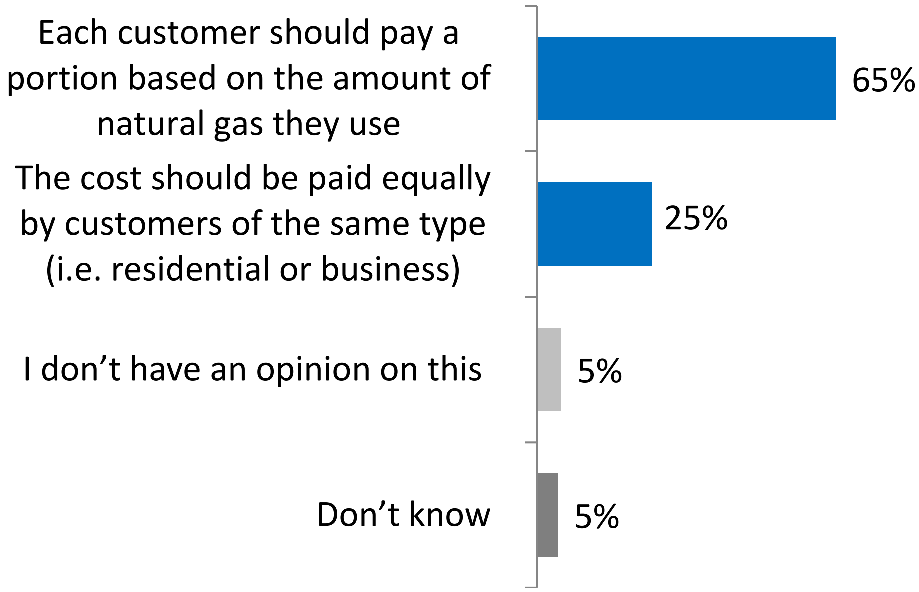
Q

One type of fixed cost is that of being connected to the network. This includes the cost of the pipeline, the pressure regulator, the natural gas meter, meter reading, billing, the contact centre and operations support. These costs are fixed for Enbridge Gas, and are similar for each customer and do not change based on the size of the customer.

How do you feel business customers like you should be billed for these costs of being connected to the network?

[asked of all respondents]

Small (n=400)



		Rate Zone		Union Region		Consumption	
	Total	EGD	Union	North	South	Low	High
Pay a portion based on the amount of natural gas used	65%	65%	66%	69%	65%	69%	62%
Paid equally by customers of the same type	25%	24%	26%	23%	27%	21%	29%
I don't have an opinion on this	5%	6%	5%	5%	4%	6%	4%
Don't know	5%	5%	4%	4%	4%	4%	5%

Fixed Cost – Network Connection

Online Survey

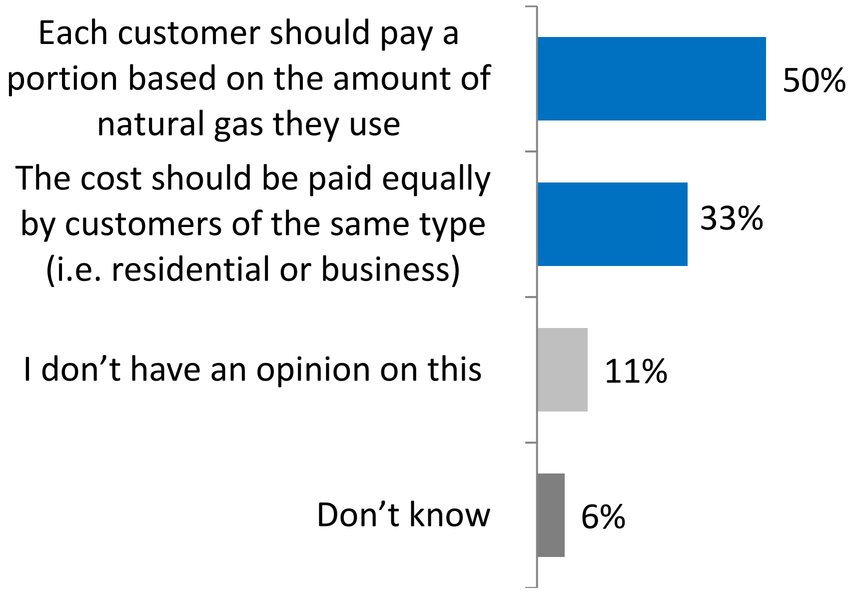
Q

One type of fixed cost is that of being connected to the network. This includes the cost of the pipeline, the pressure regulator, the natural gas meter, meter reading, billing, the contact centre and operations support. These costs are fixed for Enbridge Gas, and are similar for each customer and do not change based on the size of the customer.

How do you feel business customers like you should be billed for these costs of being connected to the network?

[asked of all respondents]

Med/Large (n=118)



	Total	Rate Zone: EGD	Rate Zone: Union	Consumption: Low	Consumption: High
Pay a portion based on the amount of natural gas used	50%	52%	48%	55%	45%
Paid equally by customers of the same type	33%	33%	32%	29%	37%
I don't have an opinion on this	11%	8%	16%	12%	10%
Don't know	6%	7%	5%	5%	7%

Fixed Cost – Network Capacity

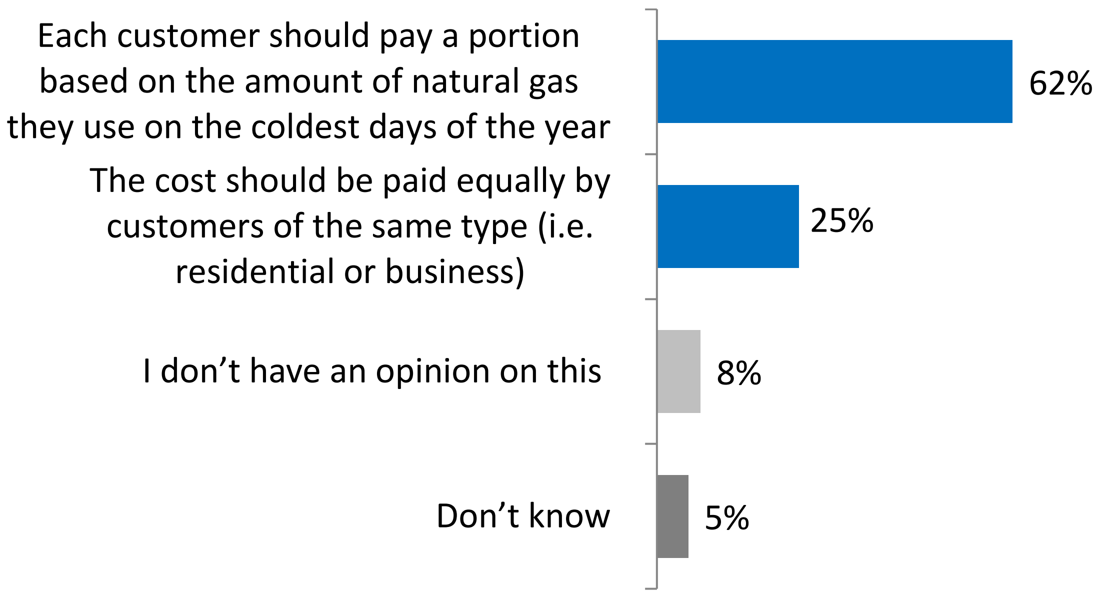
Online Survey

Q

One type of fixed cost is that of the network capacity. This includes the cost of the network infrastructure, its operation, maintenance, and natural gas storage to meet the peak demand of customers on the coldest days of the year. These costs are fixed for Enbridge Gas, but may vary for each customer based on their individual level of peak demand.

How do you feel business customers like you should be billed for these costs of accessing network capacity?
[asked of all respondents]

Small (n=400)



	Total	Rate Zone: EGD	Rate Zone: Union	Union Region: North	Union Region: South	Consumption: Low	Consumption: High
Pay a portion based on the amount of natural gas used	62%	64%	60%	68%	58%	63%	61%
Paid equally by customers of the same type	25%	25%	25%	19%	27%	23%	26%
I don't have an opinion on this	8%	6%	9%	11%	8%	7%	9%
Don't know	5%	5%	6%	2%	7%	6%	5%

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Fixed Cost – Network Capacity

Online Survey

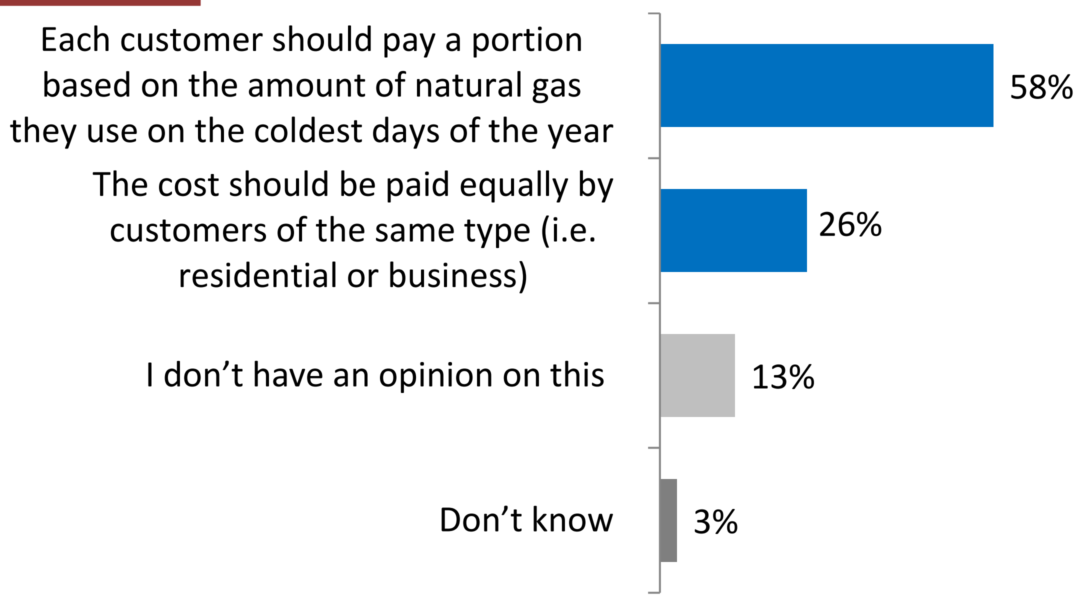
Q

One type of fixed cost is that of the network capacity. This includes the cost of the network infrastructure, its operation, maintenance, and natural gas storage to meet the peak demand of customers on the coldest days of the year. These costs are fixed for Enbridge Gas, but may vary for each customer based on their individual level of peak demand.

How do you feel business customers like you should be billed for these costs of accessing network capacity?

[asked of all respondents]

Med/Large (n=118)



		Rate Zone		Consumption	
	Total	EGD	Union	Low	High
Pay a portion based on the amount of natural gas used	58%	65%	48%	62%	54%
Paid equally by customers of the same type	26%	21%	33%	19%	33%
I don't have an opinion on this	13%	11%	16%	14%	12%
Don't know	3%	3%	3%	5%	1%

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Rate Zones

Online Survey

Q

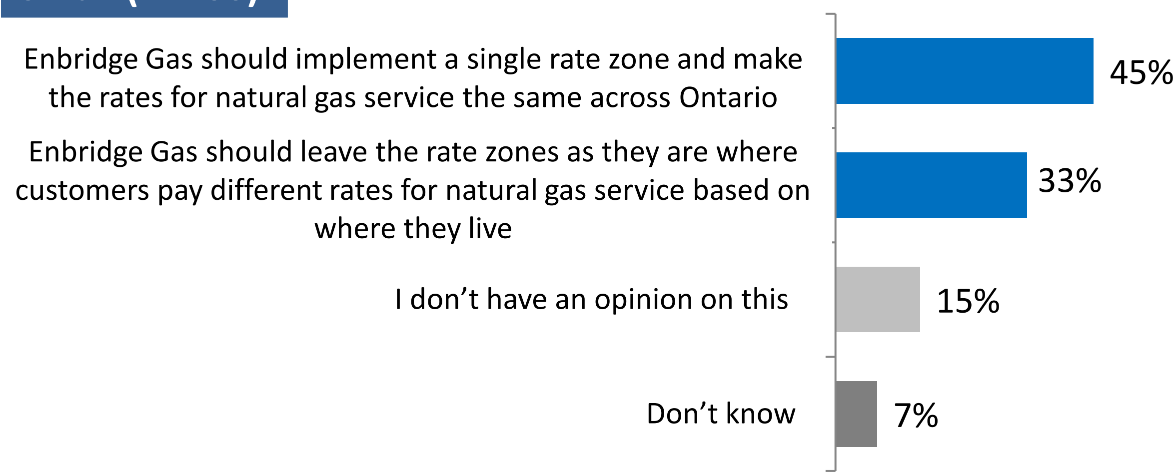
Enbridge Gas, today, is a combination of Legacy Union Gas and Legacy Enbridge Gas Distribution. Currently there are three rate zones which result in customers paying different rates depending on where you are located in the province and which company you were served by prior to the merger. Enbridge Gas is considering the option of offering one rate zone for its different types of customers, regardless of location within Ontario. There are many benefits of one rate zone including similar charges for similar customers, a consistent customer experience, and reduced administrative costs.

One rate zone could result in a change to the amount you pay today for your natural gas service. The impact is dependent on the amount of natural gas you use but could range from +5% to -10% of the amount you pay today.

Considering this, which of the following is closest to your view?

[asked of all respondents]

Small (n=400)



	Total	Rate Zone		Union Region		Consumption	
		EGD	Union	North	South	Low	High
Single rate zone and make the rates for natural gas service the same across Ontario	45%	45%	45%	45%	45%	45%	45%
Leave the rate zones as they are where customers pay different rates for natural gas service based on where they live	33%	33%	33%	42%	31%	34%	33%
I don't have an opinion on this	15%	13%	16%	7%	19%	15%	15%
Don't know	7%	9%	5%	6%	5%	7%	8%

Rate Zones

Telephone and Online Surveys

Q

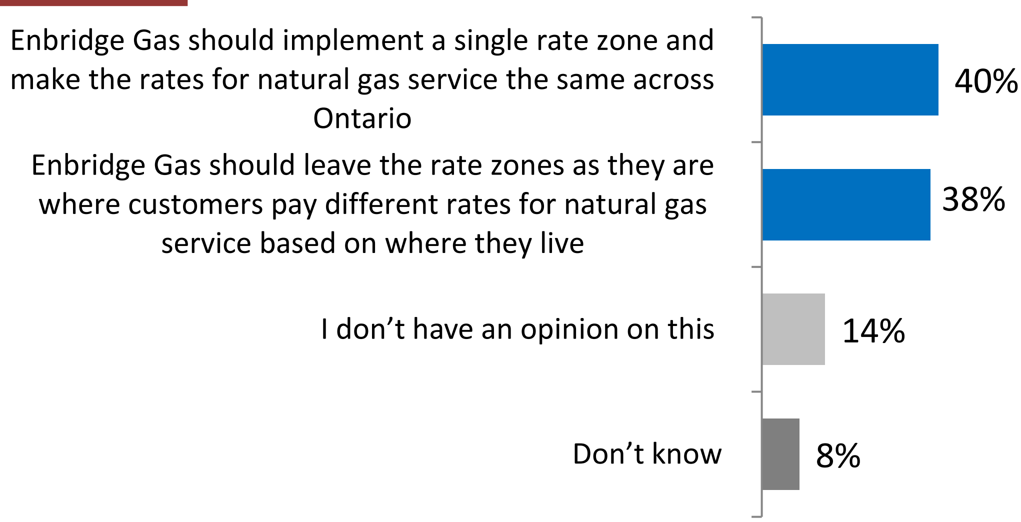
Enbridge Gas, today, is a combination of Legacy Union Gas and Legacy Enbridge Gas Distribution. Currently there are three rate zones which result in customers paying different rates depending on where you are located in the province and which company you were served by prior to the merger. Enbridge Gas is considering the option of offering one rate zone for its different types of customers, regardless of location within Ontario. There are many benefits of one rate zone including similar charges for similar customers, a consistent customer experience, and reduced administrative costs.

One rate zone could result in a change to the amount you pay today for your natural gas service. The impact is dependent on the amount of natural gas you use but could range from +5% to -10% of the amount you pay today.

Considering this, which of the following is closest to your view?

[asked of all respondents]

Med/Large (n=169)



		Rate Zone		Consumption	
	Total	**EGD**	**Union**	**Low**	**High**
Single rate zone and make the rates for natural gas service the same across Ontario	40%	41%	37%	38%	42%
Leave the rate zones as they are where customers pay different rates for natural gas service based on where they live	38%	40%	33%	38%	37%
I don't have an opinion on this	14%	11%	20%	13%	16%
Don't know	8%	8%	10%	11%	5%

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Customer Care

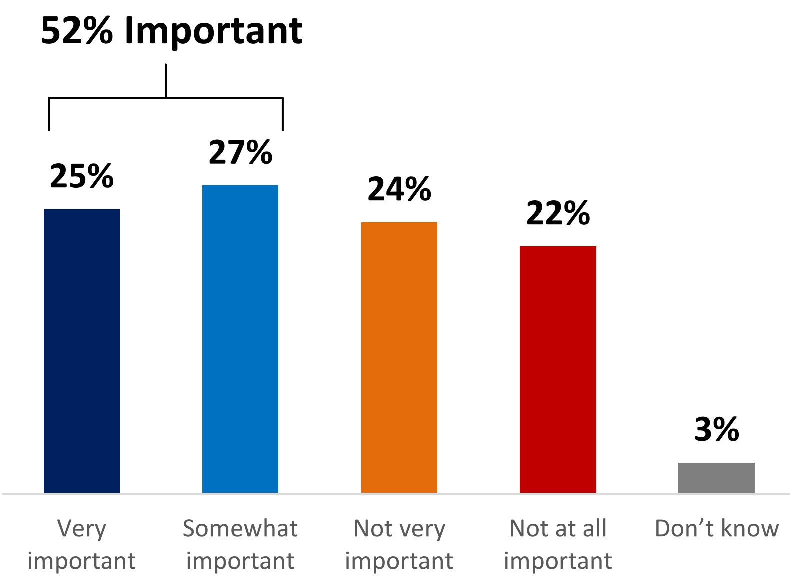
Credit Card Payment

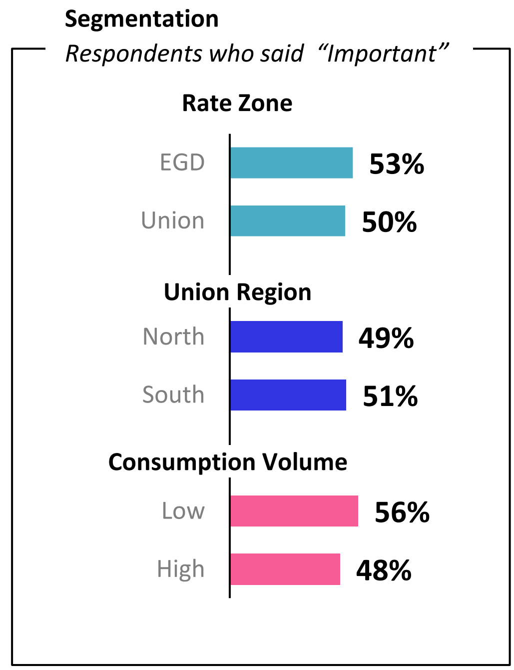
Telephone and Online Surveys

Q When you consider options for paying your bill, how important is it to you that Enbridge Gas provides customers the option to pay their bills by credit card?

[asked of all respondents]

Small (n=400)





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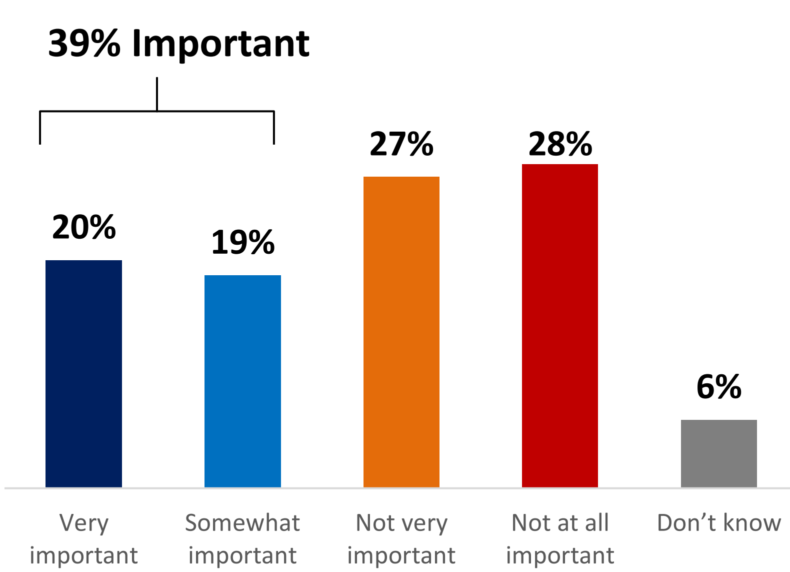

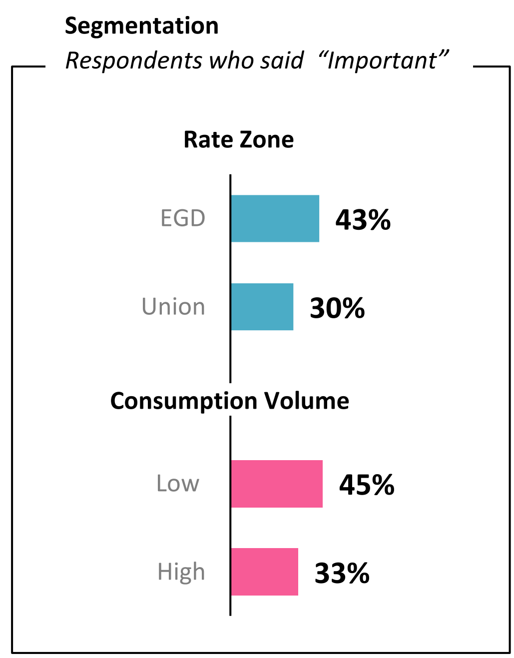

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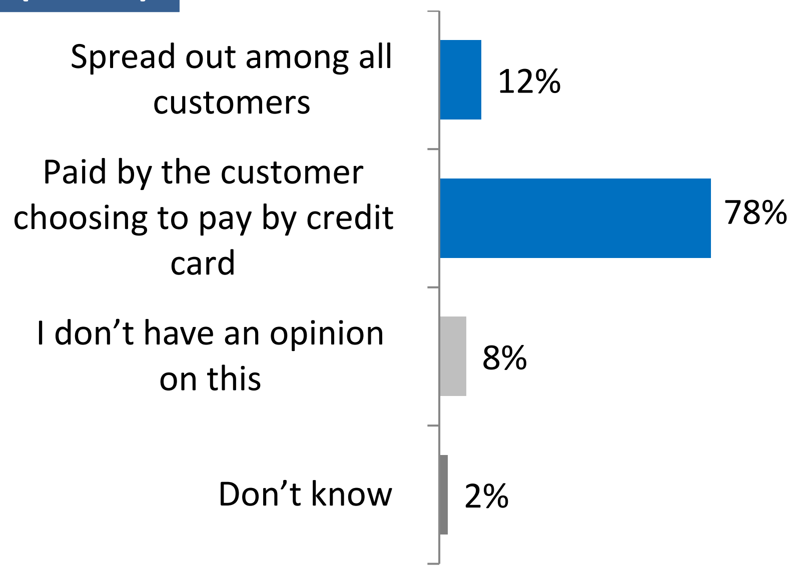
Credit Card Charges

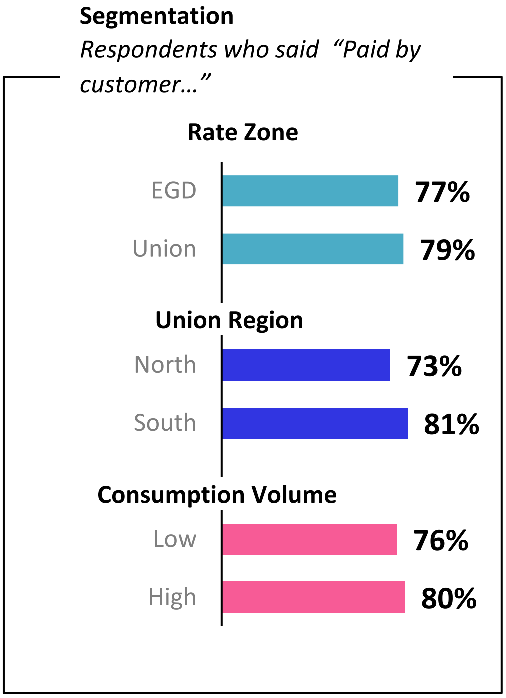
Telephone and Online Surveys

Q Credit card companies charge Enbridge Gas a fee for any payments that customers make by credit card. Do you believe that the costs of those credit card charges should be spread out among all customers, or should customers who choose to pay by credit card pay for these charges?

[asked of all respondents]

Small (n=400)





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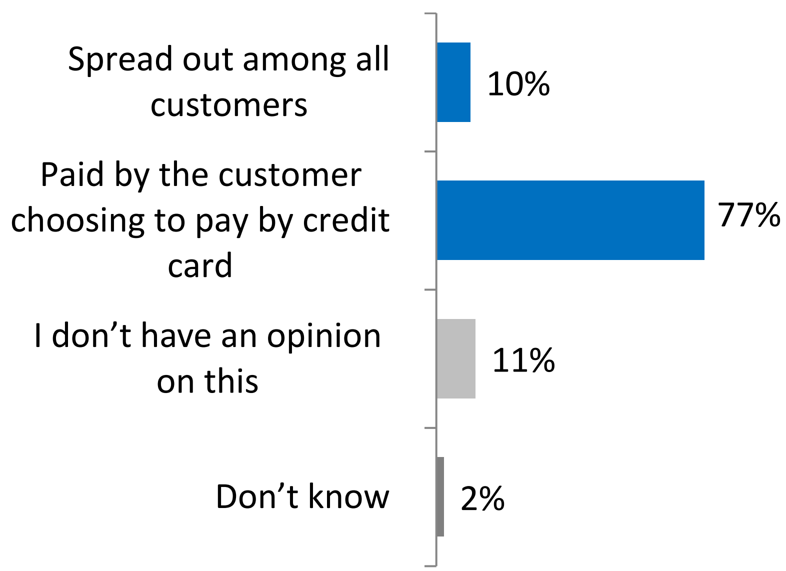

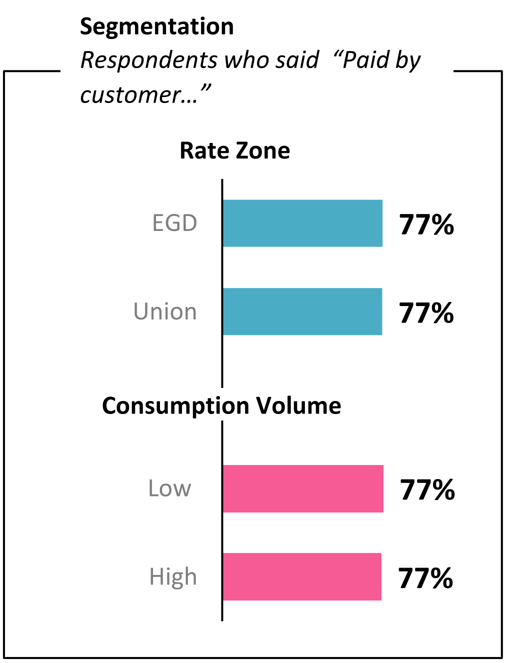

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Dedicated Customer Service Team

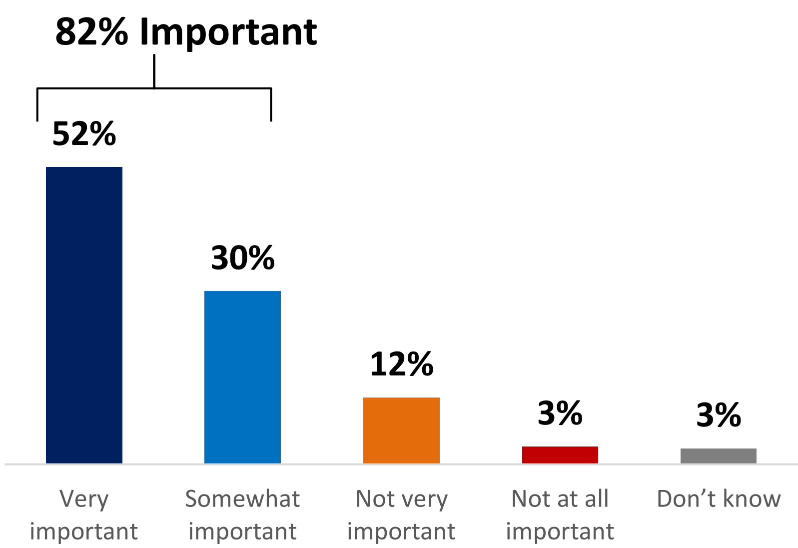
Telephone and Online Surveys

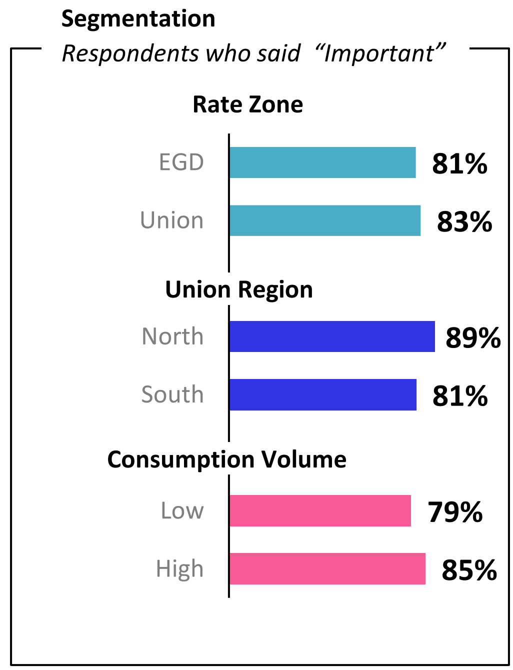
Q

One of the tools that Enbridge Gas offers customers is a customer service team that can respond to phone calls or emails. How important is it to you that business customers like you have a dedicated team to respond to business customers specifically?

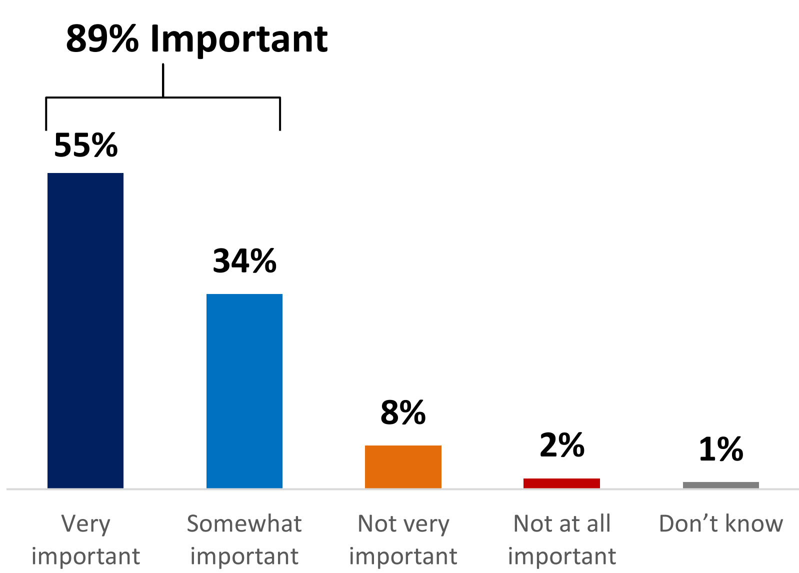
[asked of all respondents]

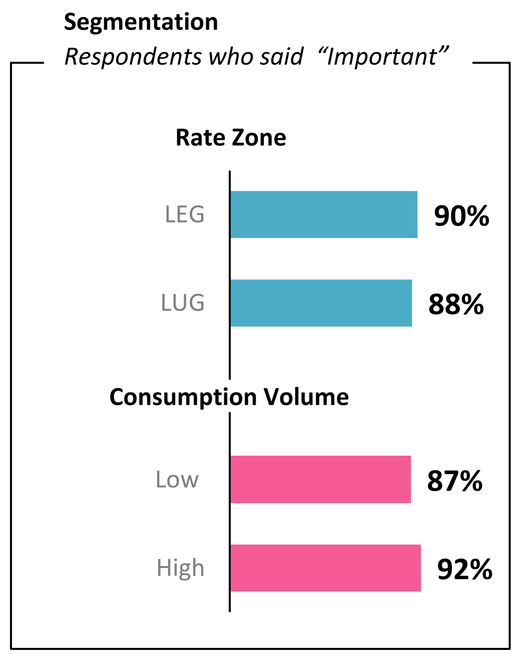
Small (n=400)





Med/Large (n=169)





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New or Harmonized Programs & Policies

Cross Bore

Online Survey

PREAMBLE:

While rare, it is possible that a natural gas line may intersect with a sewer line. When this happens, it is called a utility cross bore. This is unintentionally created when a natural gas line is installed through a process of trenchless drilling. Trenchless drilling is used to avoid creating open trenches that can disturb roads, driveways, and gardens, but it relies on locates of existing utilities which may not always be accurate for various reasons. While a utility cross bore may not pose an immediate risk, it may become an issue if a sewer line needs to be cleared in the case of a blockage.

Enbridge Gas intends to implement a program to proactively inspect and resolve any utility cross bores that may have been installed in the past. Also, a program has been implemented to prevent new installations from creating new cross bores even though that will increase the cost of the installation and require additional restoration work.

Cross Bore

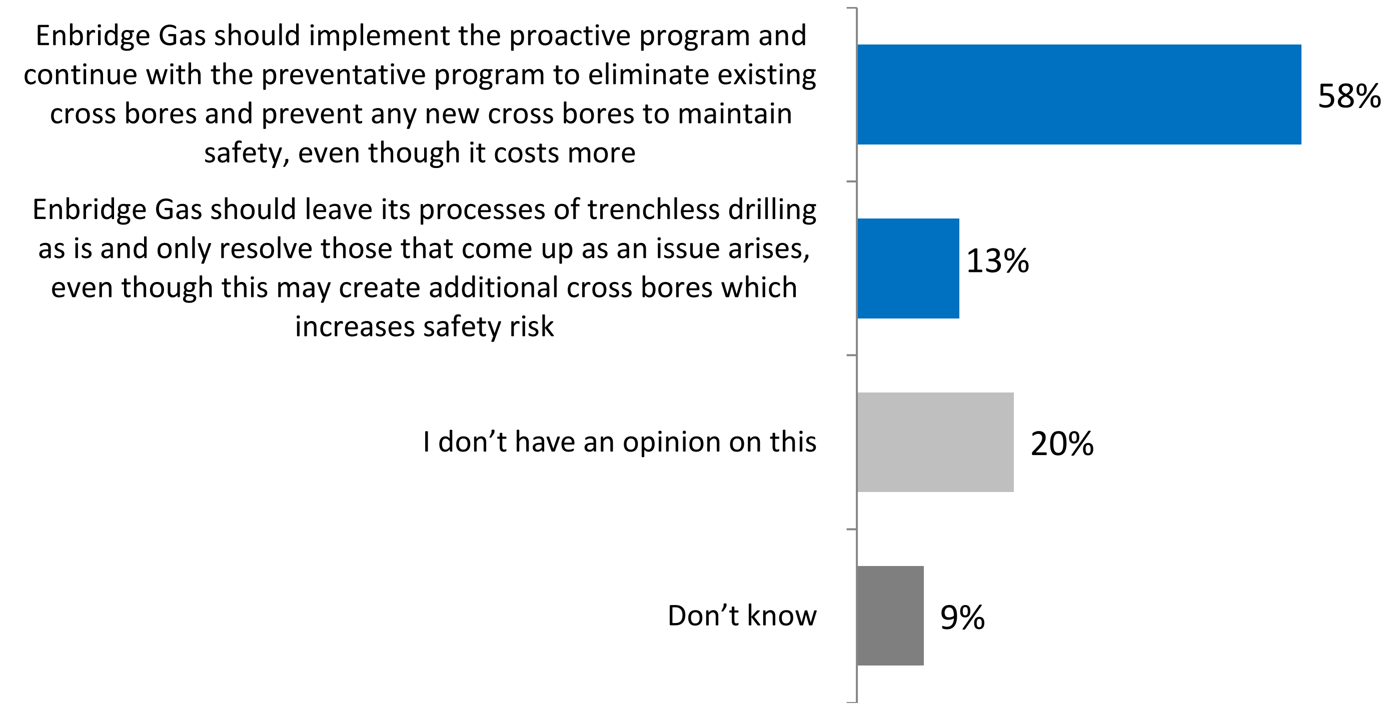
Online Survey

Q These programs to proactively inspect and resolve existing cross bores and to prevent the creation of cross bores during the completion of new installations combined would cost customers $0.50 per year for 5 years.

Which of the following is closest to your view?

[asked of all respondents]

Small (n=400)



		Rate Zone		Union Region		Consumption	
	Total	EGD	Union	North	South	Low	High
Implement the proactive program and continue with the preventative program	58%	54%	61%	59%	61%	53%	62%
Leave its processes of trenchless drilling as is and only resolve those that come up as an issue arises	13%	14%	12%	18%	11%	16%	10%
I don't have an opinion on this	20%	22%	19%	16%	20%	21%	19%
Don't know	9%	9%	8%	7%	8%	9%	8%

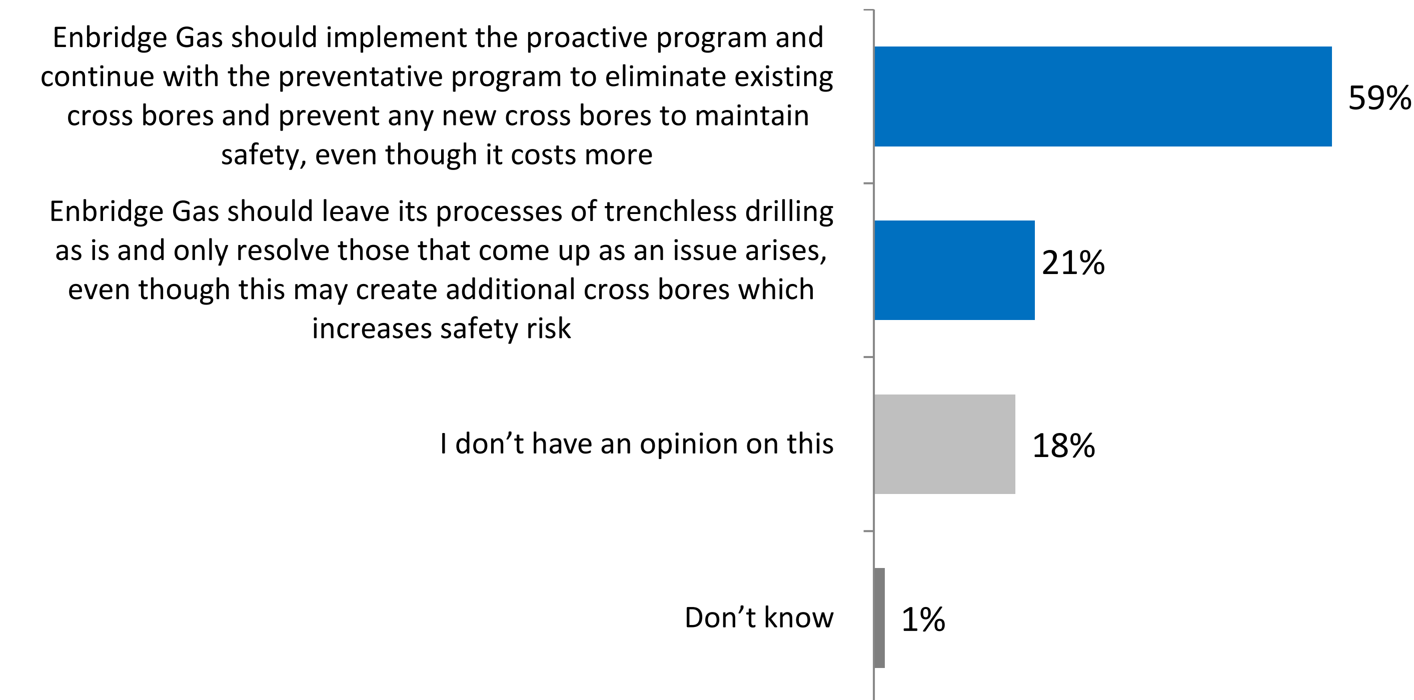
Cross Bore

Online Survey

Q These programs to proactively inspect and resolve existing cross bores and to prevent the creation of cross bores during the completion of new installations combined would cost customers $0.50 per year for 5 years.

Which of the following is closest to your view?
[asked of all respondents]

Med/Large (n=118)



		Rate Zone		Consumption	
	Total	EGD	Union	Low	High
Implement the proactive program and continue with the preventative program	59%	69%	45%	59%	59%
Leave its processes of trenchless drilling as is and only resolve those that come up as an issue arises	21%	15%	30%	23%	18%
I don't have an opinion on this	18%	16%	22%	15%	22%
Don't know	1%	0%	3%	3%	0%

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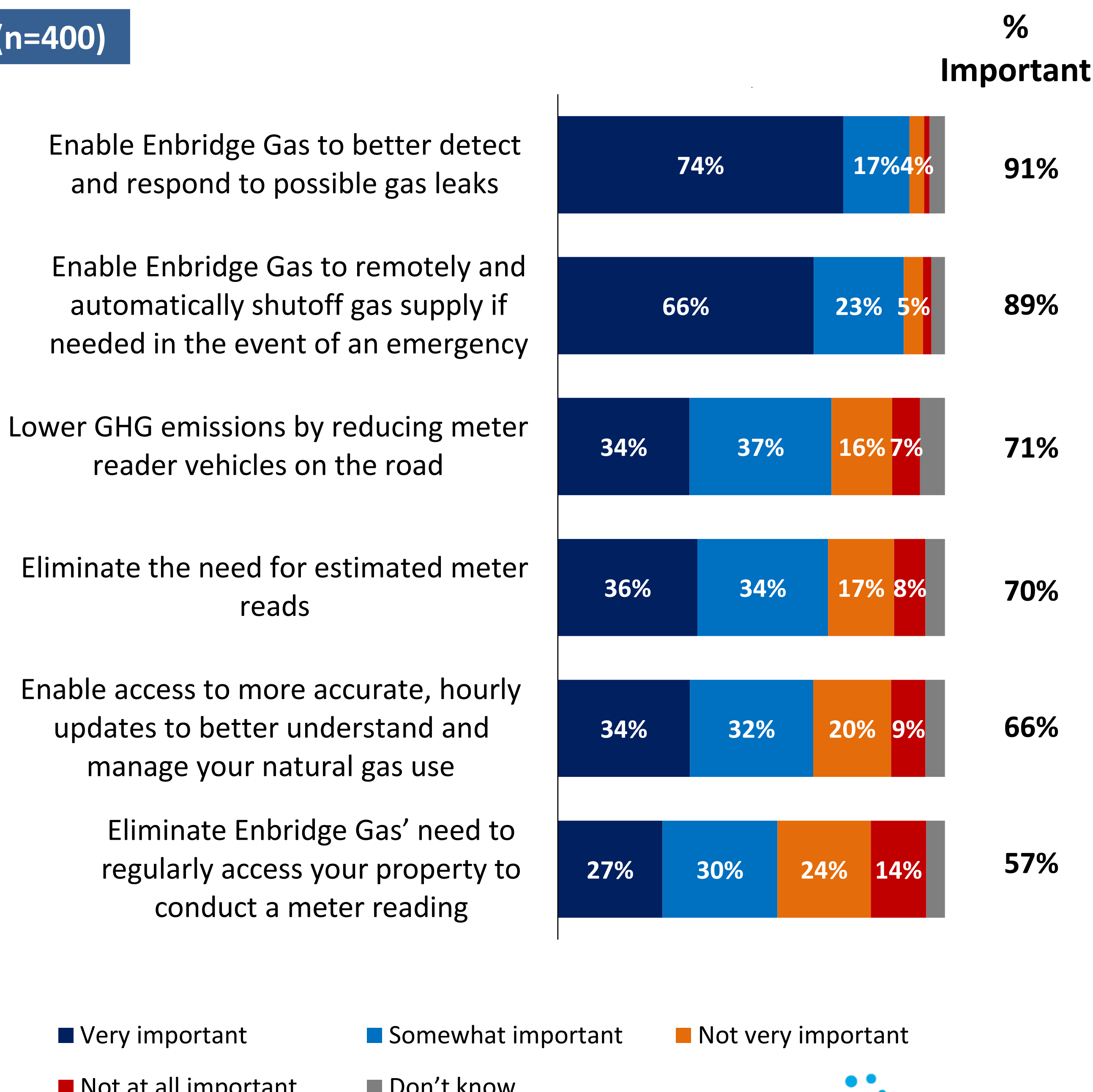
Automatic Meter Infrastructure

Online Survey

Q The gas meter technology currently used by Enbridge Gas has not changed in many years. There are new, advanced, meters available that would send the usage information to Enbridge Gas through a wireless network, similar to your electricity or water usage meters.
Please indicate how important each of the following features is to you.
[asked of all respondents]

Small (n=400)



NOTE: Data labels are removed where 3% or less

INNOVATIVE RESEARCH GROUP

Automatic Meter Infrastructure

Online Survey

Q

The gas meter technology currently used by Enbridge Gas has not changed in many years. There are new, advanced, meters available that would send the usage information to Enbridge Gas through a wireless network, similar to your electricity or water usage meters.
Please indicate how important each of the following features is to you.
[asked of all respondents]

Small (n=400)

% Important		Rate Zone		Union Region		Consumption	
	Total	EGD	Union	North	South	Low	High
Enable Enbridge Gas to better detect and respond to possible gas leaks	91%	89%	93%	89%	94%	89%	93%
Enable Enbridge Gas to remotely and automatically shutoff gas supply if needed in the event of an emergency	89%	88%	91%	89%	91%	88%	90%
Lower GHG emissions by reducing meter reader vehicles on the road	71%	68%	73%	72%	73%	66%	75%
Eliminate the need for estimated meter reads	70%	69%	71%	68%	72%	65%	74%
Enable access to more accurate, hourly updates to better understand and manage your natural gas use	66%	67%	65%	56%	68%	69%	63%
Eliminate Enbridge Gas' need to regularly access your property to conduct a meter reading	57%	54%	59%	58%	60%	55%	59%

INNOVATIVE RESEARCH GROUP

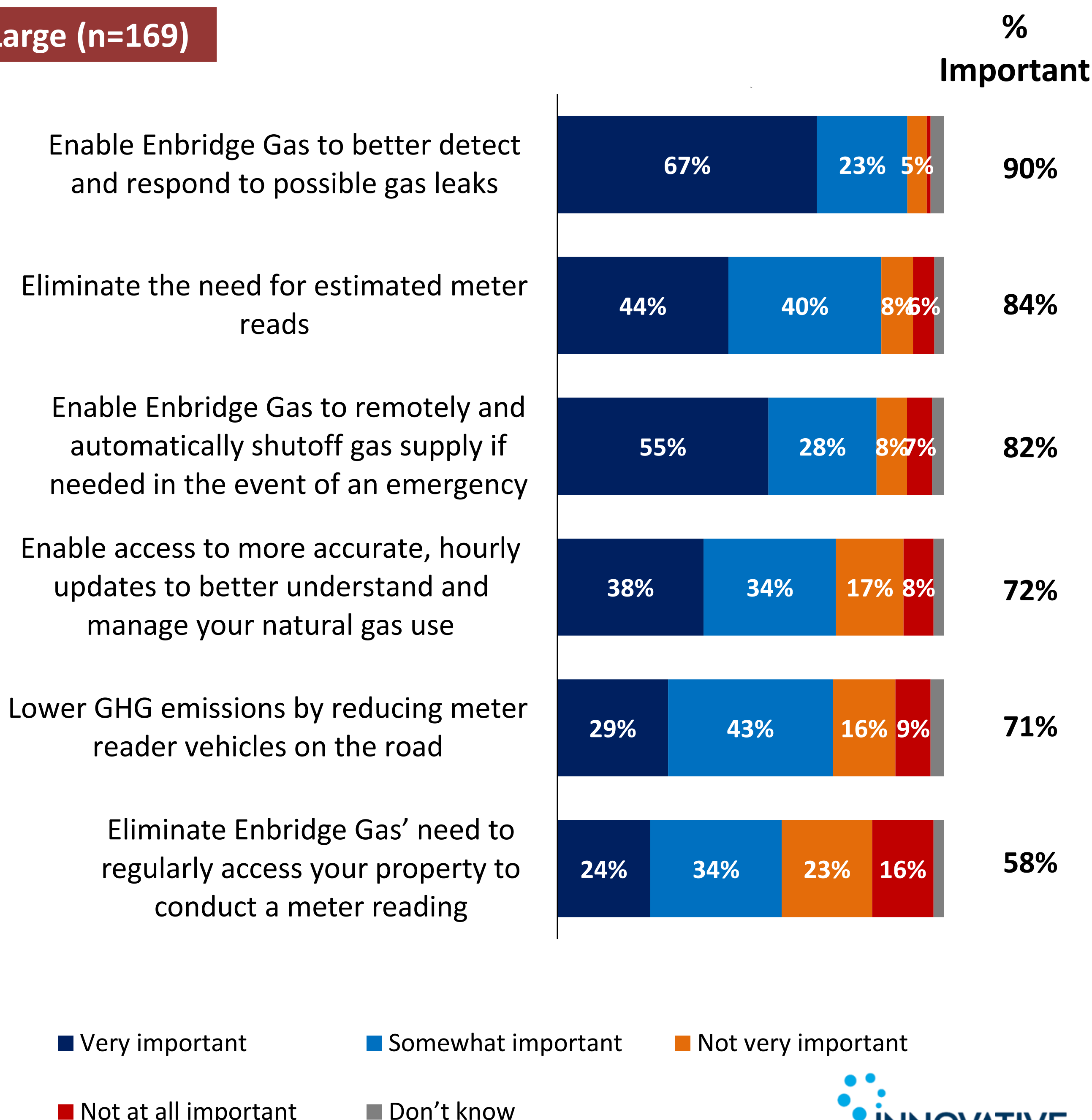
Automatic Meter Infrastructure

Telephone and Online Surveys

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 201 of 550

Q The gas meter technology currently used by Enbridge Gas has not changed in many years. There are new, advanced, meters available that would send the usage information to Enbridge Gas through a wireless network, similar to your electricity or water usage meters.
Please indicate how important each of the following features is to you.
[asked of all respondents]

Med/Large (n=169)



NOTE: Data labels are removed where 3% or less

INNOVATIVE RESEARCH GROUP

Automatic Meter Infrastructure

Telephone and Online Surveys

Q

The gas meter technology currently used by Enbridge Gas has not changed in many years. There are new, advanced, meters available that would send the usage information to Enbridge Gas through a wireless network, similar to your electricity or water usage meters.
Please indicate how important each of the following features is to you.
[asked of all respondents]

Med/Large (n=169)

% Important		Rate Zone		Consumption	
	Total	EGD	Union	Low	High
Enable Enbridge Gas to better detect and respond to possible gas leaks	90%	91%	89%	92%	89%
Enable Enbridge Gas to remotely and automatically shutoff gas supply if needed in the event of an emergency	82%	91%	66%	81%	84%
Lower GHG emissions by reducing meter reader vehicles on the road	71%	73%	68%	76%	66%
Eliminate the need for estimated meter reads	84%	85%	82%	85%	83%
Enable access to more accurate, hourly updates to better understand and manage your natural gas use	72%	74%	68%	70%	74%
Eliminate Enbridge Gas' need to regularly access your property to conduct a meter reading	58%	59%	57%	64%	52%

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Energy Transition

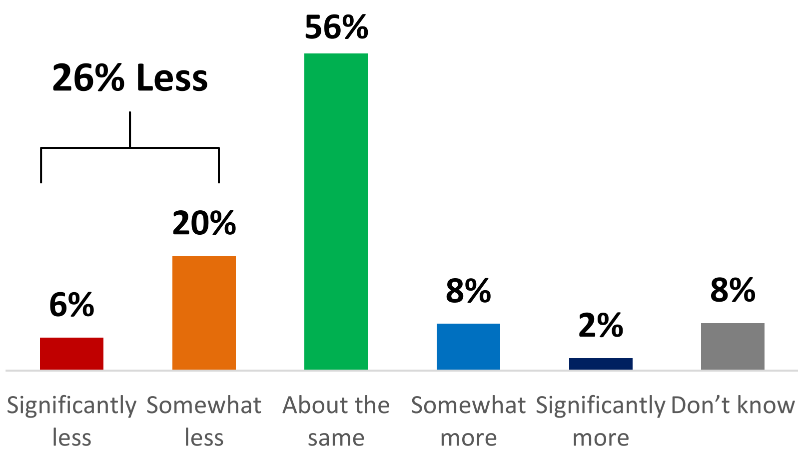
Natural Gas Consumption in 10 Years

Telephone and Online Surveys

Q Thinking about everything you know today, and considering any changes that you might expect in the future as it relates to all the energy choices available to you, how much natural gas do you think an organization like yours will be using in 10 years compared to today?

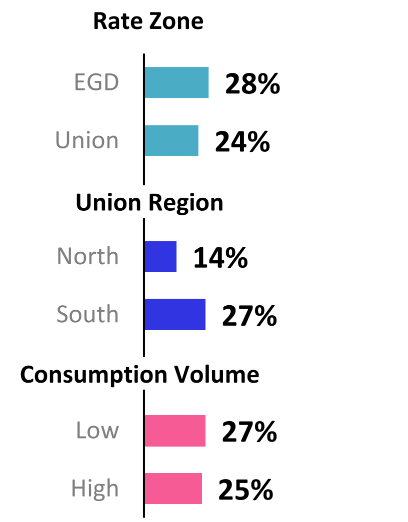
[asked of all respondents]

Small (n=400)

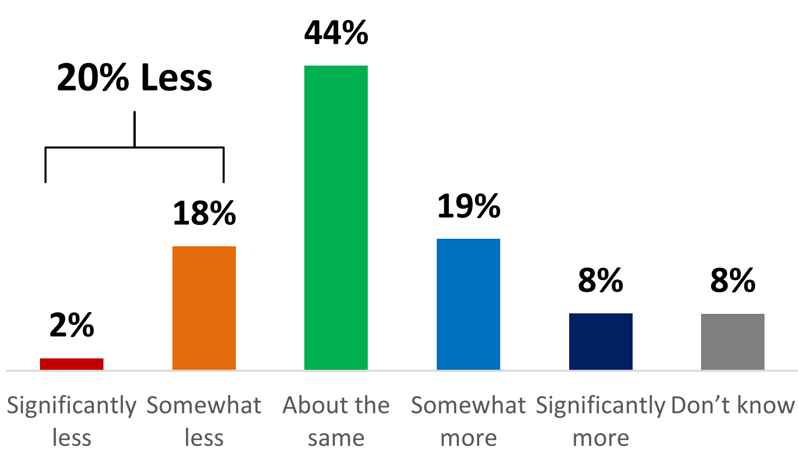


Segmentation

Respondents who said "Less"

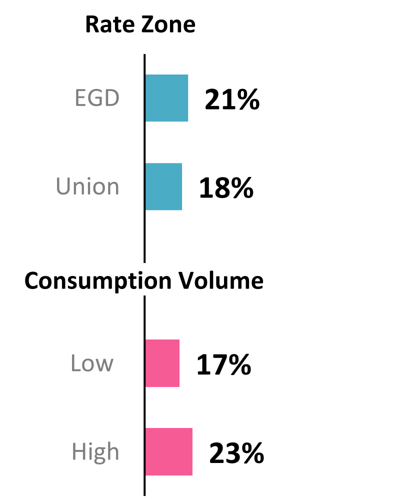


Med/Large (n=169)



Segmentation

Respondents who said "Less"



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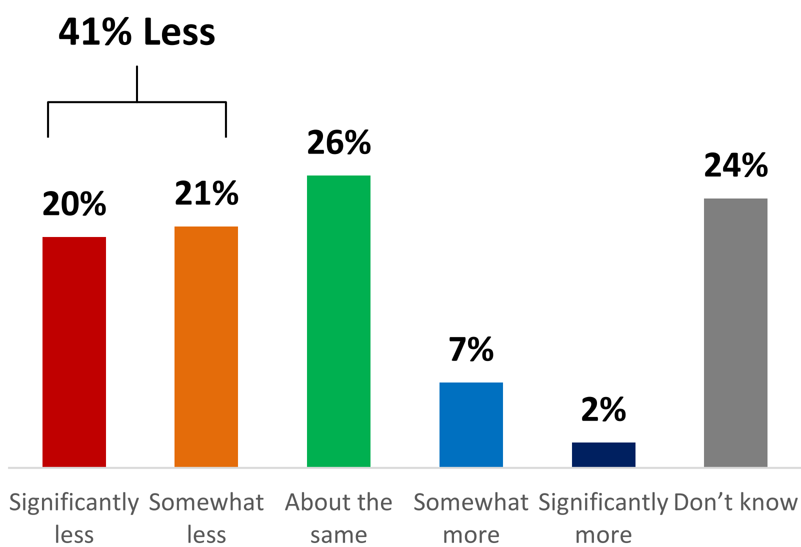
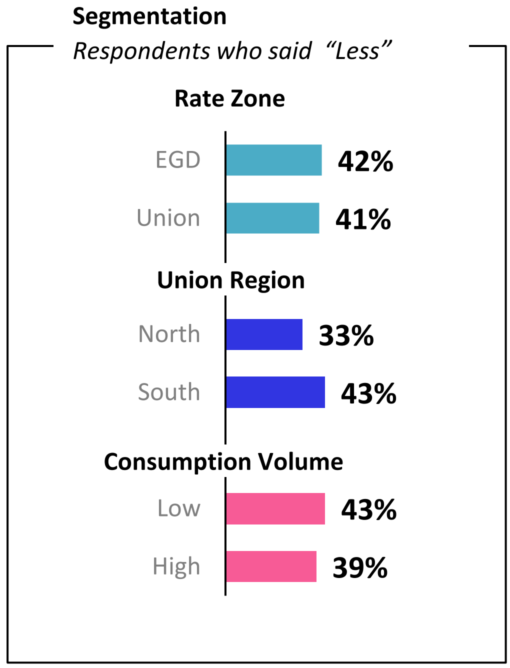
Natural Gas Consumption in 30 Years

Telephone and Online Surveys

Q How about in 30 years?
[asked of all respondents]

Small (n=400)





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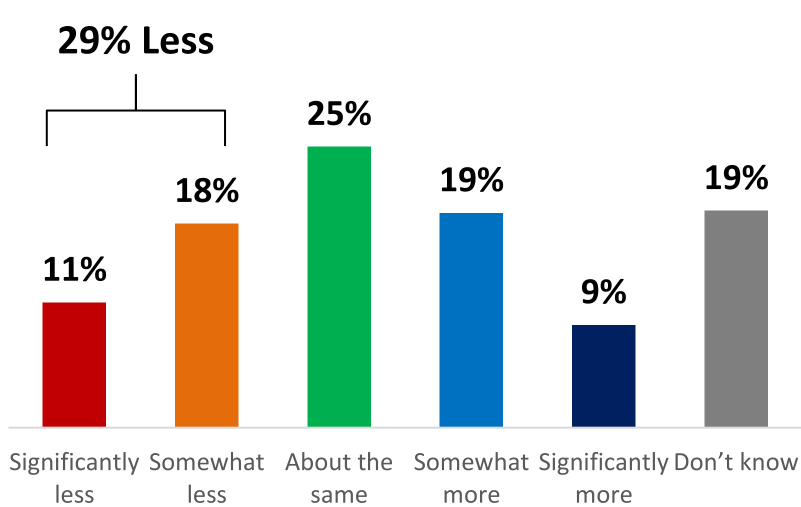

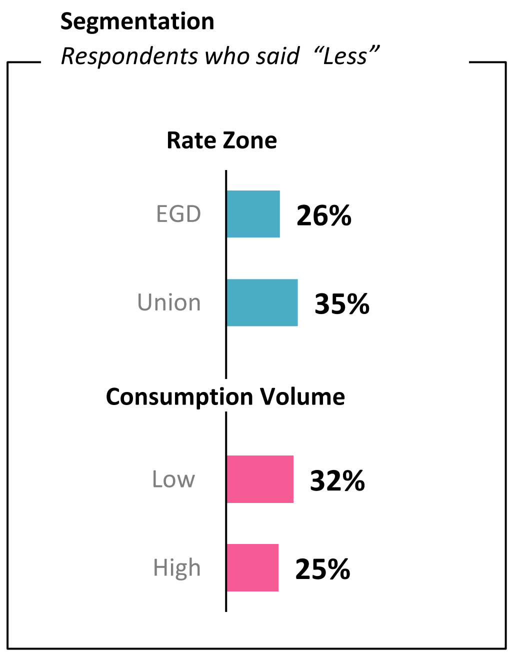

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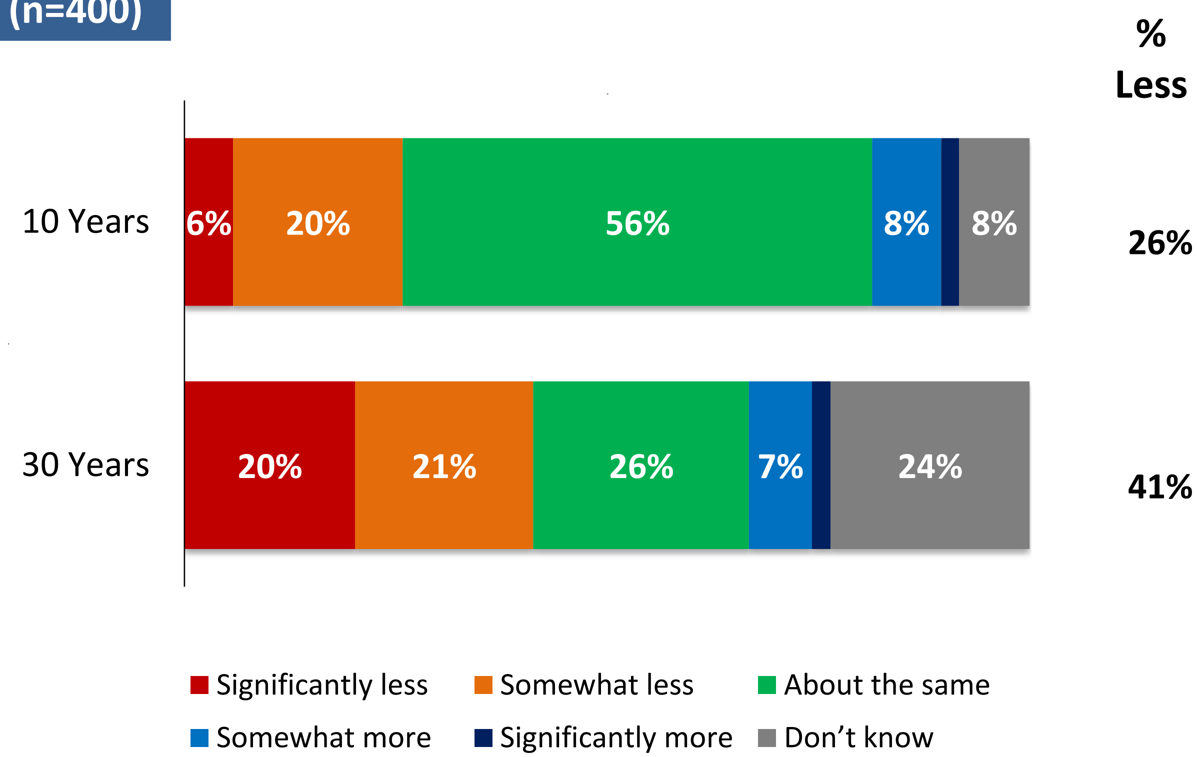
Natural Gas Consumption in 10 vs 30 Years

Telephone and Online Surveys

Small (n=400)



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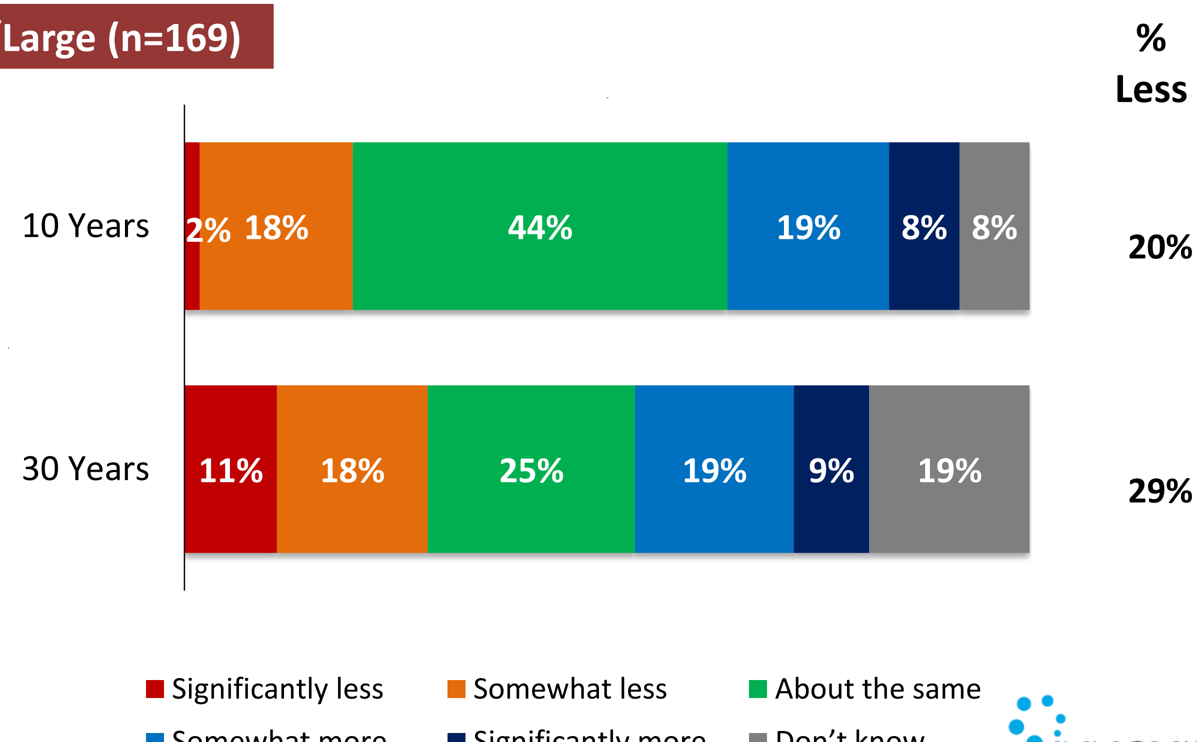


NOTE: Data labels are removed where 3% or less

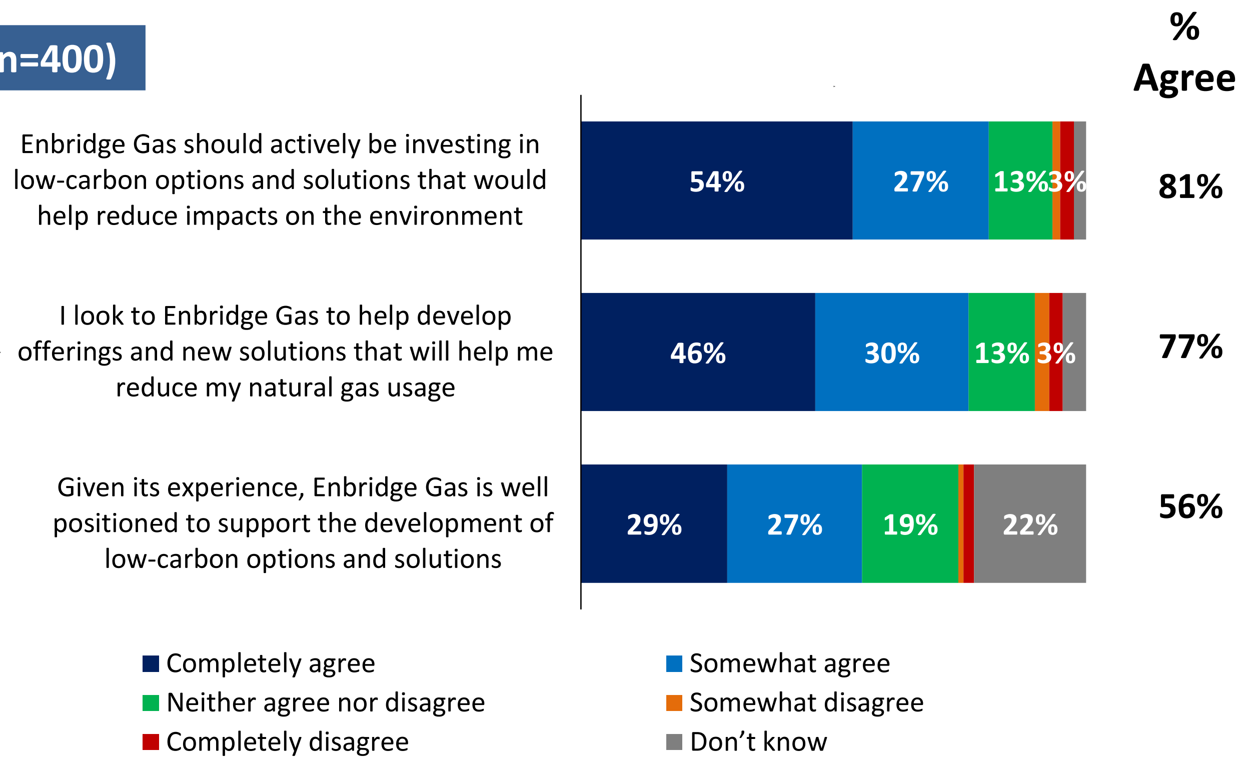
INNOVATIVE RESEARCH GROUP

Reducing Environmental Impacts

Telephone and Online Surveys

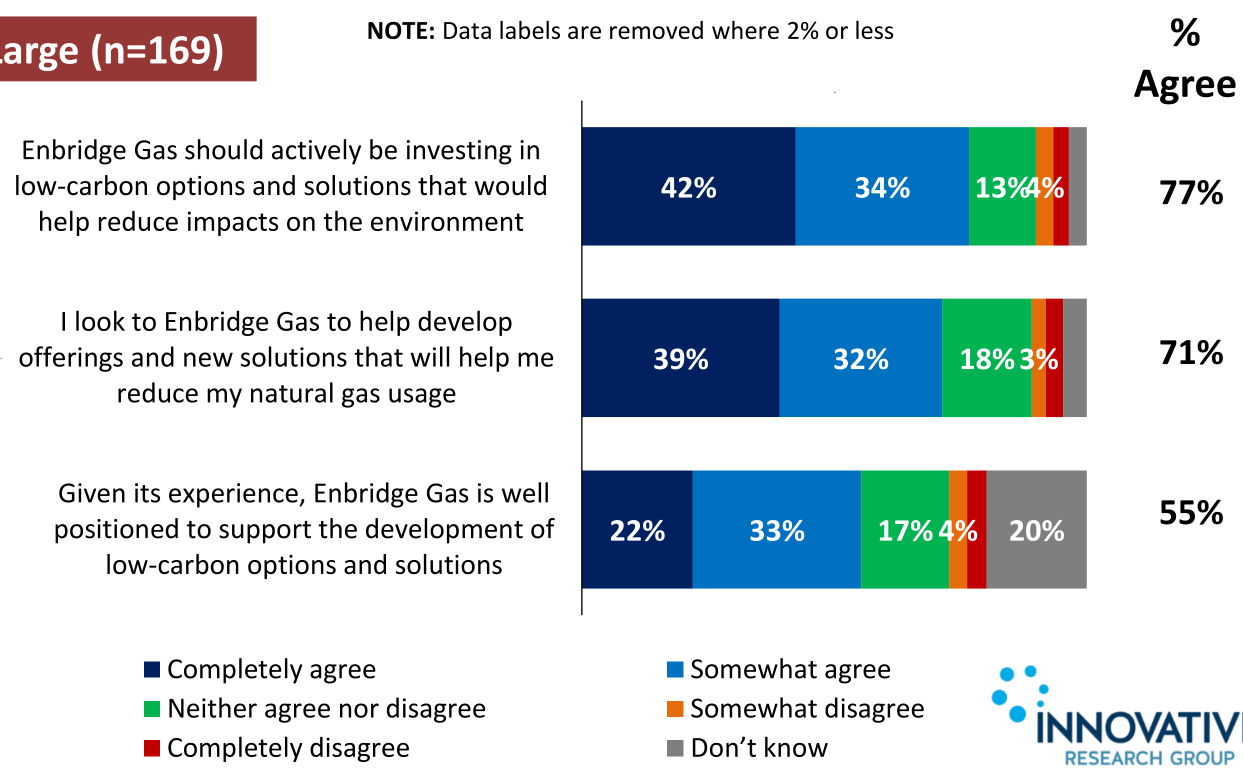
Q When you consider options and solutions to reduce impacts on the environment, please indicate whether you agree or disagree with the following statements.
[asked of all respondents]

Small (n=400)



Med/Large (n=169)

NOTE: Data labels are removed where 2% or less



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Reducing Environmental Impacts

Online Survey

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 208 of 550

Q When you consider options and solutions to reduce impacts on the environment, please indicate whether you agree or disagree with the following statements.
[asked of all respondents]

Small (n=400)

Enbridge Gas should actively be investing in low-carbon options and solutions that would help reduce impacts on the environment.

		Rate Zone		Union Region		Consumption	
	Total	EGD	Union	North	South	Low	High
Total agree	81%	79%	82%	80%	83%	79%	82%
Total disagree	4%	5%	3%	7%	2%	6%	3%

Given its experience, Enbridge Gas is well positioned to support the development of low-carbon options and solutions.

		Rate Zone		Union Region		Consumption	
	Total	EGD	Union	North	South	Low	High
Total agree	56%	53%	58%	60%	58%	54%	57%
Total disagree	3%	5%	1%	3%	0%	4%	2%

I look to Enbridge Gas to help develop offerings and new solutions that will help me reduce my natural gas usage.

		Rate Zone		Union Region		Consumption	
	Total	EGD	Union	North	South	Low	High
Total agree	77%	80%	73%	76%	72%	75%	79%
Total disagree	6%	6%	5%	10%	4%	6%	6%

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Reducing Environmental Impacts

Telephone and Online Surveys

Q When you consider options and solutions to reduce impacts on the environment, please indicate whether you agree or disagree with the following statements.
[asked of all respondents]

Med/Large (n=169)

Enbridge Gas should actively be investing in low-carbon options and solutions that would help reduce impacts on the environment.

		Rate Zone		Consumption	
	Total	EGD	Union	Low	High
Total agree	77%	78%	74%	72%	82%
Total disagree	7%	6%	8%	4%	10%

Given its experience, Enbridge Gas is well positioned to support the development of low-carbon options and solutions.

		Rate Zone		Consumption	
	Total	EGD	Union	Low	High
Total agree	55%	55%	56%	53%	57%
Total disagree	7%	7%	8%	8%	7%

I look to Enbridge Gas to help develop offerings and new solutions that will help me reduce my natural gas usage.

		Rate Zone		Consumption	
	Total	EGD	Union	Low	High
Total agree	71%	70%	73%	69%	73%
Total disagree	6%	6%	7%	6%	6%

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Reduced Demand

Online Survey

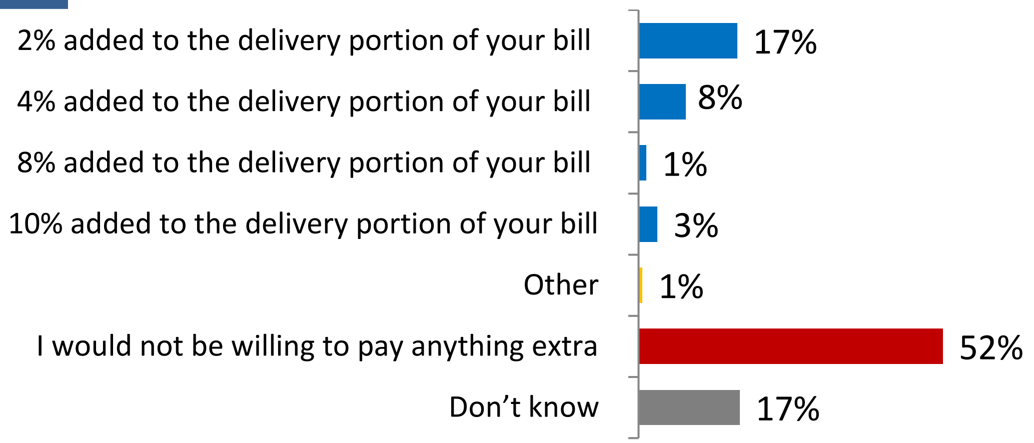
Q

When considering new or expanded pipeline projects, Enbridge Gas is required to evaluate whether alternatives are available that would eliminate the need for the project altogether. This would mean looking for ways to help 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, adding insulation, or upgrading your furnace or water heater. It could also include delivering compressed natural gas by truck or train to locations where pipelines do not exist. Other alternatives that reduce the need for natural gas might include geothermal heating and cooling, or air source heat pumps.

How much, if anything, would your organization be willing to pay per year for Enbridge Gas to develop solutions in natural gas conservation and other non-pipeline alternatives instead of new pipeline or capacity projects?

[asked of all respondents]

Small (n=400)



		Rate Zone		Union Region		Consumption	
	Total	EGD	Union	North	South	Low	High
2% added to the delivery portion of your bill	17%	16%	18%	20%	17%	15%	19%
4% added to the delivery portion of your bill	8%	9%	7%	5%	8%	6%	10%
8% added to the delivery portion of your bill	1%	2%	1%	0%	1%	1%	1%
10% added to the delivery portion of your bill	3%	4%	3%	3%	3%	4%	2%
I would not be willing to pay anything extra	52%	54%	51%	51%	51%	53%	51%

Reduced Demand

Online Survey

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 211 of 550

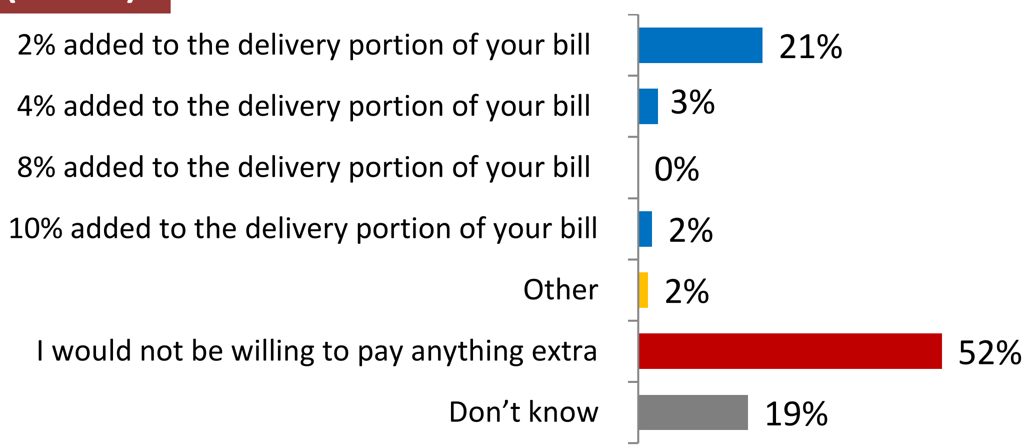
Q

When considering new or expanded pipeline projects, Enbridge Gas is required to evaluate whether alternatives are available that would eliminate the need for the project altogether. This would mean looking for ways to help 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, adding insulation, or upgrading your furnace or water heater. It could also include delivering compressed natural gas by truck or train to locations where pipelines do not exist. Other alternatives that reduce the need for natural gas might include geothermal heating and cooling, or air source heat pumps.

How much, if anything, would your organization be willing to pay per year for Enbridge Gas to develop solutions in natural gas conservation and other non-pipeline alternatives instead of new pipeline or capacity projects?

[asked of all respondents]

Med/Large (n=118)



	Total	Rate Zone: EGD	Rate Zone: Union	Consumption: Low	Consumption: High
2% added to the delivery portion of your bill	21%	21%	22%	22%	21%
4% added to the delivery portion of your bill	3%	4%	3%	2%	5%
10% added to the delivery portion of your bill	2%	4%	0%	2%	3%
I would not be willing to pay anything extra	52%	50%	55%	56%	48%

Low-Carbon Options

Online Survey

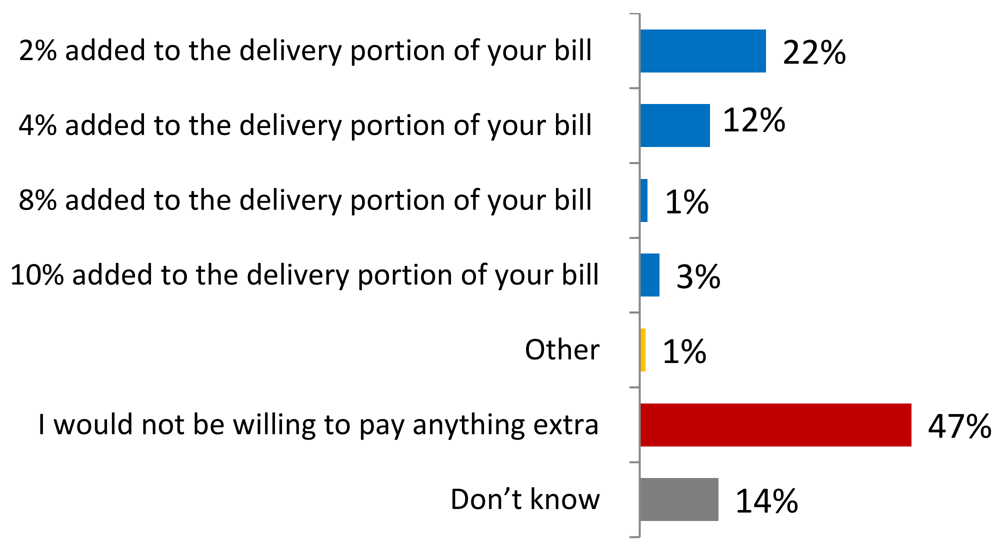
Q

Other options Enbridge Gas may invest in that focus on reducing the amount of greenhouse gas emissions can include options that "green the gas." An example of this would be blending traditional natural gas with greener sources of gas, such as renewable natural gas derived from organic waste from farms, landfills, and water treatment plants, or hydrogen gas derived from using surplus electrical energy that is converted to hydrogen gas through electrolysis technology.

How much, if anything, would your organization be willing to pay per year for Enbridge Gas to develop solutions in greening the gas to reduce the greenhouse gas emissions from the use of natural gas?

[asked of all respondents]

Small (n=400)



		Rate Zone		Union Region		Consumption	
	Total	**EGD**	**Union**	**North**	**South**	**Low**	**High**
2% added to the delivery portion of your bill	22%	21%	22%	28%	21%	22%	22%
4% added to the delivery portion of your bill	12%	12%	12%	10%	13%	10%	15%
8% added to the delivery portion of your bill	1%	1%	1%	1%	1%	2%	1%
10% added to the delivery portion of your bill	3%	3%	4%	3%	4%	3%	3%
I would not be willing to pay anything extra	47%	47%	46%	43%	47%	48%	46%

Low-Carbon Options

Online Survey

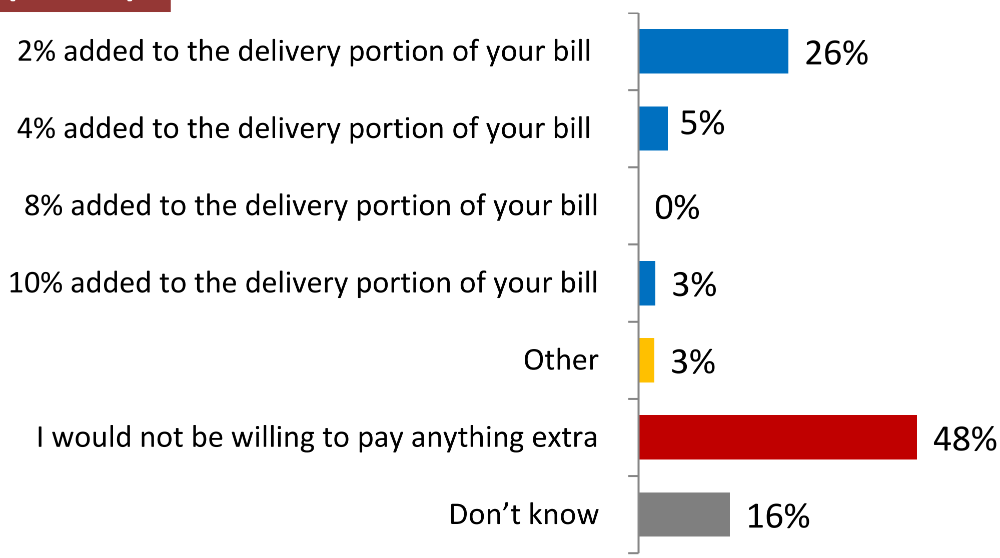
Q

Other options Enbridge Gas may invest in that focus on reducing the amount of greenhouse gas emissions can include options that "green the gas." An example of this would be blending traditional natural gas with greener sources of gas, such as renewable natural gas derived from organic waste from farms, landfills, and water treatment plants, or hydrogen gas derived from using surplus electrical energy that is converted to hydrogen gas through electrolysis technology.

How much, if anything, would your organization be willing to pay per year for Enbridge Gas to develop solutions in greening the gas to reduce the greenhouse gas emissions from the use of natural gas?

[asked of all respondents]

Med/Large (n=118)



	Total	Rate Zone: EGD	Rate Zone: Union	Consumption: Low	Consumption: High
2% added to the delivery portion of your bill	26%	29%	21%	24%	28%
4% added to the delivery portion of your bill	5%	5%	5%	6%	4%
10% added to the delivery portion of your bill	3%	4%	1%	2%	4%
I would not be willing to pay anything extra	48%	45%	53%	51%	44%

New Technologies

Online Survey

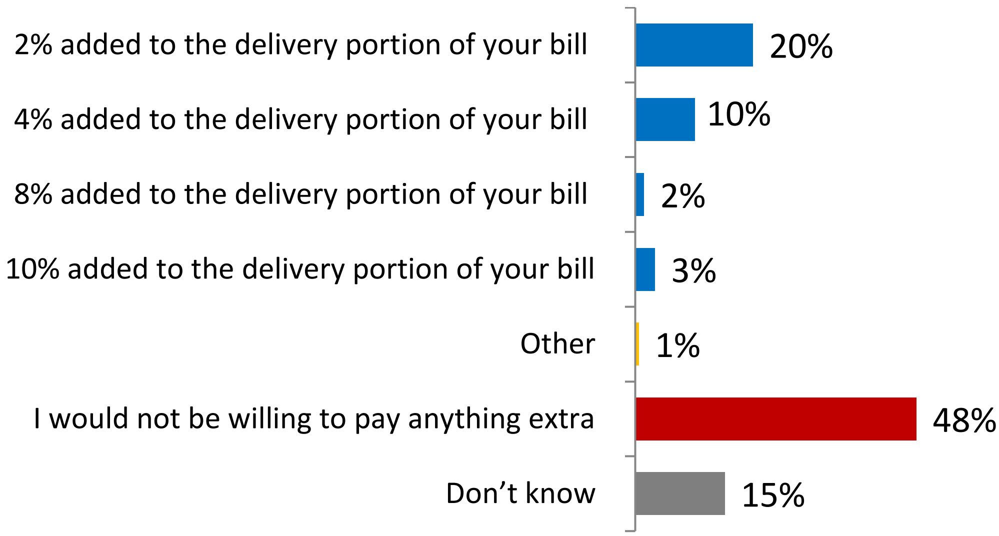
Q

Enbridge Gas can also support the advancement of various new low-carbon or energy efficient technologies that may not exist today. This would include participating in new research, development and supporting various pilot projects.

How much, if anything, would your organization be willing to pay per year for Enbridge Gas to develop solutions in developing and advancing new low-carbon and energy efficient technologies?

[asked of all respondents]

Small (n=400)



	Total	Rate Zone: EGD	Rate Zone: Union	Union Region: North	Union Region: South	Consumption: Low	Consumption: High
2% added to the delivery portion of your bill	20%	20%	20%	22%	20%	21%	19%
4% added to the delivery portion of your bill	10%	9%	12%	10%	12%	7%	14%
8% added to the delivery portion of your bill	2%	1%	2%	0%	2%	2%	1%
10% added to the delivery portion of your bill	3%	4%	3%	3%	4%	4%	3%
I would not be willing to pay anything extra	48%	51%	46%	44%	46%	50%	47%

New Technologies

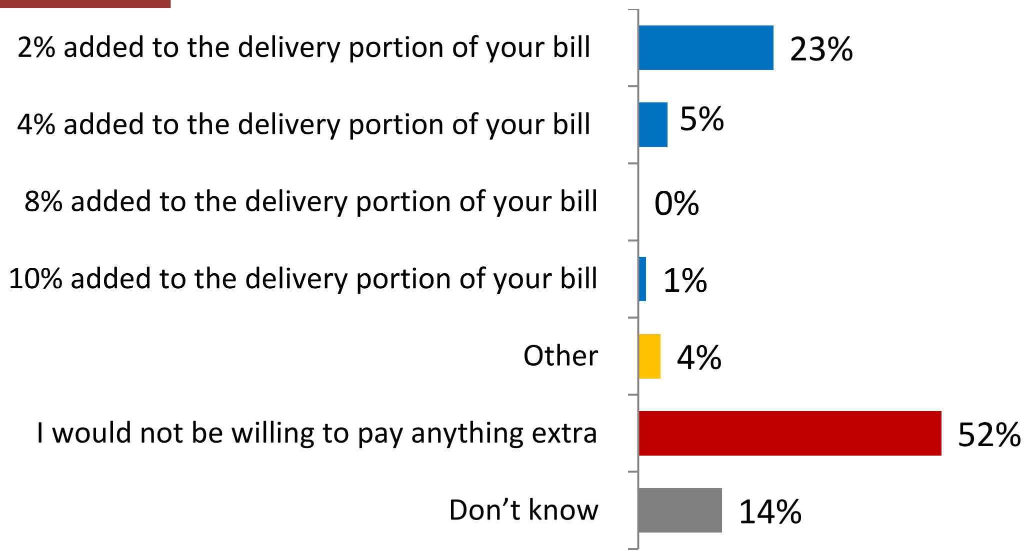
Online Survey

Q Enbridge Gas can also support the advancement of various new low-carbon or energy efficient technologies that may not exist today. This would include participating in new research, development and supporting various pilot projects.

How much, if anything, would your organization be willing to pay per year for Enbridge Gas to develop solutions in developing and advancing new low-carbon and energy efficient technologies?

[asked of all respondents]

Med/Large (n=118)



		Rate Zone		Consumption	
	Total	EGD	Union	Low	High
2% added to the delivery portion of your bill	23%	25%	21%	22%	25%
4% added to the delivery portion of your bill	5%	5%	5%	6%	4%
10% added to the delivery portion of your bill	1%	2%	0%	0%	3%
I would not be willing to pay anything extra	52%	49%	57%	54%	50%

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Paying More to Reduce Enviro. Impact

Online Survey

Small (n=400)	Natural gas conservation and other non-pipeline alternatives instead of new pipeline or capacity projects	Greening the gas to reduce the greenhouse gas emissions from the use of natural gas	Developing and advancing new low-carbon and energy efficient technologies
2% added to the delivery portion	17%	22%	20%
4% added to the delivery portion	8%	12%	10%
8% added to the delivery portion	1%	1%	2%
10% added to the delivery portion	3%	3%	3%
Not willing to pay anything extra	52%	47%	48%

Med/Large (n=118)	Natural gas conservation and other non-pipeline alternatives instead of new pipeline or capacity projects	Greening the gas to reduce the greenhouse gas emissions from the use of natural gas	Developing and advancing new low-carbon and energy efficient technologies
2% added to the delivery portion	21%	26%	23%
4% added to the delivery portion	3%	5%	5%
8% added to the delivery portion	0%	0%	0%
10% added to the delivery portion	2%	3%	1%
Not willing to pay anything extra	52%	48%	52%

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Certified Natural Gas

Online Survey

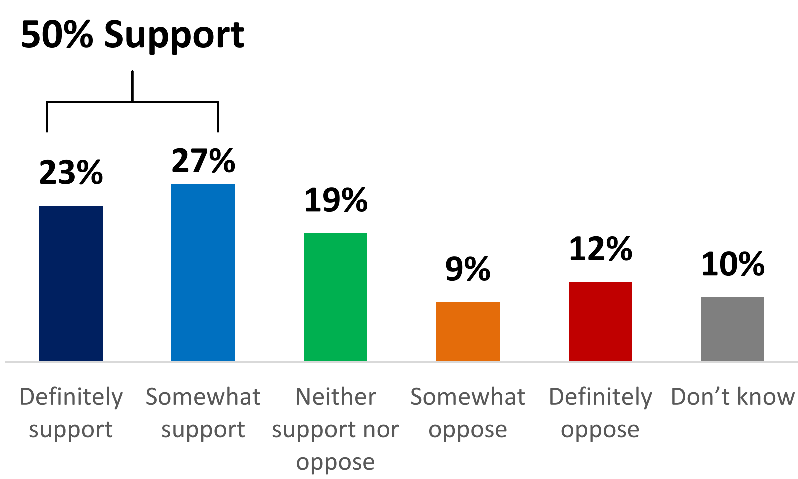
Q

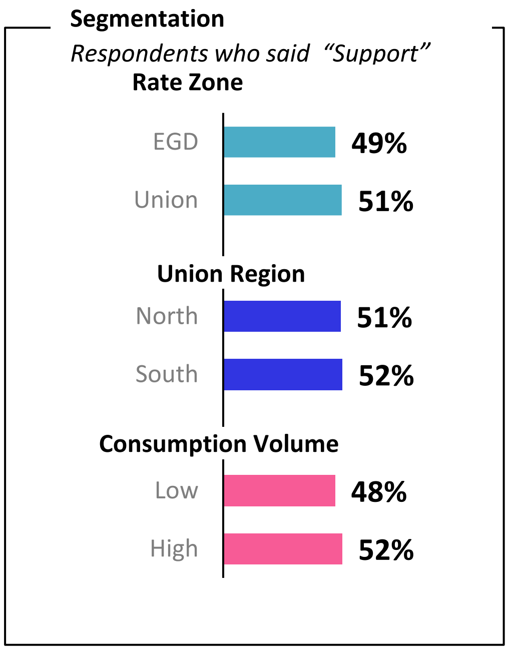
Enbridge Gas is looking at options to ensure that the natural gas it purchases is responsibly sourced. This means the companies who produce the natural gas adhere to higher standards than the minimum government standards. This relates to areas such as minimizing impacts to air and water quality, lowering carbon emissions during production, and stronger engagement with Indigenous communities, etc. While it may not always cost more, it is possible that this responsibly sourced natural gas comes at a small premium and would cost customers a little bit more.

Considering this, would you support Enbridge Gas sourcing this type of natural gas to deliver to your organization, even if it comes at a small premium?

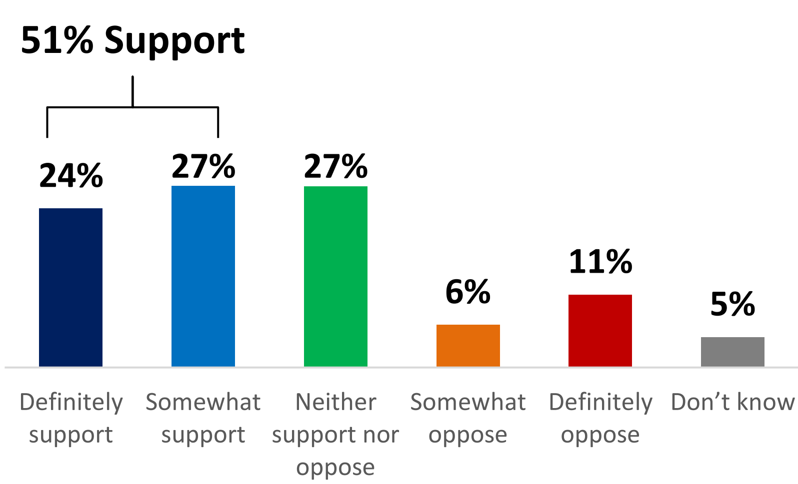
[asked of all respondents]

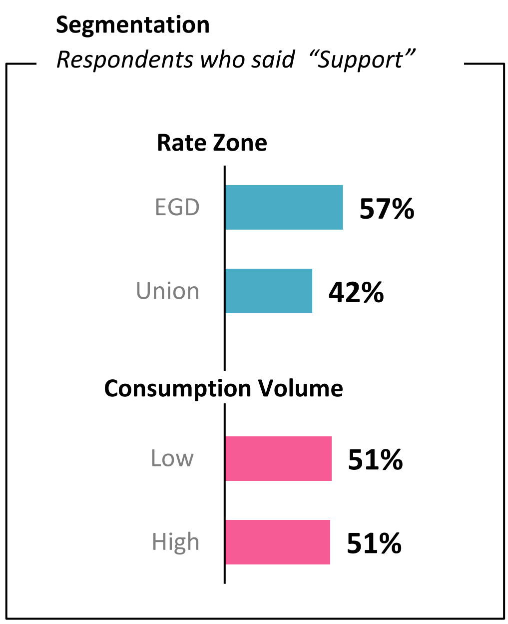
Small (n=400)





Med/Large (n=118)





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Additional Comments

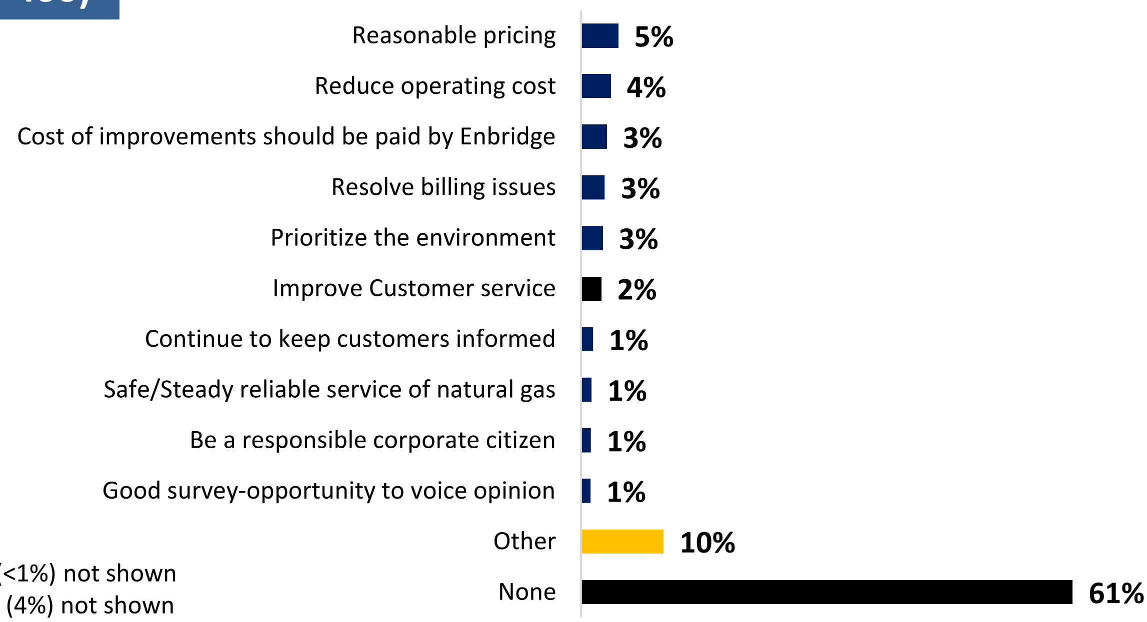
Additional Comments

Telephone and Online Surveys

Q Is there anything that you would like to share with Enbridge Gas as it works on building its investment plan for the future?

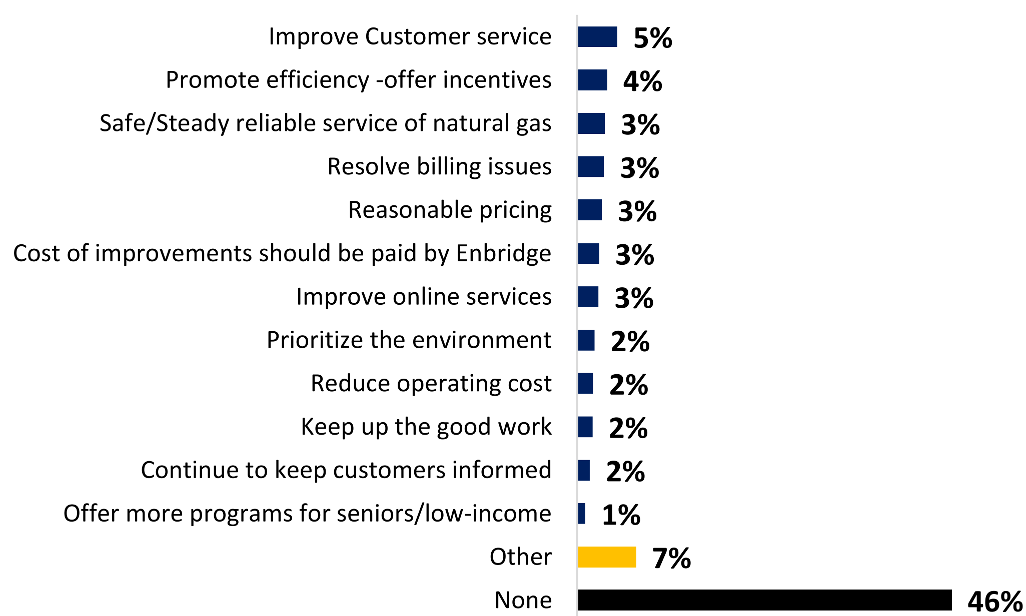
[asked of all respondents]

Small (n=400)



'Don't know' (<1%) not shown
'No response' (4%) not shown
Note: anything mentioned by fewer than 1% is included in "Other"

Med/Large (n=169)



'No response' (14%) not shown
Note: anything mentioned by fewer than 1% is included in "Other"

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Personalized research to connect you and your audiences.

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2024 Rate Rebasing Customer Engagement

ENBRIDGE

Phase Three Report :
Representative Residential Survey

January 2022

Table of Contents

Project Overview & Methodology

Enbridge Gas 2024 Rate Rebasing Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Enbridge Gas to assist in meeting its customer engagement commitments for its 2024 Rate Rebasing requirements. This engagement had three phrases:

- Phase One was an exploratory phase that used qualitative tools to identify the range of needs and outcomes that matter to customers and to explore some of the trade-offs that Enbridge Gas expected to deal with in their planning process.
- Phase Two used surveys to draw generalizable conclusions regarding the findings from Phase One.
- Following Phase Two, Enbridge Gas developed a draft plan that built on the findings of the first two phases of the customer engagement as well as other business objectives. The Phase Three survey was then designed to provide feedback on that plan that can be used by Enbridge Gas as it finalizes its plan and its submission to the Ontario Energy Board (OEB).

This report summarises the findings of the Phase Three representative online workbook-style survey with residential customers. Separate reports summarize the findings of an "openlink" version of the residential Phase Three survey, as well as surveys of business customers.

Research Objectives

There are four key objectives for the Phase Three survey:

1. To acquire feedback on key choices in the development of Enbridge Gas' business plan that involve trade-offs between customer outcomes.
2. To secure customer reaction to the potential rate impacts of the draft plan.
3. To obtain customer input on rate design choices.
4. To assess customer interest in improving Environmental, Social and Governance outcomes by pursuing responsible gas sourcing and renewable gas sourcing.

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Project Overview & Methodology

Survey Development

INNOVATIVE used a "workbook-style" survey to ensure the opinions collected on these issues were informed opinions. Through the workbook, customers were provided key background information on Enbridge Gas and its network as well as background relevant to key business planning, rate design and sourcing choices. The workbook was tested to ensure the material and questions were understandable for customers with limited knowledge of the Enbridge Gas system as well as to assess whether the workbook found the right balance between too much and too little information. Specific design features included:

- Providing both background information and an estimate of rate impact (wherever available), for capital planning choices about compression stations, vintage steel pipeline replacement, hydrogen gas, an innovation and technology fund, cutting off service at the main pipeline, cross bores, and advanced meter infrastructure.
- Comment boxes were provided for all trade-off questions.
- A review page to give respondents an option to change their responses based on the total estimated rate impact of their original choices. They could change their responses as many times as they liked.
- Additional questions touched on issues around service and rate harmonization, as well as fuel choices that would reduce GHGs and improve ESG outcomes.
- A final set of diagnostic questions allowed respondents to give feedback on the customer engagement survey itself, including overall favourability, amount of information provided and any missing content or questions they would still like answered.

The surveys were developed by Enbridge Gas and finalized with input from INNOVATIVE. All survey participants were sent an invitation from Enbridge Gas containing a unique survey URL.

All data was collected between December 6th, 2021 and January 7th, 2022. Details on sample design and weighting can be found on slide 6.

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Sample Design

Sample Design

Sample Design and Weighting

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 226 of 550

Sample Design

The representative residential survey sample was stratified based on known variables, including region and consumption. The target completes for each sample strata are shown below.

Consumption Quartile	Target Completes					
	EGD Region		Union Region			
	GTA	Other	South/ West	Central	North/ East	Total
Low	413	376	202	231	115	1338
Med Low	459	295	196	251	128	1330
Med High	582	241	158	243	128	1352
High	709	191	131	228	121	1381
Total	**2164**	**1104**	**687**	**953**	**493**	**5400**

Weighting the Data

The final data for the representative residential survey were then weighted to be proportionate based on the actual distribution of residential customers in each region, as well as by consumption quartile. *Weighted and unweighted sample sizes are outlined below. Minimal weighting was required to arrive at a representative sample.*

Consumption Quartile	Unweighted N						Weighted N					
	EGD Region		Union Region				EGD Region		Union Region			
	GTA	Other	South/ West	Central	North/ East	Total	GTA	Other	South/ West	Central	North/ East	Total
Low	579	658	329	402	178	2146	413	376	202	231	115	1338
Med Low	514	477	293	374	192	1850	459	295	196	251	128	1330
Med High	589	364	180	231	168	1532	582	241	158	243	128	1352
High	544	198	133	222	152	1249	709	191	131	228	121	1381
Total	**2226**	**1697**	**935**	**1229**	**690**	**6777**	**2164**	**1104**	**687**	**953**	**493**	**5400**

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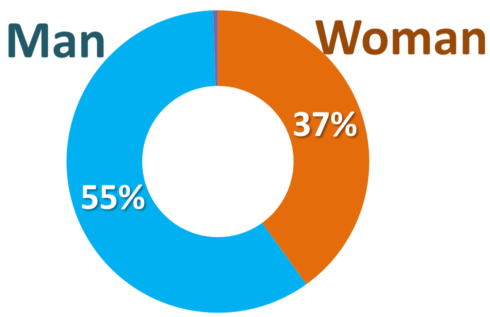
Online Workbook Results

Respondent Profile

Online Workbook

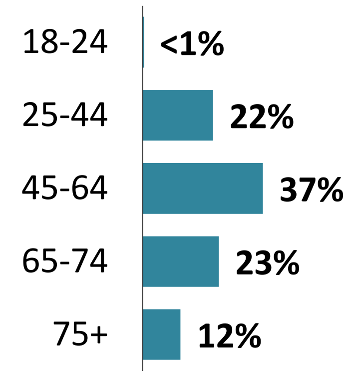
Demographic breakdown

Gender



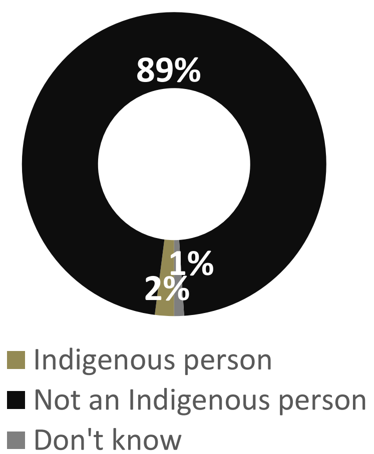
<1% 'Prefer to self-describe'

Age



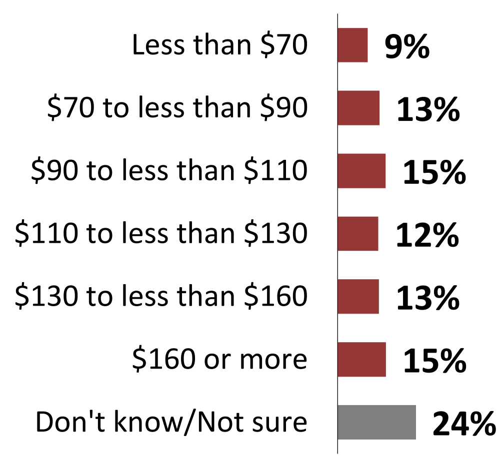
Prefer not to answer: 6%

Indigenous Identity

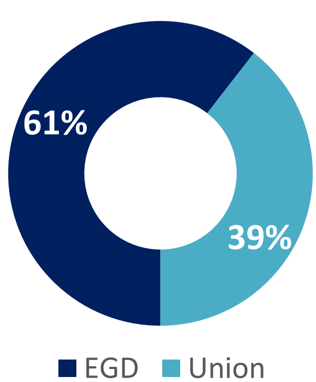


Prefer not to answer: 9%

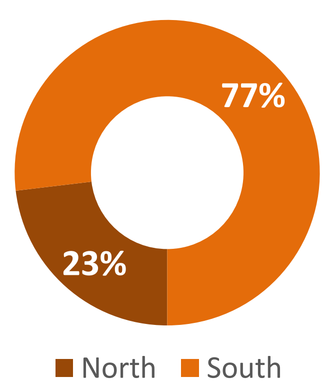
Total Enbridge Gas Bill



Rate Zone



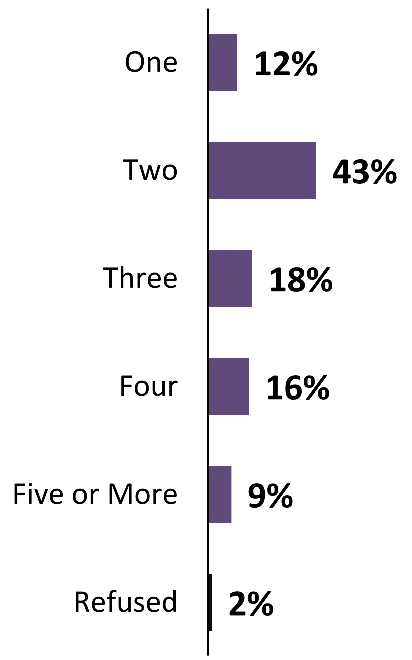
Union Region



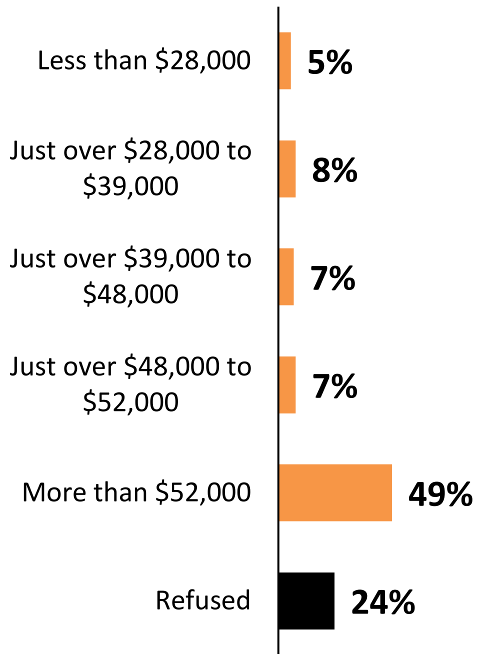
Online Workbook

Demographic breakdown

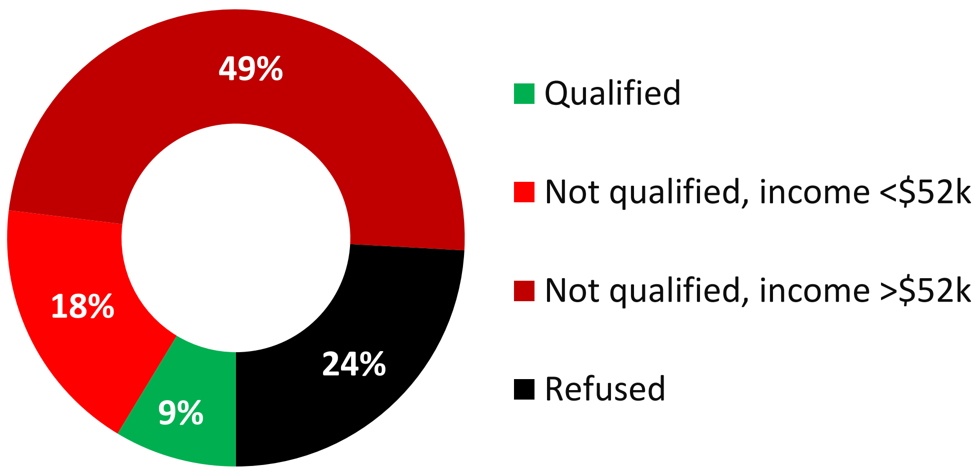
Household Size



After Tax Household Income



LEAP Qualification*



* **Note:** Calculated based on household size and household income

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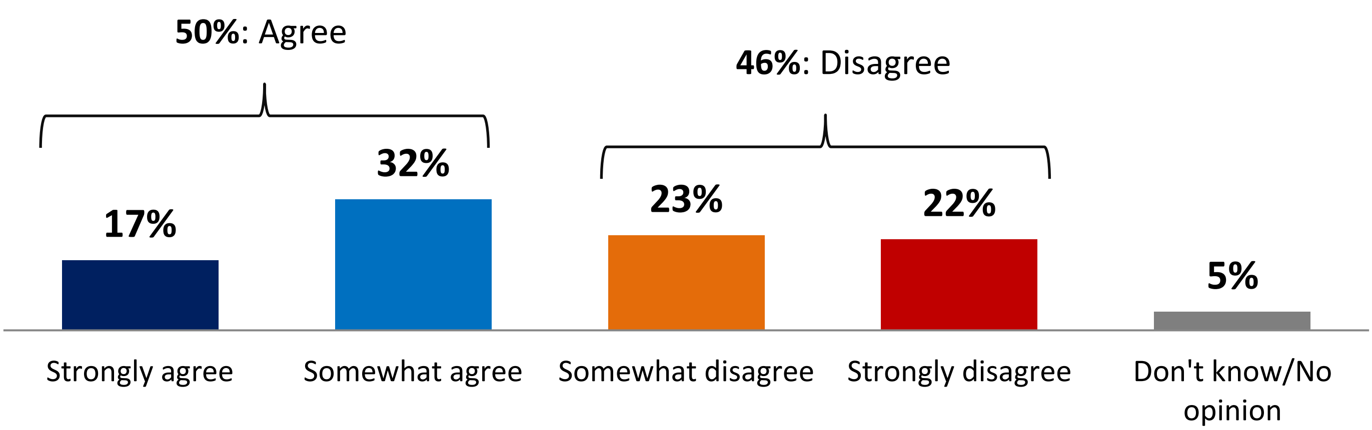
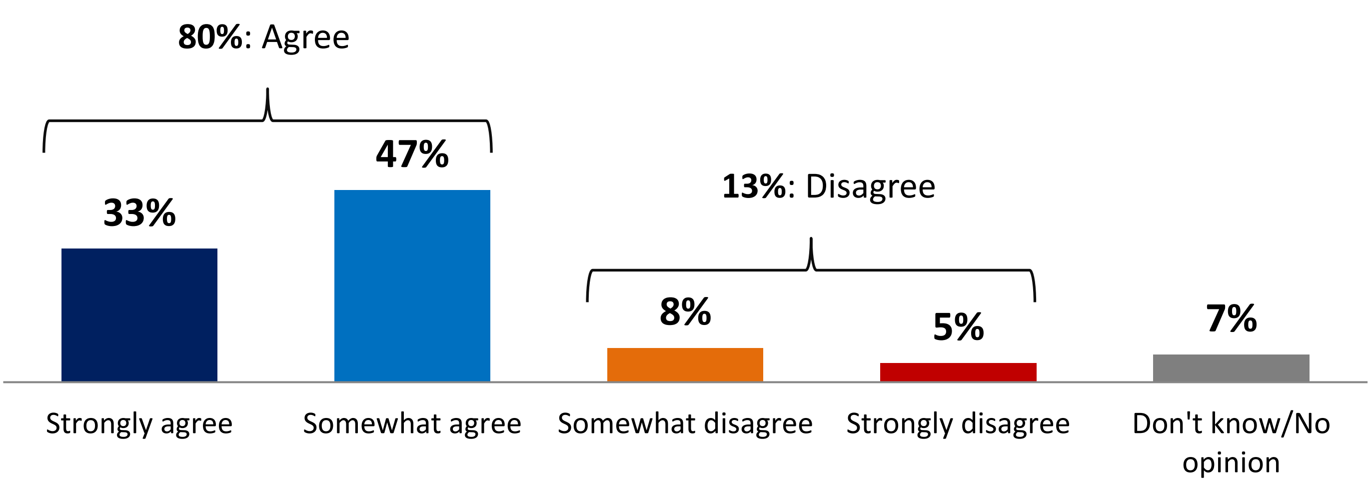
Online Workbook

Environmental Controls

Q To what extent do you agree or disagree with the following statements?
The cost of my Enbridge Gas bill has a major impact on my finances and requires I do without some other important priorities.
[asked of all respondents; n=5,400]



Q To what extent do you agree or disagree with the following statements?
Customers are well served by the energy system in Ontario.
[asked of all respondents; n= 5,400]



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Online Workbook Results

Background

A note about this report: In order to accurately represent the survey as it was viewed by respondents, we have included all of the background information that was provided to respondents before they were asked specific questions. Throughout this report, pages with grey headers show actual workbook pages as they were shown to online survey respondents. Slides with dark blue headers show the responses to the survey questions.

About this Customer Engagement

Welcome to the Enbridge Gas Customer Engagement!

As Enbridge Gas plans for the future, it needs your input into choices that will impact the services you receive and the rates you pay.

- Enbridge Gas is looking for your feedback on its draft investment plan for 2024 and beyond to ensure that the plan reflects your needs and preferences.
- You don't need to be a natural gas expert to complete this workbook. It focuses on basic choices between outcomes that matter to you and provides the background information you need to answer the questions.
- The most important part of this workbook are the survey questions. While your view may not always align exactly with any of the options presented, please select the one that is closest. If you truly aren't sure, select the "don't know" option.

This workbook will take approximately 20-30 minutes to complete. Your progress will be saved as you move through the workbook, meaning you can leave and return to complete it at any time.

Those who complete the questions that follow will be invited to enter a draw to win one of four $250 cash prizes.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback.

If you are reading this on a smaller mobile device, you may wish to access the survey from a tablet, desktop or laptop instead, so that it is easier to read.

Background

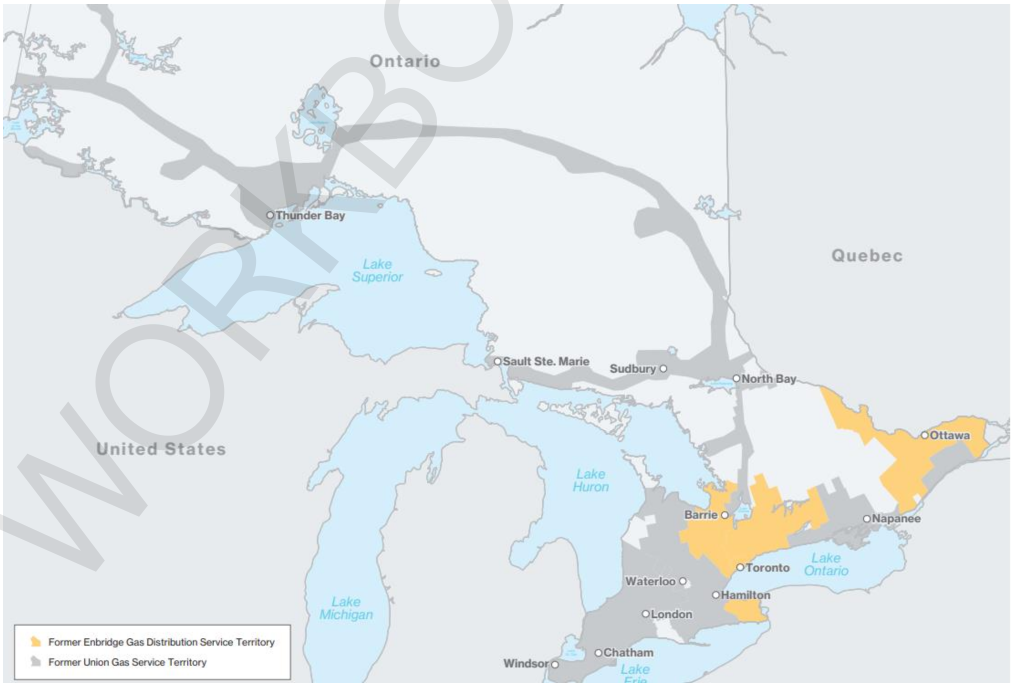
Who is Enbridge Gas?

Enbridge Gas Inc. is based in Ontario and delivers energy to customers in Ontario. Its parent company Enbridge Inc. is headquartered in Calgary, Canada, and operates across North America. Rates and business plans developed by Enbridge Gas must be approved by the Ontario Energy Board (the OEB), which regulates natural gas utilities in Ontario.

Enbridge Gas …

- ✓ Distributes natural gas to about 3.8 million residential, business and industrial customers
- ✓ Attaches more than 50,000 new customers each year
- ✓ Has agreements to provide gas distribution service within 313 municipalities and provides natural gas within 23 First Nations communities
- ✓ Has a network of over 151,500 kilometers of underground pipeline

In 2019, Enbridge Gas Distribution and Union Gas merged to form one company, Enbridge Gas Inc. Throughout this workbook we occasionally refer to Legacy Enbridge Gas Distribution and Legacy Union Gas (the previous companies), but mainly refer to the whole service area or territory that Enbridge Gas serves today.

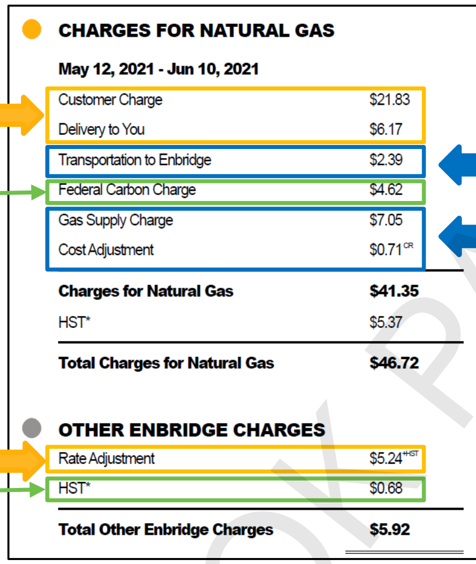


Background

Where do your rates go?

Below is an example of a residential natural gas bill.

The charges outlined in Orange are the costs of getting the gas to you once it reaches the Enbridge Gas system. At times, this may require a Rate Adjustment which, along with other rates, is determined through a regulatory process.



CHARGES FOR NATURAL GAS

May 12, 2021 - Jun 10, 2021

Customer Charge	$21.83
Delivery to You	$6.17
Transportation to Enbridge	$2.39
Federal Carbon Charge	$4.62
Gas Supply Charge	$7.05
Cost Adjustment	$0.71 CR
Charges for Natural Gas	**$41.35**
HST*	$5.37
Total Charges for Natural Gas	**$46.72**

OTHER ENBRIDGE CHARGES

Rate Adjustment	$5.24 +HST
HST*	$0.68
Total Other Enbridge Charges	**$5.92**

The charges outlined in Blue are the 'passed through' costs that pay for the natural gas you use (Gas Supply Charge and Cost Adjustment) and the cost of transporting it from where it is produced to the Enbridge Gas system (Transportation to Enbridge). If customers buy their natural gas through an energy marketer these costs would be subject to the agreement with the energy marketer.

Enbridge Gas is also responsible for collecting HST and the Federal Carbon Charge on behalf of the government. While some of these costs may be given back to customers in rebates, how these funds are used is determined by the government and is out of Enbridge Gas' control.

The average residential customer consumes approximately 2,400m3 of natural gas per year.

The pie chart below shows where the money goes.

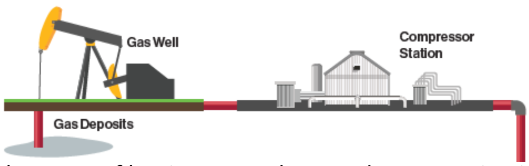
The Blue slice shows the 'passed through' costs that pay for the natural gas and transportation to the Enbridge Gas system.

The money that goes to Enbridge Gas is in the other two slices.

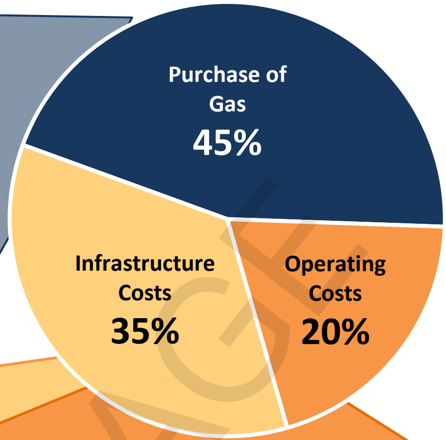
- The Light Orange slice pays the capital costs of the infrastructure (such as pipes, compressors, buildings and other equipment) used to move and store natural gas across the system.
- The Dark Orange slice pays for operations – including the people who operate and maintain the equipment and the people who answer your calls and provide customer service.

[**NOTE:** survey respondents were able to scroll down directly to the information on the following page]

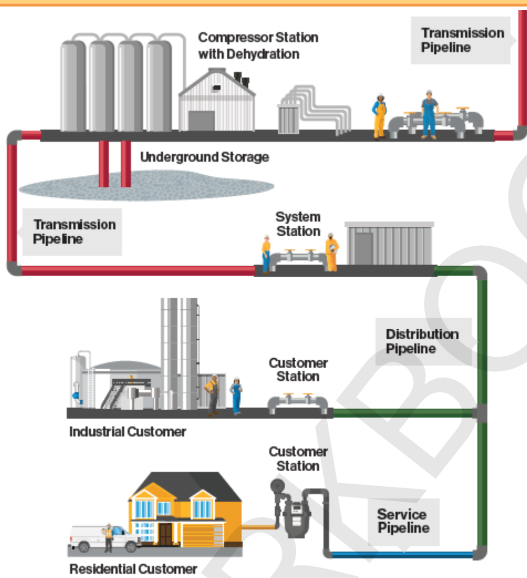
Purchase of Gas



The costs of buying natural gas and transporting it to Ontario are overseen by the Ontario Energy Board, and are passed on to customers at cost.



Infrastructure



Once gas reaches the Enbridge Gas system, it is metered and then delivered to customers through a distribution system of local gas mains, small-diameter service lines and, ultimately, customer meters.

Natural gas is often stored in large underground reservoirs to help meet spikes in demand, particularly in winter.

Operations

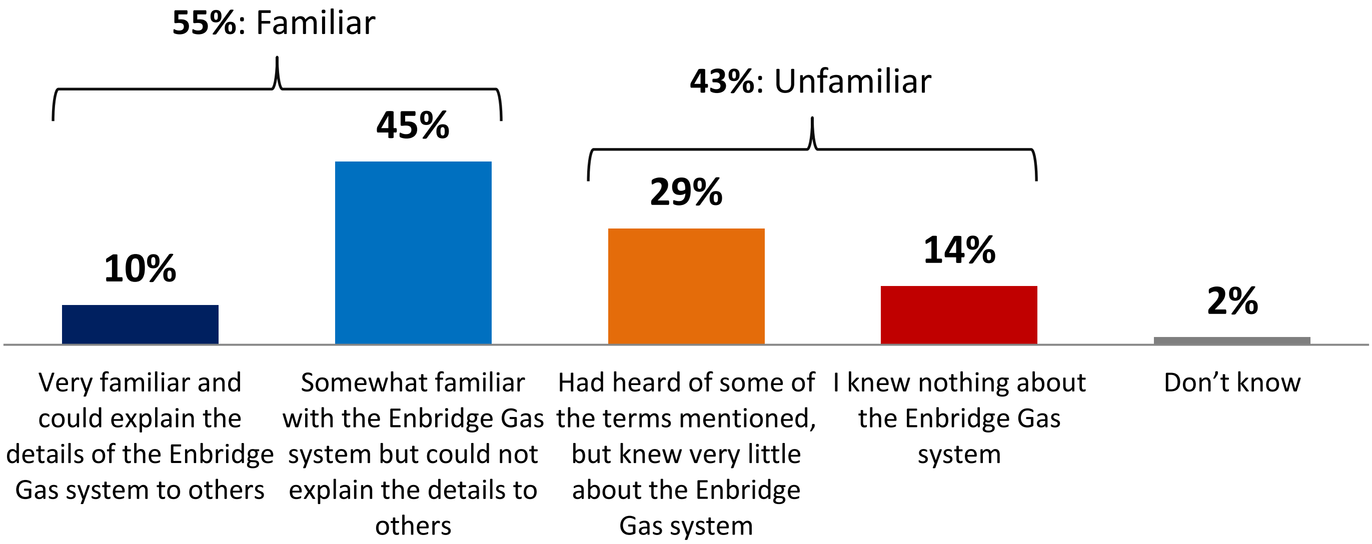
Delivering gas to customers is just one part of Enbridge Gas' activities. Enbridge Gas provides a variety of supporting services to customers including:

- Manage and operate its call centres, ombudsperson offices, and its online My Account system to help customers manage their account online.
- Complete meter replacements, inspections, and respond to emergency calls.
- Conduct millions of meter readings each year.
- Offer programs to help customers reduce their natural gas usage. Since 1995, Enbridge Gas has saved its customers 30 billion lifetime cubic meters of natural gas and 56.2 million tonnes of greenhouse gas emissions, the equivalent of taking 12.2 million cars off the road for a year or heating 13.1 million natural gas homes for a year. These programs get approved by the Ontario Energy Board in a separate process and the costs for these programs are included in your rates.

Background

Familiarity with Enbridge Gas

Q Before this survey, how familiar were you with Enbridge Gas when it comes to delivering natural gas to homes and businesses in Ontario?
[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Very familiar	10%	11%	8%	7%	8%	9%	9%	10%	11%	12%	9%	10%
Somewhat familiar	45%	46%	44%	43%	44%	44%	45%	46%	46%	32%	44%	49%
Had heard of some terms mentioned	29%	28%	29%	31%	29%	29%	30%	28%	28%	30%	29%	28%
I knew nothing about the Enbridge Gas system	14%	13%	17%	18%	17%	17%	14%	14%	12%	21%	17%	12%
Don't know	2%	2%	2%	1%	2%	2%	2%	1%	2%	5%	1%	1%
Familiar (Very + Somewhat)	**55%**	**57%**	**52%**	**50%**	**52%**	**52%**	**54%**	**56%**	**57%**	**44%**	**54%**	**59%**
Unfamiliar (Had heard + I knew nothing)	43%	41%	47%	49%	46%	46%	44%	42%	41%	51%	45%	40%

Where does this consultation fit?

Here in Ontario, customer views are central to the utility planning process.

- **Rates and business plans must be approved by the Ontario Energy Board (the OEB).**
- **The OEB requires that utilities consult with customers to understand your views on key trade-offs.**
- **In addition, the utilities must show how they took customer views into account when developing the plan.**

While some planning decisions will depend on detailed knowledge of engineering and industry standards, in other cases the choices will involve trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down. That is where you come in.

The diagram below shows how customers play a role at three points as Enbridge Gas develops and submits its business plan to the OEB.

How does Customer Engagement Impact Business Planning?

Enbridge Gas has developed a phased approach to gathering and responding to customer feedback.

✓ **1. Identify Customer Priorities**
In June through August of 2021, Enbridge Gas asked residential and business customers about their priorities for natural gas service.

✓ **2. Use Customer Feedback to Guide Development of Plan**
Enbridge Gas planners were given summaries of the key findings from the initial customer engagement to consider as they began building their plans.

You are here

3. Collect Customer Feedback on the Draft Plan
Now Enbridge Gas is returning to customers to get feedback on the draft plan and ask customers how the plan fits with their needs and preferences.

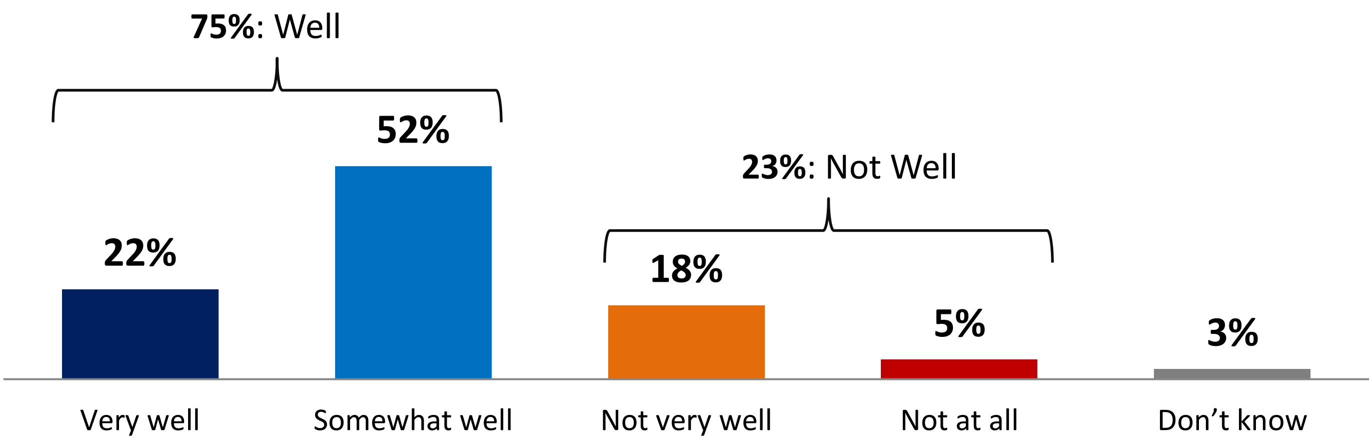
4. Re-Examine Plan
Enbridge Gas has an opportunity to make appropriate changes to the plan based on customer feedback.

5. Submit the Plan to the Ontario Energy Board (OEB)
Enbridge Gas will file the plan, with this workbook, and a summary report with the OEB, where it will be examined by the OEB, consumer advocates and other independent parties in a public hearing. **Customers** can view and comment on this application through the OEB website.

Background

Understanding the Planning Process

Q How well do you feel you understand how your feedback fits within the planning process?
[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Very well	22%	24%	20%	18%	21%	21%	21%	22%	25%	17%	17%	26%
Somewhat well	52%	51%	55%	57%	55%	53%	53%	52%	51%	49%	55%	54%
Not very well	18%	18%	18%	18%	18%	20%	18%	18%	17%	21%	21%	15%
Not at all	5%	5%	4%	4%	4%	4%	5%	5%	5%	7%	4%	4%
Don't know	3%	2%	3%	3%	3%	2%	3%	2%	2%	5%	2%	1%
Well (Very + Somewhat)	**75%**	**74%**	**75%**	**75%**	**75%**	**74%**	**74%**	**75%**	**75%**	**67%**	**72%**	**80%**
Not Well (Not very + Not at all)	23%	23%	22%	22%	22%	23%	23%	23%	22%	28%	26%	19%

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Online Workbook Results

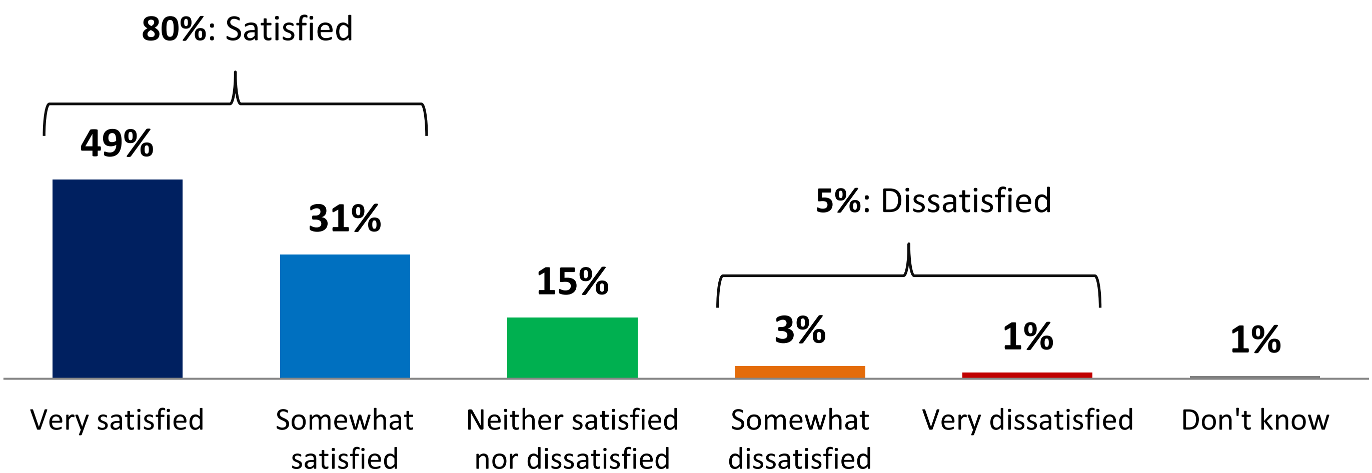
Customer Experience

Customer Experience

Satisfaction with Enbridge Gas Service

Q Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

[asked of all respondents; n=5,400]



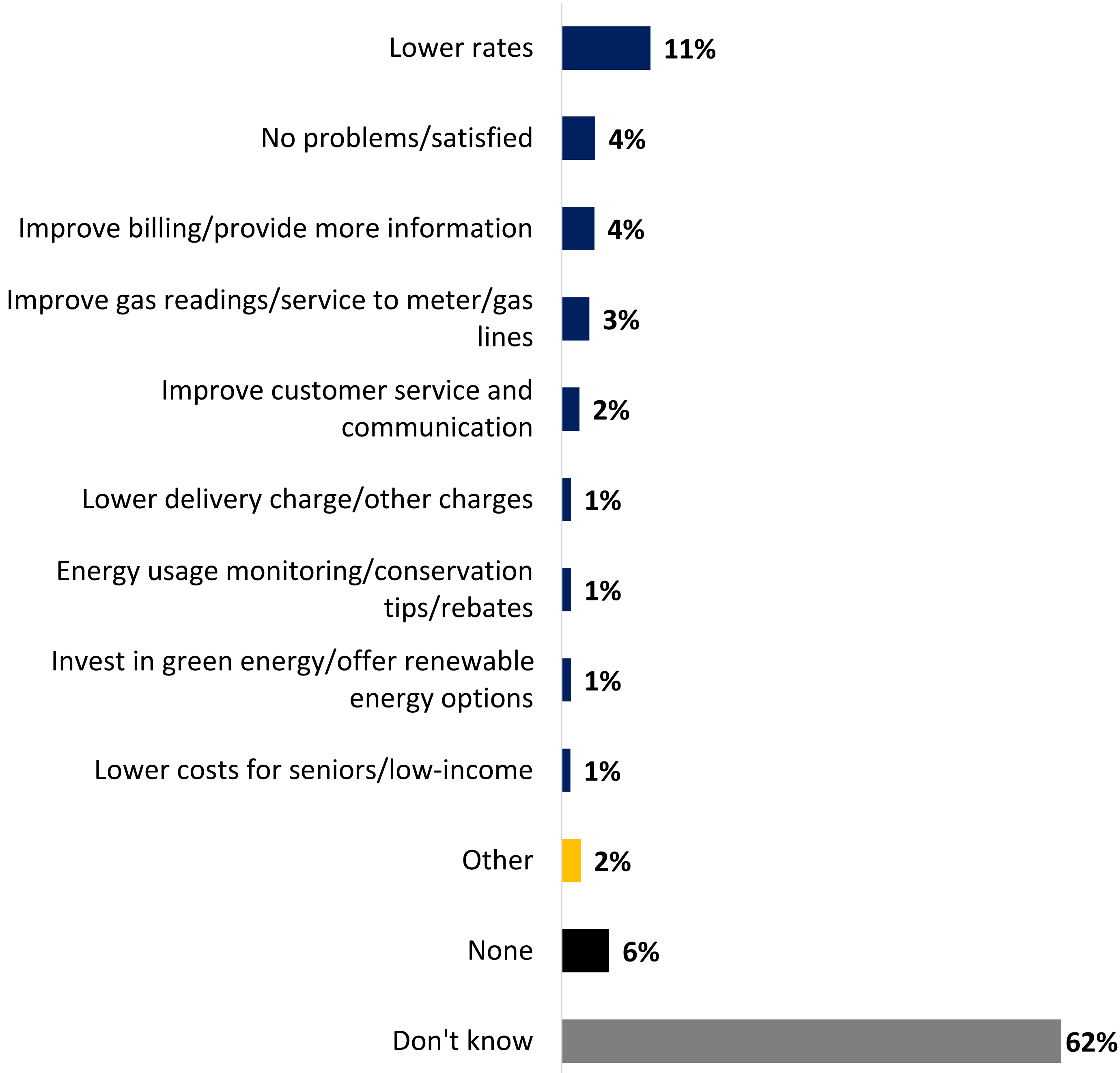
		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Very satisfied	49%	47%	52%	52%	52%	48%	49%	50%	49%	42%	50%	52%
Somewhat satisfied	31%	32%	29%	30%	29%	31%	32%	30%	29%	30%	32%	30%
Neither	15%	16%	14%	12%	15%	15%	14%	14%	17%	16%	13%	14%
Somewhat dissatisfied	3%	4%	2%	3%	2%	3%	3%	3%	4%	6%	3%	3%
Very dissatisfied	1%	1%	1%	2%	1%	2%	1%	1%	2%	4%	1%	1%
Don't know	1%	1%	1%	1%	1%	1%	1%	1%	0%	2%	0%	1%
Satisfied (Very + Somewhat)	**80%**	**79%**	**81%**	**82%**	**81%**	**80%**	**81%**	**80%**	**78%**	**73%**	**83%**	**82%**
Dissatisfied (Very + Somewhat)	5%	5%	4%	5%	4%	5%	4%	4%	5%	9%	4%	4%

Customer Experience

Improving Enbridge Gas Service

Q Is there anything in particular Enbridge Gas can do to improve their service to you? [OPEN]

[asked of all respondents; n=5,400]



Note: Refused (<1%) not shown

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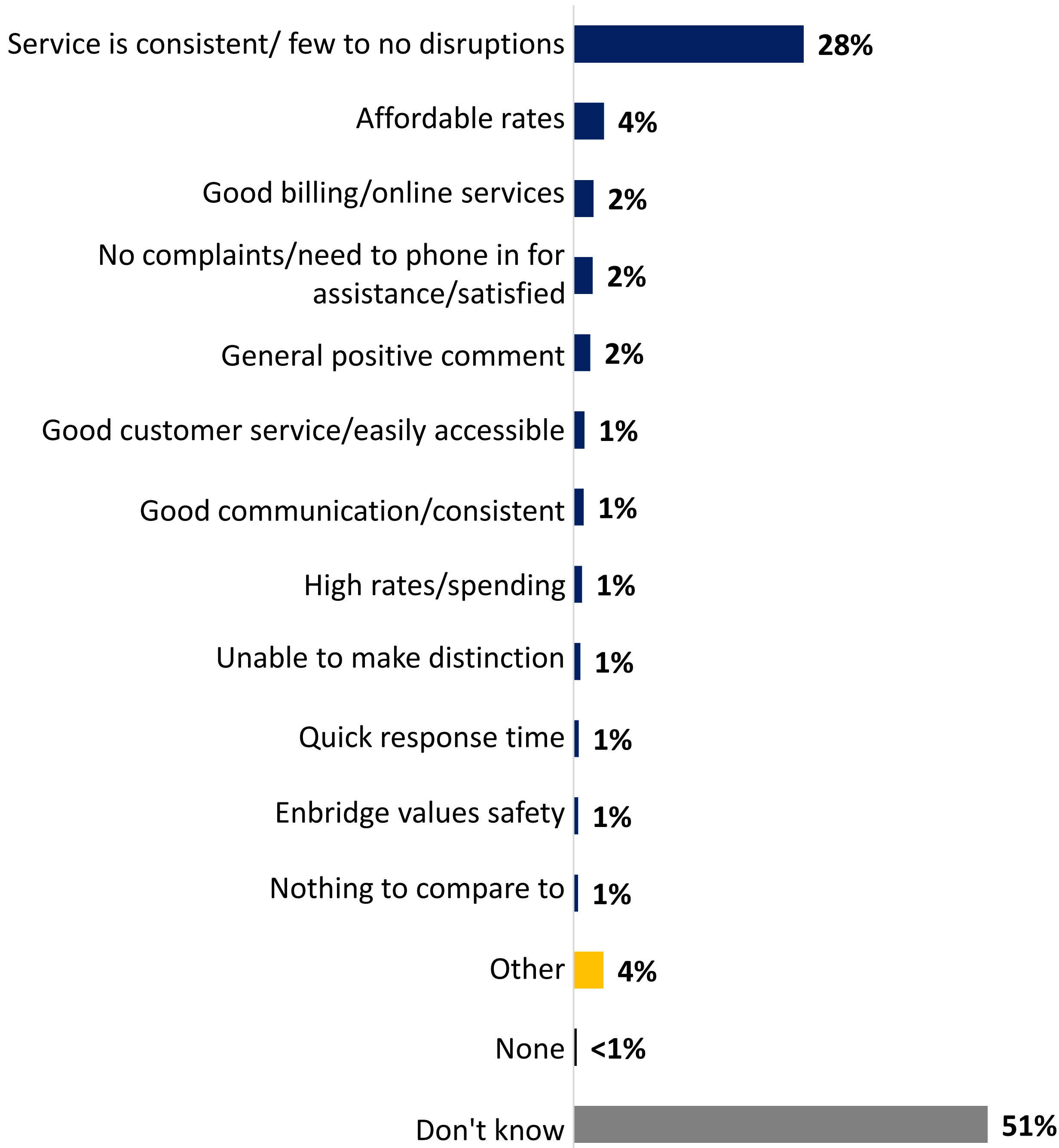
Customer Experience

Is Enbridge Gas Doing A Good Job?

Q How do you know if Enbridge Gas is doing a good job for you, or not? [OPEN]
[asked of all respondents; n=5,400]



Note: Refused (<1%) not shown

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Online Workbook Results

Business Plan Objectives and Calculating Rates

Background

2024-2028 Plan

Plan Objectives

The Enbridge Gas business plan focuses on many of the same objectives as in the past years, as well as future challenges and pressures. Some of the high-level objectives of the plan are as follows:

1. **Maintain system safety and reliability** – ensure that the system continues to operate safely and reliably.
2. **Contain costs** – the OEB requires all utilities to "demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives".
3. **Harmonize rates and services** – ensure that the offerings are consistent across the entire service area as Enbridge Gas continues its merger activities.
4. **Prepare for the future** – ensure that the system is ready for low-carbon options, as well as offer options to help customers reduce their greenhouse gas (GHG) emissions.

Climate Change Goals

Compared to the past, Enbridge Gas' 2024-2028 plan places more emphasis on preparing for the future. Enbridge Gas is looking at ways in which it can support its organizational, as well as federal and provincial goals to reduce GHG emissions and achieve net zero targets.

- **Enbridge Inc. targets to reduce, from its operations, GHG emission intensity by 35% by 2030 over 2018 levels, and to reach Net Zero GHG emissions by 2050**
- **Federal targets to reduce GHG emissions by 40-45% by 2030 over 2005 levels and to reach Net Zero GHG emissions by 2050**
- **Provincial target to reduce GHG emissions by 30% by 2030 over 2005 levels**

How We Can Reduce GHG Emissions From Natural Gas

One of the ways in which GHG emissions are created is through the burning of fossil fuels such as coal, oil, and natural gas. Two key approaches can reduce the emissions from using natural gas:

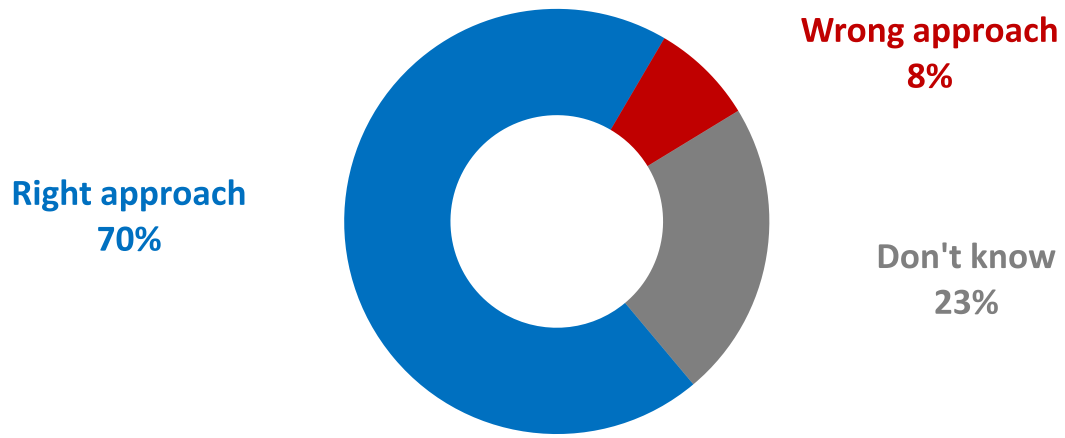
- by blending lower carbon fuels into the gas supply, including Renewable Natural Gas (RNG) and Hydrogen gas, and
- by improving energy efficiency of homes and businesses, and implementing new, lower-emitting technologies.

Each of these could introduce new, higher, costs that would be passed on to customers but would mitigate costs that might be required to introduce other programs or options to reduce overall GHG emissions in Ontario and Canada. **Later in the workbook we will ask about your views on these potential costs.**

Background

Right or Wrong Approach

Q Do these objectives seem like the right approach or the wrong approach?
[asked of all respondents; n=5,400]



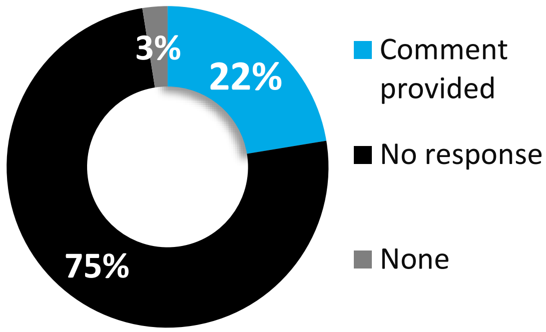
	Total	Rate Zone: EGD	Rate Zone: Union	Union Region: North	Union Region: South	Consumption: Low	Consumption: Med-low	Consumption: Med-high	Consumption: High	LEAP Qualification: Yes	LEAP Qualification: No <$52K	LEAP Qualification: No >$52K
Right approach	70%	69%	71%	71%	71%	71%	69%	68%	70%	57%	71%	77%
Wrong approach	8%	8%	7%	6%	7%	8%	8%	8%	8%	9%	6%	8%
Don’t know	23%	23%	22%	23%	22%	22%	23%	24%	22%	34%	24%	16%

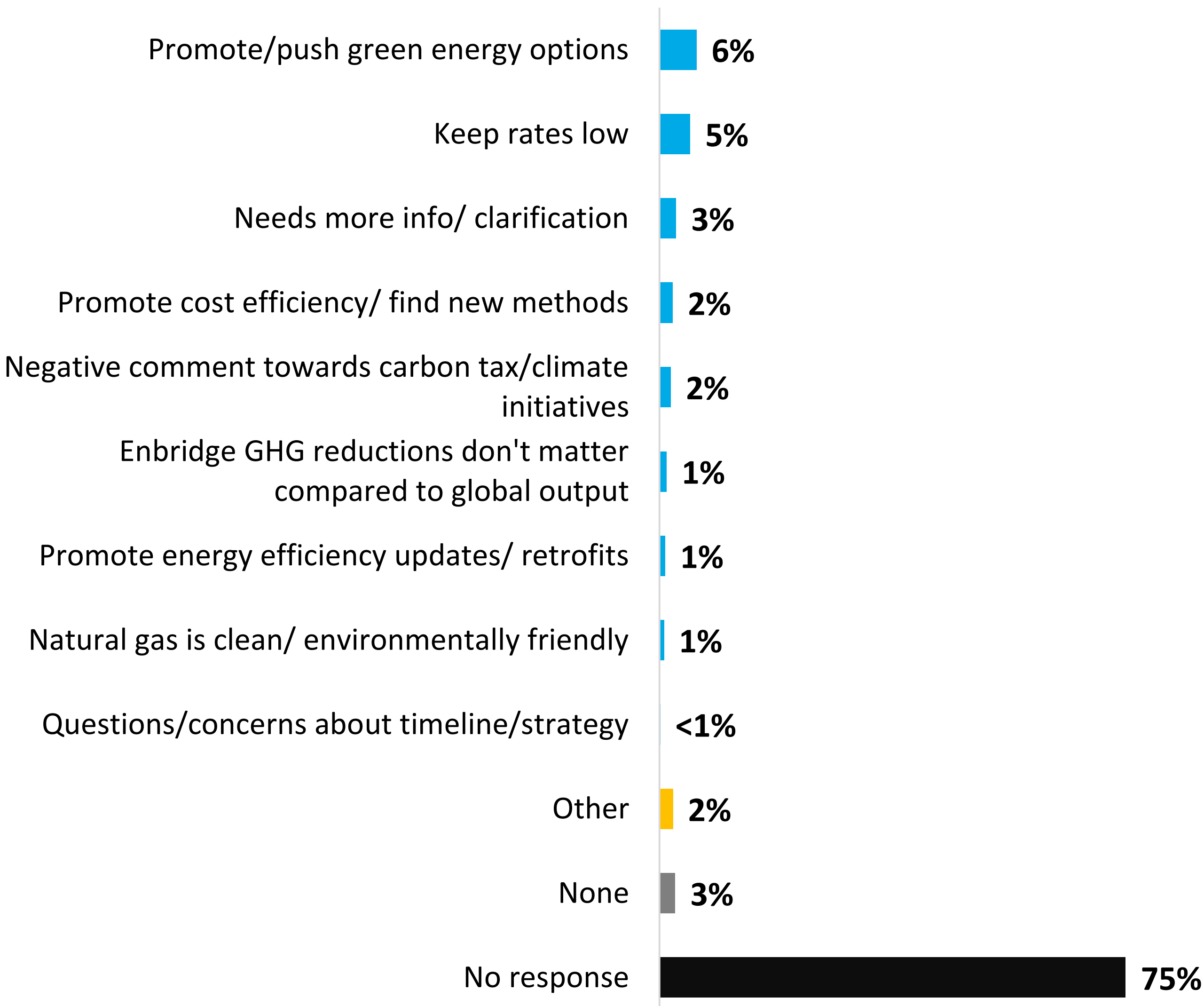
Background

Right or Wrong Approach - Additional Comments

Q Is there anything you would change about this approach or any other comments you would like to make?

[asked of all respondents; n=5,400]





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Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 247 of 550

Calculating Rates

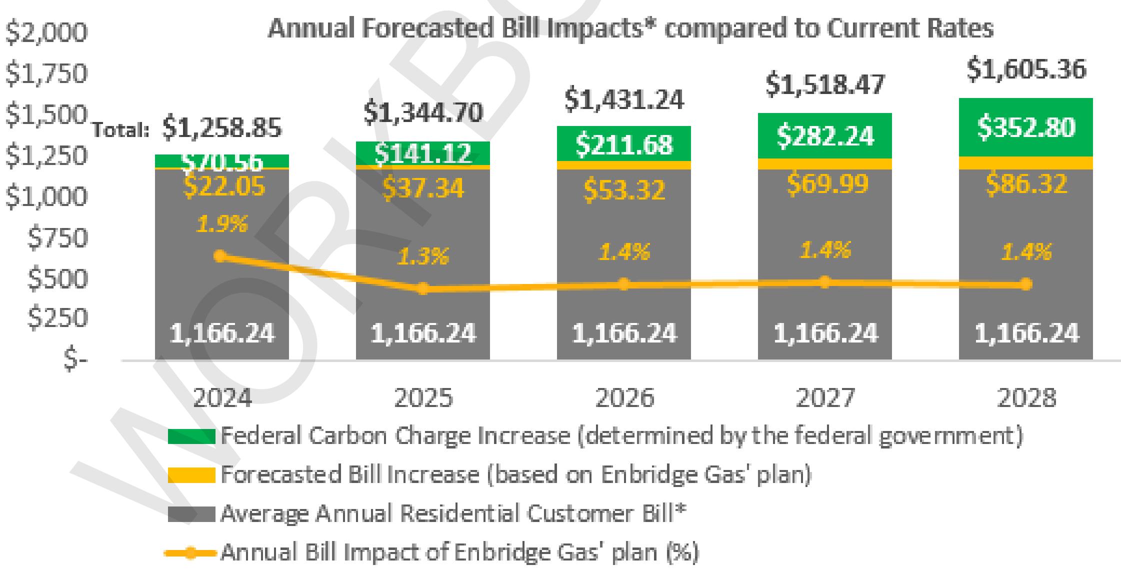
When looking at its overall objectives, and its budgets, there are many items that Enbridge Gas must consider that affect its costs, and in turn the rates that customers pay. Some of these items are determined by regulatory requirements, others by external factors in the market, and again others by decisions made by Enbridge Gas.

There are **accounting policies and factors** that affect expenditures. These include proposals through which Enbridge Gas manages business risk and how it calculates the depreciation of its assets. These types of proposals contribute significantly to the overall rate impact shown in the "Forecasted Bill Increase" below, and are partially offset by savings in other areas. While these issues are too technical for this workbook, they will be reviewed by OEB experts and intervening stakeholders in the OEB's public review process.

Operating expenses make up about 20% of Enbridge Gas' overall expenditures. Current estimates show that these expenses would increase somewhat over the 2024-2028 period, with the highest annual increase at 1.5%, which is less than inflation. Decisions on operating expenses are based on industry best practices and generally do not involve trade-offs between customer outcomes. Since these are technical issues, they will also be reviewed by OEB experts and intervening stakeholders in the OEB's public review process.

Capital expenses make up about 35% of Enbridge Gas' overall expenditures and pay for investments in its equipment that have lasting benefits over many years. Since capital spending includes major one-off projects as well as ongoing maintenance and replacement, capital spending varies from year to year. The questions in the next section focus on these choices.

The *Forecasted Bill Impacts* for the 2024 to 2028 compared to current rates are shown below. Compared to your current rates, rates in 2022 are expected to increase by $8.98 or 0.8% for the average customer, while 2023 rates are not yet established.



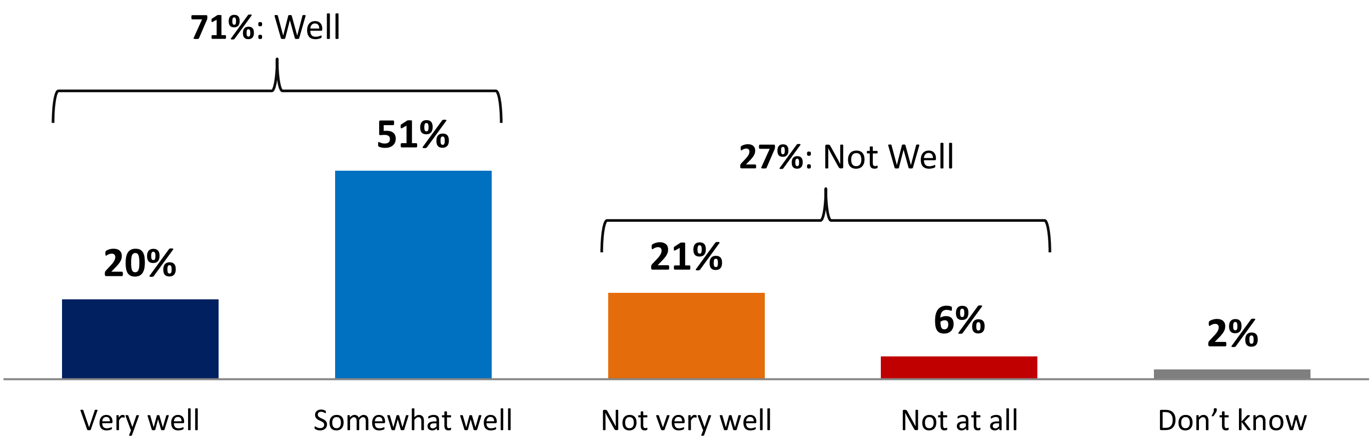
**These estimates are preliminary and are subject to both your feedback and ongoing work to review as Enbridge Gas planners continue to work on their plans. This does not include any potential changes in the fuel costs or the federal carbon charge.*
Based on the average customer consuming 2,400 m3 of natural gas per year. Oct 2021 average includes the federal carbon charge.

Calculating Rates

Understanding the Projected Increase

Q How well do you feel you understand the projected increase in your rates from 2024 to 2028?

[asked of all respondents; n=5,400]



	Total	Rate Zone		Union Region		Consumption				LEAP Qualification		
		EGD	Union	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Very well	20%	19%	20%	18%	21%	18%	18%	21%	21%	15%	15%	24%
Somewhat well	51%	50%	54%	54%	54%	53%	53%	49%	49%	41%	52%	54%
Not very well	21%	22%	20%	21%	19%	21%	20%	21%	23%	27%	26%	17%
Not at all	6%	7%	4%	5%	4%	5%	6%	7%	5%	11%	6%	4%
Don't know	2%	2%	2%	3%	2%	2%	2%	2%	2%	6%	2%	1%
Well (Very + Somewhat)	**71%**	**69%**	**74%**	**71%**	**75%**	**71%**	**72%**	**70%**	**70%**	**56%**	**66%**	**78%**
Not Well (Not very + Not at all)	27%	29%	24%	26%	23%	26%	26%	28%	27%	38%	32%	21%

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Online Workbook Results

Making Choices

Making Choices

In this next section of the workbook, we will ask you about some of the key items that Enbridge Gas is considering in its plan that see trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down.

Some of these items are currently included in the draft budget, while others will need to be added to the budget depending on further analysis and feedback from customers like you.

For each question, where applicable, the financial impact is expressed as the dollar impact each year on an average residential bill. The actual impact will depend on your own individual usage.

At the end of the section, you will have an opportunity to review your responses and their impact on your bill. You will then be able to adjust your choices to provide what you feel is the best balance

Compression Stations

Enbridge Gas has 50 Compressors, 7 Dehydrators and supporting equipment. These are required to ensure that the gas that is injected into storage or into the distribution system meets the quality specifications and to move gas along the transmission system.

As compressors age, they experience breakdowns on an increasingly frequent basis – when equipment manufacturers stop supporting these compressors, the time to complete repairs can be extensive leading to reliability and gas quality problems. There are two compressors that will need to be replaced in the coming years.

When considering a project to replace compressors like this, Enbridge Gas looks at various options:

- ✓ Replacing one larger compressor with two smaller ones,
- ✓ Using alternative fuel sources such as electricity or hydrogen gas, and
- ✓ Preparing for outages by having spare parts available.

In this case, however, there is a lack of viable alternatives at the specific locations for the two compressor stations, so Enbridge Gas is planning to replace one compressor station in 2026, with the other one being replaced after 2028 to use the existing stations for as long as possible.

Not doing this work increases the risk the station could fail. This may require Enbridge Gas to buy more gas on the market (if available), rather than drawing gas from its storage. This introduces the risk of price volatility, as gas purchased on the market during the coldest days of the year has been up to 220% more expensive in the past 5 years than the gas that could be drawn from storage.

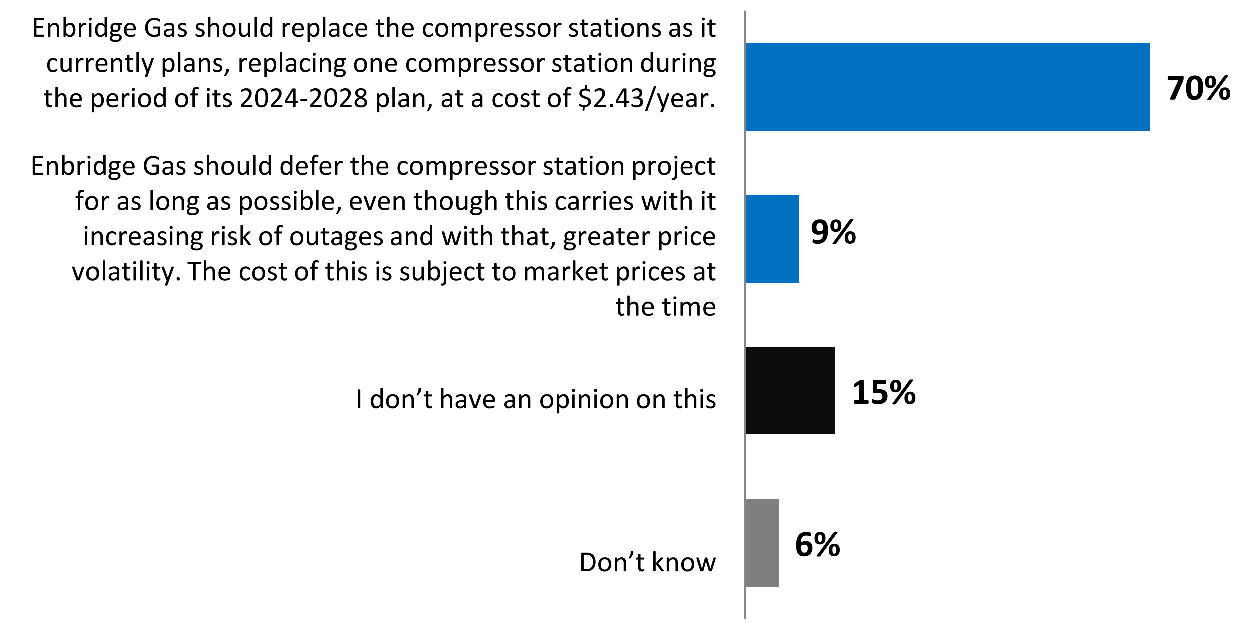
Image: inside a building housing a compressor station

Furthermore, if the station fails, replacement will still be required which would take a couple of years of construction to complete, extending the risks for longer. The replacement of the first compressor station is planned for 2026 and would cost the average customer $2.43/year.

Making Choices

Compression Station

Q Which of the following statements best represents your point of view?
[asked of all respondents; n=5,400]



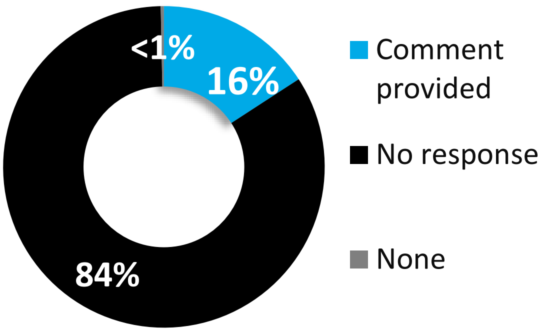
		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Replace the compressor stations	70%	67%	73%	74%	73%	70%	70%	68%	70%	48%	66%	78%
Defer the compression station project	9%	10%	8%	8%	8%	9%	9%	10%	9%	15%	11%	7%
I don’t have an opinion on this	15%	16%	14%	14%	14%	15%	15%	16%	15%	24%	18%	11%
Don’t know	6%	7%	5%	4%	5%	5%	5%	6%	6%	13%	6%	3%

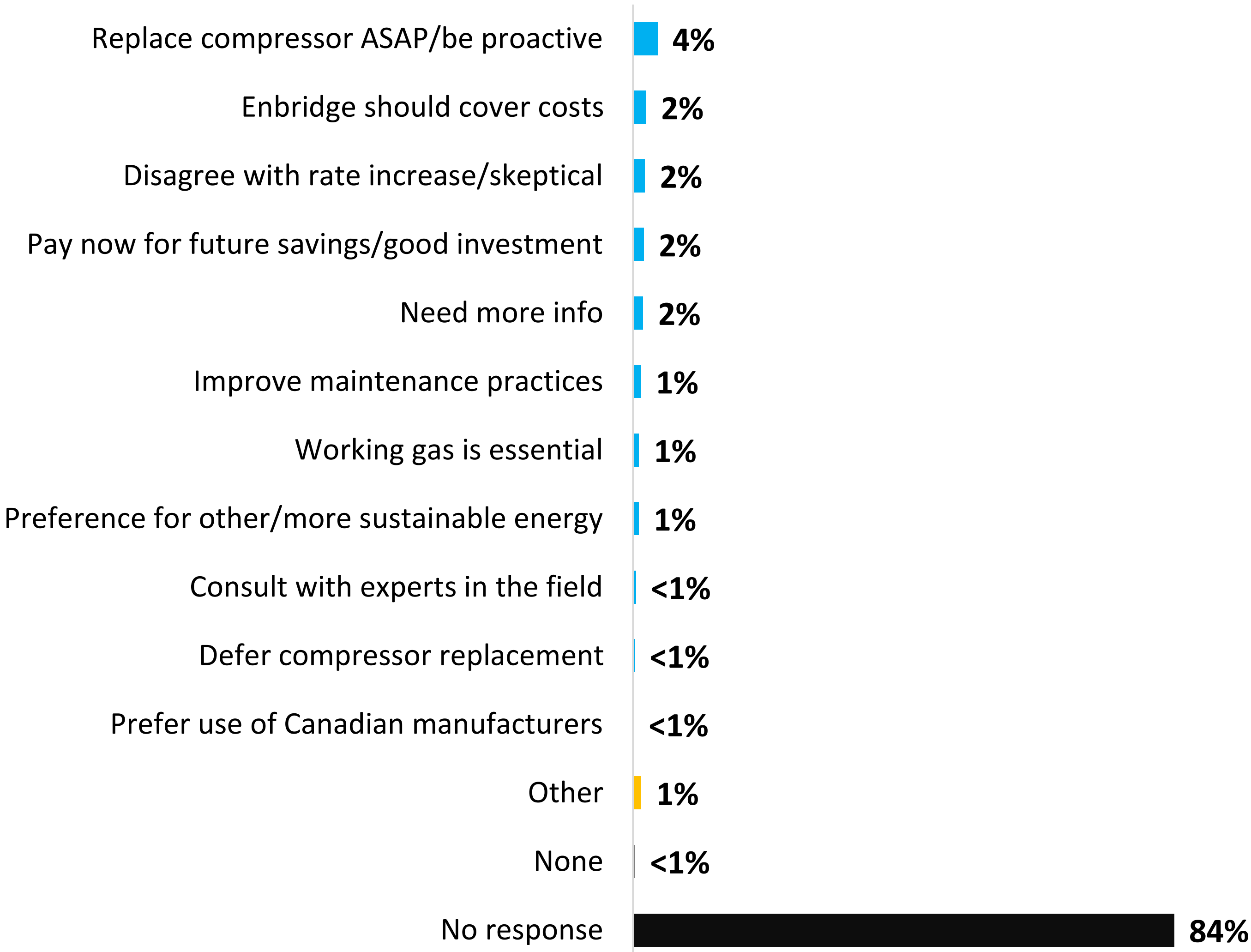
Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

Making Choices

Compression Station - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





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Making Choices

Vintage Steel Pipeline Replacement Program

Enbridge Gas has implemented a Vintage Steel Pipeline Replacement Program, which focuses on replacing older steel pipelines within the system. It is considering ramping up the program to ensure ongoing safety and reliability of the distribution system and to prepare the network for the eventual delivery of low carbon, blended hydrogen. Blended hydrogen can safely be delivered through modern steel and plastic distribution systems – however, with the rapid introduction of natural gas to Ontario during the 1950's and 60's, Enbridge Gas has a lot of older steel pipelines which are nearing end of life and require replacement in a planned and proactive manner.

This program would see an increase in work and a ramp-up of spending starting in 2024 with the goal of replacing 5,100 km of 17,000 km of vintage steel pipelines in 20 years. These vintage steel pipelines were built before 1971 and are more prone to failures compared to steel pipelines built later due to materials, construction and damage prevention practices used at the time. Using risk assessments, the program will focus on replacing pipelines that are closest to end of life first.

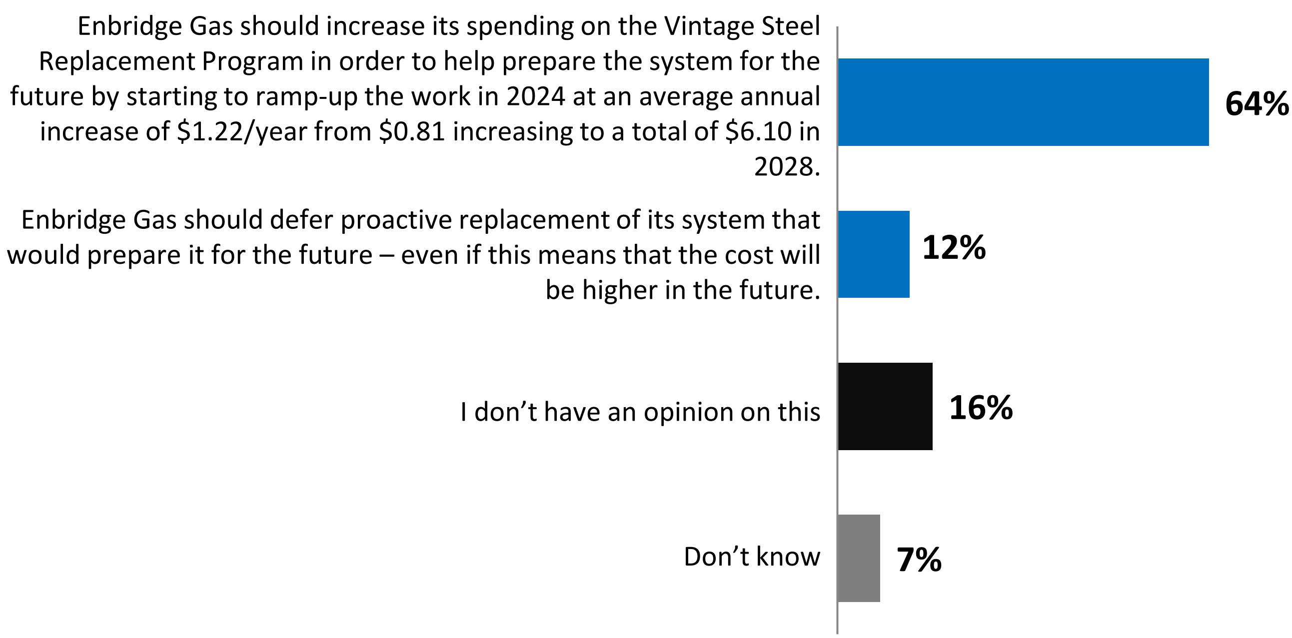
Enbridge Gas intends to start this increase in work in 2024 so that the work can be spread out over a longer period with a limited increase to internal resources. Pushing the work into the future, such as 10 years from now, to achieve the same objectives, will require additional internal as well as external resource overheads and costs, with reduced productivity due to a sharper ramp-up of skilled labour. The overall costs would be expected to be higher with a delayed approach.

It is estimated that this program, ramping up in 2024, included in the capital budget, is equivalent to an average annual increase of $1.22/year from $0.81 increasing to a total of $6.10 in 2028 for the average customer.

Making Choices

Vintage Steel Pipeline Replacement Program

Q Considering this, which of the following is closest to your view?
[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	**EGD**	**Union**	**North**	**South**	**Low**	**Med-low**	**Med-high**	**High**	**Yes**	**No <$52K**	**No >$52K**
Increase its spending	64%	62%	67%	67%	67%	63%	64%	64%	64%	42%	60%	73%
Defer proactive replacement	12%	14%	10%	10%	10%	13%	12%	13%	12%	18%	14%	11%
I don't have an opinion on this	16%	17%	15%	16%	15%	17%	16%	16%	16%	26%	18%	11%
Don't know	7%	7%	7%	7%	7%	7%	8%	7%	7%	14%	8%	4%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

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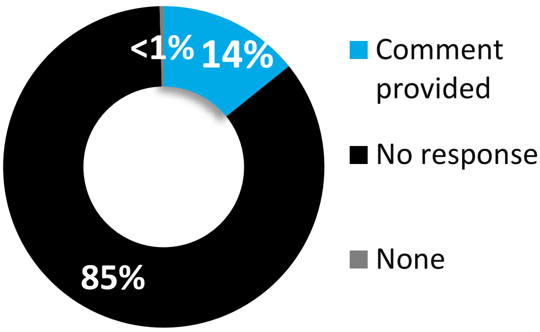
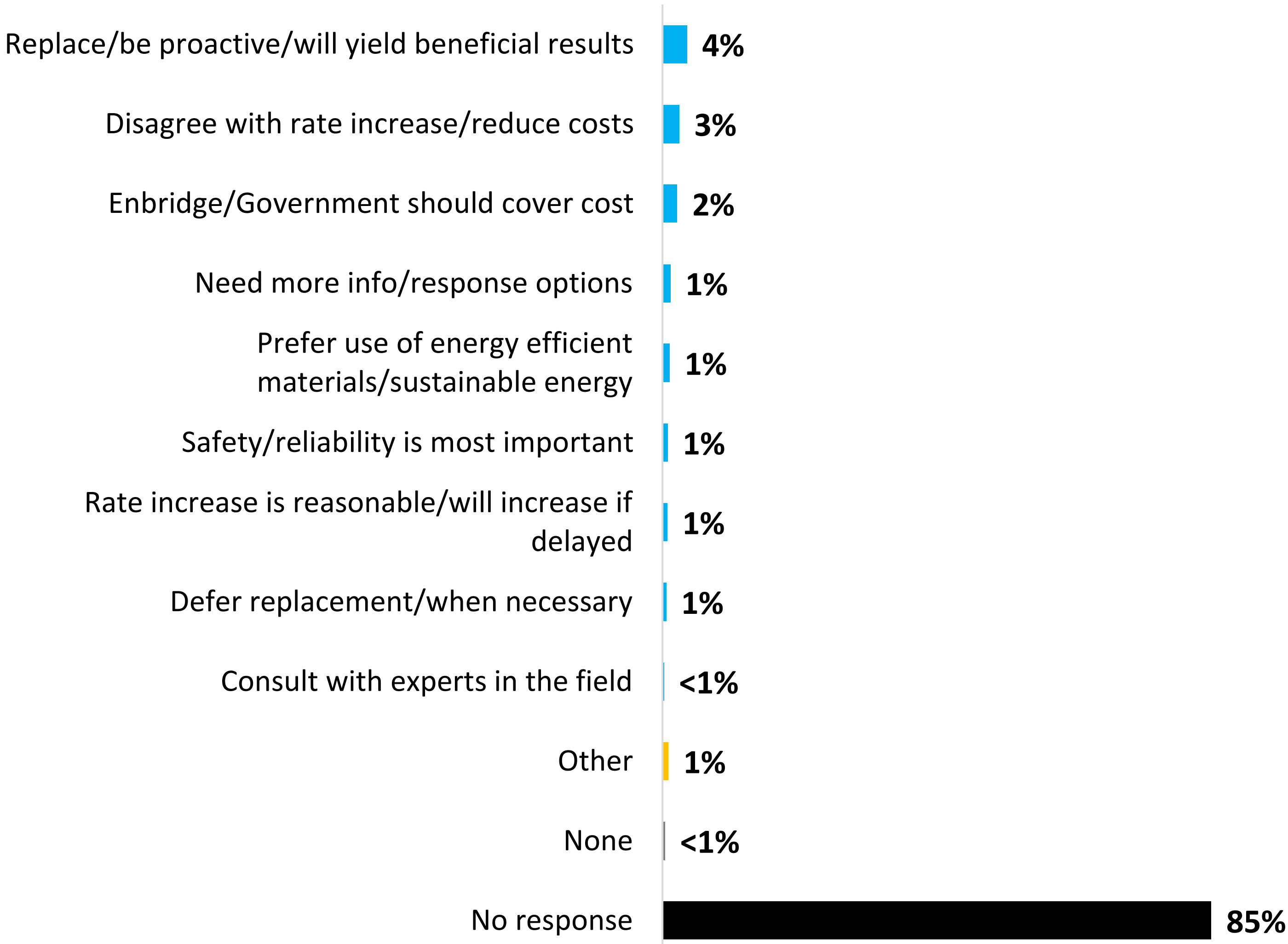
Making Choices

Vintage Steel Pipeline Replacement Program - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





Making Choices

Hydrogen Gas

Enbridge Gas is looking at options to blend more Hydrogen gas into the natural gas it delivers to green the gas supply.

Clean hydrogen gas is derived from surplus clean electrical energy that is converted to hydrogen gas through electrolysis technology. The gas is then blended with traditional natural gas, reducing GHG emissions.

Enbridge Gas is considering investing more in clean hydrogen as a tool for reducing GHG emissions in Ontario to allow for additional hydrogen gas to be blended into the natural gas distribution system. This would mean expanding the pilot project at the power-to-gas (P2G) facility in Markham where hydrogen gas is currently being produced, to deliver hydrogen-blended natural gas to a larger network of customers, expanding the blended gas area from approximately 3,600 to just under 17,000 customers.

Image: Hydrogen gas can be stored in tanks

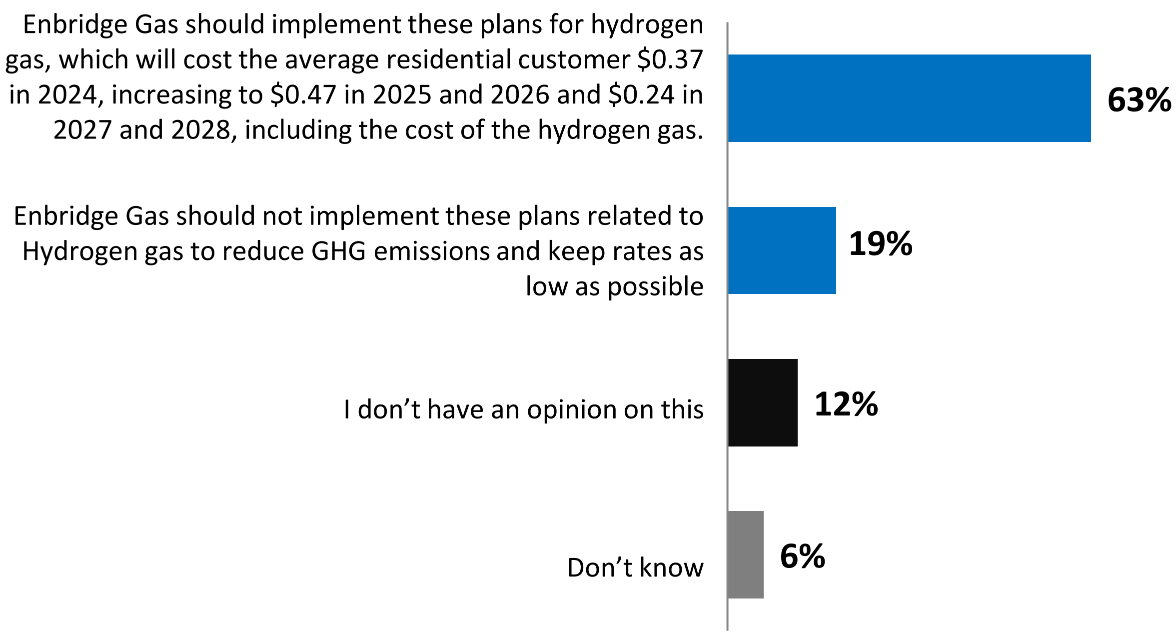
Additionally, Enbridge Gas intends to launch a feasibility study that assesses the full system's readiness for more hydrogen gas to be included in the system. The costs for these projects for the average residential customer are estimated as follows:

	2024	2025 and 2026	2027 and 2028
Annual cost	$0.37	$0.47	$0.24

Making Choices

Hydrogen Gas

Q Considering this, which of the following is closest to your view?
[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Should implement these plans	63%	61%	65%	65%	66%	65%	64%	62%	61%	44%	60%	72%
Should not implement these plans	19%	20%	16%	16%	17%	18%	17%	19%	21%	26%	19%	16%
I don't have an opinion on this	12%	12%	12%	13%	12%	11%	12%	13%	12%	18%	14%	9%
Don't know	6%	6%	6%	6%	6%	6%	7%	6%	6%	13%	7%	4%

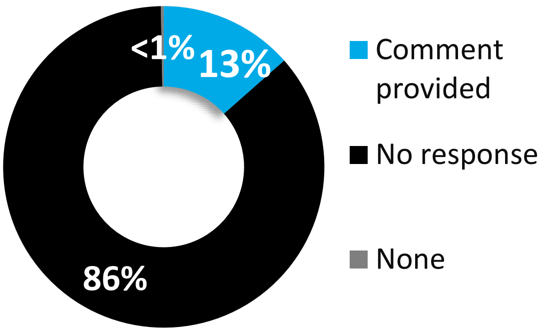
Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

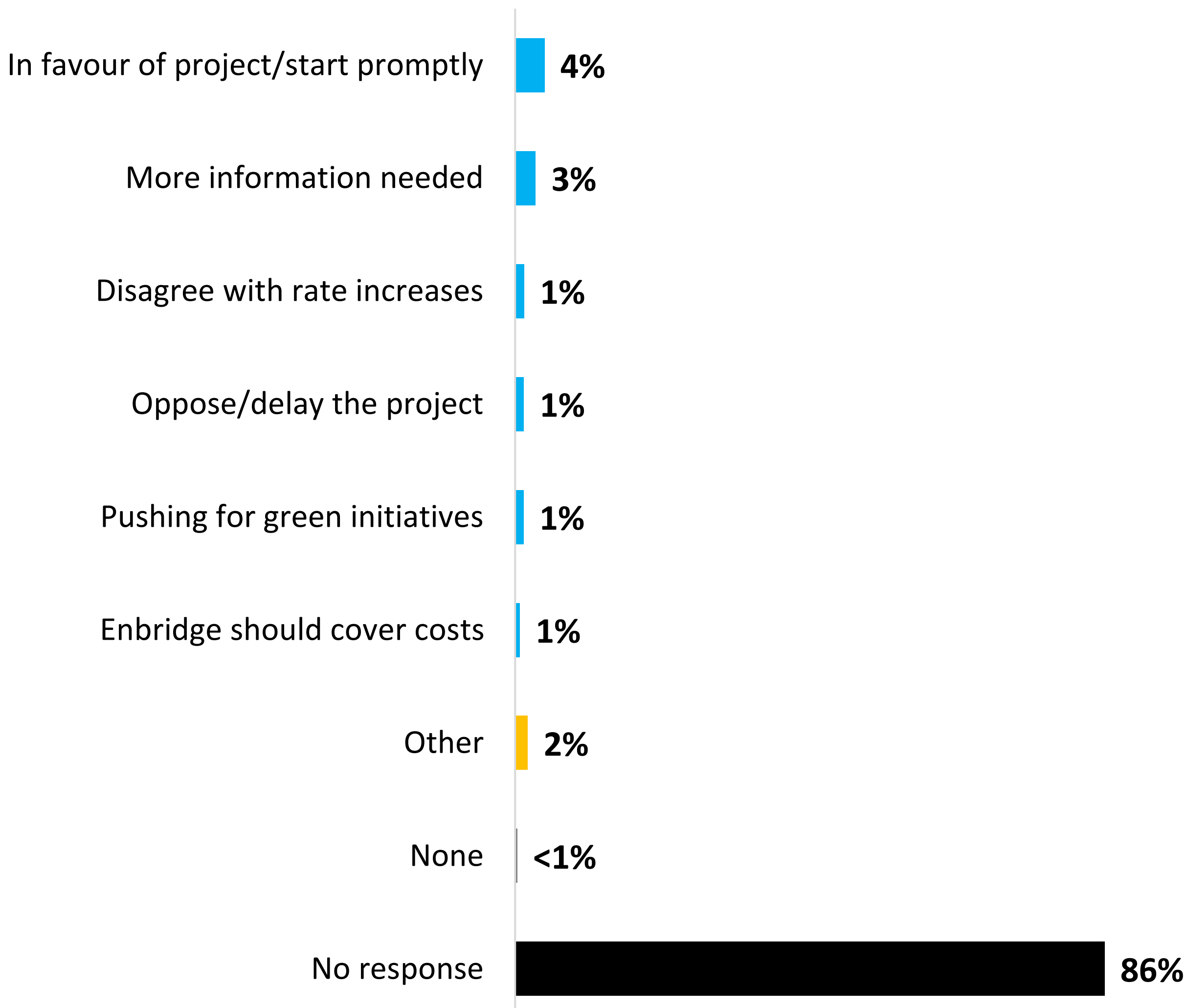
INNOVATIVE RESEARCH GROUP

Making Choices

Hydrogen Gas - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





Making Choices

Innovation and Technology Fund

Enbridge Gas can support the advancement of various new low-carbon or energy efficient technologies that may not be available to consumers today.

While some of this work is already taking place on a small scale, the budget for these types of projects is currently very limited. Additional contributions from customers would allow Enbridge Gas to expand this type of research and development work.

Similar to other jurisdictions, Enbridge Gas is considering an Innovation and Technology Fund in order to support the research, development, and the bringing to market of new low-carbon or energy efficient technologies. Where possible, this would be in partnership with other utilities and organizations.

Some options include funding for …

- new research on energy efficiency technologies,
- hydrogen gas,
- renewable natural gas, or
- carbon capture, utilization and sequestration (CCUS). This is the process of capturing carbon dioxide before it enters the atmosphere and either use it as a resource to create products or permanently storing it underground.

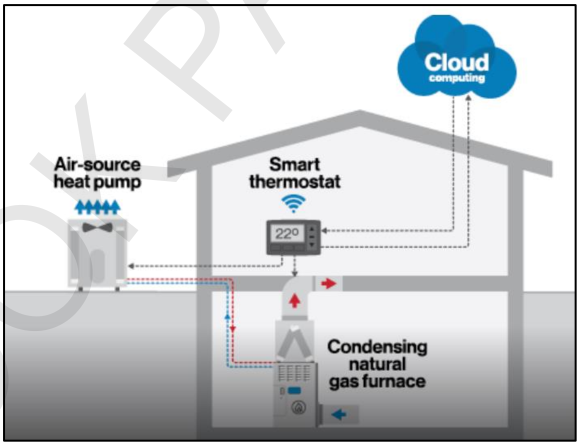


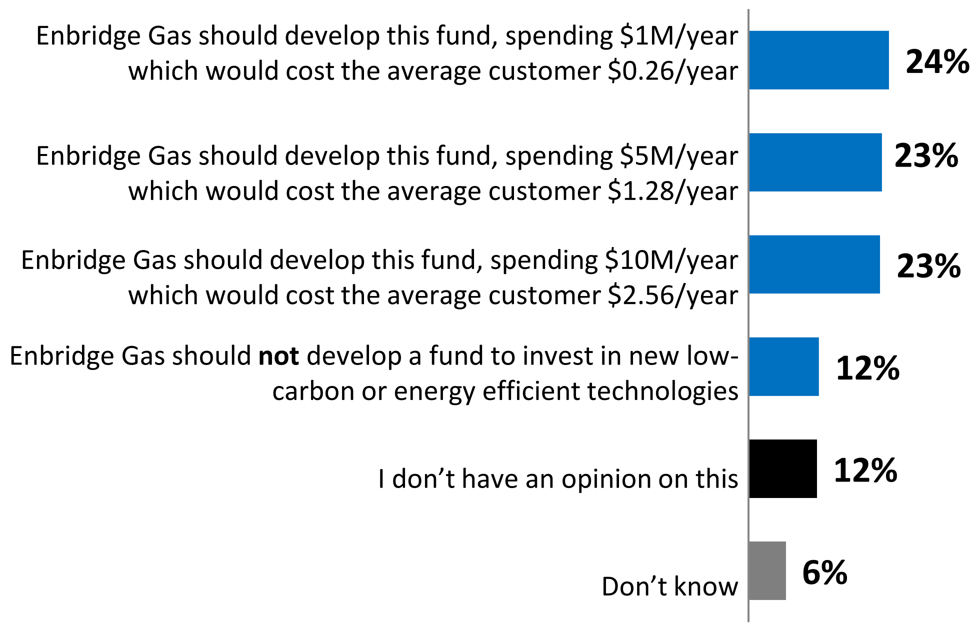
Image: Ontario pilot program tests future of advanced hybrid heating

The more money in this fund, the more projects could be completed, however Enbridge Gas is committed to finding a right balance of spending and planning for the future.

Making Choices

Innovation and Technology Fund

Q Considering this, which of the following is closest to your view?
[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	**EGD**	**Union**	**North**	**South**	**Low**	**Med-low**	**Med-high**	**High**	**Yes**	**No <$52K**	**No >$52K**
Spending $1M/year	24%	24%	24%	25%	24%	26%	23%	25%	23%	25%	28%	22%
Spending $5M/year	23%	22%	24%	28%	23%	25%	24%	22%	21%	15%	24%	26%
Spending $10M/year	23%	23%	22%	18%	23%	22%	22%	22%	24%	14%	19%	29%
Should not develop a fund to invest	12%	12%	12%	12%	12%	10%	11%	12%	14%	14%	10%	11%
I don't have an opinion on this	12%	12%	11%	11%	11%	12%	13%	12%	11%	17%	13%	8%
Don't know	6%	6%	7%	6%	7%	6%	7%	6%	7%	15%	6%	4%

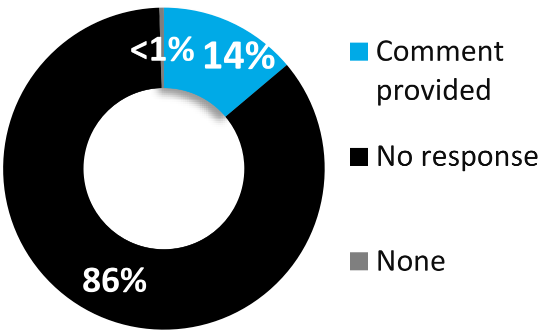
Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

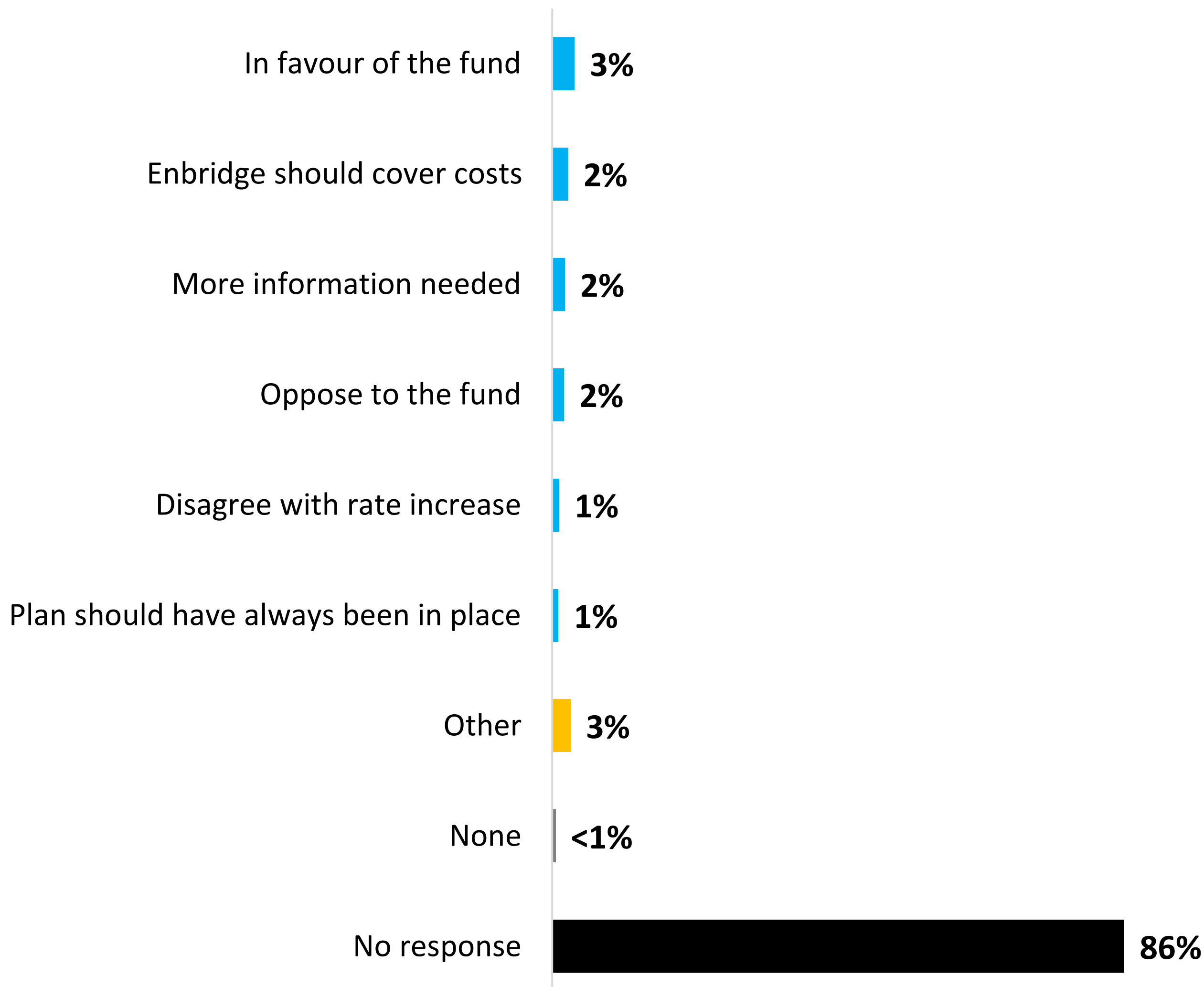
INNOVATIVE RESEARCH GROUP

Making Choices

Innovation and Technology Fund - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





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Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 262 of 550

Making Choices

Cut off at Main

When a customer wants to cut off the natural gas service, for example, when a home is being demolished, or when a customer no longer wishes to receive natural gas service, the service is cut off at the main pipeline. This customer requested work is performed by a maintenance and construction crew. After that, in many cases a new home can be attached again at the same location. Not doing this work creates abandoned natural gas lines and meters, which may pose a safety risk.

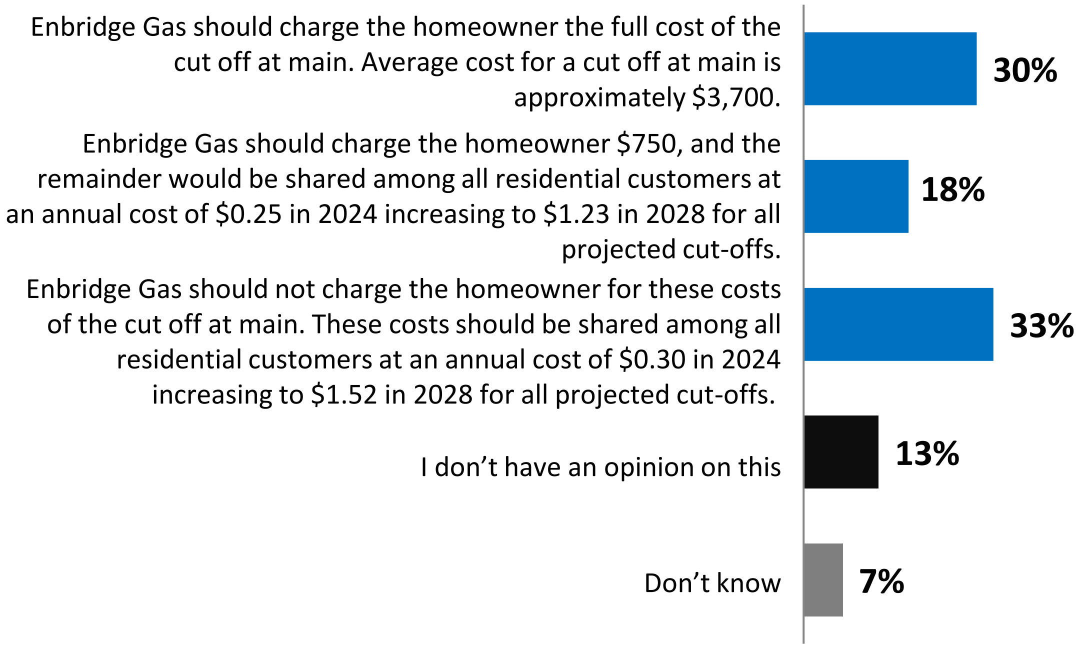
Any costs not charged to the homeowner are covered by Enbridge Gas, which means all ratepayers contribute to these costs through their rates. The average number of cutoffs in a year are projected at 3,200.

Enbridge Gas would like to create a policy that is the same across the entire territory and would like to ask you for your opinion.

Making Choices

Cut off at Main

Q Which of the following is closest to your view?
[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Charge homeowners the full cost	30%	29%	30%	27%	32%	29%	32%	29%	30%	18%	23%	35%
Charge homeowners $750	18%	17%	19%	19%	19%	19%	17%	17%	18%	12%	20%	21%
Should not charge homeowners	33%	33%	32%	34%	31%	32%	31%	34%	33%	38%	37%	31%
I don't have an opinion on this	13%	14%	12%	12%	12%	13%	13%	13%	13%	19%	14%	9%
Don't know	7%	7%	7%	8%	6%	7%	7%	8%	6%	13%	7%	4%

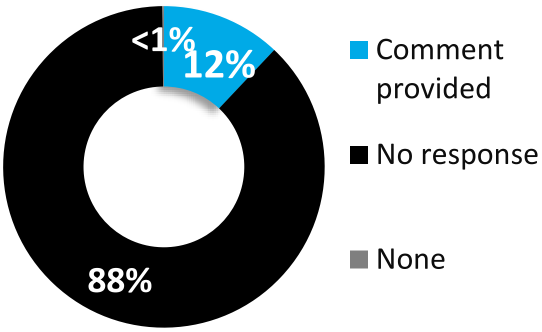
Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

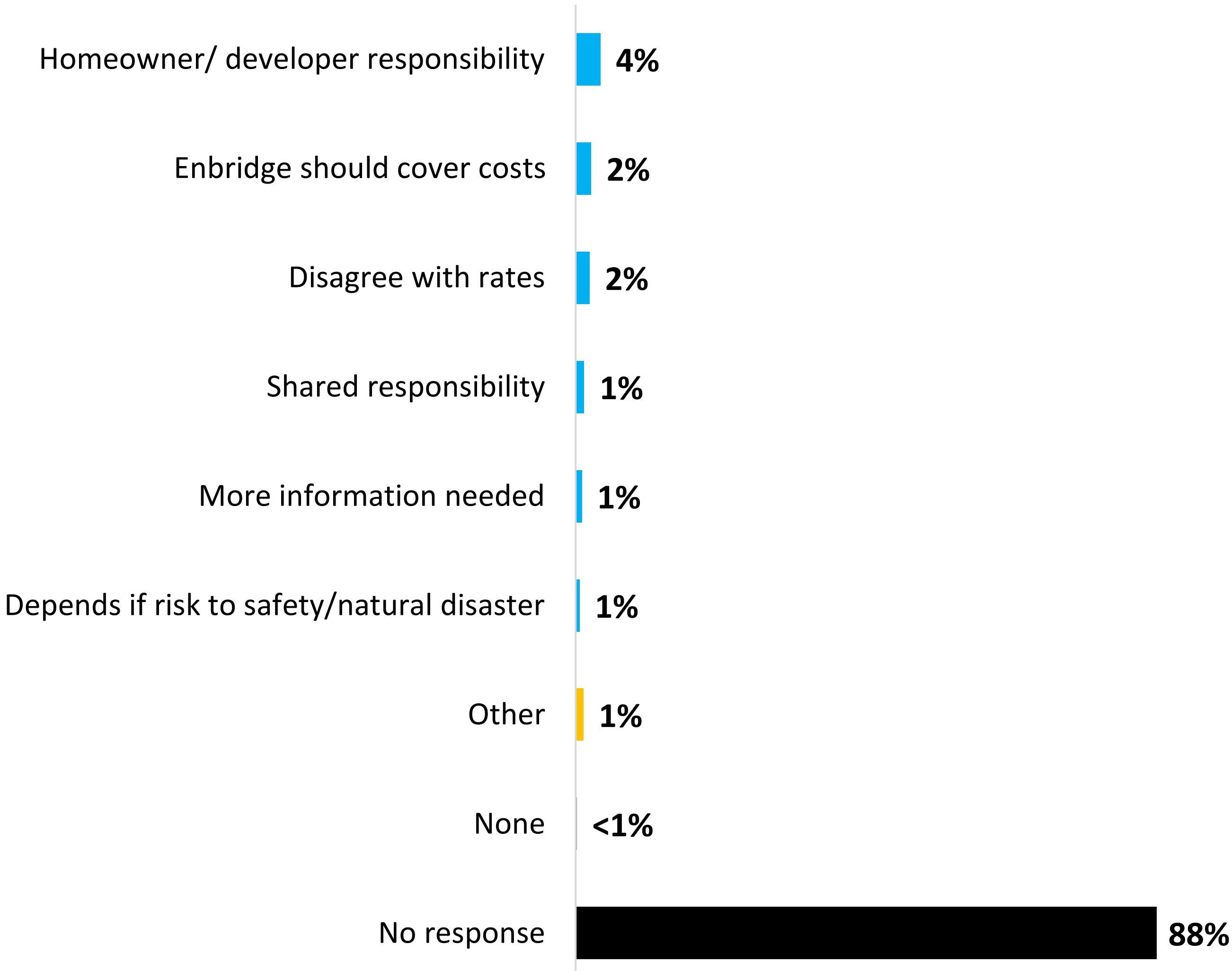
INNOVATIVE RESEARCH GROUP

Making Choices

Cut off at Main - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





Making Choices

Cross Bores

While rare, it is possible that a natural gas line may intersect with a sewer line. When this happens, it is called a utility cross bore. This is unintentionally created when a natural gas line is installed through a process of trenchless drilling.

Image: Example of a cross bore

Trenchless drilling is used to avoid creating open trenches that can disturb roads, driveways, and gardens, but it relies on locates of existing utilities which may not always be accurate for various reasons. While a utility cross bore may not pose an immediate risk, it may become an issue if a sewer line needs to be cleared in the case of a blockage. This has resulted in some instances of property damage and injury, as a result of a gas leak, fire or explosion.

To address this risk, there is currently an emergency program in place called Call Before you Clear. This program relies solely on property owner and plumber participation and through this program over 10,000 annual inspections are completed. Still, many plumbers and homeowners do not call for an inspection prior to auguring their sewer lines. To expand inspections beyond the current emergency program, Enbridge Gas intends to implement a program to **proactively inspect and resolve additional utility cross bores** that may have been installed in the past. This would double the number of annual inspections.

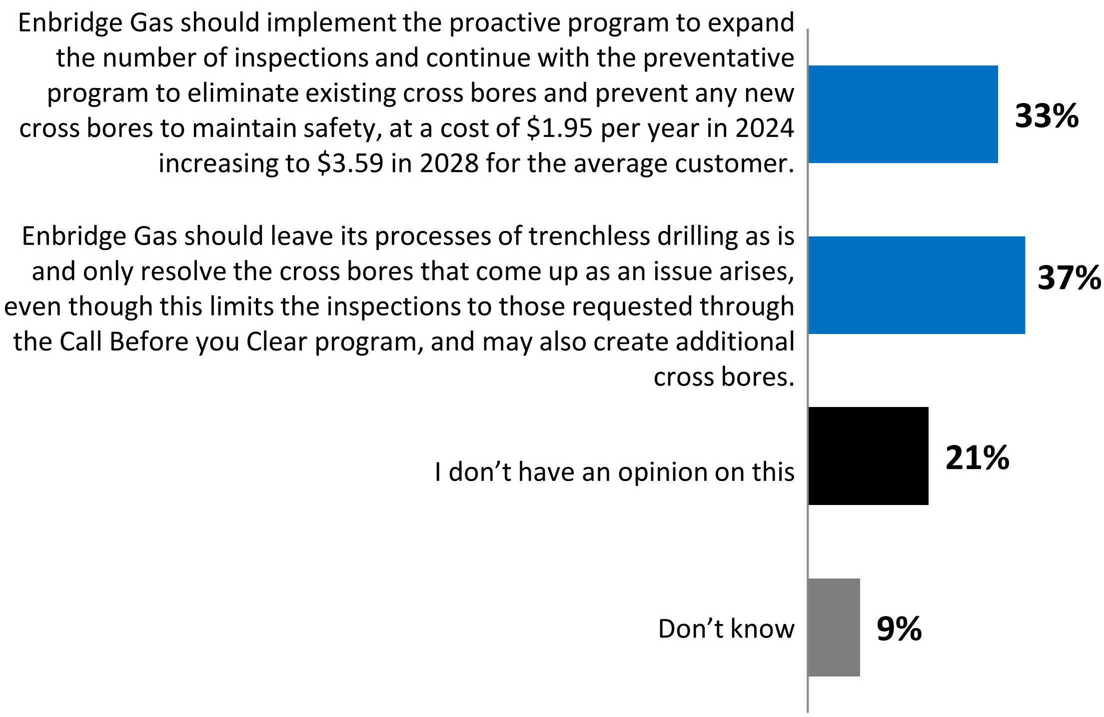
Another program has been implemented by Enbridge Gas to **prevent new installations from creating new cross bores** even though that increases the cost of the installation and requires additional restoration work during the installation process.

These programs to proactively inspect and resolve existing cross bores and to prevent the creation of cross bores during the completion of new installations combined would cost customers $1.95 per year in 2024 increasing to $3.59 per year in 2028.

Making Choices

Cross Bores

Q Which of the following is closest to your view?
[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	**EGD**	**Union**	**North**	**South**	**Low**	**Med-low**	**Med-high**	**High**	**Yes**	**No <$52K**	**No >$52K**
Should implement the proactive program	33%	33%	32%	30%	32%	34%	32%	32%	34%	24%	33%	38%
Should leave its processes of trenchless drilling	37%	37%	39%	39%	38%	36%	39%	37%	38%	33%	37%	38%
I don't have an opinion on this	21%	21%	20%	19%	21%	21%	20%	21%	21%	26%	22%	18%
Don't know	9%	9%	9%	11%	9%	9%	9%	10%	7%	17%	9%	6%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

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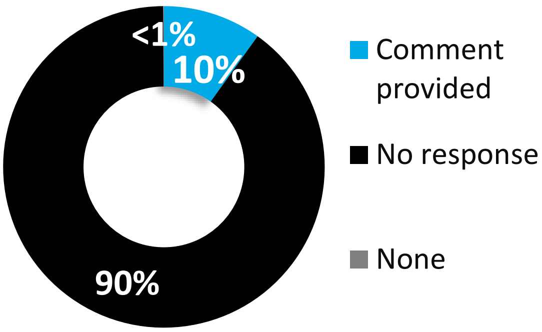
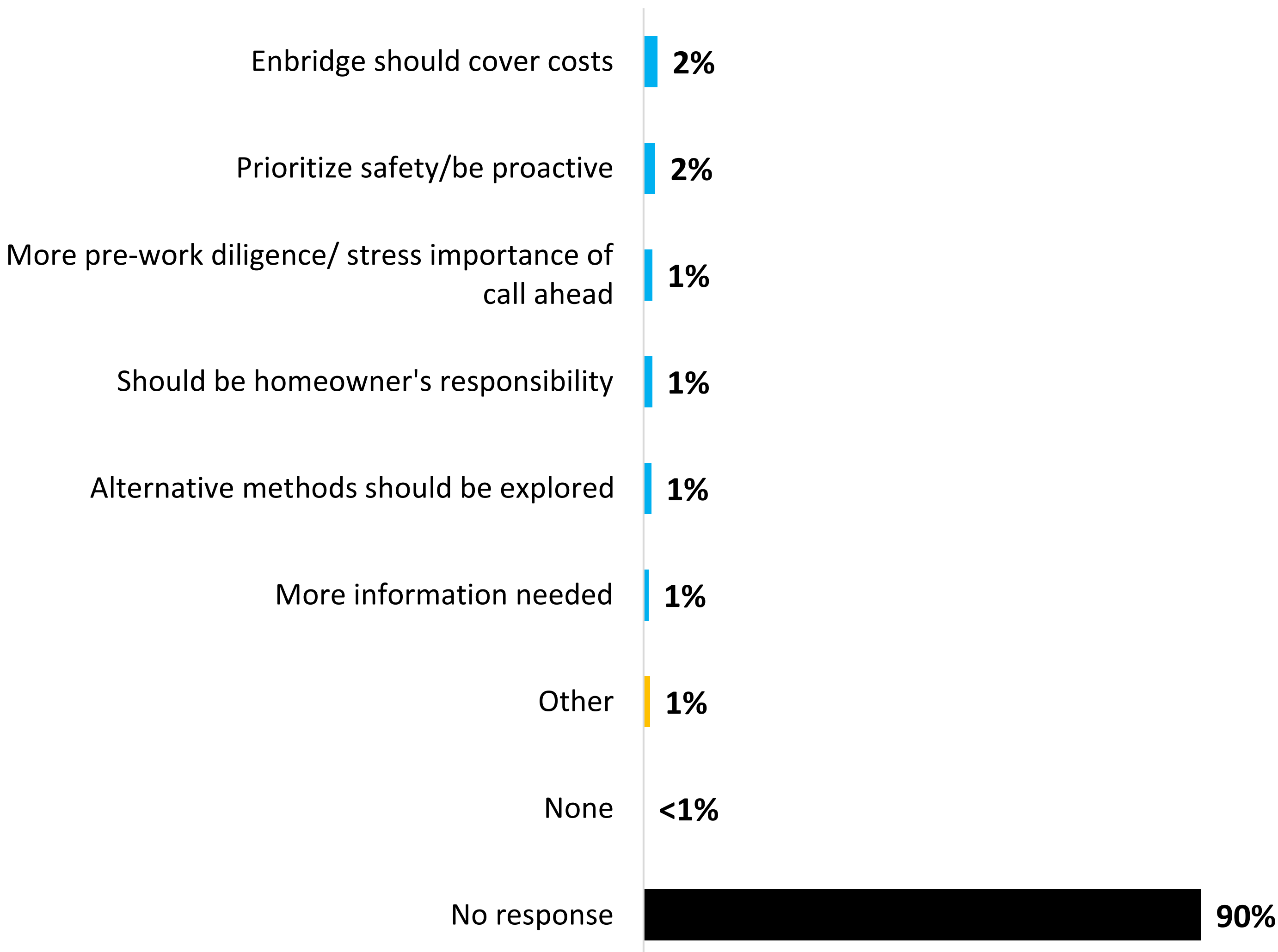
Making Choices

Cross Bores - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





Making Choices

Advanced Meter Infrastructure

The gas meter technology currently used by Enbridge Gas has not changed in many years. Enbridge Gas is working on a plan to rollout new advanced meters that would send usage information to Enbridge Gas through a wireless network, like your existing water or electricity usage meters. The meters also have additional functions that could allow Enbridge Gas to:

- ✓ Better detect and respond to possible gas leaks
- ✓ Enhance safety capabilities by enabling Enbridge Gas to remotely and automatically shutoff gas supply in the event of an emergency
- ✓ Allow for a reduction in greenhouse gas (GHG) emissions by reducing meter reader vehicles on the road
- ✓ Eliminate the need for estimated meter reads
- ✓ Provide customers detailed usage data information – this may also allow customers to be notified of faulty or left on appliances

Once all meters are rolled out, the above features would become available to all customers. Rates will increase as specified below, after which rates will decrease slowly and eventually decrease to levels lower than today as benefits are fully realized. How rates are impacted depends on timing of spend and realization of benefits.

Depending on the pace of rolling out automated meters, there are implications on the time the benefits listed above can be fully realized, and the cost involved for customers like you. These are outlined in the table below.

	Time to Fully Realize Benefits	First Year Cost (2024)	Maximum Annual Cost	Year that the Rate Impact reduces to Less than Today
Option 1	4 years	$3.25	$20.64 in 2028	2038
Option 2	8 years	$2.17	$14.88 in 2031	2039
Option 3	20 years	$1.40	$1.85 in 2026	2034

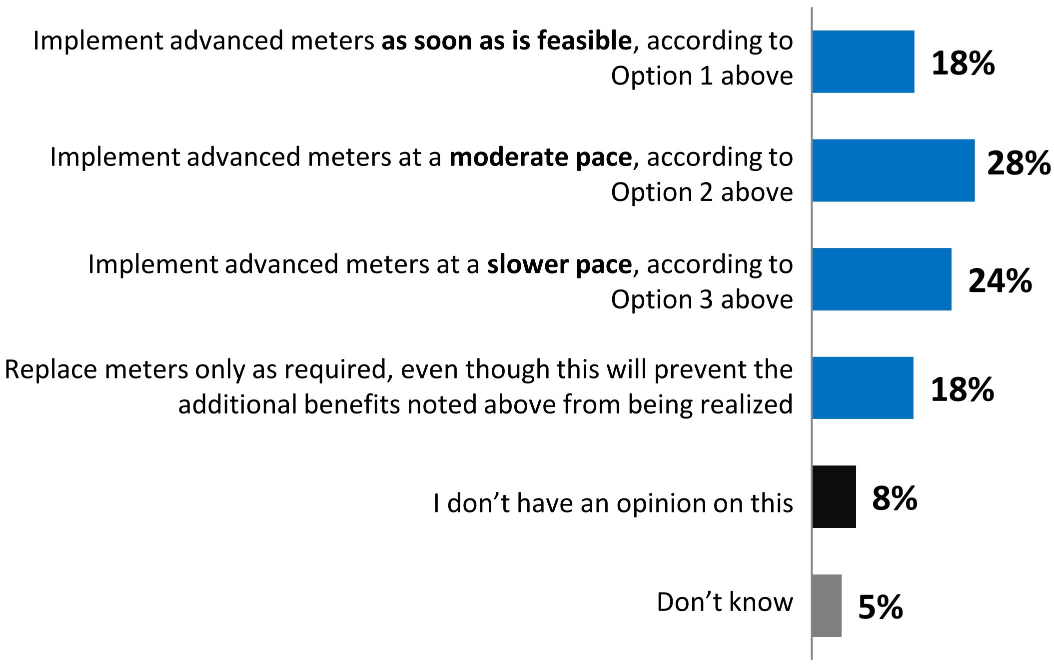
Making Choices

Advanced Meter Infrastructure

Q

Which of the following is closest to your view? Across its service area, Enbridge Gas should…

[asked of all respondents; n=5,400]



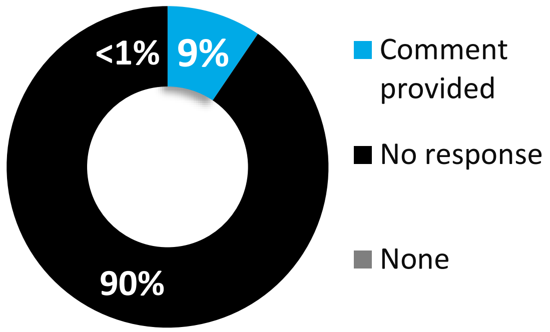
		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	**EGD**	**Union**	**North**	**South**	**Low**	**Med-low**	**Med-high**	**High**	**Yes**	**No <$52K**	**No >$52K**
As soon as is feasible	18%	19%	16%	15%	17%	16%	18%	18%	19%	11%	15%	22%
Moderate pace	28%	27%	29%	33%	28%	28%	29%	27%	28%	17%	29%	32%
Slower pace	24%	23%	25%	23%	26%	27%	24%	23%	22%	25%	25%	24%
Replace meters only as required	18%	18%	17%	16%	17%	15%	17%	19%	18%	22%	17%	14%
I don't have an opinion on this	8%	8%	8%	8%	8%	8%	7%	8%	7%	14%	9%	5%
Don't know	5%	5%	5%	5%	5%	5%	5%	5%	5%	12%	4%	3%

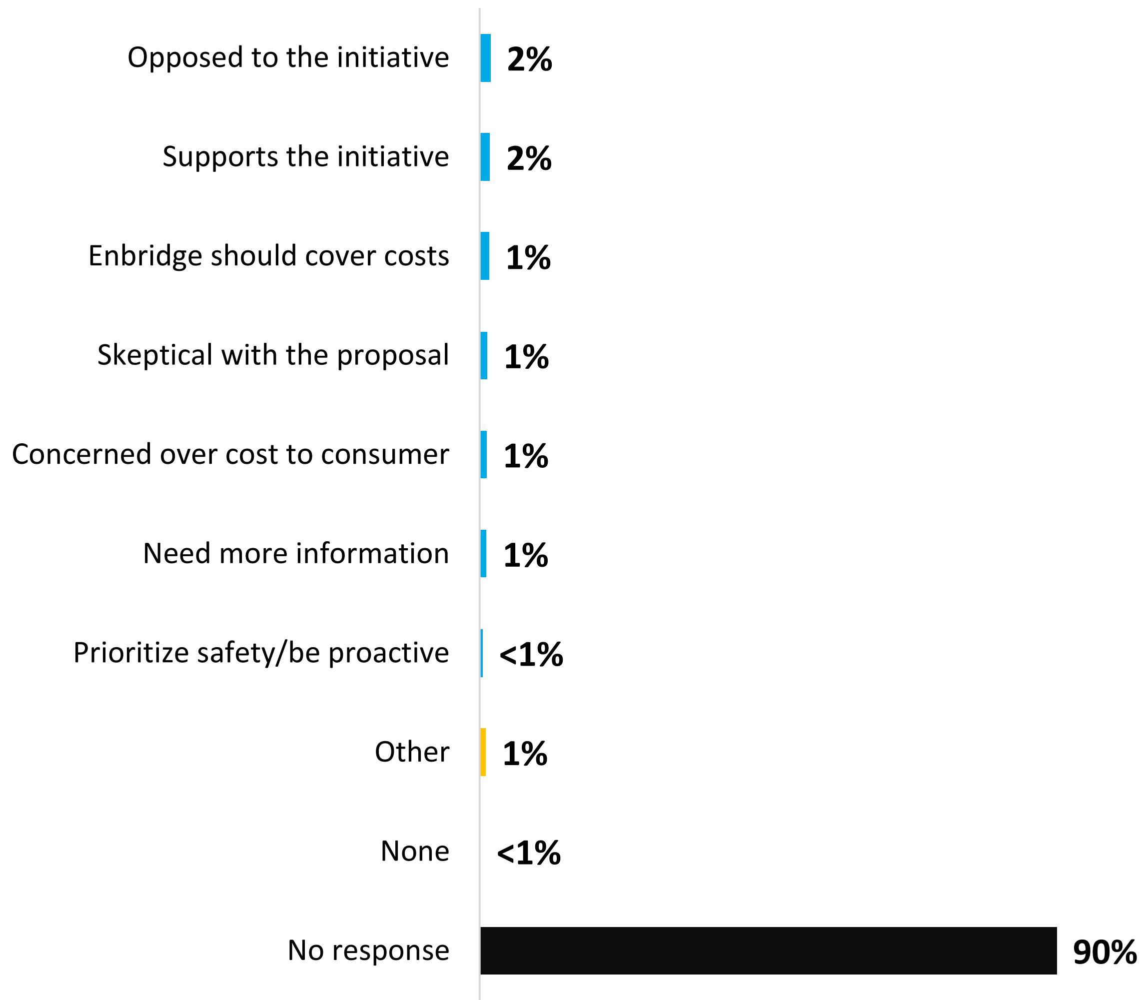
Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

Making Choices

Advanced Meter Infrastructure - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





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Online Workbook Results

Impact of Choices

Impact of Choices

Do You Want to Change Your Choices?

Impact of Choices

Do You Want to Change Your Choices?

So far in this workbook, you have been asked about **7 key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page, you will find the annual bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential annual rate impact for 2024 and 2028 will be re-calculated each time you change one of your answers at the bottom of the page. Costs for 2025-2027 will fall between this range. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Residential Customer Bill Impact Change and Magnitude of Bill Impact **(MEAN)**

2024

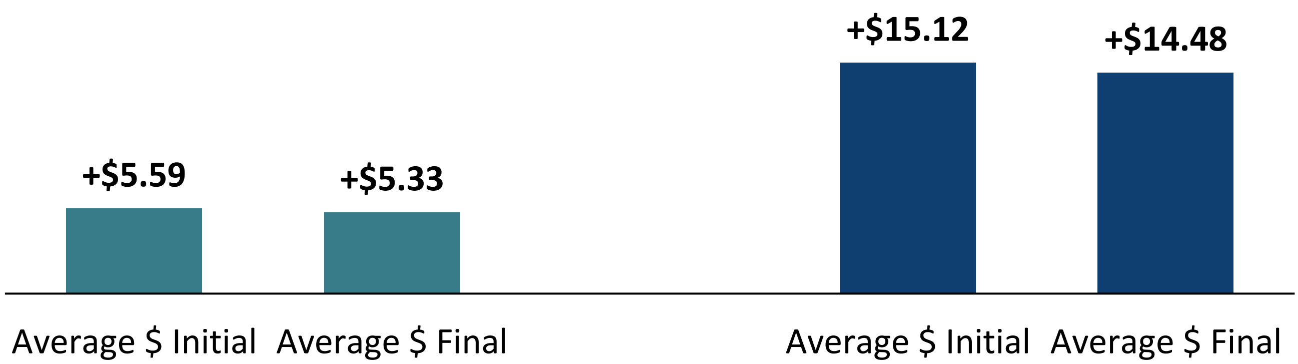
Range of Impacts

-$3.24 to +$11.67

2028

Range of Impacts

-$8.53 to +$37.08



Note: There is no statistical significance between the average initial total and the average final total.

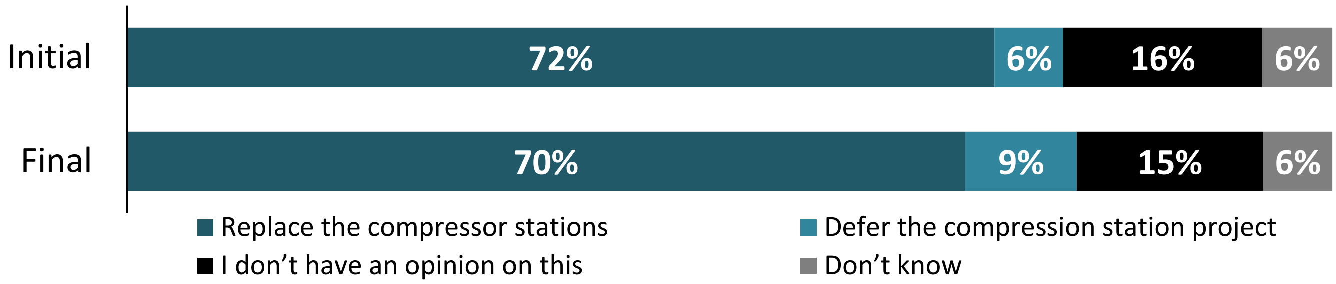
About the "Range of Impacts"

The "Range of Impacts" signifies the highest and lowest possible range of bill impacts above and beyond the Draft Plan. For instance, if a customer, where possible, were to select the most accelerated option, their bill impact would result in an **additional $11.67** annually in 2024 and **$37.08** in 2028. If they were to select the biggest decrease for each question, it would result in a **decrease of $3.24** annually in 2024 and **$8.53** in 2028.

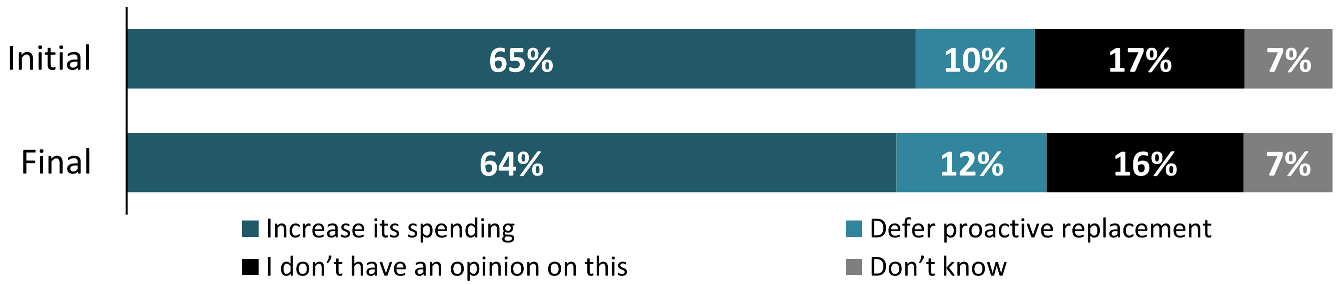
Making Choices

Impact of Choices

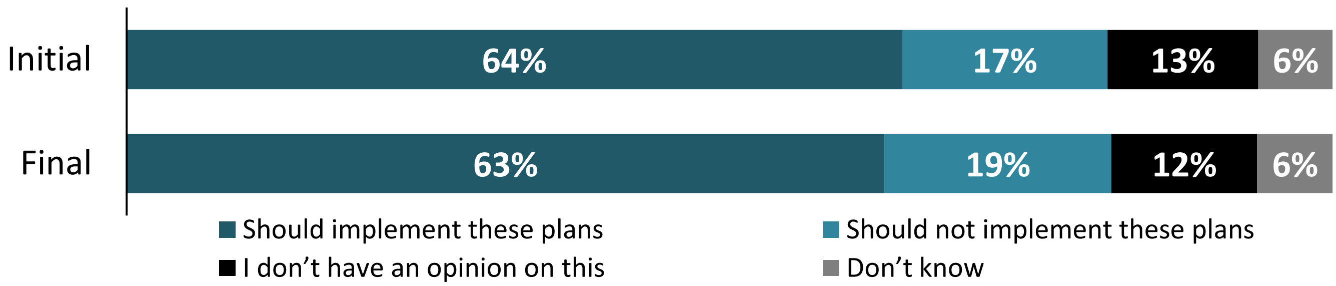
Compressor Station Project



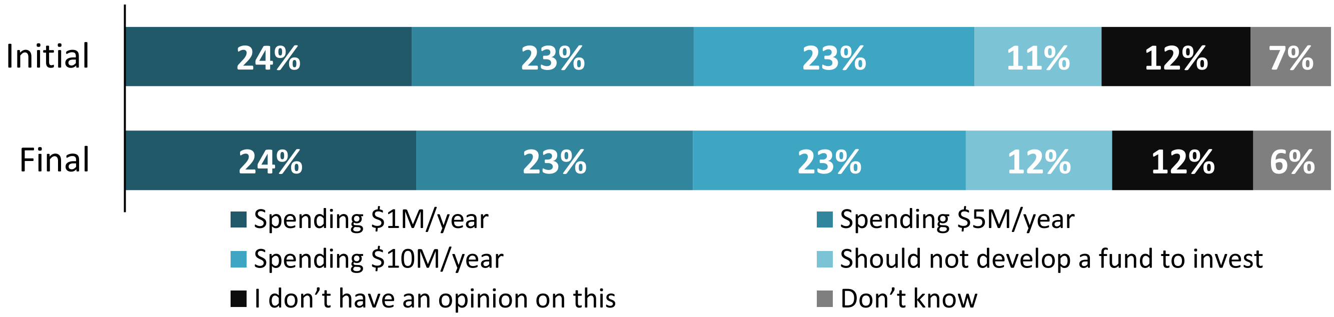
Vintage Steel Pipeline Replacement Program



Hydrogen Gas



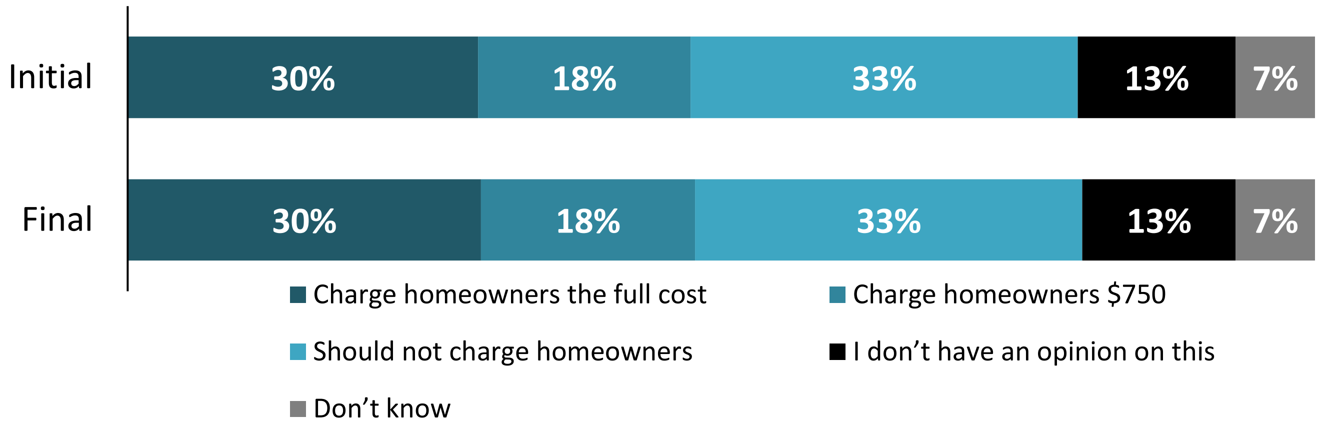
Innovation and Technology Fund



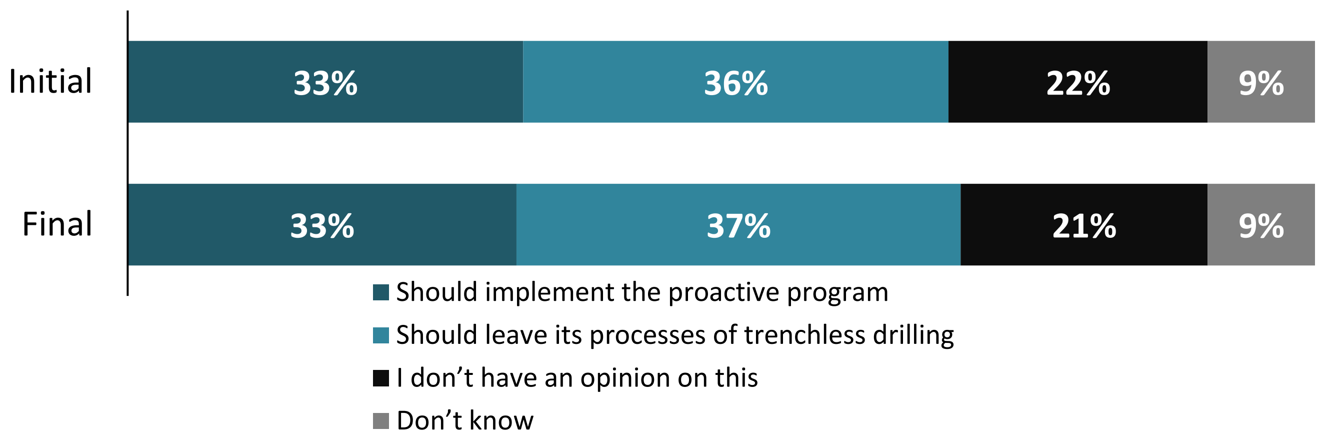
Making Choices

Impact of Choices

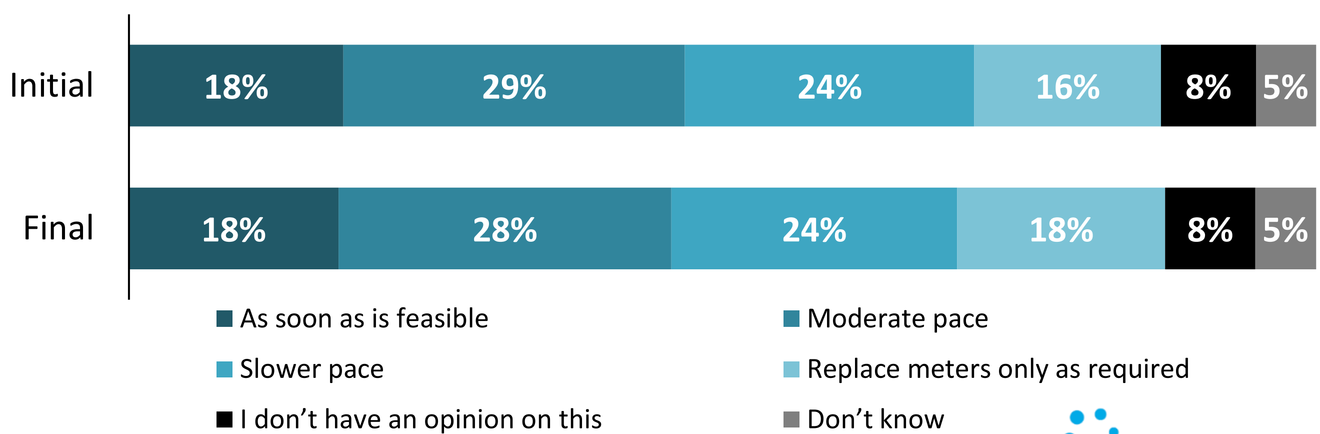
Cut off at Main



Cross Bores



Advanced Meter Infrastructure



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Enbridge Gas will be reviewing its plan based on the feedback you and other customers are sharing now. However, in doing that review, it is important for Enbridge Gas to get a sense of whether the current draft plan is generally acceptable or not. There were some choice options that Enbridge Gas had already included in the draft plan, and others that were not.

As mentioned earlier in the workbook, the Enbridge Gas plan for 2024 to 2028 focused on the following key objectives:

1. Maintaining system safety and reliability
2. Containing costs
3. Harmonizing rates and services
4. Preparing for the future

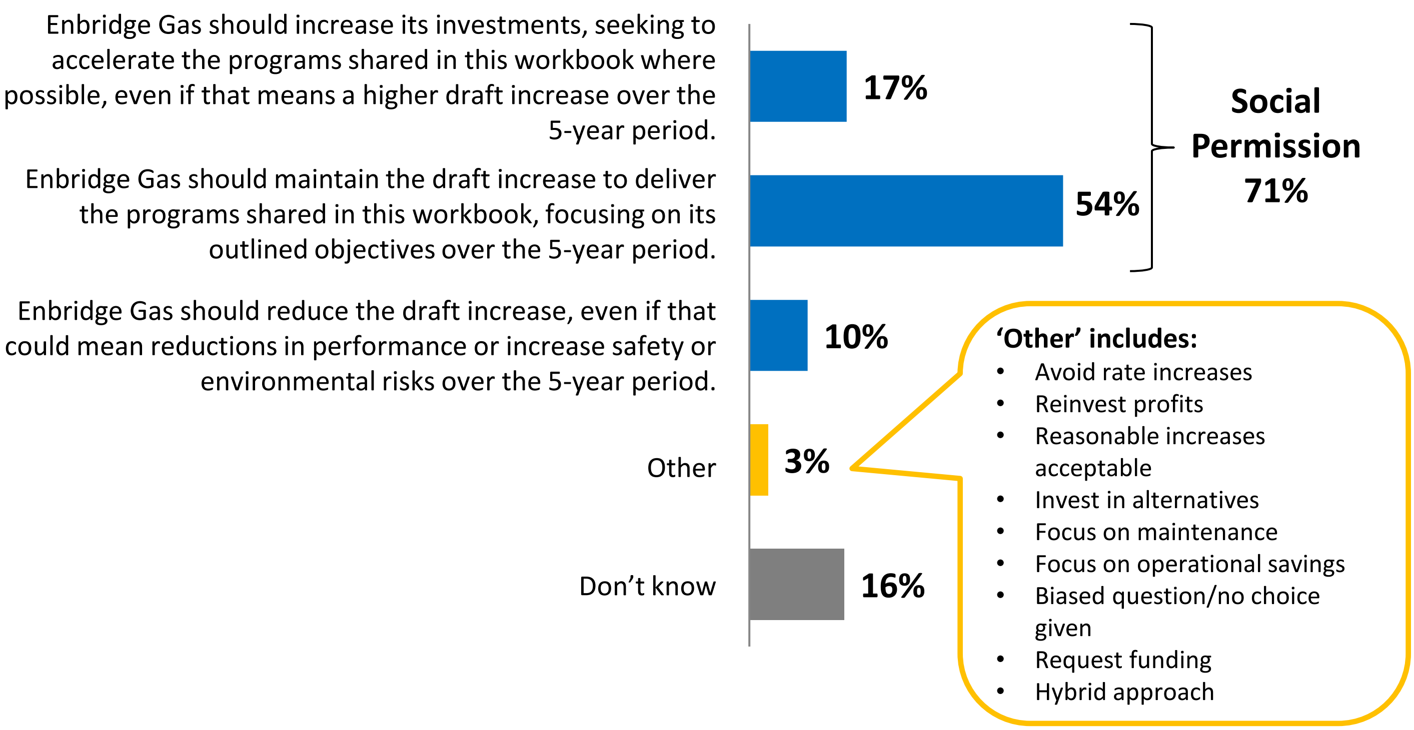
Currently the plan is estimated to result in an average annual increase of 1.9% over 2024 to 2028 for a total of 7.4% in 2028 compared to October 2021 rates. Along with your feedback on choices included within the plan, Enbridge Gas will consider your feedback on the choices that have not yet been included and update the plan accordingly.

Social Permission

Enbridge Gas' Plans

Q Considering what you know about Enbridge Gas' plans, and the choices you have been making, which of the following best represents your point of view?

[asked of all respondents; n=5,400]

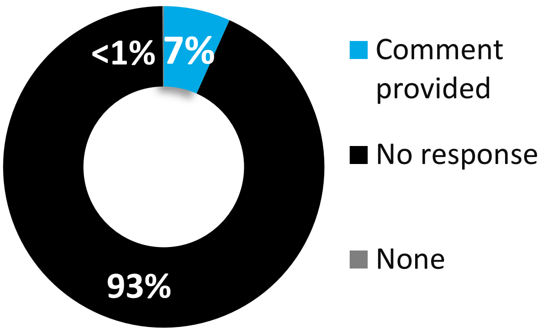


		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	**EGD**	**Union**	**North**	**South**	**Low**	**Med-low**	**Med-high**	**High**	**Yes**	**No <$52K**	**No >$52K**
Should increase its investments	17%	18%	15%	13%	15%	15%	15%	18%	18%	11%	14%	22%
Should maintain the draft increase	54%	51%	58%	58%	58%	56%	54%	53%	53%	36%	54%	58%
Should reduce the draft increase	10%	11%	8%	8%	8%	9%	10%	10%	11%	17%	11%	8%
Other	3%	3%	3%	3%	3%	3%	3%	3%	4%	3%	2%	3%
Don't know	16%	17%	16%	17%	15%	17%	18%	17%	14%	33%	19%	10%
Social Permission (Increase + Maintain)	**71%**	**69%**	**73%**	**71%**	**73%**	**71%**	**69%**	**71%**	**71%**	**47%**	**68%**	**80%**

Social Permission

Enbridge Gas' Plans – Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.



Social Permission Response

Response	Total	Increase invest-ments	Maintain draft increase	Reduce draft increase	Other	Don't know
Avoid rate increases/no further cost	1%	1%	1%	2%	9%	3%
Reasonable costs/necessary for safety	1%	4%	1%	1%	3%	<1%
Reinvest profits/Enbridge should pay	1%	1%	<1%	1%	7%	1%
Invest in alternatives/reduce GHGs	1%	2%	<1%	--	4%	<1%
Biased survey/no real choice given	1%	<1%	<1%	1%	6%	1%
Need more information	1%	<1%	<1%	1%	3%	1%
Focus on savings/efficiencies	1%	1%	<1%	2%	2%	<1%
Gradual increase more manageable	<1%	<1%	<1%	<1%	--	<1%
Necessary to protect the environment/planet	<1%	<1%	<1%	--	--	<1%
Focus on maintenance/upgrades	<1%	<1%	--	<1%	--	<1%
Improve customer service	<1%	<1%	<1%	<1%	--	<1%
More transparency required	<1%	<1%	<1%	--	1%	--
Other	<1%	<1%	<1%	<1%	<1%	<1%
None	<1%	--	<1%	<1%	<1%	<1%
No response	93%	89%	96%	92%	65%	93%

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Online Workbook Results

Service and Rate Harmonization

Service and Rate Harmonization

In its application to the OEB, Enbridge Gas is also considering several other items that may affect customers. In this section we will ask you about a few different things, including programs that it could offer, as well as some options on how rates are calculated and applied.

Infill Policy

When an existing home is located near a main line, it may receive a natural gas connection through the residential infill policy. Under regulations, existing customers cannot be charged for any of these expenses.

According to the policy, connections are provided to homeowners at no cost (because forecasted revenues from the new customer cover a portion of the cost to connect) up to a certain distance from the home to the main line. The cost for any extra distance must be paid by the homeowner.

These costs can be structured in different ways, and currently vary depending on whether someone is in the Legacy Enbridge Gas Distribution or Legacy Union Gas area. The more service length Enbridge Gas provides at no charge, the more needs to be charged for each extra metre of length to account for costs not covered by forecasted revenue.

Enbridge Gas would like to create a policy that is the same across the entire territory that reflects the cost of attaching a new customer and would like to ask you for your opinion.

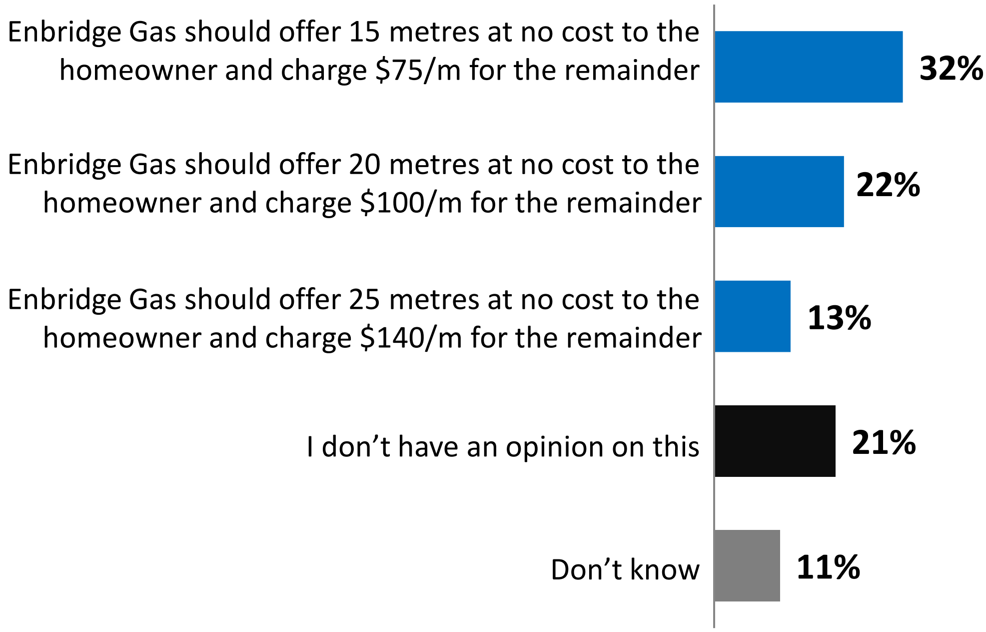
Based on data from the last 3 years of installations, which is influenced by the current policies, the following proportion of installations would be free, while the remainder would pay an amount based on the length of their line. The historical average is shown in the table below.

	Length for free	Cost for remainder	Proportion of installations that would be free	Average cost for customers who would pay
Option 1	15m	$75/m	57%	43% pay an average of $635 for the remainder
Option 2	20m	$100/m	75%	25% pay an average of $1700 for the remainder
Option 3	25m	$140/m	84%	16% pay an average of $2885 for the remainder

Service and Rate Harmonization

Infill Policy

Q Which of the following approaches is closest to your view?
[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Offer 15 metres at no cost to the homeowner	32%	33%	32%	32%	32%	33%	32%	31%	33%	28%	31%	36%
Offer 20 metres at no cost to the homeowner	22%	21%	24%	24%	24%	24%	23%	23%	20%	14%	23%	26%
Offer 25 metres at no cost to the homeowner	13%	13%	13%	13%	13%	12%	12%	14%	14%	11%	12%	14%
I don’t have an opinion on this	21%	22%	19%	19%	19%	20%	22%	21%	21%	26%	22%	18%
Don’t know	11%	11%	12%	12%	12%	11%	12%	11%	11%	21%	12%	7%

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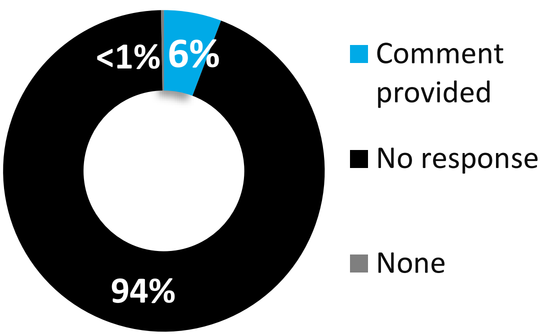
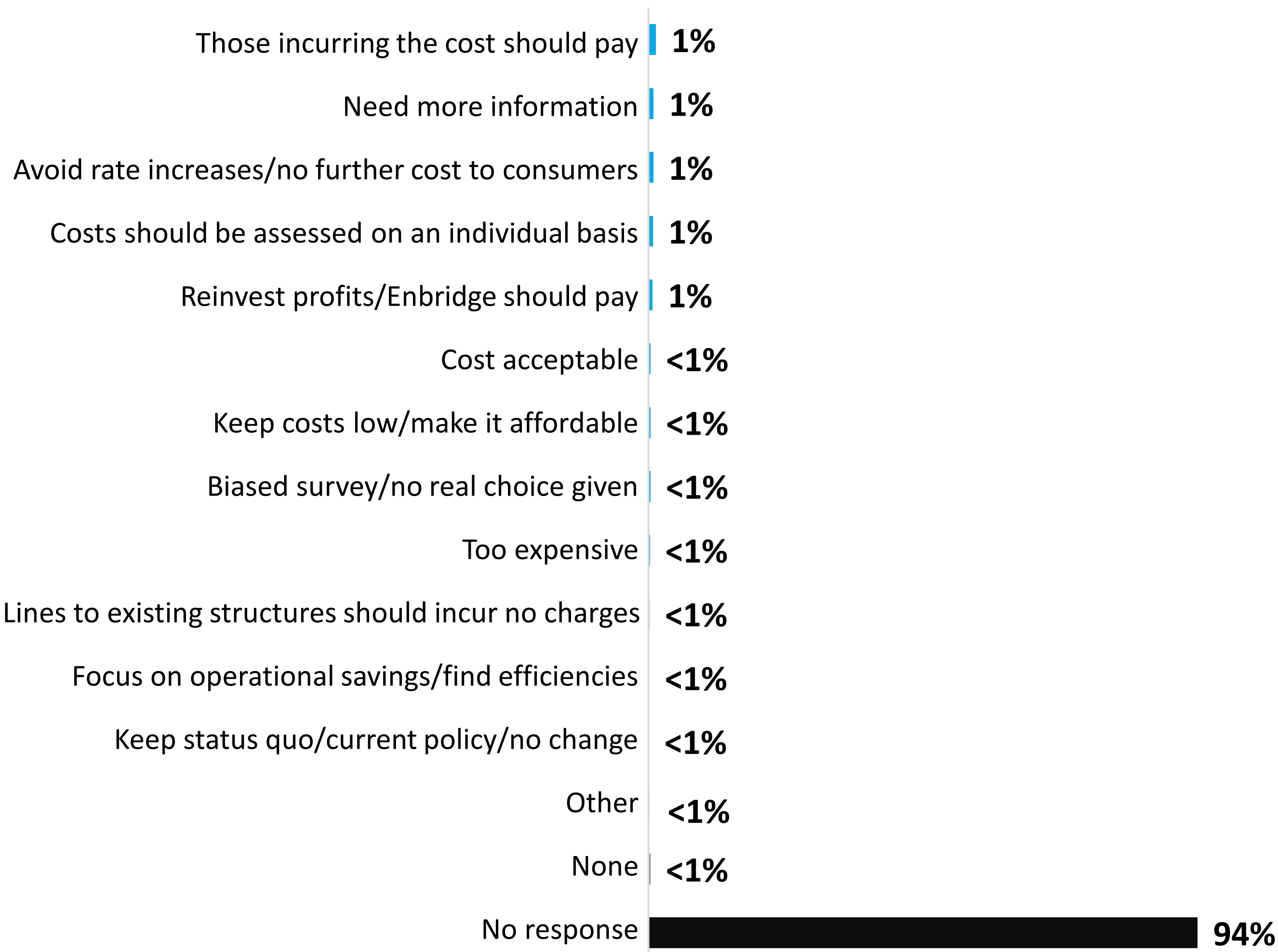
Service and Rate Harmonization

Infill Policy - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.

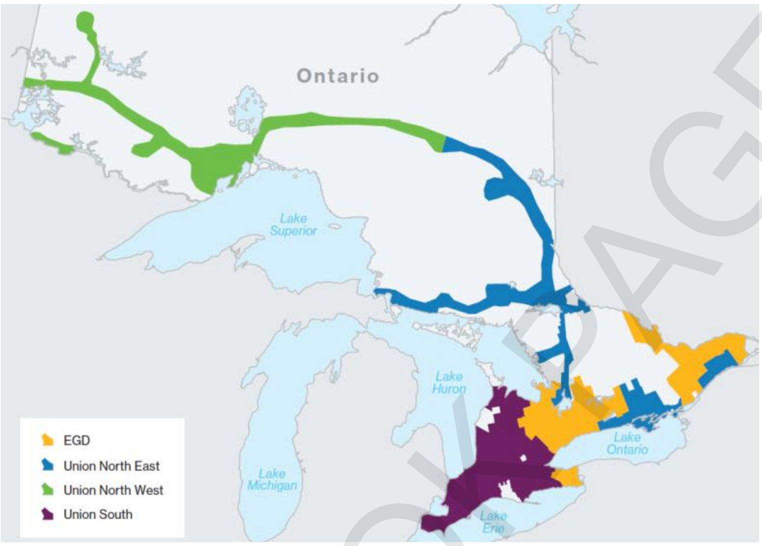




Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 282 of 550

Rate Zones

Currently, the rate you pay for natural gas delivery depends on where you live in Ontario. As previously indicated, Enbridge Gas, today, is a combination of Legacy Enbridge Gas Distribution and Legacy Union Gas. Currently there are four rate zones, each with its own rates depending on where you are located, and which company previously served you. The four rate zones look as follows:



Enbridge Gas is considering the option of offering one rate zone for its different types of customers, regardless of location within Ontario and the cost to serve them. There are many benefits of one rate zone including similar charges for similar customers, a consistent customer experience, and reduced administrative costs.

One rate zone could result in a change to the amount customers pay for their natural gas service, and varies on the rate zone a customer is currently located in. The adjustment as a result of this change is impacted by the number of customers in a rate zone and is shown in the table below.

Current rate zone	Current average annual bill based on 2,400m3	Average cost adjustment at current rates
EGD	$1,149	Decrease of approximately 1% ($1 per month)
Union North East	$1,302	Decrease of approximately 10% ($10 per month)
Union North West	$1,230	Decrease of approximately 10% ($10 per month)
Union South	$1,018	Increase of approximately 5% ($5 per month)

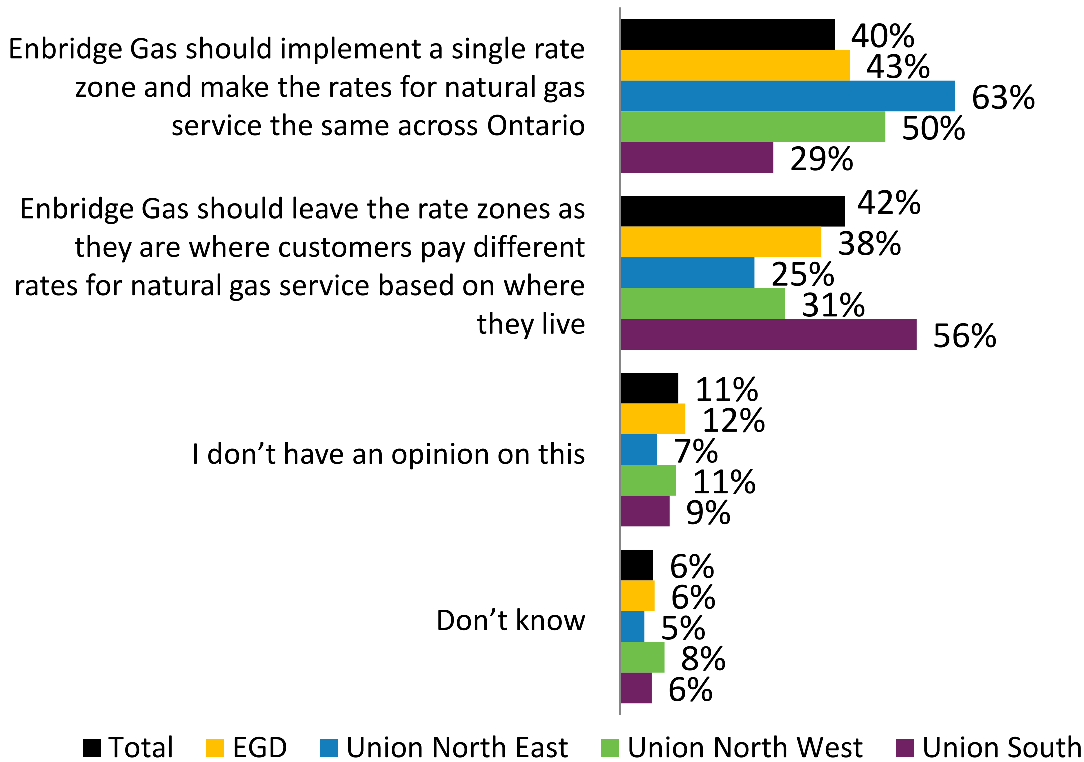
Service and Rate Harmonization

Rate Zones

Q

You are located in (PIPE IN RATE ZONE BASED ON SAMPLE). Considering this, which of the following is closest to your view?

[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	**EGD**	**Union**	**North**	**South**	**Low**	**Med-low**	**Med-high**	**High**	**Yes**	**No <$52K**	**No >$52K**
Should implement a single rate zone	40%	43%	36%	60%	29%	40%	39%	40%	43%	31%	41%	44%
Should leave the rate zones as they are	42%	38%	49%	27%	56%	43%	43%	42%	42%	40%	41%	43%
I don't have an opinion on this	11%	12%	9%	8%	9%	12%	11%	11%	9%	15%	12%	9%
Don't know	6%	6%	6%	5%	6%	6%	6%	7%	6%	14%	6%	3%

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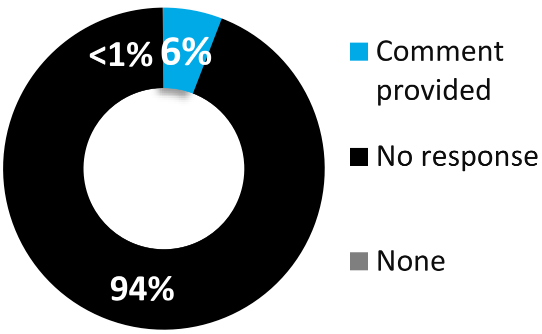
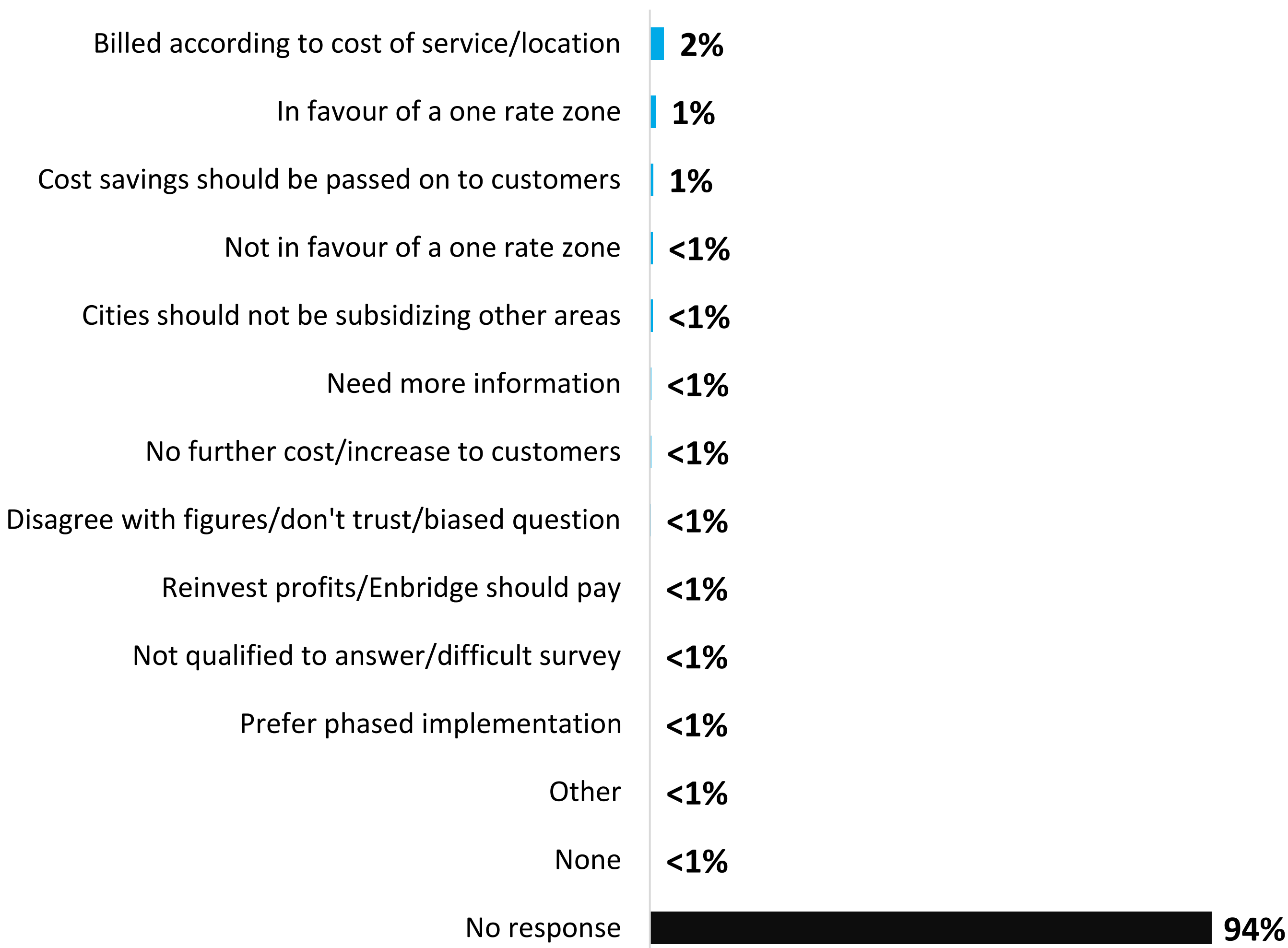
Service and Rate Harmonization

Rate Zone - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





Rate Design

Similar to your electric utility, your gas bill is split into the cost of the natural gas you use and the cost of delivering that gas to you. This question focuses on the delivery charge. Enbridge Gas incurs two types of costs in delivering natural gas to customers like you.

- **Variable costs** depend on how much natural gas you use.
- **Fixed costs** are the same regardless of how much natural gas you use.

The fixed costs that Enbridge Gas incurs can be divided into two groups: the cost of having access to the system, and the cost of the demand that you place on the system which drives the system capacity. We'll look at these two separately.

Cost of being connected to the system

One type of fixed cost is that of being connected to the system. This includes the cost of the pipeline, the pressure regulator, the natural gas meter, meter reading, billing, the contact centre and operations support. These costs are **fixed for Enbridge Gas** and are **similar for each customer** and do not change based on the size of the customer.

Cost of accessing a portion of the system

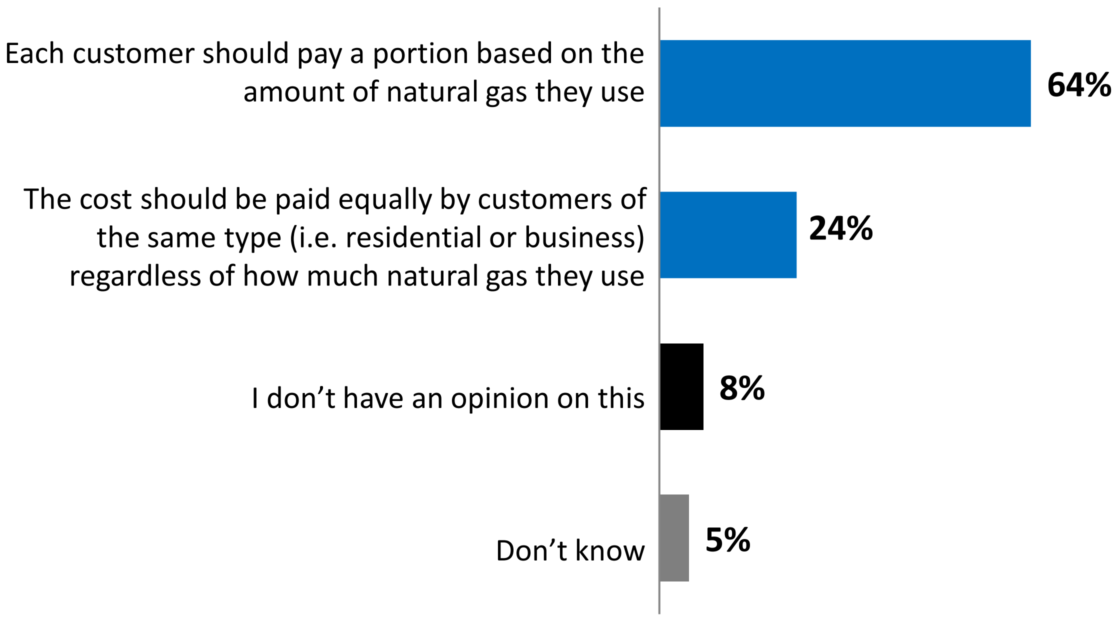
The other type of fixed cost is that of the system capacity. This includes the cost of the infrastructure, its operation, maintenance, and natural gas storage to meet the peak demand of customers on the coldest days of the year. These costs are **fixed for Enbridge Gas** but **may vary for each customer** based on their individual level of peak demand, which is often on the coldest days of the year.

Service and Rate Harmonization

Rate Design - Costs of Being Connected to the System

Q How do you feel residential customers like you should be billed for these costs of being connected to the system?

[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Customers should pay a portion based on use	64%	65%	62%	59%	64%	68%	65%	62%	60%	59%	66%	65%
The cost should be paid equally	24%	23%	25%	27%	25%	19%	22%	25%	28%	16%	20%	27%
I don't have an opinion on this	8%	8%	7%	9%	7%	8%	7%	8%	7%	12%	9%	5%
Don't know	5%	5%	5%	6%	5%	5%	6%	5%	5%	13%	5%	2%

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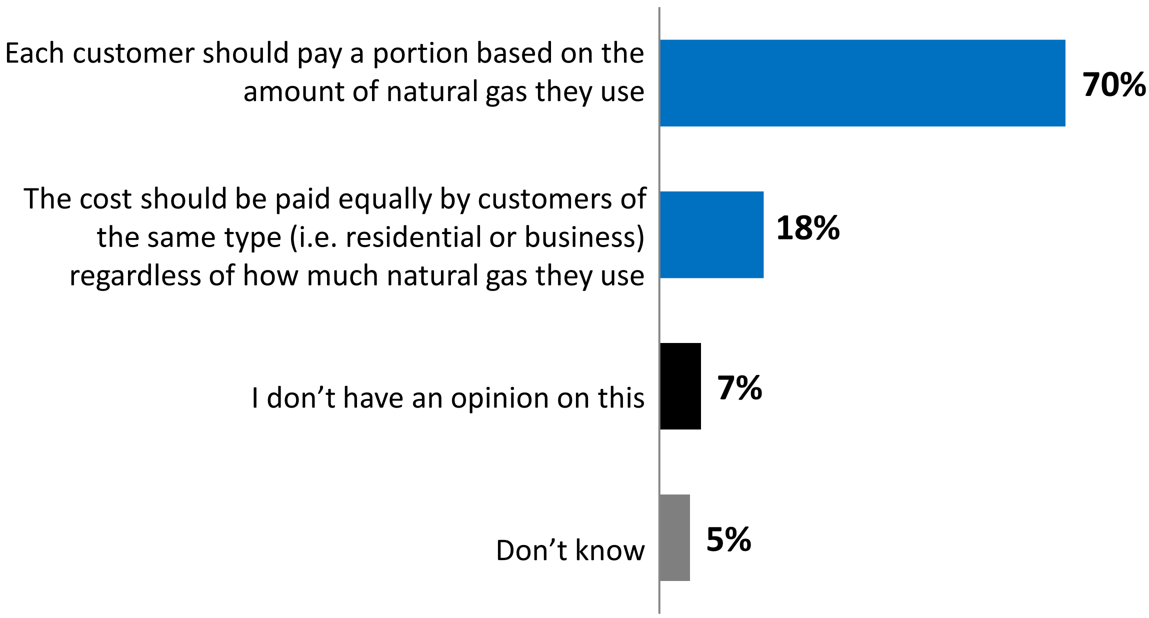
Service and Rate Harmonization

Rate Design - Cost of Accessing System Capacity

Q How do you feel residential customers like you should be billed for these costs of accessing system capacity?

[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	**EGD**	**Union**	**North**	**South**	**Low**	**Med-low**	**Med-high**	**High**	**Yes**	**No <$52K**	**No >$52K**
Customers should pay a portion based on use	70%	70%	70%	64%	71%	74%	71%	69%	66%	61%	71%	73%
The cost should be paid equally	18%	17%	19%	21%	18%	15%	16%	19%	22%	16%	16%	20%
I don't have an opinion on this	7%	7%	7%	9%	6%	7%	7%	7%	7%	11%	8%	5%
Don't know	5%	6%	5%	5%	4%	4%	6%	5%	5%	13%	5%	2%

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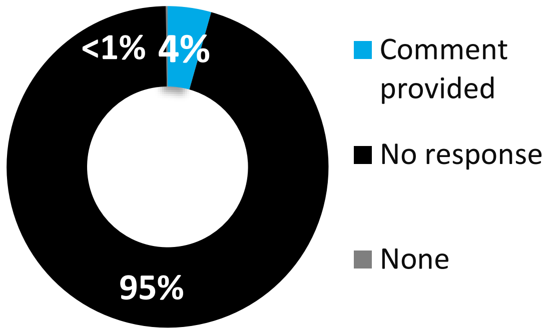
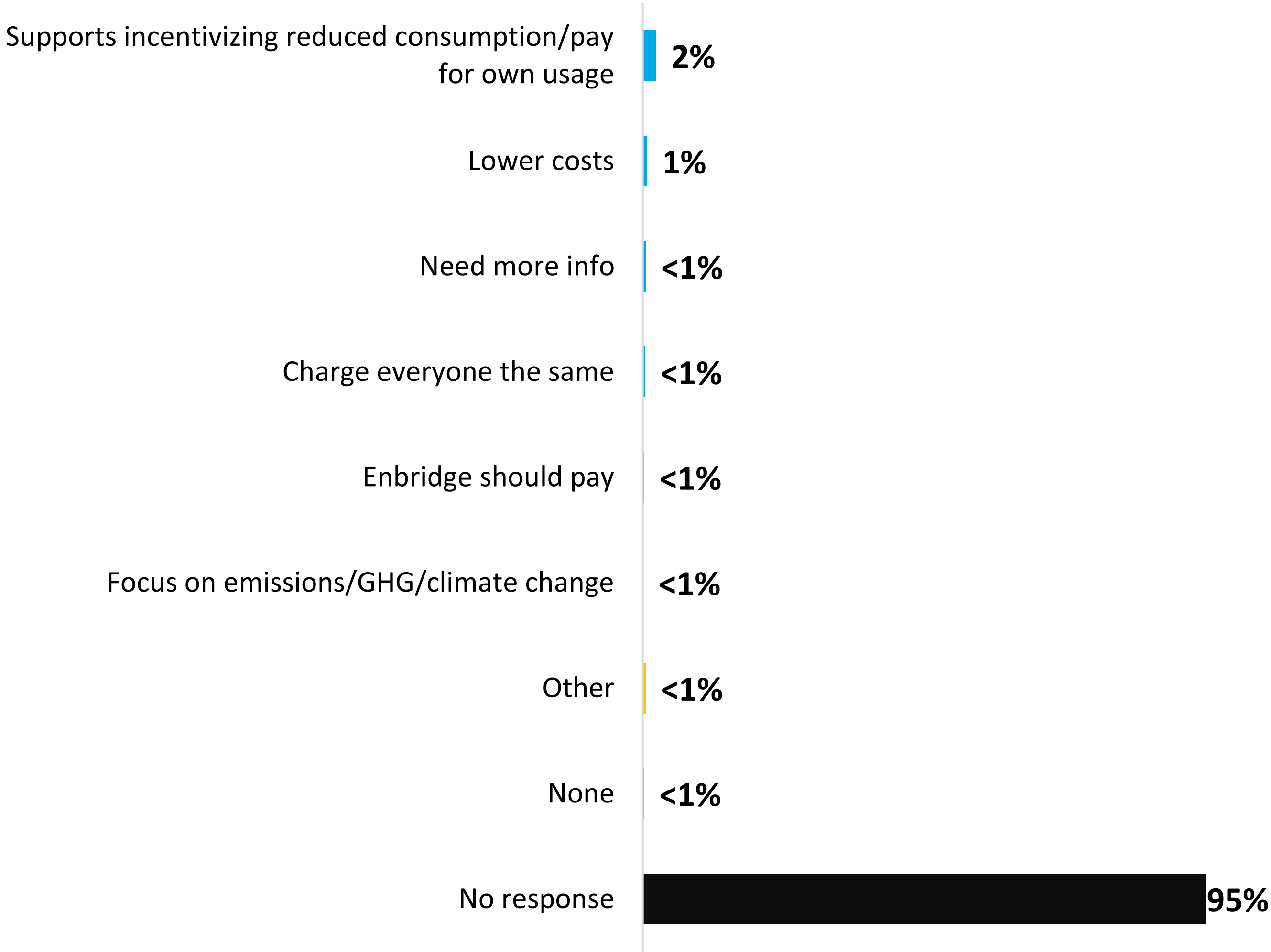
Service and Rate Harmonization

Rate Design - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





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Online Workbook Results

Fuel Choices

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 290 of 550

Cost of the fuel

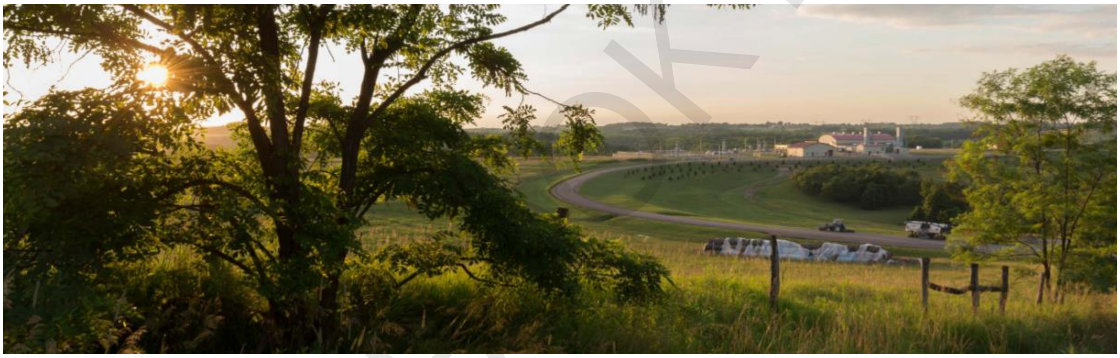
Fuel Choices

As previously discussed, the costs of buying natural gas and transporting it to Ontario are overseen by the Ontario Energy Board and are passed on to customers at cost. However, Enbridge Gas can make some choices about the natural gas it purchases, beyond focusing on the lowest price in the market. We would like to ask you a couple of questions about gas supply options.

Responsibly Sourced Gas

Enbridge Gas is looking at options to ensure that the natural gas it purchases is responsibly sourced. This means that the companies who produce the natural gas adhere to higher standards than the minimum government standards. This relates to areas such as:

- minimizing impacts to air and water quality
- lowering GHG emissions during production
- stronger engagement with Indigenous communities, etc.

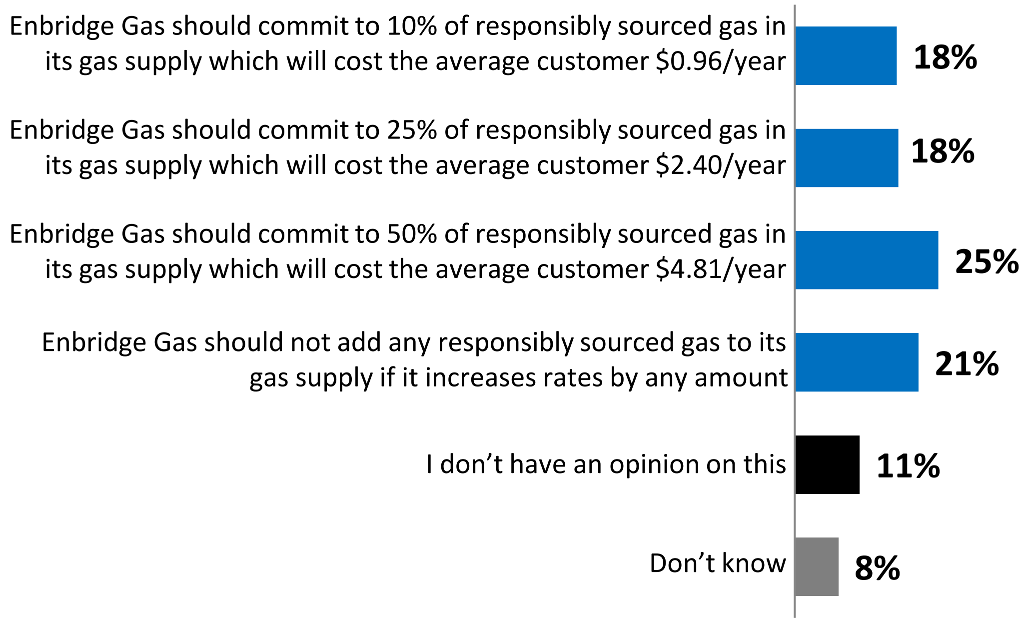


Enbridge Gas can offer some options to include Responsibly Sourced Gas in its portfolio, which can be purchased at a small premium. Responsibly Sourced Gas is a new and emerging trend in the North American natural gas industry. For this reason, current supply options are limited.

Cost of the Fuel

Responsibly Sourced Gas

Q Considering this, which of the following is closest to your view?
[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Commit to 10% of responsibly sourced gas	18%	18%	17%	18%	16%	20%	17%	16%	17%	17%	21%	18%
Commit to 25% of responsibly sourced gas	18%	17%	19%	20%	18%	18%	19%	18%	16%	14%	19%	19%
Commit to 50% of responsibly sourced gas	25%	24%	26%	24%	26%	24%	24%	25%	26%	11%	21%	32%
Not add any responsibly sourced gas	21%	22%	21%	20%	21%	20%	21%	21%	23%	25%	19%	19%
I don't have an opinion on this	11%	11%	11%	10%	11%	11%	12%	12%	10%	18%	12%	8%
Don't know	8%	8%	7%	8%	7%	7%	8%	8%	8%	16%	8%	4%

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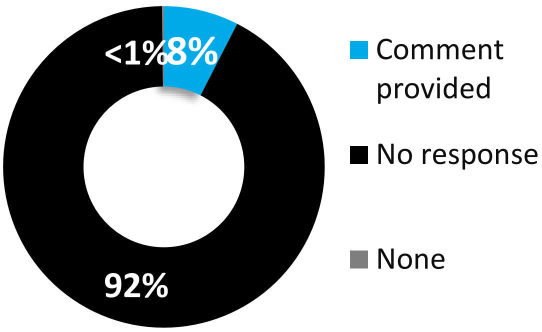
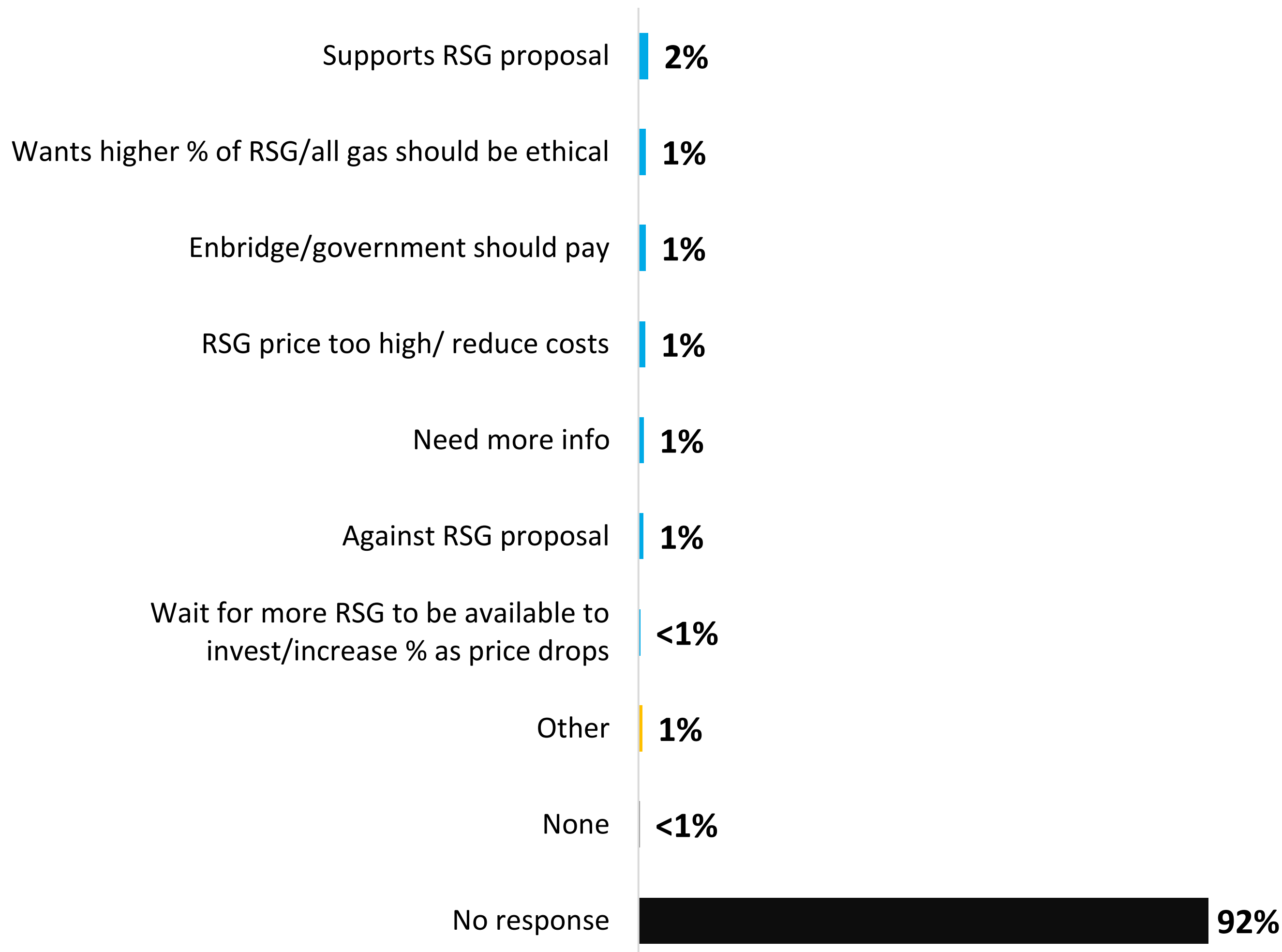
Cost of the Fuel

Responsibly Sourced Gas - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 293 of 550

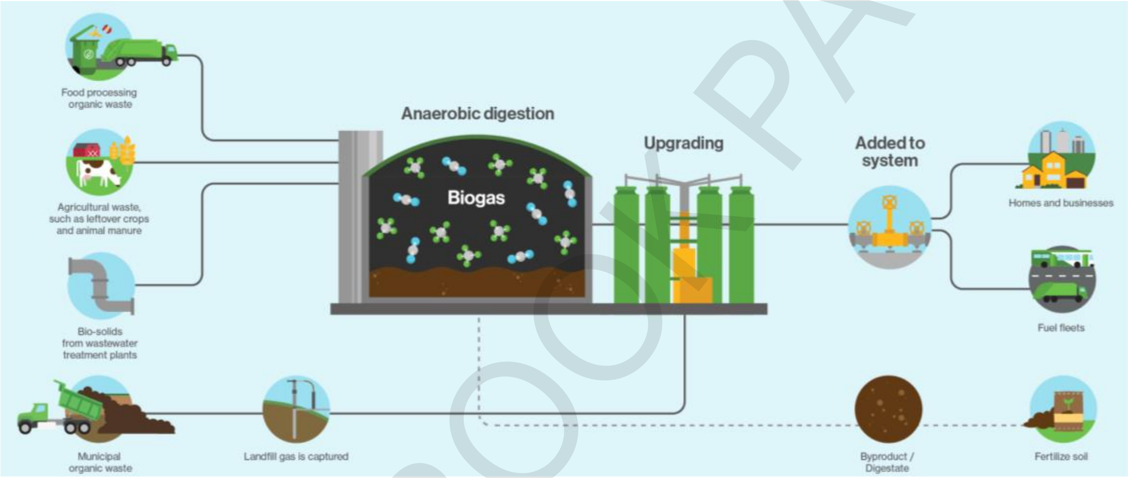
Cost of the fuel

Fuel Choices

Renewable Natural Gas

Enbridge Gas is looking at options to blend more Renewable Natural Gas (RNG) into the natural gas it delivers to green the gas supply. The gas is derived from organic waste from farms, landfills, and water treatment plants. The gas is then blended with traditional natural gas and supplied to customers using existing natural gas infrastructure.

RNG is considered to be carbon neutral and would reduce GHG emissions to help meet climate change targets. Every one percent of RNG in the gas supply reduces GHG emissions by one percent, in a 1:1 ratio. That means every additional 1% of RNG reduces your natural gas GHG emissions by 1%, and across the Enbridge Gas system, this is equivalent to taking 55,000 cars off the road.



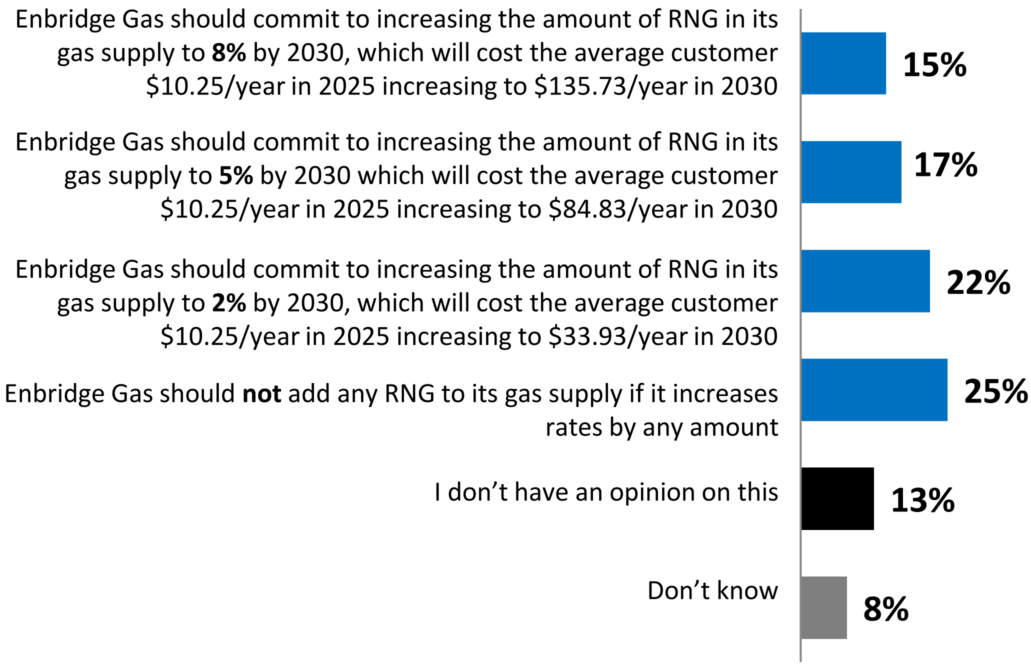
Enbridge Gas is developing a plan to increase the blend of RNG in the gas system from 0.5% in 2025 to a higher amount over the course of the 2024 to 2028 plan and beyond. This amount is limited by the amount of RNG available in the market. Since the cost to produce RNG is currently higher than that of traditional natural gas it could have an impact on your rates.

The federal carbon charge would not be applied to the volume of RNG on customer bills, which is accounted for in the costs shown below.

Cost of the Fuel

Renewable Natural Gas

Q Considering this, which of the following is closest to your view?
[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	**EGD**	**Union**	**North**	**South**	**Low**	**Med-low**	**Med-high**	**High**	**Yes**	**No <$52K**	**No >$52K**
Increasing the amount of RNG in its gas supply to **8%**	15%	15%	14%	12%	15%	13%	15%	15%	15%	8%	12%	20%
Increasing the amount of RNG in its gas supply to **5%**	17%	17%	18%	18%	18%	18%	17%	18%	16%	7%	17%	21%
Increasing the amount of RNG in its gas supply to **2%**	22%	22%	23%	24%	22%	23%	22%	21%	22%	18%	23%	24%
Should not add any RNG to its gas supply	25%	26%	24%	25%	24%	24%	24%	25%	28%	31%	26%	21%
I don’t have an opinion on this	13%	13%	12%	13%	12%	13%	13%	13%	12%	21%	13%	10%
Don’t know	8%	8%	9%	8%	9%	8%	8%	9%	7%	16%	9%	5%

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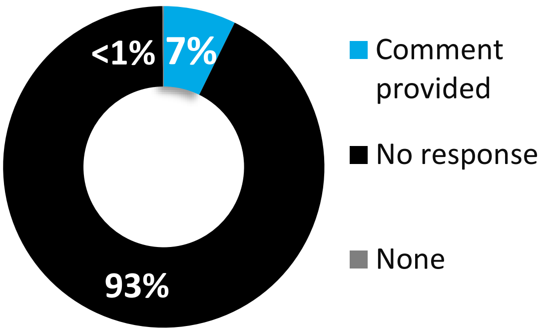
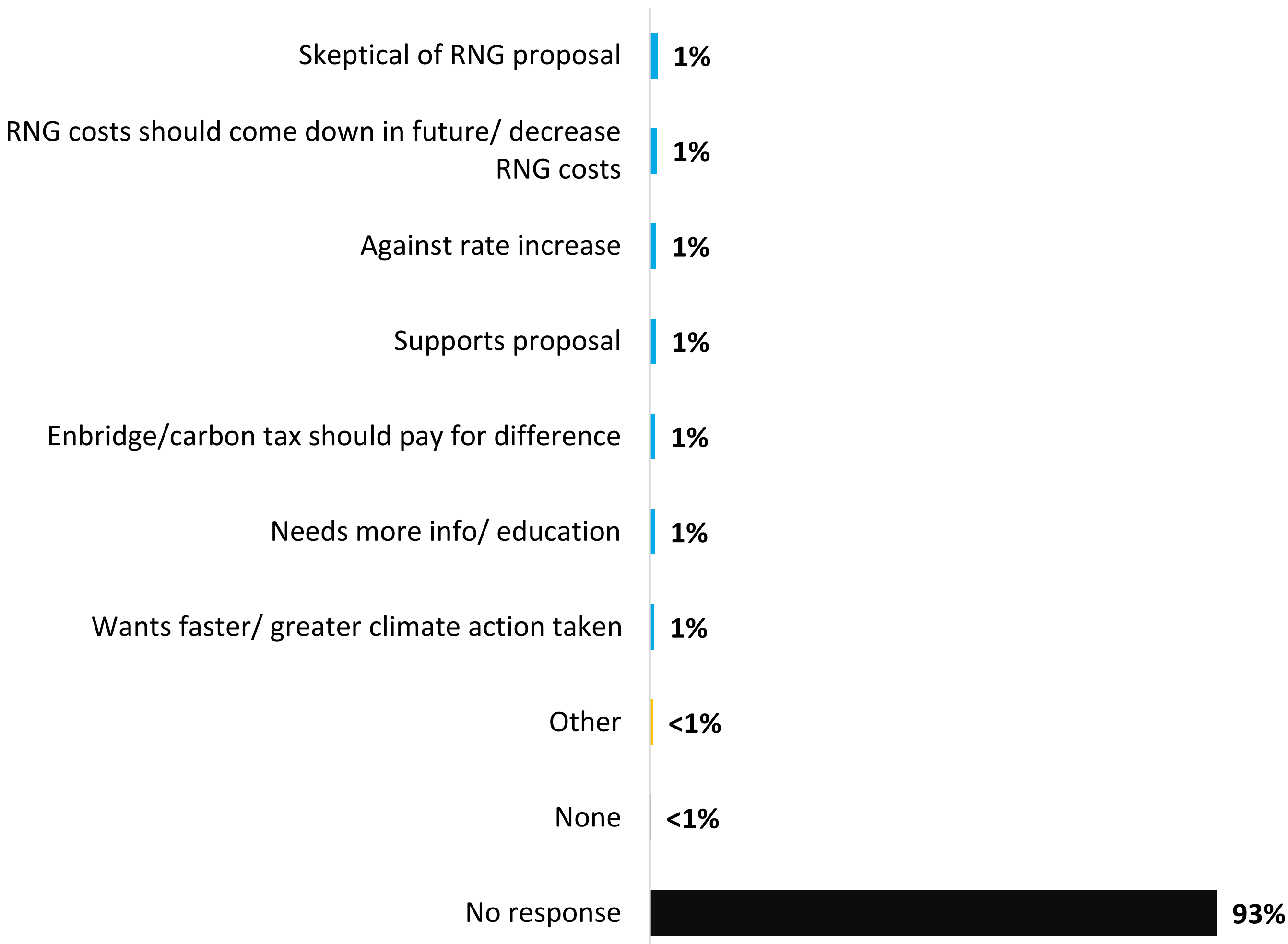
Cost of the Fuel

Renewable Natural Gas - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





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Online
Workbook Diagnostics

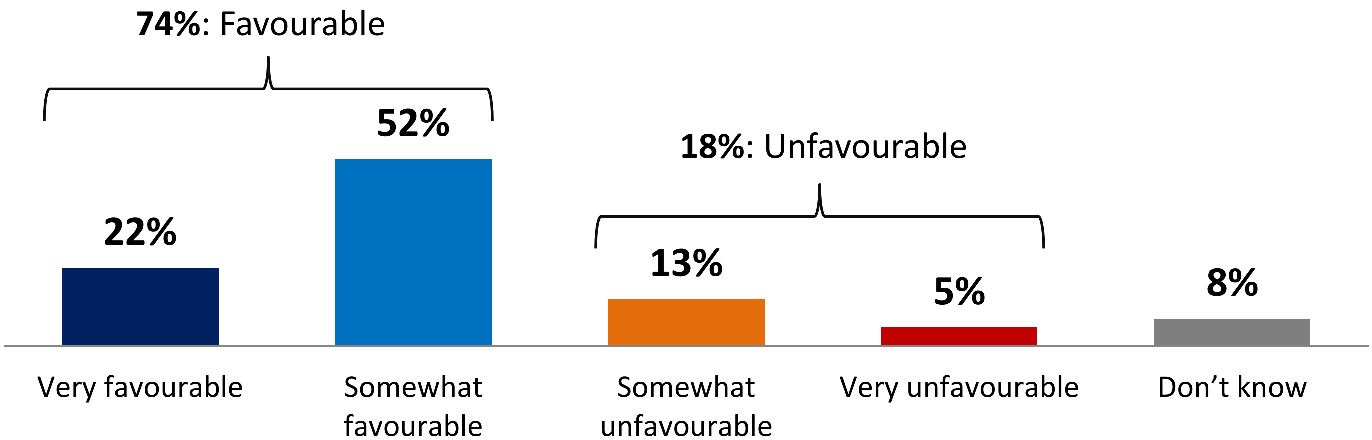
Final Thoughts

Workbook Impression

Q

Overall, did you have a favourable or unfavourable impression of the workbook you just completed?

[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Very favourable	22%	22%	21%	19%	22%	21%	20%	23%	23%	12%	22%	27%
Somewhat favourable	52%	51%	54%	55%	54%	54%	55%	50%	50%	44%	53%	53%
Somewhat unfavourable	13%	13%	13%	14%	12%	13%	13%	14%	13%	17%	14%	11%
Very unfavourable	5%	6%	5%	4%	5%	5%	5%	5%	6%	9%	4%	4%
Don't know	8%	8%	7%	7%	7%	8%	7%	8%	7%	18%	7%	4%
Favourable (Very + Somewhat)	**74%**	**73%**	**76%**	**74%**	**76%**	**74%**	**75%**	**73%**	**74%**	**56%**	**76%**	**80%**
Unfavourable (Very + Somewhat)	18%	19%	17%	18%	17%	18%	18%	19%	19%	26%	18%	15%

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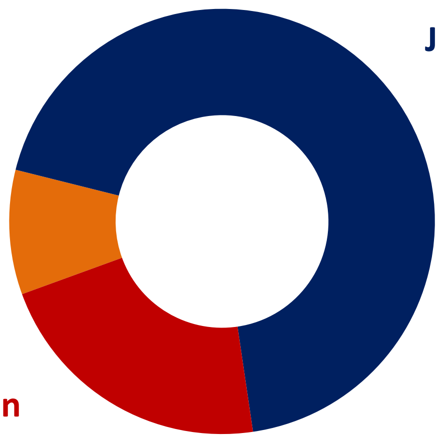
Final Thoughts

Amount of Information

Q

In this workbook, do you feel that Enbridge Gas provided too much information, not enough, or just the right amount?

[asked of all respondents; n=5,400]



		Rate Zone		Union Region		Consumption				LEAP Qualification		
	Total	EGD	Union	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Too little information	9%	10%	8%	8%	8%	9%	9%	10%	10%	14%	8%	8%
Just the right amount	69%	68%	70%	69%	70%	71%	68%	67%	68%	57%	71%	74%
Too much information	22%	22%	22%	22%	21%	21%	23%	22%	21%	29%	21%	19%

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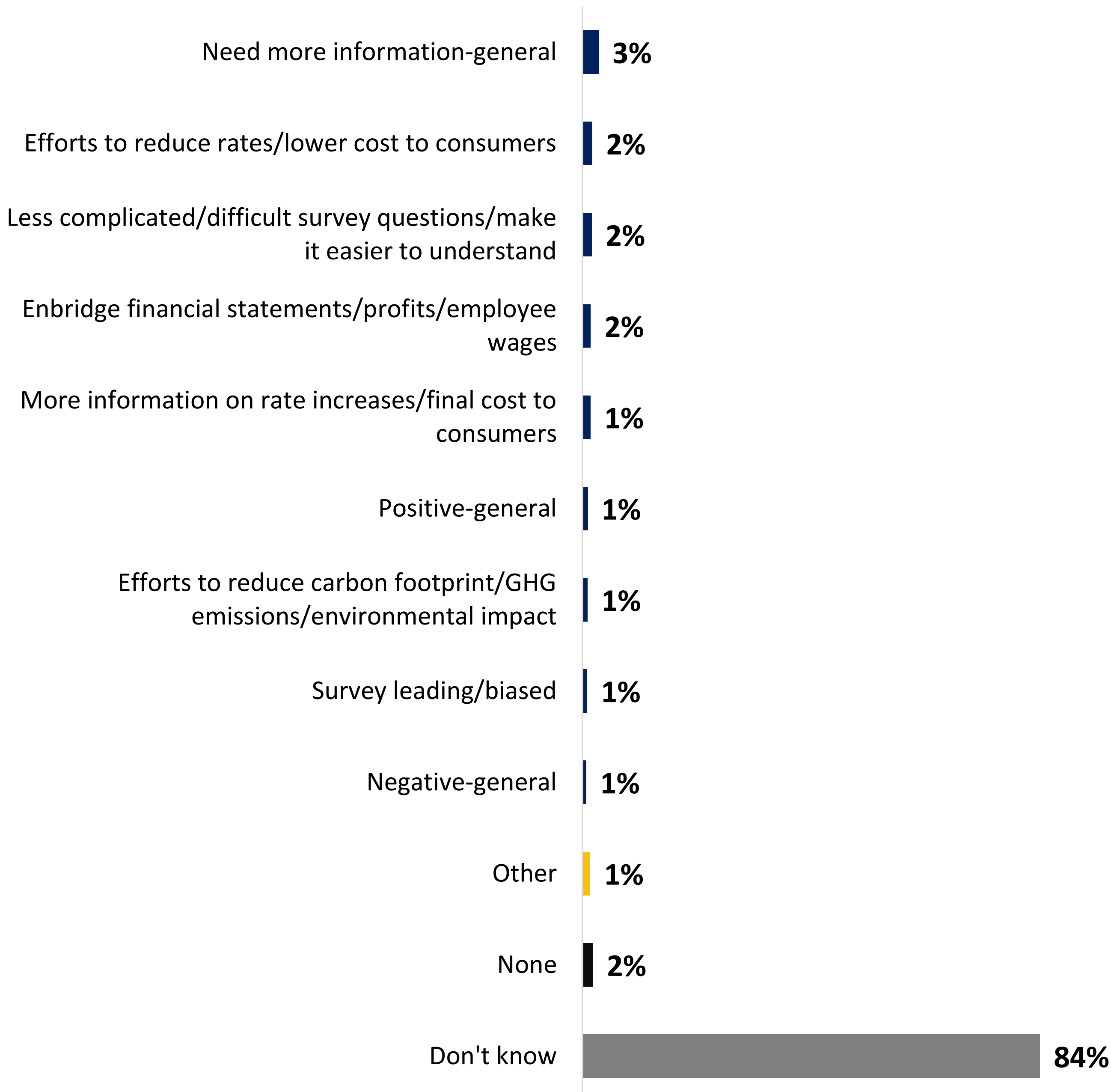
Final Thoughts

Content Missing from Engagement

Q

Was there any content missing that you would have liked to have seen included in this workbook?

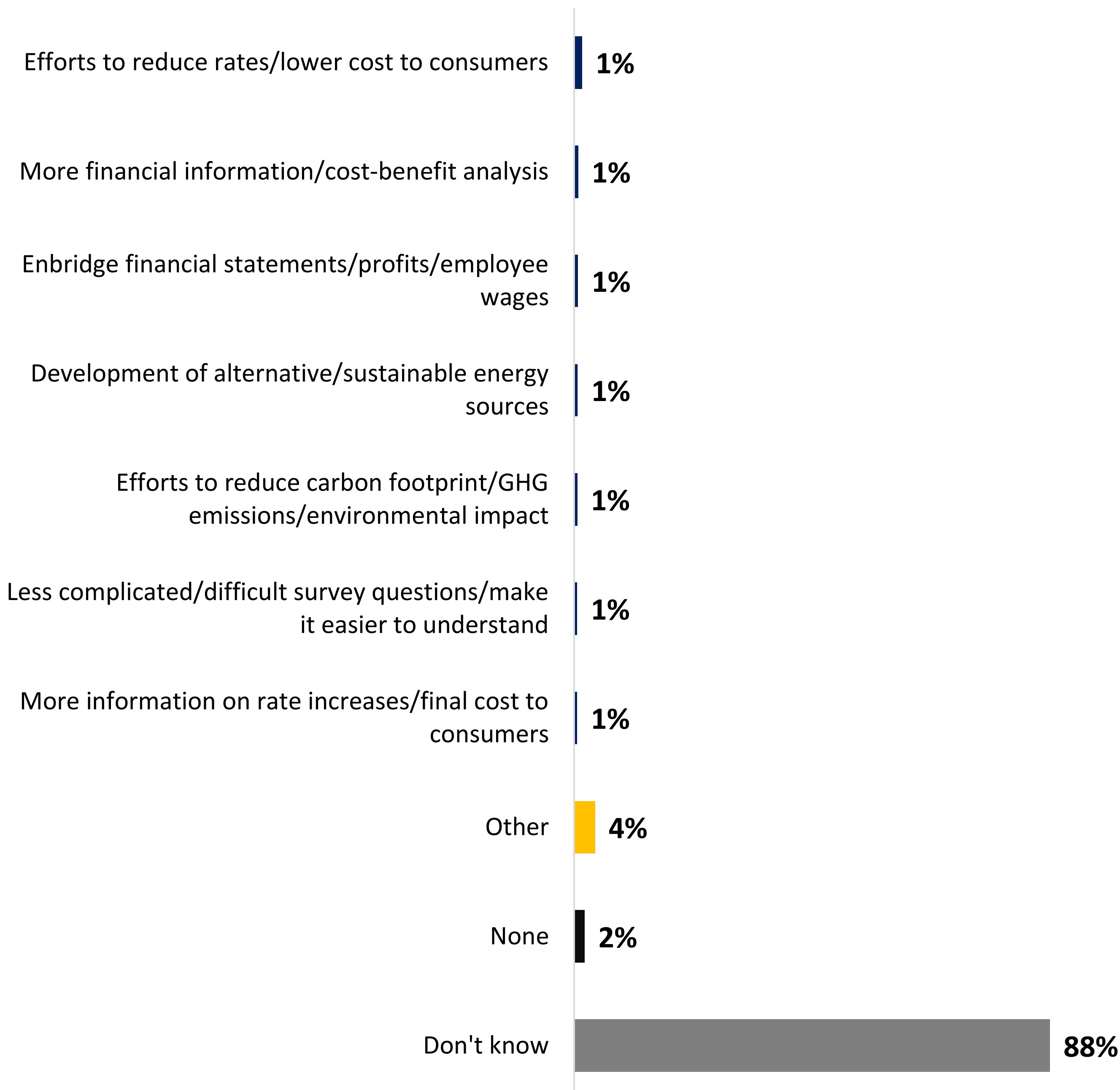
[asked of all respondents; n=5,400]



Final Thoughts

Outstanding Questions

Q Is there anything that you would still like answered?
[asked of all respondents; n=5,400]



Note: Refused (<1%) not shown

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2024 Rate Rebasing Customer Engagement

Phase Three Report :
Small & Medium-Large Business Survey

January 2022

Table of Contents

Project Overview & Methodology

Enbridge Gas 2024 Rate Rebasing Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Enbridge Gas to assist in meeting its customer engagement commitments for its 2024 Rate Rebasing requirements. This engagement had three phrases:

- Phase One was an exploratory phase that used qualitative tools to identify range of needs and outcomes that matter to customers and to explore some of the trade-offs that Enbridge expected to deal with in their planning process.
- Phase Two used surveys to draw generalizable conclusions regarding the findings from Phase One.
- Following Phase Two, Enbridge Gas developed a draft plan that built on the findings of the first two phases of the customer engagement as well as other business objectives. The Phase Three survey was then designed to provide feedback on that plan that can be used by Enbridge gas as it finalises its plan and its submission to the Ontario Energy Board (OEB).

This report summarises the findings of the Phase Three representative online workbook-style survey with small and medium-large business customers. Separate reports summarise the findings of both a representative and “voluntary” version of the residential Phase Three survey.

Research Objectives

There are four key objectives for the Phase Three survey:

1. To acquire feedback on key choices in the development of Enbridge Gas’ capital plan that involve trade-offs between customer outcomes.
2. To secure customer reaction to the potential rate impacts of the draft plan.
3. To obtain customer input on rate design choices.
4. To assess customer interest in improving Environmental, Social and Governance outcomes by pursuing responsible gas sourcing and renewable gas sourcing.

Project Overview & Methodology

Survey Development

INNOVATIVE used a "workbook-style" survey to ensure the opinions collected on these issues were informed opinions. Through the workbook, customers were provided key background information on Enbridge Gas and its network as well as background relevant to key capital, rate design and sourcing choices. The workbook was tested to ensure the material and questions were understandable for customers with limited knowledge of the Enbridge Gas system as well as to assess whether the workbook found the right balance between too much and too little information. Specific design features included:

- Providing both background information and an estimate of rate impact (wherever available), for capital planning choices about compression stations, vintage steel pipeline replacement, hydrogen gas, an innovation and technology fund, cross bores, and advanced meter infrastructure.
- Comment boxes were provided for all trade-off questions.
- A review page to give respondents an option to change their responses based on the total estimated rate impact of their original choices. They could change their responses as many times as they liked.
- Additional questions touched on issues around service and rate harmonization, as well as fuel choices that would reduce GHGs and improve ESG outcomes.
- A final set of diagnostic questions allowed respondents to give feedback on the customer engagement survey itself, including overall favourability, amount of information provided and any missing content or questions they would still like answered.

The surveys were developed by Enbridge Gas and finalized with input from INNOVATIVE. All survey participants were sent an invitation from Enbridge Gas via email containing a unique survey URL.

All data was collected between December 10th, 2021 and January 10th, 2022. Details on data weighting can be found on slide 6.

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Sample Design

Weighting the Data

In order to get as many completed surveys as possible from this group of business customers, all customers were invited to complete the survey.

We then compared the breakdown of survey respondents by region and consumption volume to the breakdown of the entire population of small and medium-large business customers. The final data for the business survey were then weighted to be proportionate based on the actual distribution of business customers in each region, as well as by consumption volume. *Weighted and unweighted sample sizes are outlined below. Minimal weighting was required to arrive at a representative sample of 3,500.*

Consumption Volume	Unweighted N						Weighted N					
	EGD Region		Union Region				EGD Region		Union Region			
	GTA	Other	South/ West	Central	North/ East	Total	GTA	Other	South/ West	Central	North/ East	Total
Low	356	158	146	190	86	936	440	146	86	121	49	842
Med Low	327	149	160	172	105	913	405	140	91	116	61	813
Med High	307	170	155	158	129	919	383	140	89	124	78	814
High	351	170	148	171	106	946	406	143	79	117	68	814
Med-Large	98	27	32	40	11	208	128	34	17	28	10	217
Total	**1439**	**674**	**641**	**731**	**437**	**3922**	**1763**	**602**	**362**	**506**	**267**	**3500**

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

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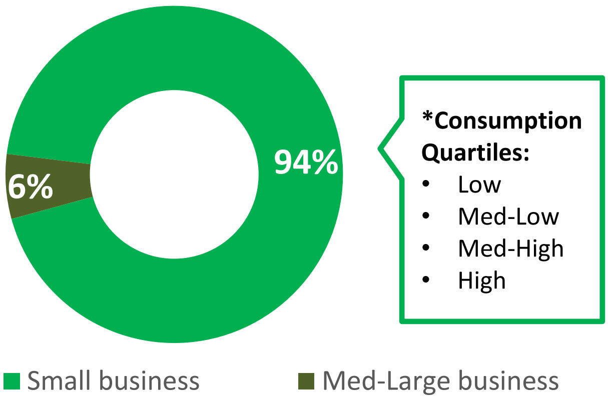
Online Workbook Results

Respondent Profile

Online Workbook

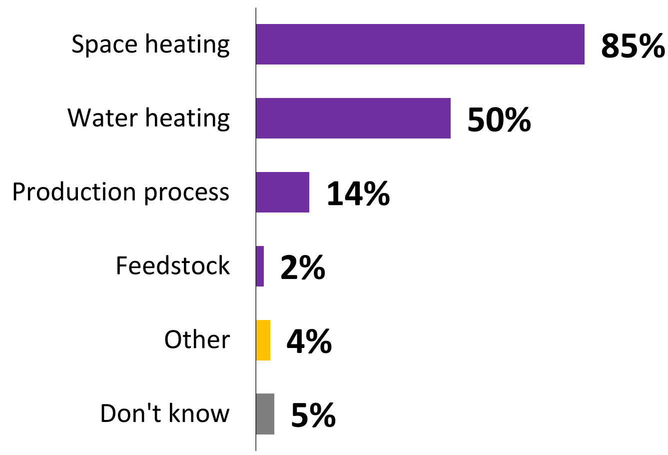
Firmographic breakdown

Consumption Volume

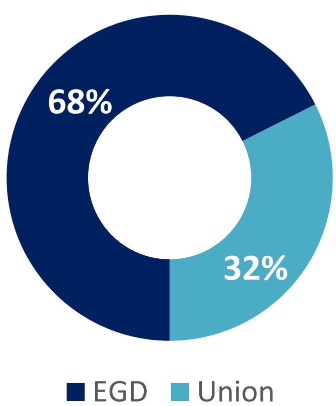


*Small business was evenly divided across consumption quartiles

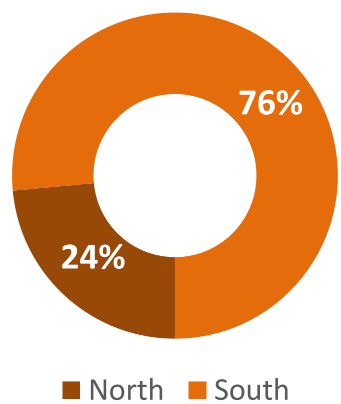
Natural Gas Use



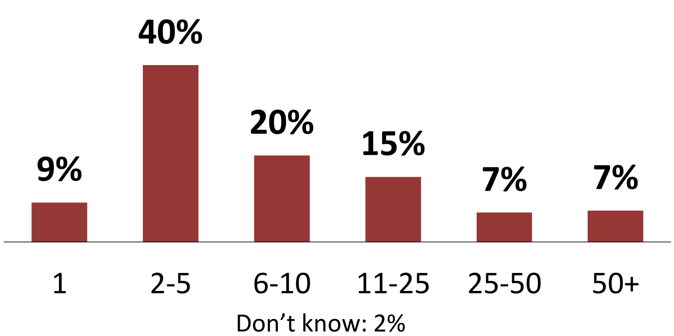
Rate Zone



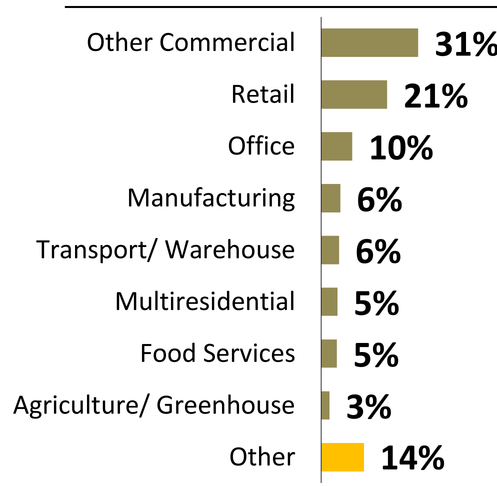
Union Region



Number of Employees



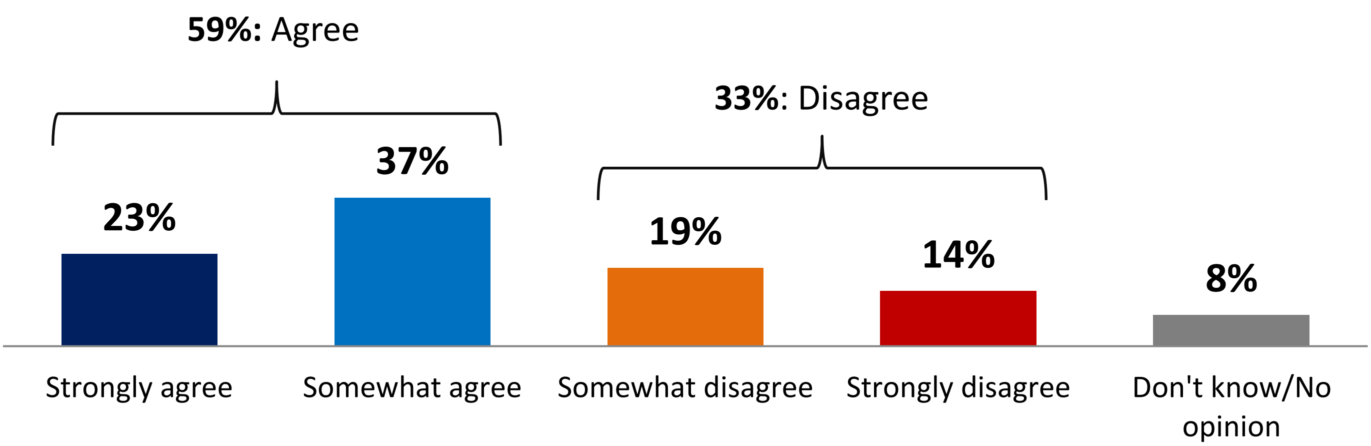
Sector



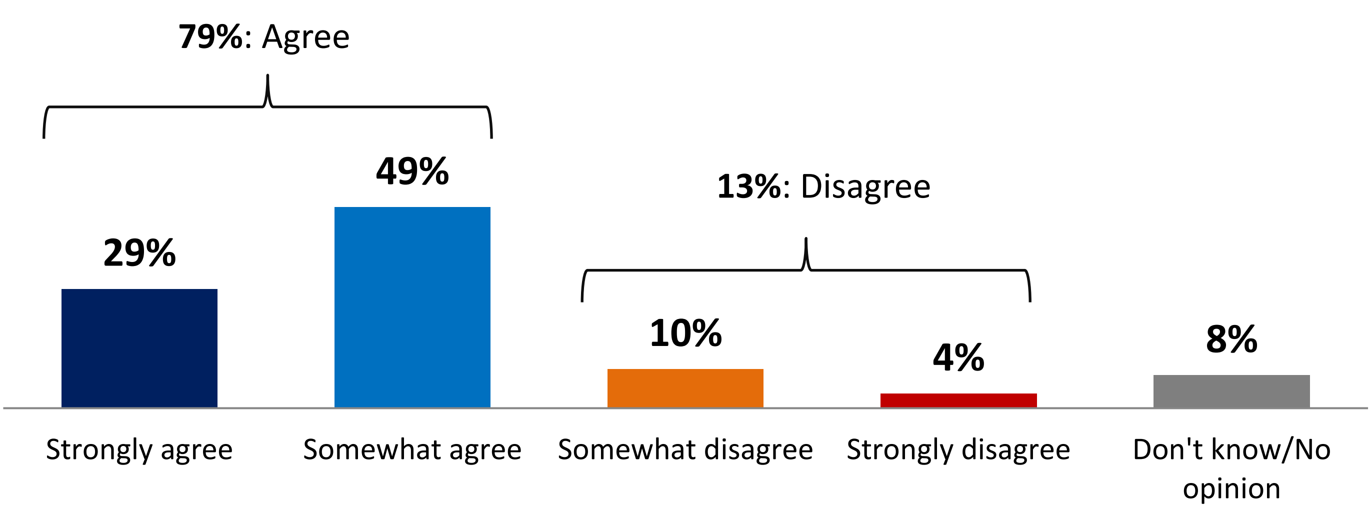
Online Workbook

Environmental Controls

Q To what extent do you agree or disagree with the following statements?
The cost of my Enbridge Gas bill has a major impact on my business' finances and requires the business do without some other important priorities.



Q To what extent do you agree or disagree with the following statements?
Customers are well served by the energy system in Ontario.



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Online Workbook Results

Background

A note about this report: In order to accurately represent the survey as it was viewed by respondents, we have included all of the background information that was provided to respondents before they were asked specific questions. Throughout this report, pages with grey headers show actual workbook pages as they were shown to online survey respondents. Slides with dark blue headers show the responses to the survey questions.

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 312 of 550

About this Customer Engagement

Welcome to the Enbridge Gas Customer Engagement!

As Enbridge Gas plans for the future, it needs your input into choices that will impact the services you receive and the rates you pay.

- Enbridge Gas is looking for your feedback on its draft investment plan for 2024 and beyond to ensure that the plan reflects your needs and preferences.
- You don't need to be a natural gas expert to complete this workbook. It focuses on basic choices between outcomes that matter to you and provides the background information you need to answer the questions.
- The most important part of this workbook are the survey questions. While your view may not always align exactly with any of the options presented, please select the one that is closest. If you truly aren't sure, select the "don't know" option.

This workbook will take approximately 20-30 minutes to complete. Your progress will be saved as you move through the workbook, meaning you can leave and return to complete it at any time.

Those who complete the questions that follow will be invited to enter a draw to win one of two $500 cash prizes.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback.

If you are reading this on a smaller mobile device, you may wish to access the survey from a tablet, desktop or laptop instead, so that it is easier to read.

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 313 of 550

Background

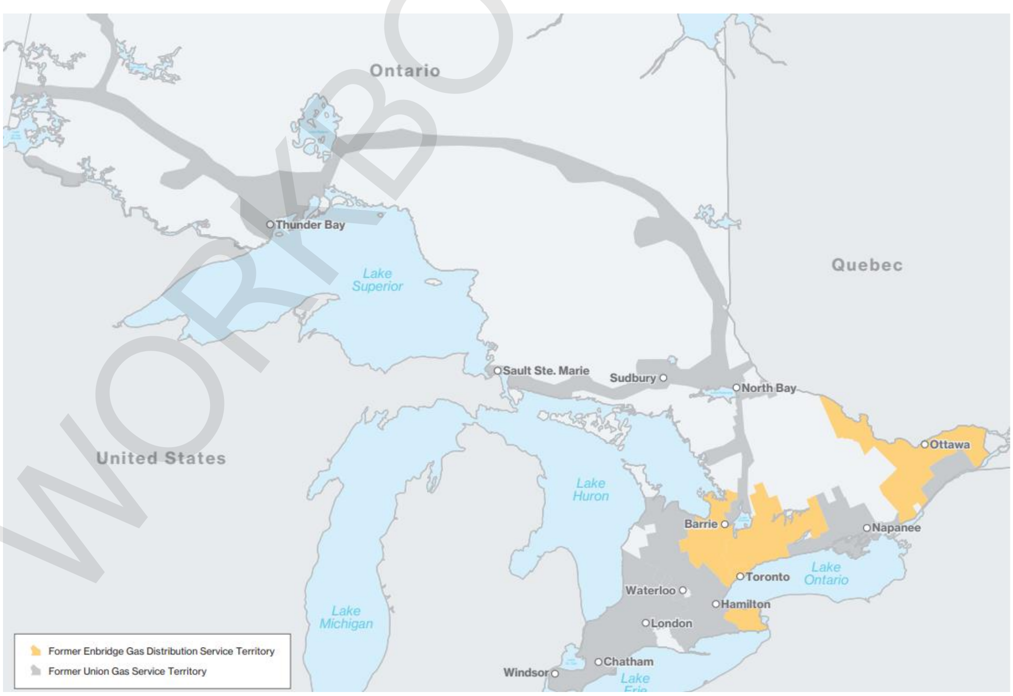
Who is Enbridge Gas?

Enbridge Gas Inc. is based in Ontario and delivers energy to customers in Ontario. Its parent company Enbridge Inc. is headquartered in Calgary, Canada, and operates across North America. Rates and business plans developed by Enbridge Gas must be approved by the Ontario Energy Board (the OEB), which regulates natural gas utilities in Ontario.

Enbridge Gas …

- ✓ Distributes natural gas to about 3.8 million residential, business and industrial customers
- ✓ Attaches more than 50,000 new customers each year
- ✓ Has agreements to provide gas distribution service within 313 municipalities and provides natural gas within 23 First Nations communities
- ✓ Has a network of over 151,500 kilometers of underground pipeline

In 2019, Enbridge Gas Distribution and Union Gas merged to form one company, Enbridge Gas Inc. Throughout this workbook we occasionally refer to Legacy Enbridge Gas Distribution and Legacy Union Gas (the previous companies), but mainly refer to the whole service area or territory that Enbridge Gas serves today.

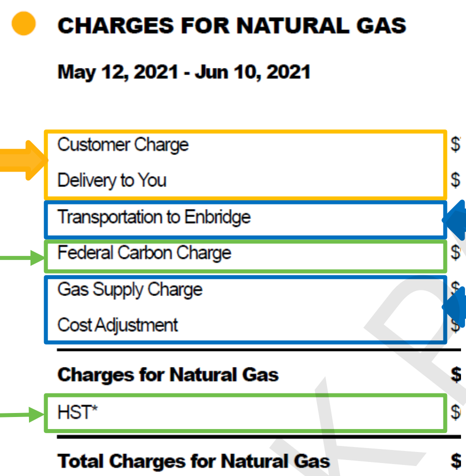


Background

Where do your rates go?

Below is an example of a natural gas bill.

The charges outlined in Orange are the costs of getting the gas to you once it reaches the Enbridge Gas system. At times, this may require a Rate Adjustment which, along with other rates, is determined through a regulatory process.



The charges outlined in Blue are the 'passed through' costs that pay for the natural gas you use (Gas Supply Charge and Cost Adjustment) and the cost of transporting it from where it is produced to the Enbridge Gas system (Transportation to Enbridge). If customers buy their natural gas through an energy marketer these costs would be subject to the agreement with the energy marketer.

Enbridge Gas is also responsible for collecting HST and the Federal Carbon Charge on behalf of the government. While some of these costs may be given back to customers in rebates, how these funds are used is determined by the government and is out of Enbridge Gas' control.

The pie chart below shows where the money goes.

The Blue slice shows the 'passed through' costs that pay for the natural gas and transportation to the Enbridge Gas system.

The money that goes to Enbridge Gas is in the other two slices.

- The Light Orange slice pays the capital costs of the infrastructure (such as pipes, compressors, buildings and other equipment) used to move and store natural gas across the system.
- The Dark Orange slice pays for operations – including the people who operate and maintain the equipment and the people who answer your calls and provide customer service.

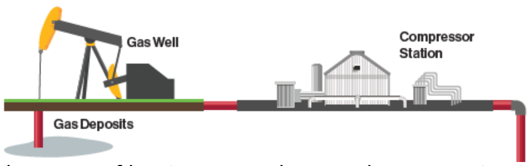
[**NOTE:** survey respondents were able to scroll down directly to the information on the following page]

Enbridge Gas Customer Engagement

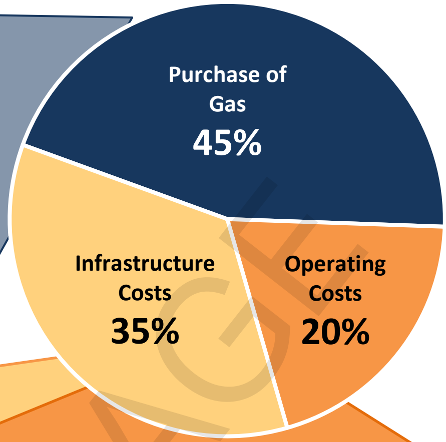
2024 Rate Rebasing Customer Engagement Workbook

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 315 of 550

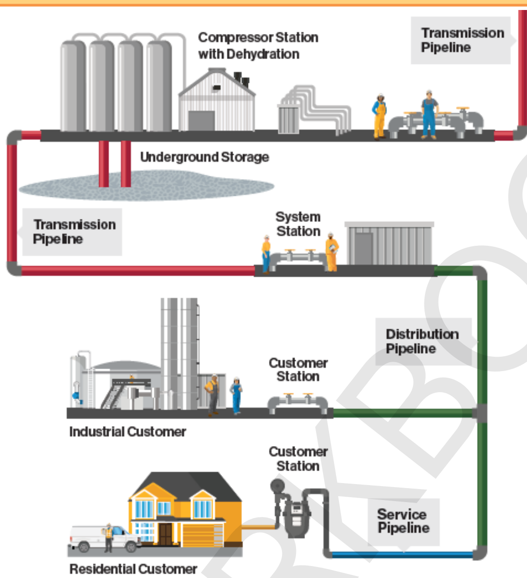
Purchase of Gas



The costs of buying natural gas and transporting it to Ontario are overseen by the Ontario Energy Board, and are passed on to customers at cost.



Infrastructure



Once gas reaches the Enbridge Gas system, it is metered and then delivered to customers through a distribution system of local gas mains, small-diameter service lines and, ultimately, customer meters.

Natural gas is often stored in large underground reservoirs to help meet spikes in demand, particularly in winter.

Operations

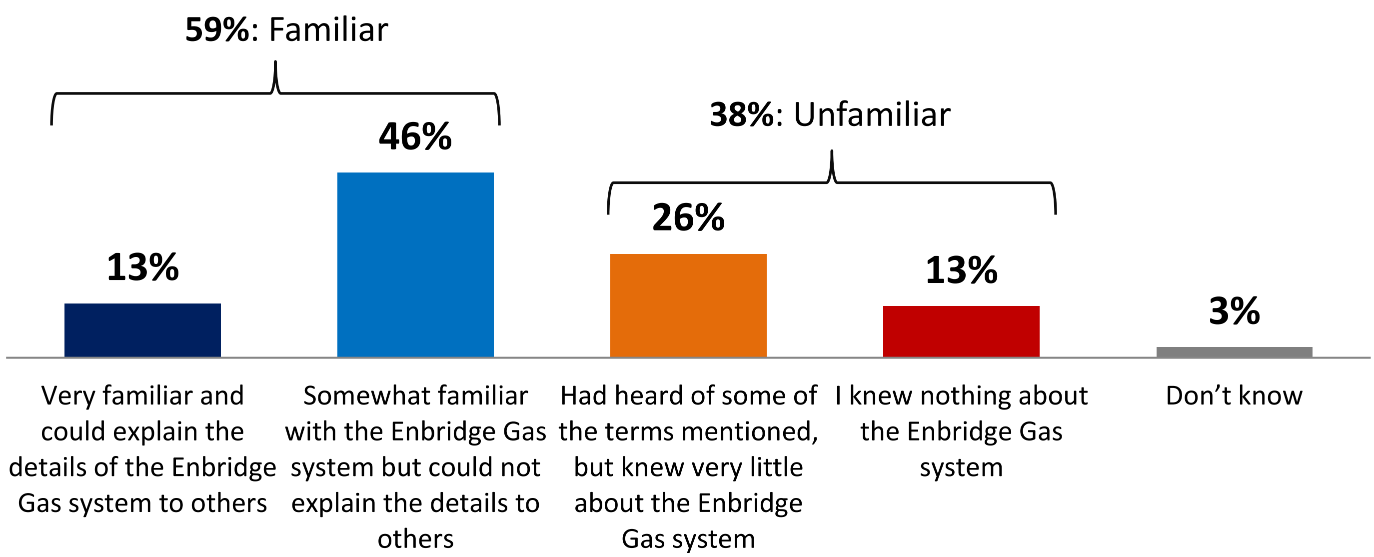
Delivering gas to customers is just one part of Enbridge Gas' activities. Enbridge Gas provides a variety of supporting services to customers including:

- Manage and operate its call centres, ombudsperson offices, and its online My Account system to help customers manage their account online.
- Complete meter replacements, inspections, and respond to emergency calls.
- Conduct millions of meter readings each year.
- Offer programs to help customers reduce their natural gas usage. Since 1995, Enbridge Gas has saved its customers 30 billion lifetime cubic meters of natural gas and 56.2 million tonnes of greenhouse gas emissions, the equivalent of taking 12.2 million cars off the road for a year or heating 13.1 million natural gas homes for a year. These programs get approved by the Ontario Energy Board in a separate process and the costs for these programs are included in your rates.

Background

Familiarity with Enbridge Gas

Q Before this survey, how familiar were you with Enbridge Gas when it comes to delivering natural gas to homes and businesses in Ontario?



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	**EGD**	**Union**	**North**	**South**	**Med-Large**	**Small**	**Low**	**Med-low**	**Med-high**	**High**
Very familiar	13%	14%	11%	11%	11%	14%	13%	13%	13%	14%	13%
Somewhat familiar	46%	44%	48%	50%	48%	55%	45%	43%	43%	45%	49%
Had heard of some terms mentioned	26%	26%	26%	25%	26%	19%	26%	25%	27%	26%	25%
I knew nothing about the Enbridge Gas system	13%	13%	13%	13%	13%	10%	13%	16%	13%	12%	10%
Don't know	3%	3%	2%	1%	2%	1%	3%	3%	3%	3%	2%
Familiar (Very + Somewhat)	**59%**	**59%**	**60%**	**61%**	**59%**	**69%**	**58%**	**56%**	**57%**	**59%**	**62%**
Unfamiliar (Had heard + I knew nothing)	38%	38%	39%	38%	39%	30%	39%	41%	40%	38%	36%

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Background

Familiarity with Enbridge Gas (cont'd)

Q

Before this survey, how familiar were you with Enbridge Gas when it comes to delivering natural gas to homes and businesses in Ontario?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Very familiar	13%	16%	12%	13%	15%	12%	14%	13%	12%	12%	21%	11%	11%	12%
Somewhat familiar	46%	51%	42%	54%	52%	48%	43%	41%	49%	49%	38%	50%	48%	49%
Had heard of some terms mentioned	26%	23%	29%	21%	17%	25%	26%	28%	26%	26%	24%	26%	29%	24%
I knew nothing about the Enbridge Gas system	13%	9%	15%	11%	14%	13%	13%	14%	9%	11%	13%	11%	11%	14%
Don't know	3%	1%	2%	2%	2%	1%	3%	3%	5%	1%	3%	1%	2%	1%
Familiar (Very + Somewhat)	**59%**	**67%**	**55%**	**66%**	**67%**	**60%**	**57%**	**55%**	**61%**	**61%**	**59%**	**62%**	**58%**	**61%**
Unfamiliar (Had heard + I knew nothing)	38%	32%	44%	32%	31%	39%	39%	42%	34%	37%	38%	37%	40%	38%

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Where does this consultation fit?

Here in Ontario, customer views are central to the utility planning process.

- **Rates and business plans must be approved by the Ontario Energy Board (the OEB).**
- **The OEB requires that utilities consult with customers to understand your views on key trade-offs.**
- **In addition, the utilities must show how they took customer views into account when developing the plan.**

While some planning decisions will depend on detailed knowledge of engineering and industry standards, in other cases the choices will involve trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down. That is where you come in.

The diagram below shows how customers play a role at three points as Enbridge Gas develops and submits its business plan to the OEB.

How does Customer Engagement Impact Business Planning?

Enbridge Gas has developed a phased approach to gathering and responding to customer feedback.

✔ **1. Identify Customer Priorities**
In June through August of 2021, Enbridge Gas asked residential and business customers about their priorities for natural gas service.

✔ **2. Use Customer Feedback to Guide Development of Plan**
Enbridge Gas planners were given summaries of the key findings from the initial customer engagement to consider as they began building their plans.

You are here

3. Collect Customer Feedback on the Draft Plan
Now Enbridge Gas is returning to customers to get feedback on the draft plan and ask customers how the plan fits with their needs and preferences.

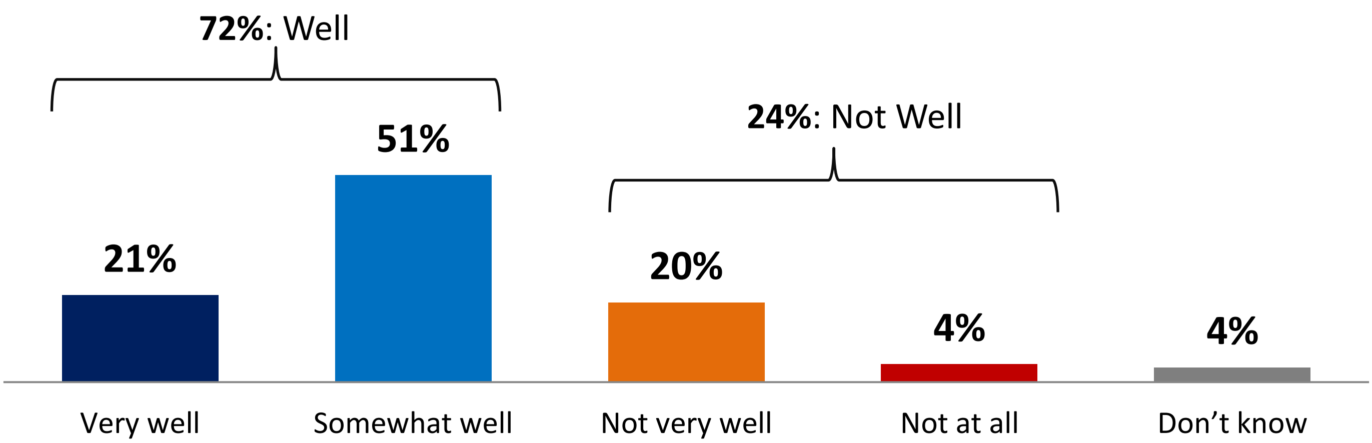
4. Re-Examine Plan
Enbridge Gas has an opportunity to make appropriate changes to the plan based on customer feedback.

5. Submit the Plan to the Ontario Energy Board (OEB)
Enbridge Gas will file the plan, with this workbook, and a summary report with the OEB, where it will be examined by the OEB, consumer advocates and other independent parties in a public hearing. **Customers** can view and comment on this application through the OEB website.

Background

Understanding the Planning Process

Q How well do you feel you understand how your feedback fits within the planning process?



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Very well	21%	22%	21%	19%	21%	19%	22%	21%	20%	22%	23%
Somewhat well	51%	50%	53%	55%	52%	54%	51%	48%	51%	51%	53%
Not very well	20%	20%	19%	18%	19%	21%	19%	21%	22%	18%	17%
Not at all	4%	4%	4%	5%	4%	3%	4%	6%	4%	4%	4%
Don't know	4%	4%	3%	2%	3%	3%	4%	4%	3%	4%	3%
Well (Very + Somewhat)	**72%**	**72%**	**74%**	**75%**	**73%**	**73%**	**72%**	**70%**	**71%**	**73%**	**76%**
Not Well (Not very + Not at all)	24%	24%	23%	23%	23%	24%	24%	27%	26%	23%	21%

Background

Understanding the Planning Process (Cont'd)

Q How well do you feel you understand how your feedback fits within the planning process?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Very well	21%	17%	23%	16%	27%	21%	23%	19%	20%	24%	27%	18%	20%	27%
Somewhat well	51%	56%	47%	56%	46%	54%	49%	50%	52%	54%	42%	58%	52%	52%
Not very well	20%	20%	19%	21%	21%	17%	20%	23%	17%	16%	21%	19%	21%	15%
Not at all	4%	2%	7%	5%	4%	5%	4%	5%	5%	3%	6%	3%	3%	4%
Don't know	4%	5%	3%	2%	2%	3%	5%	3%	6%	3%	4%	2%	3%	3%
Well (Very + Somewhat)	**72%**	**74%**	**71%**	**72%**	**73%**	**75%**	**72%**	**69%**	**72%**	**78%**	**70%**	**76%**	**73%**	**79%**
Not Well (Not very + Not at all)	24%	22%	26%	26%	25%	22%	24%	27%	22%	19%	27%	22%	24%	18%

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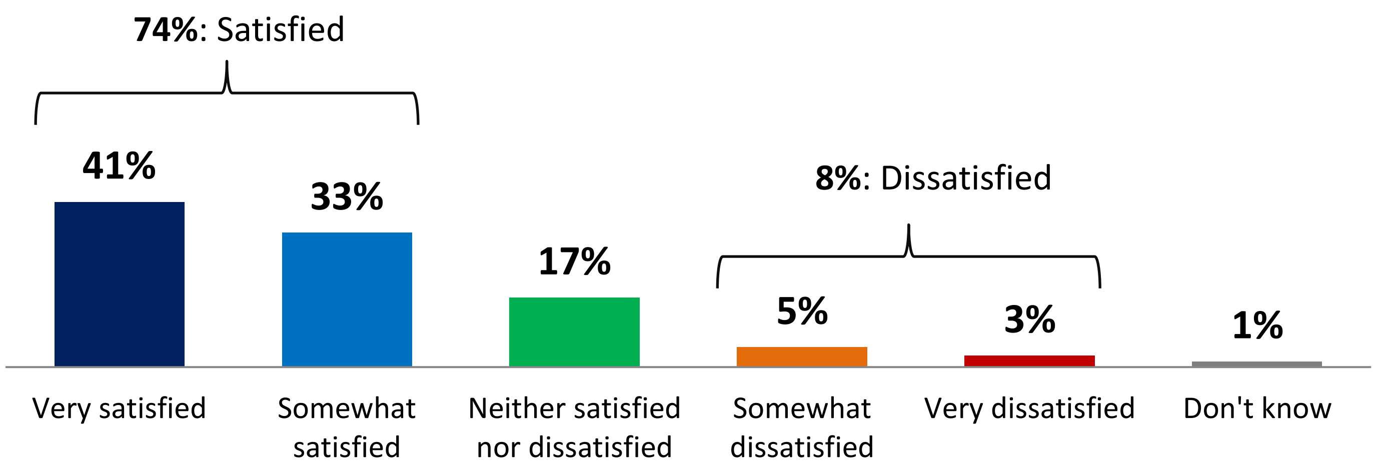
Online Workbook Results

Customer Experience

Customer Experience

Satisfaction with Enbridge Gas Service

Q Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Very satisfied	41%	39%	44%	46%	43%	40%	41%	37%	41%	42%	44%
Somewhat satisfied	33%	35%	30%	29%	30%	40%	33%	34%	30%	32%	34%
Neither	17%	17%	17%	14%	18%	12%	17%	18%	19%	18%	15%
Somewhat dissatisfied	5%	5%	5%	6%	5%	4%	5%	6%	6%	4%	4%
Very dissatisfied	3%	3%	3%	5%	2%	2%	3%	3%	3%	2%	3%
Don't know	1%	1%	1%	1%	1%	1%	1%	2%	1%	1%	1%
Satisfied (Very + Somewhat)	**74%**	**74%**	**74%**	**75%**	**73%**	**80%**	**73%**	**71%**	**71%**	**75%**	**77%**
Dissatisfied (Very + Somewhat)	8%	8%	8%	10%	7%	7%	8%	9%	9%	6%	7%

Customer Experience

Satisfaction with Enbridge Gas Service (Cont'd)

Q Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Very satisfied	41%	47%	34%	39%	43%	45%	39%	40%	50%	40%	36%	38%	44%	56%
Somewhat satisfied	33%	28%	34%	39%	26%	30%	35%	33%	24%	36%	32%	38%	34%	24%
Neither	17%	13%	20%	16%	18%	17%	18%	19%	13%	15%	18%	17%	16%	14%
Somewhat dissatisfied	5%	7%	10%	2%	7%	5%	4%	4%	7%	5%	7%	5%	4%	4%
Very dissatisfied	3%	5%	1%	3%	5%	3%	3%	2%	3%	3%	6%	2%	2%	1%
Don't know	1%	-	2%	2%	2%	1%	2%	1%	2%	1%	1%	0%	1%	1%
Satisfied (Very + Somewhat)	**74%**	**75%**	**68%**	**77%**	**68%**	**75%**	**74%**	**73%**	**74%**	**77%**	**67%**	**76%**	**79%**	**80%**
Dissatisfied (Very + Somewhat)	8%	12%	11%	5%	12%	7%	7%	7%	10%	8%	13%	7%	5%	5%

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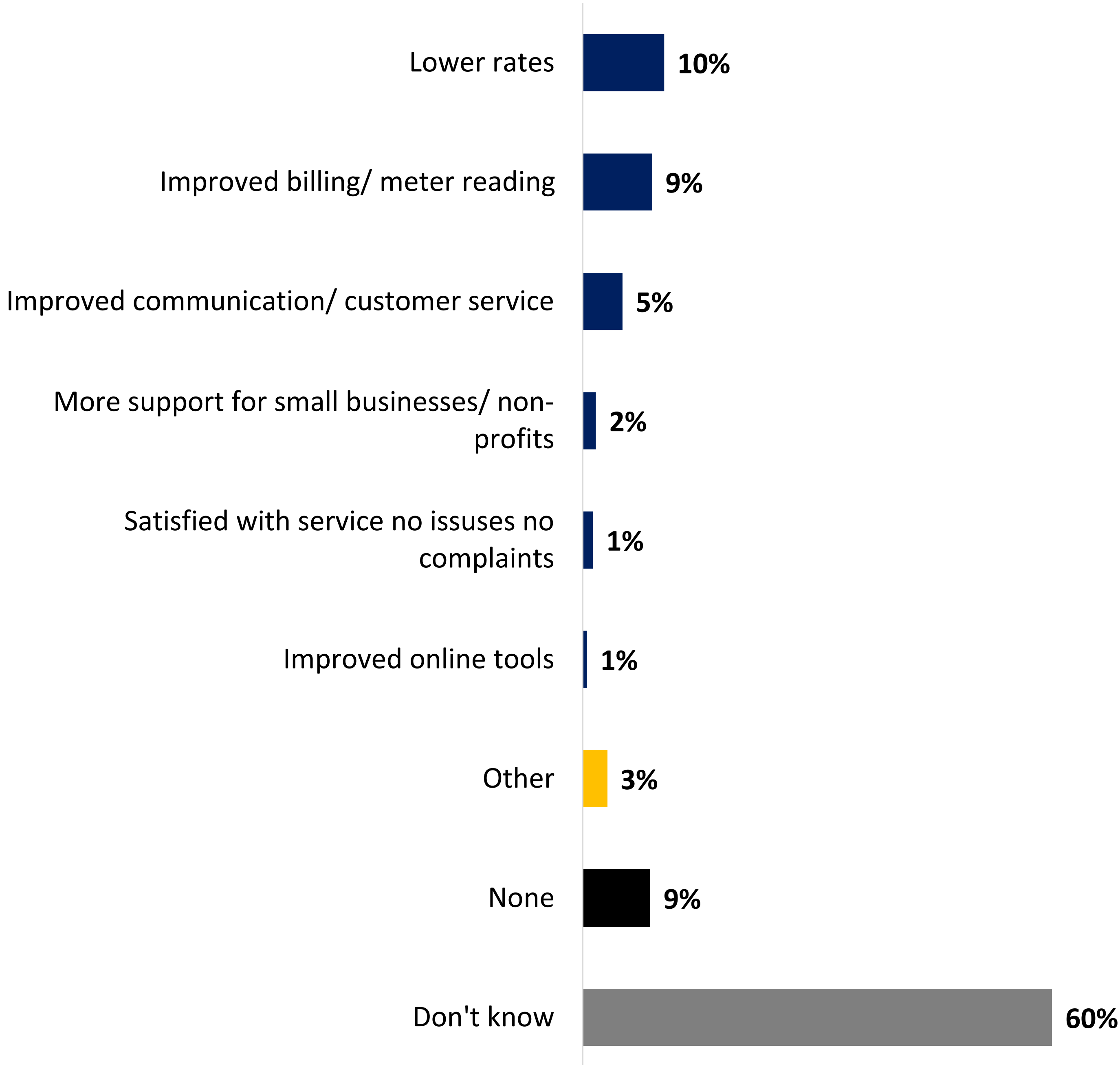
Customer Experience

Improving Enbridge Gas Service

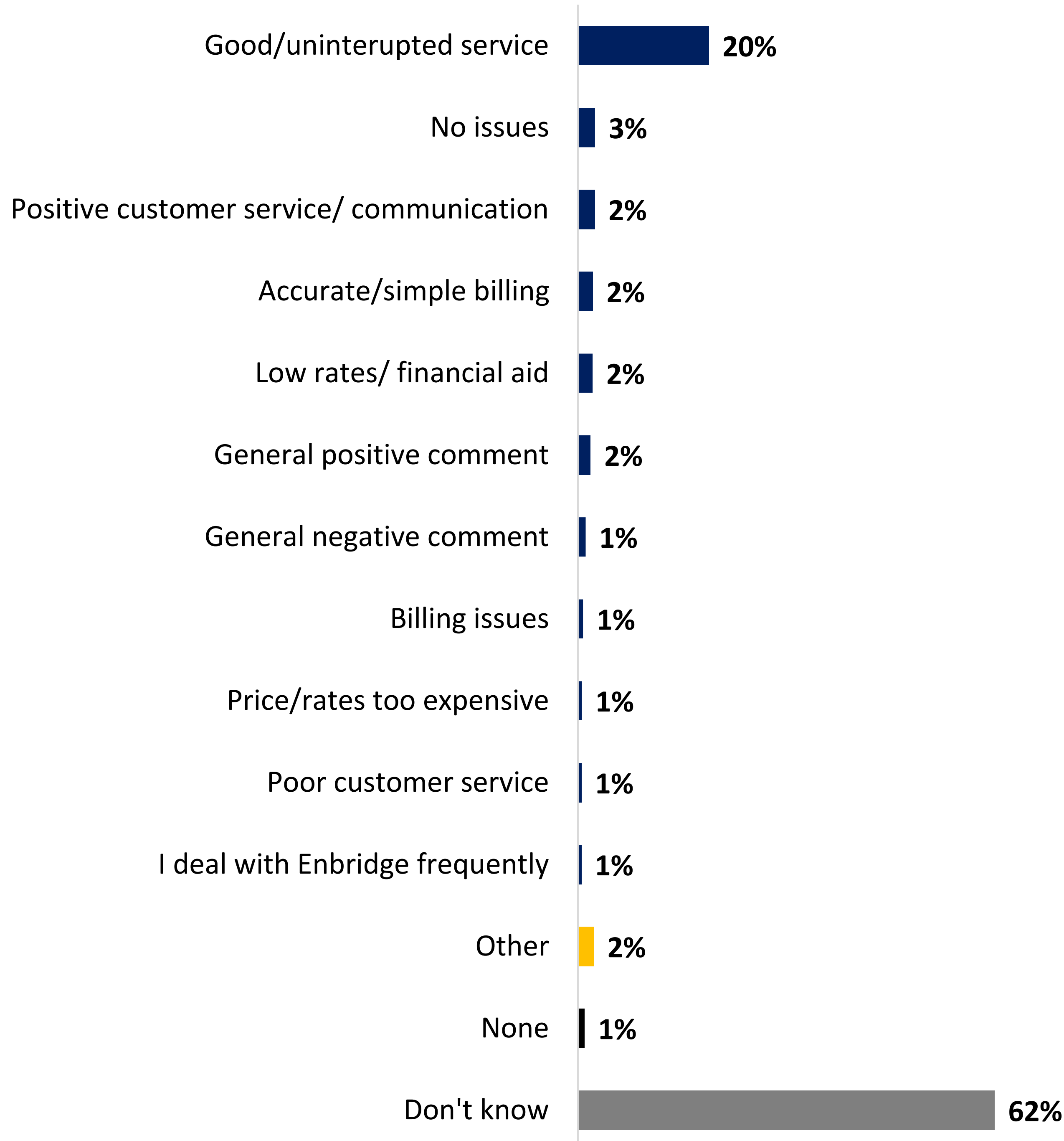
Q Is there anything in particular Enbridge Gas can do to improve their service to your organization? [OPEN]



Customer Experience

Is Enbridge Gas Doing A Good Job?

Q How do you know if Enbridge Gas is doing a good job for you, or not? [OPEN]



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Online Workbook Results

Business Plan Objectives and Calculating Rates

Background

2024-2028 Plan

Plan Objectives

The Enbridge Gas business plan focuses on many of the same objectives as in the past years, as well as future challenges and pressures. Some of the high-level objectives of the plan are as follows:

1. **Maintain system safety and reliability** – ensure that the system continues to operate safely and reliably.
2. **Contain costs** – the OEB requires all utilities to "demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives".
3. **Harmonize rates and services** – ensure that the offerings are consistent across the entire service area as Enbridge Gas continues its merger activities.
4. **Prepare for the future** – ensure that the system is ready for low-carbon options, as well as offer options to help customers reduce their greenhouse gas (GHG) emissions.

Climate Change Goals

Compared to the past, Enbridge Gas' 2024-2028 plan places more emphasis on preparing for the future. Enbridge Gas is looking at ways in which it can support its organizational, as well as federal and provincial goals to reduce GHG emissions and achieve net zero targets.

- **Enbridge Inc. targets to reduce, from its operations, GHG emission intensity by 35% by 2030 over 2018 levels, and to reach Net Zero GHG emissions by 2050**
- **Federal targets to reduce GHG emissions by 40-45% by 2030 over 2005 levels and to reach Net Zero GHG emissions by 2050**
- **Provincial target to reduce GHG emissions by 30% by 2030 over 2005 levels**

How We Can Reduce GHG Emissions From Natural Gas

One of the ways in which GHG emissions are created is through the burning of fossil fuels such as coal, oil, and natural gas. Two key approaches can reduce the emissions from using natural gas:

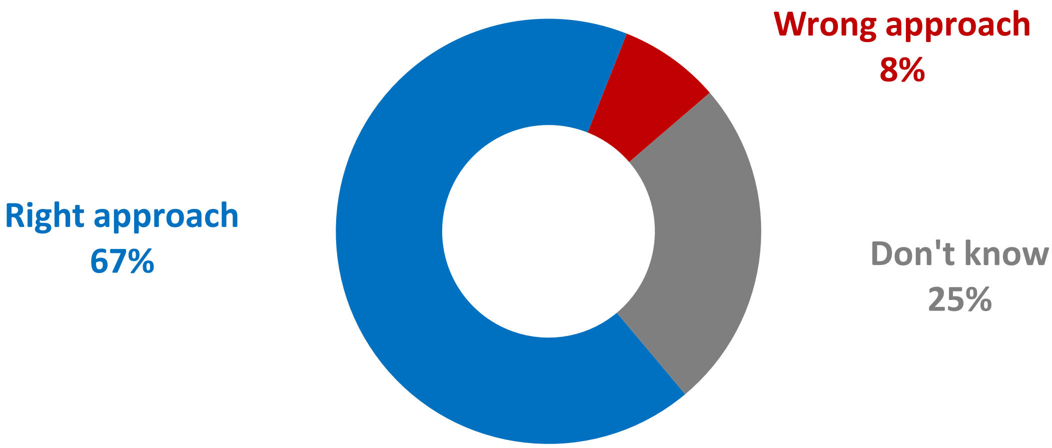
- by blending lower carbon fuels into the gas supply, including Renewable Natural Gas (RNG) and Hydrogen gas, and
- by improving energy efficiency of homes and businesses, and implementing new, lower-emitting technologies.

Each of these could introduce new, higher, costs that would be passed on to customers but would mitigate costs that might be required to introduce other programs or options to reduce overall GHG emissions in Ontario and Canada. **Later in the workbook we will ask about your views on these potential costs.**

Background

Right or Wrong Approach

Q Do these objectives seem like the right approach or the wrong approach?



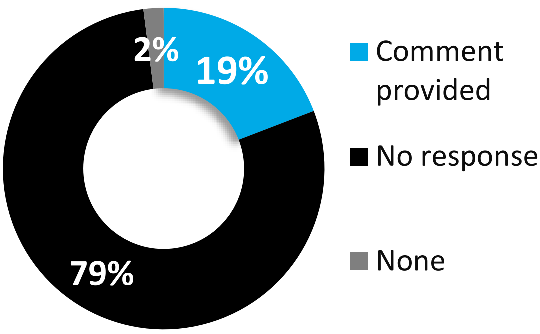
	Total	Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
		EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Right approach	67%	67%	66%	68%	66%	68%	67%	68%	66%	64%	70%
Wrong approach	8%	7%	8%	6%	9%	8%	8%	9%	8%	7%	7%
Don’t know	25%	25%	25%	26%	25%	24%	25%	24%	25%	29%	23%

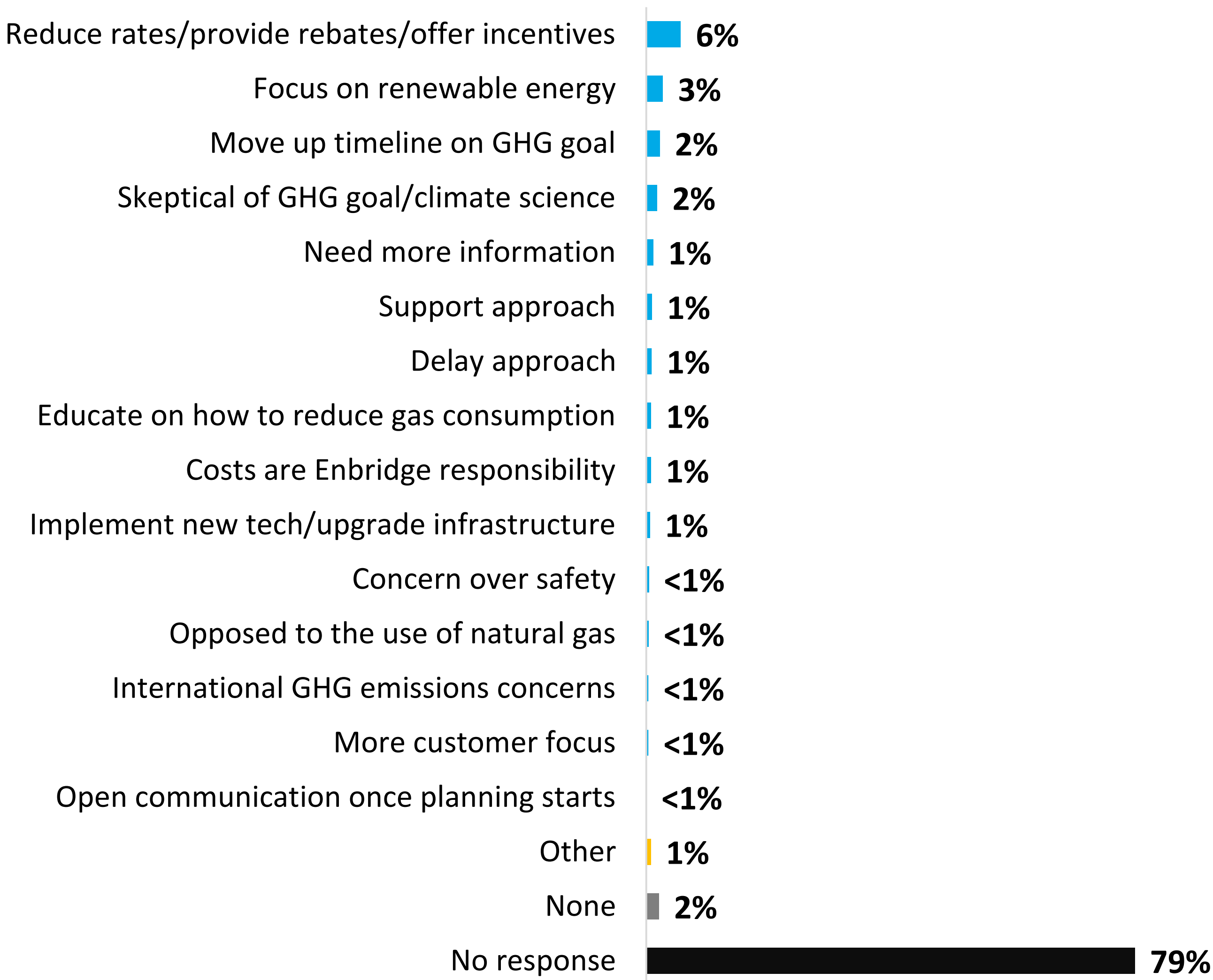
	Total	Sector									Enbridge Gas Bill Impacts Finances			
		Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Right approach	67%	65%	66%	63%	65%	65%	68%	67%	69%	71%	63%	69%	72%	73%
Wrong approach	8%	10%	6%	8%	8%	8%	7%	8%	9%	7%	11%	8%	6%	6%
Don’t know	25%	25%	29%	29%	27%	27%	25%	25%	22%	22%	26%	23%	22%	21%

Background

Right or Wrong Approach - Additional Comments

Q Is there anything you would change about this approach or any other comments you would like to make?





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Calculating Rates

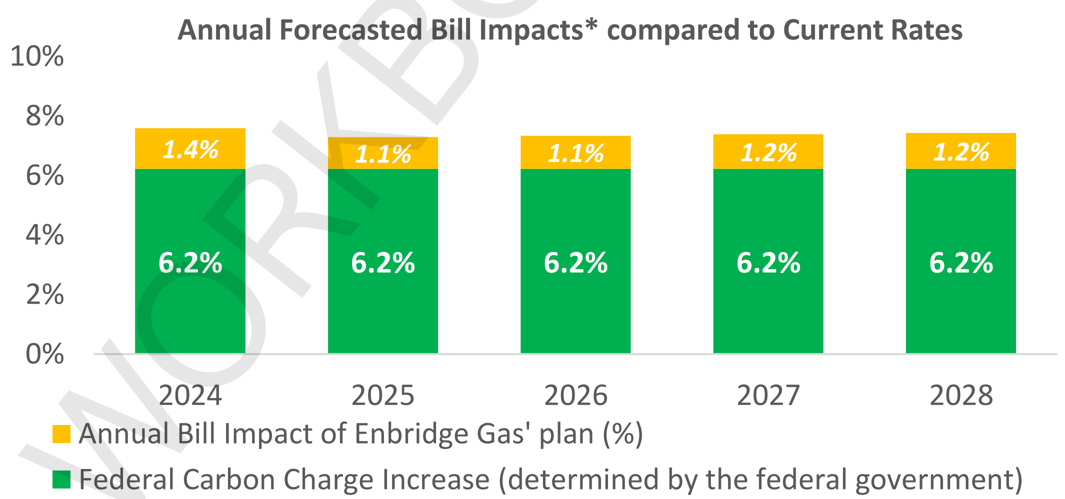
When looking at its overall objectives, and its budgets, there are many items that Enbridge Gas must consider that affect its costs, and in turn the rates that customers pay. Some of these items are determined by regulatory requirements, others by external factors in the market, and again others by decisions made by Enbridge Gas.

There are **accounting policies and factors** that affect expenditures. These include proposals through which Enbridge Gas manages business risk and how it calculates the depreciation of its assets. These types of proposals contribute significantly to the overall rate impact shown in the "Forecasted Bill Increase" below and are partially offset by savings in other areas. While these issues are too technical for this workbook, they will be reviewed by OEB experts and intervening stakeholders in the OEB's public review process.

Operating expenses make up about 20% of Enbridge Gas' overall expenditures. Current estimates show that these expenses would increase somewhat over the 2024-2028 period, with the highest annual increase at 1.5%, which is less than inflation. Decisions on operating expenses are based on industry best practices and generally do not involve trade-offs between customer outcomes. Since these are technical issues, they will also be reviewed by OEB experts and intervening stakeholders in the OEB's public review process.

Capital expenses make up about 35% of Enbridge Gas' overall expenditures and pay for investments in its equipment that have lasting benefits over many years. Since capital spending includes major one-off projects as well as ongoing maintenance and replacement, capital spending varies from year to year. The questions in the next section focus on these choices.

The *Forecasted Bill Impacts* for 2024 to 2028 compared to current rates are shown below. Compared to your current rates, rates in 2022 are expected to increase by 2.1% for the average commercial customer, while 2023 rates are not yet established.



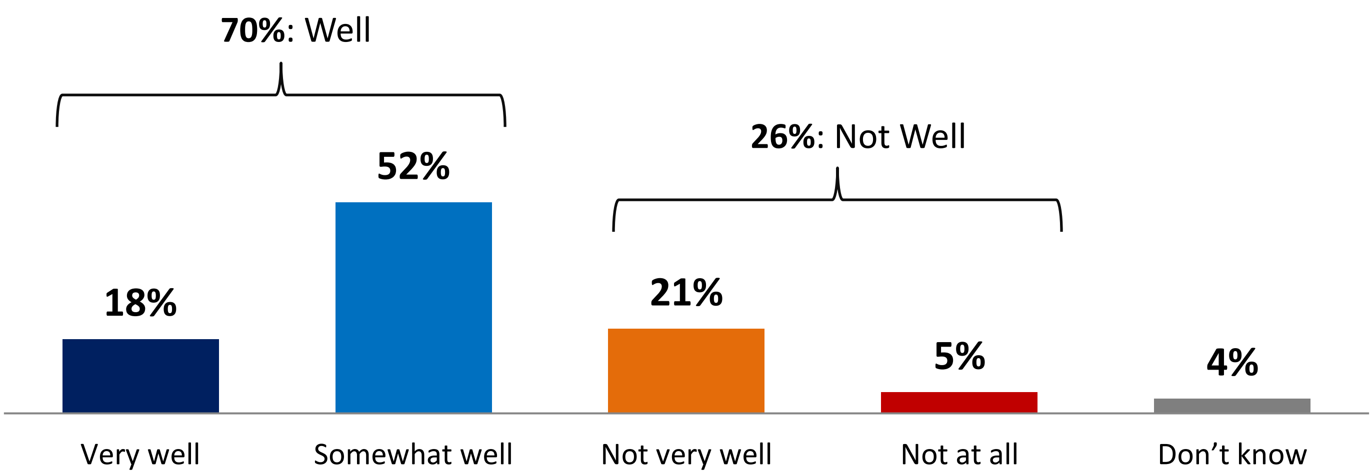
These charges for business customers may vary somewhat by rate class, and in all cases where we're showing a rate impact, it is the highest potential impact across rate classes.

**These estimates are preliminary and are subject to both your feedback and ongoing work to review as Enbridge Gas planners continue to work on their plans. This does not include any potential changes in the fuel costs or the federal carbon charge.*
Based on the average customer consuming 2,400 m3 of natural gas per year. Oct 2021 average includes the federal carbon charge.

Calculating Rates

Understanding the Projected Increase

Q How well do you feel you understand the projected increase in your rates from 2024 to 2028?



	Total	Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
		EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Very well	18%	18%	20%	19%	20%	19%	18%	17%	18%	19%	20%
Somewhat well	52%	51%	54%	54%	54%	52%	52%	51%	53%	51%	54%
Not very well	21%	22%	19%	21%	18%	20%	21%	23%	20%	22%	18%
Not at all	5%	6%	4%	4%	5%	4%	5%	6%	5%	5%	5%
Don't know	4%	4%	3%	2%	3%	5%	4%	3%	4%	3%	3%
Well (Very + Somewhat)	**70%**	**69%**	**74%**	**73%**	**74%**	**70%**	**70%**	**68%**	**71%**	**70%**	**73%**
Not Well (Not very + Not at all)	26%	28%	23%	24%	23%	24%	26%	29%	26%	27%	23%

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Calculating Rates

Understanding the Projected Increase (Cont'd)

Q How well do you feel you understand the projected increase in your rates from 2024 to 2028?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	**Agriculture/ Greenhouse**	**Food Services**	**Manufacturing**	**Multiresidential**	**Office**	**Other Commercial**	**Retail**	**Transportation/ Warehouse**	**Other**	**Strongly Agree**	**Somewhat Agree**	**Somewhat Disagree**	**Strongly Disagree**
Very well	18%	21%	19%	20%	24%	18%	19%	15%	19%	18%	21%	15%	18%	28%
Somewhat well	52%	49%	45%	52%	44%	54%	52%	53%	46%	58%	44%	58%	56%	53%
Not very well	21%	24%	22%	21%	22%	20%	21%	22%	24%	18%	22%	21%	21%	14%
Not at all	5%	2%	8%	4%	7%	5%	5%	6%	7%	5%	8%	4%	2%	3%
Don't know	4%	4%	6%	4%	2%	3%	4%	4%	4%	2%	4%	2%	2%	2%
Well (Very + Somewhat)	**70%**	**70%**	**64%**	**72%**	**68%**	**72%**	**71%**	**68%**	**65%**	**76%**	**65%**	**73%**	**74%**	**81%**
Not Well (Not very + Not at all)	26%	25%	30%	24%	29%	25%	26%	28%	30%	22%	31%	25%	24%	17%

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Online Workbook Results

Making Choices

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 334 of 550

Making Choices

In this next section of the workbook, we will ask you about some of the key items that Enbridge Gas is considering in its plan that see trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down.

Some of these items are currently included in the draft budget, while others will need to be added to the budget depending on further analysis and feedback from customers like you.

For each question, where applicable, the financial impact is expressed as the percentage impact each year on an average business customer bill. The actual impact will depend on your own individual usage.

At the end of the section, you will have an opportunity to review your responses and their impact on your bill. You will then be able to adjust your choices to provide what you feel is the best balance.

Compression Stations

Enbridge Gas has 50 Compressors, 7 Dehydrators and supporting equipment. These are required to ensure that the gas that is injected into storage or into the distribution system meets the quality specifications and to move gas along the transmission system.

As compressors age, they experience breakdowns on an increasingly frequent basis – when equipment manufacturers stop supporting these compressors, the time to complete repairs can be extensive leading to reliability and gas quality problems. There are two compressors that will need to be replaced in the coming years.

When considering a project to replace compressors like this, Enbridge Gas looks at various options:

- ✓ Replacing one larger compressor with two smaller ones,
- ✓ Using alternative fuel sources such as electricity or hydrogen gas, and
- ✓ Preparing for outages by having spare parts available.

In this case, however, there is a lack of viable alternatives at the specific locations for the two compressor stations, so Enbridge Gas is planning to replace one compressor station in 2026, with the other one being replaced after 2028 to use the existing stations for as long as possible.

Not doing this work increases the risk the station could fail. This may require Enbridge Gas to buy more gas on the market (if available), rather than drawing gas from its storage. This introduces the risk of price volatility, as gas purchased on the market during the coldest days of the year has been up to 220% more expensive in the past 5 years than the gas that could be drawn from storage.

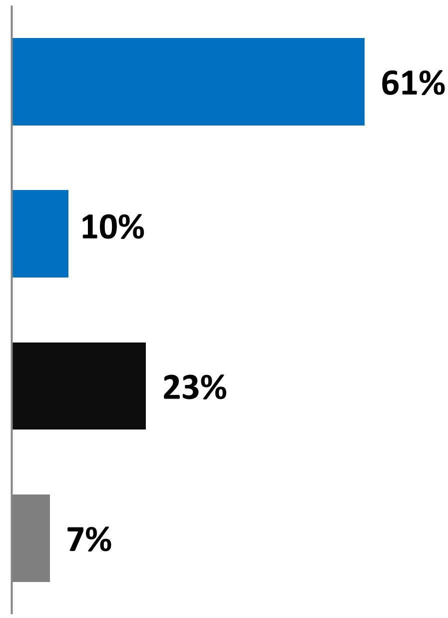
Image: inside a building housing a compressor station

Furthermore, if the station fails, replacement will still be required which would take a couple of years of construction to complete, extending the risks for longer. The replacement of the first compressor station is planned for 2026 and would cost the average customer 0.028%/year.

Making Choices

Compression Station

Q Which of the following statements best represents your point of view?



	Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	**EGD**	**Union**	**North**	**South**	**Med-Large**	**Small**	**Low**	**Med-low**	**Med-high**	**High**
Replace the compressor stations	61%	58%	66%	67%	66%	65%	60%	57%	59%	62%	64%
Defer the compression station project	10%	10%	8%	7%	8%	6%	10%	13%	11%	8%	7%
I don’t have an opinion on this	23%	25%	20%	23%	19%	23%	23%	24%	22%	24%	22%
Don’t know	7%	7%	6%	4%	6%	6%	7%	6%	7%	6%	7%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

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Making Choices

Compression Station (Cont'd)

Q Which of the following statements best represents your point of view?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Replace the compressor stations	61%	72%	50%	59%	65%	64%	59%	58%	54%	69%	45%	64%	70%	81%
Defer the compression station project	10%	4%	18%	8%	8%	9%	10%	10%	10%	8%	17%	11%	8%	2%
I don't have an opinion on this	23%	16%	26%	25%	21%	21%	24%	25%	28%	19%	29%	22%	17%	13%
Don't know	7%	9%	7%	8%	6%	6%	7%	7%	8%	5%	9%	4%	5%	4%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

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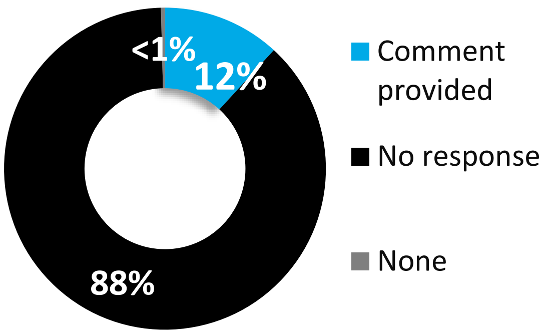
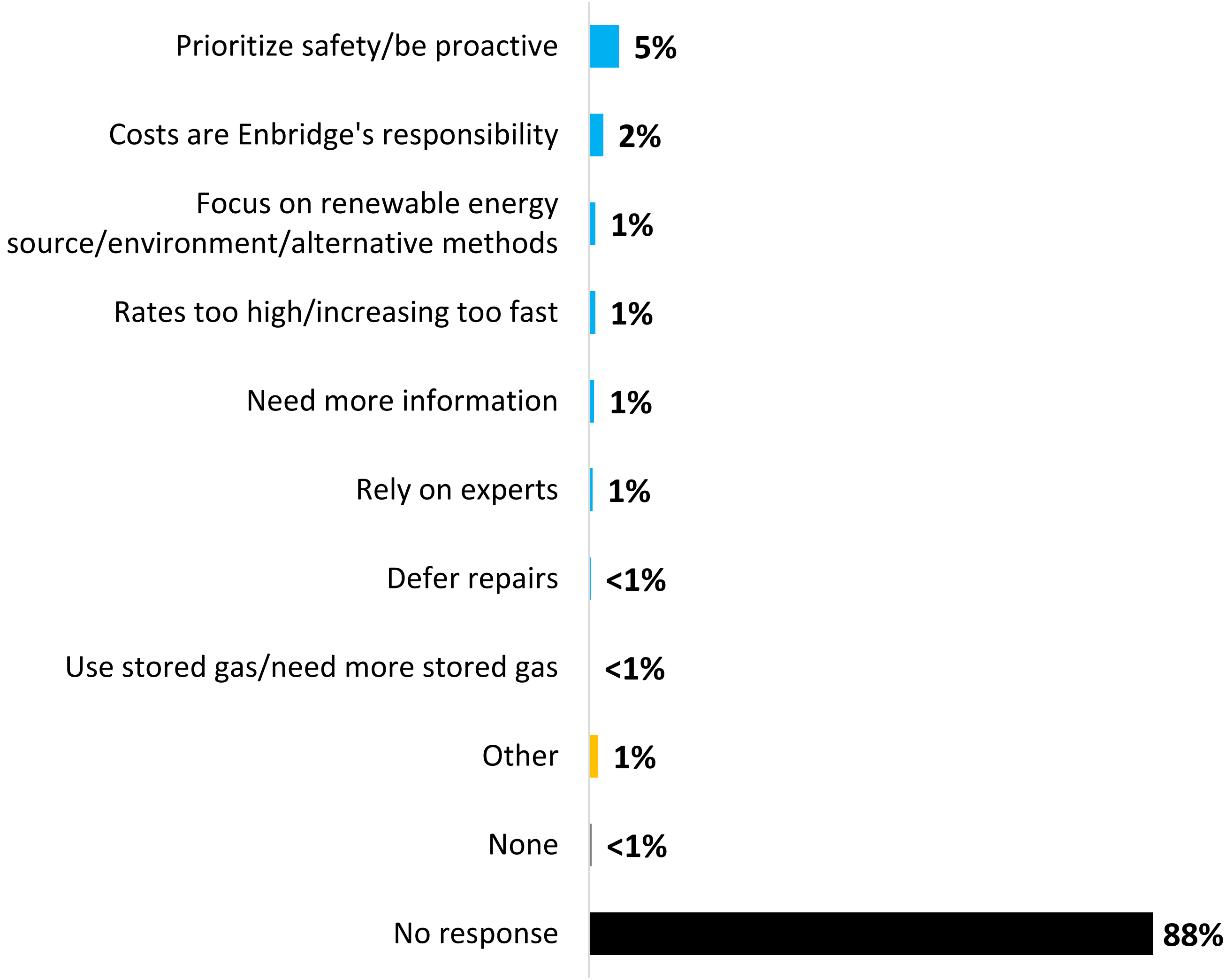
Making Choices

Compression Station - Additional Comments

Q

After making their choice, respondents were given an opportunity to make any additional comments they may have.





Making Choices

Vintage Steel Pipeline Replacement Program

Enbridge Gas has implemented a Vintage Steel Pipeline Replacement Program, which focuses on replacing older steel pipelines within the system. It is considering ramping up the program to ensure ongoing safety and reliability of the distribution system and to prepare the network for the eventual delivery of low carbon, blended hydrogen. Blended hydrogen can safely be delivered through modern steel and plastic distribution systems – however, with the rapid introduction of natural gas to Ontario during the 1950's and 60's, Enbridge Gas has a lot of older steel pipelines which are nearing end of life and require replacement in a planned and proactive manner.

This program would see an increase in work and a ramp-up of spending starting in 2024 with the goal of replacing 5,100 km of 17,000 km of vintage steel pipelines in 20 years. These vintage steel pipelines were built before 1971 and are more prone to failures compared to steel pipelines built later due to materials, construction and damage prevention practices used at the time. Using risk assessments, the program will focus on replacing pipelines that are closest to end of life first.

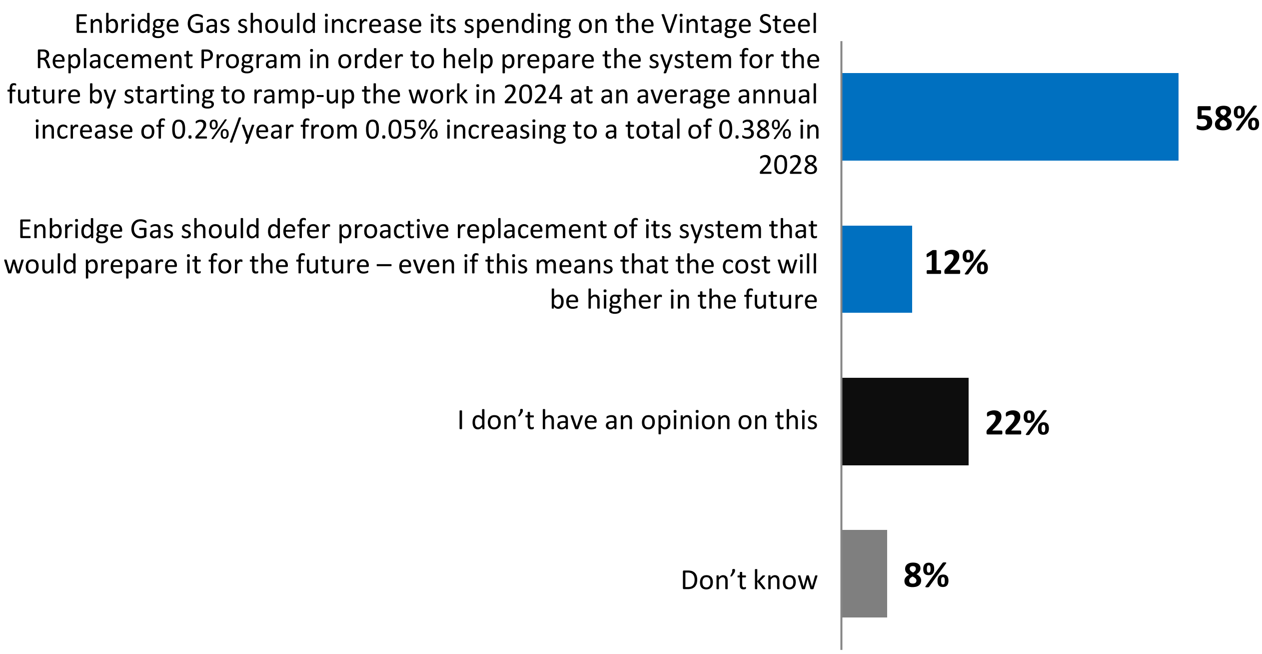
Enbridge Gas intends to start this increase in work in 2024 so that the work can be spread out over a longer period with a limited increase to internal resources. Pushing the work into the future, such as 10 years from now, to achieve the same objectives, will require additional internal as well as external resource overheads and costs, with reduced productivity due to a sharper ramp-up of skilled labour. The overall costs would be expected to be higher with a delayed approach.

It is estimated that this program, ramping up in 2024, included in the capital budget, is equivalent to an average annual increase of 0.2%/year from 0.05% increasing to a total of 0.38% in 2028 for the average business customer.

Making Choices

Vintage Steel Pipeline Replacement Program

Q Considering this, which of the following is closest to your view?



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Increase its spending	58%	55%	63%	64%	63%	59%	58%	55%	57%	58%	62%
Defer proactive replacement	12%	13%	10%	12%	10%	11%	12%	14%	13%	11%	10%
I don't have an opinion on this	22%	23%	19%	19%	20%	20%	22%	24%	21%	24%	20%
Don't know	8%	8%	7%	4%	8%	10%	8%	7%	9%	7%	8%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

Making Choices

Vintage Steel Pipeline Replacement Program (Cont'd)

Q Considering this, which of the following is closest to your view?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Increase its spending	58%	67%	42%	57%	62%	61%	57%	56%	56%	65%	44%	61%	67%	78%
Defer proactive replacement	12%	4%	20%	13%	14%	11%	13%	12%	11%	10%	17%	13%	11%	7%
I don't have an opinion on this	22%	23%	29%	22%	14%	21%	22%	24%	26%	18%	29%	21%	16%	11%
Don't know	8%	7%	10%	8%	11%	7%	9%	8%	7%	7%	10%	6%	6%	4%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

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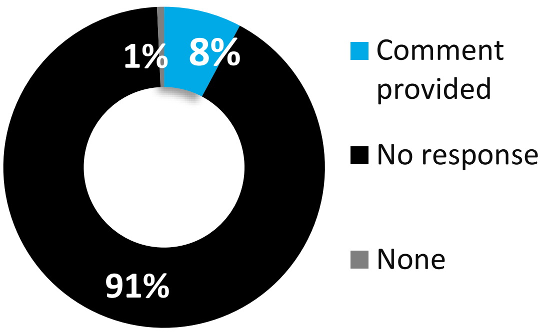
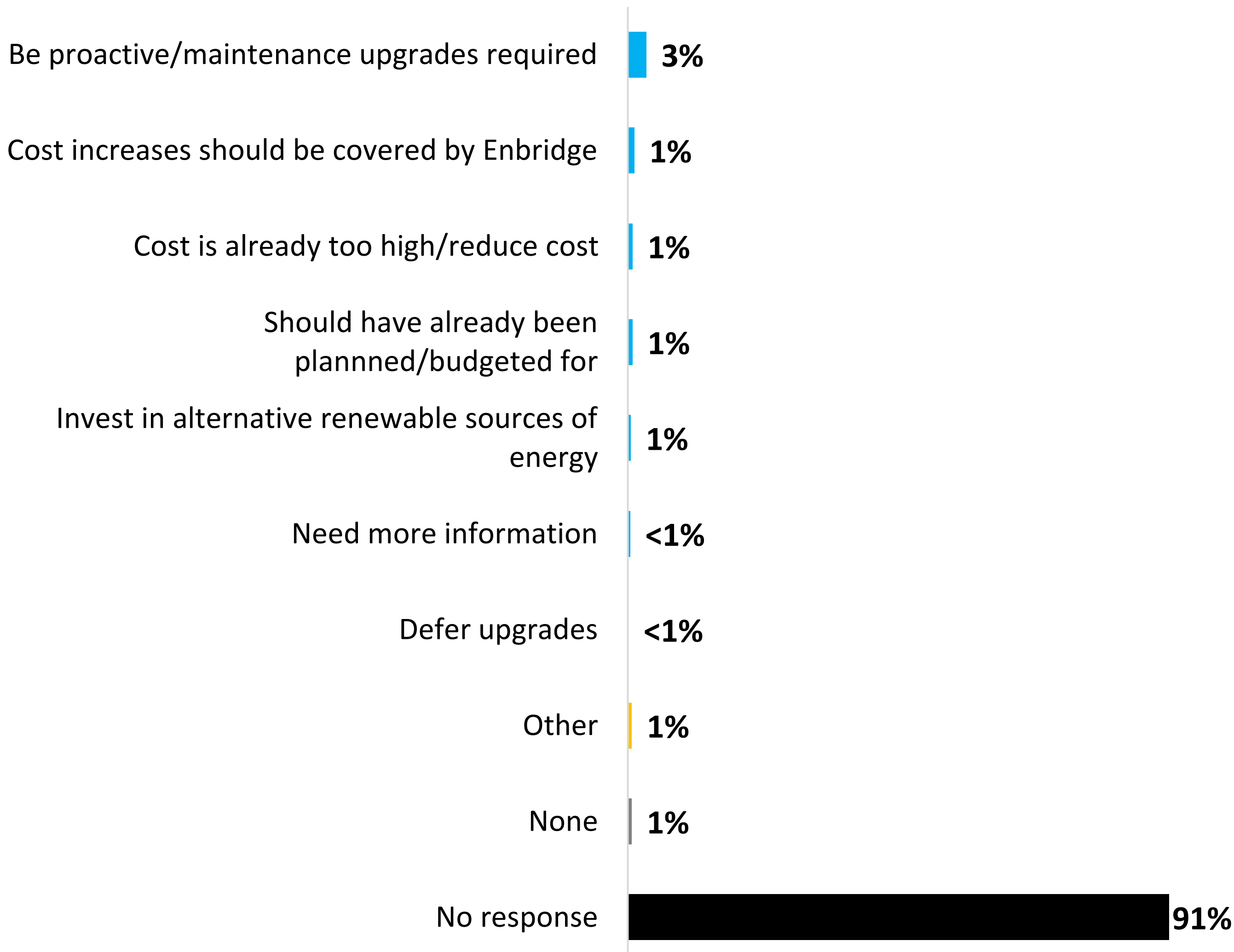
Making Choices

Vintage Steel Pipeline Replacement Program - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 342 of 550

Making Choices

Hydrogen Gas

Enbridge Gas is looking at options to blend more Hydrogen gas into the natural gas it delivers to green the gas supply.

Clean hydrogen gas is derived from surplus clean electrical energy that is converted to hydrogen gas through electrolysis technology. The gas is then blended with traditional natural gas, reducing GHG emissions.

Enbridge Gas is considering investing more in clean hydrogen as a tool for reducing GHG emissions in Ontario to allow for additional hydrogen gas to be blended into the natural gas distribution system. This would mean expanding the pilot project at the power-to-gas (P2G) facility in Markham where hydrogen gas is currently being produced, to deliver hydrogen-blended natural gas to a larger network of customers, expanding the blended gas area from approximately 3,600 to just under 17,000 customers.

Image: Hydrogen gas can be stored in tanks

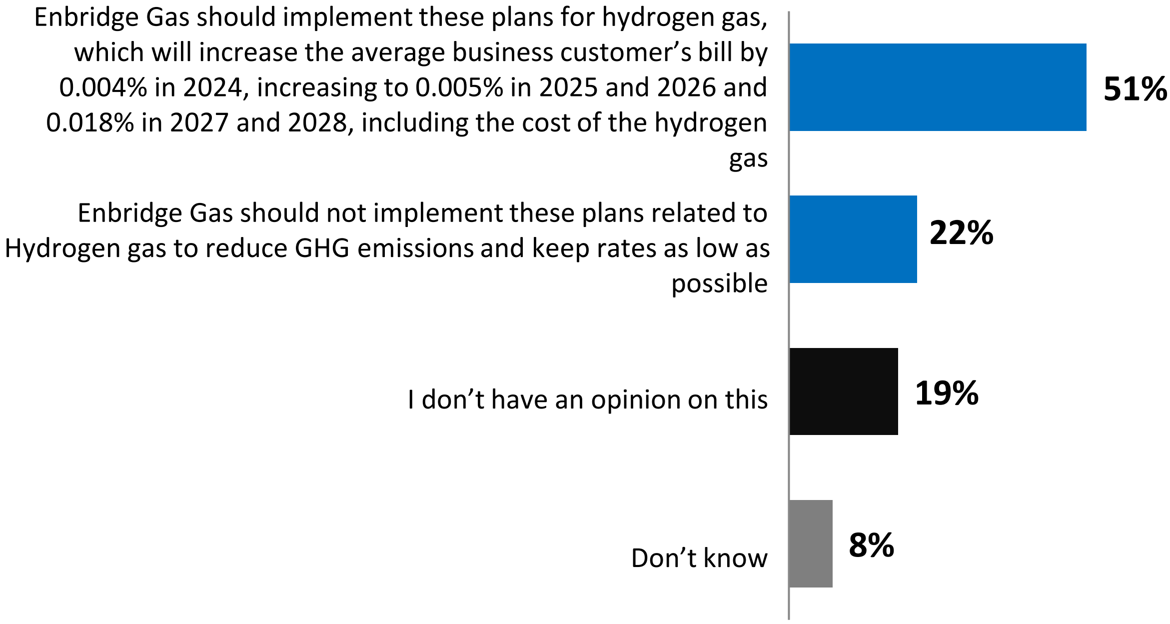
Additionally, Enbridge Gas intends to launch a feasibility study that assesses the full system's readiness for more hydrogen gas to be included in the system. The costs for these projects for the average customer are estimated as follows:

	2024	2025 and 2026	2027 and 2028
Annual cost	0.004%	0.005%	0.018%

Making Choices

Hydrogen Gas

Q Considering this, which of the following is closest to your view?



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Should implement these plans	51%	50%	55%	55%	55%	54%	51%	48%	50%	53%	53%
Should not implement these plans	22%	23%	21%	21%	21%	21%	22%	24%	23%	21%	20%
I don't have an opinion on this	19%	19%	18%	18%	19%	17%	19%	21%	18%	18%	19%
Don't know	8%	8%	6%	6%	6%	7%	8%	6%	8%	7%	8%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

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Making Choices

Hydrogen Gas

Q Considering this, which of the following is closest to your view?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Should implement these plans	51%	51%	42%	51%	61%	53%	49%	52%	44%	58%	37%	55%	60%	68%
Should not implement these plans	22%	21%	30%	19%	18%	22%	23%	23%	21%	19%	32%	23%	17%	15%
I don't have an opinion on this	19%	23%	21%	19%	13%	19%	19%	18%	26%	17%	23%	17%	16%	13%
Don't know	8%	5%	8%	10%	8%	6%	8%	7%	9%	6%	9%	4%	8%	4%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

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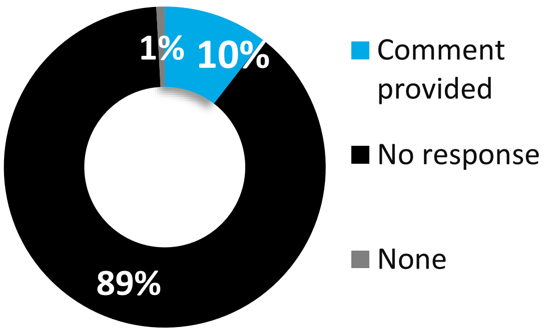
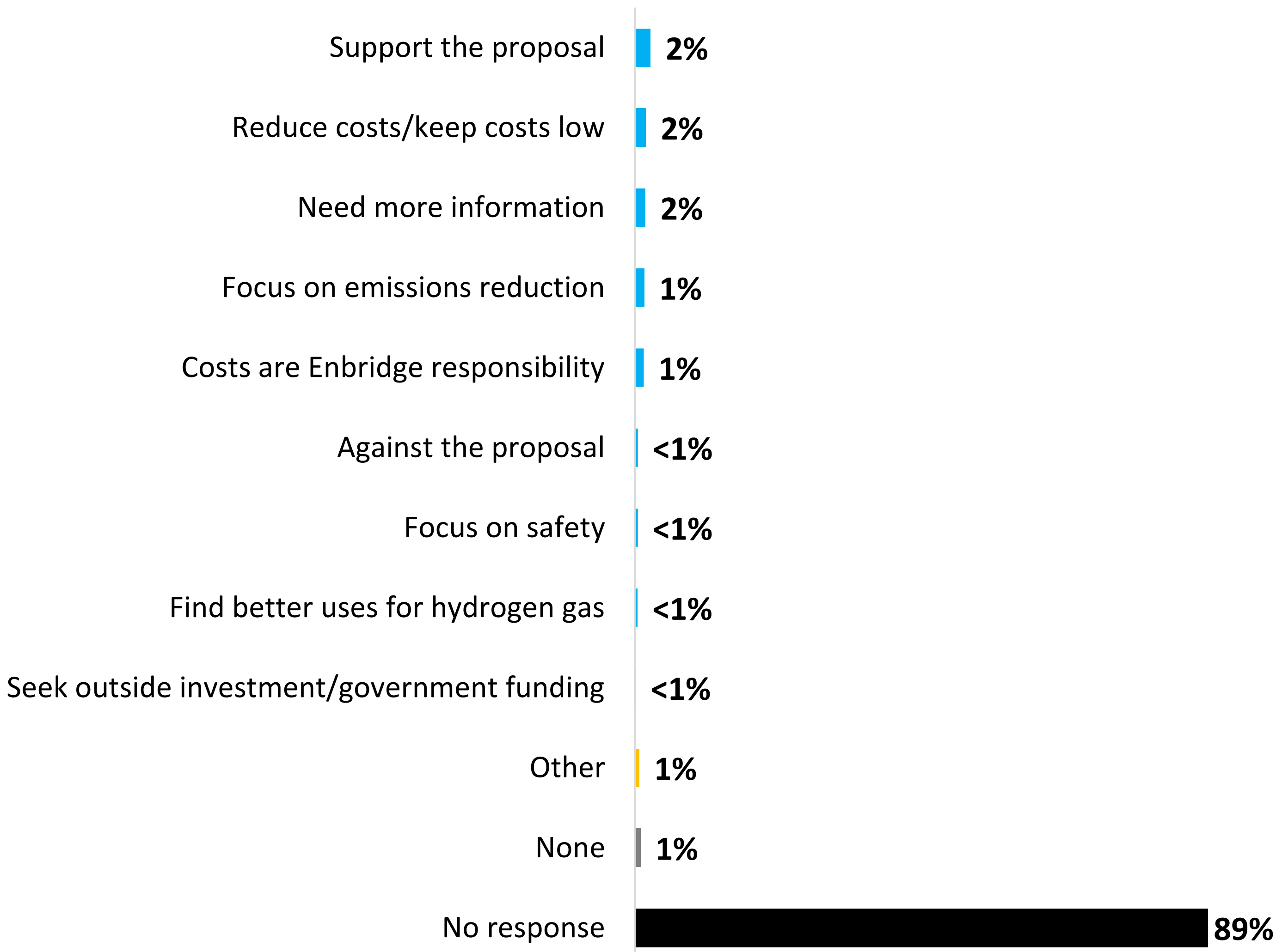
Making Choices

Hydrogen Gas - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





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Making Choices

Innovation and Technology Fund

Enbridge Gas can support the advancement of various new low-carbon or energy efficient technologies that may not be available to consumers today.

While some of this work is already taking place on a small scale, the budget for these types of projects is currently very limited. Additional contributions from customers would allow Enbridge Gas to expand this type of research and development work.

Similar to other jurisdictions, Enbridge Gas is considering an **Innovation and Technology Fund** in order to support the research, development, and the bringing to market of new low-carbon or energy efficient technologies. Where possible, this would be in partnership with other utilities and organizations.

Some options include funding for …

- new research on energy efficiency technologies,
- hydrogen gas,
- renewable natural gas, or
- carbon capture, utilization and sequestration (CCUS). This is the process of capturing carbon dioxide before it enters the atmosphere and either use it as a resource to create products or permanently storing it underground.

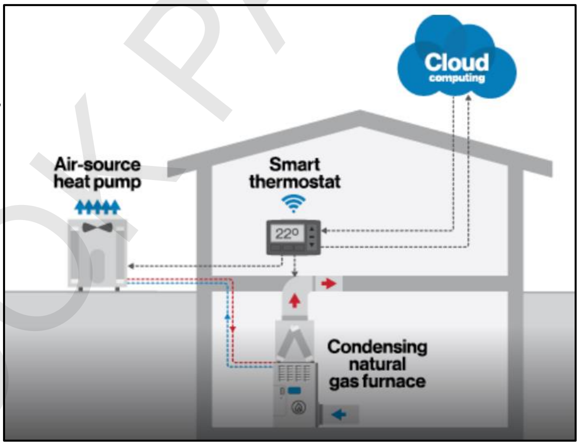


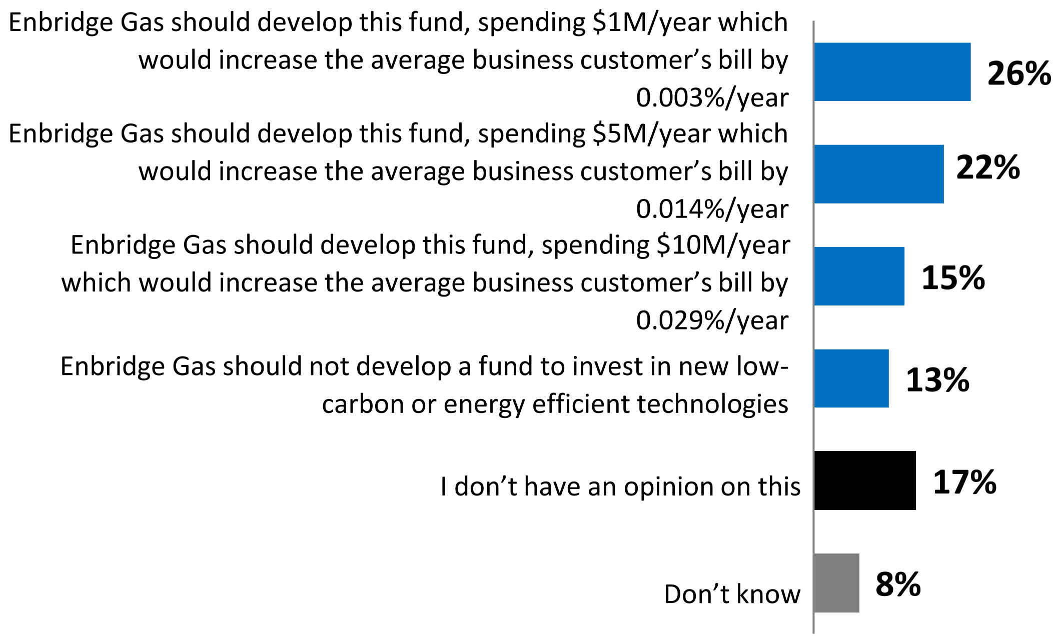
Image: Ontario pilot program tests future of advanced hybrid heating

The more money in this fund, the more projects could be completed, however Enbridge Gas is committed to finding a right balance of spending and planning for the future.

Making Choices

Innovation and Technology Fund

Q Considering this, which of the following is closest to your view?



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Spending $1M/year	26%	28%	23%	23%	23%	21%	26%	27%	26%	27%	26%
Spending $5M/year	22%	21%	24%	23%	24%	24%	21%	19%	23%	20%	23%
Spending $10M/year	15%	15%	16%	16%	16%	13%	15%	16%	14%	16%	15%
Should not develop a fund to invest	13%	12%	14%	12%	15%	14%	12%	12%	13%	13%	11%
I don't have an opinion on this	17%	17%	16%	20%	15%	17%	17%	20%	14%	17%	17%
Don't know	8%	8%	7%	6%	8%	12%	7%	7%	10%	6%	7%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

Making Choices

Innovation and Technology Fund (Cont'd)

Q Considering this, which of the following is closest to your view?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Spending $1M/year	26%	22%	28%	27%	22%	25%	27%	26%	25%	26%	27%	30%	26%	21%
Spending $5M/year	22%	21%	19%	19%	19%	21%	22%	24%	22%	22%	14%	24%	25%	28%
Spending $10M/year	15%	17%	9%	17%	20%	16%	15%	13%	15%	18%	10%	14%	18%	26%
Should not develop a fund to invest	13%	18%	17%	11%	16%	13%	12%	12%	8%	13%	20%	12%	9%	10%
I don't have an opinion on this	17%	15%	19%	18%	15%	18%	16%	18%	22%	15%	21%	15%	15%	10%
Don't know	8%	6%	8%	8%	9%	8%	8%	7%	10%	6%	8%	5%	7%	5%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

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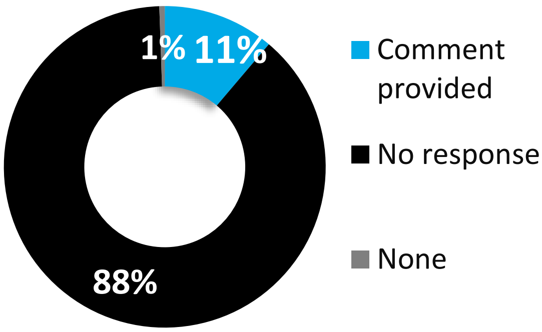
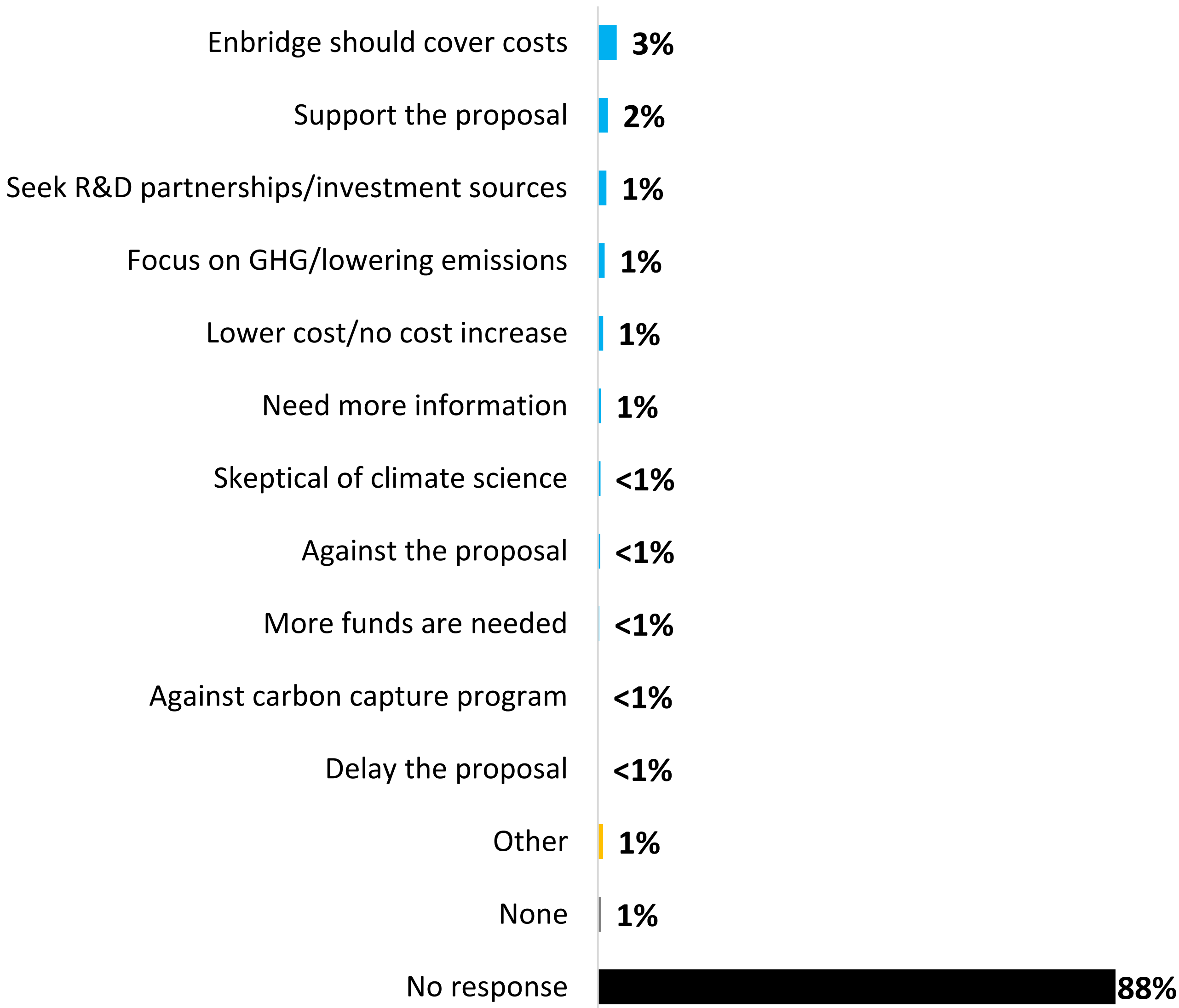
Making Choices

Innovation and Technology Fund - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





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Making Choices

Cross Bores

While rare, it is possible that a natural gas line may intersect with a sewer line. When this happens, it is called a utility cross bore. This is unintentionally created when a natural gas line is installed through a process of trenchless drilling.

Image: Example of a cross bore

Trenchless drilling is used to avoid creating open trenches that can disturb roads, driveways, and gardens, but it relies on locates of existing utilities which may not always be accurate for various reasons. While a utility cross bore may not pose an immediate risk, it may become an issue if a sewer line needs to be cleared in the case of a blockage. This has resulted in some instances of property damage and injury, as a result of a gas leak, fire or explosion.

To address this risk, there is currently an emergency program in place called Call Before you Clear. This program relies solely on property owner and plumber participation and through this program over 10,000 annual inspections are completed. Still, many plumbers and homeowners do not call for an inspection prior to auguring their sewer lines. To expand inspections beyond the current emergency program, Enbridge Gas intends to implement a program to **proactively inspect and resolve additional utility cross bores** that may have been installed in the past. This would double the number of annual inspections.

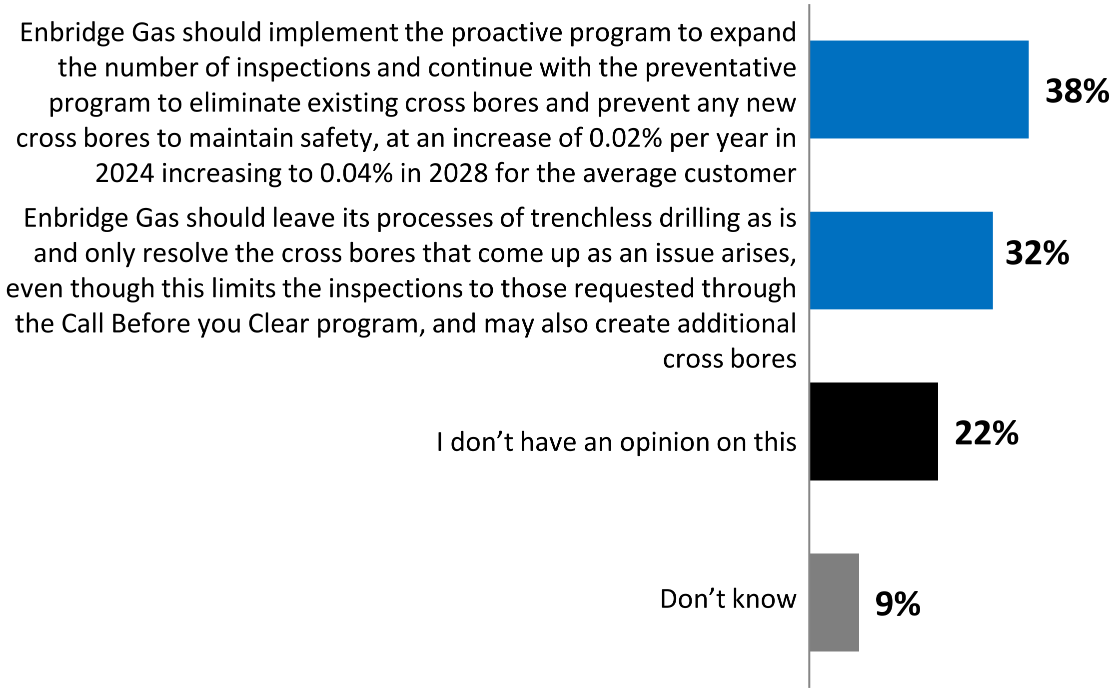
Another program has been implemented by Enbridge Gas to **prevent new installations from creating new cross bores** even though that increases the cost of the installation and requires additional restoration work during the installation process.

These programs to proactively inspect and resolve existing cross bores and to prevent the creation of cross bores during the completion of new installations combined would increase the average business customer's bill by 0.02% per year in 2024 increasing to $0.04% per year in 2028.

Making Choices

Cross Bores

Q Considering this, which of the following is closest to your view?



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	**EGD**	**Union**	**North**	**South**	**Med-Large**	**Small**	**Low**	**Med-low**	**Med-high**	**High**
Should implement the proactive program	38%	38%	37%	35%	37%	36%	38%	37%	38%	38%	38%
Should leave its processes of trenchless drilling	32%	30%	35%	35%	35%	32%	32%	30%	30%	33%	33%
I don't have an opinion on this	22%	23%	21%	24%	20%	26%	22%	25%	21%	20%	21%
Don't know	9%	9%	7%	6%	8%	6%	9%	8%	11%	8%	7%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

INNOVATIVE RESEARCH GROUP

Making Choices

Cross Bores (Cont'd)

Q Considering this, which of the following is closest to your view?

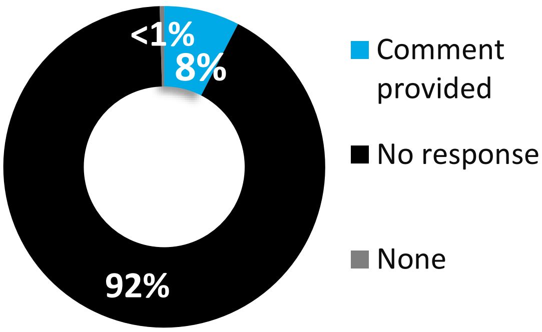
		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Should implement the proactive program	38%	35%	29%	31%	37%	40%	38%	37%	35%	44%	29%	40%	45%	47%
Should leave its processes of trenchless drilling	32%	45%	36%	36%	34%	31%	30%	30%	27%	33%	37%	32%	30%	32%
I don't have an opinion on this	22%	15%	23%	24%	22%	22%	24%	23%	26%	16%	23%	22%	18%	16%
Don't know	9%	5%	12%	9%	8%	7%	8%	10%	13%	6%	11%	6%	7%	5%

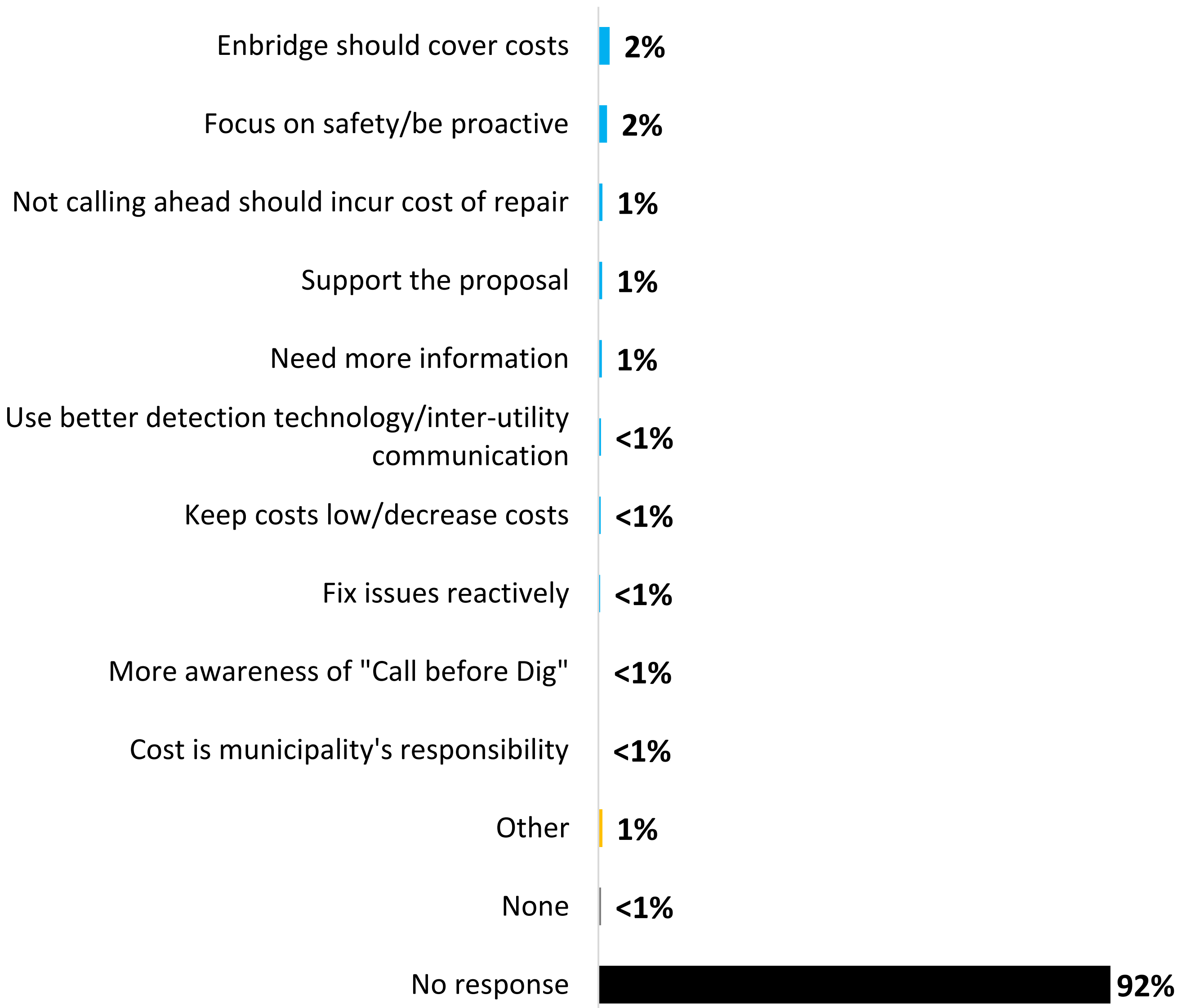
Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

Making Choices

Cross Bores - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





Making Choices

Advanced Meter Infrastructure

The gas meter technology currently used by Enbridge Gas has not changed in many years. Enbridge Gas is working on a plan to rollout new advanced meters that would send usage information to Enbridge Gas through a wireless network, like your existing water or electricity usage meters. The meters also have additional functions that could allow Enbridge Gas to:

- ✓ Better detect and respond to possible gas leaks
- ✓ Enhance safety capabilities by enabling Enbridge Gas to remotely and automatically shutoff gas supply in the event of an emergency
- ✓ Allow for a reduction in greenhouse gas (GHG) emissions by reducing meter reader vehicles on the road
- ✓ Eliminate the need for estimated meter reads
- ✓ Provide customers detailed usage data information – this may also allow customers to be notified of faulty or left on appliances or equipment

Once all meters are rolled out, the above features would become available to all customers. Rates will increase as specified below, after which rates will decrease slowly and eventually decrease to levels lower than today as benefits are fully realized. How rates are impacted depends on timing of spend and realization of benefits.

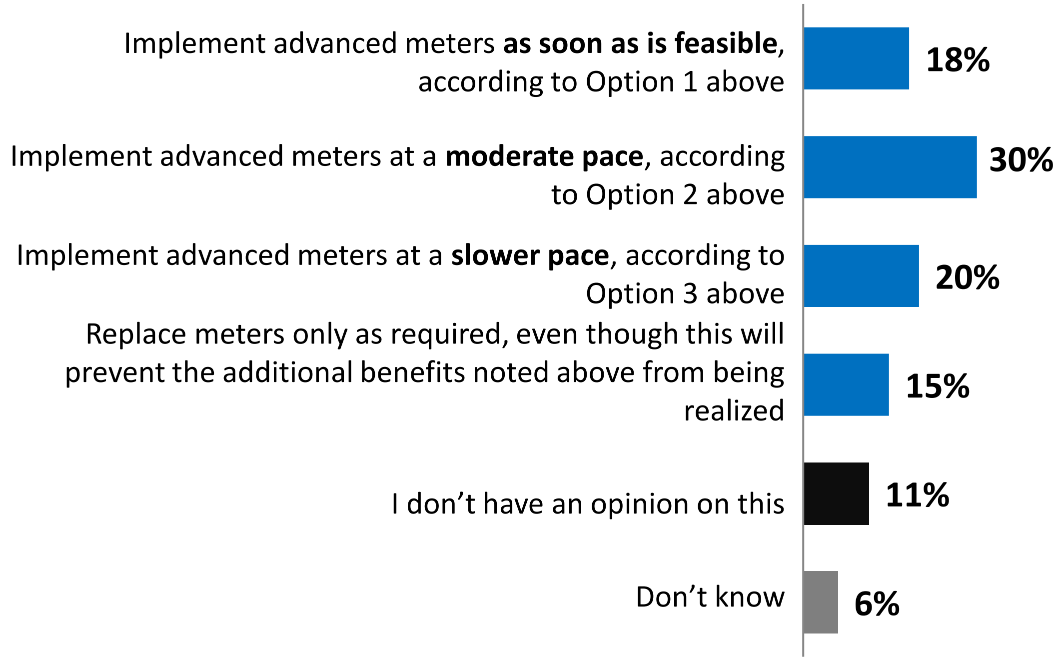
Depending on the pace of rolling out automated meters, there are implications on the time the benefits listed above can be fully realized, and the cost involved for customers like you. These are outlined in the table below.

	Time to Fully Realize Benefits	First Year Cost (2024)	Maximum Annual Cost	Year that the Rate Impact reduces to Less than Today
Option 1	4 years	0.04%	0.23% in 2028	2038
Option 2	8 years	0.02%	0.17% in 2031	2039
Option 3	20 years	0.02%	0.02% in 2026	2034

Making Choices

Advanced Meter Infrastructure

Q Which of the following is closest to your view? Across its service area, Enbridge Gas should …



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	**EGD**	**Union**	**North**	**South**	**Med-Large**	**Small**	**Low**	**Med-low**	**Med-high**	**High**
As soon as is feasible	18%	18%	18%	17%	18%	25%	18%	18%	17%	19%	18%
Moderate pace	30%	28%	33%	31%	33%	27%	30%	29%	30%	29%	32%
Slower pace	20%	20%	19%	20%	19%	18%	20%	20%	20%	21%	19%
Replace meters only as required	15%	14%	16%	17%	16%	14%	15%	15%	15%	16%	14%
I don't have an opinion on this	11%	12%	9%	10%	9%	11%	11%	13%	11%	10%	10%
Don't know	6%	7%	5%	4%	5%	5%	6%	5%	7%	6%	6%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

INNOVATIVE RESEARCH GROUP

Making Choices

Advanced Meter Infrastructure (Cont'd)

Q Which of the following is closest to your view? Across its service area, Enbridge Gas should …

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
As soon as is feasible	18%	22%	20%	15%	19%	18%	18%	17%	16%	22%	18%	18%	18%	23%
Moderate pace	30%	35%	23%	23%	29%	34%	29%	31%	29%	33%	20%	34%	34%	37%
Slower pace	20%	15%	17%	25%	20%	19%	21%	20%	18%	19%	21%	22%	20%	17%
Replace meters only as required	15%	18%	16%	16%	17%	15%	14%	13%	17%	15%	19%	13%	15%	13%
I don't have an opinion on this	11%	8%	16%	14%	8%	10%	11%	14%	13%	7%	14%	9%	9%	6%
Don't know	6%	3%	8%	7%	7%	4%	7%	6%	7%	4%	8%	3%	4%	4%

Note: Data being displayed reflects the results after customers were given the opportunity to revise their initial responses

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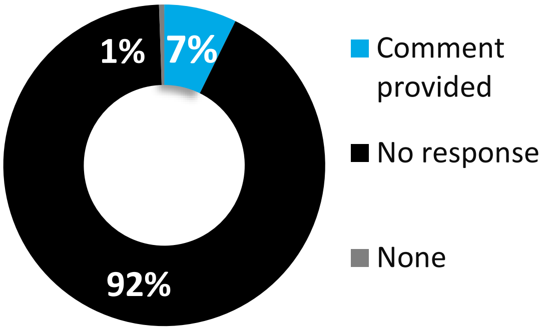
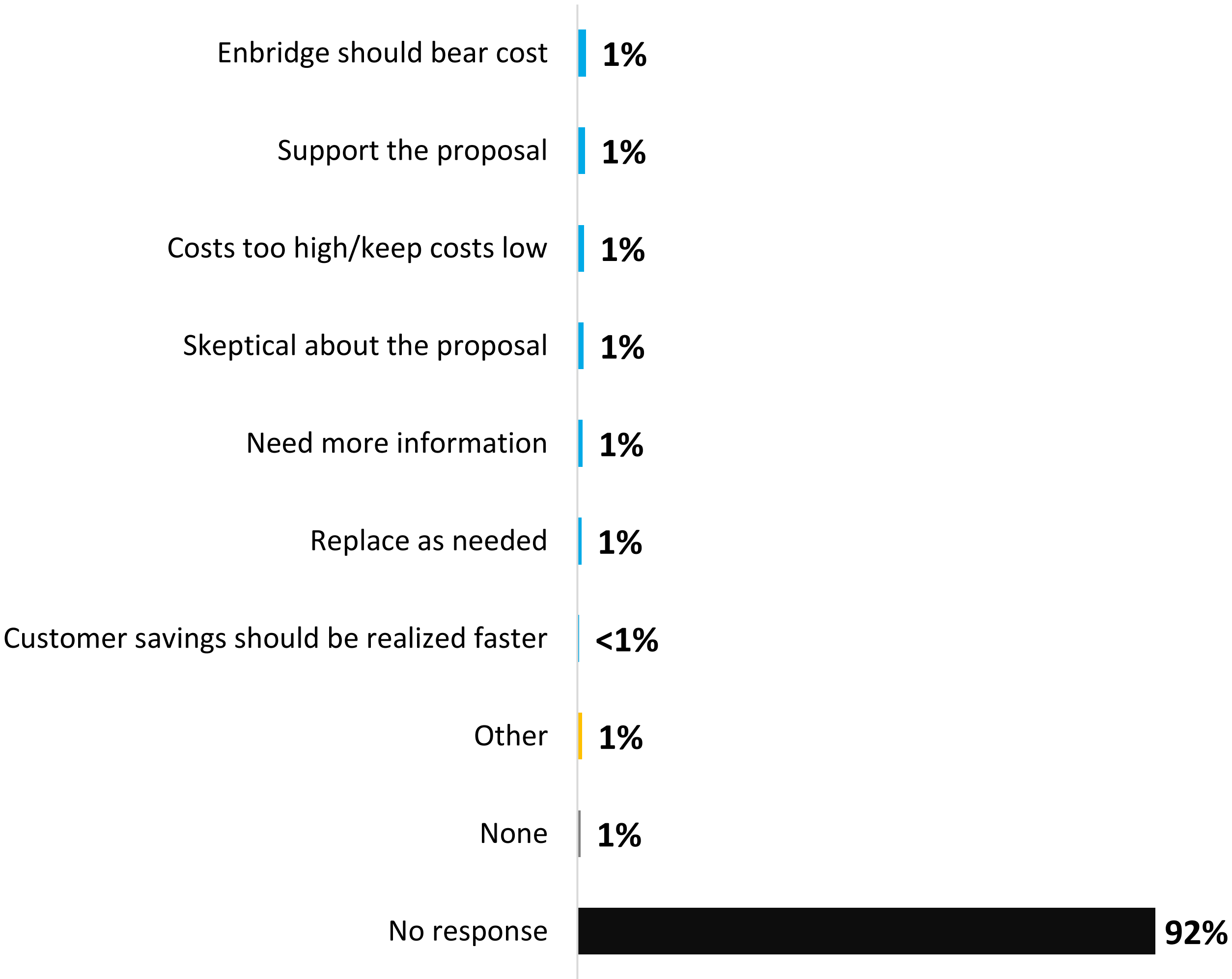
Making Choices

Advanced Meter Infrastructure - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





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Online Workbook Results

Impact of Choices

Impact of Choices

Do You Want to Change Your Choices?

So far in this workbook, you have been asked about **6 key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page, you will find the annual bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential annual rate impact for 2024 and 2028 will be re-calculated each time you change one of your answers at the bottom of the page. Costs for 2025-2027 will fall between this range. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Business Customer Bill Impact Change and Magnitude of Bill Impact **(MEAN)**

2024

Range of Impacts
-0.08% to +0.17%

2028

Range of Impacts
-0.41% to +0.73%

Note: There is no statistical significance between the average initial total and the average final total.

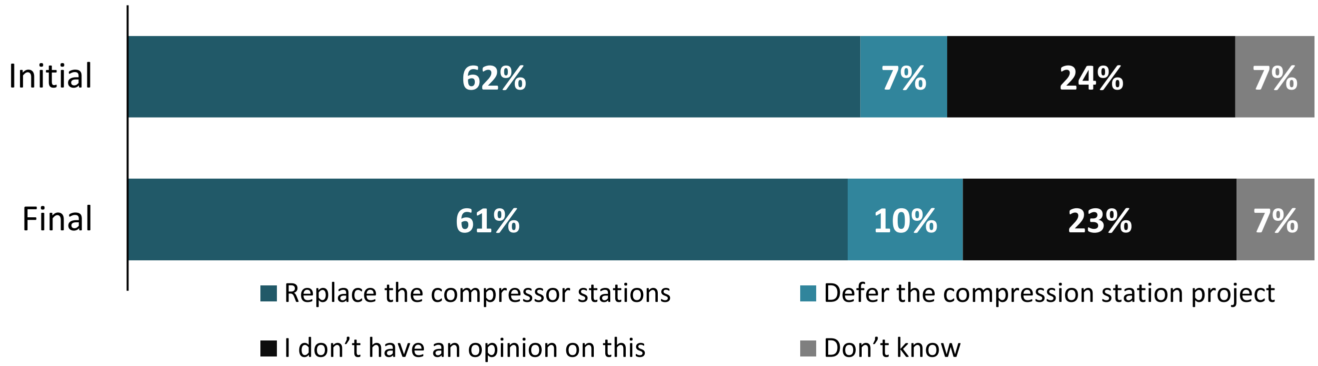
About the "Range of Impacts"

The "Range of Impacts" signifies the highest and lowest possible range of bill impacts above and beyond the Draft Plan. For instance, if a customer, where possible, were to select the most accelerated option, their bill impact would result in an **additional 0.17%** annually in 2024 and **0.73%** in 2028. If they were to select the biggest decrease for each question, it would result in a **decrease of 0.08%** annually in 2024 and **0.41%** in 2028.

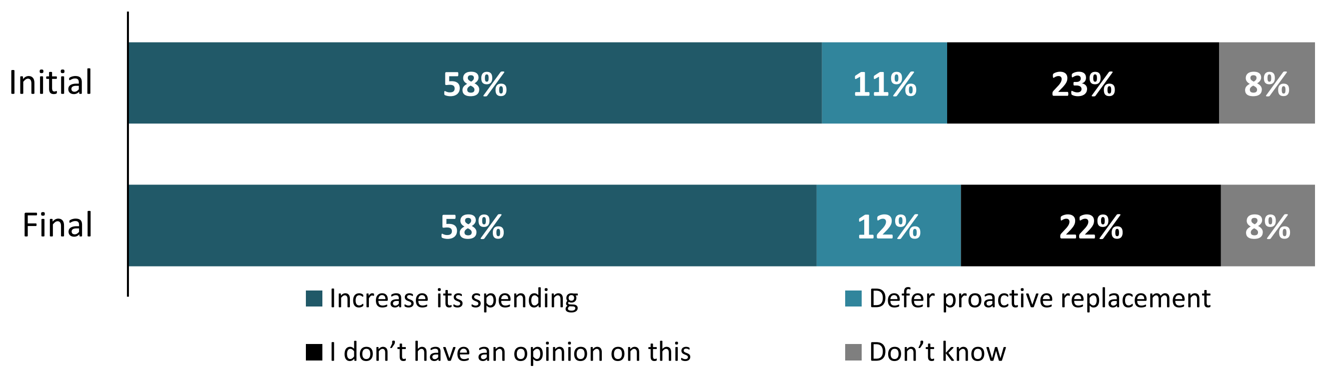
Making Choices

Impact of Choices

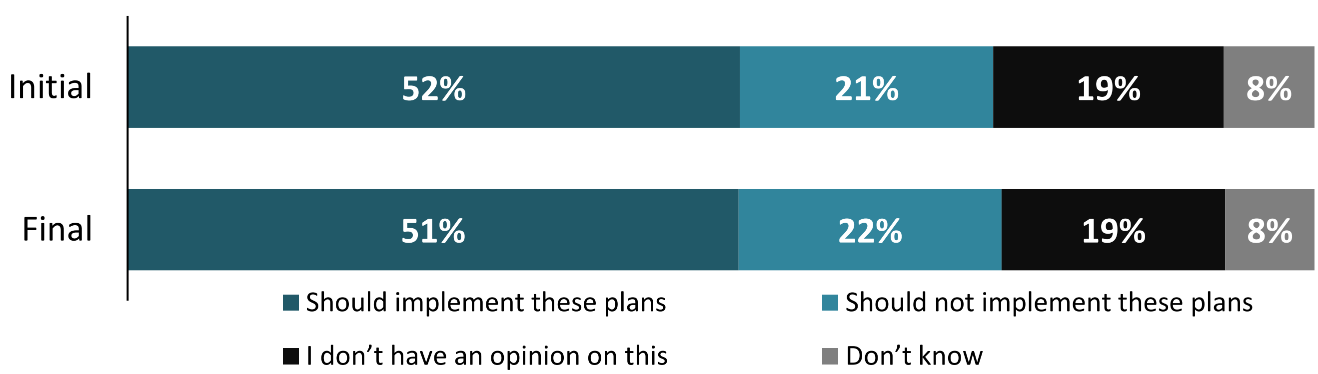
Compressor Station Project



Vintage Steel Pipeline Replacement Program



Hydrogen Gas



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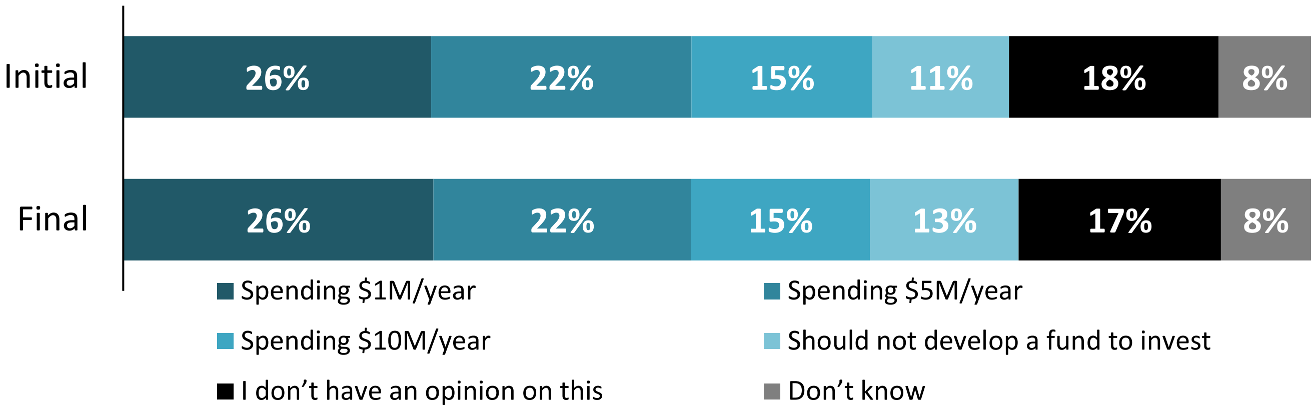
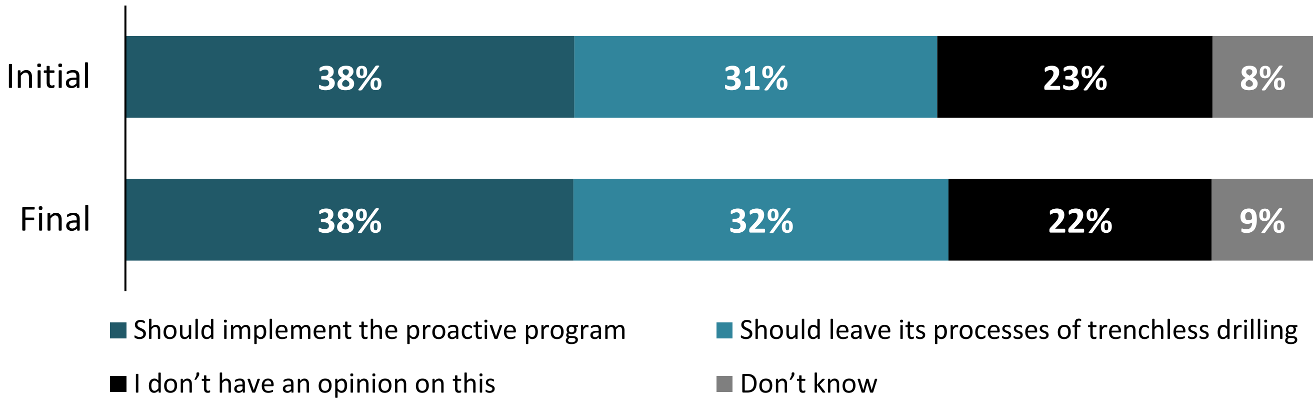
Making Choices

Impact of Choices

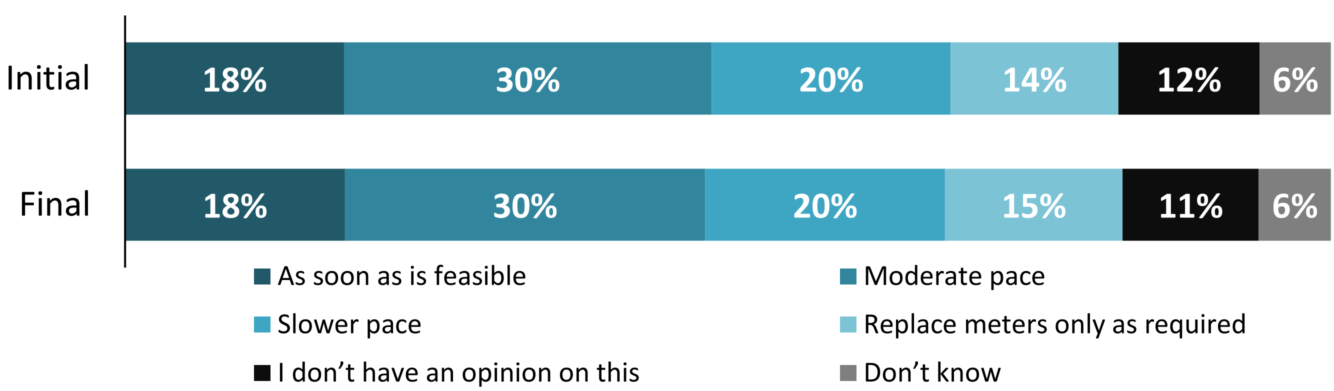
Innovation and Technology Fund



Cross Bores



Advanced Meter Infrastructure



Enbridge Gas will be reviewing its plan based on the feedback you and other customers are sharing now. However, in doing that review, it is important for Enbridge Gas to get a sense of whether the current draft plan is generally acceptable or not. There were some choice options that Enbridge Gas had already included in the draft plan, and others that were not.

As mentioned earlier in the workbook, the Enbridge Gas plan for 2024 to 2028 focused on the following key objectives:

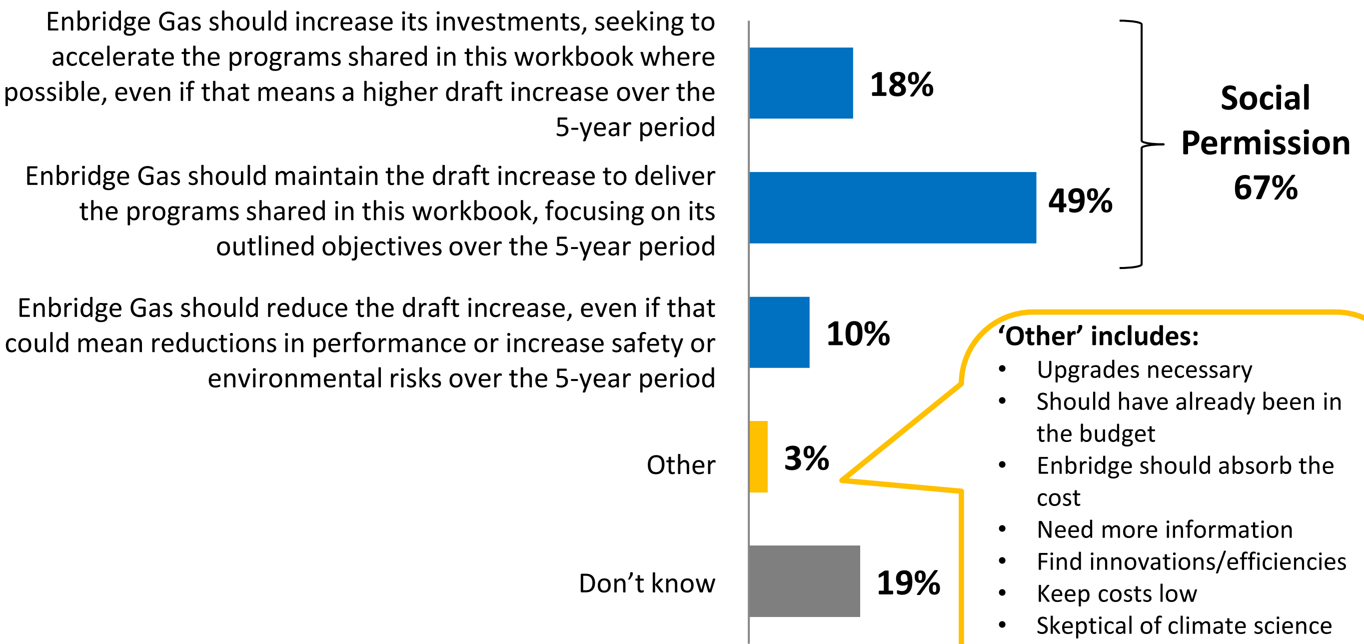
1. Maintaining system safety and reliability
2. Containing costs
3. Harmonizing rates and services
4. Preparing for the future

Currently the plan is estimated to result in an average annual increase of 1.4% over 2024 to 2028 for a total of 5.9% in 2028 compared to October 2021 rates. Along with your feedback on choices included within the plan, Enbridge Gas will consider your feedback on the choices that have not yet been included and update the plan accordingly.

Social Permission

Enbridge Gas' Plans

Q Considering what you know about Enbridge Gas' plans, and the choices you have been making, which of the following best represents your point of view?



'Other' includes:

- Upgrades necessary
- Should have already been in the budget
- Enbridge should absorb the cost
- Need more information
- Find innovations/efficiencies
- Keep costs low
- Skeptical of climate science
- Focus on environment/GHG reduction
- Government grant

		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Should increase its investments	18%	18%	17%	17%	17%	17%	18%	19%	16%	18%	19%
Should maintain the draft increase	49%	48%	53%	53%	53%	55%	49%	44%	52%	49%	51%
Should reduce the draft increase	10%	11%	10%	11%	10%	6%	11%	13%	10%	10%	10%
Other	3%	3%	4%	3%	4%	3%	3%	3%	4%	2%	3%
Don't know	19%	20%	17%	17%	17%	19%	19%	21%	18%	20%	17%
Social Permission (Increase + Maintain)	**67%**	**66%**	**70%**	**70%**	**70%**	**72%**	**67%**	**63%**	**68%**	**67%**	**70%**

Social Permission

Enbridge Gas' Plans (Cont'd)

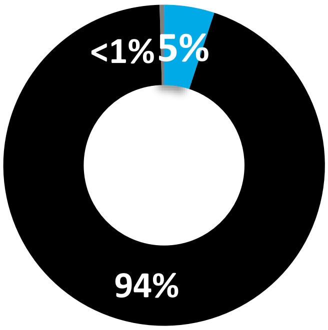
Q Considering what you know about Enbridge Gas' plans, and the choices you have been making, which of the following best represents your point of view?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Should increase its investments	18%	15%	18%	16%	22%	16%	18%	18%	17%	18%	17%	18%	18%	25%
Should maintain the draft increase	49%	61%	41%	49%	46%	52%	49%	48%	44%	55%	37%	54%	57%	59%
Should reduce the draft increase	10%	4%	14%	8%	8%	10%	12%	11%	7%	9%	18%	11%	6%	4%
Other	3%	3%	2%	6%	4%	3%	3%	2%	4%	4%	5%	3%	2%	3%
Don't know	19%	17%	26%	21%	20%	18%	18%	20%	27%	14%	23%	15%	16%	9%
Social Permission (Increase + Maintain)	**67%**	**75%**	**58%**	**65%**	**68%**	**68%**	**67%**	**66%**	**61%**	**73%**	**55%**	**71%**	**75%**	**84%**

Social Permission

Enbridge Gas' Plans – Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.



Response	Total	Social Permission Response				
		Increase invest-ments	Maintain draft increase	Reduce draft increase	Other	Don't know
Opposed to rate increase	1%	1%	1%	3%	5%	1%
Satisfy rate increase using profits	1%	<1%	<1%	1%	5%	1%
Satisfied with effort/Invest in new project if necessary	1%	2%	<1%	<1%	1%	<1%
Infrastructure/system maintenance is top priority	<1%	1%	<1%	1%	3%	--
Concerned about climate change	<1%	1%	<1%	<1%	4%	<1%
Enbridge should cover the cost	<1%	<1%	<1%	1%	2%	<1%
Transparency/open communication	<1%	<1%	<1%	1%	2%	<1%
Utilize expert opinion	<1%	--	<1%	--	2%	1%
Defer new projects	<1%	--	<1%	1%	--	--
Biased information	<1%	--	<1%	<1%	2%	<1%
Other	<1%	1%	<1%	<1%	1%	<1%
None	<1%	1%	<1%	1%	--	1%
No response	94%	92%	97%	91%	72%	96%

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Online Workbook Results

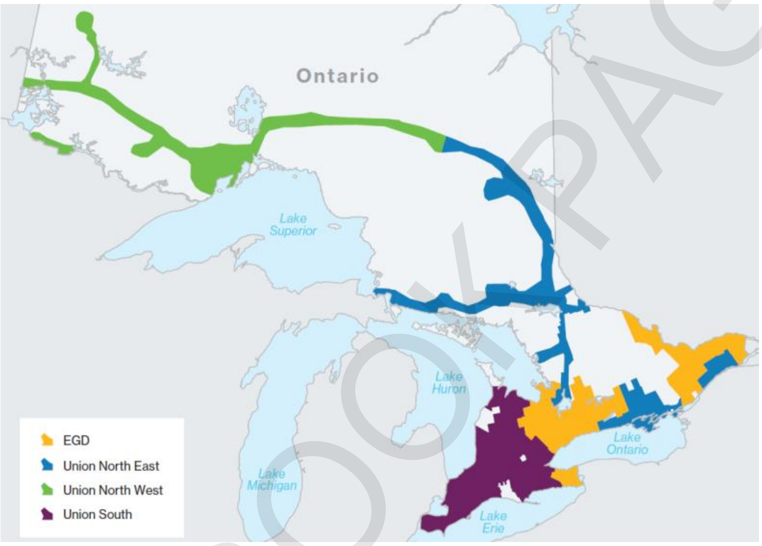
Service and Rate Harmonization

Service and Rate Harmonization

In its application to the OEB, Enbridge Gas is also considering several other items that may affect customers. In this section we will ask you about a few different things, including programs that it could offer, as well as some options on how rates are calculated and applied.

Rate Zones

Currently, the rate you pay for natural gas delivery depends on where you live in Ontario. As previously indicated, Enbridge Gas, today, is a combination of Legacy Enbridge Gas Distribution and Legacy Union Gas. Currently there are four rate zones, each with its own rates depending on where you are located, and which company previously served you. The four rate zones look as follows:



Enbridge Gas is considering the option of offering one rate zone for its different types of customers, regardless of location within Ontario and the cost to serve them. There are many benefits of one rate zone including similar charges for similar customers, a consistent customer experience, and reduced administrative costs.

One rate zone could result in a change to the amount customers pay for their natural gas service, and varies on the rate zone a customer is currently located in. The adjustment as a result of this change is impacted by the number of customers in a rate zone and is shown in the table below.

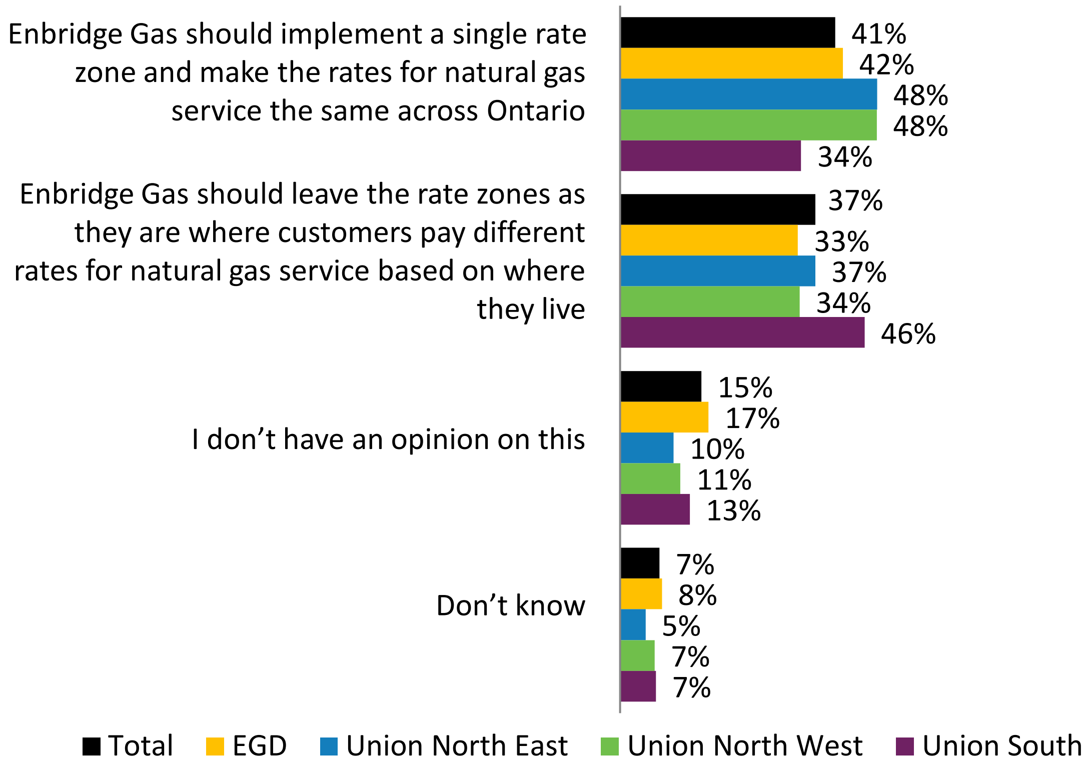
Current rate zone	Average cost adjustment at current rates
EGD	Decrease of approximately 1%
Union North East	Decrease of approximately 10%
Union North West	Decrease of approximately 10%
Union South	Increase of approximately 5%

Service and Rate Harmonization

Rate Zones

Q

You are located in (PIPE IN RATE ZONE BASED ON SAMPLE). Considering this, which of the following is closest to your view?



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Should implement a single rate zone	41%	42%	37%	48%	34%	34%	41%	39%	41%	43%	41%
Should leave the rate zones as they are	37%	33%	44%	36%	46%	43%	36%	37%	35%	35%	38%
I don't have an opinion on this	15%	17%	12%	10%	13%	15%	15%	18%	16%	14%	14%
Don't know	7%	8%	6%	5%	7%	8%	7%	7%	8%	7%	7%

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Service and Rate Harmonization

Rate Zones (Cont'd)

Q You are located in (PIPE IN RATE ZONE BASED ON SAMPLE). Considering this, which of the following is closest to your view?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Should implement a single rate zone	41%	32%	41%	41%	43%	42%	40%	39%	36%	46%	42%	43%	40%	43%
Should leave the rate zones as they are	37%	52%	32%	35%	32%	39%	36%	38%	38%	37%	35%	39%	40%	39%
I don't have an opinion on this	15%	13%	15%	16%	16%	12%	17%	15%	17%	13%	16%	13%	14%	13%
Don't know	7%	3%	12%	8%	8%	7%	8%	8%	9%	4%	8%	5%	6%	6%

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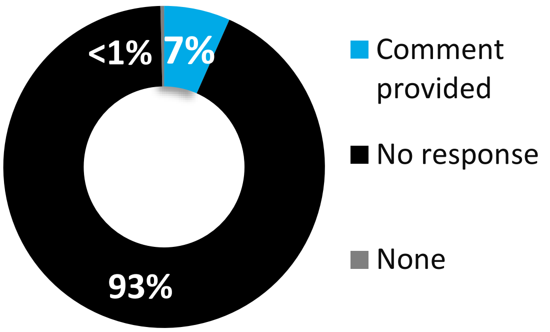
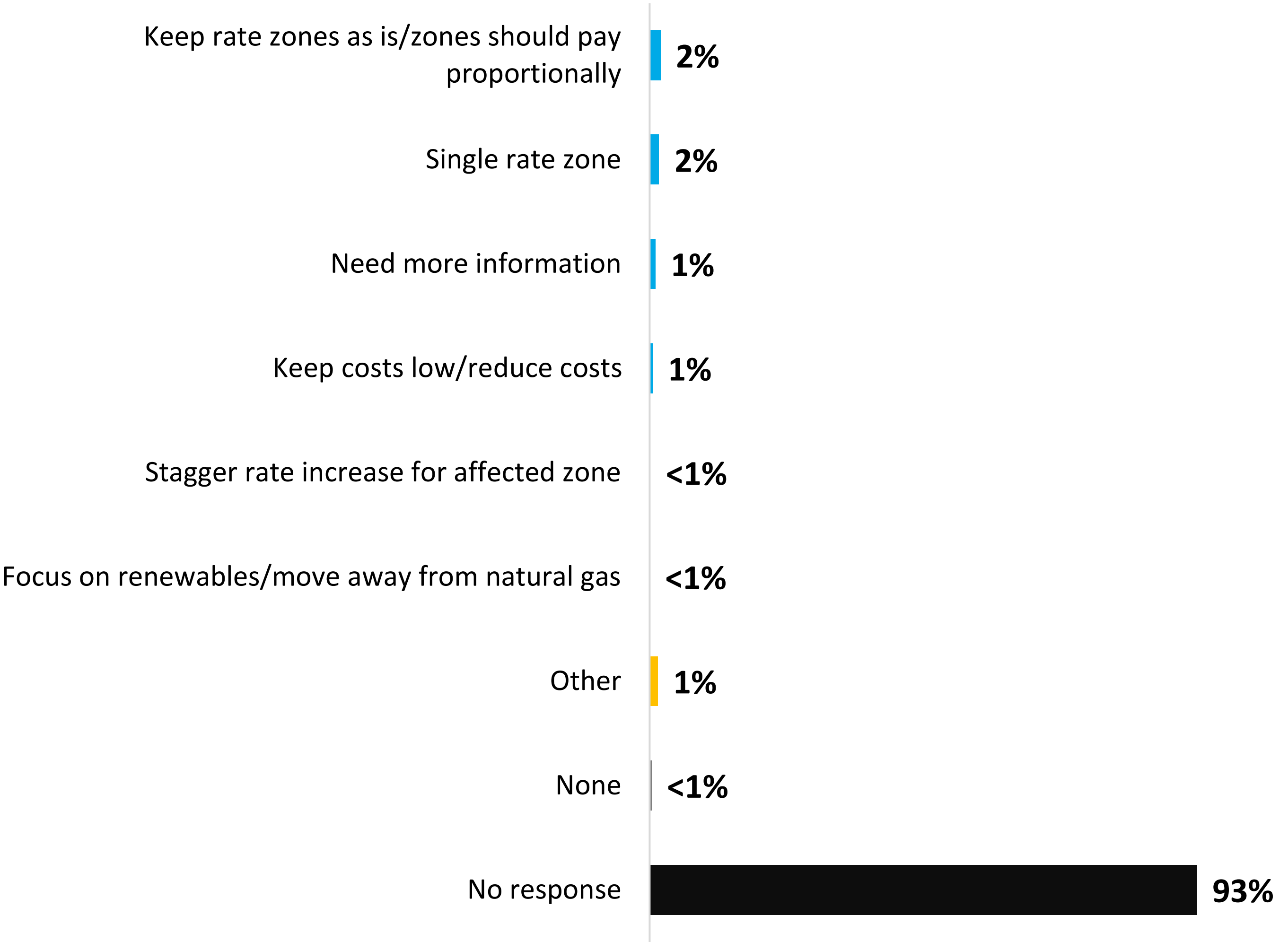
Service and Rate Harmonization

Rate Zone - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





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Rate Design

Similar to your electric utility, your gas bill is split into the cost of the natural gas you use and the cost of delivering that gas to you. This question focuses on the delivery charge. Enbridge Gas incurs two types of costs in delivering natural gas to customers like you.

- **Variable costs** depend on how much natural gas you use.
- **Fixed costs** are the same regardless of how much natural gas you use.

The fixed costs that Enbridge Gas incurs can be divided into two groups: the cost of having access to the system, and the cost of the demand that you place on the system which drives the system capacity. We'll look at these two separately.

Cost of being connected to the system

One type of fixed cost is that of being connected to the system. This includes the cost of the pipeline, the pressure regulator, the natural gas meter, meter reading, billing, the contact centre and operations support. These costs are **fixed for Enbridge Gas** and are **similar for each customer** and do not change based on the size of the customer.

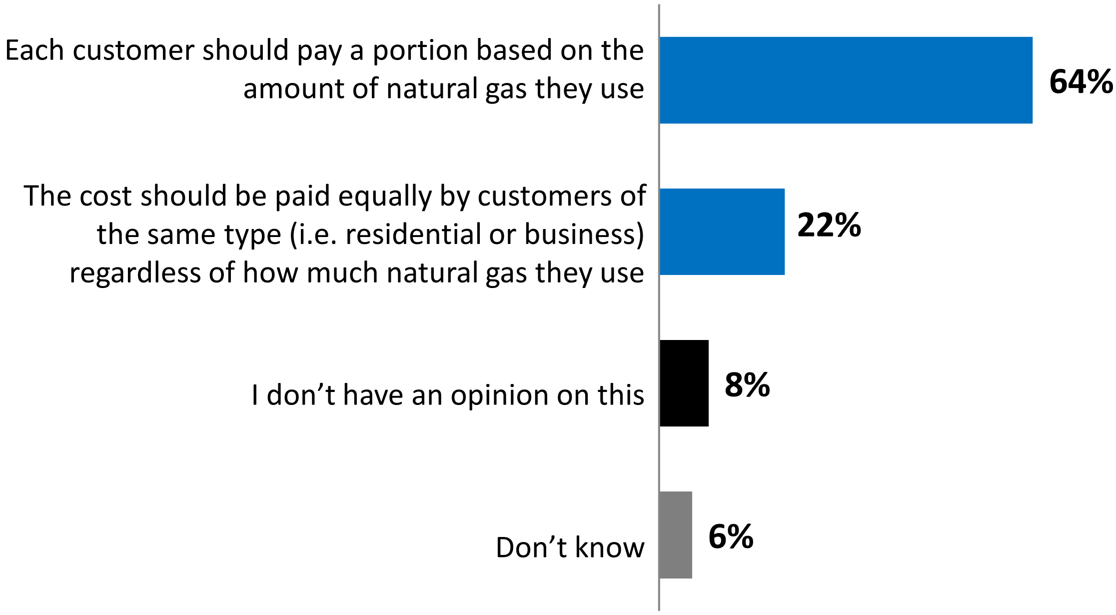
Cost of accessing a portion of the system

The other type of fixed cost is that of the system capacity. This includes the cost of the infrastructure, its operation, maintenance, and natural gas storage to meet the peak demand of customers on the coldest days of the year. These costs are **fixed for Enbridge Gas** but **may vary for each customer** based on their individual level of peak demand, which is often on the coldest days of the year.

Service and Rate Harmonization

Rate Design - Costs of Being Connected to the System

Q How do you feel business customers like you should be billed for these costs of being connected to the system?



	Total	Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Customers should pay a portion based on use	64%	65%	63%	61%	64%	58%	65%	66%	65%	64%	63%
The cost should be paid equally	22%	20%	24%	25%	24%	25%	21%	20%	20%	23%	23%
I don't have an opinion on this	8%	9%	8%	9%	7%	7%	9%	9%	9%	8%	9%
Don't know	6%	6%	5%	4%	5%	9%	5%	5%	6%	5%	6%

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Service and Rate Harmonization

Rate Design - Costs of Being Connected to the System (Cont'd)

Q How do you feel business customers like you should be billed for these costs of being connected to the system?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Customers should pay a portion based on use	64%	58%	57%	67%	63%	66%	65%	64%	61%	68%	59%	70%	68%	67%
The cost should be paid equally	22%	30%	23%	15%	23%	21%	22%	23%	19%	21%	25%	21%	20%	26%
I don't have an opinion on this	8%	8%	10%	12%	6%	8%	8%	8%	12%	8%	9%	7%	7%	5%
Don't know	6%	4%	10%	6%	8%	5%	5%	6%	8%	3%	7%	3%	5%	3%

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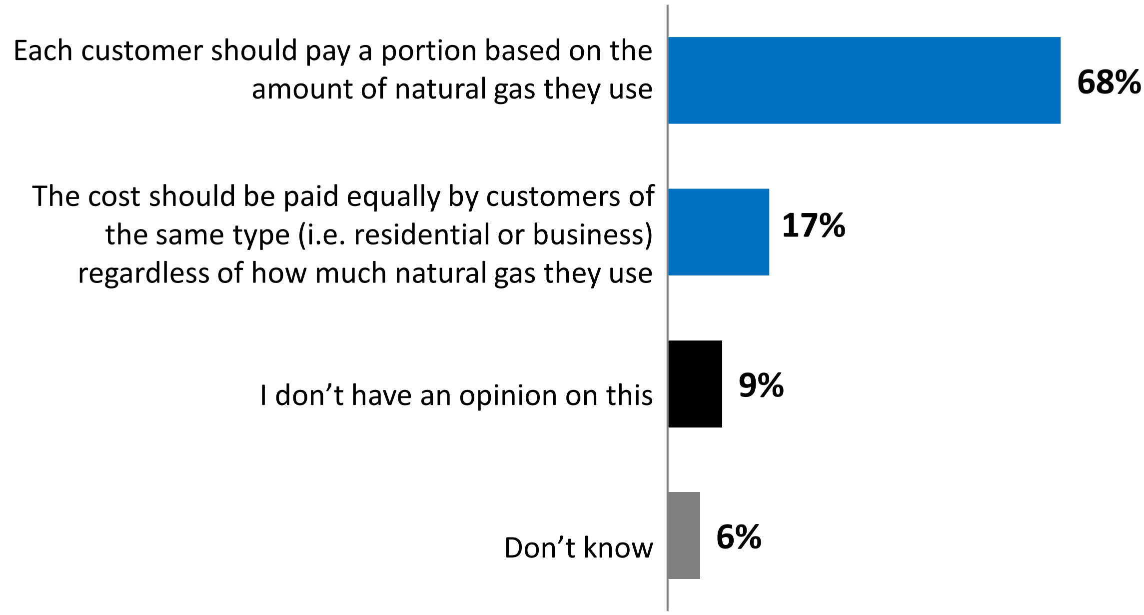
Service and Rate Harmonization

Rate Design - Cost of Accessing System Capacity

Q How do you feel business customers like you should be billed for these costs of accessing system capacity?



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Customers should pay a portion based on use	68%	67%	69%	66%	70%	62%	68%	68%	69%	68%	67%
The cost should be paid equally	17%	17%	18%	21%	18%	20%	17%	16%	17%	18%	18%
I don't have an opinion on this	9%	10%	8%	8%	7%	10%	9%	10%	9%	9%	10%
Don't know	6%	6%	5%	5%	5%	8%	5%	6%	5%	5%	5%

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Service and Rate Harmonization

Rate Design - Cost of Accessing System Capacity (Cont'd)

Q How do you feel business customers like you should be billed for these costs of accessing system capacity?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Customers should pay a portion based on use	68%	69%	61%	67%	66%	68%	67%	68%	67%	72%	61%	69%	74%	79%
The cost should be paid equally	17%	17%	18%	15%	17%	19%	18%	18%	14%	17%	22%	20%	13%	12%
I don't have an opinion on this	9%	9%	12%	12%	7%	7%	10%	9%	12%	9%	11%	8%	8%	5%
Don't know	6%	6%	8%	7%	9%	6%	5%	5%	7%	3%	6%	3%	5%	4%

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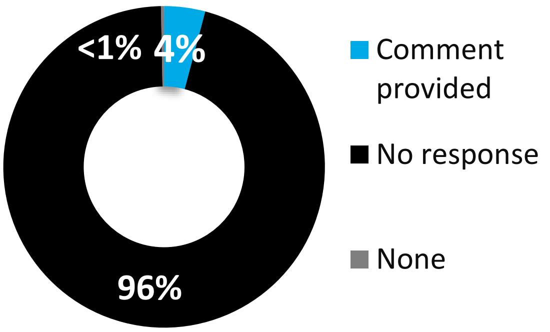
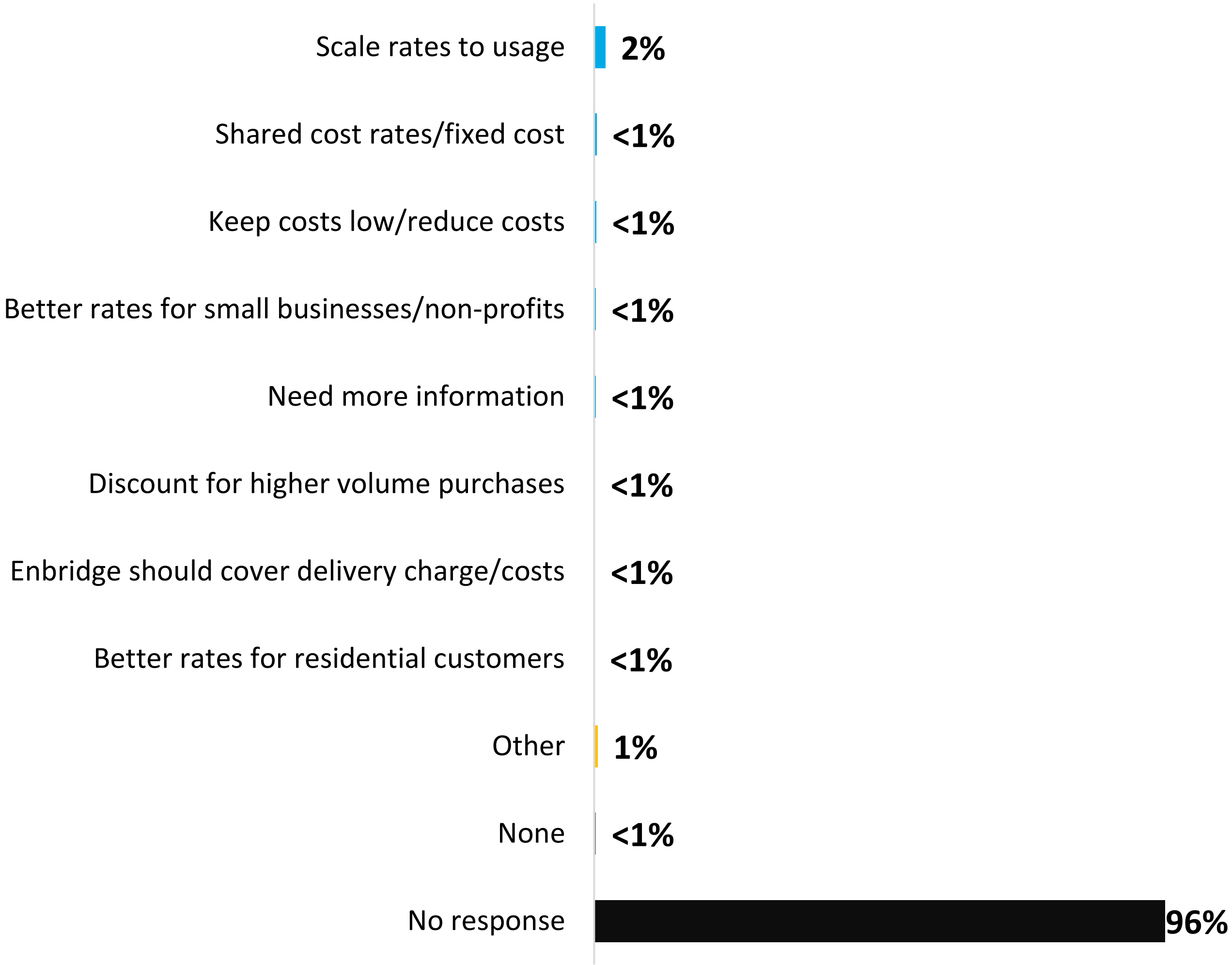
Service and Rate Harmonization

Rate Design - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





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Online Workbook Results

Fuel Choices

Cost of the fuel

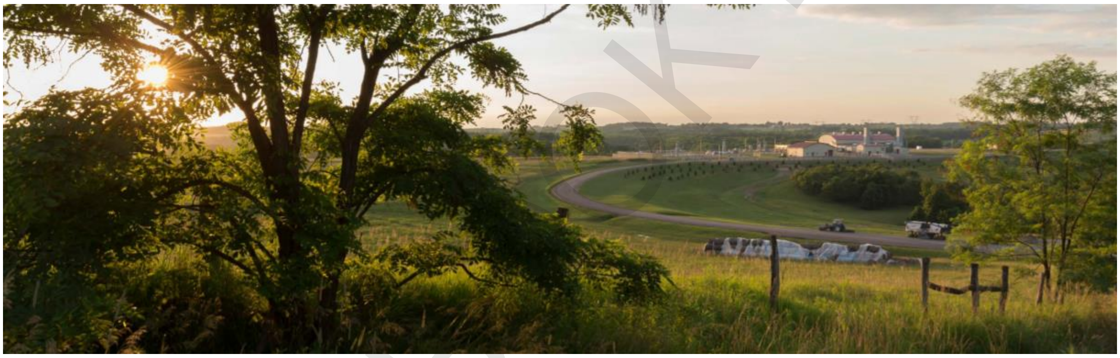
Fuel Choices

As previously discussed, the costs of buying natural gas and transporting it to Ontario are overseen by the Ontario Energy Board and are passed on to customers at cost. However, Enbridge Gas can make some choices about the natural gas it purchases, beyond focusing on the lowest price in the market. We would like to ask you a couple of questions about gas supply options.

Responsibly Sourced Gas

Enbridge Gas is looking at options to ensure that the natural gas it purchases is responsibly sourced. This means that the companies who produce the natural gas adhere to higher standards than the minimum government standards. This relates to areas such as:

- minimizing impacts to air and water quality
- lowering GHG emissions during production
- stronger engagement with Indigenous communities, etc.

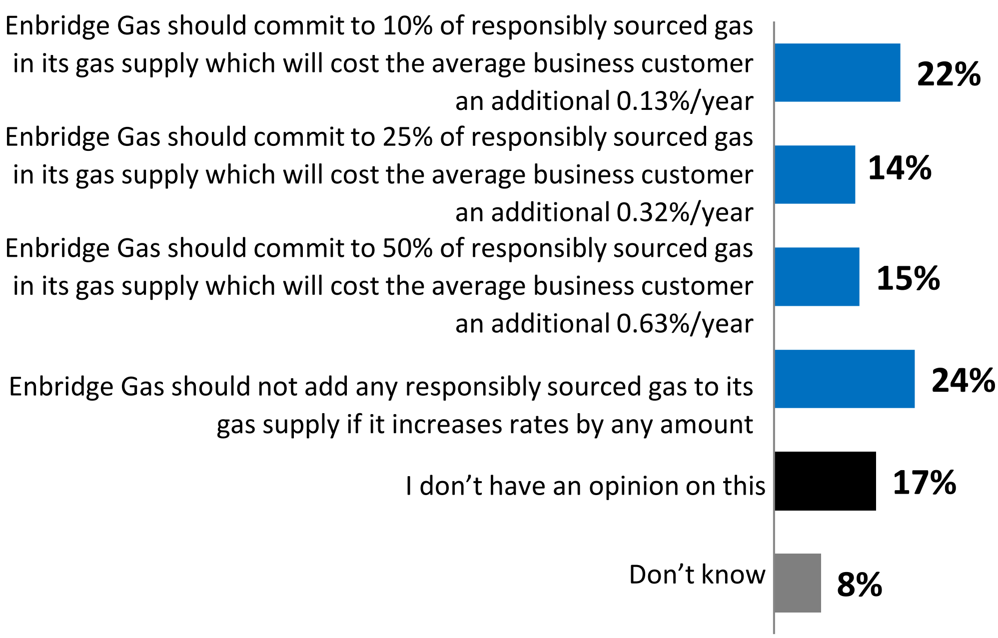


Enbridge Gas can offer some options to include Responsibly Sourced Gas in its portfolio, which can be purchased at a small premium. Responsibly Sourced Gas is a new and emerging trend in the North American natural gas industry. For this reason, current supply options are limited.

Cost of the Fuel

Responsibly Sourced Gas

Q Considering this, which of the following is closest to your view?



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Commit to 10% of responsibly sourced gas	22%	23%	20%	23%	19%	25%	21%	20%	21%	22%	23%
Commit to 25% of responsibly sourced gas	14%	14%	15%	17%	14%	12%	14%	13%	16%	14%	14%
Commit to 50% of responsibly sourced gas	15%	14%	16%	12%	17%	13%	15%	15%	15%	14%	14%
Not add any responsibly sourced gas	24%	24%	25%	25%	25%	27%	24%	25%	23%	24%	23%
I don't have an opinion on this	17%	18%	16%	17%	16%	16%	18%	19%	17%	17%	17%
Don't know	8%	8%	8%	7%	8%	6%	8%	7%	8%	9%	8%

Cost of the Fuel

Responsibly Sourced Gas (Cont'd)

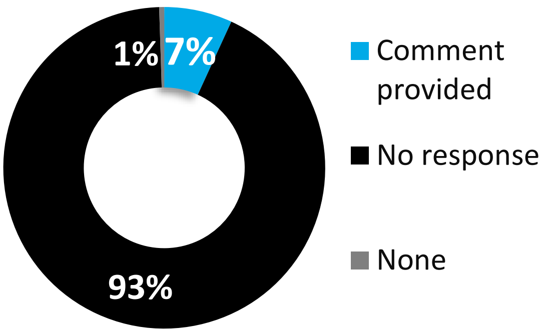
Q Considering this, which of the following is closest to your view?

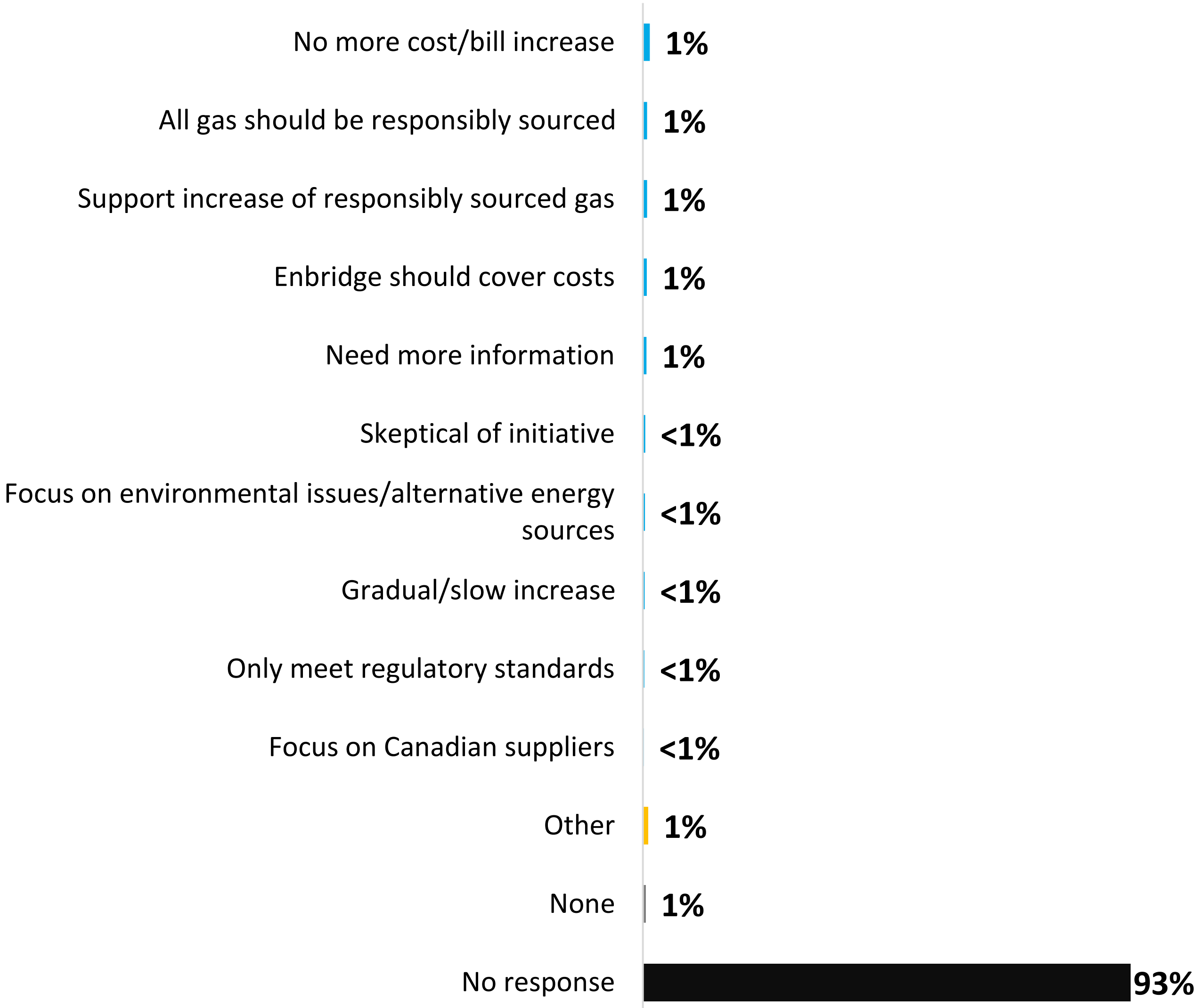
		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Commit to 10% of responsibly sourced gas	22%	22%	23%	20%	21%	21%	20%	23%	26%	23%	23%	25%	24%	18%
Commit to 25% of responsibly sourced gas	14%	11%	9%	16%	12%	14%	15%	14%	13%	15%	6%	17%	18%	17%
Commit to 50% of responsibly sourced gas	15%	14%	12%	16%	20%	14%	14%	14%	11%	17%	9%	14%	17%	27%
Not add any responsibly sourced gas	24%	33%	29%	22%	28%	24%	25%	24%	16%	23%	35%	24%	19%	20%
I don't have an opinion on this	17%	14%	16%	20%	10%	19%	19%	18%	20%	15%	18%	16%	15%	13%
Don't know	8%	6%	10%	6%	9%	7%	8%	7%	14%	7%	8%	5%	8%	6%

Cost of the Fuel

Responsibly Sourced Gas - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





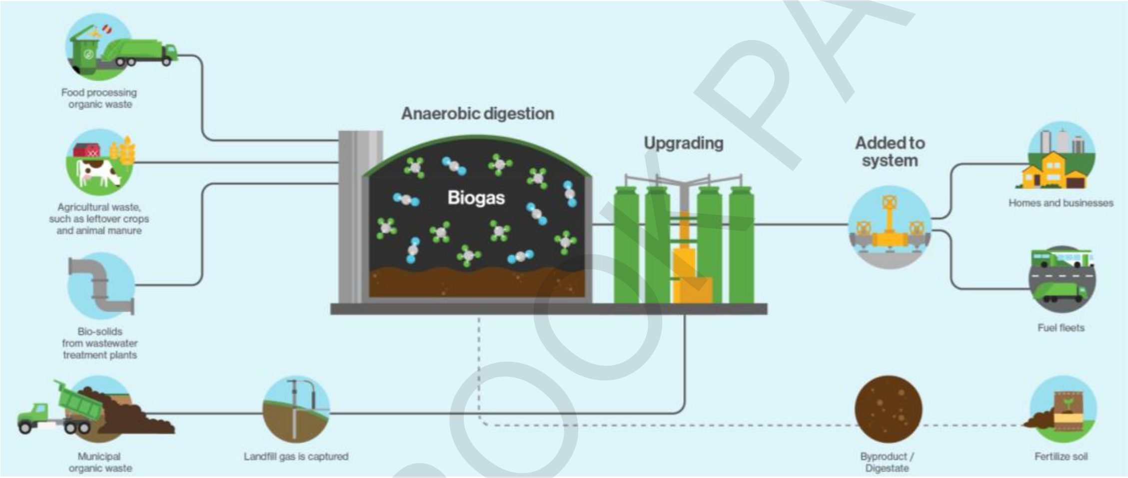
Cost of the fuel

Fuel Choices

Renewable Natural Gas

Enbridge Gas is looking at options to blend more Renewable Natural Gas (RNG) into the natural gas it delivers to green the gas supply. The gas is derived from organic waste from farms, landfills, and water treatment plants. The gas is then blended with traditional natural gas and supplied to customers using existing natural gas infrastructure.

RNG is considered to be carbon neutral and would reduce GHG emissions to help meet climate change targets. Every one percent of RNG in the gas supply reduces GHG emissions by one percent, in a 1:1 ratio. That means every additional 1% of RNG reduces your natural gas GHG emissions by 1%.



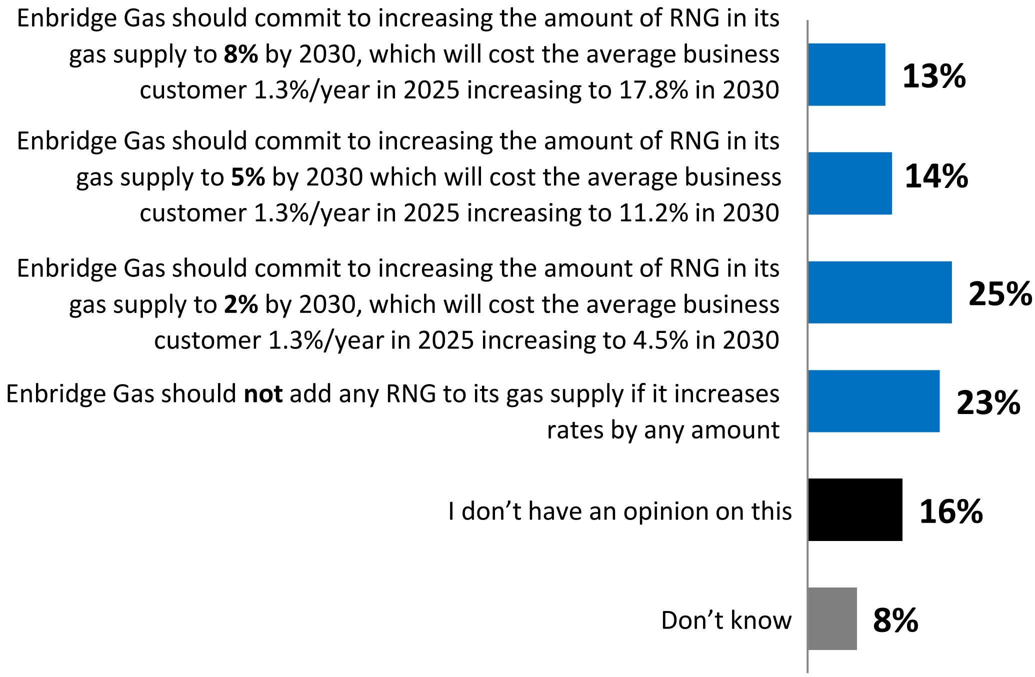
Enbridge Gas is developing a plan to increase the blend of RNG in the gas system from 0.5% in 2025 to a higher amount over the course of the 2024 to 2028 plan and beyond. This amount is limited by the amount of RNG available in the market. Since the cost to produce RNG is currently higher than that of traditional natural gas it could have an impact on your rates.

The federal carbon charge would not be applied to the volume of RNG on customer bills, which is accounted for in the costs shown below.

Cost of the Fuel

Renewable Natural Gas

Q Considering this, which of the following is closest to your view?



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	EGD	Union	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Increasing the amount of RNG in its gas supply to **8%**	13%	14%	13%	12%	13%	14%	13%	14%	13%	15%	12%
Increasing the amount of RNG in its gas supply to **5%**	14%	14%	16%	17%	16%	14%	15%	12%	16%	14%	16%
Increasing the amount of RNG in its gas supply to **2%**	25%	25%	24%	24%	24%	21%	25%	24%	25%	24%	27%
Should not add any RNG to its gas supply	23%	22%	23%	22%	24%	25%	23%	24%	22%	23%	22%
I don't have an opinion on this	16%	17%	15%	16%	15%	20%	16%	18%	15%	16%	14%
Don't know	8%	8%	8%	9%	8%	7%	9%	8%	9%	8%	8%

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Cost of the Fuel

Renewable Natural Gas (Cont'd)

Q Considering this, which of the following is closest to your view?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Increasing the amount of RNG in its gas supply to **8%**	13%	11%	12%	11%	19%	11%	14%	13%	13%	15%	10%	12%	16%	22%
Increasing the amount of RNG in its gas supply to **5%**	14%	16%	11%	16%	14%	17%	14%	14%	13%	16%	8%	17%	18%	19%
Increasing the amount of RNG in its gas supply to **2%**	25%	23%	24%	25%	21%	24%	25%	25%	21%	28%	22%	28%	27%	25%
Should not add any RNG to its gas supply	23%	31%	24%	23%	21%	21%	23%	23%	21%	23%	34%	23%	16%	16%
I don't have an opinion on this	16%	13%	19%	19%	15%	18%	17%	16%	18%	12%	18%	14%	15%	11%
Don't know	8%	6%	11%	6%	10%	8%	8%	9%	14%	6%	8%	6%	8%	6%

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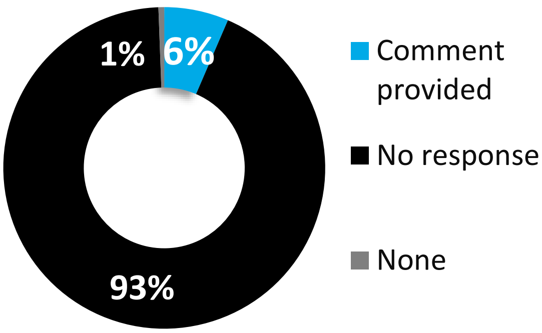
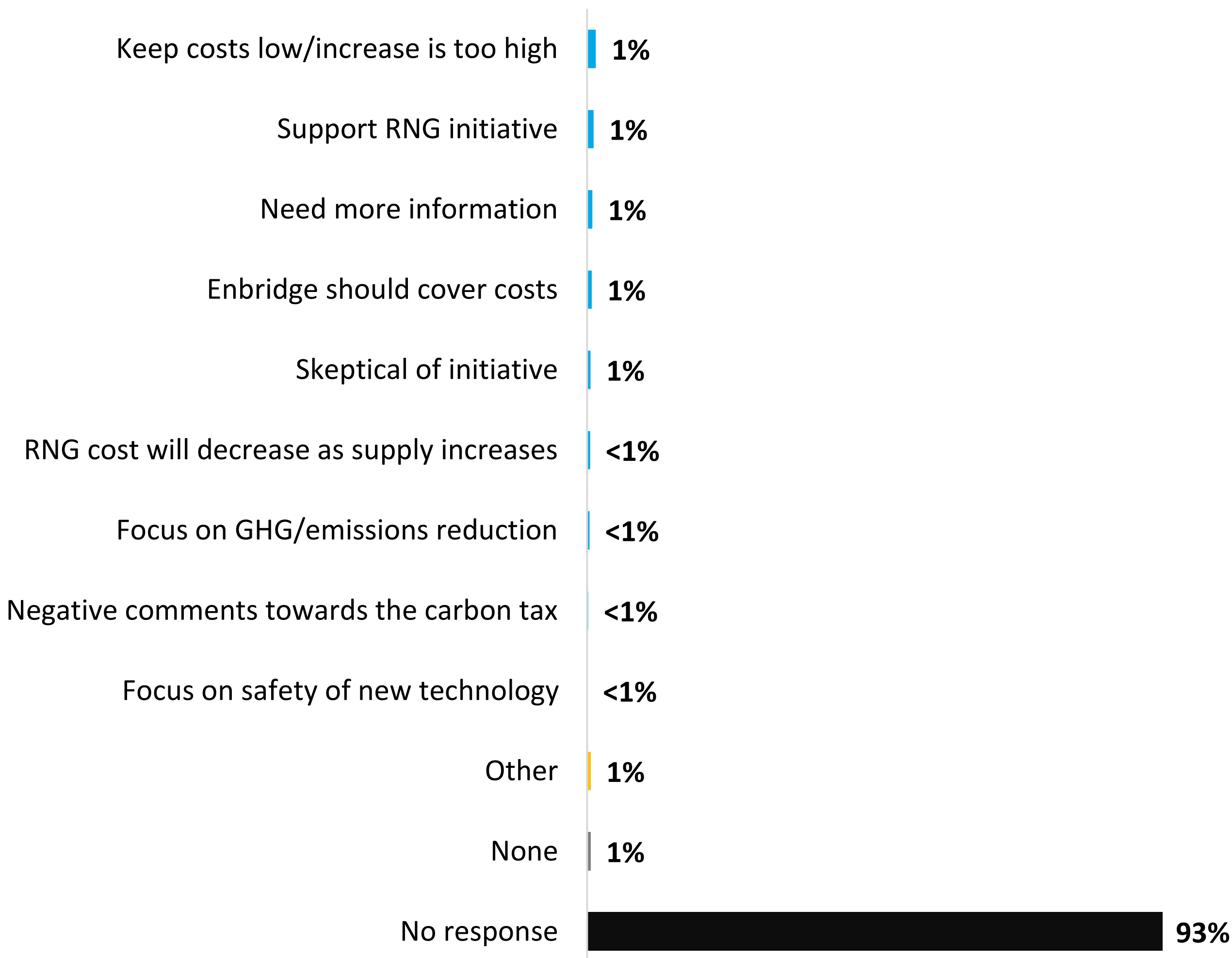
Cost of the Fuel

Renewable Natural Gas - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





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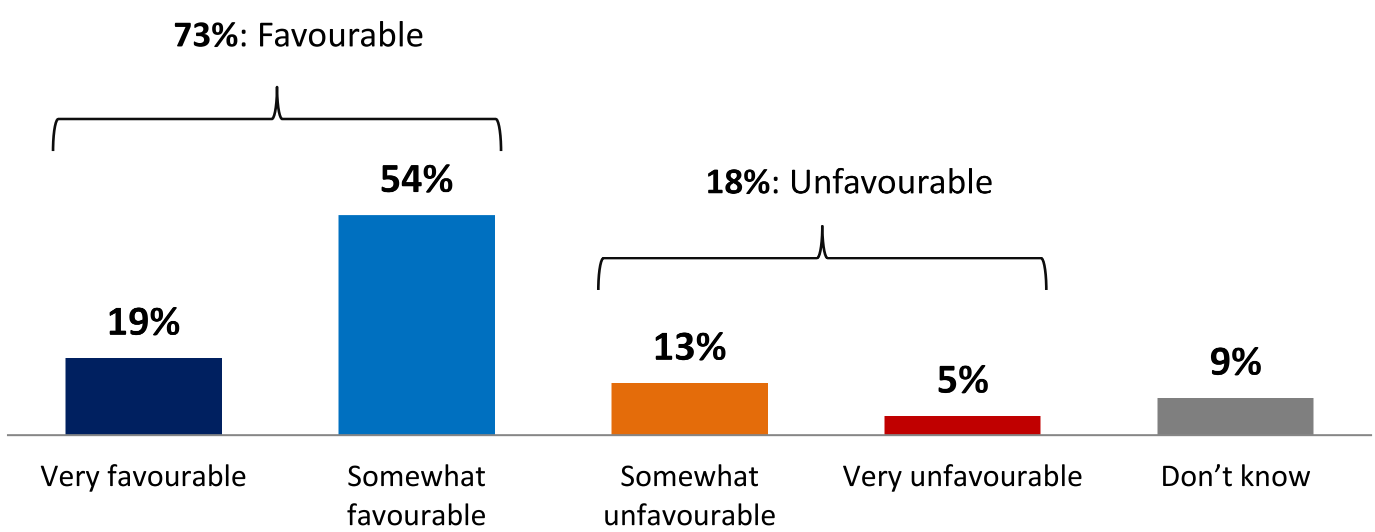
Online
Workbook Diagnostics

Final Thoughts

Workbook Impression

Q Overall, did you have a favourable or unfavourable impression of the workbook you just completed?



		Rate Zone		Union Region		Business Size		Small Business Consumption Quartile			
	Total	**EGD**	**Union**	**North**	**South**	**Med-Large**	**Small**	**Low**	**Med-low**	**Med-high**	**High**
Very favourable	19%	19%	19%	20%	18%	21%	19%	18%	18%	19%	20%
Somewhat favourable	54%	54%	55%	54%	55%	52%	54%	55%	53%	53%	57%
Somewhat unfavourable	13%	13%	13%	13%	13%	13%	13%	13%	13%	14%	10%
Very unfavourable	5%	5%	4%	5%	4%	4%	5%	5%	5%	4%	5%
Don't know	9%	9%	9%	8%	9%	10%	9%	8%	11%	9%	9%
Favourable (Very + Somewhat)	**73%**	**73%**	**74%**	**74%**	**74%**	**74%**	**73%**	**74%**	**71%**	**72%**	**76%**
Unfavourable (Very + Somewhat)	18%	18%	17%	17%	17%	16%	18%	18%	19%	19%	15%

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Final Thoughts

Workbook Impression (Cont'd)

Q Overall, did you have a favourable or unfavourable impression of the workbook you just completed?

		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Very favourable	19%	16%	18%	15%	25%	21%	18%	18%	18%	22%	19%	16%	20%	33%
Somewhat favourable	54%	62%	44%	60%	47%	53%	54%	56%	49%	58%	46%	64%	56%	50%
Somewhat unfavourable	13%	14%	18%	11%	16%	12%	13%	13%	15%	10%	16%	12%	14%	11%
Very unfavourable	5%	4%	5%	3%	3%	5%	6%	4%	5%	4%	11%	3%	3%	2%
Don't know	9%	4%	14%	11%	10%	8%	9%	9%	12%	6%	8%	6%	7%	4%
Favourable (Very + Somewhat)	**73%**	**78%**	**62%**	**75%**	**71%**	**74%**	**72%**	**74%**	**68%**	**80%**	**65%**	**80%**	**76%**	**82%**
Unfavourable (Very + Somewhat)	18%	18%	23%	15%	19%	18%	18%	17%	20%	14%	27%	14%	17%	13%

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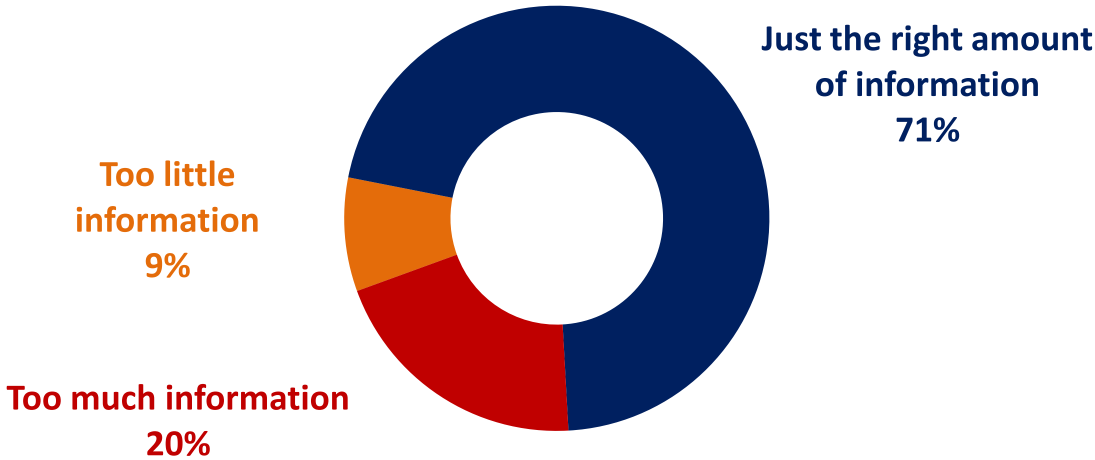
Final Thoughts

Amount of Information

Q In this workbook, do you feel that Enbridge Gas provided too much information, not enough, or just the right amount?



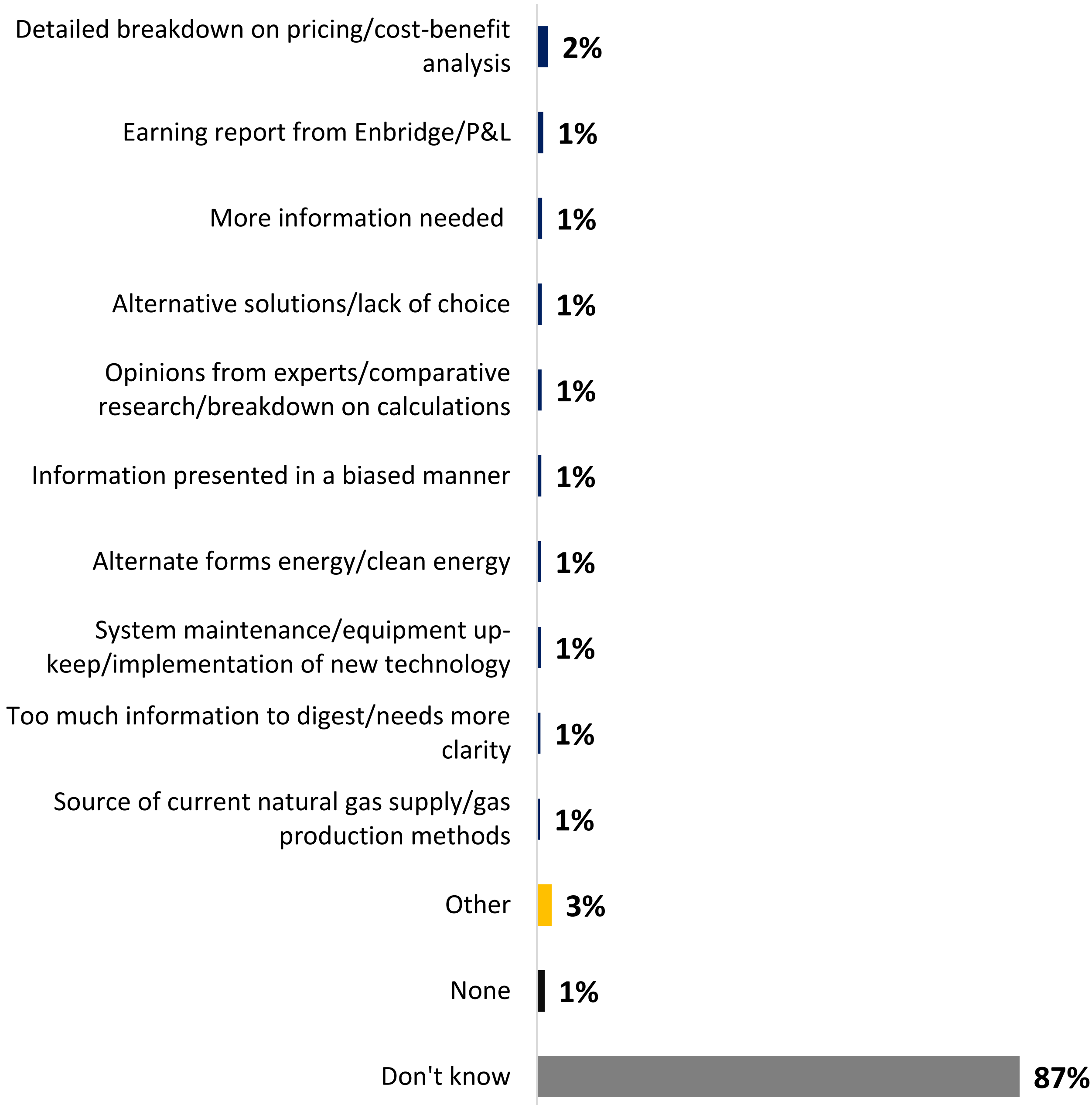
	Total	Rate Zone: EGD	Rate Zone: Union	Union Region: North	Union Region: South	Business Size: Med-Large	Business Size: Small	Small Business Consumption Quartile: Low	Small Business Consumption Quartile: Med-low	Small Business Consumption Quartile: Med-high	Small Business Consumption Quartile: High
Too little information	9%	9%	8%	8%	8%	11%	9%	9%	9%	8%	8%
Just the right amount	71%	69%	74%	73%	75%	71%	71%	70%	71%	71%	71%
Too much information	20%	21%	18%	19%	18%	18%	20%	21%	20%	21%	21%

	Total	Sector: Agriculture/ Greenhouse	Sector: Food Services	Sector: Manufacturing	Sector: Multiresidential	Sector: Office	Sector: Other Commercial	Sector: Retail	Sector: Transportation/ Warehouse	Sector: Other	Enbridge Gas Bill Impacts Finances: Strongly Agree	Enbridge Gas Bill Impacts Finances: Somewhat Agree	Enbridge Gas Bill Impacts Finances: Somewhat Disagree	Enbridge Gas Bill Impacts Finances: Strongly Disagree
Too little information	9%	11%	13%	10%	12%	7%	8%	9%	7%	7%	12%	8%	8%	6%
Just the right amount	71%	72%	57%	70%	69%	75%	72%	69%	71%	75%	62%	76%	75%	79%
Too much information	20%	17%	30%	20%	19%	18%	20%	22%	21%	18%	26%	16%	17%	15%

Final Thoughts

Content Missing from Engagement

Q Was there any content missing that you would have liked to have seen included in this workbook?

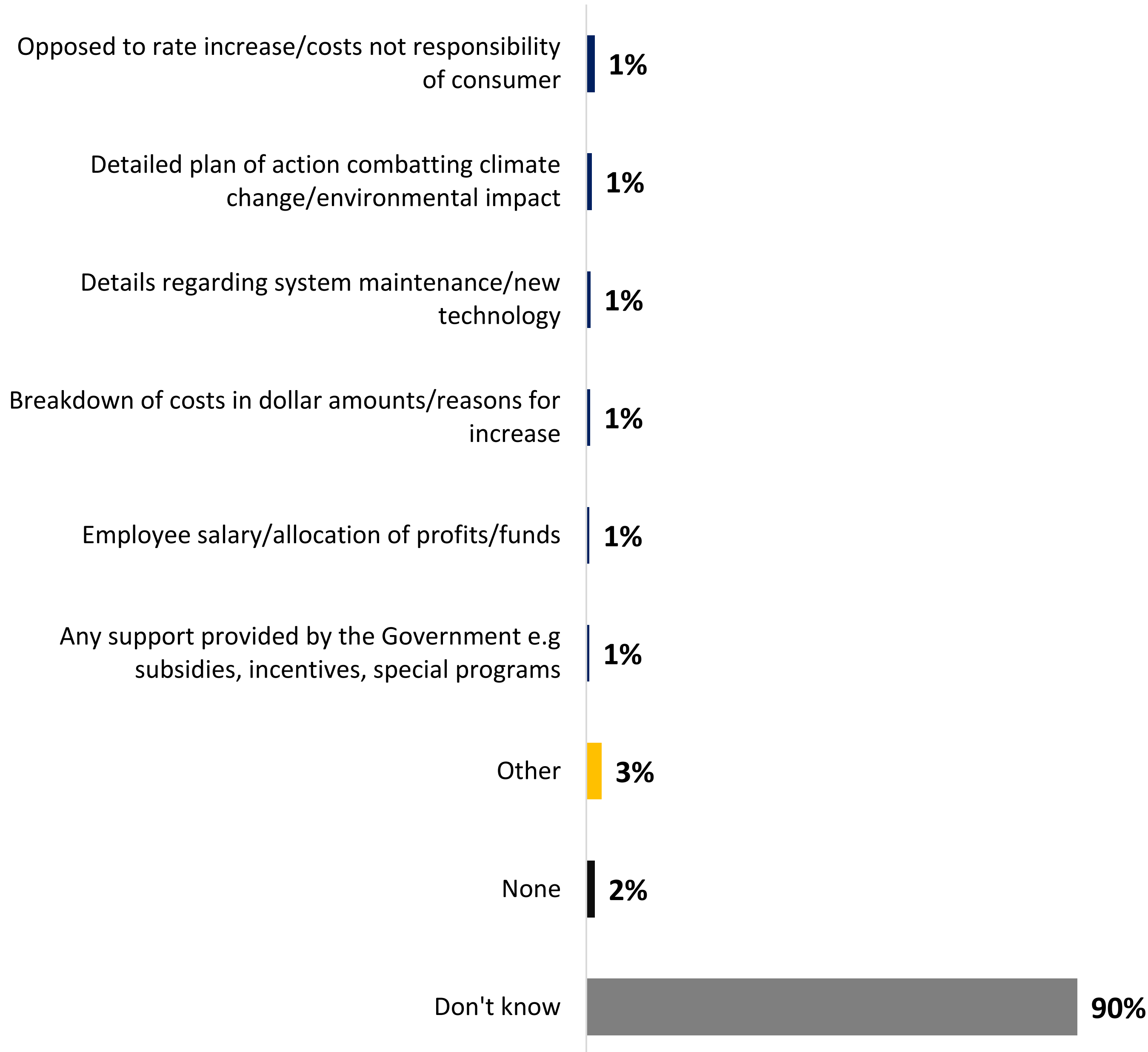


Note: Refused (<1%) not shown

Final Thoughts

Outstanding Questions

Q Is there anything that you would still like answered?



Note: Refused (<1%) not shown

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2024 Rate Rebasing Customer Engagement

ENBRIDGE

Phase Three Report:
Contract Customer Survey

February 2022

Table of Contents

INNOVATIVE RESEARCH GROUP

Project Overview & Methodology

Enbridge Gas 2024 Rate Rebasing Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Enbridge Gas to assist in meeting its customer engagement commitments for its 2024 Rate Rebasing requirements. This engagement had three phrases:

- Phase One was an exploratory phase that used qualitative tools to identify range of needs and outcomes that matter to customers and to explore some of the trade-offs that Enbridge Gas expected to deal with in their planning process.
- Phase Two used surveys to draw generalizable conclusions regarding the findings from Phase One.
- Following Phase Two, Enbridge Gas developed a draft plan that built on the findings of the first two phases of the customer engagement as well as other business objectives. The Phase Three survey was then designed to provide feedback on that plan that can be used by Enbridge Gas as it finalises its plan and its submission to the Ontario Energy Board (OEB).

This report summarises the findings of the Phase Three online workbook-style survey with Contract Customers. Separate reports summarise the findings of general service residential and business customer Phase Three surveys.

Research Objectives

There are four key objectives for the Phase Three survey:

1. To acquire feedback on key choices in the development of Enbridge Gas' business plan that involve trade-offs between customer outcomes.
2. To secure customer reaction to the potential rate impacts of the draft plan.
3. To obtain customer input on rate design choices.
4. Unique to this customer segment, the workbook also included questions on service and rate harmonization for both contract rate distribution services and direct purchase services.

Project Overview & Methodology

Survey Development

INNOVATIVE used a “workbook-style” survey to ensure the opinions collected on these issues were informed opinions. Through the workbook, customers were provided key background information on Enbridge Gas and its network as well as background relevant to key capital, rate design and sourcing choices. The workbook was tested to ensure the material and questions were understandable for customers with limited knowledge of the Enbridge Gas system as well as to assess whether the workbook found the right balance between too much and too little information. Specific design features included:

- Providing both background information and an estimate of rate impact (wherever available), for specific capital planning choices.
- Comment boxes were provided for all trade-off questions.
- A review page to give respondents an option to change their responses based on the total estimated rate impact of their original choices. They could change their responses as many times as they liked.
- Additional questions touched on issues around service and rate harmonization with regard to both contract rate distribution services and direct purchase services. Embedded in the survey were links to videos which provided respondents with background information specific to these issues.
- A final set of diagnostic questions allowed respondents to give feedback on the customer engagement survey itself, including overall favourability, amount of information provided and any missing content or questions they would still like answered.

The surveys were developed by Enbridge Gas and finalized with input from INNOVATIVE. All survey participants were sent an invitation from Enbridge Gas via email containing a unique survey URL. Reminders were sent to encourage those who had not yet completed the survey, as well as to those who had started the survey but not yet completed it.

All data was collected between February 3rd and 17th, 2022.

Contact and Completion Rates

In order to get as many completed surveys as possible from Contract Customers, all customers were invited to complete the survey.

Enbridge Gas started with a list of 1,008 Contract Customers. From this list, some were removed due to being on their DNC list, or they had already been included in the general service business customer engagement, and some emails bounced back, resulting in a total of 953 email invitations being sent out.

Original list	1,008
Removed due to DNC list or duplicate from general service	26
Emails bounced back	29
Final valid emails sent	953
Contact rate	**95%**

Due the complexity of the business planning issues that are unique to this customer segment, and the videos used to provide additional background information, the average time to complete the entire survey was 71 minutes. In total, 173 Contract Customers opened their unique survey URL (18% open rate). As anticipated, not all respondents completed the entire survey. Specific cut-off points were established at which a respondent would be counted as having completed a particular section of the workbook for reporting purposes. This report is broken down into five sections, each with its own sample size, as shown below, along with the completion rate.

Section Title	Sample Size	Completion Rate
Customer Experience	89	9%
Distribution Costs	81	8%
Contract Rate Distribution Services	66	7%
Direct Purchase Services	63	7%
Workbook Diagnostics	63	7%

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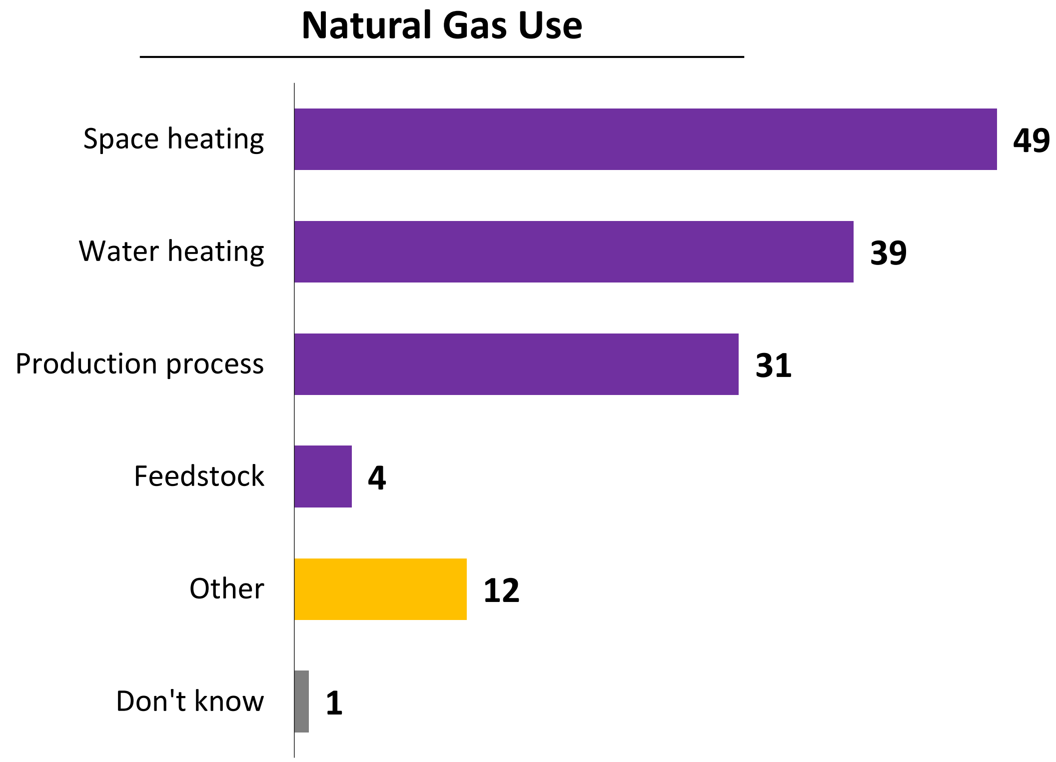
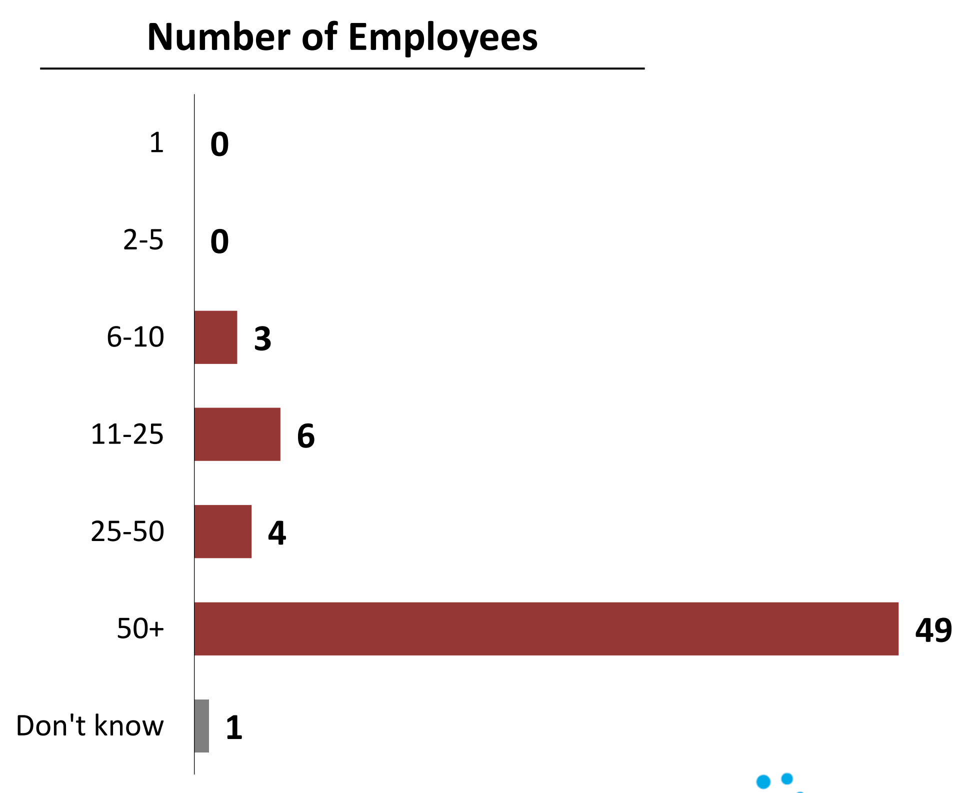
Online Workbook Results

Respondent Profile

Online Workbook

Firmographic breakdown





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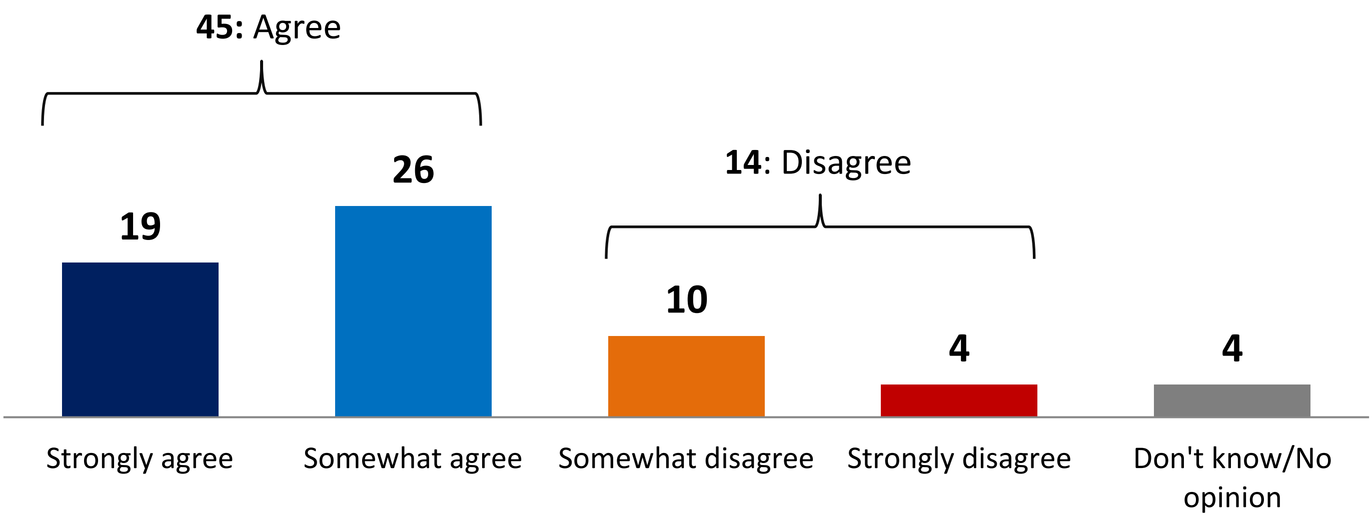
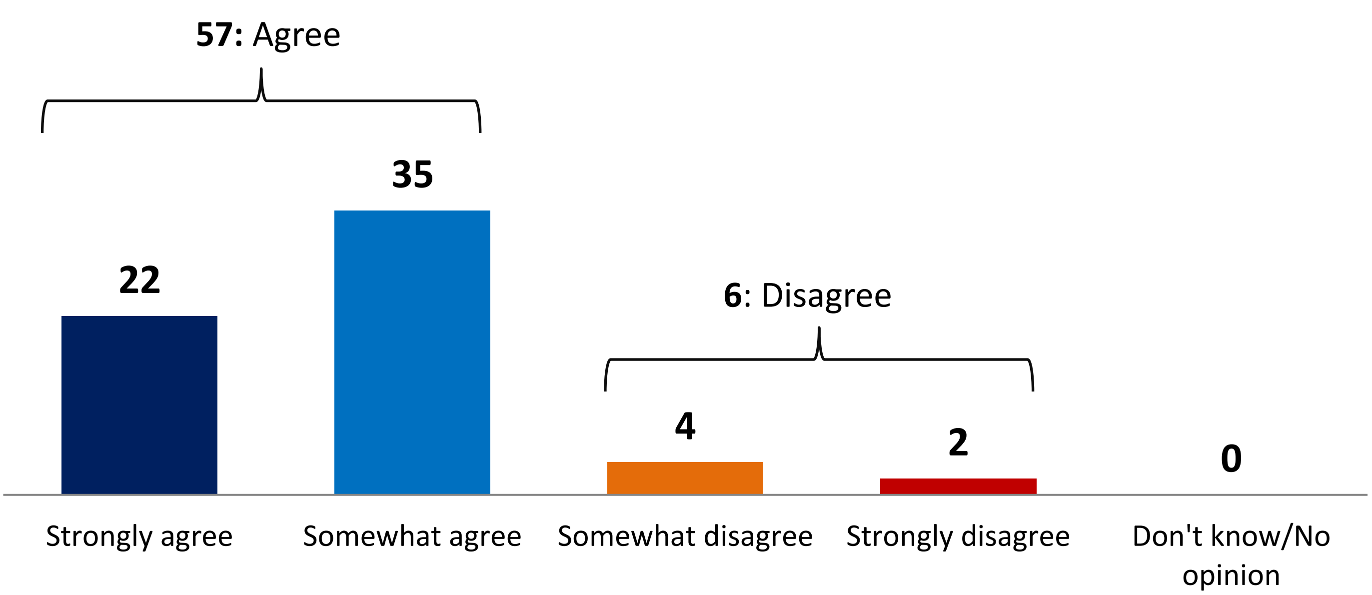
Online Workbook

Environmental Controls

Q To what extent do you agree or disagree with the following statements?
The cost of my Enbridge Gas bill has a major impact on my business' finances and requires the business do without some other important priorities.
[asked of all respondents who completed the entire survey; n=63]



Q To what extent do you agree or disagree with the following statements?
Customers are well served by the energy system in Ontario.
[asked of all respondents who completed the entire survey; n=63]



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Online Workbook Results

Customer Experience

A note about this report: In order to accurately represent the survey as it was viewed by respondents, we have included all of the background information that was provided to respondents before they were asked specific questions. Throughout this report, pages with grey headers show actual workbook pages as they were shown to online survey respondents. Slides with dark blue headers show the responses to the survey questions.

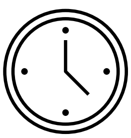
Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 402 of 550

About this Customer Engagement

Welcome to the Enbridge Gas Customer Engagement!

As Enbridge Gas plans for the future, it needs your input into choices that will impact the services you receive and the rates you pay.

- Enbridge Gas is looking for your feedback on its draft investment plan for 2024 and beyond to ensure that the plan reflects your needs and preferences.
- Enbridge Gas' contract customers are important to its business and their views are important.



This is Enbridge Gas' first rate application and investment plan since the merger of Union Gas and Enbridge Gas Distribution, and it will address a large number of issues that could affect your rates and services. In addition to the workbook itself, there are also links to videos that explain the proposals for contract rate distribution services, and direct purchase services in more detail.

We want to hear from you on all those changes, so we are asking for an hour or so of your time.

You don't have to do this all at once. Your progress will be saved as you move through the workbook, so you can leave and return to complete it at any time.

While this engagement is dealing with all the issues that may affect you in one comprehensive conversation, future engagements could conduct several smaller conversations. We will ask you for your feedback on this choice near the end.

Those who complete the questions that follow will be invited to enter a draw to win one of two $500 cash prizes.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback.

If you are reading this on a smaller mobile device, you may wish to access the survey from a tablet, desktop or laptop instead, so that it is easier to read.

While many customers are familiar with natural gas contract terminology, you can click on "Glossary" at the bottom of any page to open a list of acronyms in a separate window.

Background

Who is Enbridge Gas?

Company Overview

Enbridge Gas Inc. is based in Ontario and delivers energy to customers in Ontario. Its parent company Enbridge Inc. is headquartered in Calgary, Canada, and operates across North America. Rates and business plans developed by Enbridge Gas must be approved by the Ontario Energy Board (the OEB), which regulates natural gas utilities in Ontario.

Enbridge Gas …

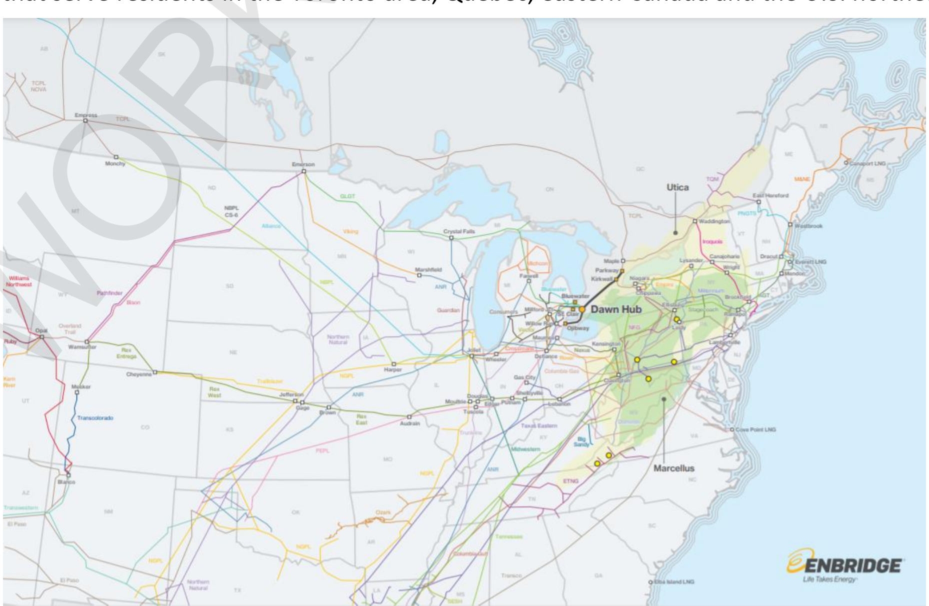
- ✓ Distributes natural gas to about 3.8 million residential, business and industrial customers
- ✓ Attaches more than 50,000 new customers each year
- ✓ Has agreements to provide gas distribution service within 313 municipalities and provides natural gas within 23 First Nation communities
- ✓ Has a network of over 151,500 kilometers of underground pipeline

In 2019, Enbridge Gas Distribution and Union Gas merged to form one company, Enbridge Gas Inc. Throughout this workbook we occasionally refer to Legacy Enbridge Gas Distribution and Legacy Union Gas (the previous companies), but mainly refer to the whole service area or territory that Enbridge Gas serves today.

The Storage and Transmission Market

In addition to providing distribution services to customers in our franchise area, Enbridge Gas serves the surrounding storage and transmission marketplace. The Dawn Hub is the largest integrated underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from Western Canadian and U.S. supply basins to markets in central Canada, the Great Lakes region and the northeast U.S.

The Dawn-Parkway transmission system is a series of four transmission pipelines (229 km/143 mi), and compressor stations that move natural gas through Ontario from the Dawn Hub near Sarnia, east to the Parkway compressor facility near Mississauga. At Parkway, the system connects with other pipelines that serve residents in the Toronto area, Quebec, eastern Canada and the U.S. northeast.



Background

Where do your rates go?

The pie chart below shows where the money goes.

The Blue slice shows the 'pass through' costs that pay for the natural gas and transportation to the Enbridge Gas system.

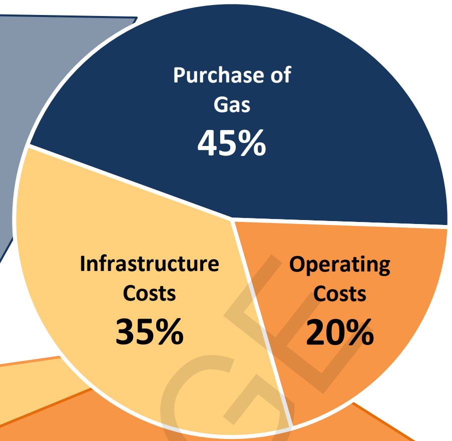
The money that goes to Enbridge Gas is in the other two slices.

- The Light Orange slice pays the capital costs of the infrastructure (such as pipes, compressors, buildings and other equipment) used to move and store natural gas across the system.
- The Dark Orange slice pays for operations – including the people who operate and maintain the equipment and the people who answer your calls and provide customer service.

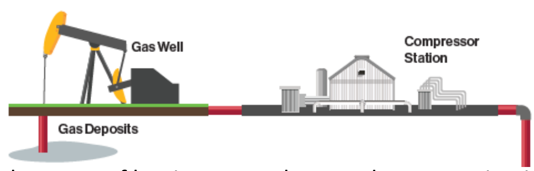
[**NOTE:** survey respondents were able to scroll down directly to the information on the following page]

Enbridge Gas Customer Engagement

2024 Rate Rebasing Customer Engagement Workbook

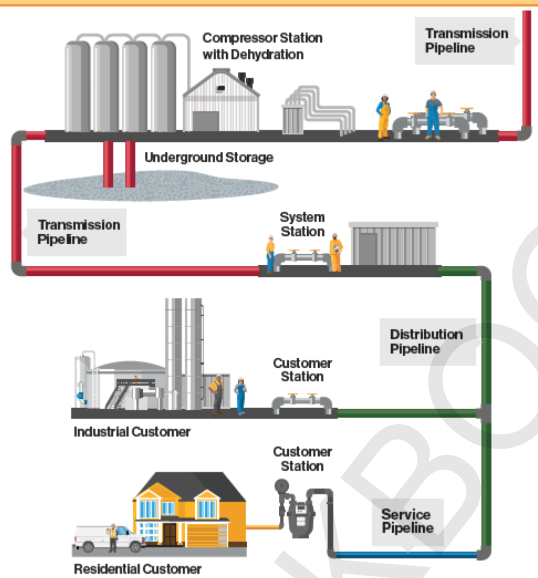


Purchase of Gas



The costs of buying natural gas and transporting it to Ontario are overseen by the Ontario Energy Board, and are passed on to customers at cost.

Infrastructure



Once gas reaches the Enbridge Gas system, it is metered and then delivered to customers through a distribution network of local gas mains, small-diameter service lines and, ultimately, customer meters.

Natural gas is often stored in large underground reservoirs to help meet spikes in demand, particularly in winter.

Operations

Delivering gas to customers is just one part of Enbridge Gas' activities. Enbridge Gas employees provide a variety of supporting services to customers including:

- ✓ Manage and operate its call centres, ombudsperson offices, and its online My Account system to help customers manage their account online.
- ✓ Complete meter replacements, inspections, and respond to emergency calls.
- ✓ Conduct millions of meter readings each year.
- ✓ Offer programs to help customers reduce their natural gas usage. Since 1995, Enbridge Gas has saved its customers 30 billion lifetime cubic meters of natural gas and 56.2 million tonnes of greenhouse gas emissions, the equivalent of taking 12.2 million cars off the road for a year or heating 13.1 million natural gas homes for a year. These programs get approved by the Ontario Energy Board in a separate process and the costs for these programs are included in your rates.

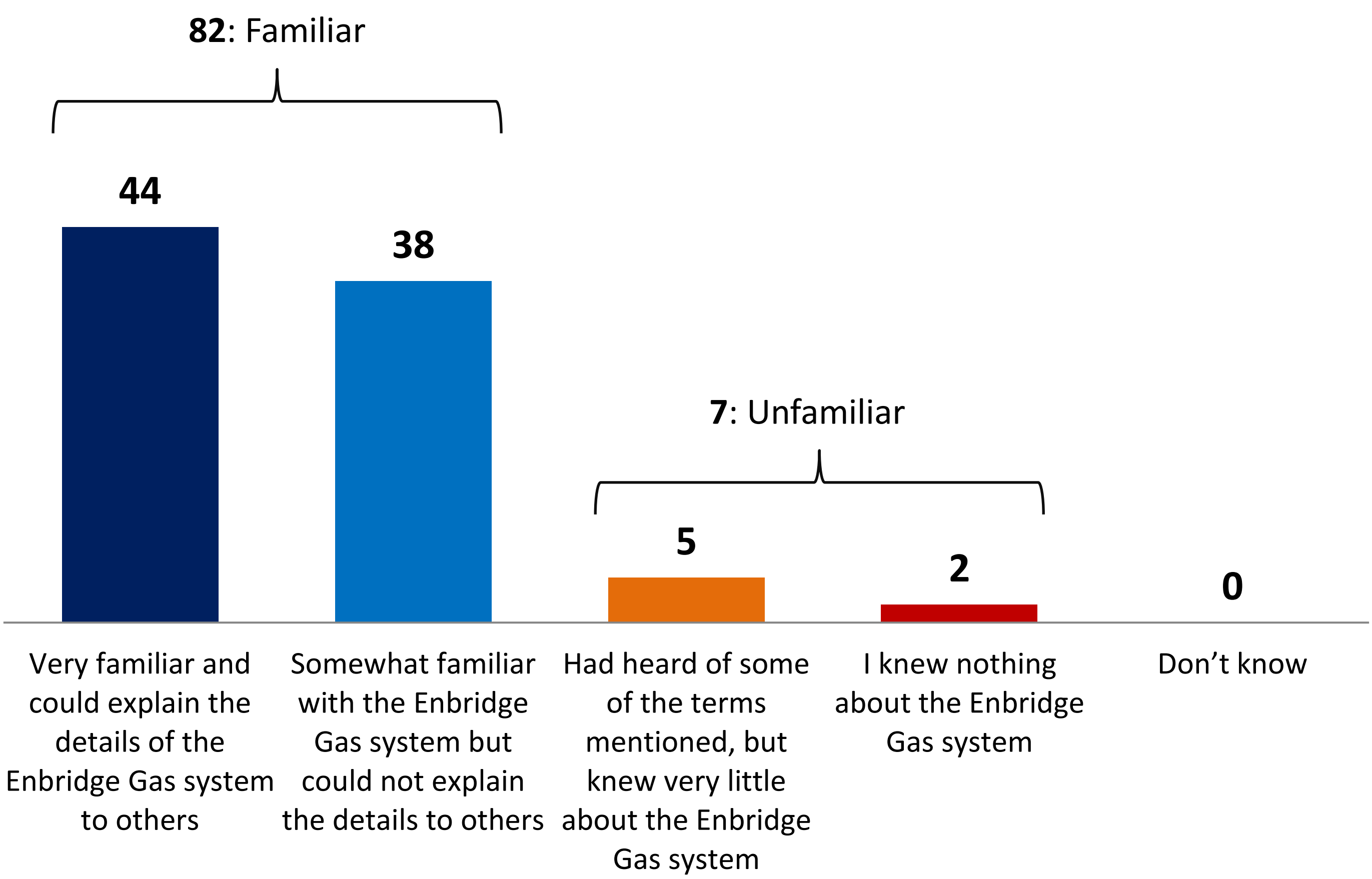
Background

Familiarity with Enbridge Gas

Q

Before this survey, how familiar were you with Enbridge Gas when it comes to delivering natural gas to homes and businesses in Ontario?

[asked of all respondents; n=89]



Where does this consultation fit?

Here in Ontario, customer views are central to the utility planning process.

- **Rates and business plans must be approved by the Ontario Energy Board (the OEB).**
- **The OEB requires that utilities consult with customers to understand your views on key trade-offs.**
- **In addition, the utilities must show how they took customer views into account when developing the plan.**

While some planning decisions will depend on detailed knowledge of engineering and industry standards, in other cases the choices will involve trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down. That is where you come in.

The diagram below shows how customers play a role as Enbridge Gas develops and submits its business plan to the OEB.

How does Customer Engagement Impact Business Planning?

Enbridge Gas has developed a phased approach to gathering and responding to customer feedback.

✓ **1. Information Gathering and Issue Identification**
Enbridge Gas planners gathered information and identified key issues to address in its plans. This process included review of previous research engagements, as well as informal conversations with customers and industry associations to identify customer needs and priorities.

✓ **2. Develop the Draft Plan**
Enbridge Gas planners use the key findings from the information gathering and issue identification phase as they began building their plans.

You are here

3. Collect Customer Feedback on the Draft Plan
Enbridge Gas is asking customers for feedback on the draft plan and how the plan fits with your needs and preferences.

4. Re-Examine Plan
Enbridge Gas has an opportunity to make appropriate changes to the plan based on customer feedback.

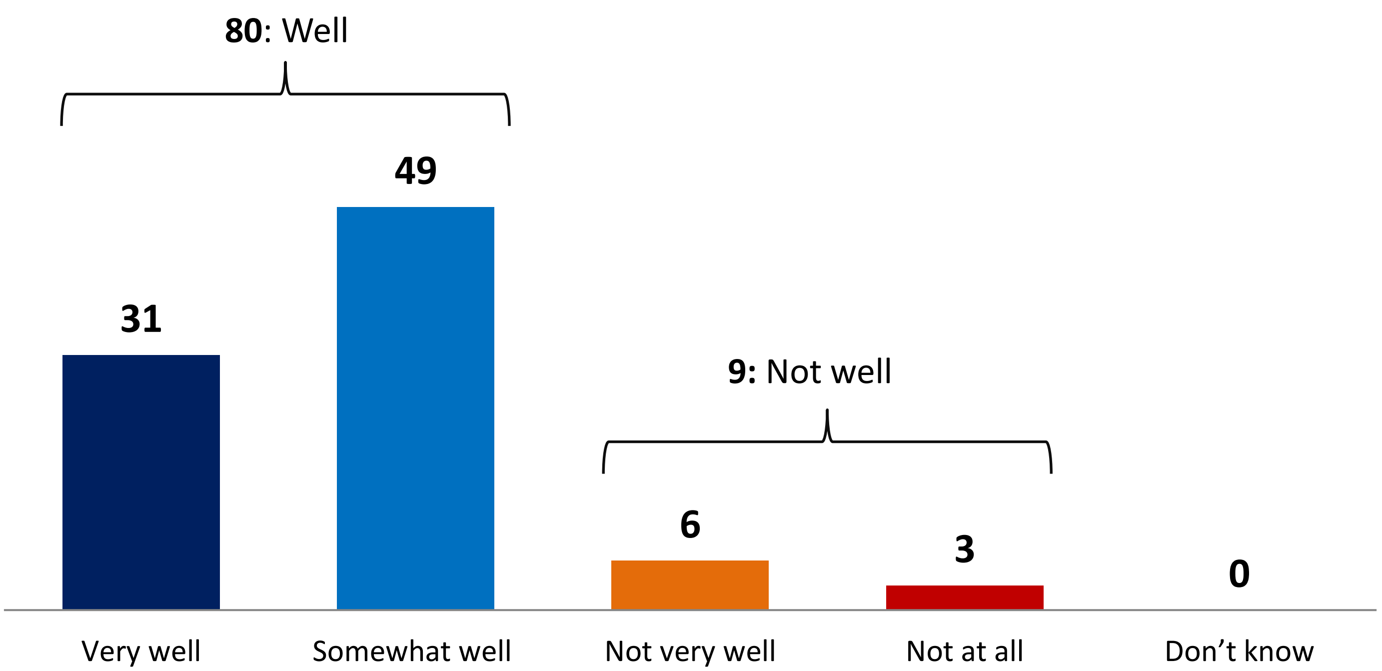
5. Submit the Plan to the Ontario Energy Board (OEB)
Enbridge Gas will file the plan, with this workbook, and a summary report with the OEB, where it will be examined by the OEB, consumer advocates and other independent parties in a public hearing. **Customers** can view and comment on this application through the OEB website.

Background

Familiarity with Enbridge Gas

Q How well do you feel you understand how your feedback fits within the planning process?

[asked of all respondents; n=89]



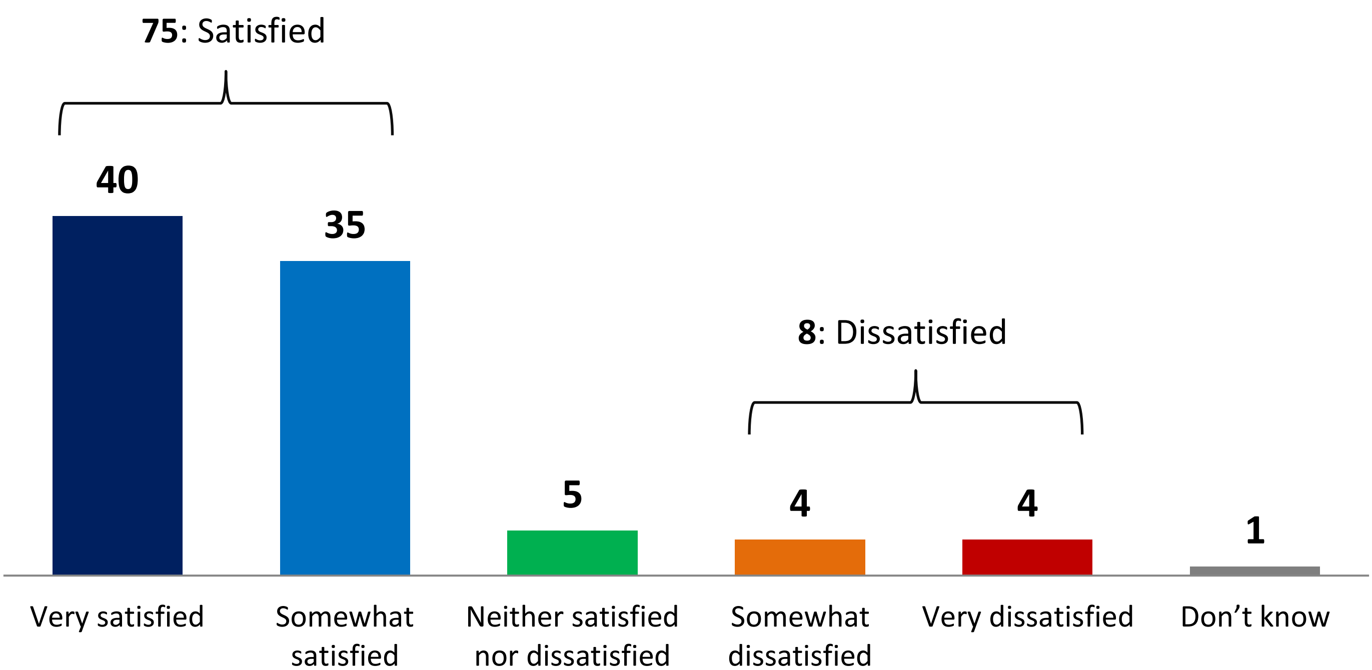
Customer Experience

Satisfaction and Areas of Improvement

Q ***The Ontario Energy Board (OEB) expects Enbridge Gas to develop a plan that will focus on cost effective delivery of outcomes that matter to customers.***

Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

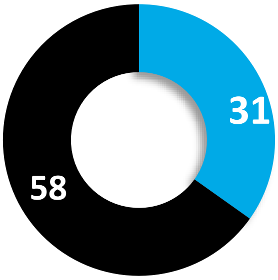
[asked of all respondents; n= 89]



Customer Experience

Satisfaction and Areas of Improvement – Additional Comments [1 of 2]

After making their choice, respondents were given an opportunity to make any additional comments they may have.



Customer Service
"As a relatively large consumer, I feel our service rep has always helped me understand the options, schedules, and benefits of the different options available. As he has learned about our business he has helped us through our decisions and with infrastructure needs here."
"Basic service. Good customer rep for supply. Concerned about time it takes for incentives."
"Can't get straight answers to line capabilities."
"Current Account Manager is very good."
"Enbridge Gas quick to respond to my concerns and questions. Customer service and service request response are both excellent."
"Enbridge have always kept us informed and assisted us with our needs."
"Enbridge, through its customer representative, is quick to respond to our queries and concerns. Enbridge provides regular feedback on on-going issues being resolved, especially on those related to billing."
"Generally satisfied."
"The customer service and attention paid to large industrial have deteriorated following the merger with Union Gas."
"There has been instances where data in Entrac/Unionline were incorrect and/or response to email or calls have taken longer than usual to get a reply. We had expected some delay due to the integration of the 2 entities and hopefully it will improve."
"Trying to get answers, there has been a large turnover in personnel and trying to get answers is difficult."
"We did a major renovation at our facility and we got answers fairly quickly from your office."

Comments continue on next page…

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Customer Experience

Satisfaction and Areas of Improvement – Additional Comments [2 of 2]

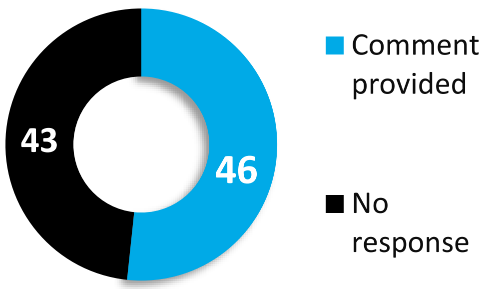
Service
"As an end use customer the utility experience is generally much easier to navigate than on the electricity side given the fact that electricity rates are more complex to understand and are subject to more modification (e.g. setting of RPP and alt rate structures) As the employee of an organization with numerous end use accounts we have from time to time encountered billing and metering issues which have require rectification."
"For existing services there are no major concerns."
"Good at delivering gas, not very good at being available to solve problems related to administration."
"Haven't had any need for service escalation."
"I am satisfied with Enbridge services related to direct purchase program. I do not have experience in "all aspects of your utility service experience."
"I work in the industry and your ways of reporting and accuracy have gone downhill."
"Needs regular scheduled updates and communications."
"No interruptions, reliable supply and support when there are any questions."
"No service interruptions."
"Somewhat satisfied with general service. However, videos of proposed changes lack the opportunity for dialog and clarity on the changes and impacts specific to our contract."
Merger
"Since Enbridge had merger with Union Gas the billing and data access became worse. The Union system was far superior to Enbridge's system and the whole market was aware of this. You made the service worse and created problems as part of the merger. These issues directly impact our daily and monthly services."
"The merger - and subsequent billing system changes for legacy Union Gas customers was poorly handled. Functionality that had been available was suddenly not with no interim plans to accommodate and recover information. An example - the online My Account can only have 1 staff contact. We have hundreds of accounts and different staff require access to different information. Prior to this there was more flexibility in viewing account information, downloading data etc."
"The recent merger of EGD and Union Gas has been quite poorly managed both from the Direct Purchase aspect as well as the myriad of billing issues that have resulted since the billing changeover in July 2021."
Costs
"Occasional metering issues Billing issues IT issues."
"Something has gone seriously awry with your meter-reading and usage estimation abilities in the last many years. My cost and consumption is always wrong."
Other
"As a large volume customer, it is no longer feasible for our institution to remain on a firm/interruptible contract for the supply of natural gas. We do not have systems in place to significantly curtail our consumption on consecutive colder days. Enbridge has also informed us that there is no opportunity for a firm only contract due to restrictions in its pipeline and compressor stations."
"Extortion."
"Utilities are not very flexible suppliers, and Enbridge is not any different than others."
"When a meter goes down. I don't think I should be charged theoretically. We should look at the usage to see if it was the same as prior years."

Customer Experience

Satisfaction and Areas of Improvement – Additional Comments [1 of 3]

Q Is there anything in particular Enbridge Gas can do to improve their service to your organization? [OPEN]

[asked of all respondents; n=89]



Service
"Allow greater consumption fluctuations without 'penalty'."
"Better training and empowering people to make decisions."
"Client consumption data reporting needs improvement. Up to date data not always accurate and/or available."
"Continue workshops and educate how to save energy."
"Creating a plan and activate education of plan to end users and customers."
"Customer consumption reporting requires improvement."
"For new services (new metering stations and/or accounts) timing remains an issue. Too many just-in-time completions. Also, when multiple buildings exist on one site, it would be great to have one meter instead of multiple meters."
"Generally like the online business portal - easy to get the information. Changing to excel spreadsheet from a CSV has helped. On smaller billings, would like to see reintroduced the information of heating days / average temp, as use to statistically compare periods for excess usage."
"Give answers, why the games with holding back information. Waste of time"
"Long notice for service interruptions. They are typically same day or one day ahead. If inventory is filling up, Enbridge is aware of that and should issue a warning in addition to provide ample time to respond."
"Looking forward to more in-person meetings or customer update events post the pandemic."
"Stop contracting out all the work. Used to be great service company but now since all works are contracted out the service is terrible."
"Technicians should report to commercial property owners when they are on site to do work. Countless times we have had issues with them working on site and it causing problems with our plant, usually due to the smell of gas, only to find out they are performing service. We have strict protocols on work being done on site and Enbridge refuses to adhere to them."
"Timing from Engineering is too long. Business decisions shouldn't be held up due to bureaucracy at Enbridge."

Comments continue on next page…

Customer Experience

Satisfaction and Areas of Improvement – Additional Comments [2 of 3]

Customer Service
"Customer focus."
"General Customer service - hard to navigate to get to the correct person and seem to lack some understanding for bigger corporations that have multiple accounts (we have hundreds) and directing staff appropriately who are inquiring and making requests. Customer service seem to have a more residential/small commercial mentality when it comes to providing direction. I understand the security aspect but there needs to be some accommodation here (again - there seems to be 1 name on file with the accounts)."
"Improve communication."
"Improve customer service and pay attention on large industrials."
"Opportunities for customer engagement prior to this survey have been limited; Enbridge's plans for rate rebasing only came to our attention through this survey. This is less engagement than we have experienced with other large pipelines."
"Providing regular virtual meetings with customers on updates."
"Transparency and better costumer service."
"We would like to revert back to a dedicated main contact and not a generic mailbox and/or 1-800 phone number."

Cost/Billing
"Better information on incentive."
"Continue to work to reduce costs. Collaborate more with large industrial customers."
"For larger accounts or for organizations with multiple end use accounts, offer consolidated YE consumption and cost reporting (aggregate by account, for whole year) given billing adjustments may not reflect retroactive consumption adjustments. BPS organizations require accurate consumption data for GHG emissions reporting and Provincial energy benchmark reporting."
"Go back to reporting reads every month, stop skipping months, sending estimates, and report the reads in the correct month."
"Have timely and accurate billing that meets our needs."
"I dislike all the estimated bills and then large credits that come back at certain buildings, but not sure how easily that can fixed."
"Improve energy incentives and efficiency programs."
"Meter readings seem to be a thing of the past resulting in a lot of estimated readings. A focus on billing on actual readings would be something that could improve."
"Our large account for CNG has a lot of parameters. Changing the parameters changes our total monthly cost. I am not an expert on these parameters. So it would be helpful if somebody from Enbridge could periodically review our account to ensure we're on the best set of parameters from a financial standpoint."
"Provide access to actual invoices on Entrac."
"Regular meter reading; more concerted effort to fix billing/measurement/client-interfacing systems issues."
"Stop extorting money from us."
"To properly inform the extra indicators (adjustment factors) applied on the monthly invoices. Details about how these adjustments are applied / reasons/how often."

Comments continue on next page…

Customer Experience

Satisfaction and Areas of Improvement – Additional Comments [3 of 3]

Infrastructure
"Improve infrastructure for rural distribution at affordable rates to potential businesses."
"Improve your infrastructure. The OEB should also note that it should not be up to firm/interruptible customers to pay for its infrastructure upgrades."
Merger
"It has only been a couple years since the transition from Union Gas, but the transition has seemed seamless."
"Stop operating as 2 separate entities while at the same time calling yourself 1 entity."
Other
"Ditch all of the automation or make it more intuitive. You are rivaling Rogers and Bell for a complete lack of service when you call Enbridge."
"Lobby for removal of the carbon tax."
"More clarity on the bill regarding carbon tax."
"More proactive on decarbonization. Improve flow and timing of incentive program."
"Not anything in particular, just keep moving forward."
"Not at this time."
"Keep doing what they have been doing."

INNOVATIVE RESEARCH GROUP

Customer Experience

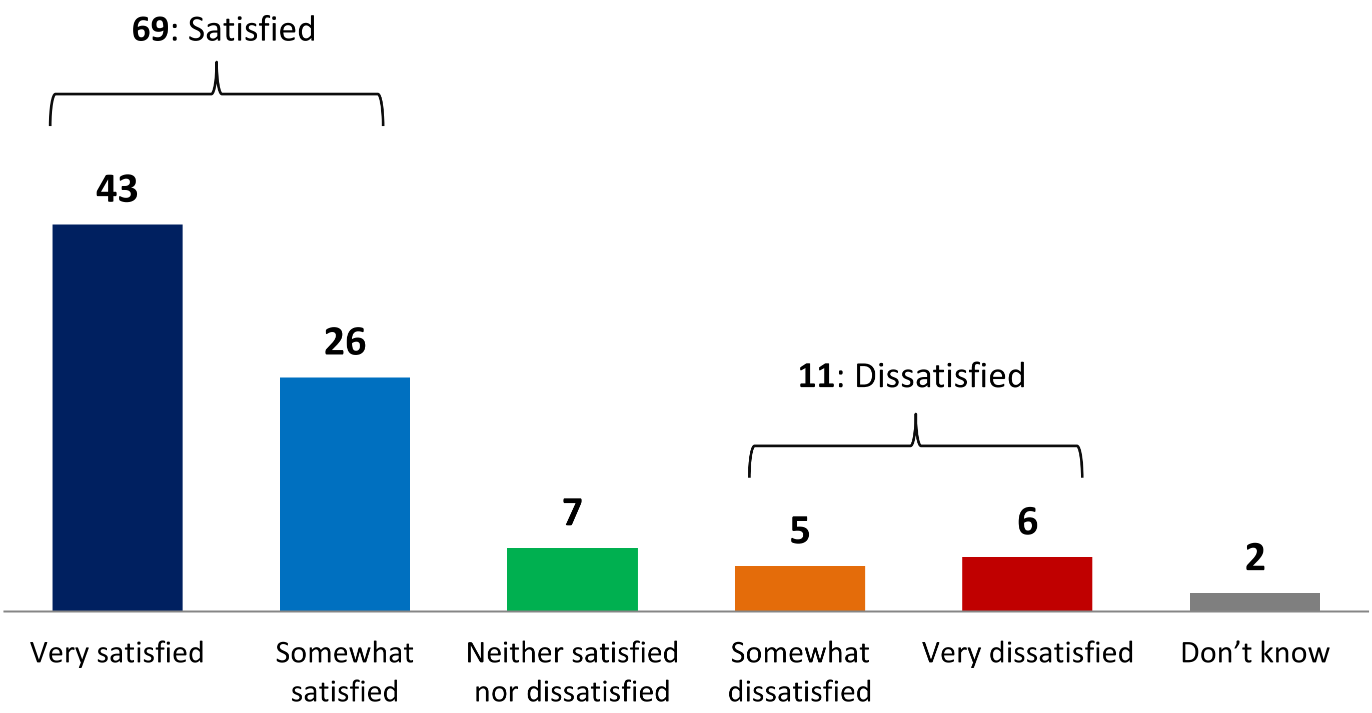
Overall Customer Service

Q

Contract customers have a unique set of needs compared to other rate classes. The following questions will help us understand how well we are currently meeting your needs and where there is room for improvement.

Taking into consideration all aspects of Enbridge Gas' customer service, how satisfied are you with Enbridge Gas' customer service?

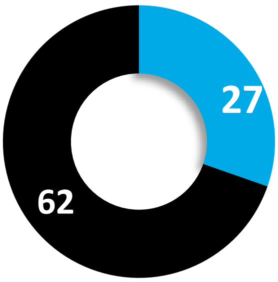
[asked of all respondents; n=89]



Customer Experience

Overall Customer Service – Additional Comments [1 of 2]

After making their choice, respondents were given an opportunity to make any additional comments they may have.



Customer Service
"Customer reps' responsiveness did improve significantly in the past 18 months."
"Customer service is excellent."
"Customer service?"
"Despite the many many many issues as a result of the poorly managed merger, the customer service reps do try their best to resolve any issues. Albeit management is very slow to approve/respond."
"Generally all personal interactions with Enbridge have been fine. Interactions with Enbridge for accounts for employer often through key account manager or sponsor under DPA MSA (which has changed in recent years)."
"I believe customer service can be augmented and costs of non value added services reduced. This will reduce net cost to customer. Most questions and customer service answer are vague. We know Enbridge is a valuable company that society values."
"I don't deal often with the customer service team, but when I have it has been easy and pleasant. Generally just on changing rate classes to save money."
"I have problems involving my customer and basically there is no consideration for the customer. The system is not capable of adapting to the customer needs. And sometimes Enbridge decisions are aligned with the bigger brokers who profit from the way the system works. Also have one representative who just wants to follow the rules without considering the impact to the customer and the utility as well. Does not understand what a customer really is!"
"No issues with customer service."
"Our account rep is helpful."
"Quickly responds to queries and acts on resolving issues such as those related to billing."
"The LBA group is great to work with. Always responsive. They never bounce me from person to person. Always knowledgeable and friendly."
"We would like to have a dedicated contact within the Direct Purchase department."
"We would value more frequent proactive engagement; for example, Rate Rebasing came as a surprise through this survey with limited time to respond."

Comments continue on next page…

INNOVATIVE RESEARCH GROUP

Customer Experience

Overall Customer Service – Additional Comments [2 of 2]

Service
"Again, I am satisfied related to the direct purchasing program. I am not familiar with "all aspects of Enbridge Gas' customer service"."
"Again, my rep has been an excellent partner."
"Always get a quick turnaround whenever I ask for hourly or gas chromatograph data. Very much appreciated!"
"Answers are coming in a reasonable timeline."
"As mentioned earlier (Give answers, why the games with holding back information. Waste of time)."
"Can't get me logged into the Enbridge portal. I quit trying and gave up."
"For supply, rates, etc. - excellent. For incentives - okay to poor."
"Six months of estimated accounts, nearly impossible to get resolution on account issues....."
"Slow response times, no phone communication."
Other
"Have not had any need to contact Enbridge for service."
"Historically, Enbridge has negotiated in bad faith."
"My meter was read last year only by estimation. Its access supposedly was blocked, when in reality it was very accessible. This is a significant meter and very worthy of reading. We use the readings to make business decisions and if the reads are unreliable then we make bad decisions."
"Satisfied."

Customer Experience

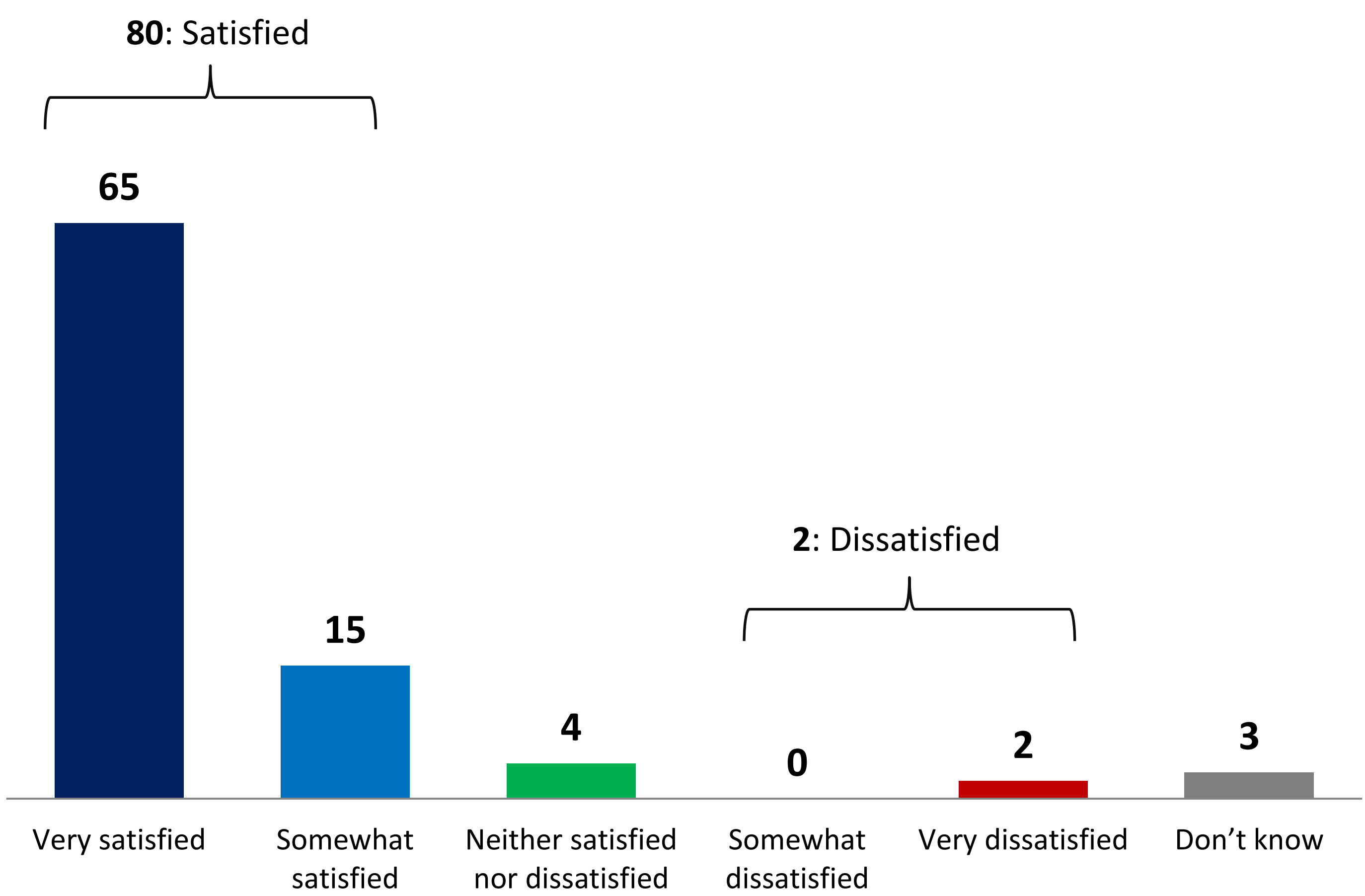
Firm Distribution Service

Q

Firm distribution service offers firm deliveries of natural gas to the end use customer every day of the year. This is the most common service.

How satisfied are you with the reliability of Enbridge Gas' firm distribution services?

[asked of all respondents; n=89]



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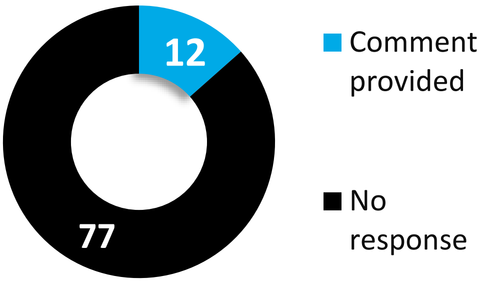
Customer Experience

Firm Distribution Service– Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.



Reliability
"Reliable firm delivery. Distribution and infrastructure capacities appear to be appropriate to meet peak demand."
"Very reliable firm delivery."
"We are satisfied with the reliability of the contracted firm. Our satisfaction could be improved through offering additional cost-effective Firm service."
Other
"Does Enbridge bring gas lines to other buildings on a property or do they just bring it to the site? The reason is that if they would bring it to different locations on a property, we would be able to afford using natural gas instead of propane."
"Does not apply to us."
"Enbridge has infrastructure issues to provide firm to large volume customers who are looking for firm."
"Have not had any issues."
"No concerns with firm delivery."
"No issues at all."
"No issues with firm service."
"Not sure we have firm service, we are interruption service, thankfully rarely."
"Unclear if we use this. I guess we must?"

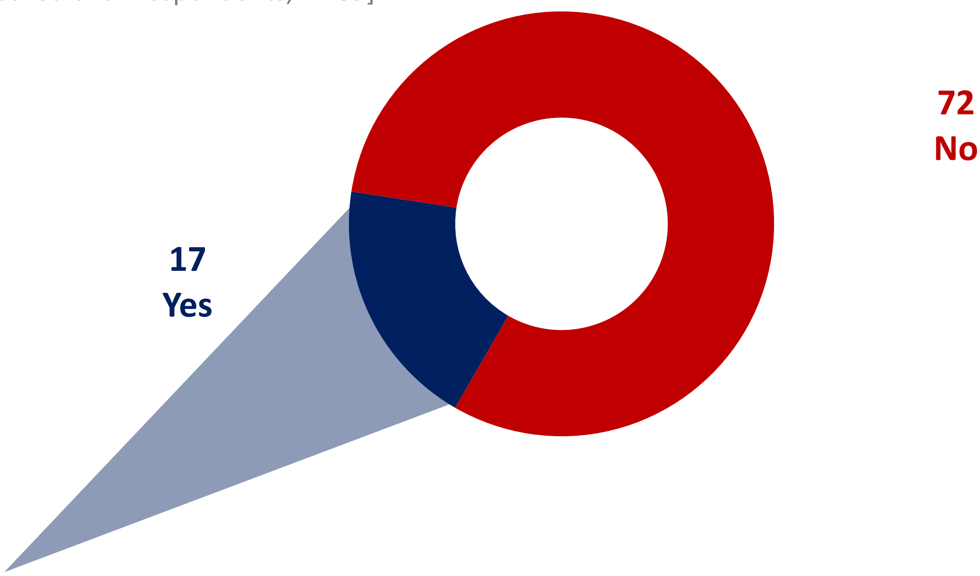
Customer Experience

Seasonal Distribution Service

Q

Seasonal distribution service is a form of firm service that provides access to firm deliveries of natural gas in months where Enbridge Gas does not expect to see peak demand on the system. This service is tailored for customers who do not have their peak demands in the winter.

Do you contract for seasonal distribution service today?
[asked of all respondents; n= 89]



Q

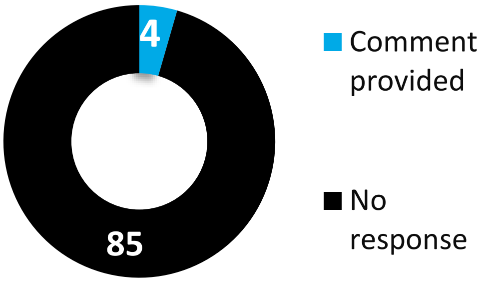
How satisfied are you with Enbridge Gas' current seasonal distribution services?
[asked of all respondents who contract for seasonal distribution service; n=17]

INNOVATIVE RESEARCH GROUP

Customer Experience

Seasonal Distribution Service – Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.



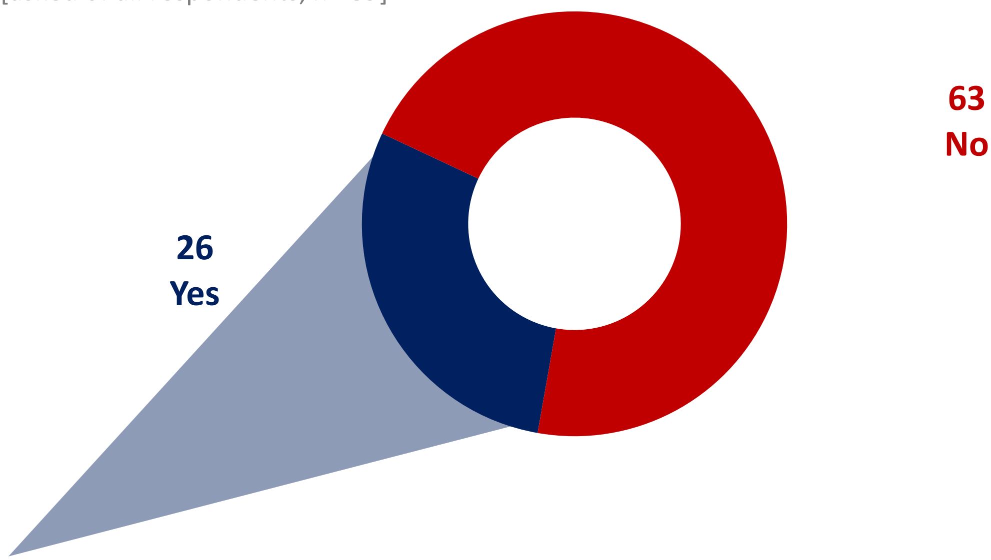
Comments
"At present it meets my customer's requirements."
"Billing errors, missed meter readings and wholly inappropriate estimations have caused havoc with cash flow and misapplied costs/credits to the fiscal period ... and some invoices are completely wrong and severely over-charged."
"I do not have an understanding of seasonal distribution services."
"More timely communication on December Authorized Overrun availability would be helpful."

Customer Experience

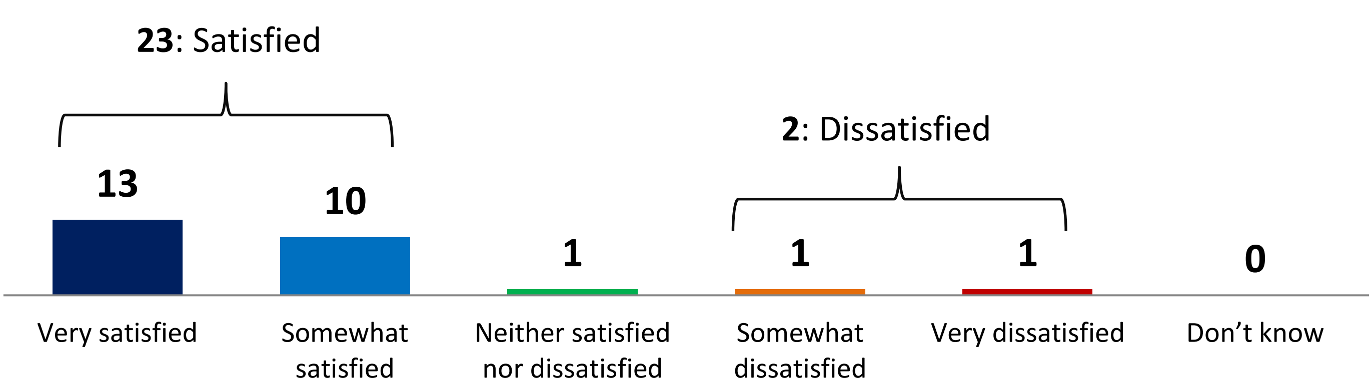
Interruptible Distribution Service

Q ***Interruptible distribution service can be added to firm distribution service or can be contracted separately. This service allows Enbridge Gas to issue a notice of interruption that requires an end user to reduce their consumption completely, or to reduce it to the level of firm service they have contracted.***

Do you contract for interruptible distribution service today?
[asked of all respondents; n= 89]



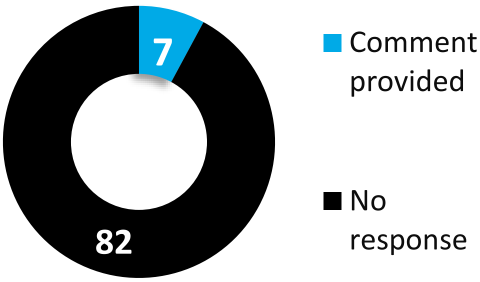
Q How satisfied are you with Enbridge Gas' current interruptible distribution services?
[asked of all respondents who contract for interruptible distribution service; n=26]



Customer Experience

Interruptible Distribution Service – Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.



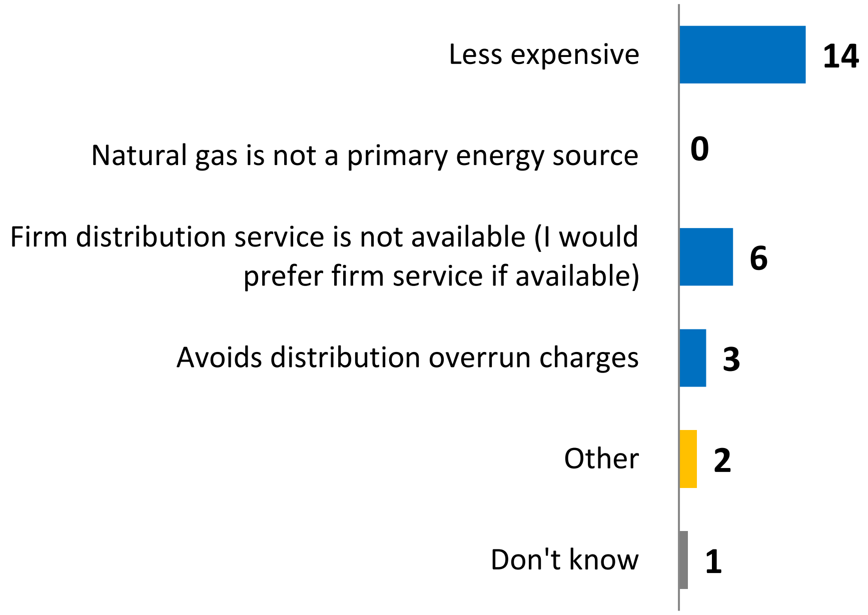
Service
"Honestly the most important part of the interruptible service is understanding the demands of my facility and what I can live without and what I can't live without."
"Interruptible curtailment frequency and duration have significant impacts on our business and operations."
"Rarely interrupted."
"System works and is totally weather dependent. It would be nice if the customer could pre-purchase amounts for interruption and have it at their disposal during interruption. Buying gas when curtailment is called is prohibitive, yes I know there are constraints and market dictates pricing. But....."
"The notification services and protocols have improved dramatically in the last decade."
"We need to be a firm customer however Enbridge distribution issues are preventing us from going firm."
Cost
"Concern about the penalty being ridiculously high for using gas during an interruption."

Customer Experience

Interruptible Distribution Service

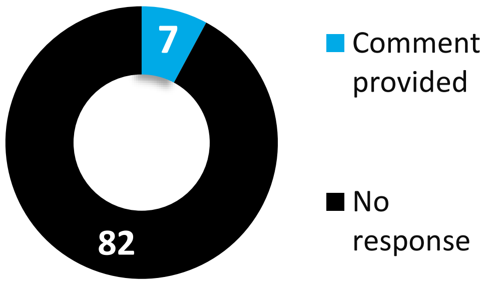
Q Why do you use interruptible distribution service?

[asked of all respondents who contract for interruptible distribution service; n=26]



Q Are there any other reasons that you use interruptible distribution service? Please indicate them below:

[asked of all respondents who contract for interruptible distribution service; n=26]



Comments
"Additional firm distribution service is not available; IT is the only service available to us. We would welcome Enbridge making more cost-effective firm available as part of the rebasing proposal."
"Historically, cost."
"Interruptible Distribution service is vastly to be used when Firm services hit its contract limits."
"Multiple fuel options."
"No firm available."
"Not sure on the historical aspects."
"Some Rate 135 Customers do not burn Jan-Apr."

Customer Experience

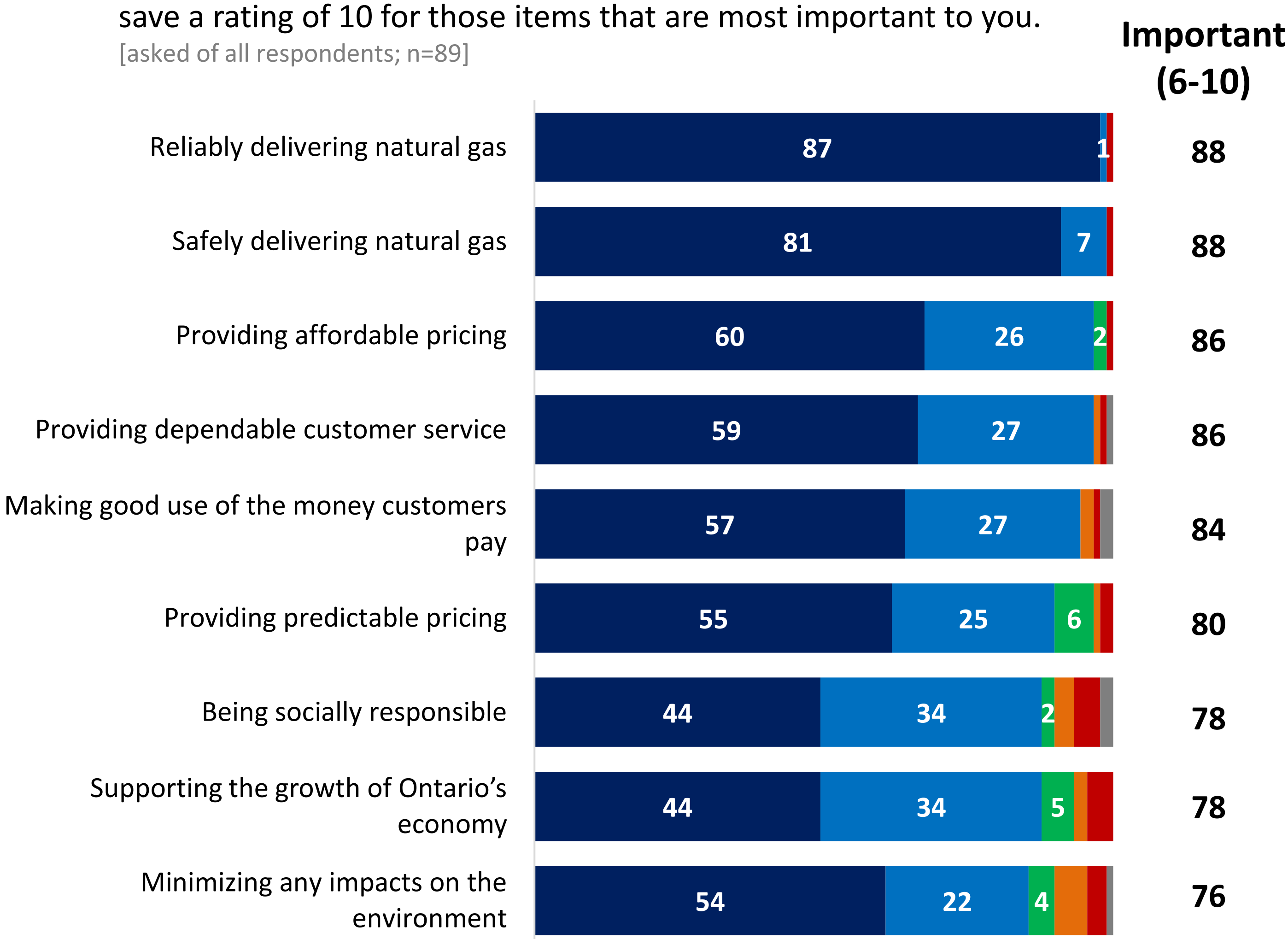
Customer Outcomes – Importance Rating

Q

In considering its business plan to be implemented starting in 2024, Enbridge Gas must make many decisions. We would like your feedback on the outcomes you would like Enbridge Gas to focus on in its plan. Outcomes are the goals and priorities that matter to you.

There is a list of broad outcomes that Enbridge Gas will need to consider. Using a scale from 0 to 10, where 0 means “not at all important” and 10 means “extremely important”, please tell us how important each one is to you. Be sure to save a rating of 10 for those items that are most important to you.

[asked of all respondents; n=89]



Are there any other outcomes?

- Decarbonization
- Easy to do business with Enbridge
- Expansion on other sites
- Harmonized rates
- Minimizing monopolistic attitude
- Providing more options for RNG supply
- Supporting low-income customers

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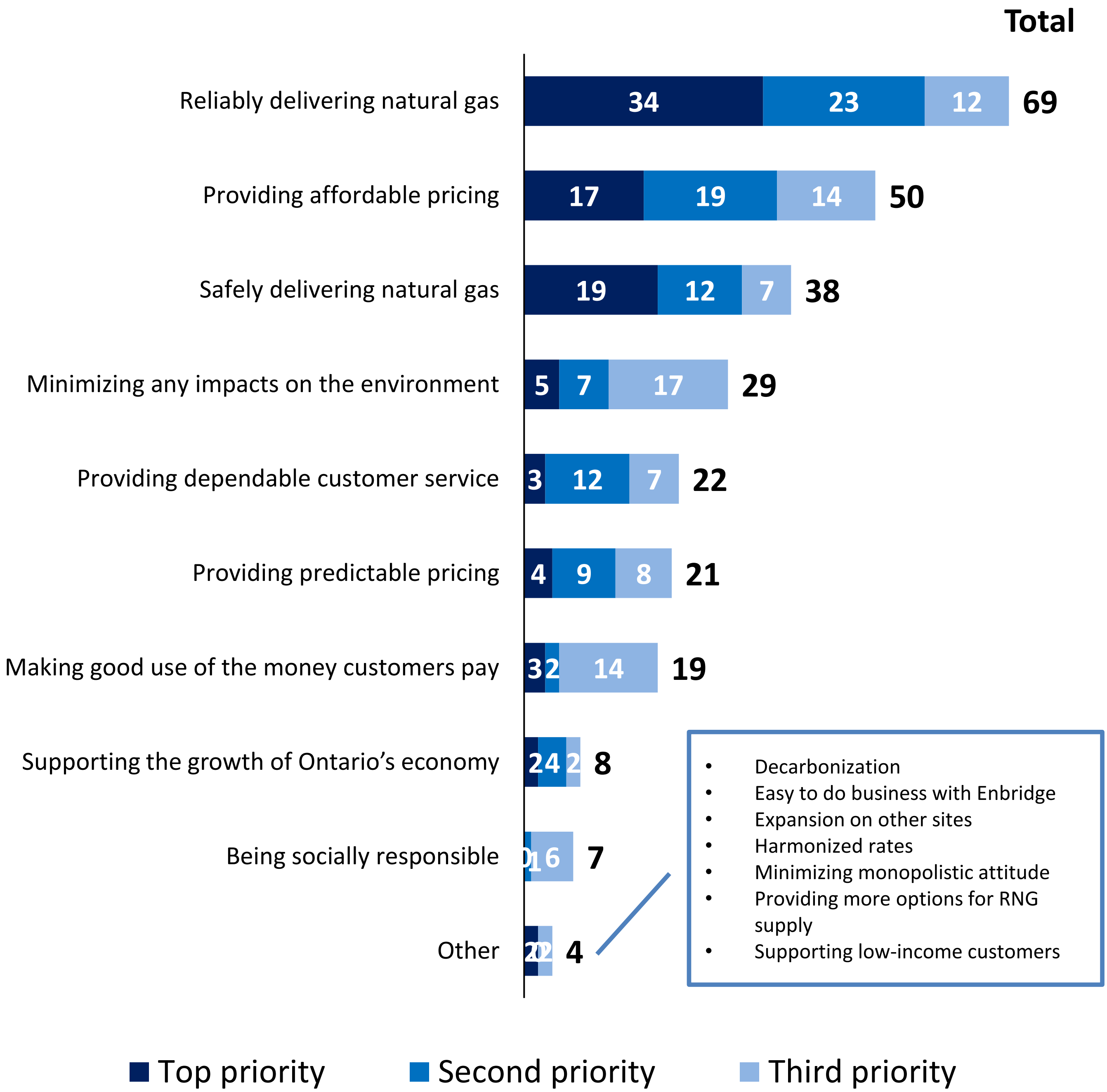
Customer Experience

Customer Outcomes – Priorities

Q

Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which ones would you rank as first, second and third, in terms of importance to you.

[asked of all respondents; n= 89]



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Online Workbook Results

Distribution Cost Section

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 428 of 550

Background

2024-2028 Plan

Plan Objectives

The Enbridge Gas business plan focuses on many of the same objectives as in the past years, as well as future challenges and pressures. Some of the high-level objectives of the plan are as follows:

1. **Maintain system safety and reliability –** ensure that the system continues to operate safely and reliably.
2. **Contain costs –** the OEB requires all utilities to "demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives".
3. **Harmonize rates and services –** ensure that the offerings are consistent across the entire service area as Enbridge Gas continues its merger activities.
4. **Prepare for the future –** ensure that the system is ready for low-carbon options, as well as offer options to help customers reduce their greenhouse gas (GHG) emissions.

Climate Change Goals

Compared to the past, Enbridge Gas' 2024-2028 plan places more emphasis on preparing for the future. Enbridge Gas is looking at ways in which it can support its organizational, as well as federal and provincial goals to reduce GHG emissions and achieve net zero targets.

- **Enbridge Inc. targets to reduce, from its operations, GHG emission intensity by 35% by 2030 over 2018 levels, and to reach Net Zero GHG emissions by 2050**
- **Federal targets to reduce GHG emissions by 40-45% by 2030 over 2005 levels and to reach Net Zero GHG emissions by 2050**
- **Provincial target to reduce GHG emissions by 30% by 2030 over 2005 levels**

How We Can Reduce GHG Emissions From Natural Gas

One of the ways in which GHG emissions are created is through the burning of fossil fuels such as coal, oil, and natural gas. Two key approaches can reduce the emissions from using natural gas:

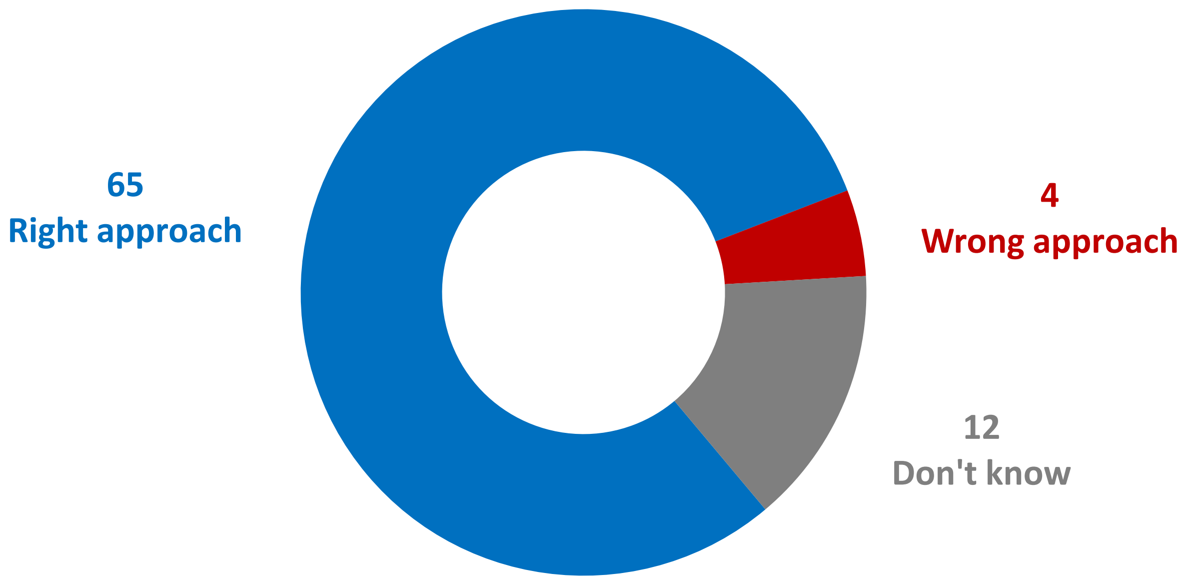
- by blending lower carbon fuels into the gas supply, including Renewable Natural Gas (RNG) and Hydrogen gas, and
- by improving energy efficiency of homes and businesses, and implementing new, lower-emitting technologies.

Each of these could introduce new, higher, costs that would be passed on to customers but would mitigate costs that might be required to introduce other programs or options to reduce overall GHG emissions in Ontario and Canada. **Later in the workbook we will ask about your views on these potential costs.**

Background

Right or Wrong Approach

Q Do these objectives seem like the right approach or the wrong approach?
[asked of all respondents; n=81]

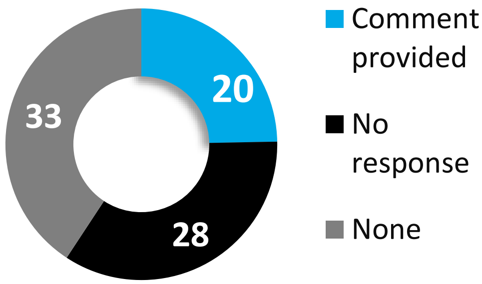


Background

Right or Wrong Approach – Additional Comments [1 of 2]

Q Is there anything you would change about this approach or any other comments you would like to make?

[asked of all respondents; n=81]



Cost
"Concerned about "future" costs. While emission reduction is valid, there should be more targeting on the higher emissions (oil) by providing greater access across the province to alternatives (NG). Need higher efficiency products for everyone. Low efficiency products will ultimately increase costs while minimizing efficiency gains."
"Containing cost while maintaining safety shall be core function. Having too many objectives dilutes the focus. Rest of the items are connected to first."
"Enbridge implements systems not to make things better necessarily. It is their priority to reduce staff thereby cutting operating cost."
"I know most of these targets are set by our Federal government but I do appreciate the innovative thinking to improve, sometimes I wonder at what cost elsewhere though."
"Procurement of cost effective RNG through competitive long term procurement processes supporting local producers and projects can assist in lowering carbon intensity of supply. Competitive environment will seek to ensure best value for customers."
"RNG is expensive so I have a cost concern... but it says that will come up later."
"While the approach overall appears sound, plans should be developed in detail and communicated so the scope and pace can be appreciated by customers bearing the costs. This would allow customers to consider the relative affordability and the alternatives customers have to abate their own choices."
Alternative Energy Source
"A "green" surcharge that is then used to construct greener forms of energy (solar, wind, etc)."
"Enbridge also needs to look at shifting from a gas company to an energy company and supporting electrification."
"I think it's ok for now. Ideally we would transition to cleaner sources than natural gas, but that is still far in the future, so we need transitional sources for the foreseeable future."
"Invest in greenhouses co-gen systems."
"More lobbying that natural gas is clean energy and doesn't need to be reduced in consumption."
"Provide access to funds to help businesses reduce their energy footprint."

Comments continue on next page…

Background

Right or Wrong Approach – Additional Comments [2 of 2]

Efficiency
"By improving energy efficiency, gas consumption will be dropped and this will compensate the increase of RNG and Hydrogen gas costs."
"Kind of indifferent on the use of blending RNG into the mix. Improving efficiency is the best approach."
"Research into more efficient gas consumption products so more bang for the buck."
Other
"Any hydrogen blending must be sequestered from industrial operations. Very targeted uses in Enbridge's system."
"Approach is reasonable."
"Demand response. Collaboration with electric utilities."
"Does it change its heating value by changing the blend of Nat Gas?"

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Calculating Rates

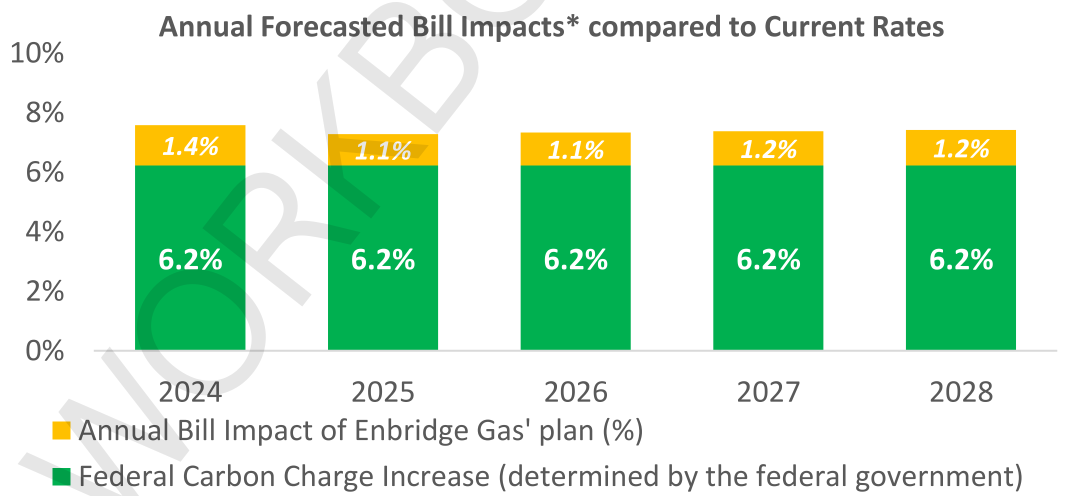
When looking at its overall objectives, and its budgets, there are many items that Enbridge Gas must consider that affect its costs, and in turn the rates that customers pay. Some of these items are determined by regulatory requirements, others by external factors in the market, and again others by decisions made by Enbridge Gas.

There are **accounting policies and factors** that affect expenditures. These include proposals through which Enbridge Gas manages business risk and how it calculates the depreciation of its assets. These types of proposals contribute significantly to the overall rate impact shown in the "Forecasted Bill Impacts" below and are partially offset by savings in other areas. While these issues are too technical for this workbook, they will be reviewed by OEB experts and intervening stakeholders in the OEB's public review process.

Operating expenses make up about 20% of Enbridge Gas' overall expenditures. Current estimates show that these expenses would increase somewhat over the 2024-2028 period, with the highest annual increase at 1.5%, which is less than inflation. Decisions on operating expenses are based on industry best practices and generally do not involve trade-offs between customer outcomes. Since these are technical issues, they will also be reviewed by OEB experts and intervening stakeholders in the OEB's public review process.

Capital expenses make up about 35% of Enbridge Gas' overall expenditures and pay for investments in its equipment that have lasting benefits over many years. Since capital spending includes major one-off projects as well as ongoing maintenance and replacement, capital spending varies from year to year. The questions in the next section focus on these choices.

The *Forecasted Bill Impacts* for 2024 to 2028 compared to current rates are shown below. Compared to your current rates, rates in 2022 are expected to increase by 2.1% for the average commercial customer, while 2023 rates are not yet established.



These charges for business customers may vary somewhat by rate class, and in all cases where we're showing a rate impact, it is the highest potential impact across rate classes.

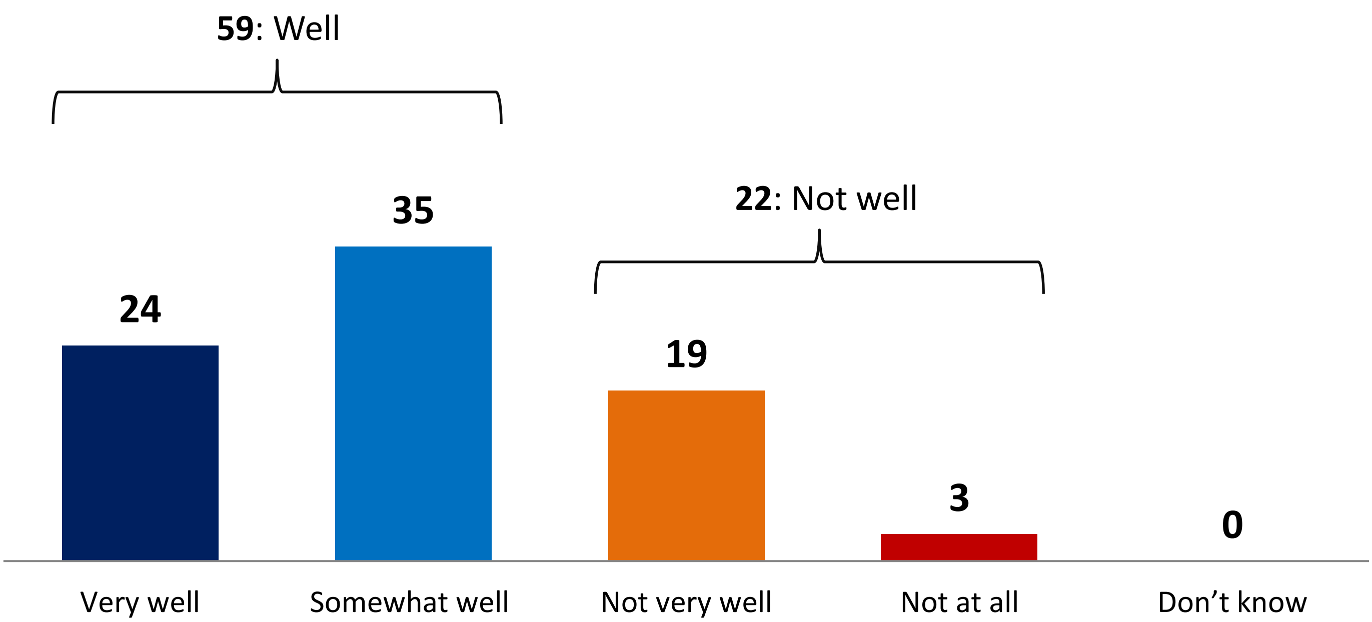
**These estimates are preliminary and are subject to both your feedback and ongoing work to review as Enbridge Gas planners continue to work on their plans. This does not include any potential changes in the fuel costs or the federal carbon charge.*

Calculating Rates

Understanding the Projected Increase

Q How well do you feel you understand the projected increase in your rates from 2024 to 2028?

[asked of all respondents; n=81]



Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 434 of 550

Making Choices

In this next section of the workbook, we will ask you about some of the key items that Enbridge Gas is considering in its plan that see trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down.

Some of these items are currently included in the draft budget, while others will need to be added to the budget depending on further analysis and feedback from customers like you.

For each question, where applicable, the financial impact is expressed as the percentage impact each year on an average business customer bill. The actual impact will depend on your own individual usage.

At the end of the section, you will have an opportunity to review your responses and their impact on your bill. You will then be able to adjust your choices to provide what you feel is the best balance.

Compression Stations

Enbridge Gas has 50 Compressors, 7 Dehydrators and supporting equipment. These are required to ensure that the gas that is injected into storage or into the distribution system meets the quality specifications and to move gas along the transmission system.

As compressors age, they experience breakdowns on an increasingly frequent basis – when equipment manufacturers stop supporting these compressors, the time to complete repairs can be extensive leading to reliability and gas quality problems. There are two compressors that will need to be replaced in the coming years.

When considering a project to replace compressors like this, Enbridge Gas looks at various options:

- ✓ Replacing one larger compressor with two smaller ones,
- ✓ Using alternative fuel sources such as electricity or hydrogen gas, and
- ✓ Preparing for outages by having spare parts available.

In this case, however, there is a lack of viable alternatives at the specific locations for the two compressor stations, so Enbridge Gas is planning to replace one compressor station in 2026, with the other one being replaced after 2028 to use the existing stations for as long as possible.

Not doing this work increases the risk the station could fail. This may require Enbridge Gas to buy more gas on the market (if available), rather than drawing gas from its storage. This introduces the risk of price volatility, as gas purchased on the market during the coldest days of the year has been up to 220% more expensive in the past 5 years than the gas that could be drawn from storage.

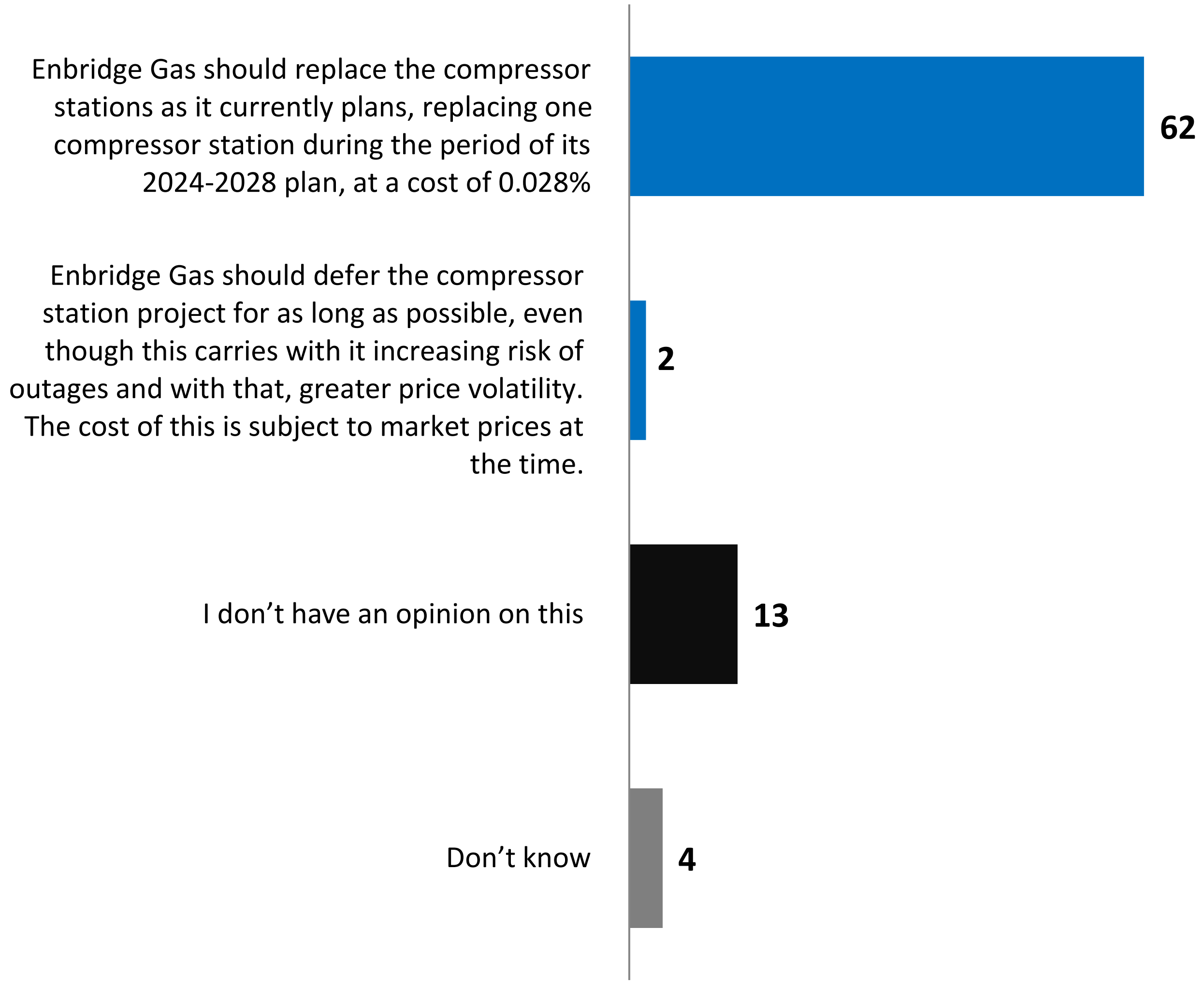
Image: inside a building housing a compressor station

Furthermore, if the station fails, replacement will still be required which would take a couple of years of construction to complete, extending the risks for longer. The replacement of the first compressor station is planned for 2026 and would cost the average customer 0.028%/year.

Making Choices

Compression Stations

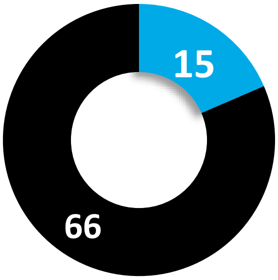
Q Which of the following statements best represents your point of view?
[asked of all respondents; n=81]



Making Choices

Compression Stations – Additional Comments [1 of 2]

After making their choice, respondents were given an opportunity to make any additional comments they may have.



Enbridge's Responsibility
"Enbridge should be budgeting/planning for capital replacement / upgrade projects from its profits. This plan seems to indicate Enbridge is to surcharge users."
"Enbridge should plan his maintenance and reliability projects to ensure quality and availability."
"I have several comments here. Enbridge is a for profit company and should have been saving for this replacement all along, the money should be in the bank and not be passed on to the customer. In my opinion there are other options for replacement and reliability, certainly there is already redundancy there and a staged approach to replacement can be taken. Replacing and upgrading one compressor bank at a time, etc. Don't know the plant completely myself but there has to be an option."
"In any business there should be allowance in the budget for replacement and upgrades of equipment, where is it in your budget and why don't you use that? Why pass on the new costs when you already have an allowance for it?"
"Utilities must make their investment decisions however there should be some portion of revenue reinvested in maintaining and upkeeping the asset infrastructure. Industrial customers do the same - sometime with eating the cost to provide best customer services."
Need More Information
"More context should be provided to the location on the distribution system for the compressor in question and why this is of importance to ratepayers on a system-wide basis (rather than a location specific concern)."
"This question is difficult to answer without Enbridge sharing details on its maintenance strategies, data on the reliability performance of the current machines, how the alternatives were evaluated, and the economic evaluation of the options."
"What are the risks of deferring the project for a year? 3 years? 5 years? Are there any back up plans if not approved by 2026?"
"While I say continue with plans, what is the impact of carbon and to have the province wean itself off of natural gas, oil, propane and go to electricity? Is replacing the compressors still a necessity, if there are 50 such compressors out there?"
In Favour Of Replacement
"It is better to be proactive than reactive."
"Need to be pro-active."

Comments continue on next page…

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Making Choices

Compression Stations – Additional Comments [2 of 2]

Defer Replacement
“Enbridge is better positioned to determine its own deferred maintenance. Your customers should not be weighing in here.”
Other
“It is very difficult to make an End of Life assessment here. We need reliable gas service, manage accordingly.”
“Enbridge should create a public forum and provide EOL assessment in a transparent manner. Create qualifications where end users can comment and create better processes to spend end users money. This will create a free talent pool of qualified assessors for Enbridge to tap into.”
“Outages could have significant impact on customer operations ie equipment, production delay etc.”

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Making Choices

Vintage Steel Pipeline Replacement Program

Enbridge Gas has implemented a Vintage Steel Pipeline Replacement Program, which focuses on replacing older steel pipelines within the system. It is considering ramping up the program to ensure ongoing safety and reliability of the distribution system and to prepare the network for the eventual delivery of low carbon, blended hydrogen. Blended hydrogen can safely be delivered through modern steel and plastic distribution systems – however, with the rapid introduction of natural gas to Ontario during the 1950's and 60's, Enbridge Gas has a lot of older steel pipelines which are nearing end of life and require replacement in a planned and proactive manner.

This program would see an increase in work and a ramp-up of spending starting in 2024 with the goal of replacing 5,100 km of 17,000 km of vintage steel pipelines in 20 years. These vintage steel pipelines were built before 1971 and are more prone to failures compared to steel pipelines built later due to materials, construction and damage prevention practices used at the time. Using risk assessments, the program will focus on replacing pipelines that are closest to end of life first.

Enbridge Gas intends to start this increase in work in 2024 so that the work can be spread out over a longer period with a limited increase to internal resources. Pushing the work into the future, such as 10 years from now, to achieve the same objectives, will require additional internal as well as external resource overheads and costs, with reduced productivity due to a sharper ramp-up of skilled labour. The overall costs would be expected to be higher with a delayed approach.

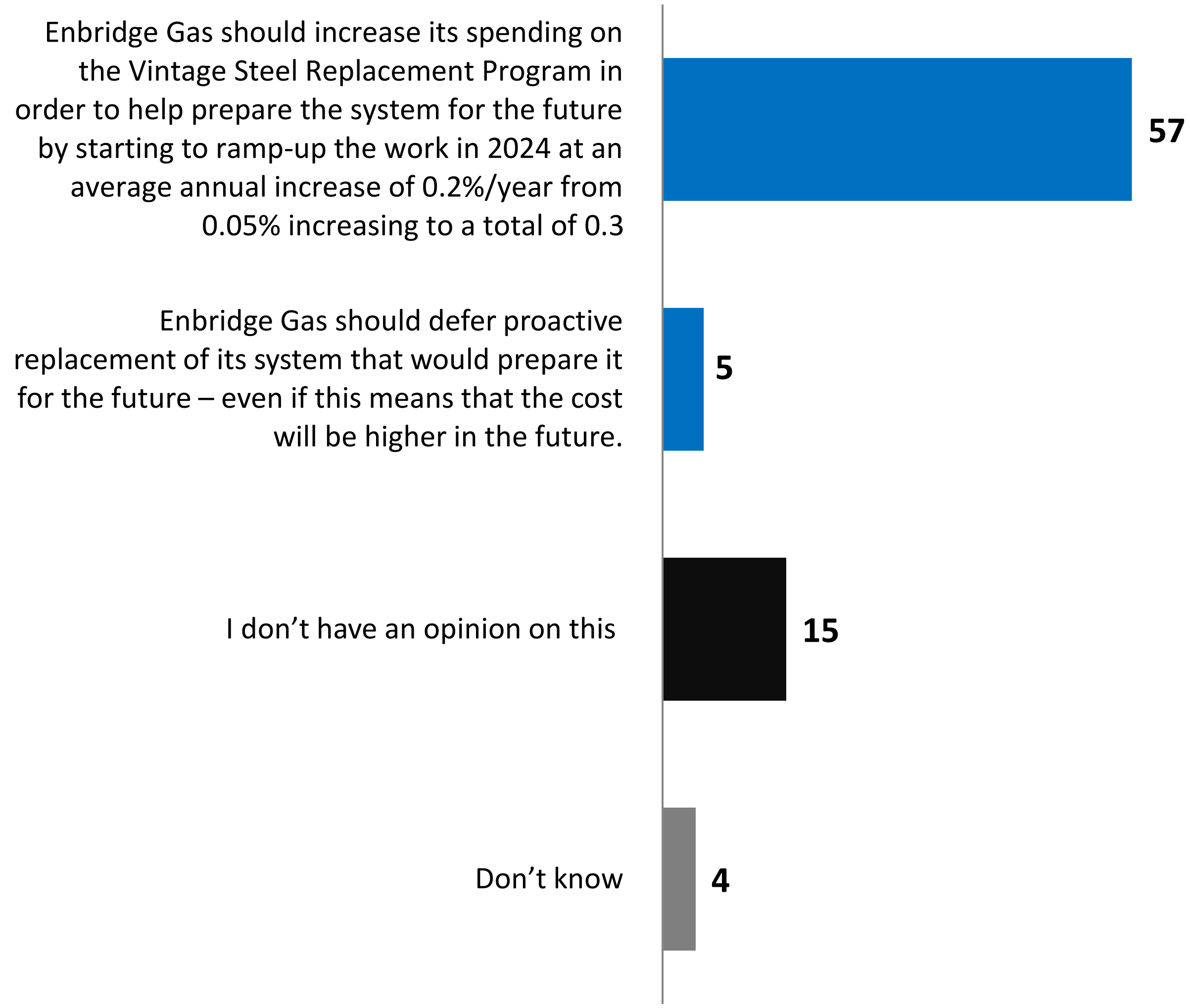
It is estimated that this program, ramping up in 2024, included in the capital budget, is equivalent to an average annual increase of 0.2%/year from 0.05% increasing to a total of 0.38% in 2028 for the average customer.

Making Choices

Vintage Steel Pipeline Replacement Program

Q Considering this, which of the following is closest to your view?

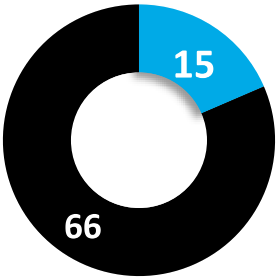
[asked of all respondents; n=81]



Making Choices

Vintage Pipeline Replacement Program – Additional Comments [1 of 2]

After making their choice, respondents were given an opportunity to make any additional comments they may have.



Defer Replacement
"1. Assuming you are already prioritizing what vintage steel is at risk to being stranded asset should low carbon future see less use of natural gas, if so then option 2 above (increase spending but in targeted manner to reflect risks). 2. invest in complimentary business such as District Energy which is pipelines connecting large emitters - this creates Enbridge role as solution provider to low carbon future and protects business model by providing growth opportunities."
"As a customer, I am concerned about quality and delivery and expect Enbridge to take the necessary steps to provide. I don't feel I am the best one to tell what to do next. And it won't make me feel better with higher rates because I know where the money goes. If I have my say I would suggest to do continuous improvement, lower the costs and maintain your assets accordingly."
"If it's broke fix it, if not don't."
"If the government is successful in having all of us reduce our GHG emissions to net zero by 2050, this inherently means reducing the use of all fossil fuels, including natural gas (albeit the cleanest of all fossil fuels) ... does it make sense to invest in infrastructure that could be mostly obsolete well before its end of life?"
"Natural gas will eventually be largely phased out. Only replace what's necessary."
Enbridge/Stakeholders Should Cover Cost
"Again, being a for profit company Enbridge should have been budgeting for this replacement on an ongoing basis, not putting it on the customer."
"Enbridge shall make end user stakeholders by making them invest in your infrastructure and giving rebate on invoices."
"Same as previous comment (there should be some portion of revenue reinvested in maintaining and upkeeping the asset infrastructure)."
"See comments to previous question (In any business there should be allowance in the budget for replacement and upgrades of equipment, where is it in your budget and why don't you use that?)."
Concern with Cost
"Again concern...impact of electricity replacing natural gas/alternatives, therefore reducing gas demand and ability to cover costs. As well concerned that inflation is currently exceeding many targets and the above costs are severely short of what those costs will be."
"It should be undertaken the safest most economical manner possible."

Comments continue on next page…

Making Choices

Vintage Pipeline Replacement Program – Additional Comments [2 of 2]

Support Replacement
"Again, Enbridge understands its deferred maintenance better than anyone else. Tackling deferred maintenance is important. The worst business decision is to do nothing!"
"Good planning would be to proactively replace, but that also means that Enbridge should proactively budget and not rely on surcharges or rate increases."
Other
"At what point do you factor in alternative energy sources and resulting infrastructure change/abandonment?"
"While we appreciate Enbridge thinking ahead to the future, this question does not quantify the merits to customers of the proposed plan. In the absence of a reliability driver, this appears to be a cost pressure to customers without a quantified benefit."

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Making Choices

Hydrogen Gas

Enbridge Gas is looking at options to blend more Hydrogen gas into the natural gas it delivers to green the gas supply.

Clean hydrogen gas is derived from surplus clean electrical energy that is converted to hydrogen gas through electrolysis technology. The gas is then blended with traditional natural gas, reducing GHG emissions.

Enbridge Gas is considering investing more in clean hydrogen as a tool for reducing GHG emissions in Ontario to allow for additional hydrogen gas to be blended into the natural gas distribution system. This would mean expanding the pilot project at the power-to-gas (P2G) facility in Markham where hydrogen gas is currently being produced, to deliver hydrogen-blended natural gas to a larger network of customers, expanding the blended gas area from approximately 3,600 to just under 17,000 customers.

Image: Hydrogen gas can be stored in tanks

Additionally, Enbridge Gas intends to launch a feasibility study that assesses the full system's readiness for more hydrogen gas to be included in the system. The costs for these projects for the average customer are estimated as follows:

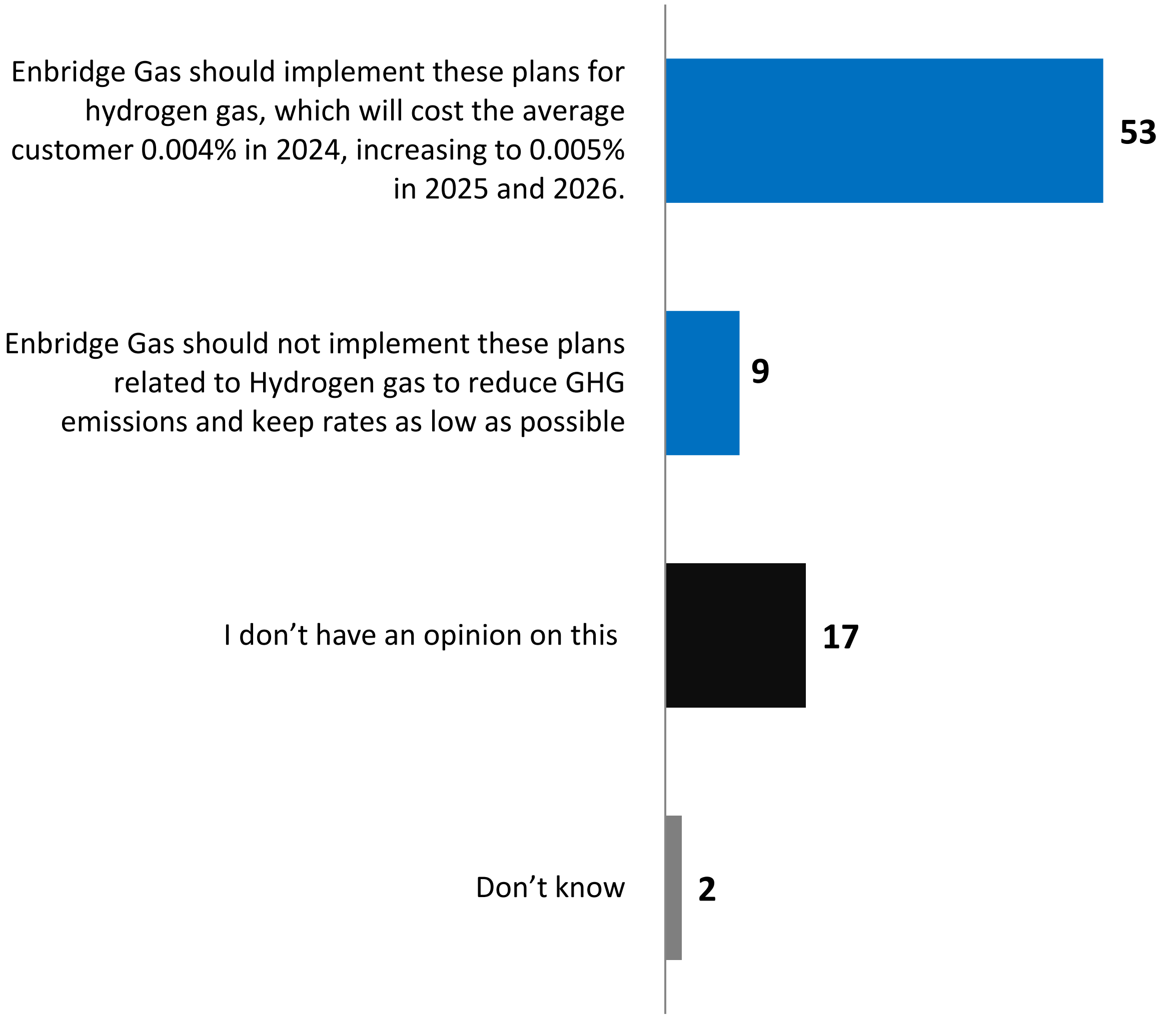
	2024	2025 and 2026
Annual cost	0.004%	0.005%

Making Choices

Hydrogen Gas

Q Considering this, which of the following is closest to your view?

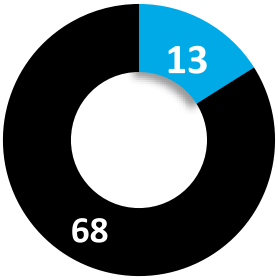
[asked of all respondents; n=81]



Making Choices

Hydrogen Gas – Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.



Need More Information
"Concerned, as I do not know this information, on the impact of gas efficiency. Will it have a different energy rate, which could increase or decrease customer demand (especially where the energy is used for other reasons than simply generating comfort heat)."
"Depends on whether the overall cost of the project creates GHG reductions at a cost per tonne that is comparable to other GHG reduction projects."
"To gather better feedback on this project, Enbridge should be providing details on the plan and the cost-effectiveness compared to alternatives (eg $/tonne of GHG abatement?)."
"Understand broad ratepayer impacts versus those who stand to benefit from decarbonization in natural gas (or explain how provides broader system wide impacts)."
Enbridge/Government Should Cover Costs
"Enbridge can implement plans related to Hydrogen Gas but funding for these types of projects should come from the taxes collected by the government from natural gas. It would be double charging the customers as these taxes related to Carbon (Carbon Taxes) already have significant impact to the rate increases."
"The carbon tax should come back to you to do this and not 'double dip' from your customers to complete this."
"The Federal government should be putting our carbon tax dollars to this, not asking us to pay for another increase."
Other
"Economics and environment should be a priority."
"Hydrogen should be "green", i.e. not derived from fossil fuels."
"I agree that this cost should be passed on to all consumers."
"See previous comment about ensuring hydrogen is not injected in any part of the system impacting industrial customers."
"The alternative use of the NG pipelines makes sense given the GHG reduction and net-zero societal goals ... however, the concern I would have is to ensure that Enbridge stays OUT of the energy-supply business, which would include Hydrogen. Enabling the system to accommodate the transition and addition of Hydrogen is a reasonable objective, but should be done in a way that wholly allows competition and access by others ..."
"Use the best of class in this technology for RNG."

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Making Choices

Innovation and Technology Fund

Enbridge Gas can support the advancement of various new low-carbon or energy efficient technologies that may not be available to consumers today.

While some of this work is already taking place on a small scale, the budget for these types of projects is currently very limited. Additional contributions from customers would allow Enbridge Gas to expand this type of research and development work.

Similar to other jurisdictions, Enbridge Gas is considering an **Innovation and Technology Fund** in order to support the research, development, and the bringing to market of new low-carbon or energy efficient technologies. Where possible, this would be in partnership with other utilities and organizations.

Some options include funding for …

- new research on energy efficiency technologies,
- hydrogen gas,
- renewable natural gas, or
- carbon capture, utilization and sequestration (CCUS). This is the process of capturing carbon dioxide before it enters the atmosphere and either use it as a resource to create products or permanently storing it underground.

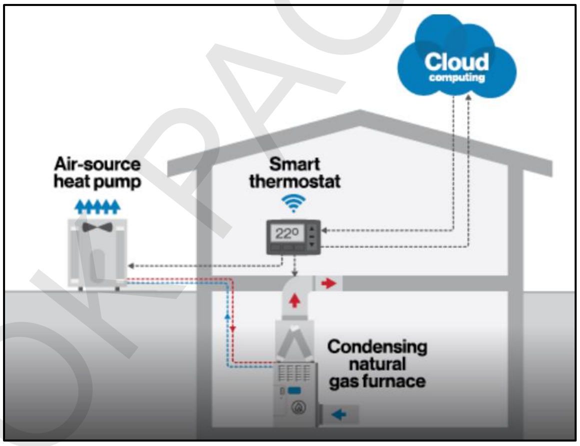


Image: Ontario pilot program tests future of advanced hybrid heating

The more money in this fund, the more projects could be completed, however Enbridge Gas is committed to finding a right balance of spending and planning for the future.

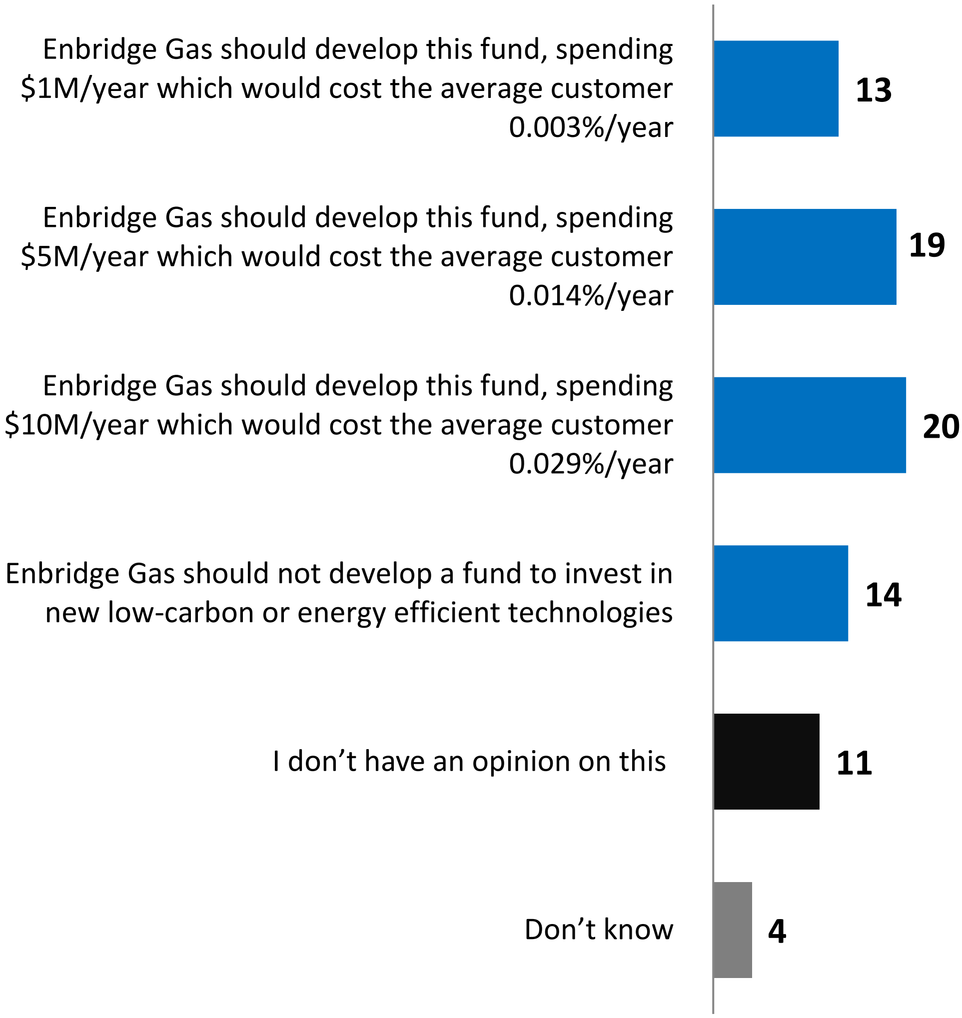
Making Choices

Innovation and Technology Fund

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 446 of 550

Q Considering this, which of the following is closest to your view?

[asked of all respondents; n=81]



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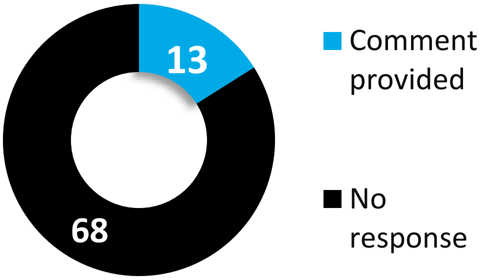
Making Choices

Innovation and Technology Fund – Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.



Enbridge/Carbon Tax Should Cover Cost
"Enbridge can still develop new low-carbon and energy efficient technologies, but this again has to be funded by the Carbon Taxes collected by the government. Having the funds for these technologies collected from the gas rates would be double charging the customers who are already impacted by the high Carbon Taxes collected for natural gas."
"Enbridge should develop a fund, however, it should be funded out of profits and not by increasing customer billing."
"Enbridge should try other avenues of fund raising to achieve the same objectives through tapping into the Carbon Tax already being levied."
"It is not Enbridge's place to take money from end users and decide where and how to spend. You can spend from your profits."
"The development of new technology is paramount for green house gas reduction. However the profit associated with this technology should be available to reduce customer energy cost for customers and not be there to further enhance Enbridge's pocket!"
"The funding should come from our carbon tax."
Transparency
"Enbridge should provide clarity on how much of this activity is Enbridge corporate activity vs that which is appropriate to flow through to regulated customers."
"Enbridge should provide clarity on how much of this activity is Enbridge corporate activity vs that which is appropriate to flow through to regulated customers."
Other
"Carbon capture should not be part of this."
"Enbridge should determine its long term goals and pass it on to its consumers."
"Is this not the government's position?"
"Need to spur innovation for things like RNG and decarbonization of the grid with support for local production sources (i.e. AD facilities)."
"Where would the funding come from? Rate base?"

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Impact of Choices

Do You Want to Change Your Choices?

So far in this workbook, you have been asked about **4 key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page, you will find the annual bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential annual rate impact for 2024 and 2028 will be re-calculated each time you change one of your answers at the bottom of the page. Costs for 2025-2027 will fall between this range. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Business Customer Bill Impact Change and Magnitude of Bill Impact **(MEAN)**

2024

Range of Impacts

-0.07% to +0.11%

2028

Range of Impacts

-0.41% to +0.44%

Note: There is no statistical significance between the average initial total and the average final total.

About the "Range of Impacts"

The "Range of Impacts" signifies the highest and lowest possible range of bill impacts above and beyond the Draft Plan. For instance, if a customer, where possible, were to select the most accelerated option, their bill impact would result in an **additional 0.11%** annually in 2024 and **0.44%** in 2028. If they were to select the biggest decrease for each question, it would result in a **decrease of 0.07%** annually in 2024 and **0.41%** in 2028.

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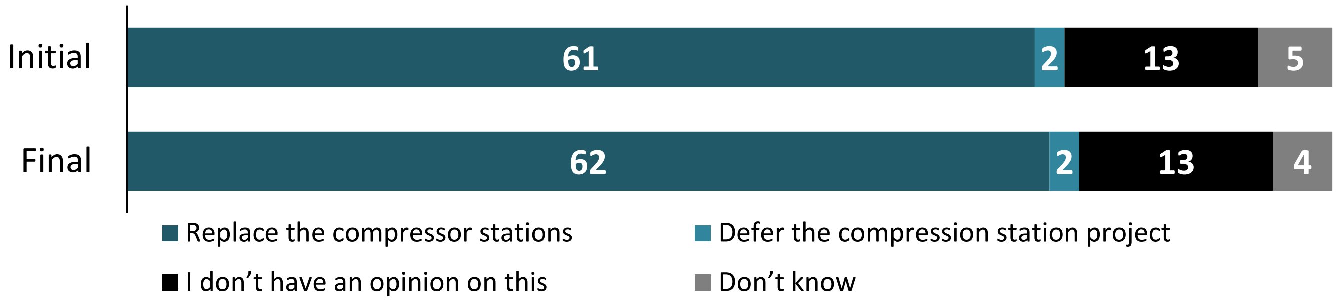
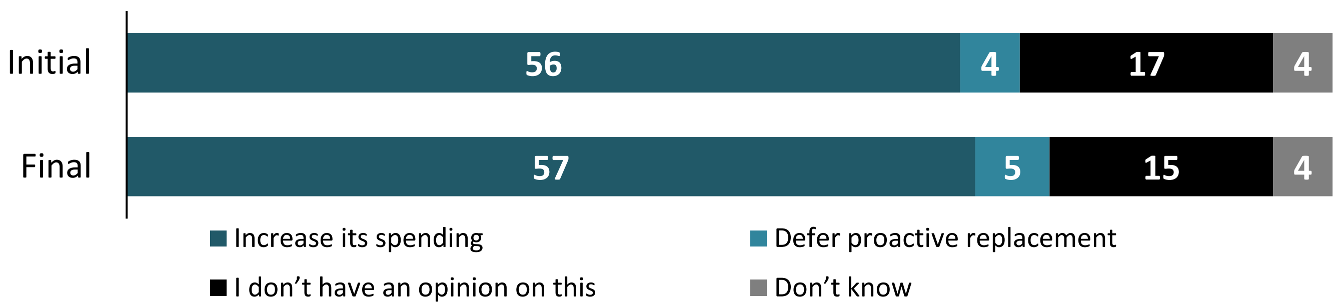
Making Choices

Impact of Choices

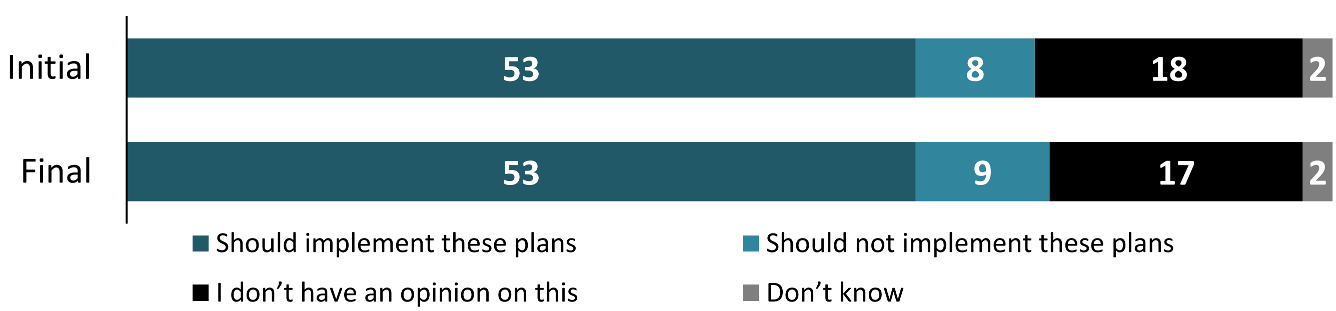
Compressor Station Project



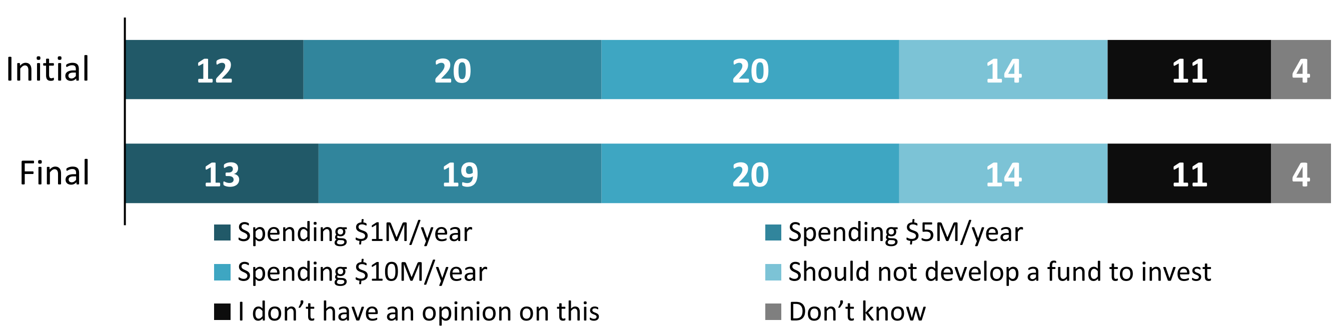
Vintage Steel Pipeline Replacement Program



Hydrogen Gas



Innovation and Technology Fund



Enbridge Gas will be reviewing its plan based on the feedback you and other customers are sharing now. However, in doing that review, it is important for Enbridge Gas to get a sense of whether the current draft plan is generally acceptable or not. There were some choice options that Enbridge Gas had already included in the draft plan, and others that were not.

As mentioned earlier in the workbook, the Enbridge Gas plan for 2024 to 2028 focused on the following key objectives:

1. Maintaining system safety and reliability
2. Containing costs
3. Harmonizing rates and services
4. Preparing for the future

Currently the plan is estimated to result in an average annual increase of an average of 1.4% over 2024 to 2028 for a total of 5.9% in 2028 compared to October 2021 rates. Along with your feedback on choices included within the plan, Enbridge Gas will consider your feedback on the choices that have not yet been included and update the plan accordingly.

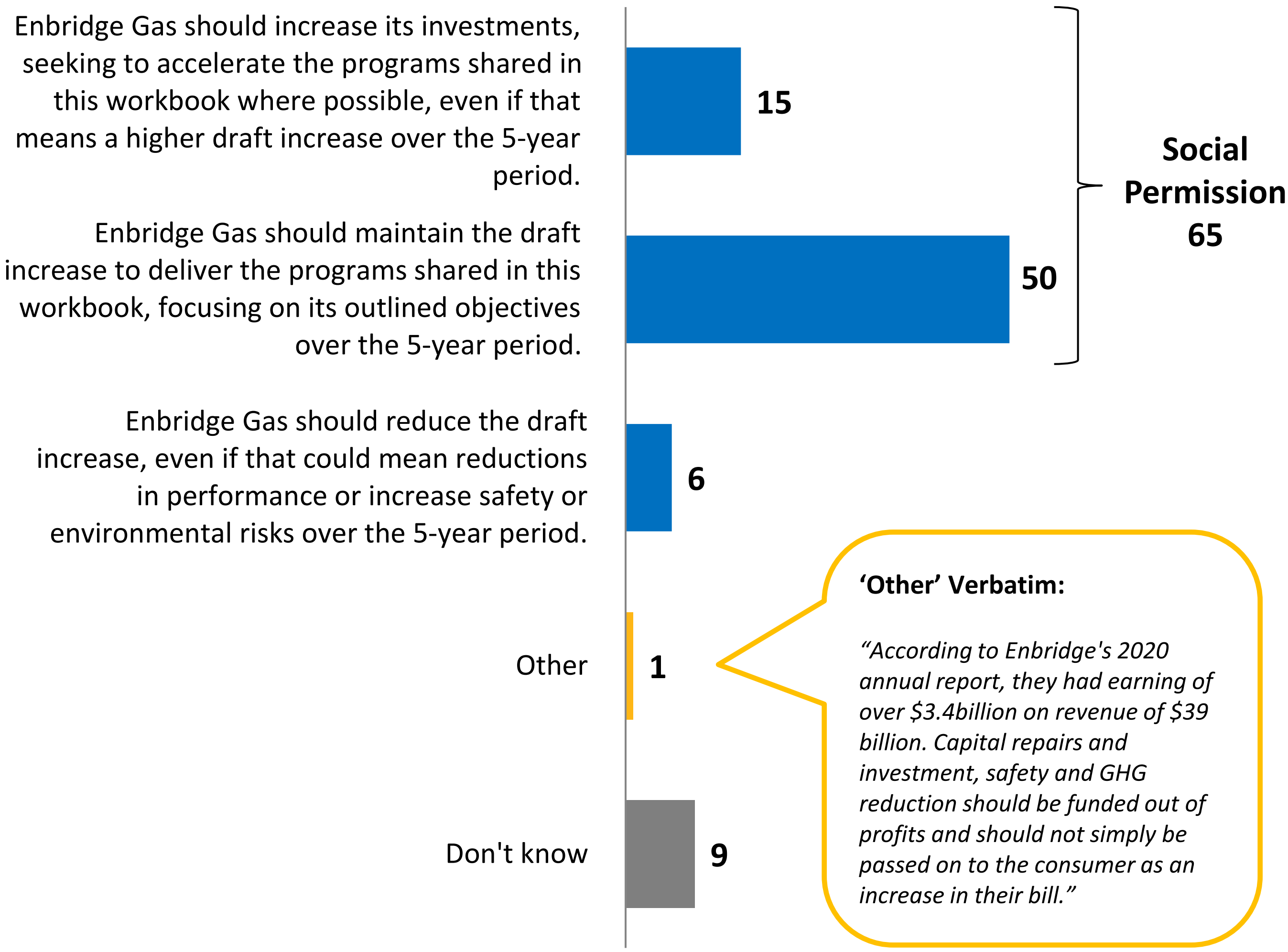
Social Permission

Enbridge Gas' Plans

Q

Considering what you know about Enbridge Gas' plans, and the choices you have been making, which of the following best represents your point of view?

[asked of all respondents; n=81]



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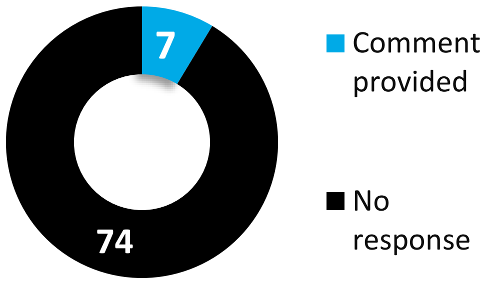
Social Permission

Enbridge Gas' Plans – Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.



Comments – Increase Investments
"I support an investment in infrastructure upgrades to meet the needs of the customers."
"Part of the issue we're seeing now with climate change is that too many people want to put off the cost of actually trying to fix a problem, and instead just ride it out. Adding 3%-5% over 4-5 years is a small price to pay to actually start being a tiny bit proactive in these areas, rather than just ignoring the larger problem and hoping it goes away."

Comments – Maintain Draft Increase
"Enbridge's plans related to environmental risks should not be funded through the rates, but through the Carbon Taxes collected by the government from the use of natural gas. This will minimize the impact of rate increases borne by the gas customers."
"If the development of new technologies proceeds the outcome should help in reducing operating cost and this should be applied to the operating cost and it may reduce the increase projected."
"Plan for your own future, as a publicly traded company you are responsible for your own infrastructure and have a responsibility to your customers not just your investors. For innovative futures reach out to the Federal Government for utilization of the carbon tax, that pool has to be getting huge.."

Comments – Reduce Draft Increase
"It's really hard to support an increase in spending on other areas when the utility's performance related to its integration of the Union organization, particularly its systems has been so poorly managed and supported. Moreover, until the utility can regain control over its meter-reading, consumption reporting and billing estimation capabilities it's hard to have faith that the utility is likely to have success in new undertakings."
"This survey is biased and geared towards desired outcome. Please do not waste my time. You want to have a serious debate, please approach with a desire to audit.."

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Online Workbook Results

Contract Rate Distribution Services

Service and Rate Harmonization

In its plan objectives, Enbridge Gas is looking at harmonizing its rates and services to ensure that the offerings are consistent across the entire service area as Enbridge Gas continues its integration activities. These service offerings are intended to address the needs of customers, to provide incremental flexibility where possible, and to be as simple as possible.

In this section we will ask you about some of the service harmonization proposals that Enbridge Gas is considering. The proposals discussed in this section are not yet finalized and your input, along with further work by Enbridge Gas planners, will help shape the final proposals that Enbridge Gas will include in its application to the Ontario Energy Board. We'll cover:

- ✓ **Contract Rate Distribution Services**: firm, interruptible and seasonal distribution services
- ✓ **Direct Purchase Services**: bundled, semi-unbundled and unbundled services

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 455 of 550

Customer Experience

Service Harmonization: Contract Rate Distribution Services

The next series of questions are about Enbridge Gas' contract rate distribution services.

Enbridge Gas has prepared a video presentation that explains the service proposals it is considering for contract rate distribution services in more detail. Please watch this video before answering the following questions. You may wish to move back and forth between the video and the workbook in a separate browser to answer all the questions.

Not all the questions may be relevant to the services you are currently receiving, in which case you may choose to select "I don't have an opinion on this" in the answer choices.

There are also various comment boxes available where you can provide additional thoughts on the various topics to share with Enbridge Gas. Your feedback is very important, so please take this opportunity to share your thoughts or concerns on the listed proposals.

Link: : https://www.enbridgegas.com/business-industrial/commercial-industrial/workbook#draftproposal

If you're experiencing technical difficulties with the video link, please contact marketresearch@enbridge.com for further support.

Firm distribution services

Firm distribution service offers firm deliveries of natural gas to the end use customer every day of the year. This is the most common service.

The table below summarizes the proposed changes to Enbridge Gas' firm distribution service offering.

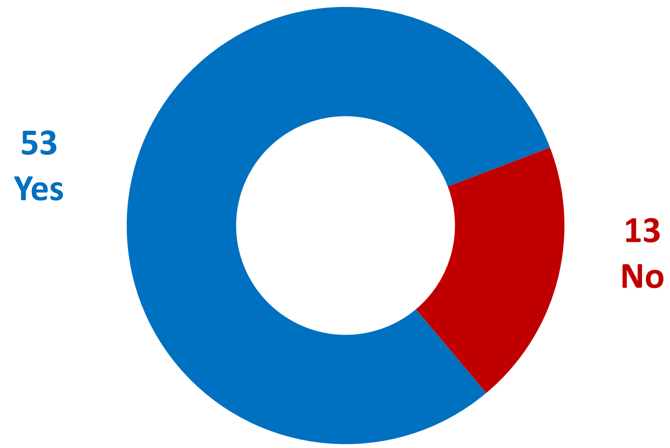
Customer Type	Rate Zone	Changes to Distribution Services
Firm Service	**Union North**	✓ Addition of low-load factor firm service ✓ Broader application of high-load factor service ✓ New compliance rules for overrun - automatic increase of contract demand
	EGD	✓ Ability to request authorized overrun of firm services
	Union South	✓ Addition of low-load factor firm service ✓ Addition of high-load factor firm service ✓ New compliance rules for overrun - automatic increase of contract demand

Contract Rate Distribution Service

Q

Were you able to watch the Contract Rate Distribution Service Harmonization video?

[asked of all respondents; n=66]



Comments on Contract Rate Distribution Service Harmonization video:

Comments
"I had to read them and advance myself."
"Seasonal and interruptible service does not currently apply to any of our end use accounts."
"While informative, we found the video format less effective than engagement sessions with opportunity for dialog and discuss specifics applicable to each customer."

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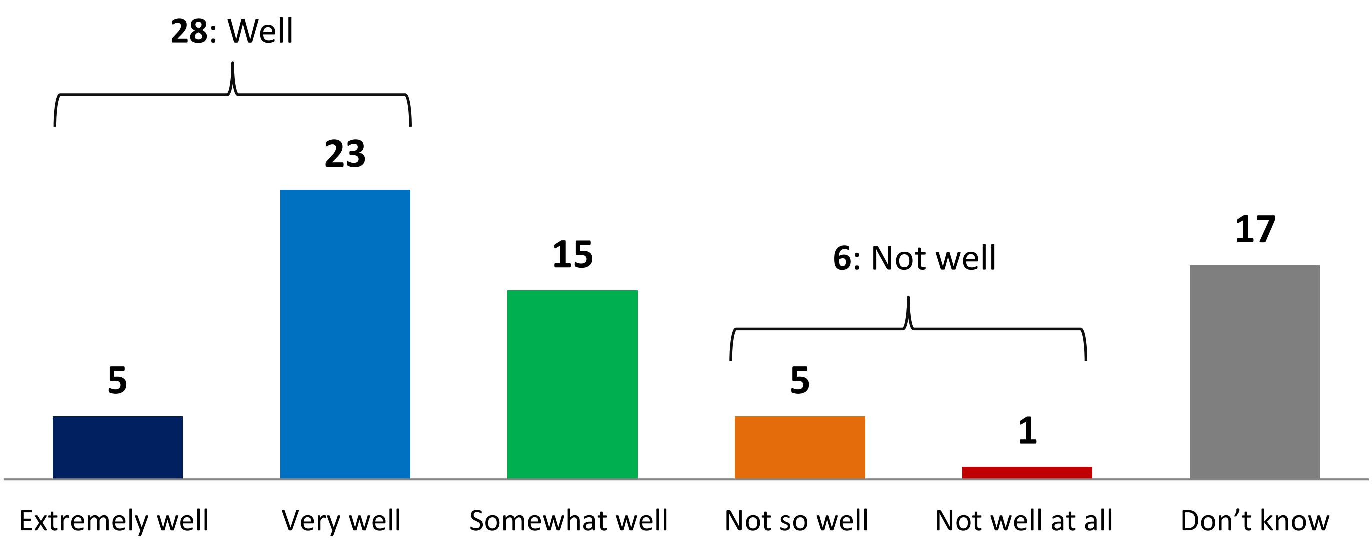
Proposed Firm Distribution Services

Q To what extent does the proposed firm distribution service offering meet the needs of your company?

[asked of all respondents; n=66]



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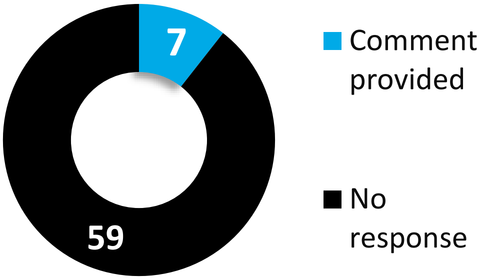
Proposed Firm Distribution Services

Additional Comments

Q Are there any parts of this proposal that work particularly well for your company? [OPEN]

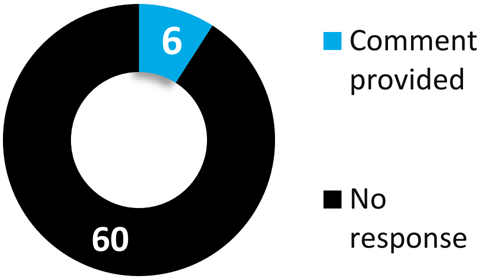
[asked of all respondents; n=66]



Comments
"Authorized overrun."
"Authorized overrun gas Low load factor service."
"Does not apply to my company."
"New compliance rules for overrun."
"Offering differentiation between load factor customers."
"Somewhat unclear to what impacts would be to our firm service Rate 1, Rate 6 and Rate 110 accounts."
"We are a firm/interruptible customer. We need to be firm only."

Q Any parts that do not work well for your company? [OPEN]

[asked of all respondents; n=66]



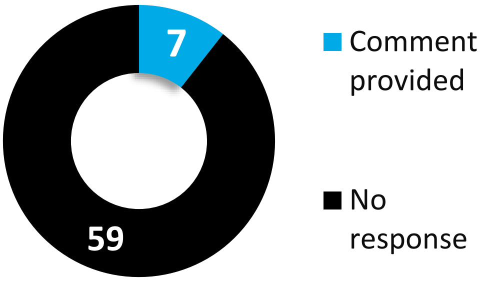
Comments
"Are there any plans to upgrade the infrastructure to natural gas delivery?"
"Does not apply to my company."
"High load factor service. Auto increase of CD."
"Overrun resulting in increase of CD."
"Somewhat unclear to what impacts would be to our firm service Rate 1, Rate 6 and Rate 110 accounts."
"We are a Healthcare facility that would potentially evacuate due to service interruption."

Proposed Firm Distribution Services

Additional Comments

Q Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

[asked of all respondents; n=66]



Comments
"Due to lack of clarity provided to our specific situation, it's hard to answer this definitively. For example, how does overrun work when Firm service is not available? Will these changes result in more or less firm available?"
"Legacy Union plans to move to automatically increase CD if it is exceeded it twice during the contract period; is this with the 120% penalty all the way back to the beginning of the contract period or just establishing a new CD level going forward for the rest of the year?"
"Low impact."
"Need to see the actual impact to us....we are a T1 and not sure if it will."
"Not at this time."
"Somewhat unclear to what impacts would be to our firm service Rate 1, Rate 6 and Rate 110 accounts."
"With changing weather patterns and ventilation requirements (e.g. for pandemic), difficult to accurately estimate gas volumes needed."

Service Harmonization: Contract Rate Distribution Services

Interruptible distribution services

Interruptible distribution service can be added to firm distribution service or can be contracted separately. This service allows Enbridge Gas to issue a notice of interruption that requires an end user to reduce their consumption completely, or to reduce it to the level of firm service they have contracted.

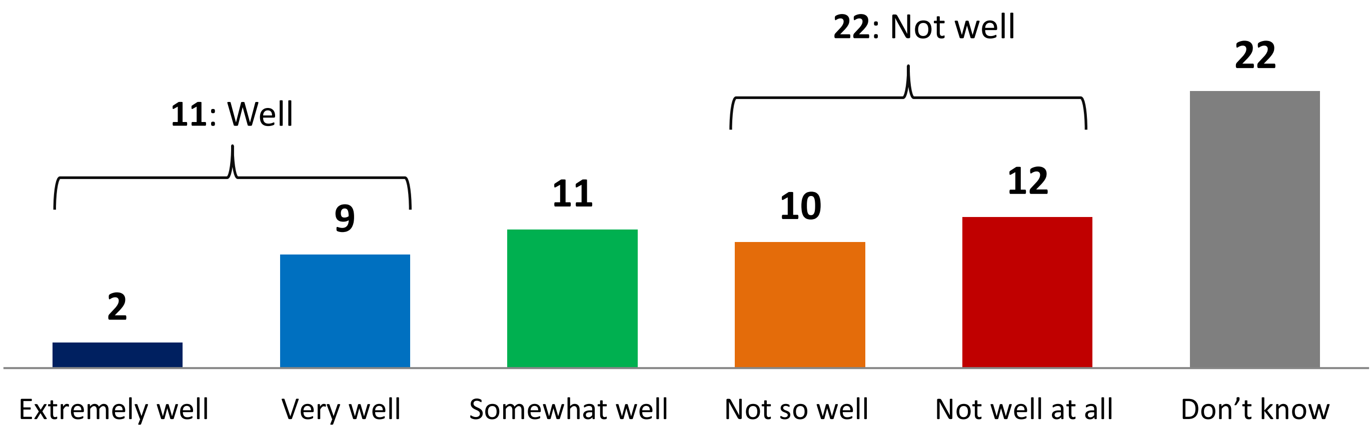
The table below summarizes the proposed changes to Enbridge Gas' interruptible distribution service offering.

Customer Type	Rate Zone	Changes to Distribution Services	
Interruptible Service	**Union North**	✓	Retirement of Rate 25 Sales service
	EGD	✓	Change in non-compliance methodology from curtailment credits/overrun charge to a simplified $/GJ charge
	Union South	✓	Removal of 40-day restriction on interruption

Proposed Interruptible Distribution Services

Q To what extent does the proposed interruptible distribution service offering meet the needs of your company?

[asked of all respondents; n=66]

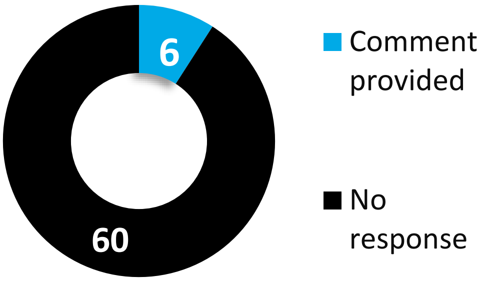


Proposed Interruptible Distribution Services

Additional Comments

Q Are there any parts of this proposal that work particularly well for your company? [OPEN]

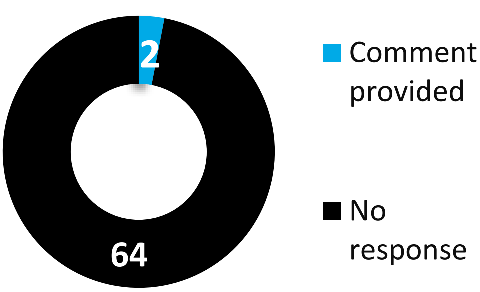
[asked of all respondents; n=66]



Comments
"Does not apply to my company,"
"Need to better understand how the removal of the 40-day restriction impacts us."
"Our site is used for filling up trucks with compressed natural gas. Gas consumption varies."
"Removal of 40-day restriction on interruption appears to be a positive for us."
"We cannot have any interruptions."
"We have never had a contract overrun on a Rate 110 contract but a simplified charge may assist in understanding the cost implication for violating contract demand thresholds."

Q Any parts that do not work well for your company? [OPEN]

[asked of all respondents; n=66]



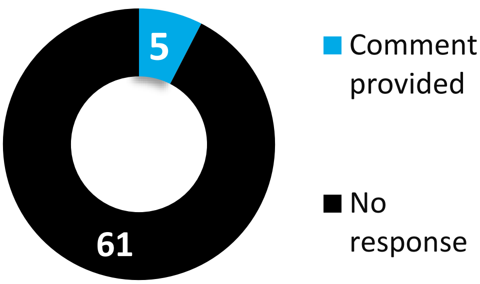
Comments
"Does not apply to my company."
"We do not use this practice."

Proposed Interruptible Distribution Services

Additional Comments

Q Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

[asked of all respondents; n=66]



Comments
"Do not currently have interruptible service - not a good fit for us."
"Do not use interruptible services."
"Interruptible service changes; we would need to see examples and cost impacts to understand how this would work."
"N/A - rarely use interruptible service, if ever."
"Not used much by our customers - they all needed to firm up."

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 464 of 550

Customer Experience

Service Harmonization: Contract Rate Distribution Services

Seasonal distribution services

Seasonal distribution service is a form of firm service that provides access to firm deliveries of natural gas in months where Enbridge Gas does not expect to see peak demand on the system. This service is tailored for customers who do not have their peak demands in the winter.

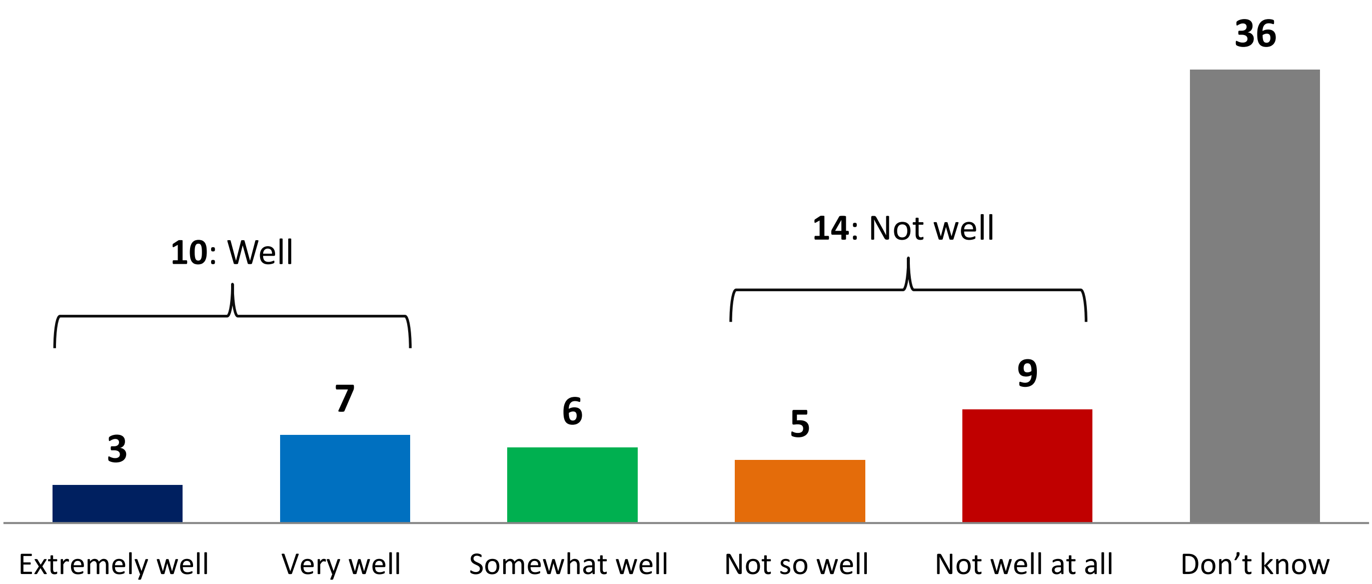
The table below summarizes the proposed changes to Enbridge Gas' seasonal distribution service offering.

Customer Type	Rate Zone	Changes to Distribution Services
Seasonal Service	Union North	✓ Addition of seasonal service
	EGD	✓ Reduction in seasonal service parameters in the winter instead of 5% annual consumption allowance ✓ Ability to add seasonal service to a base level of firm service
	Union South	✓ Broader application of the seasonal option

Proposed Seasonal Distribution Services

Q To what extent does the proposed seasonal distribution service offering meet the needs of your company?

[asked of all respondents; n=66]

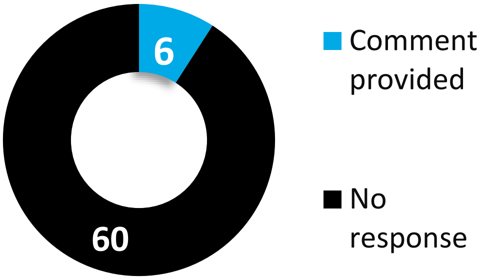


Proposed Seasonal Distribution Services

Additional Comments

Q Are there any parts of this proposal that work particularly well for your company? [OPEN]

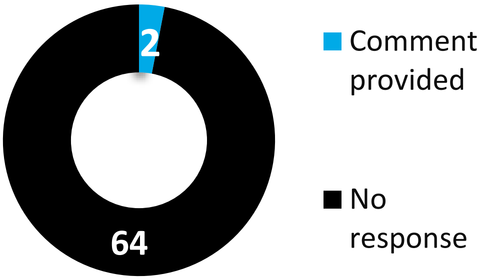
[asked of all respondents; n=66]



Comments
"Does not apply to my company."
"EGD."
"I don't think we use this."
"Offering this to broader range of customers."
"We have no seasonal."
"We use natural gas all year round. We run approximately 70 trucks that need natural gas for fueling."

Q Any parts that do not work well for your company? [OPEN]

[asked of all respondents; n=66]



Comments
"Addition of seasonal service."
"Does not apply to my company. However noting that some seasonal customers may consume gas at a high rate early December."

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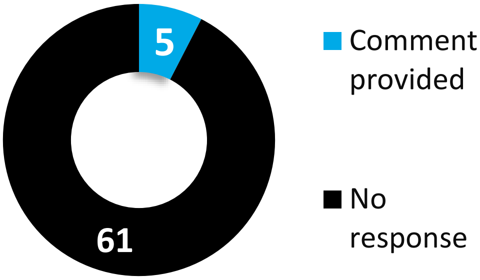
Proposed Seasonal Distribution Services

Additional Comments

Q

Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

[asked of all respondents; n=66]



Comments
"A few customers would benefit from this so am intrigued to see what the rate structure will look like."
"Do not have seasonal demand."
"I represent a lot of paving companies; the proposal to reduce their hourly and daily parameters to only 10% in Dec to Mar will be problematic"
"N/A - do not use seasonal option."
"Not applicable for us."

Customer Experience

Service Harmonization: Contract Rate Distribution Services

Reduced rates for interruptible distribution service

Customers with interruptible distribution service are required to stop consuming natural gas upon receipt of a **notice of interruption**. Interruption notifications are sent because of constraints on the Enbridge Gas system, generally due to cold weather or maintenance.

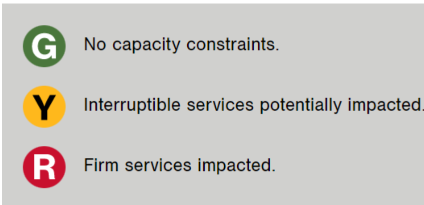


Image: Operational Status information is posted on the Enbridge Gas website

Customers generally comply with interruptions by to an alternate fuel source or, in some cases, by stopping their operations during the interruption period. Non-compliance with a notice of interruption results in financial charges to ensure compliance.

Enbridge Gas is studying whether <u>a reduced interruptible rate</u> compared to firm service would result in existing firm, or new, customers converting to interruptible service.

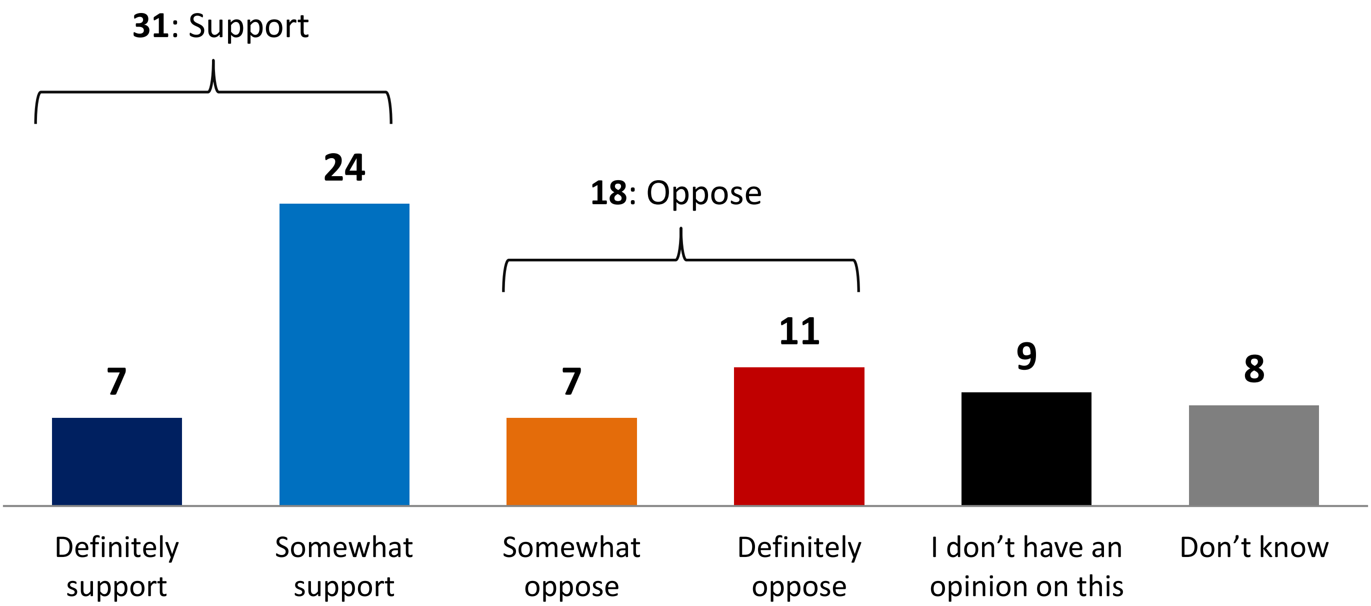
This conversion may result in Enbridge Gas having a reduced or deferred requirement for capital investment to expand the distribution and transmission system. However, the reduced rates for interruptible customers would result in an increase in firm distribution service rates to offset the reduced rates charged to interruptible customers.

Reduced Rates For Interruptible Distribution Service

Q

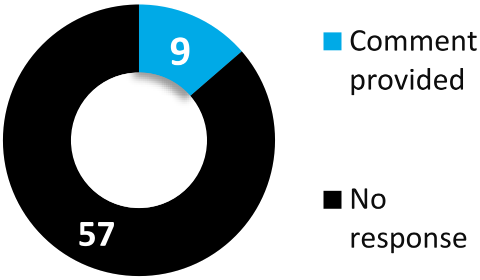
Generally, do you support or oppose Enbridge Gas reducing interruptible rates to potentially reduce or defer the requirement for capital investments?

[asked of all respondents; n=66]



Reduced Rates For Interruptible Distribution Service – Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.

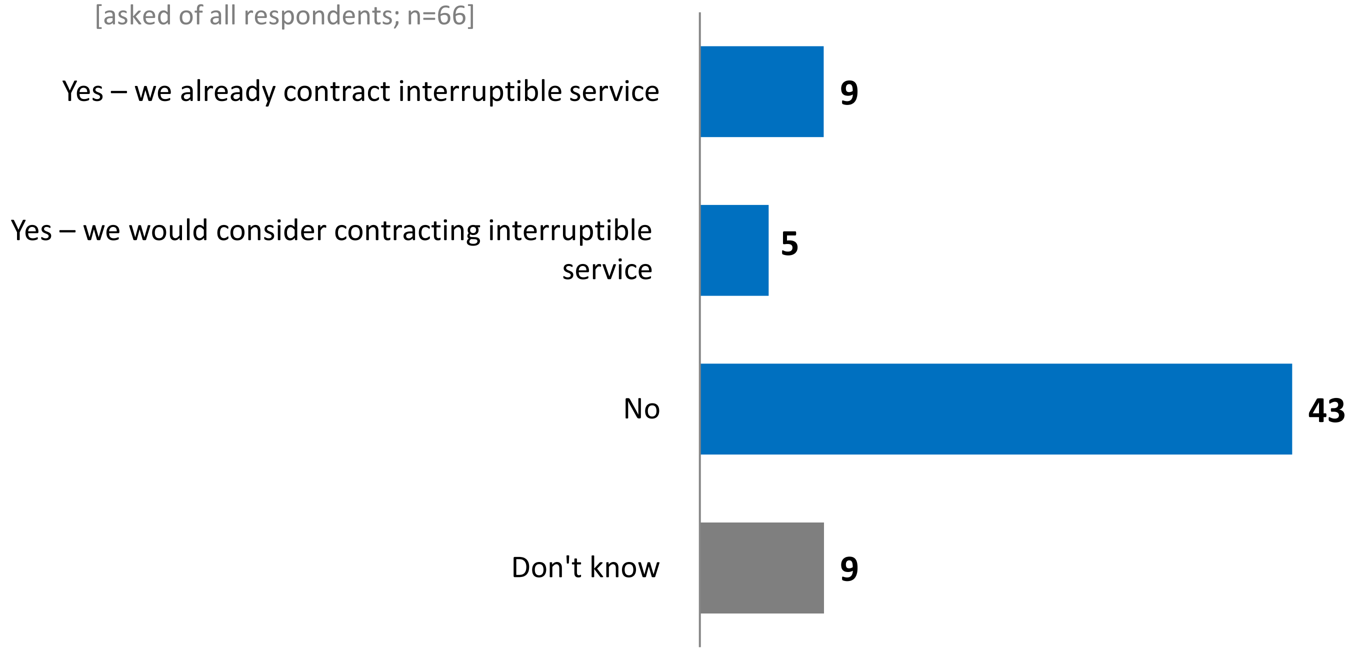


Support Reducing Interruptible Rates
"Healthcare needs constant supply."
"I support but being a hospital, we cannot participate at this time."
"Support although we would not use this service."
"Support it - but as a continuous manufacturing facility we would not participate."
"We are supportive to the degree that additional firm could become available."
Defer The Requirement
"Interruptible service is not a good fit for us, so we do not have."
Other
"It's a hard trade off - will depend on business owner."
"They are users like the rest of us so they should also pay for their portion."
"We have no interruptible services. Many of our services are essential so difficult to consider interruptible service."

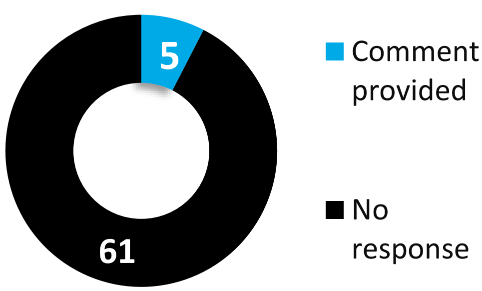
Interruptible Distribution Service

Q Is your company in a position to consider interruptible service if the lower rate provides sufficient benefit?

[asked of all respondents; n=66]



After making their choice, respondents were given an opportunity to make any additional comments they may have.



Comments
"Challenging to have an alternate fuel source."
"Many of our services are essential."
"We cannot accommodate service interruption."
"While we already contract IT, we would directionally prefer more Firm and if lower IT cost made this available, it would be positive for us."
"Would not consider - we require firm service as we use natural gas as feedstock."

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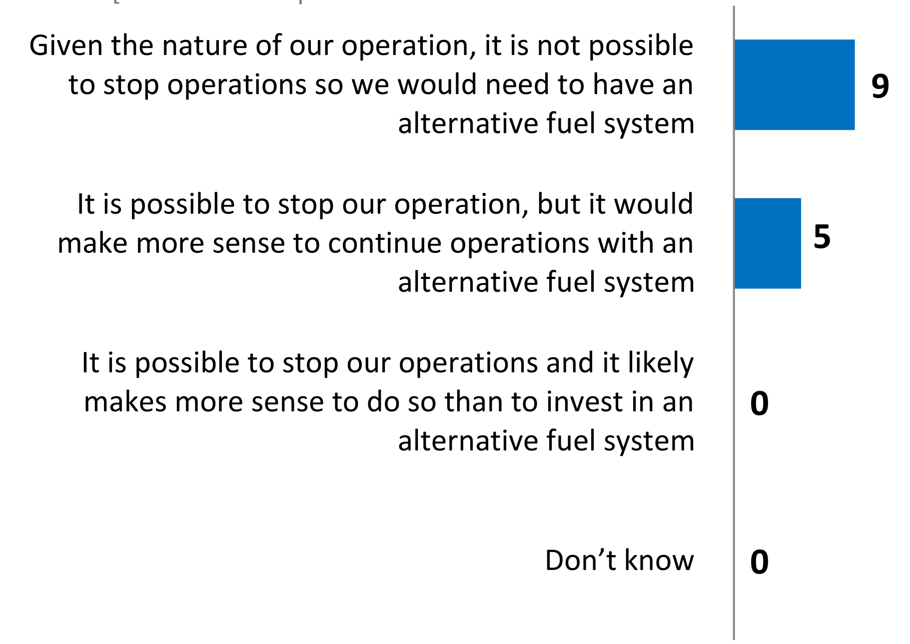
Interruptions and Alternative Fuel Systems

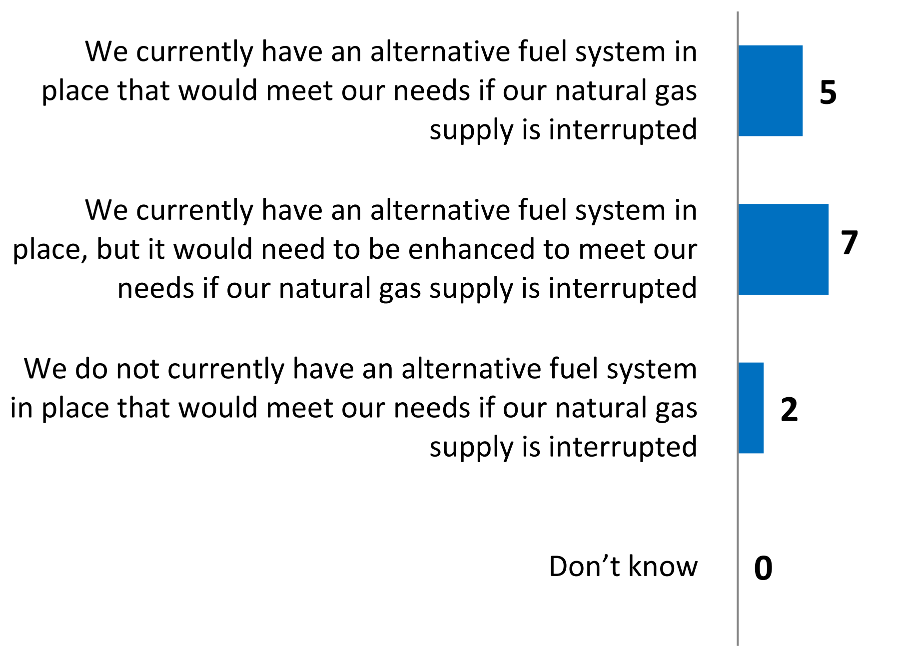
Q Based on what you know now, which of the following best reflects your company's situation when it comes to possibly stopping its operations in case of a notice of interruption?

[asked of all respondents who contract or would consider contracting interruptible service; n=14]



Q Which of the following statements best reflects your company's situation when it comes to an alternative fuel system?

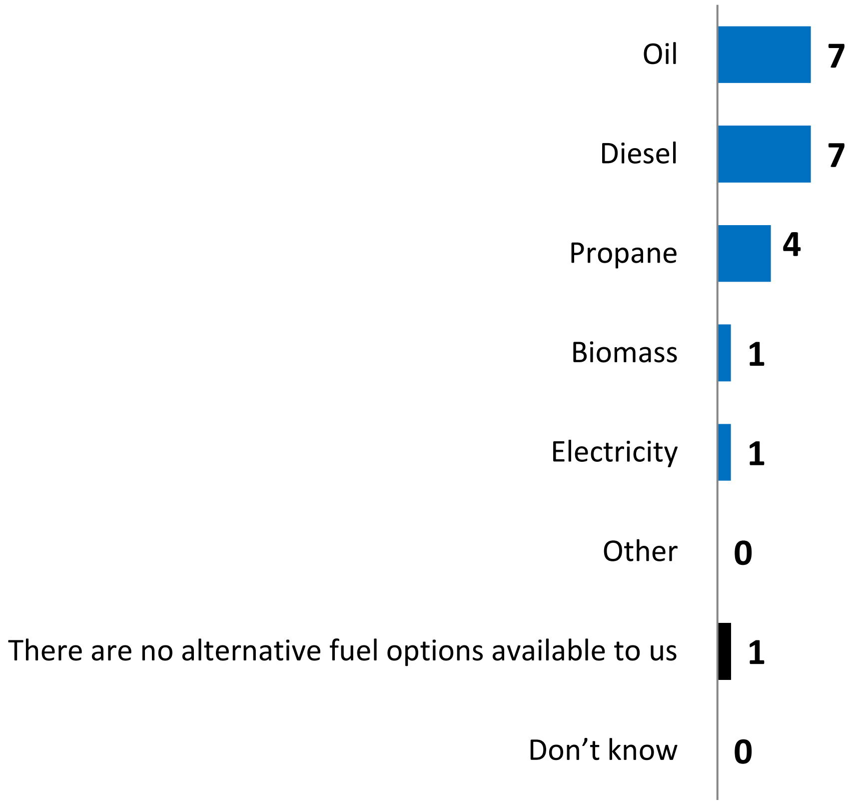
[asked of all respondents who contract or would consider contracting interruptible service; n=14]



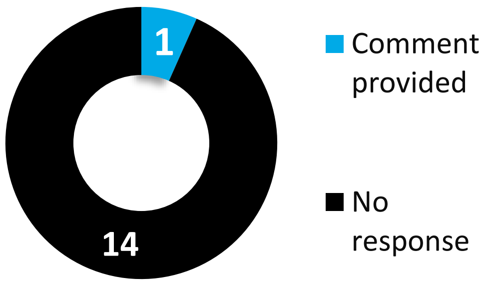
Alternative Fuels

Q If your company currently has an alternative fuel system in place, or if you were to consider one, what type of alternative fuel do you use or are you most likely to use? *Select all that apply.*

[asked of all respondents who contract or would consider contracting interruptible service; n=14]



After making their choice, respondents were given an opportunity to make any additional comments they may have.



Comments
"In the process of installing electric boilers for future backup."

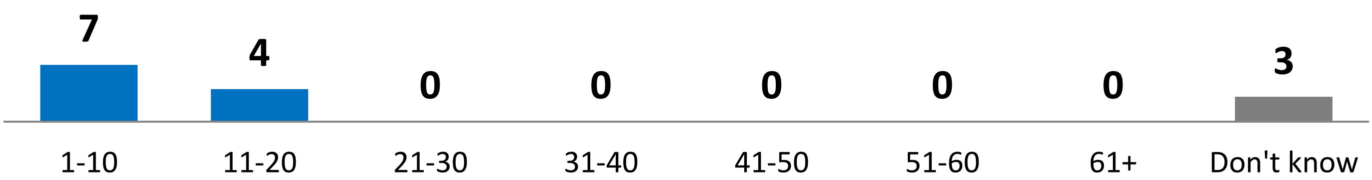
Conversion to Interruptible Distribution Service

Q

Conversion of existing customers from firm to interruptible service may allow Enbridge Gas to provide incremental firm service to the market without capital investment for additional facilities. This may result in increased frequency of interruption for interruptible customers.

If your company elected to take interruptible service, how many days per calendar year would you be able to meet the requirements of a notice of interruption for distribution service?

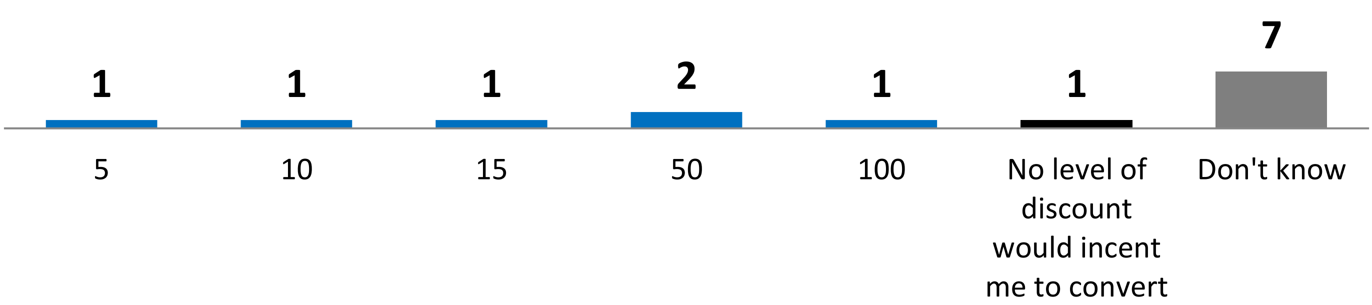
[asked of all respondents who contract or would consider contracting interruptible service; n=14]



Q

How much of a discount, relative to firm distribution rates, would incent you to convert to interruptible service? Please note that the level of discount is only applicable to the interruptible distribution rate and does not impact the commodity cost (i.e. the cost of the natural gas).

[asked of all respondents who contract or would consider contracting interruptible service; n=14]



NOTE: Respondents were invited to provide any comments they may have at this point, but none were provided

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Online Workbook Results

Direct Purchase Services

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 476 of 550

Service Harmonization: Direct Purchase (DP) Services

This next series of questions are about Enbridge Gas' direct purchase services.

Enbridge Gas has prepared a video presentation that explains the service proposals it is considering for direct purchase services in more detail. Please watch this video before answering the following questions. You may wish to move back and forth between the video and the workbook in a separate browser to answer all the questions.

Not all the questions may be relevant to the services you are currently receiving, in which case you may choose to select "I don't have an opinion on this" in the answer choices.

There are also various comment boxes available where you can provide additional thoughts on the various topics to share with Enbridge Gas. Your feedback is very important, so please take this opportunity to share your thoughts or concerns on the listed proposals.

Link: https://www.enbridgegas.com/business-industrial/commercial-industrial/workbook#draftproposal

If you're experiencing technical difficulties with the video link, please contact marketresearch@enbridge.com for further support.

Utility sale of system gas supply to bundled direct purchase customers

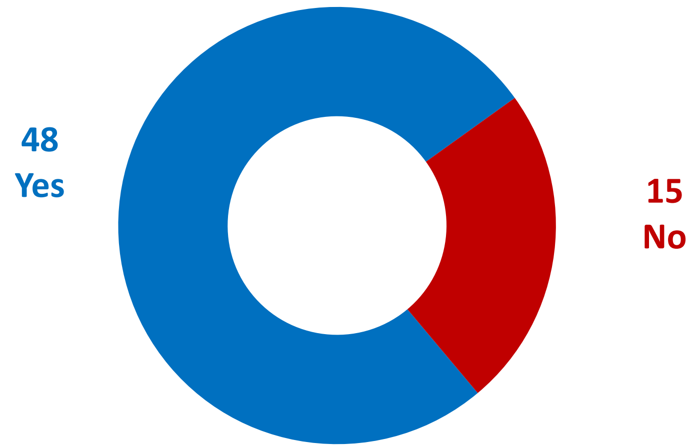
In the Union North rate zones, unlike the other rate zones, Enbridge Gas provides system gas supply to meet the interruptible consumption of bundled DP customers.

Enbridge Gas is considering eliminating the sale of system supply to bundled DP customers in the Union North rate zone. Instead, bundled DP customers would provide their own supply through their DCQ to meet their planned interruptible consumption needs just as they already do to meet their planned firm consumption.

Direct Purchase (DP) Services

Q

Were you able to watch the Direct Purchase Service Harmonization video?
[asked of all respondents; n=63]

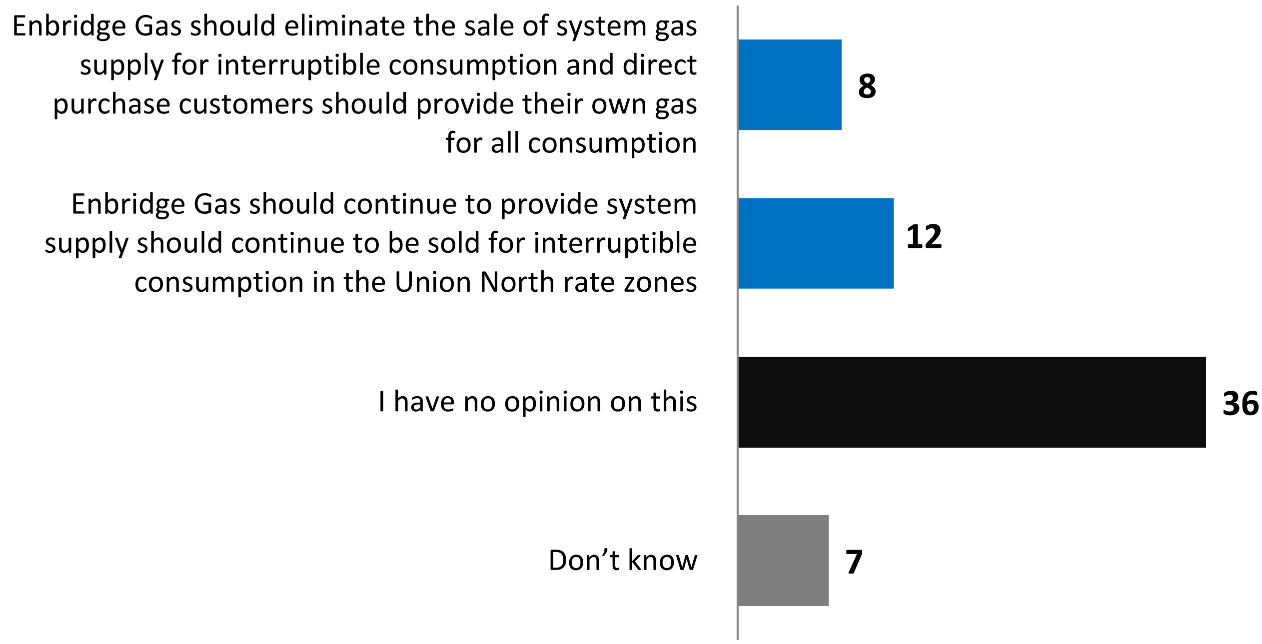


Comments on Direct Purchase Service Harmonization video:

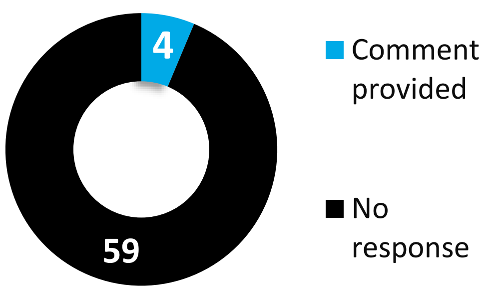
Comments
"Some components not applicable but elements of bundled DPA would affect us."
"The video does not work."
"The volume was quite low."
"Tough to hear it."
"What would be the impact on the availability and pricing of market-based storage at Dawn ?"

Sale Of System Gas Supply To Bundled DP Customers

Q Which of the following comes closest to your view?
[asked of all respondents; n=63]



Q Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]
[asked of all respondents; n=63]



Comments
"Am I understanding that any remaining volume at Empress (Union or Enbridge pools) will be transferred to the Dawn delivery point? Some customers have purchased long-term fixed price gas at Empress; would there be flexibility in when the change would happen by customer? When would these customers know that the change is going to occur?"
"Has no effect on our supply."
"We are not located in the Union North zone."
"We have no business in the Union North zone. Provided there is no impact of the change to Union South customers, we have no opinion on this."

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Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Bundled direct purchase gas delivery receipt points

Bundled direct purchase customers currently deliver their gas at the following points:

Rate Zone	Receipt Point
Enbridge Gas Distribution (EGD)	• Empress; or • Dawn; or • Ontario (Enbridge Central Delivery Area (ECDA) or Enbridge Eastern Delivery Area (EEDA)
Union North East	• Dawn (required)
Union North West	• Empress (required)
Union South	• Dawn; and/or • Parkway

When given the choice, customers have been showing a strong preference for delivering their supply at Dawn. Currently:

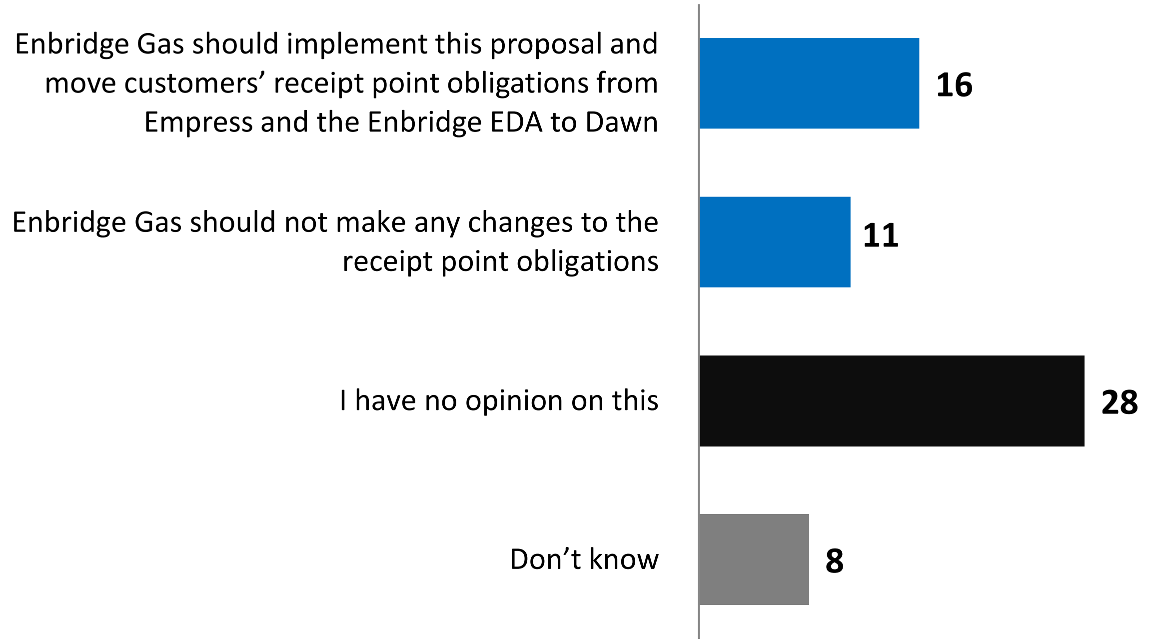
- 4% of bundled direct purchase gas is delivered at Empress; and
- less than 1% is delivered in the Enbridge EDA

The Enbridge CDA receipt point and Parkway receipt points are in close proximity and Enbridge Gas is considering handling these receipt points similarly.

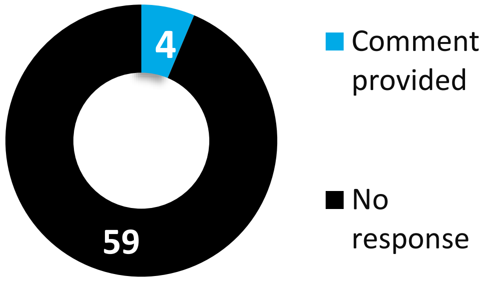
Enbridge Gas is considering simplifying the administration of the service by moving the small remaining bundled Direct Purchase customers' receipt point obligations from the Empress and Enbridge EDA receipt points to Dawn.

Bundled DP Gas Delivery Receipt Points

Q Which of the following comes closest to your view?
[asked of all respondents; n=63]



Q Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]
[asked of all respondents; n=63]



Comments
"Customers may perhaps have different reasons for wanting to secure supply from points other than Dawn. Of note is that all of our supply for all our managed pools use Dawn as the receipt point (moved from Empress and CDA several years ago)."
"Does not apply to our company."
"If this does not impact me as a customer it is a moot point."
"We do not have bundled direct purchase service; provided this change is neutral or cost reducing for other customers, we have no opinion on this."

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Service Harmonization: Direct Purchase (DP) Services

Bundled direct purchase gas delivery receipt points (cont'd)

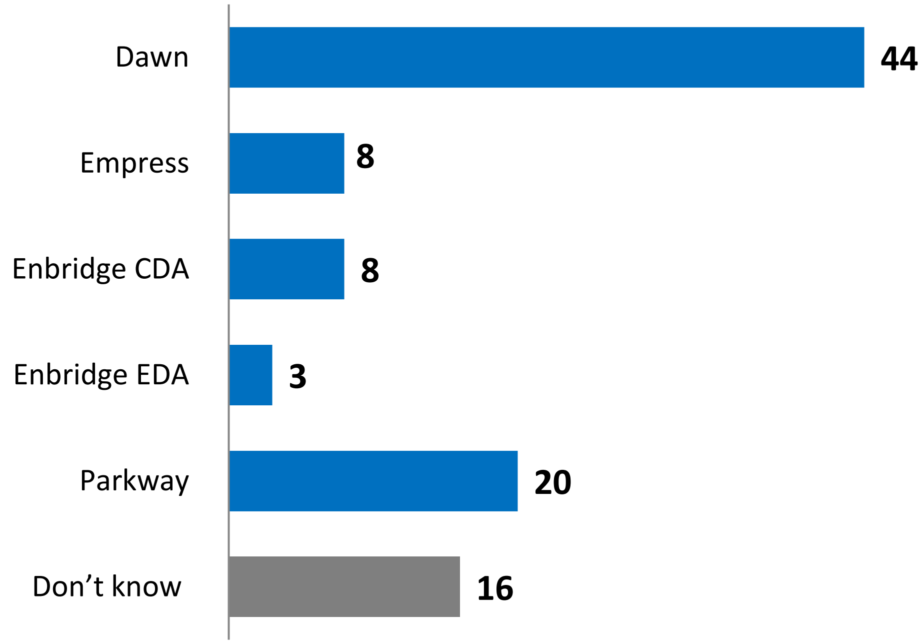
Customers obtain their supply and deliver it to meet their contracted DCQ obligation to the receipt point(s) defined in their contract. It is up to the customer where and how they get their supply to that receipt point (delivered service to the receipt point or acquired at some other point and transported to the contracted receipt point(s)).

Enbridge Gas would like to understand if there is significant interest by customers in delivering their gas supply to other points to Enbridge Gas's transmission system. If there is significant interest, Enbridge Gas will evaluate further.

Bundled DP Gas Delivery Receipt Points (Cont'd)

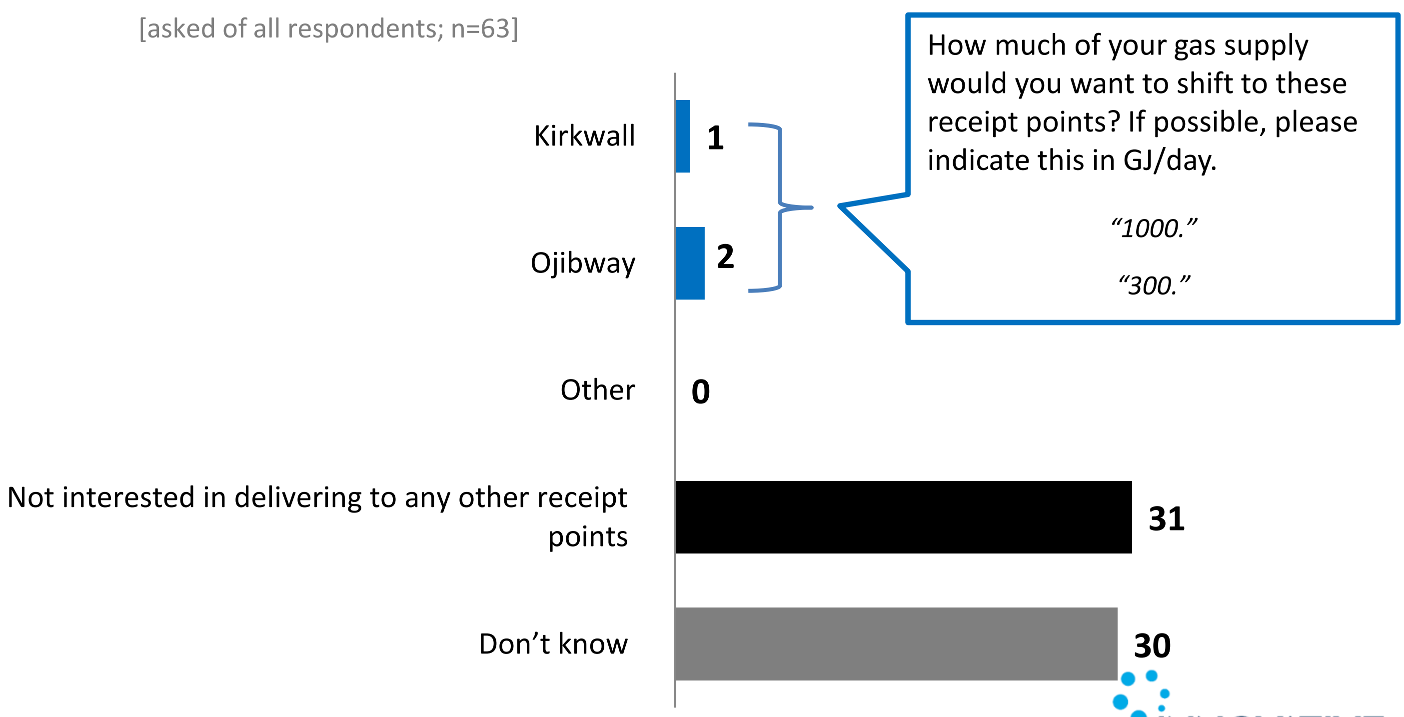
Q What are your current receipt point(s)? *Please select all that apply.*

[asked of all respondents; n=63]



Q Are there other receipt points to Enbridge Gas' transmission system where you are interested in delivering your gas supply? If so, which ones? *Please select all that apply.*

[asked of all respondents; n=63]



Bundled DP Gas Delivery Receipt Points (Cont'd)

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 483 of 550

Q

Which of the following comes closest to your view?
BY
What are your current receipt point(s)? *Please select all that apply.*
[asked of all respondents; n=63]

	EGI should implement proposal and move receipt point obligations	EGI should not make any changes to the receipt point obligations	I have no opinion on this	Don't know
Dawn	15	8	19	2
Empress	5	2	1	0
Enbridge CDA	4	3	1	0
Enbridge EDA	1	2	0	0
Parkway	8	4	8	0
Don't know	0	1	9	6

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Bundled direct purchase balancing

Enbridge Gas provides a base level of load balancing to manage differences between planned consumption and customer's contracted DCQ deliveries for all bundled DP customers. However, across the rate zones, customers have differing responsibilities and control over costs to manage differences from that plan.

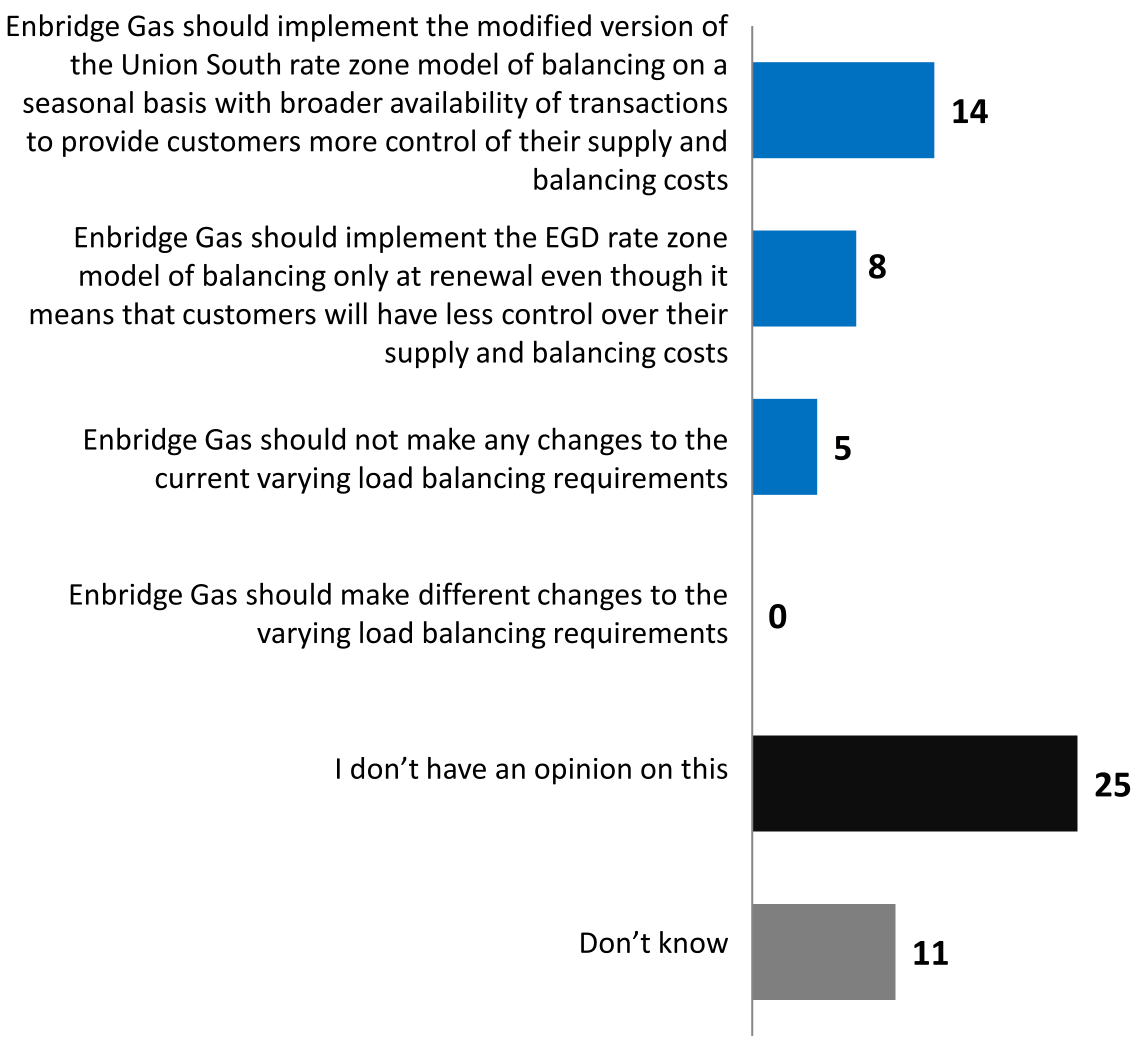
Rate Zone	Responsibilities and Options
Enbridge Gas Distribution (EGD)	✓ Balance within a tolerance by the end of contract term ✓ Have access to balancing transactions (some subject to seasonal availability) ✓ Enbridge Gas manages incremental balancing needs, so customers are subject to allocation of the costs of managing these needs
Union North	✓ Not required to balance but may have DCQ deliveries reduced by Enbridge Gas to manage lower than planned consumption ✓ Suite of transactions available throughout the year (some subject to daily operational capability) ✓ Enbridge Gas manages incremental balancing needs, so customers are subject to allocation of the costs of managing these needs
Union South	✓ Balance within a tolerance by the end of contract term ✓ Ensure Banked Gas Account balance is no less than planned by end of February if short (by bringing in more gas), and no greater than planned by end of September if long (by removing gas) ✓ Suite of transactions available throughout the year (some subject to daily operational capability) ✓ Customer has control over the costs of doing so

Enbridge Gas is considering moving to a modified version of the model used in the Union South rate zone today where bundled DP customers manage and control the costs of variances from the planned BGA by balancing, where necessary, on a seasonal basis (and where the modification is to remove the requirement to balance at renewal).

With the adoption of the above, Enbridge Gas is considering offering a common set of cost-based balancing transactions like the Union South rate zone today which will provide a broader suite of transactions with broader availability to allow customers to better manage their gas supply costs.

Bundled Direct Purchase Balancing

Q Which of the following comes closest to your view?
[asked of all respondents; n=63]

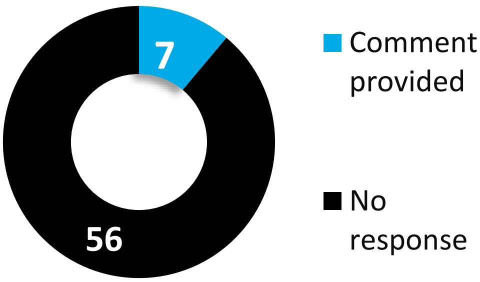


Bundled Direct Purchase Balancing

Additional Comments

Q Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]

[asked of all respondents; n=63]



Comments
"Difficult to determine financial impact without being able to predict gas needs first...which has gotten more complex with changing weather patterns and other factors impacting consumption."
"Eliminate the Enbridge ETT charge. Allow ETT transactions between Enb, Union S and Union N with no seasonal restrictions. Reduce the 3 day lead time for ITT/ETT requests to 1 day."
"Enbridge should work to enable the widest range of balancing options for end of term and within term."
"In a typical year, buying gas in February during the most volatile period for prices just to meet a seasonal checkpoint has never made sense as usually have to go and sell in September when prices are cheaper. EGD model is better for end-use customers and provides more flexibility for when to buy and sell. There's no hard buy/sell timeline except at contract renewal. Why not spread out the contract renewal dates throughout the entire Enbridge Gas system?"
"This one concerns me given the current state of the meter reading situation; asking customers to balance twice a year doesn't work when meters aren't being read consistently and accurately; it can also be costly for direct purchase customers who are balancing on estimates from one season to the next."
"We do not have bundled direct purchase service; provided this change does not impact semi-bundled Union South customers, we have no opinion on this."
"Would not impact us as we are already located in Union South - not educated enough to comment on other zones' impacts."

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 487 of 550

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

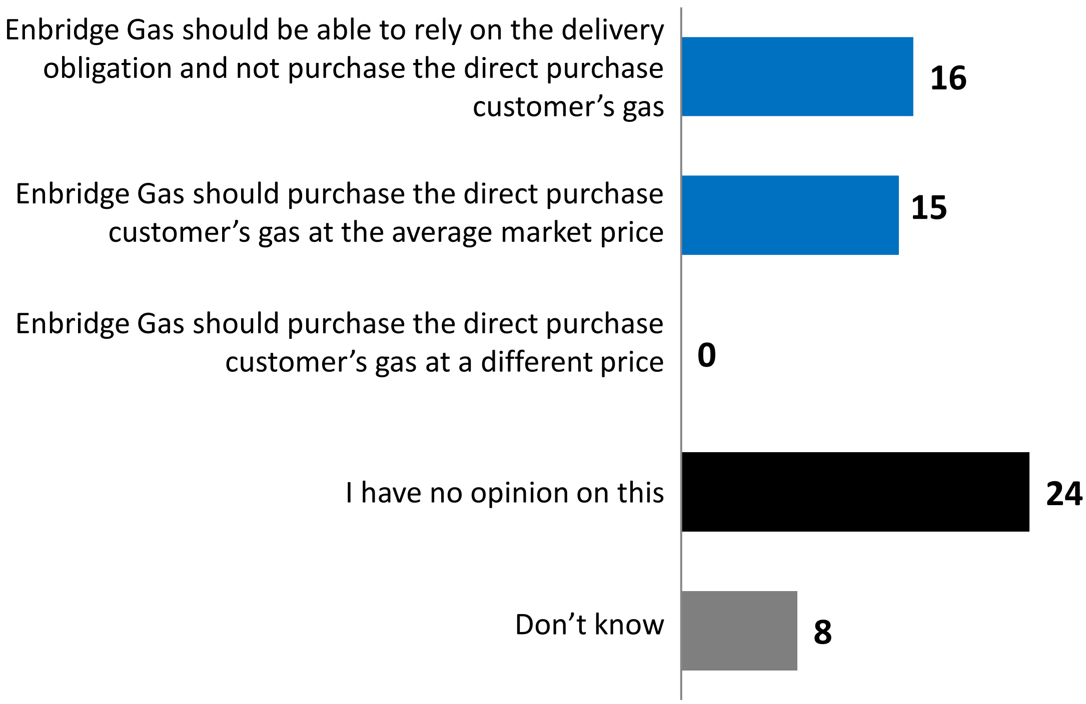
Enbridge Gas purchase of bundled direct purchase customer supply during an interruption of distribution service

In the EGD rate zone, unlike the other rate zones, if Enbridge Gas curtails bundled direct purchase customers' interruptible consumption, Enbridge Gas will purchase the proportion of the customers' Mean Daily Volume (MDV) or Daily Contract Quantity (DCQ) that is intended to meet the customer's annual interruptible consumption each day during the distribution interruption period at the average market price for the month of the distribution interruption.

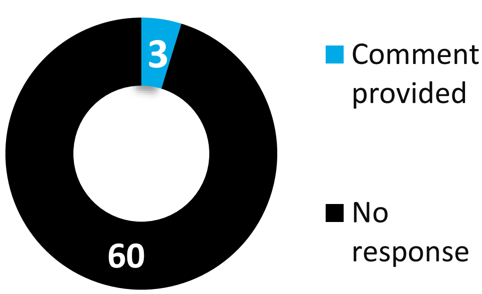
Instead of purchasing the direct purchase customer's gas, **Enbridge Gas is considering adopting the approach used in the Union South rate zone today which is to rely on the customer's contractual obligation to deliver its obligated deliveries and not purchase the customer's gas.** This allows the customer to maintain control over the cost of all its supply costs.

Purchase Of Bundled DP Supply During Interruption

Q Which of the following comes closest to your view?
[asked of all respondents; n=63]



Q Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]
[asked of all respondents; n=63]



Comments
"Does not apply to our company."
"We are not interruptible."
"We do not have bundled direct purchase service; provided this change does not impact semi-bundled Union South customers, we have no opinion on this."

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Semi-unbundled direct purchase gas delivery receipt points

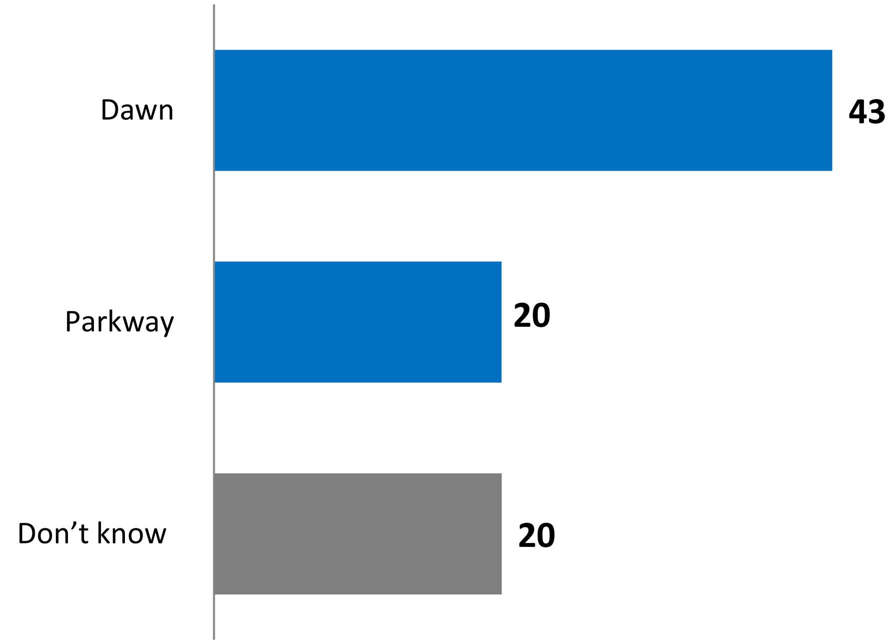
Customers obtain their supply and deliver it to meet their contracted DCQ obligation to the receipt point(s) defined in their contract. It is up to the customer where and how they get their supply to that receipt point (delivered service to the receipt point or acquired at some other point and transported to the contracted receipt point(s)).

Enbridge Gas would like to understand if there is significant interest by customers in delivering their gas supply to other points to Enbridge Gas's transmission system. If there is significant interest, Enbridge Gas will evaluate further.

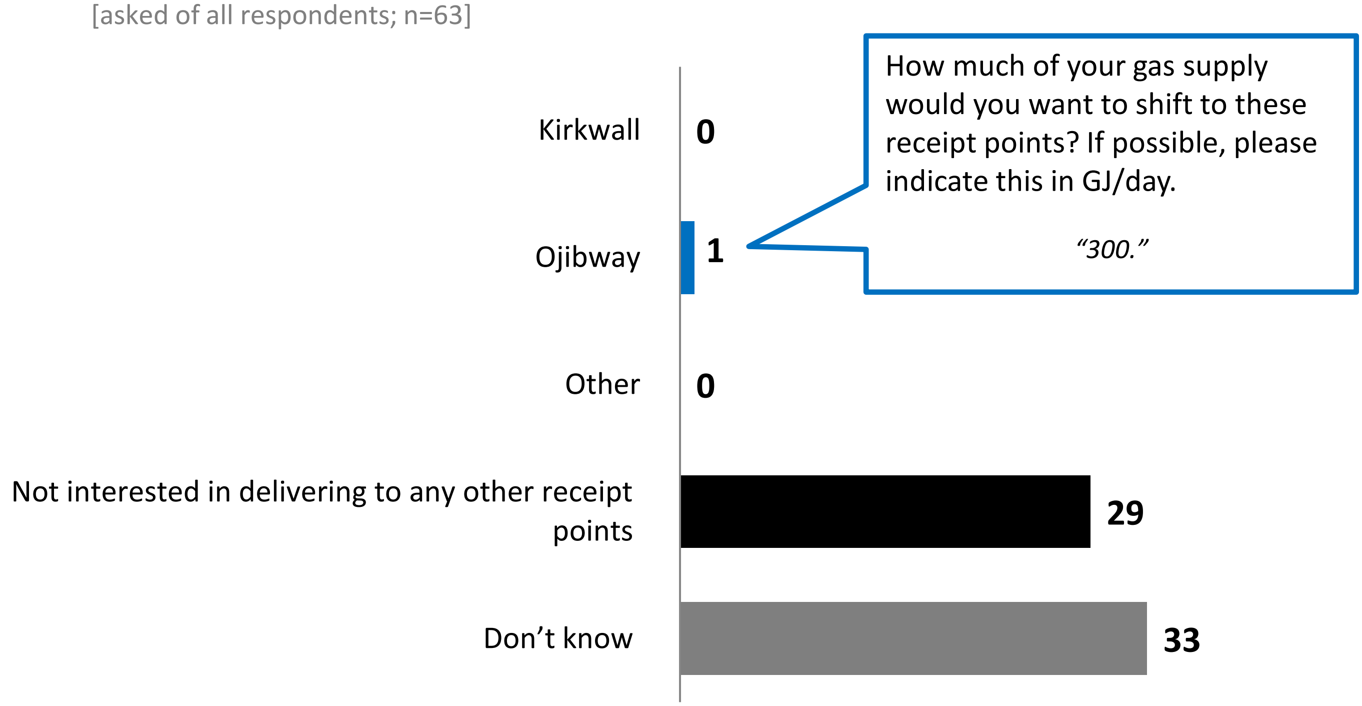
Semi-unbundled DP Gas Delivery Receipt Points

Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 490 of 550

Q What are your current receipt point(s)? *Please select all that apply.*
[asked of all respondents; n=63]



Q Are there other receipt points to Enbridge Gas' transmission system where you are interested in delivering your gas supply? If so, which ones?
Please select all that apply.
[asked of all respondents; n=63]



Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 491 of 550

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

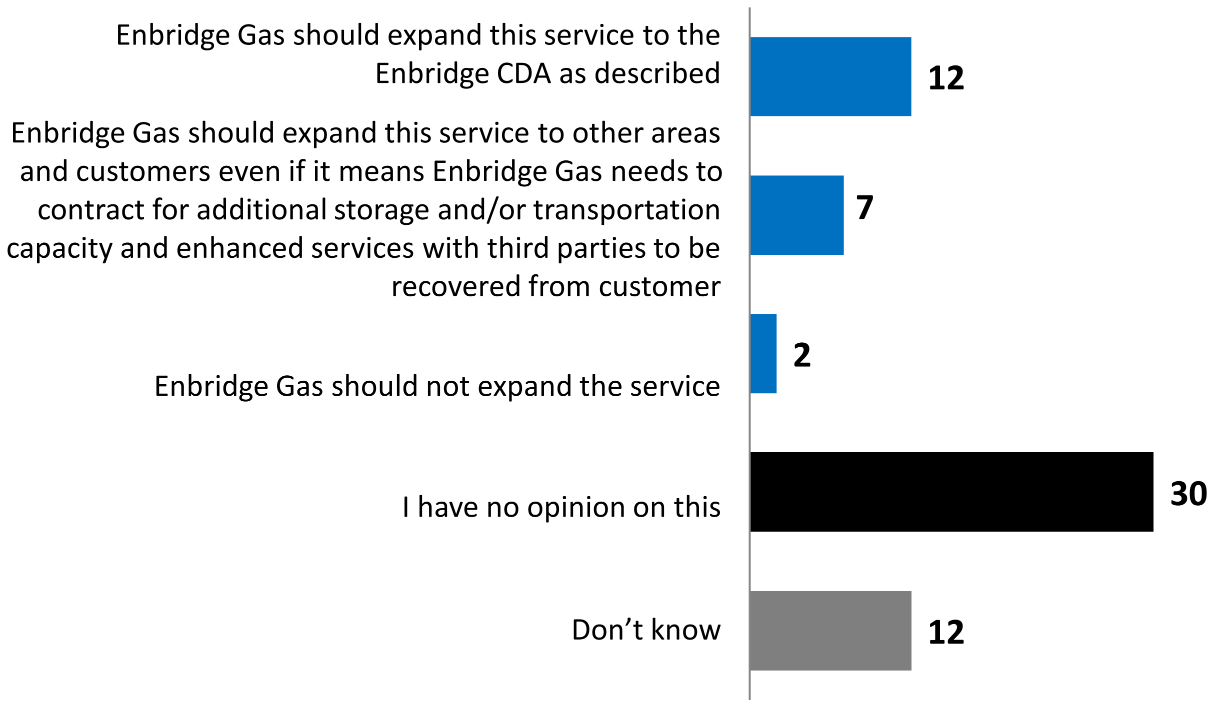
Expansion of the semi-unbundled direct purchase service to bundled DP customers in the Enbridge CDA

In the Union South rate zone, customers have a semi-unbundled DP service available under the current Rate T1 and T2 services. Under this service, customers have obligated deliveries for their gas supply like the bundled DP service and storage has been unbundled from distribution service. Customers can tailor their storage space and storage injection/withdrawal parameters, under OEB approved allocation methods, to meet their reasonable operational needs.

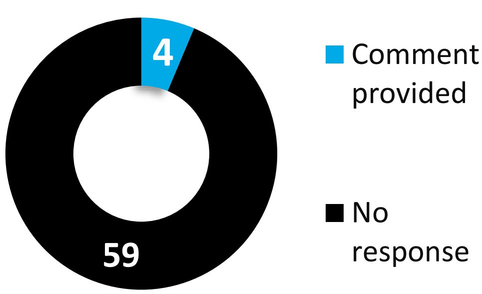
Enbridge Gas is considering expansion of this service beyond the Union South rate zone to bundled customers in areas where the company has the company owned transportation and distribution facilities connected to Enbridge Gas's storage facilities at Dawn [i.e., without the use of transportation facilities owned by third party pipeline companies]. Currently, only bundled customers in the Toronto area of the EGD rate zone meet this requirement.

Expansion of Semi-Unbundled DP Service

Q Which of the following comes closest to your view?
[asked of all respondents; n=63]



Q Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]
[asked of all respondents; n=63]



Comments
“Hard to say without seeing the impact on costs and risks further.”
“How does this impact pricing?”
“Provided this change does not impact existing semi-bundled Union South customers, we have no opinion on this.”
“We may be looking at storage options for future natural gas servicing requirements including for management of our RNG production. Ability to link DPA with storage option for both consumption and production side will be needed.”

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Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 493 of 550

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Capping semi-unbundled direct purchase storage withdrawal rights

In the Union South rate zone, customers that contract for semi-unbundled service with obligated deliveries can choose an allocation of storage deliverability up to the higher of their DCQ or firm CD – obligated DCQ.

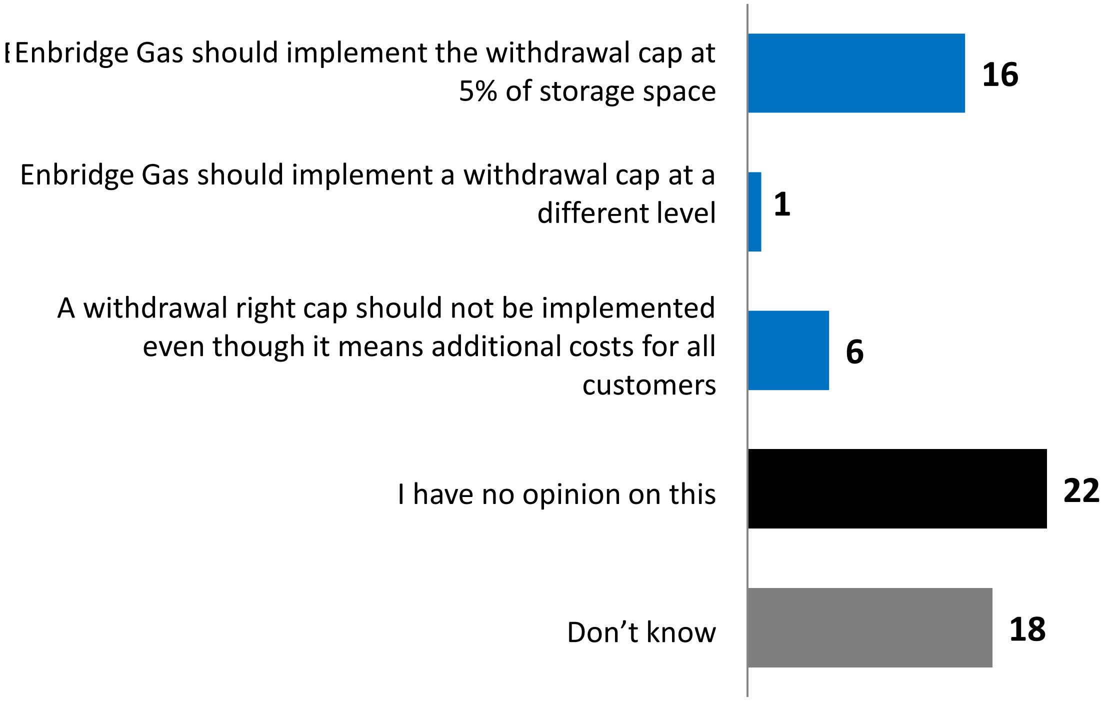
On a peak day in the winter, Enbridge Gas meets contracted peak day needs of its customers with withdrawals from storage generally equivalent to firm CD less obligated DCQ (unless customers have contracted for less). Overall utility peak day deliverability out of storage is approximately 2% of storage space. Through the approved allocation methods, some customers currently receive a significantly higher amount of withdrawal deliverability as a percentage of their contracted storage space. The costs of meeting deliverability is shared by all customers.

Enbridge Gas is considering capping the withdrawal rights resulting from the approved allocation methods to 5% of storage space.

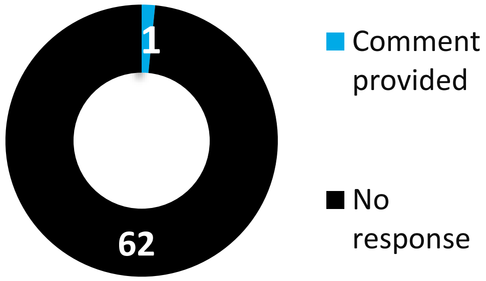
- ✓ This allows from some variability between customer profiles but would reduce the need for Enbridge Gas to purchase deliverability at higher market-based prices and better manage the overall average cost of storage shared by all customers.
- ✓ Most customer allocations are within the 5%.
- ✓ Customers who have their deliverability reduced to 5% would be required to meet their need in excess of the capped amount through additional deliveries of supply in the winter or contracting for market-based deliverability or contracting for an unbundled service or contracting for bundled service.

Capping Semi-Unbundled DP Storage Withdrawal Rights

Q Which of the following comes closest to your view?
[asked of all respondents; n=63]



Q Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]
[asked of all respondents; n=63]



Comments
"Unclear how this cap will interact with firm contract terms at different delivery points."

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Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 495 of 550

Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Utility sale of system gas supply to unbundled (or T-service) direct purchase customers

In the Union North rate zone, unlike the other rate zones, Enbridge Gas provides system gas supply as a source of supply/balancing to meet some of the interruptible consumption of DP customers.

Enbridge Gas is considering the elimination of system supply to meet the needs of unbundled (aka T-service) customers in the Union North rate zone.

- Most of these customers deliver their own gas to the delivery area to meet their interruptible consumption needs and use a Customer Balancing Service (CBS) account (equivalent to 100% of the customer's firm contract demand) to manage daily imbalances between nominated and actual quantities.
- For these customers, the system supply service supplements the CBS and is equivalent to 15% of the customer's firm contract demand.

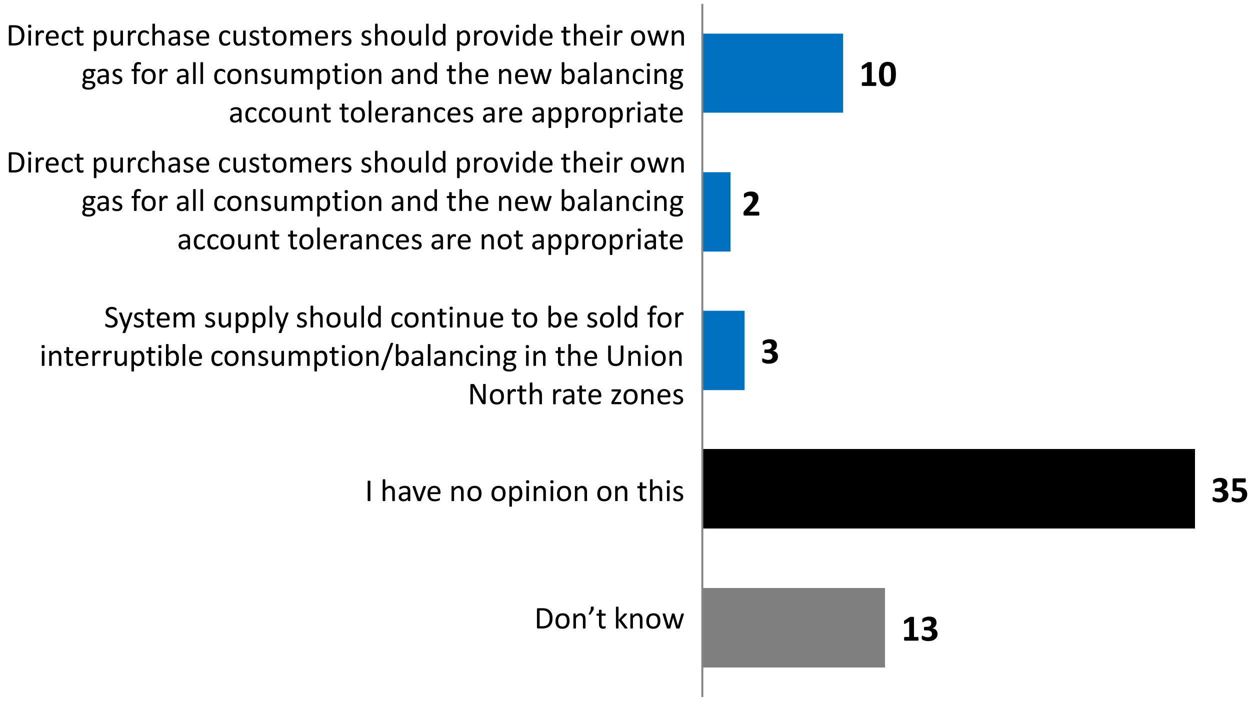
Since Enbridge Gas does not have firm contracted capacity to support system supply and CBS services, both are subject to the same operational availability.

With an elimination of system gas supply for these customers, Enbridge Gas would:

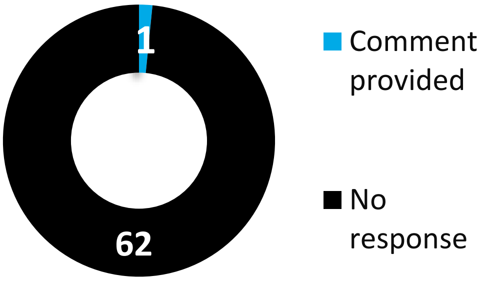
- ✓ Provide Union North T-service customers greater thresholds in the CBS on a daily basis equivalent to what had been available under the utility supply service for a total of 115% of firm contract demand
- ✓ Allow the cumulative balance in the CBS to increase to 150% of firm CD to allow customers time to replace the gas consumed. This provides unbundled DP customers the ability to manage all their gas supply costs.

Sale of System Gas Supply To Unbundled DP Customers

Q Which of the following comes closest to your view?
[asked of all respondents; n=63]



Q Do you have any further thoughts or comments about this proposal that you would like to share? [OPEN]
[asked of all respondents; n=63]



Comments
"We do not have service in Union North; provided this change does not impact semi-bundled Union South customers, we have no opinion on this."

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Customer Experience

Service Harmonization: Direct Purchase (DP) Services

Harmonization of CBS, LLB, and DVA used by unbundled (or T-Service) direct purchase customers

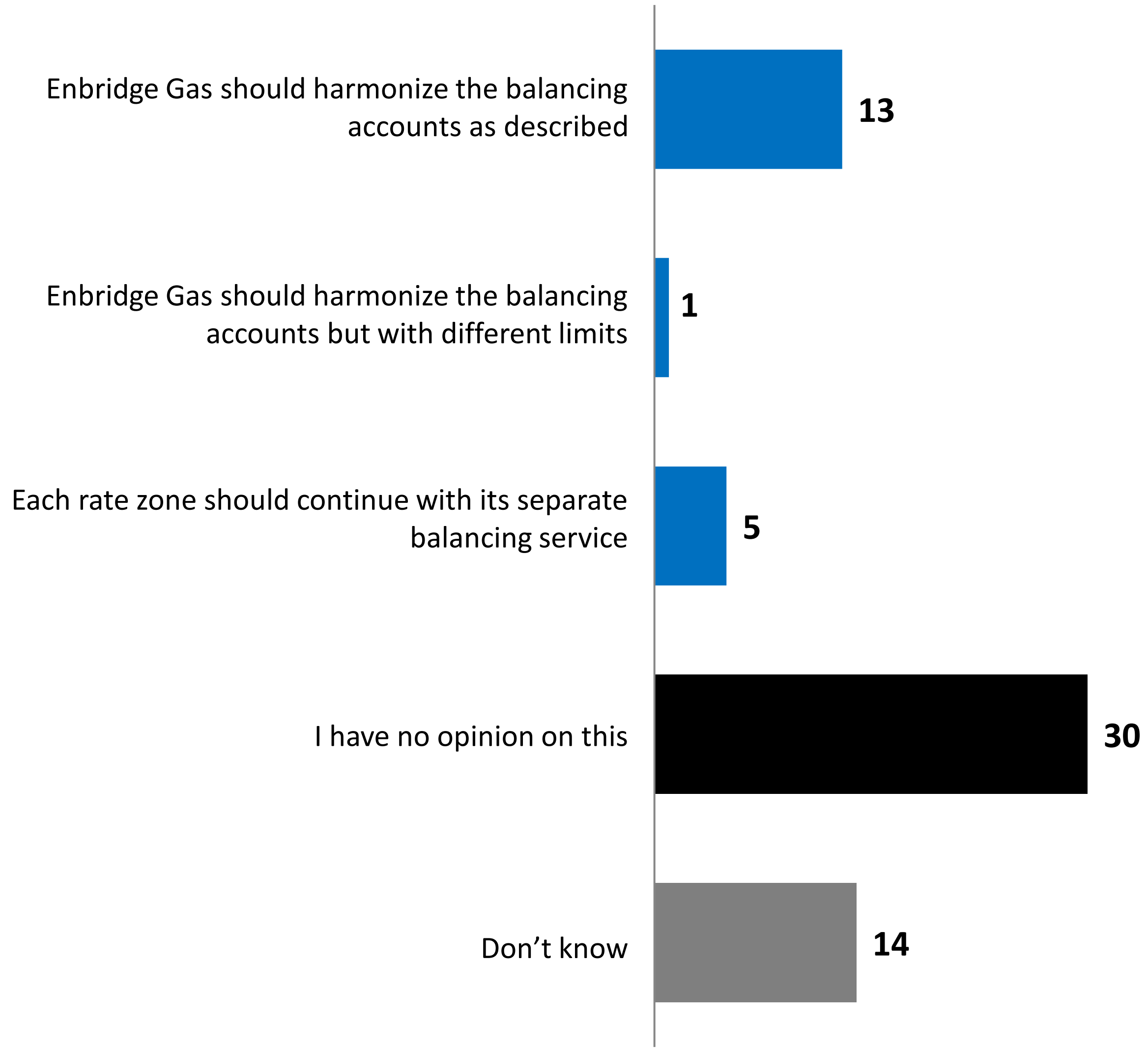
Enbridge Gas is considering harmonizing the limits and operation of the CBS used by unbundled (also known as T-service) customers in the Union North rate zone, the Limited Load Balancing (LLB) service used by unbundled customers in the EGD rate zone, and the Daily Variance Account (DVA) used by certain customers in the Union South rate zone. The customer is required to manage the balance in these accounts within certain tolerances which differ by rate zone/service.

These customers have non-obligated gas deliveries to Enbridge Gas and instead nominate their supply each day to meet their planned consumption on the following day. The purpose of these services/accounts is the same - to capture the small differences that occur between the customer's nominated supply and their actual consumption.

Enbridge Gas is considering harmonizing the service with daily limits set at 115% of firm CD and cumulative limits set at 150%. In addition, the service would be subject to interruption based on Enbridge Gas' daily capability.

Harmonization of CBS, LLB, and DVA

Q Which of the following comes closest to your view?
[asked of all respondents; n=63]



NOTE: Respondents were invited to provide any comments they may have at this point, but none were provided

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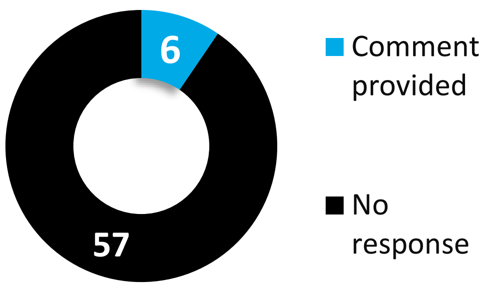
Service Harmonization

Additional Comments

Q

Those are all our questions about the service harmonization proposals.
Do you have any further thoughts or comments you would like to share about the service harmonization for contract rate or direct purchase proposals discussed in this workbook, in the video, or any other services? [OPEN]

[asked of all respondents; n=63]



Comments
"As large volume customer in the north, we are looking for firm delivery. We also do not have internal resources to review and understand service harmonization."
"Please maintain the rate structure currently available in Union South."
"Some better explanations of the penalties that can be occurred with the changes would be helpful for context."
"The proposals and survey attempt to cover all customers with the same content. It is more challenging to understand specifics applicable to us with such broad materials aimed to cover all customers. The lack of opportunity for dialog and clarifications is unusual and we perceive is ineffective."
"We intend to be producing RNG for injection to Enbridge system in a few years. We intend to be entering into BSA with Enbridge although PGA framework will be evolving to other structure (e.g. contracted storage options). Will need to better understand how will manage DPA and link to produced RNG for potential self consumption within managed pool as well as within/outside market sales."
"Will customers who currently have a pool in Enbridge and Union be able to consolidate them if they both deliver at Dawn in future?"

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Online
Workbook Diagnostics

Final Thoughts

Videos Impression

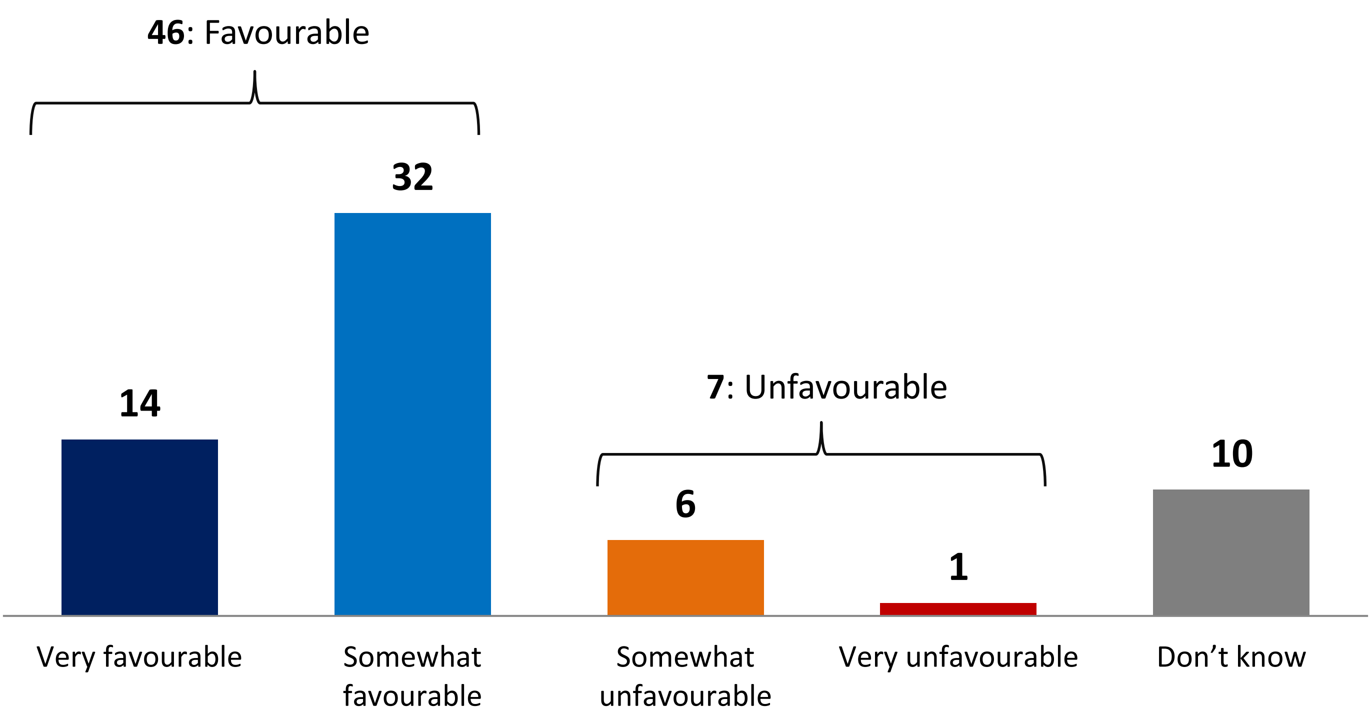
Filed: 2022-10-31, EB-2022-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1, Page 501 of 550

Q

Enbridge Gas values your feedback. This is the first time the utility has conducted a review about its upcoming plans in this type of format.

Thinking about the videos for contract rate distribution services and direct purchase services, please indicate whether you have a favourable or unfavourable impression of those videos.

[asked of all respondents; n=63]

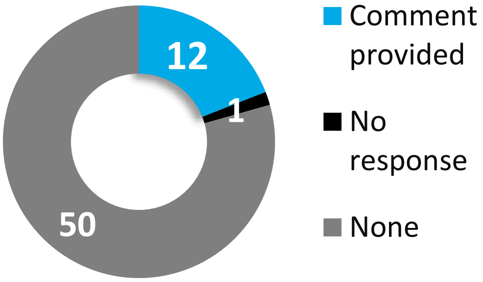


Final Thoughts

Videos Impression – Additional Comments

Q Do you have any suggestions for how the videos could be improved in future consultations? [OPEN]

[asked of all respondents; n=63]

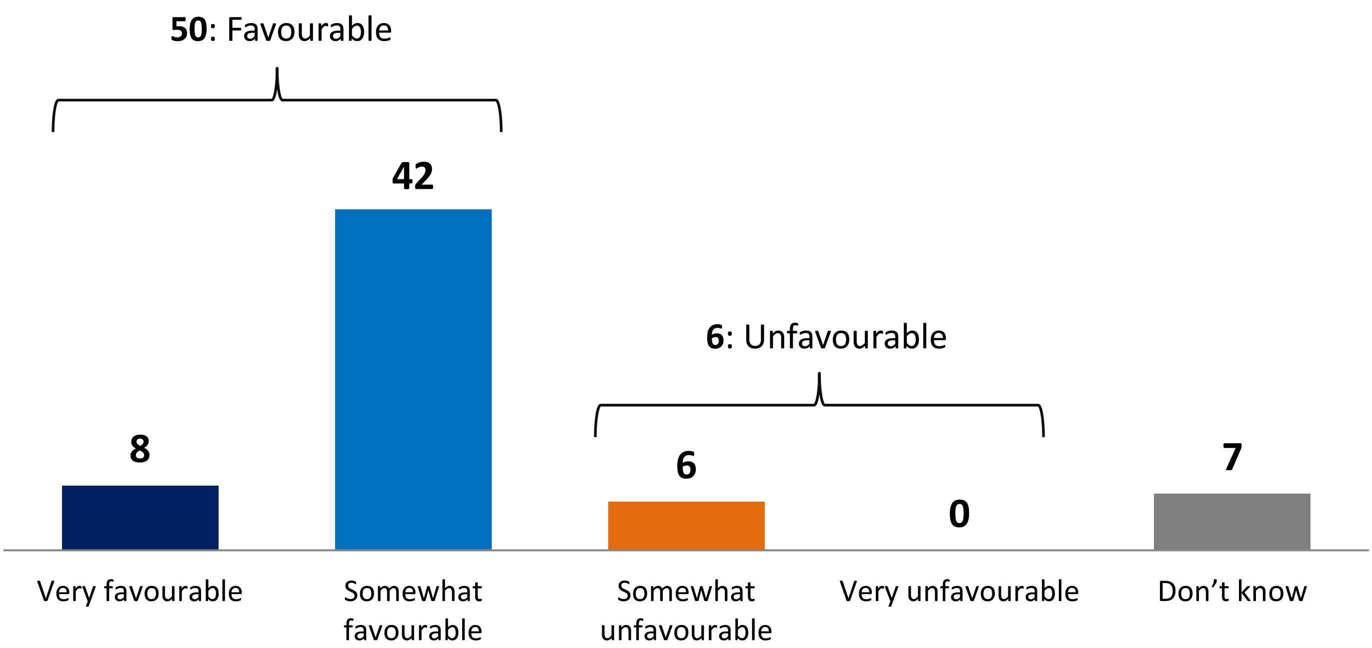


Alternative Approaches
"A direct meeting with some interaction in person, via Zoom or some other platform would be more beneficial."
"More examples instead of just explanation."
"More visuals. Provide pdf of slides."
"Videos could be produced with a customer focus (eg for rate zone, type of customer, etc) instead of appearing to come from a one-size-fits all Enbridge perspective. Examples could be included to show cost impacts.'
Shorten the Length of the Video
"Don't make the videos too long."
"Listening to narrator increases time needed to watch videos - viewers should have the option to manually forward slides once they've had a chance to read."
"Short and clarity."
Other
"Better audio."
"Could not view the videos so I had to read the slides."
"Direct purchase speaker too soft spoken."
"Natural gas distribution choices way too complex for a customer who is not positioned to curtail and who is looking for firm delivery."
"Sound was not great on some."

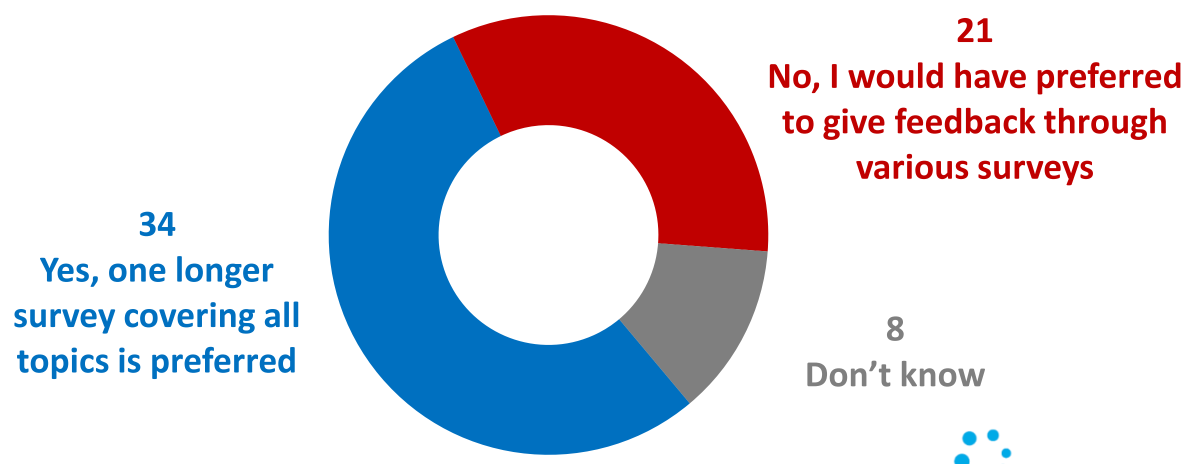
Final Thoughts

Workbook Impression

Q Now thinking about the online workbook, overall, did you have a favourable or unfavourable impression of the workbook you just completed?
[asked of all respondents; n=63]



Q Enbridge Gas indicated that they had a choice of reaching out to customers like you more than once with multiple surveys, or once with a more comprehensive survey that takes longer to complete. Do you feel that Enbridge Gas made the right choice?
[asked of all respondents; n=63]



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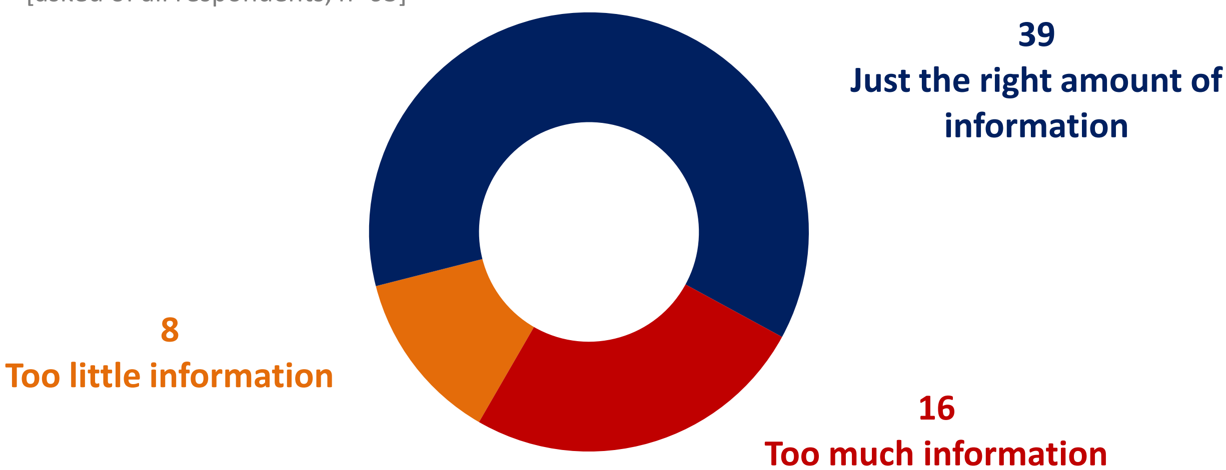
Final Thoughts

Amount of Information

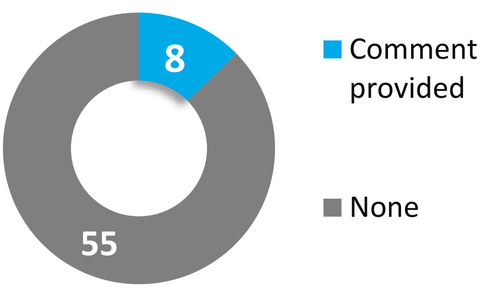
Q In this workbook, do you feel that Enbridge Gas provided too much information, not enough, or just the right amount?

[asked of all respondents; n=63]



Q Was there any content missing that you would have liked to have seen included in this workbook?

[asked of all respondents; n=63]



Comments
"All this is great in theory, what about $ impact."
"Examples with costing."
"Financial/rate impact of service harmonization. The Dawn transport rate should be discounted for customers in Union South and CDA vs customers in North and East."
"More on rate impact of harmonization of DP services. More on how these harmonization efforts may change the availability of market based services or capacity in different areas of the Enbridge system."
"Perhaps for each proposal, how many customers (by volume maybe?) are impacted. To understand magnitude of change."
"Please address your inability to provide firm infrastructure issues in the north."
"Some more links or background content to some of the items that's not directly contained within the pages."
"This workbook was one-size fits-all in nature resulting in customers having to review questions which are not applicable to them or unclear if they are applicable. The lack of ability to go to the prior page made this survey more difficult to complete and likely reduced the quality of the feedback we were able to provide as we were unsure what questions were upcoming. The information provided to ask customers to provide input on trade-offs was inadequate, with benefits not quantified."

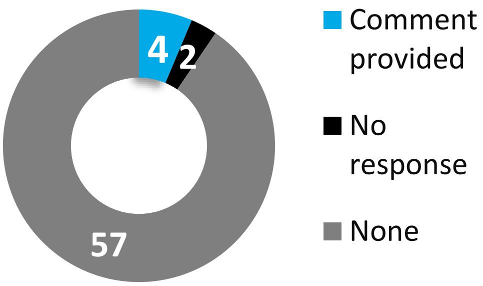
Final Thoughts

Outstanding Questions

Q

Is there anything that you would still like answered?

[asked of all respondents; n=63]



Comments
"Cost impacts of changes to the services."
"How will these harmonization efforts impact M17, LBA, and the availability / rate of market based storage?"
"I think we have to wait and see what the new rate structures will look like."
"Yes, we have several outstanding questions that were described in the survey and have asked our account rep for further specifics for us."

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2024 Rate Rebasing Customer Engagement

ENBRIDGE

Phase Three Report :
Voluntary Residential Survey

January 2022

Project Overview & Methodology

Enbridge Gas 2024 Rate Rebasing Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Enbridge Gas to assist in meeting its customer engagement commitments for its 2024 Rate Rebasing requirements. This engagement had three phrases:

- Phase One was an exploratory phase that used qualitative tools to identify the range of needs and outcomes that matter to customers and to explore some of the trade-offs that Enbridge Gas expected to deal with in their planning process.
- Phase Two used surveys to draw generalizable conclusions regarding the findings from Phase One.
- Following Phase Two, Enbridge Gas developed a draft plan that built on the findings of the first two phases of the customer engagement as well as other business objectives. The Phase Three survey was then designed to provide feedback on that plan that can be used by Enbridge Gas as it finalizes its plan and its submission to the Ontario Energy Board (OEB).

This report summarises the findings of the Phase Three **voluntary** online workbook-style survey with residential customers which was accessible to all Enbridge Gas residential customers and publicized by social media and the Enbridge Gas website. A total of 303 Enbridge Gas customers completed this voluntary version of the workbook, between December 13th, 2021 and January 16th, 2022.

Separate reports summarize the findings of a representative version of the residential Phase Three survey, as well as surveys of business customers.

Voluntary Workbook Results

Environmental Controls & LEAP Qualification

	Voluntary Respondents (n=303)
The cost of my Enbridge Gas bill has a major impact on my finances and requires I do without some other important priorities.	
Strongly agree	26%
Somewhat agree	30%
Somewhat disagree	22%
Strongly disagree	18%
Don't know/No opinion	4%
Customers are well served by the energy system in Ontario.	
Strongly agree	32%
Somewhat agree	43%
Somewhat disagree	10%
Strongly disagree	8%
Don't know/No opinion	6%
LEAP Qualification	
Income <$52k, LEAP Qualified	12%
Income <$52k, not LEAP Qualified	28%
Income >$52k, not LEAP Qualified	35%
Refused	25%

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Voluntary Workbook Results

Summary of planning preferences

	Voluntary Respondents (n=303)
Feedback on Approach	
Right approach	60%
Wrong approach	13%
Don’t know	27%
Understanding Projected Rate Increase	
Very well	21%
Somewhat well	52%
Not very well	16%
Not at all	7%
Don’t know	4%
Compression Stations	
Replace the compressor stations	66%
Defer the compression station project	12%
I don’t have an opinion on this	15%
Don’t know	7%
Vintage Steel Pipeline Replacement Program	
Increase its spending	64%
Defer proactive replacement	15%
I don’t have an opinion on this	12%
Don’t know	10%
Hydrogen Gas	
Should implement these plans	58%
Should not implement these plans	23%
I don’t have an opinion on this	9%
Don’t know	9%

Voluntary Workbook Results

Summary of planning preferences

	Voluntary Respondents (n=303)
Innovation and Technology Fund	
Spending $1M/year	21%
Spending $5M/year	25%
Spending $10M/year	18%
Should not develop a fund to invest	15%
I don’t have an opinion on this	11%
Don’t know	10%
Cut off at Main	
Charge homeowners the full cost	24%
Charge homeowners $750	21%
Should not charge homeowners	36%
I don’t have an opinion on this	9%
Don’t know	10%
Cross Bores	
Should implement the proactive program	31%
Should leave its processes of trenchless drilling	44%
I don’t have an opinion on this	15%
Don’t know	10%
Advanced Meter Infrastructure	
As soon as is feasible	15%
Moderate pace	22%
Slower pace	27%
Replace meters only as required	23%
I don’t have an opinion on this	7%
Don’t know	7%

Voluntary Workbook Results

Summary of planning preferences

	Voluntary Respondents (n=303)
Social Permission	
Should increase its investments	12%
Should maintain the draft increase	50%
Should reduce the draft increase	16%
Other	5%
Don’t know	17%
Social Permission (Increase + Maintain)	61%
Infill Policy	
Offer 15 metres at no cost to the homeowner	33%
Offer 20 metres at no cost to the homeowner	23%
Offer 25 metres at no cost to the homeowner	14%
I don’t have an opinion on this	17%
Don’t know	14%
Rate Zones	
Should implement a single rate zone	46%
Should leave the rate zones as they are	34%
I don’t have an opinion on this	13%
Don’t know	8%
Cost of Being Connected to the System	
Customers should pay a portion based on use	61%
The cost should be paid equally	25%
I don’t have an opinion on this	7%
Don’t know	7%

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Voluntary Workbook Results

Summary of planning preferences

	Voluntary Respondents (n=303)
Cost of Accessing System Capacity	
Customers should pay a portion based on use	66%
The cost should be paid equally	18%
I don't have an opinion on this	8%
Don't know	8%
Responsibly Sourced Gas	
Commit to 10% of responsibly sourced gas	19%
Commit to 25% of responsibly sourced gas	15%
Commit to 50% of responsibly sourced gas	21%
Not add any responsibly sourced gas	28%
I don't have an opinion on this	9%
Don't know	8%
Renewable Natural Gas	
Increasing the amount of RNG in its gas supply to **8%**	14%
Increasing the amount of RNG in its gas supply to **5%**	12%
Increasing the amount of RNG in its gas supply to **2%**	20%
Should not add any RNG to its gas supply	35%
I don't have an opinion on this	10%
Don't know	9%

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Voluntary Workbook Results

Workbook diagnostics

	Voluntary Respondents (n=303)
Overall Impression	
Very favourable	23%
Somewhat favourable	50%
Somewhat unfavourable	13%
Very unfavourable	8%
Don’t know	6%
Amount of Information	
Too little information	23%
Just the right amount	50%
Too much information	13%

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INNOVATIVE RESEARCH GROUP

2024 Rate Rebasing Customer Engagement

ENBRIDGE

Phase Three Report : *Validation Interviews*

February 2022

Project Overview & Methodology

2024 Rate Rebasing Validation Interviews

Innovative Research Group (INNOVATIVE) conducted validation phone calls with Transportation (M12/C1) and Ontario Producers (M13) customers. After customers were consulted on its 2024 Rate Rebasing plan by Enbridge Gas, INNOVATIVE followed-up by telephone in order to validate the process and to verify that Enbridge Gas had provided these customers with the information they needed to provide informed feedback.

The initial Enbridge Gas consultations were held throughout December, 2021 and January, 2022. INNOVATIVE followed up with both M12/C1 and M13 customers that provided their contact information for further contact. All validation interviews were conducted in February, 2022 via telephone, and each lasted approximately five minutes.

NOTE: Results contained within this report are based on a very limited sample and should be interpreted as directional only.

Recruiting Participants

The participants were selected from a client-provided list. This consultation was in conjunction with regular engagement practices between Enbridge Gas and their M12/C1 and M13 accounts.

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Participant Feedback

The following section highlights the general feedback from the Transportation (M12/C1) and the Ontario Producer (M13) customer groups.

Overall Take-Away

There was an overall sense of satisfaction from customers, they appreciated the time, effort, and depth of information that was provided during their consultation.

Coverage of Topics

Multiple customers expressed satisfaction and felt that Enbridge Gas covered areas they expected. One such customer felt the complexity of the topics were conveyed well and felt they were well informed to make decisions.

Another customer expressed trust in Enbridge Gas and the regulator processes to hear their concerns and to make the right choices.

Another customer expressed concerns about there not being enough information regarding costs and cost allocation related to the parkway.

Overall, most customers felt that Enbridge Gas provided adequate information to make informed decisions.

Consultation Process

One customer would have liked further information on how their information and answers were to be used in formulating the 2024 Rate Rebasing application. The customer was unclear of how their answers would impact the potential changes.

The other customers that were interviewed were satisfied with the level of consultation and felt that Enbridge Gas had done a good job providing them with the necessary information.

Validation Interview Questionnaire Results

The following tables are the tabulations of M12/C1 and M13 customer feedback to the validation questions INNOVATIVE asked when following up on Enbridge Gas' interviews with these customer segments.

Numbers in purple denote the total sum

Group	Number of Participants
MC12/C1	**4**
M13	**3**

Q Can you please confirm that you completed the Enbridge Gas customer engagement to discuss their business plan for the period of time starting in 2024 either online or with a representative?

Response	A1	A2	A3	A4	A5	A6	A7	Count
Yes	1	1	1	1	1	1	1	7
No	0	0	0	0	0	0	0	0
Total	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**7**

Q Did Enbridge Gas ask for your feedback on the customer outcomes they should focus on in their business plan development like affordable pricing, reliability, safety and making good use of the money customers pay?

Response	A1	A2	A3	A4	A5	A6	A7	Count
Yes	1	1	1	1	1	1	1	7
No	0	0	0	0	0	0	0	0
Total	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**7**

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Validation Interview Questionnaire Results

Q Did Enbridge Gas ask for your satisfaction with their performance on a number of items including customer service, communications, reliability, etc.?

Response	A1	A2	A3	A4	A5	A6	A7	Count
Yes	1	1	1	0	1	1	1	6
No	0	0	0	1	0	0	0	1
Total	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**7**

Q Did you have a chance to provide any additional comments or leave any questions?

Response	A1	A2	A3	A4	A5	A6	A7	Count
Yes	1	1	1	1	1	1	1	7
No	0	0	0	0	0	0	0	0
Total	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**7**

Q Did Enbridge Gas cover the key areas you expected?

Response	A1	A2	A3	A4	A5	A6	A7	Count
Yes, completely	0	1	0	0	0	1	1	3
Yes, somewhat	1	0	1	0	1	0	0	3
No	0	0	0	1	0	0	0	1
Don’t know	0	0	0	0	0	0	0	0
Total	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**7**

Validation Interview Questionnaire Results

Q Did Enbridge Gas adequately explain the next steps in their customer consultation process?

Response	A1	A2	A3	A4	A5	A6	A7	Count
Yes	1	1	0	1	0	1	1	5
No	0	0	1	0	1	0	0	2
Total	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**7**

Q From what you have experienced so far, how confident are you that Enbridge Gas is committed to addressing customer needs and preferences in their upcoming business plan?

Response	A1	A2	A3	A4	A5	A6	A7	Count
Very confident	0	1	0	0	0	0	1	2
Somewhat confident	1	0	1	0	1	1	0	4
Not very confident	0	0	0	0	0	0	0	0
Not at all confident	0	0	0	0	0	0	0	0
Don’t know	0	0	0	1	0	0	0	1
Total	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**7**

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2024 Rate Rebasing – Customer Engagement Phase 2: Refinement Questionnaire

Telephone & Online Survey

Enbridge Gas Inc.
50 Keil Drive North
Chatham, ON N7M 5M1

Prepared by:

Innovative Research Group, Inc.
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888 Dunsmuir Street, Suite 350
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56 The Esplanade, Suite 310
Toronto, ON | M5E 1A7

Survey Design

Method: Online and Telephone
Language: English
Sample Size: See table below
Sample Frame: Residential Customers who are responsible for paying the bill and Business Customers who are responsible for decisions regarding their natural gas account

Sample Design

Customer Segments	Methodology	Sample Size
Residential	Phone and Online	2400 online, 600 phone
Business (Small, Billed)	Phone and Online	200 total
Business (Medium/Large, Billed)	Phone and Online	200 total

Sample Variables

1. **Type of customer (CUSTOMER) (Residential (CUSTOMER=1) vs Business (CUSTOMER=2))**
2. **Type of Business customer (Small vs Medium/Large)**
3. **For Residential customers – E-billing (Y/N)**
4. **Consumption**
5. **Legacy Utility**
6. **Region**

Notes:

- This document contains the survey questions asked of both residential and Business customers. There are some minor differences in wording and in the actual questions, as noted herein.
- This document contains both the online (longer) and telephone (core questions only) versions of the survey. Minor wording changes were made in the programming of the surveys to make the language appropriate for each mode of data collection. For example, “I am going to read you a list…” in the telephone version was changed to “Below is a list …” in the online version.

Email Invitation Sent by Enbridge Gas – Residential

Subject: Enbridge Gas is planning! Your Opinion Matters!

Dear [FULL NAME FROM SAMPLE],

Enbridge Gas Inc. is undertaking a Customer Engagement process that is designed to understand customers' needs and preferences as it develops its investment plans for 2024 and beyond. The goal of this process is to understand the specific outcomes that are valued by customers like you and to consider these when making key business decisions. Your rates may be impacted by this plan so please take this opportunity to have a say.

For this survey, we would like to hear from someone in your household who is responsible or jointly responsible for decisions regarding natural gas such as viewing and paying your natural gas bill. If that is not you, please forward this email to the appropriate person.

As an Enbridge Gas customer, you are invited to complete an online survey. This survey will take approximately 15 minutes to complete, and if you're unable to complete it in one session, you can pick up where you left off by clicking the survey link again – your progress will be saved. We kindly ask that you complete the survey prior to August 22, 2021 by clicking the link below.

Start Survey

To ensure all responses are kept anonymous and confidential, all survey responses will be collected by INNOVATIVE Research Group, an independent market research company. If you would like to verify the authenticity of this survey or would like more information about the survey you can contact marketresearch@enbridge.com.

If you have any problems with the above link please copy and paste the following address into your web browser.

Survey Link: >>>>

Many thanks in advance for your time and input into this planning process.

Enbridge Gas Inc.

Email Invitation Sent by Enbridge Gas – Business

Dear [FULL NAME FROM SAMPLE],

Enbridge Gas Inc. is undertaking a Customer Engagement process that is designed to understand customers' needs and preferences as it develops its investment plans for 2024 and beyond. The goal of this process is to understand the specific outcomes that are valued by customers like you and to consider these when making key business decisions. Your rates may be impacted by this plan so please take this opportunity to have a say.

For this survey, we would like to hear from the person in your organization who is responsible or jointly responsible for decisions regarding your natural gas account. If that is not you, please forward this email to the appropriate person. As an Enbridge Gas customer, you are invited to complete an online survey. This survey will take approximately 15 minutes to complete, and if you're unable to complete it in one session, you can pick up where you left off by clicking the survey link again – your progress will be saved. In appreciation of your time and input, once you have completed the survey, you will be entered into a draw for one of two $500 cash prizes. We kindly ask that you complete the survey prior to August 22, 2021 by clicking the link below.

Start Survey

To ensure all responses are kept anonymous and confidential, all survey responses will be collected by INNOVATIVE Research Group, an independent market research company. If you would like to verify the authenticity of this survey or would like more information about the survey you can contact marketresearch@enbridge.com.

If you have any problems with the above link please copy and paste the following address into your web browser.

Survey Link: >>>>

Many thanks in advance for your time and input into this planning process.

Enbridge Gas Inc.

Please do not "**Reply**" to this email. This mailbox is not regularly monitored. To stop receiving invitations for our online surveys, please click here to unsubscribe. Your privacy is important to us. For more information please review our Privacy Policy.

Introduction – Telephone Only

[IF RESIDENTIAL CUSTOMER (CUSTOMER=1)]

Hello, my name is ____. I'm calling from Innovative Research Group, a national public opinion research firm. Today, we are conducting a customer survey for Enbridge Gas about your natural gas service as Enbridge Gas develops its investment plans for 2024 and beyond.

I assure you we are not selling anything; we are only interested in your opinions and all of your answers will be kept strictly confidential. This call will take approximately 20 minutes and may be monitored or recorded for quality assurance purposes.

Can I speak with the person in your household who is responsible or jointly responsible for decisions regarding natural gas such as viewing and paying your natural gas bill?

01	Yes – Continue	
02	No – Ask to speak with person	
03	Unavailable – Schedule call back	
97	Do not receive a natural gas bill	**[THANK & TERMINATE]**
98	DK or REFUSE	**[THANK & TERMINATE]**

Thank you. I have some questions to see if you qualify for this study.

[IF BUSINESS CUSTOMER (CUSTOMER=2)]

Hello, my name is ____. I'm calling from Innovative Research Group, a national public opinion research firm. Today, we are conducting a customer survey for Enbridge Gas about your natural gas service as Enbridge Gas develops its investment plans for 2024 and beyond.

I assure you we are not selling anything; we are only interested in your opinions and all of your answers will be kept strictly confidential. This call will take approximately 20 minutes and may be monitored or recorded for quality assurance purposes. In appreciation of your time, upon completion of the survey, you will be entered into a draw for one of two $500 cash prizes.

Can I speak with the person in your organization who is responsible or jointly responsible for decisions regarding your natural gas account?

01	Yes – Continue	
02	No – Ask to speak with person	
03	Unavailable – Schedule call back	
97	Do not receive a natural gas bill	**[THANK & TERMINATE]**
98	DK or REFUSE	**[THANK & TERMINATE]**

Thank you. I have some questions to see if you qualify for this study.

A. SCREENER

Screening for qualified respondents

[ONLY ASK A1-A3 IF RESIDENTIAL CUSTOMER (CUSTOMER=1)]

A1. In what year were you born?

	[RANGE 1850-2021]	**[SKIP NEXT QUESTION]**
99	Prefer not to answer	

A2. Which of the following age categories do you fall into?

96	Under 18	**[THANK & TERMINATE]**
01	18 to 24	
02	25 to 44	
03	45 to 64	
04	65 to 74	
05	75 or older	
99	Prefer not to answer	

A3. Do you, or does anyone else in your immediate family work in any of the following areas?

01	Marketing research	**[THANK & TERMINATE]**
02	Energy providers, such as natural gas, oil, electricity, propane	
03	A gas equipment or appliance contractor or retailer	
04	Energy sector regulator or intervener	
97	None of the above	**[MUTUALLY EXCLUSIVE]**

[ONLY ASK A4-A6 IF BUSINESS CUSTOMER (CUSTOMER=2)]

A4. To confirm, does your organization receive a natural gas bill from Enbridge Gas?

01	Yes	
02	No	**[THANK & TERMINATE:** Thank you for your interest, but this survey is for customers who receive and pay their natural gas bill]
99	Don't know	

A5. Are you responsible or partially responsible for decisions regarding your natural gas account for your organization?

01	Yes	**[SKIP TO INTRODUCTION]**
02	No	
99	Don't know	

Note: in the online version, the survey terminates if the person selects "no" or "don't know" in A5.

Note: A6 is only asked in the telephone survey.

A6. May I speak to the person who is responsible or partially responsible for decisions regarding your natural gas account for your organization?

01	Yes	
02	No	**[THANK & TERMINATE]**
99	Don't know	**[THANK & TERMINATE]**

And … can I have their …

First Name ______________

Last Name ______________

Title/Position ____________

Phone Number ___________

ASK to be transferred …

- **if transferred → go to INTRODUCTION**
- **if not transferred → Thank & Add to Callback List**

B. INTRODUCTION

Enbridge Gas is preparing its business plan to be implemented in 2024 and would like to hear your feedback on a number of things that it is considering in this plan.

Near the end of this survey, you will have the opportunity to provide any additional feedback that you would like to share with Enbridge Gas.

Throughout this survey, if you aren't sure what your response is, please say so. Thank you in advance for your feedback and participation!

C. SATISFACTION

Let's talk about your overall experience with Enbridge Gas.

C7. Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

01	Very satisfied	
02	Somewhat satisfied	
03	Neither satisfied nor dissatisfied	
04	Somewhat dissatisfied	
05	Very dissatisfied	
99	I Don't know	

[ASK C8 IF CUSTOMER=2 (BUSINESS) AND 03, 04 OR 05 AT C7]

C8. Is there anything in particular Enbridge Gas can do to improve their service?
[OPEN-ENDED]

D. CUSTOMER OUTCOMES

In considering its business plan to be implemented starting in 2024, Enbridge Gas must make many decisions. We would like your feedback on the outcomes you would like Enbridge Gas to focus on in its plan. Outcomes are the goals and priorities that matter to you.

There is a list of broad outcomes that Enbridge Gas will need to consider. Using a scale from 0 to 10, where 0 means "not at all important" and 10 means "extremely important", please tell us how important each one is to you. Be sure to save a rating of 10 for those items that are most important to you. (IF NECESSARY: If you don't know just say so.) How about… (read list) (Repeat scale as necessary)

[RANDOMIZE]

D9. Reliably delivering natural gas
D10. Safely delivering natural gas
D11. Making good use of the money customers pay
D12. Providing affordable pricing
D13. Providing predictable pricing
D14. Providing dependable customer service
D15. Minimizing any impacts on the environment
D16. Being socially responsible
D17. Supporting the growth of Ontario's economy

00	Not at all important	
01-09		
10	Extremely important	
99	Don't know	

D18. Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which one would you say is most important to you as a customer? If you don't know, just say so.

[USE THE SAME RANDOMIZATION ORDER AT D9-D17]

01	Reliably delivering natural gas	
02	Safely delivering natural gas	
03	Making good use of the money customers pay	
04	Providing affordable pricing	
05	Providing predictable pricing	
06	Providing dependable customer service	
07	Minimizing any impacts on the environment	
08	Being socially responsible	
09	Supporting the growth of Ontario's economy	
99	Don't know	**[SKIP TO NEXT SECTION]**

D19. And which one is second most important to you?
[INSERT LIST, REMOVE ITEM SELECTED AT D18]

D20. And, finally, which one is third most important to you?
[INSERT LIST, REMOVE ITEM SELECTED AT D18 and D19]

E. ASSET MANAGEMENT

Thinking about the level of safety, reliability, and customer service you receive from Enbridge Gas would you like to see the company invest in maintaining or invest in improving upon the current level? How about [INSERT ITEM]? Should Enbridge Gas [INSERT RESPONSE OPTIONS]?

01	Invest in maintaining the current level	
02	Invest in improving the current level	
99	Don't know	

[RANDOMIZE E21-E23]

E21. Safety
E22. Reliability
E23. Customer service

E24. Thinking generally about Enbridge Gas' budget for replacing pipelines and equipment that deliver gas to your **[home/organization]**, which of the following statements best represents your point of view?

[RANDOMIZE 01 AND 02]

01	Enbridge Gas should look at the long-term health of the system and spread costs out evenly over time even if that means higher rates now
02	Enbridge Gas should focus on the immediate impact on rates and only spend what it takes to keep the system in good order now to keep rates low, even if that means an increase in rates later that may end up being more expensive for customers overall
98	I don't have an opinion on this
99	Don't know

F. RATES

Note: F25 and F26, F27 and their preambles were only asked in the online survey.

Enbridge Gas is the only distributor of natural gas service in your area and there is not a competitive market in which rates are determined. For this reason, the Ontario Energy Board (OEB) reviews and approves all Enbridge Gas costs (that is, the costs to operate), and also reviews and approves how customer rates should be calculated.

Enbridge Gas incurs two types of costs in delivering natural gas to your **[home/organization]**, those that are variable and those that are fixed.

One of these is the cost of the natural gas that customers use. This cost is determined by the market and will be passed on to you based on your measured consumption of natural gas.

The fixed costs that Enbridge Gas incurs can be divided into two groups.

[RANDOMIZE PREAMBLE AND F25 WITH PREAMBLE AND F26]

One type of fixed cost is that of being connected to the network. This includes the cost of the pipeline, the pressure regulator, the natural gas meter, meter reading, billing, the contact centre and operations support. These costs are fixed for Enbridge Gas, and are similar for each customer and do not change based on the size of the customer.

F25. How do you feel **[residential/business]** customers like you should be billed for these costs of being connected to the network?

[RANDOMIZE 01 AND 02]

01	Each customer should pay a portion based on the amount of natural gas they use
02	The cost should be paid equally by customers of the same type (i.e. residential or business)
98	I don't have an opinion on this
99	Don't know

One type of fixed cost is that of the network capacity. This includes the cost of the network infrastructure, its operation, maintenance, and natural gas storage to meet the peak demand of customers on the coldest days of the year. These costs are fixed for Enbridge Gas, but may vary for each customer based on their individual level of peak demand.

F26. How do you feel **[residential/business]** customers like you should be billed for these costs of accessing network capacity?

[RANDOMIZE 01 AND 02]

01	Each customer should pay a portion based on the amount of natural gas they use on the coldest days of the year
02	The cost should be paid equally by customers of the same type (i.e. residential or business)
98	I don't have an opinion on this
99	Don't know

[IF RESIDENTIAL CUSTOMER (CUSTOMER=1)]

Enbridge Gas, today, is a combination of Legacy Union Gas and Legacy Enbridge Gas Distribution. Currently there are three rate zones which result in customers paying different rates depending on where you are located in the province and which company you were served by prior to the merger. Enbridge Gas is considering the option of offering one rate zone for its different types of customers, regardless of location within Ontario. There are many benefits of one rate zone including similar charges for similar customers, a consistent customer experience, and reduced administrative costs.

One rate zone could result in a change to the amount you pay today for your natural gas service. Approximately 60% of customers will see very little change to the amount they pay today. Approximately 30% of customers will see an increase of roughly 5% (or roughly $5 per month). Approximately 10% of customers will see a decrease of roughly 10% (or roughly $10 per month).

F27. Considering this, which of the following is closest to your view?
[RANDOMIZE 01 AND 02]

01	Enbridge Gas should implement a single rate zone and make the rates for natural gas service the same across Ontario
02	Enbridge Gas should leave the rate zones as they are where customers pay different rates for natural gas service based on where they [live/operate]
98	I don’t have an opinion on this
99	Don’t know

Note: F28 was asked in the telephone and online versions of the survey.

[IF BUSINESS CUSTOMER (CUSTOMER=2)]

Enbridge Gas, today, is a combination of Legacy Union Gas and Legacy Enbridge Gas Distribution. Currently there are three rate zones which result in customers paying different rates depending on where you are located in the province and which company you were served by prior to the merger. Enbridge Gas is considering the option of offering one rate zone for its different types of customers, regardless of location within Ontario. There are many benefits of one rate zone including similar charges for similar customers, a consistent customer experience, and reduced administrative costs.

One rate zone could result in a change to the amount you pay today for your natural gas service. The impact is dependent on the amount of natural gas you use but could range from +5% to -10% of the amount you pay today.

F28. Considering this, which of the following is closest to your view? If you don’t have an opinion or are not sure, please say so.

01	Enbridge Gas should implement a single rate zone and make the rates for natural gas service the same across Ontario

02	Enbridge Gas should leave the rate zones as they are where customers pay different rates for natural gas service based on where they [live/operate]
98	I don’t have an opinion on this
99	Don’t know

G. CUSTOMER CARE

G29. When you consider options for paying your bill, how important is it to you that Enbridge Gas provides customers the option to pay their bills by credit card?

01	Very important	
02	Somewhat important	
03	Not very important	
04	Not at all important	
99	Don't know	

G30. Credit card companies charge Enbridge Gas a fee for any payments that customers make by credit card. Do you believe that the costs of those credit card charges should be spread out among all customers, or should customers who choose to pay by credit card pay for these charges? If you don't have an opinion on this question or are not sure just say so.

[ROTATE 01 AND 02]

01	Spread out among all customers	
02	Paid by the customer choosing to pay by credit card	
98	I don't have an opinion on this	
99	Don't know	

[ASK G31 IF CUSTOMER=2 (BUSINESS)]

G31. One of the tools that Enbridge Gas offers customers is a customer service team that can respond to phone calls or emails. How important is it to you that business customers like you have a dedicated team to respond to business customers specifically?

01	Very important	
02	Somewhat important	
03	Not very important	
04	Not at all important	
99	Don't know	

H. New or Harmonized Programs and Policies

Note: H32, H33 and H34 and their corresponding preambles were only asked in the online survey.

Cross Bore

While rare, it is possible that a natural gas line may intersect with a sewer line. When this happens, it is called a utility cross bore. This is unintentionally created when a natural gas line is installed through a process of trenchless drilling. Trenchless drilling is used to avoid creating open trenches that can disturb roads, driveways, and gardens, but it relies on locates of existing utilities which may not always be accurate for various reasons. While a utility cross bore may not pose an immediate risk, it may become an issue if a sewer line needs to be cleared in the case of a blockage.

Enbridge Gas intends to implement a program to proactively inspect and resolve any utility cross bores that may have been installed in the past. Also, a program has been implemented to prevent new installations from creating new cross bores even though that will increase the cost of the installation and require additional restoration work.

H32. These programs to proactively inspect and resolve existing cross bores and to prevent the creation of cross bores during the completion of new installations combined would cost customers $0.50 per year for 5 years. Which of the following is closest to your view?

[RANDOMIZE 01 AND 02]

01	Enbridge Gas should implement the proactive program and continue with the preventative program to eliminate existing cross bores and prevent any new cross bores to maintain safety, even though it costs more.
02	Enbridge Gas should leave its processes of trenchless drilling as is and only resolve those that come up as an issue arises, even though this may create additional cross bores which increases safety risk.
98	I don't have an opinion on this
99	Don't know

Infill Policy – RESIDENTIAL CUSTOMERS ONLY

[ASK IF CUSTOMER=1 (RESIDENTIAL)]

When an existing home is located near a main line, it may receive a natural gas connection through the residential infill policy. Under regulations, existing customers cannot be charged for any of these expenses.

According to the policy, connections are provided to homeowners at no cost (because forecasted revenues cover a portion of the cost to connect) up to a certain distance from the home to the main line. The cost for any extra distance must be paid by the homeowner. These costs can be structured in a number of different ways, and currently vary depending on whether someone is in the Legacy Enbridge Gas or Legacy Union Gas area.

H33. Enbridge Gas would like to create a policy that is the same across the entire territory and would like to ask you for your opinion. Thinking about general principles, which of the following approaches is closest to your view?

[RANDOMIZE 01 THROUGH 05]

01	Enbridge Gas should offer a shorter distance of the pipe at no cost, and charge a lower cost per meter for the remaining length to the homeowner
02	Enbridge Gas should offer a longer distance of the pipe at no cost, and charge a higher cost per meter for the remaining length to the homeowner
03	Enbridge Gas should determine a flat rate that would require each homeowner to pay the same amount regardless of the length of the pipeline required
04	Enbridge Gas should offer a cost per meter for the entire length of the pipe
05	Enbridge Gas should develop a full feasibility study for each new attachment, even if this requires additional resources, and charge homeowners the actual cost of the installation
98	I don’t have an opinion on this
99	Don’t know

Cut off at Main – RESIDENTIAL CUSTOMERS ONLY

[ASK IF CUSTOMER=1 (RESIDENTIAL)]

When a customer wants to cut off the natural gas service, for example, when a home is being demolished, when there has been a fire, or when a customer no longer wishes to receive natural gas service, the service is cut off at the main pipeline. This work is performed by a maintenance and construction crew. After that, in many cases a new home can be attached again at the same location. Not doing this work creates abandoned natural gas lines and meters, which may pose a safety risk.

Any costs not charged to the homeowner are covered by Enbridge Gas, which means all ratepayers contribute to these costs through their rates.

H34. Enbridge Gas would like to create a policy that is the same across the entire territory and would like to ask you for your opinion. Which of the following is closest to your view?

[RANDOMLY FLIP ORDER OF FIRST 3 OPTIONS]

01	Enbridge Gas should charge the homeowner the full cost of the cut off at main.
02	Enbridge Gas should charge a portion of the cost to the homeowner, ensuring that costs are not too prohibitive that natural gas lines are not left in an unsafe condition.
03	Enbridge Gas should not charge the homeowner for these costs of the cut off at main. These costs should be shared among all ratepayers.
98	I don’t have an opinion on this
99	Don’t know

Automated Meter Infrastructure – ASK ALL

The gas meter technology currently used by Enbridge Gas has not changed in many years. There are new, advanced, meters available that would send the usage information to Enbridge Gas through a wireless network, similar to your electricity or water usage meters.

Please tell me how important each of these features is to you.

01	Very important
02	Somewhat important
03	Not very important
04	Not at all important
99	Don't know

[RANDOMIZE]

H35. Enable Enbridge Gas to remotely and automatically shutoff gas supply if needed in the event of an emergency
H36. Enable Enbridge Gas to better detect and respond to possible gas leaks
H37. Lower GHG emissions by reducing meter reader vehicles on the road
H38. Enable access to more accurate, hourly updates to better understand and manage your natural gas use
H39. Eliminate Enbridge Gas' need to regularly access your property to conduct a meter reading
H40. Eliminate the need for estimated meter reads (where your usage and bill are estimated and adjusted in a following month)

I. ENERGY TRANSITION

Let's look ahead and think about the future.

Thinking about everything you know today, and considering any changes that you might expect in the future as it relates to all the energy choices available to you, how much natural gas do you think **[someone like you/an organization like yours]** will be using in **(INSERT TIME)**, compared to today? How about in **(INSERT other TIME)**?

01	Significantly less
02	Somewhat less
03	About the same
04	Somewhat more
05	Significantly more
99	Don't know

[DO NOT RANDOMIZE]

I41. 10 years
I42. 30 years

When you consider options and solutions to reduce impacts on the environment, please tell me whether you agree or disagree with the following statements.

01	Completely agree
02	Somewhat agree
03	Neither agree nor disagree
04	Somewhat disagree
05	Completely disagree
99	Don't know

[RANDOMIZE]

I43. Enbridge Gas should actively be investing in low-carbon options and solutions that would help reduce impacts on the environment
I44. Given its experience, Enbridge Gas is well positioned to support the development of low-carbon options and solutions
I45. I look to Enbridge Gas to help develop offerings and new solutions that will help me reduce my natural gas usage

[END BATTERY]

Note: I46, I47, I48 and I49 and their corresponding preambles were only asked in the online survey.

Let's focus on some ways that Enbridge Gas can help minimize any impacts on the environment. Following are descriptions of three potential ways in which Enbridge Gas can minimize the impact of natural gas on the environment.

[RANDOMIZE PREAMBLE+I46, PREAMBLE+I47 AND PREAMBLE+I48]

Reduce demand / avoid new infrastructure (IRP)

When considering new or expanded pipeline projects, Enbridge Gas is required to evaluate whether alternatives are available that would eliminate the need for the project altogether. This would mean looking for ways to help 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, adding insulation, or upgrading your furnace or water heater. It could also include delivering compressed natural gas by truck or train to locations where pipelines do not exist. Other alternatives that reduce the need for natural gas might include geothermal heating and cooling, or air source heat pumps.

I46. How much, if anything, would **[you/your organization]** be willing to pay per year for Enbridge Gas to develop solutions in natural gas conservation and other non-pipeline alternatives instead of new pipeline or capacity projects?

[RANDOMIZE SCALE IN ASCENDING VS DESCENDING ORDER]

Residential response choices are in blue

Business response choices are in red

01	$1.00/month or $12.00 extra per year / 2% added to the delivery portion of your bill
02	$2.00/month or $24.00 extra per year / 4% added to the delivery portion of your bill
03	$4.00/month or $48.00 extra per year / 8% added to the delivery portion of your bill
04	$10.00/month or $120.00 extra per year / 10% added to the delivery portion of your bill
88	Some other amount per month [ON-SCREEN INSTRUCTION: [RES] Please enter a numeric response in the space below. You may use a decimal point, but do not include a dollar sign. [BUS] Please enter a numeric response in the space below. Do not include the % sign.]
97	I would not be willing to pay anything extra
99	Don't know

Low-carbon options / greening the gas

Other options Enbridge Gas may invest in that focus on reducing the amount of greenhouse gas emissions can include options that "green the gas." An example of this would be blending traditional natural gas with greener sources of gas, such as renewable natural gas derived from organic waste from farms, landfills, and water treatment plants, or hydrogen gas derived from using surplus electrical energy that is converted to hydrogen gas through electrolysis technology.

I47. How much, if anything, would **[you/your organization]** be willing to pay per year for Enbridge

Gas to develop solutions in greening the gas to reduce the greenhouse gas emissions from the use of natural gas?

[RANDOMIZE SCALE IN ASCENDING VS DESCENDING ORDER]

01	$1.00/month or $12.00 extra per year / 2% added to the delivery portion of your bill
02	$2.00/month or $24.00 extra per year / 4% added to the delivery portion of your bill
03	$4.00/month or $48.00 extra per year / 8% added to the delivery portion of your bill
04	$10.00/month or $120.00 extra per year / 10% added to the delivery portion of your bill
88	Some other amount per month [ON-SCREEN INSTRUCTION: [RES] Please enter a numeric response in the space below. You may use a decimal point, but do not include a dollar sign. [BUS] Please enter a numeric response in the space below. Do not include the % sign.]
97	I would not be willing to pay anything extra
99	Don't know

New Technologies

Enbridge Gas can also support the advancement of various new low-carbon or energy efficient technologies that may not exist today. This would include participating in new research, development and supporting various pilot projects.

I48. How much, if anything, would **[you/your organization]** be willing to pay per year for Enbridge Gas to develop solutions in developing and advancing new low-carbon and energy efficient technologies?

[RANDOMIZE SCALE IN ASCENDING VS DESCENDING ORDER]

01	$1.00/month or $12.00 extra per year / 2% added to the delivery portion of your bill
02	$2.00/month or $24.00 extra per year / 4% added to the delivery portion of your bill
03	$4.00/month or $48.00 extra per year / 8% added to the delivery portion of your bill
04	$10.00/month or $120.00 extra per year / 10% added to the delivery portion of your bill
88	Some other amount per month [ON-SCREEN INSTRUCTION: [RES] Please enter a numeric response in the space below. You may use a decimal point, but do not include a dollar sign. [BUS] Please enter a numeric response in the space below. Do not include the % sign.]
97	I would not be willing to pay anything extra
99	Don't know

Certified natural gas

Enbridge Gas is looking at options to ensure that the natural gas it purchases is responsibly sourced. This means the companies who produce the natural gas adhere to higher standards than the minimum government standards. This relates to areas such as minimizing impacts to air and water quality, lowering carbon emissions during production, and stronger engagement with Indigenous communities, etc. While it may not always cost more, it is possible that this responsibly sourced natural gas comes at a small premium and would cost customers a little bit more.

I49. Considering this, would you support Enbridge Gas sourcing this type of natural gas to deliver to **[you/your organization]**, even if it comes at a small premium?

01	Definitely support
02	Somewhat support
03	Neither support nor oppose
04	Somewhat oppose
05	Definitely oppose
99	Don't know

J. ADDITIONAL COMMENTS

J50. Is there anything that you would like to share with Enbridge Gas as it works on building its investment plan for the future?

[OPEN-ENDED]

K. RESIDENTIAL DEMOGRAPHICS

[ASK SECTION L ONLY IF CUSTOMER=1 (RESIDENTIAL)]

These last few questions are for statistical purposes only, and all of your responses are confidential.

K51. Including yourself, how many people in total live in your household?

	[RANGE 1 TO 100]
99	Prefer not to answer

K52. Which of the following best describes your total annual household income (after taxes)? *Please stop me when I get to your response… **READ LIST***

01	$28,000 or less	**[COMBINE WITH K51 TO DETERMINE LEAP QUALIFICATION]**
02	Between $28,001 and $39,000	
03	Between $39,001 and $48,000	
04	Between $48,001 and $52,000	
05	Between $52,001 and $72,000	
06	Between $72,000 and $81,300	
07	Between $81,301 and $90,500	
08	Over $90,500	
99	Prefer not to answer	

L. FIRMOGRAPHICS

[ASK ONLY IF CUSTOMER=2 (BUSINESS)]

L53. Approximately how many employees, including yourself, does your company presently employ at this location?

[RANGE 1-999999]

99	Don't know

L54. How do you use natural gas at your organization? Please check as many as apply.

01	Natural gas is used in production process
02	Natural gas is used as feedstock
03	Natural gas is used for heating or space conditioning
04	Natural gas is used for water heating
88	Other
99	Don't know

M. THE END

Those are all the questions we have for you. It is greatly appreciated and very helpful that you took the time to help us serve you better. On behalf of Enbridge Gas, thank you.

[ASK ONLY IF CUSTOMER=2 (BUSINESS)]

In order to make sure we are entering the correct person in the prize draw, may I please get your full name and mailing address?

FIRST NAME
LAST NAME
STREET ADDRESS
CITY
POSTAL CODE
PHONE NUMBER
[PROVIDE OPTION TO REFUSE INCENTIVE]

2024 Rebasing Report

Customer Engagement

Transportation (M12/C1) Customers

ENBRIDGE
Life Takes Energy

February 2022

Prepared by Customer & Market Insights

STRICTLY PRIVILEGED AND CONFIDENTIAL

Project Overview

Enbridge Gas 2024 Rate Rebasing Customer Engagement

Enbridge Gas is undertaking a customer engagement process that is designed to gather feedback from customers on their needs and preferences. These are incorporated in the business planning process for 2024 and beyond.

This report summarizes the findings of consultations with M12/C1 customers. Separate reports summarize the findings of consultations with other groups of customers.

Methodology

Enbridge Gas invited customers to complete a “workbook-style” survey to ensure the opinions collected on these issues were informed opinions. Through the workbook, customers were provided key background information on Enbridge Gas and its network as well as background relevant to various choices.

Customers were given the option to complete the workbook online or to meet with an Enbridge Gas representative to discuss the questions in the workbook and complete the workbook together.

The workbook was available online between December 8, 2021, and January 31, 2022.

A total of 15 customers completed the workbook during this time.

All figures in this report are counts (i.e. number of responses) rather than percentages due to the limited number of responses.

Customers include those in the transportation market segments which include the following: Canadian Local Distribution Companies (LDCs), Interconnecting Pipelines, Marketers, Power Generators, and US LDCs. All customers interviewed as part of the consultation process were members of Gas Supply, Regulatory, Commercial or Operational departments at their respective companies.

About this Customer Engagement

Welcome to the Enbridge Gas Customer Engagement!

- Enbridge Gas is looking for your feedback to support its investment plan for 2024 and beyond to ensure that plan reflects your needs and preferences.
- You don't need to be a natural gas expert to complete this workbook. It focuses on choices between outcomes that matter to you and provides the background information you need to answer the questions.

If you are completing this workbook online, please note that it will take approximately 20-30 minutes to complete. Your progress will be saved as you move through the workbook, meaning you can leave and return to complete it at any time.

The most important part of this workbook are the survey questions. Utilities are expected to develop a genuine understanding of their customers' interests and preferences and integrate them into their plans. As such, the goal of this workbook is to understand the general priorities and criteria you would like Enbridge Gas to use when making key business decisions. While your view may not always align exactly with any of the options presented, please select the one that is closest. If you truly aren't sure, select the "don't know" option.

If you are reading this on a smaller mobile device, you may wish to access the survey from a tablet, desktop or laptop instead, so that it is easier to read.

Background

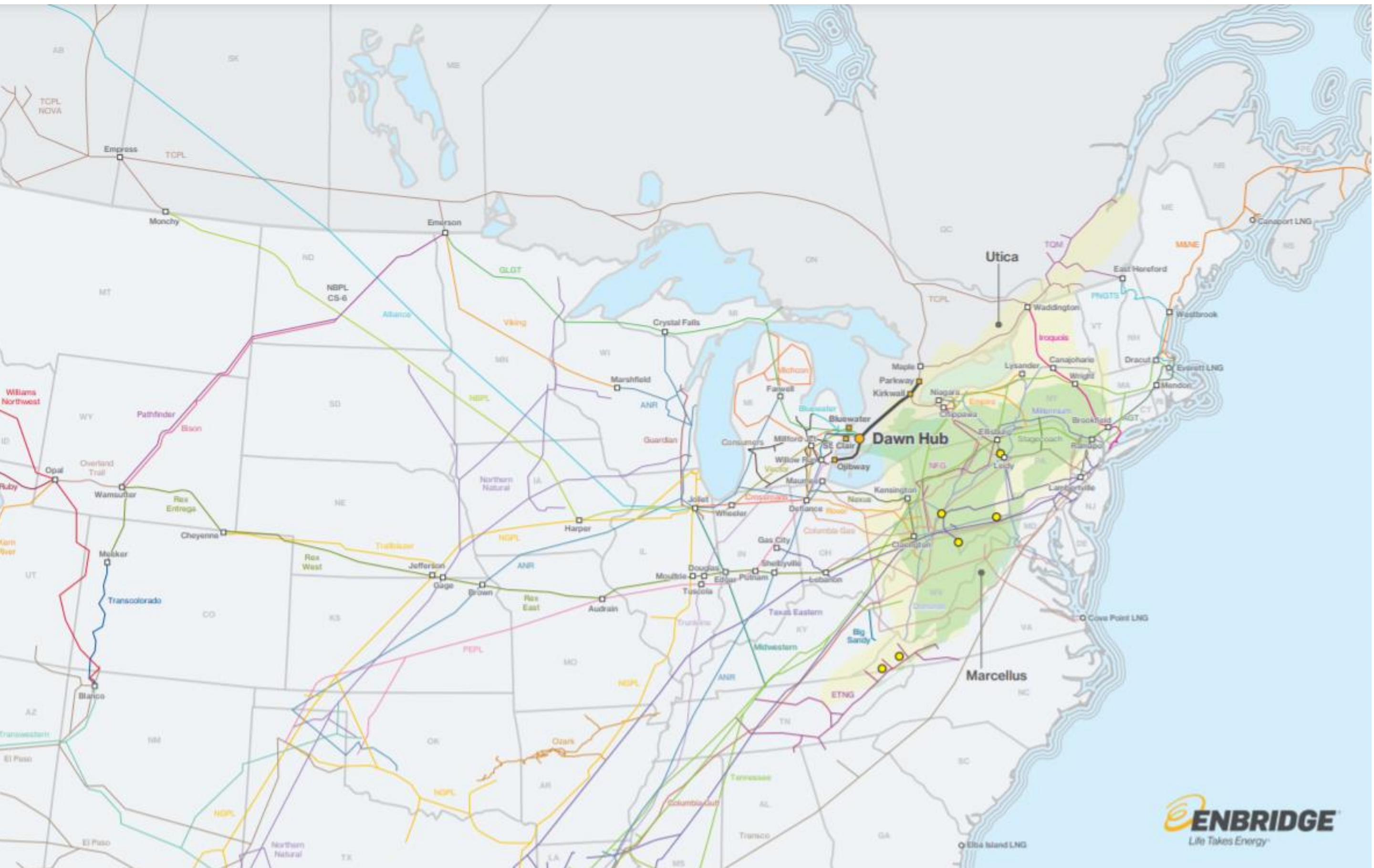
Who is Enbridge Gas?

Enbridge Gas Inc. is based in Ontario and delivers energy to customers in Ontario. Its parent company Enbridge Inc. is headquartered in Calgary, Canada, and operates across North America. All rates and business plans developed by Enbridge Gas must be approved by the Ontario Energy Board (the OEB), which regulates natural gas and electric utilities in Ontario.

Enbridge Gas distributes natural gas to about 3.8 million residential, business and industrial customers, attaching more than 50,000 new customers each year. Enbridge Gas has agreements to provide gas distribution service within 313 municipalities and provides natural gas within 23 First Nation communities across Ontario through a network of over 151,500 kilometers of underground pipeline.

In addition to providing distribution services to customers in our franchise area, Enbridge Gas serves the surrounding storage and transmission marketplace. The Dawn Hub is the largest integrated underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from Western Canadian and U.S. supply basins to markets in central Canada, the Great Lakes region and the northeast U.S.

The Dawn-Parkway transmission system is a series of four transmission pipelines (229 km/143 mi), and compressor stations that move natural gas through Ontario from the Dawn Hub near Sarnia, east to the Parkway compressor facility near Mississauga. At Parkway, the system connects with other pipelines that serve residents in the Toronto area, Quebec, eastern Canada and the U.S. northeast.



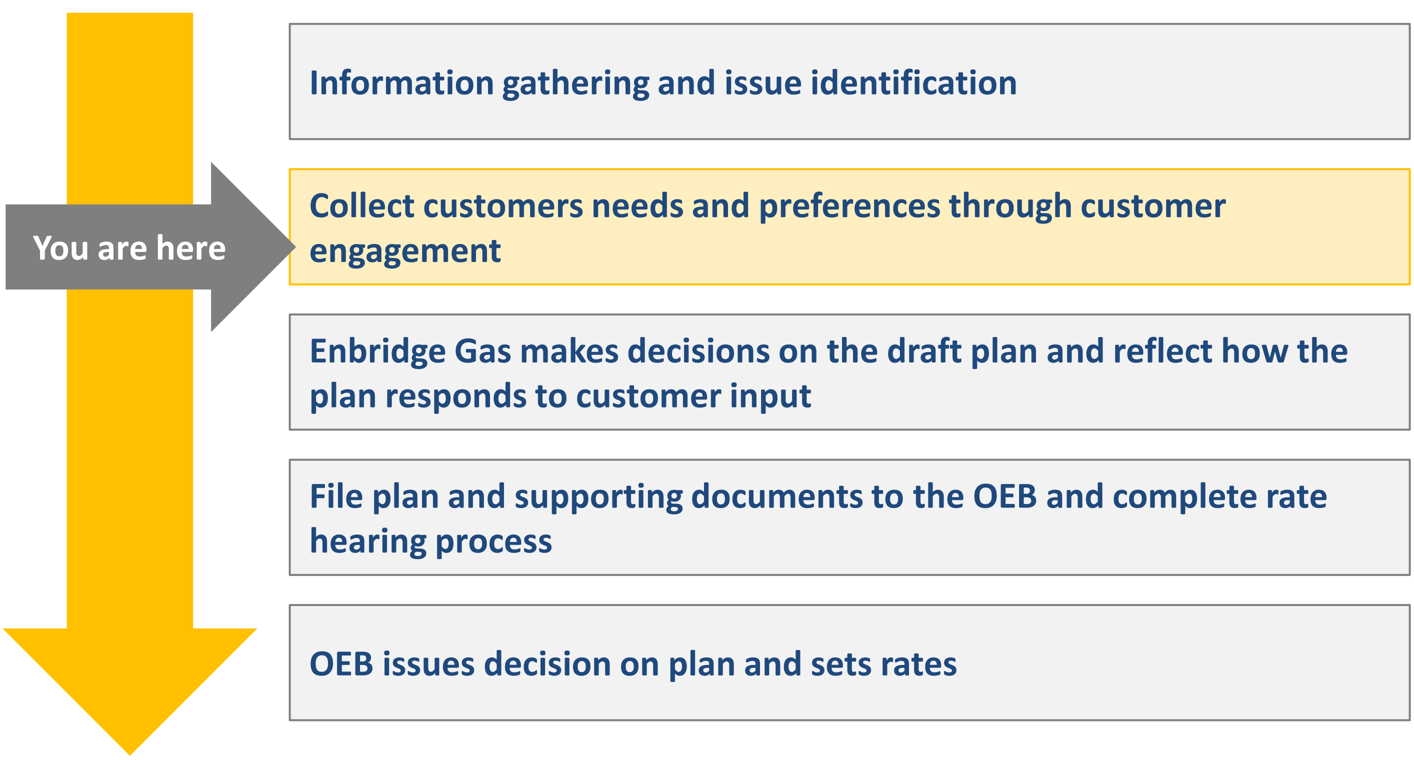
Where does this consultation fit?

Here in Ontario, customer views are central to the utility planning process.

- **All rates and business plans must be approved by the Ontario Energy Board (the OEB).**
- **The OEB requires that utilities consult with customers to understand your views on key trade-offs.**
- **In addition, the utilities must show how they took customer views into account when developing the plan.**

While some planning decisions will depend on detailed knowledge of engineering and industry standards, in other cases the choices will involve trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down. That is where you come in.

The diagram below shows how customers play a role as Enbridge Gas develops and submits its business plan to the Ontario Energy Board.



Consultation Summary

As shown in the background pages, Enbridge Gas provided an overview of the company, and an overview of how the consultation fits into the application process. Through the overview, Enbridge Gas emphasized the importance of customer feedback to ensure that its plans reflect customer needs and preferences.

Customers indicated that they understood how their feedback fits within the planning process.

How well do you feel you understand how your feedback fits within the planning process?

Very well	Somewhat well	Not very well	Not at all	Don’t know	No answer
8	5	-	-	1	1

Customer Outcomes (Ratings)

To establish the outcomes that matter most to customers, Enbridge Gas developed a list of outcomes for customers to review. Customers were encouraged to review the list and supplement the list with any additional outcomes to consider.

There is a list of broad outcomes that Enbridge Gas will need to consider. Using a scale from 0 to 10, where 0 means "not at all important" and 10 means "extremely important", please tell us how important each one is to you.

Rating:	10	9	8	7	6	5	4	3	2	1	0	Not answered
Reliably delivering natural gas	12	1	1	-	-	1	-	-	-	-	-	-
Safely delivering natural gas	13	1	1	-	-	-	-	-	-	-	-	-
Making good use of the money customers pay	4	3	6	-	-	1	-	-	-	-	-	1
Providing affordable pricing	4	5	4	2	-	-	-	-	-	-	-	-
Providing predictable pricing	4	2	6	1	2	-	-	-	-	-	-	-
Providing dependable customer service	3	6	3	1	2	-	-	-	-	-	-	-
Minimizing any impacts on the environment	4	3	4	3	-	1	-	-	-	-	-	-
Being socially responsible	5	1	1	5	1	2	-	-	-	-	-	-
Supporting the growth of Ontario's economy	1	1	4	4	-	3	-	1	-	-	-	1
Other	5 mentions shown											

Other:

Enbridge plays a vital role in ensuring, championing, and educating that Natural Gas Generations is a key resource to maintaining the reliability of the IESO grid; note: In our view, "Minimizing any impacts on the environment" is a subset of "Being socially responsible".

Flexibility is important, to retain the existing operational flexibility that Enbridge offers. Also, having high liquidity, numerous options. Access to storage options is also very important.

Providing reasonable and affordable storage options for customers.

Improve customer satisfaction in terms of transparency and data quality and availability.

Work collaboratively with connecting pipelines that result in cohesive solutions for downstream customers that rely upon the Enbridge Gas systems.

Customer Outcomes (Priorities)

To establish the outcomes that matter most to customers, Enbridge Gas developed a list of outcomes for customers to review. Customers rank which of the outcomes were most important to them. Some provided more than one ranking for first, second, and third, the inclusion of those are in the brackets.

Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which ones would you rank as first, second and third, in terms of importance to you.

Ranking:	Rank 1	Rank 2	Rank 3
Reliably delivering natural gas	4 (6)	7	-
Safely delivering natural gas	6 (8)	4	-
Making good use of the money customers pay	-	-	2 (3)
Providing affordable pricing	-	2	6 (7)
Providing predictable pricing	1	(1)	1
Providing dependable customer service	1 (2)	-	2
Minimizing any impacts on the environment	(1)	(1)	2
Being socially responsible	(1)	(1)	-
Supporting the growth of Ontario’s economy	-	-	(1)
Other: Providing reasonable and affordable storage options for customers	1	-	-

Overall Customer Satisfaction

Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don’t know	No answer
10	4	1	-	-	-	-

Enbridge has been very reliable, providing consistent service at predictable rates.

Have been having some inconsistencies in how nominations are handled. Had to call in monthly to assign names to some balancing transactions starting September this year - did not have this issue last year.

Reliable service, trustworthy and affordable. Good Customer service.

Taking into consideration all aspects of Enbridge Gas’ customer service, how satisfied are you with Enbridge Gas’ customer service?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don’t know	No answer
11	3	1	-	-	-	-

Enbridge is responsive to customer questions.

Consistent customer service has been excellent.

Customer Satisfaction

ENBRIDGE
Life Takes Energy

Overall communications

How satisfied are you with the quality of communications you received from Enbridge Gas over the past year?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don’t know	No answer
10	4	-	1	-	-	-

Based on review of the remainder of this survey, we would like better understanding and communication of any planned changes to rate making process or know changes in cost.

Enbridge does not inform about amounts disbursed related to deferral if the customer has an AMA. Timely and clear communications can be improved.

Relevant issues concerning our service have been communicated both timely and effectively.

We would like to be informed about rate change filings and impacts (or anticipated impacts) from our rep before the change.

Firm gas transportation is highly reliable

How satisfied are you with the reliability of Enbridge Gas' firm transportation services?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don’t know	No answer
12	2	1	-	-	-	-

Reliability has been key.

Customer Satisfaction

ENBRIDGE
Life Takes Energy

Effectiveness of the pipeline system for nominating, reporting & invoicing

How satisfied are you with Enbridge Gas' systems for nominating, reporting and invoicing?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don't know	No answer
8	5	-	1	-	1	-

Assets are managed by a 3rd party, but we have no concerns regarding invoicing.

Enbridge cannot provide monthly invoice when a customer is on an AMA. Enbridge does not inform customer about disbursement of deferral amount to supplier assigned of AMA.

Enbridge URICA Reporting system for RATE125 customer could be further improved.

Have been having issues with balancing transactions requiring a call to the nomination hotline to resolve. did not have this issue last year.

[We] use an asset manager, so we don't directly nominate on Enbridge's system.

Effectiveness of operational communications

How would you characterize the frequency of communications from Enbridge Gas about their operations?

Too much	Just about right	Not enough	No answer
-	15	-	-

Customer Satisfaction

ENBRIDGE
Life Takes Energy

Accurate operational information is readily available

How satisfied are you with Enbridge Gas providing your business relevant and accurate operational information?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don’t know	No answer
6	8	1	-	-	-	-

Not applicable, given assets are managed by a 3rd party.

There should be additional information on storage and anticipated change in operational lights.

Would prefer having access to real time hourly information.

Competitive rates and discounts

How satisfied are you with Enbridge Gas' transportation rates and discounts are competitive?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don’t know	No answer
1	5	8	1	-	-	-

There seems to be a disconnect with market pricing and the tolls.

We are committed to firm transportation at an OEB approved rate. Discounts are not available.

There is no competition.

Customer Satisfaction

ENBRIDGE
Life Takes Energy

Account representatives are responsive

How satisfied are you with Enbridge Gas' response time to your inquiries?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don't know	No answer
13	1	1	-	-	-	-

We never had an account representative specifically for M12 rate (or we do not know). We only have a representative for [one] rate. He was approached to provide information on M12 invoicing.

Account representatives are readily available

How satisfied are you with the availability of Enbridge Gas' representatives when you reach out to them?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don't know	No answer
11	3	-	-	-	1	-

Although our questions are infrequent, Enbridge Gas staff have always been responsive.

We never had an account representative specifically for M12 rate. We only have account representative for T3 rate.

Transportation Rates

Customers were provided the following overview on how transportation rates are calculated in Ontario:

What are the costs?
Enbridge Gas transportation rates are largely driven by Dawn Parkway transmission system and Dawn Station costs. Dawn Parkway transmission costs include transmission pipelines, the compressors and metering equipment along the pipeline including facilities at the Parkway Station. Dawn Station demand costs include the facilities and compressors at the Dawn Station used for transmission purposes.

How are costs included in rates?
The transportation costs are allocated between in-franchise and ex-franchise rate classes based on distance weighted design day demands. The Dawn Station costs are allocated between rate classes based on the use of the Dawn station. The cost allocated to ex-franchise rate classes are recovered through rates based on the use of the transportation services available to customers on the Dawn to Parkway system.

How are rates updated?
Enbridge Gas transportation rates are adjusted using a five-year framework which was approved by the Ontario Energy Board. An annual update includes a formula that adjusts rates each year based on inflation less a productivity factor and approved investments in infrastructure. At the end of the five-year period, Enbridge Gas reviews all of its costs and applies to the Ontario Energy Board for new rates and a new framework to adjust rates going forward. This customer engagement will support plans for the 2024-2028 period.

How well do you understand the basics of how natural gas transportation rates are set?

Completely understand	Somewhat understand	Do not understand	Don’t know	No answer
8	7	-	-	-

Cost Allocation Considerations

Enbridge Gas provided customers with the following background on Enbridge Gas' cost allocation practice:

"Enbridge Gas allocates its costs for providing services to the different rate classes for the purpose of designing rates.

Enbridge Gas' cost allocation practice allocates costs to rate classes based on cost causality principles using specific knowledge of how its system is operated. Although judgment is required in allocating costs, cost allocation results in rate classes that reflect 'user pay' – that is, customers pay in their rate for the cost of the service they use."

How familiar are you with the cost allocation objectives?

Very familiar	Somewhat familiar	Not very familiar	Not at all familiar	Don't know	No answer
7	5	3	-	-	-

Parkway Station Methodology

ENBRIDGE Life Takes Energy

Enbridge Gas provided customers with the following background information on the cost allocation change for the Parkway Station:

“As a result of significant system growth over the last five years, Enbridge Gas is considering a change to the cost allocation methodology of the Parkway Station costs. As you may be aware, Enbridge Gas has invested substantially in expanding this part of our system and the Parkway Station now represents approximately 20% of the Dawn Parkway transmission costs. The cost allocation change being considered involves allocating the Parkway Station costs to rates that use the Parkway Station rather than including it in the overall costs of the Dawn Parkway system.

The Parkway Station facilities are designed to meet Enbridge Gas’ design day requirement to export gas from the Enbridge Gas system into the TransCanada and Enbridge Gas systems through Parkway. They are not necessary to transport or deliver natural gas to other locations along Dawn to Parkway. Allocating Parkway Station demand costs using this user pay methodology will result in an increase of M12 rate class costs by approximately 4%.”

Thinking about Enbridge Gas’ consideration of the cost allocation change for the Parkway Station, which of the following statements best describes your view?

Enbridge Gas should **not** change the recovery of the Parkway Station and all M12/C1 paths should pay for it based on the use of the Dawn to Parkway system.	Enbridge Gas should change the recovery of the Parkway Station costs and recover the costs from only those M12/C1 paths that use the Parkway Station.	I don’t have an opinion on this	Don’t know	No answer
8	4	3	-	-

Are there other ways that Enbridge Gas should consider allocating Parkway Station costs?

A number of contracts still have their delivery point at Parkway. How will Enbridge consider moving them to Dawn.

All Enbridge Gas customers benefits greatly from the liquidity created by export customers.
Parkway Station is integral to creating this liquidity and should continue to be allocated across all classes.

[Company] will have to evaluate the rebasing application before it can fully evaluate the proposal.

The KISS principle should be employed where practicable.

Rate Design Considerations

Enbridge Gas provided customers with the following background information on the rate design considerations for the Parkway Station costs:

"Within the M12/C1 rate classes, these questions will examine how costs are allocated by specific paths. In addition to the consideration of possible changes in the cost allocation of the Parkway Station, Enbridge Gas is also considering assigning the costs of the Parkway Station to those M12/C1 paths that use the Parkway Station.

Enbridge Gas' current rate design recovers the costs of the Dawn Parkway transmission costs (including Parkway Station) from each M12/C1 path based on a distance weighted use of the Dawn to Parkway system. Currently, Dawn Station costs are recovered from M12/C1 paths that use Dawn Station only.

This change would mean that the Parkway Station costs would be recovered in a similar manner as the Dawn Station and assigned to the Dawn to Parkway and Kirkwall to Parkway rates but not to the Kirkwall to Dawn rate.

Assigning Parkway Station costs to the M12/C1 paths that use the Parkway Station will result in an increase to the Kirkwall to Parkway rate, a decrease to the Kirkwall to Dawn rate and have very little impact on the Dawn to Parkway rate."

Thinking about Enbridge Gas' consideration of the rate design change for the Parkway Station, which of the following statements best describes your view?

Enbridge Gas should **not** change the recovery of the Parkway Station and all M12 paths should pay for it based on the use of the Dawn to Parkway system.	Enbridge Gas should change the recovery of the Parkway Station costs from those M12 paths that use the Parkway Station.	I don't have an opinion on this	Don't know	No answer
7	3	4	1	-

Are there other rate design methodologies that Enbridge Gas should consider?

Again - all M12 customers benefit from the Parkway Station - even those who don't have it as a point on their contract.

Could Enbridge provide the impact of this design methodologies to the M12 rate as relates to [our] facilities?

Rate Design Considerations

If the Ontario Energy Board approved a rate increase for 2024 and beyond, which of the following statements best describes your view on the implementation of the rate change?

Adjust rates to reflect costs as they occur, which may result in more annual volatility (option 1)	Apply a steady annual increase in rates over a 5-year period to minimize annual volatility (option 2)	Apply a larger one time increase in the first rebasing year and then leave rates flat for the remaining period (option 3)	I don't have an opinion on this	Don't know	No answer
2	8	2	2	1	-

Indifferent to option 1 or 2 but happy with the way the current methodology works.

[We] will need to see the full details of the rebasing application in order to be able to evaluate the proposed change. We would like to better understand how LCU costs are allocated across the system.

Select both: Adjust rates to reflect costs as they occur, which may result in more annual volatility. Apply a steady annual increase in rates over a 5-year period to minimize annual volatility. If rate change is "acceptable" we would suggest to adjust rates to reflect costs as they occur, which may result in more annual volatility. Otherwise, if rate changes are significant, apply a steady annual increase in rates over a 5-year period to minimize annual volatility.

2 or 3 would be our top choices. It depends on the level of increase on whether 3 would be preferable and whether or not there would be overall cost savings. Please keep in mind that we are on the front end of 15- and 20- year contracts and are wary of dramatic changes in cost allocation that we didn't know about prior to entering these contracts.

Energy Transition

Enbridge Gas provided customers with the following background information on energy transition, and asked customers for their perspectives.

“Enbridge Gas is also looking at ways in which it can support its organizational, as well as federal and provincial goals to reduce greenhouse gas (GHG) emissions and achieve net zero targets.

- Enbridge Inc. targets to reduce, from its operations, GHG emission intensity by 35% by 2030 over 2018 levels, and to reach Net Zero GHG emissions by 2050
- Federal targets to reduce GHG emissions by 40-45% by 2030 over 2005 levels and to reach Net Zero GHG emissions by 2050
- Provincial target to reduce GHG emissions by 30% by 2030 over 2005 levels

There are several options that Enbridge Gas is considering in its efforts to minimize impact on the environment, which include reducing the demand for natural gas, greening the gas through the blending of Renewable Natural Gas (RNG) or Hydrogen Gas with traditional natural gas, and supporting the development of new technologies and options that may not exist today.”

Energy Transition

ENBRIDGE Life Takes Energy

Thinking about your organization's goals, as well as broader climate targets, what are some ways in which Enbridge Gas can support these goals and targets?

[Company] is looking at ways to incorporate RSG and RNG into its supply portfolio.

Coordinate with [us] on opportunities to reduce emissions.

Demand side management, energy efficiency measures, heat pumps and new technology adoption.

[Company] is committed to achieving Net zero emissions related to the energy distributed to its customers by 2050 (which are downstream Scope 3 emissions). To achieve this will demand that [company] be leaders in the development of decarbonization solutions that will support their customers and society. To decarbonize its natural gas network, we must continue and even accelerate certain actions, such as increasing our customers' energy efficiency and injecting RNG in our network without increasing our customers' energy bills. We will need to procure our fossil-based natural gas from producers able to demonstrate performance in ESG and methane emissions reductions. Enbridge can therefore help [company] in multiple different areas that could demonstrably help to reduce our Scope 3 GHG emissions both upstream and downstream through RSG, RNG and emissions reductions initiatives that can take place throughout the full life-cycle of the energy we distribute.

Focus on reducing fugitive methane emissions from the Enbridge system.

Hydrogen.

Look at and develop sustainable green projects with minimized cost increase.

Our organization has a similar goal of reducing GHG from operations. We also support the efforts of individual organizations and the entire natural gas sector and energy utility industry to reduce GHG emissions but believe a strong focus on maintaining safety and reliability are critical. We do not have specific GHG reductions strategies to offer at this time but appreciate Enbridge including Energy Transition considerations in their planning.

Research into green hydrogen and blending a percentage of H into traditionally sourced gas.

RNG and Hydrogen Gas development are critical initiatives for the natural gas industry. Investment in these initiatives are imperative to providing a sustainable service for future generations.

Support the development of new technologies, the ones that exist today are not readily available or adequate. Interested in carbon capture at the customer site.

The blending of Hydrogen gas with natural gas should be one of the focus of helping the Enbridge customers to reduce the GHG emissions.

To achieve the targets, data quality has to be improved. Live metering is essential in reducing GHG emissions, so Enbridge need to invest in providing customers with live, accurate data about their consumption on timely manner.

We are interested in Hydrogen blending.

Feedback on the Engagement

Customers were provided the opportunity to share their feedback on the customer engagement. No answers were provided to the question “Is there anything that you would still like answered?”

Overall, did you have a favourable or unfavourable impression of the workbook you just completed?

Very favourable	Somewhat favourable	Somewhat unfavourable	Very unfavourable	Don’t know	No answer
6	9	-	0	1	1

In this workbook, do you feel that Enbridge Gas provided …

Too little information	Just the right amount of information	Too much information	No answer
5	10	-	-

Was there any content missing that you would have liked to have seen included in this workbook?

In addition to this survey, an in-person discussion on this would be helpful.
In future, consider providing Energy Transition options to guide customers in their responses.
Interest in future expansions and growth.Topics related in changes to use of the d-p system, projections, etc.
More detail explanation of cost allocation approach is required
More details on the impacts of the proposed Parkway changes. Any information about possible expansions, maintenance, or new builds.
More details on the parkway cost allocation, perhaps example calculation.

Next Steps

At the conclusion of the workbook:

- Customers could indicate whether they would like to be notified of how Enbridge Gas used their feedback.
- Customers were asked to confirm they would be willing to receive a follow-up call from INNOVATIVE Research Group to confirm their participation in the customer engagement.
- Customers were advised that

> "Enbridge Gas will use the findings from this consultation to ensure that its 2024-2028 plan meets customers' needs, which will be filed to the Ontario Energy Board as part of the Enbridge Gas 2024 Rate Rebasing application in Q4 2022."

2024 Rebasing Report

Customer Engagement

Ontario Producers (M13) Customers

ENBRIDGE
Life Takes Energy

February 2022

Prepared by Customer & Market Insights

Project Overview

Enbridge Gas 2024 Rate Rebasing Customer Engagement

Enbridge Gas is undertaking a customer engagement process that is designed to gather feedback from customers on their needs and preferences. These are incorporated in the business planning process for 2024 and beyond.

This report summarizes the findings of consultations with M13 customers. Separate reports summarize the findings of consultations with other groups of customers.

Methodology

Enbridge Gas invited customers to complete a “workbook-style” survey to ensure the opinions collected on these issues were informed opinions. Through the workbook, customers were provided key background information on Enbridge Gas and its network as well as background relevant to various choices.

Customers were given the option to complete the workbook online or to meet with an Enbridge Gas representative to discuss the questions in the workbook and complete the workbook together.

The workbook was available online between December 17, 2021, and January 31, 2022.

A total of seven M13 customers completed the workbook during this time.

All figures in this report are counts (i.e. number of responses) rather than percentages due to the limited number of responses.

Customers include those in the M13 and Rate 401 rate classes. These customers produce conventional and renewable natural gas in the Enbridge Gas franchise areas.

About this Customer Engagement

Welcome to the Enbridge Gas Customer Engagement!

- Enbridge Gas is looking for your feedback to support its investment plan for 2024 and beyond to ensure that plan reflects your needs and preferences.
- You don't need to be a natural gas expert to complete this workbook. It focuses on choices between outcomes that matter to you and provides the background information you need to answer the questions.

If you are completing this workbook online, please note that it will take approximately 20-30 minutes to complete. Your progress will be saved as you move through the workbook, meaning you can leave and return to complete it at any time.

The most important part of this workbook are the survey questions. Utilities are expected to develop a genuine understanding of their customers' interests and preferences and integrate them into their plans. As such, the goal of this workbook is to understand the general priorities and criteria you would like Enbridge Gas to use when making key business decisions. While your view may not always align exactly with any of the options presented, please select the one that is closest. If you truly aren't sure, select the "don't know" option.

If you are reading this on a smaller mobile device, you may wish to access the survey from a tablet, desktop or laptop instead, so that it is easier to read.

Background

Who is Enbridge Gas?

Enbridge Gas Inc. is based in Ontario and delivers energy to customers in Ontario. Its parent company Enbridge Inc. is headquartered in Calgary, Canada, and operates across North America. Rates and business plans developed by Enbridge Gas must be approved by the Ontario Energy Board (the OEB), which regulates natural gas utilities in Ontario.

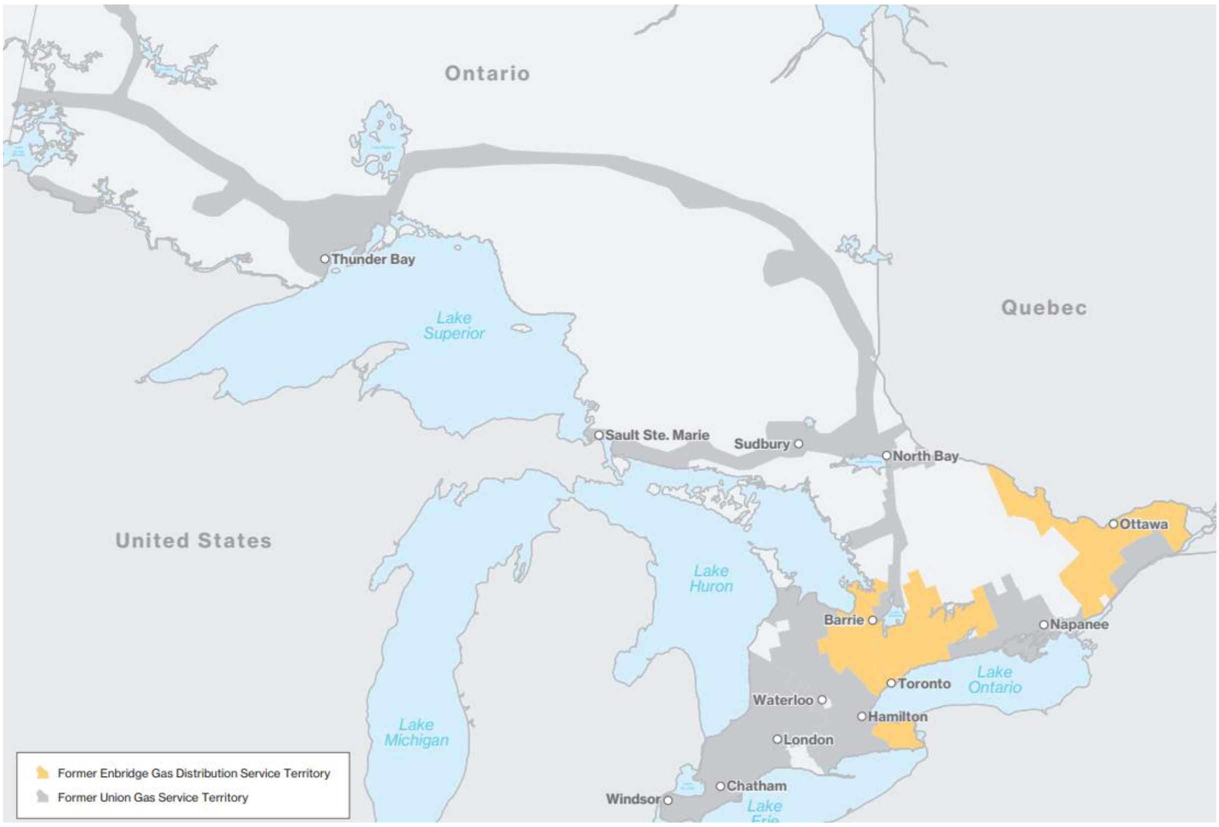
Enbridge Gas …

- ✓ Distributes natural gas to about 3.8 million residential, business and industrial customers
- ✓ Attaches more than 50,000 new customers each year
- ✓ Has agreements to provide gas distribution service within 313 municipalities and provides natural gas within 23 First Nation communities
- ✓ Has a network of over 151,500 kilometers of underground pipeline

In 2019, Enbridge Gas Distribution and Union Gas merged to form one company, Enbridge Gas Inc. Throughout this workbook we occasionally refer to Legacy Enbridge Gas Distribution and Legacy Union Gas (the previous companies), but mainly refer to the whole service area or territory that Enbridge Gas serves today.

In addition to providing distribution services to customers in our franchise area, Enbridge Gas serves the surrounding storage and transmission marketplace. The Dawn Hub is the largest integrated underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from Western Canadian and U.S. supply basins to markets in central Canada, the Great Lakes region and the northeast U.S.

The Dawn-Parkway transmission system is a series of four transmission pipelines (229 km/143 mi), and compressor stations that move natural gas through Ontario from the Dawn Hub near Sarnia, east to the Parkway compressor facility near Mississauga. At Parkway, the system connects with other pipelines that serve residents in the Toronto area, Quebec, eastern Canada and the U.S. northeast.



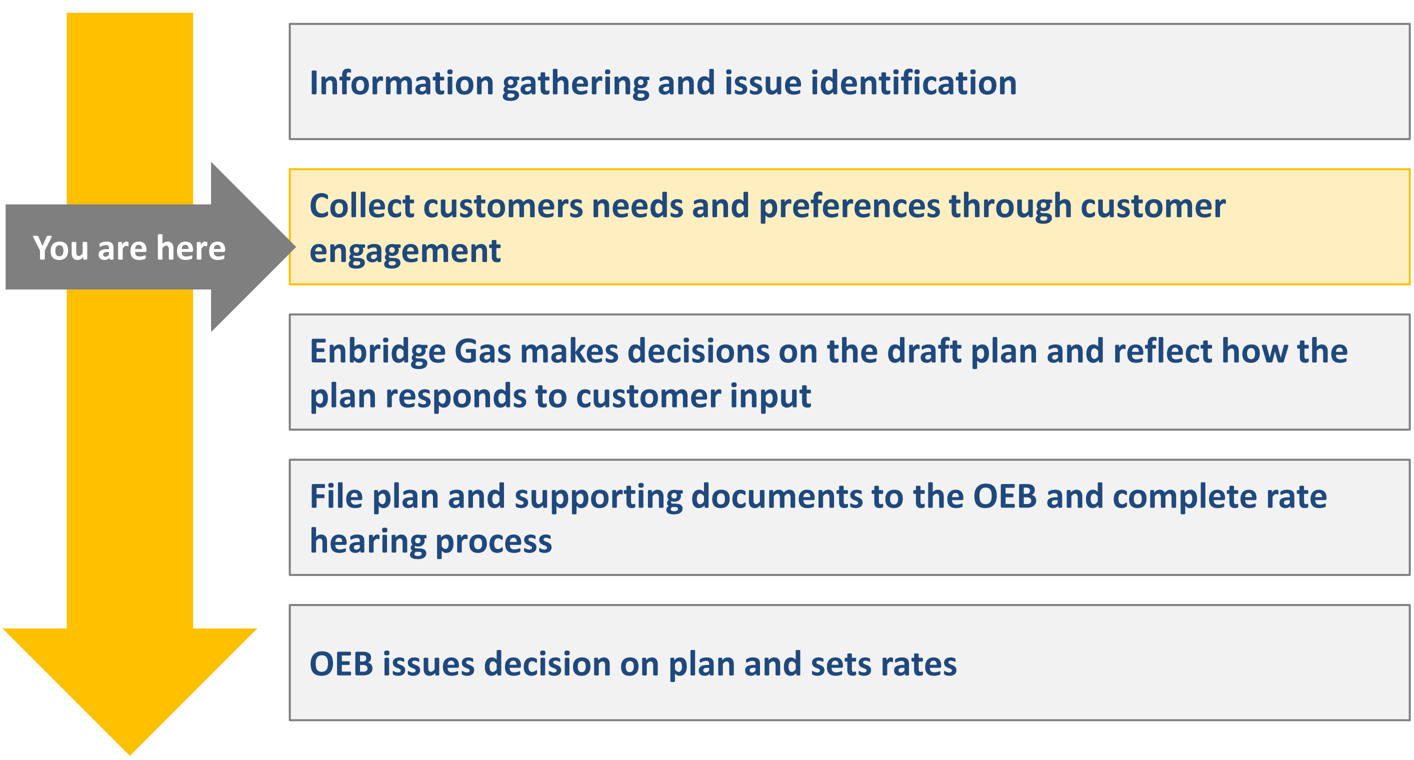
Where does this consultation fit?

Here in Ontario, customer views are central to the utility planning process.

- **All rates and business plans must be approved by the Ontario Energy Board (the OEB).**
- **The OEB requires that utilities consult with customers to understand your views on key trade-offs.**
- **In addition, the utilities must show how they took customer views into account when developing the plan.**

While some planning decisions will depend on detailed knowledge of engineering and industry standards, in other cases the choices will involve trade-offs between competing outcomes, such as doing more to meet customer needs or reduce greenhouse gas (GHG) emissions, versus keeping bills down. That is where you come in.

The diagram below shows how customers play a role as Enbridge Gas develops and submits its business plan to the Ontario Energy Board.



Consultation Summary

As shown in the previous page, Enbridge Gas provided an overview of the company, and an overview of how the consultation fits into the application process. Through the overview, Enbridge Gas emphasized the importance of customer feedback to ensure that its plans reflect customer needs and preferences.

Customers indicated that they understood how their feedback fits within the planning process.

How well do you feel you understand how your feedback fits within the planning process?

Very well	Somewhat well	Not very well	Not at all	Don’t know	No answer
2	4	-	-	1	-

Customer Outcomes (Ratings)

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To establish the outcomes that matter most to customers, Enbridge Gas developed a list of outcomes for customers to review. Customers were encouraged to review the list and supplement the list with any additional outcomes to consider.

There is a list of broad outcomes that Enbridge Gas will need to consider. Using a scale from 0 to 10, where 0 means "not at all important" and 10 means "extremely important", please tell us how important each one is to you.

Rating:	10	9	8	7	6	5	4	3	2	1	0	Not answered
Reliably delivering natural gas	5	-	1	1	-	-	-	-	-	-	-	-
Safely delivering natural gas	5	1	1	-	-	-	-	-	-	-	-	-
Making good use of the money customers pay	2	1	2	1	1	-	-	-	-	-	-	-
Providing affordable pricing	-	1	1	1	-	3	-	-	-	-	-	1
Providing predictable pricing	1	-	2	3	-	-	-	-	-	-	-	1
Providing dependable customer service	2	1	-	1	1	1	-	-	-	-	-	1
Minimizing any impacts on the environment	3	1	-	-	1	1	-	-	-	-	-	1
Being socially responsible	3	-	1	-	1	1	-	-	-	-	-	1
Supporting the growth of Ontario's economy	3	-	2	-	-	1	-	-	-	-	-	1
Other	4 mentions shown											

Other:

Local gas supplies should be utilized where possible to ensure security of supply, support Ontario's economy and reduce greenhouse gas emissions from transporting gas in from other jurisdictions.

I feel being reliable, safe and providing good customer service are just pillars of a good business, therefore while important, I don't think are fair to rank against being socially responsible. Whereas being socially responsible and affordable may need to be ranked, as you can't necessarily have both.

Providing "green" natural gas options to customers.

Transportation and storage services.

Customer Outcomes (Priorities)

To establish the outcomes that matter most to customers, Enbridge Gas developed a list of outcomes for customers to review. Customers rank which of the outcomes were most important to them. 6 out of 7 customers completed this question.

Sometimes we need to choose between priorities that are all considered important. Thinking about these outcomes, which ones would you rank as first, second and third, in terms of importance to you.

Ranking:	Rank 1	Rank 2	Rank 3
Reliably delivering natural gas	3	1	2
Safely delivering natural gas	1	3	-
Making good use of the money customers pay	-	-	-
Providing affordable pricing	-	1	-
Providing predictable pricing	-	1	1
Providing dependable customer service	-	-	-
Minimizing any impacts on the environment	2	-	2
Being socially responsible	-	-	-
Supporting the growth of Ontario's economy	-	-	1
Other	-	-	-

Overall Customer Satisfaction

Taking into consideration all aspects of your utility service experience, how satisfied are you with your Enbridge Gas service?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don't know	No answer
1	5	-	-	-	-	1

The utility could provide more support to RNG developers to help them get on the Enbridge system.

Overall once system was completed very satisfied. Extremely dissatisfied with the construction and procurement aspects of the project.

Taking into consideration all aspects of Enbridge Gas' customer service, how satisfied are you with Enbridge Gas' customer service?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don't know	No answer
2	3	1	-	-	-	1

As a large user, we deal with several different customer service areas. We are largely satisfied with our account reps and contract reps and the "collective billing". However, the general customer service (ex. call centre for billing, account questions etc.) is frustrating and lacking in knowledge and/or the ability to correct situations..

Customer Satisfaction

Overall communications

How satisfied are you with the quality of communications you received from Enbridge Gas over the past year?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don’t know	No answer
3	2	1	-	-	-	1

As an RNG producer, we feel on the M13 contracting we have received good communication to support our unique situation.

Effectiveness of the pipeline system for nominating, reporting & invoicing

How satisfied are you with Enbridge Gas’ systems for nominating, reporting and invoicing?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don’t know	No answer
-	3	2	-	-	1	1

This is looked after by others on my behalf.

I don't do nominations.

As an RNG producer, we are in a unique situation where we are a new technology, providing beneficial services to Enbridge, however we are treated as if we were a typical well. We cannot control our flow as much as others, and yet there isn’t any consideration for this. I would support the growth of the industry to have more forgiving terms for nominations.

Customer Satisfaction

Effectiveness of operational communications

How would you characterize the frequency of communications from Enbridge Gas about their operations?

Too much	Just about right	Not enough	No answer
-	4	1	2

Indifferent.

Have been responsive when our site calls gas control.

Would like more information on timing and duration of pipeline work that affects producer sales points.

Accurate operational information is readily available

How satisfied are you with Enbridge Gas providing your business relevant and accurate operational information?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don't know	No answer
2	2	3	-	-	-	-

Not really something we have dealt with.

Customer Satisfaction

ENBRIDGE
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Account representatives are responsive

How satisfied are you with Enbridge Gas' response time to your inquiries?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don't know	No answer
4	2	1	-	-	-	-

Account representatives are readily available

How satisfied are you with the availability of Enbridge Gas' representatives when you reach out to them?

Very satisfied	Somewhat satisfied	Neither satisfied nor dissatisfied	Somewhat dissatisfied	Very dissatisfied	Don't know	No answer
3	4	-	-	-	1	-

Rates (background)

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Customers were provided an overview of Enbridge Gas' costs.

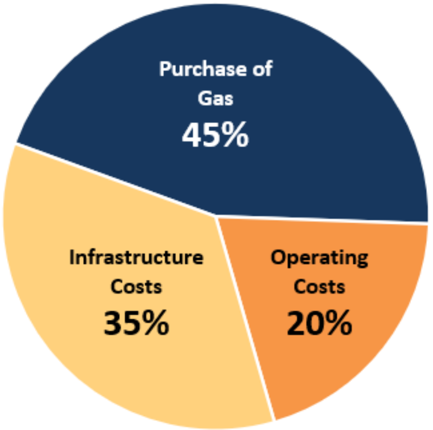
Enbridge Gas Customer Engagement
2024 Rate Rebasing Customer Engagement Workbook

Customer Experience

Rates

What are the costs?
The proportions of Enbridge Gas' expenditures are shown in the pie chart.

- ✓ The **Purchase of Gas** shows the 'passed through' costs that pay for the natural gas and transportation to the Enbridge Gas system.
- ✓ The **Infrastructure Costs** pay the capital costs of the infrastructure (such as pipes, compressors, buildings and other equipment) used to move and store natural gas across the system.
- ✓ The **Operating Costs** pay for operations – including the people who operate and maintain the equipment and the people who provide customer service.



These costs will be reviewed in detail through the application to the OEB.

Cost Allocation Considerations

Enbridge Gas provided customers with the following background on Enbridge Gas' cost allocation practice:

"Enbridge Gas' cost allocation practice allocates costs to rate classes based on cost causality principles using specific knowledge of how its system is operated. Although judgment is required in allocating costs, cost allocation results in rate classes that reflect 'user pay' – that is, customers pay in their rate for the cost of the service they use."

How familiar are you with the cost allocation objectives?

Very familiar	Somewhat familiar	Not very familiar	Not at all familiar	Don't know	No answer
1	5	-	1	-	-

Enbridge Gas provided customers with the following background on how rates are updated:

"Enbridge Gas rates are adjusted using a five-year framework which was approved by the Ontario Energy Board. An annual update includes a formula that adjusts rates each year based on inflation less a productivity factor and approved investments in infrastructure. At the end of the five-year period, Enbridge Gas reviews all of its costs and applies to the Ontario Energy Board for new rates and a new framework to adjust rates going forward. This customer engagement will support plans for the 2024-2028 period."

How well do you understand the basics of how natural gas rates are set?

Completely understand	Somewhat understand	Do not understand	Don't know	No answer
1	5	1	-	-

We have had poor communication of rates, how they increase and when they do. Billing has been incredibly slow for one of our facilities and we were caught off guard on increased rates because of lack of billing.

Cost of New Facilities

“When a producer asks for a new attachment to the Enbridge Gas system, estimates for both the capital costs required for attachment along with the future revenue stream that will be received by Enbridge Gas from signing a contract with the producer are performed.

If the estimated revenues are insufficient to cover the capital costs, Enbridge Gas requires the producer to pay for the difference. Depending on the rate zone that the producer is in, the recovery of this capital cost occurs as follows:
For the Enbridge Gas Distribution Rate Zone: If the producer passes the Enbridge Gas capital requirements, they have the option to pay the capital shortfall over the term of the agreement signed by the producer. If the producer doesn’t pass the credit requirements or chooses not to pay the shortfall over the term of the agreement, they have the option to pay the shortfall in an upfront lump-sum amount.
For the Union Rate Zone: The producer is required to pay half of the shortfall prior to procurement of construction materials with the balance to be paid in full prior to construction starting.

For both rate zones, a true-up based on actual costs incurred is performed after construction has been completed.
Enbridge Gas is considering alternatives to the payment of shortfall amounts that would be consistent regardless of which rate zone the producer is in.”

Thinking about Enbridge Gas’ consideration of the treatment of Contribution in Aid of Construction (CIAC) payments, which of the following statements best describes your view?

Enbridge Gas should require **the full shortfall payment from producers** prior to the facilities being constructed	Enbridge Gas should offer producers the **option to pay for the shortfall over the term of the agreement**, subject to the producer meeting Enbridge Gas credit requirements	The producer should have the option to choose from **either option**, subject to meeting Enbridge Gas credit requirements	I don’t have an opinion on this	Don’t know	No answer
-	1	4	1	-	1

This is my largest concern. The procurement methods for the capital equipment are unreasonable. Labour rates, productivity and effectiveness of installations are prohibitive. Current quotes of $2.5million per RNG injection point will not allow for construction of RNG facilities in Enbridge's connection area. Alternative procurement and construction methods are required, such as owner built under Enbridge supervision and free issue to the utility as is done with electrical connections to Hydro One Network are required.

Options For The Sale of Production

"Enbridge Gas is considering three (3) different elections that a producer can make to sell their production.

1) Transport the production to the Enbridge Gas Dawn Hub and sell to market participants (marketers or direct purchase customers of Enbridge Gas). This option would require the producer to nominate the transportation from the meter location to Dawn daily.
2) If the producer is also an Enbridge Gas direct purchase customer, the production can be used to meet the customer's direct purchase obligations. The molecule would be transferred by the producer to their direct purchase obligated delivery point and transferred to the direct purchase account. Normal direct purchase rules would still apply once the molecule is delivered.
3) The producer would sell to Enbridge Gas' Gas Supply group. The sale would be deemed to occur at Dawn and would be a firm service. The producer would not be required to nominate the service and the payment would be based on actual production during the month.

Enbridge Gas is currently proposing that the producer makes an election for one of the three choices at the time of contract execution."

Thinking about Enbridge Gas' options proposed for the sale of production, do you support or oppose these options?

Strongly support	Somewhat support	Somewhat oppose	Strongly oppose	Don't know	No answer
-	2	1	2	1	1

I support having different options for producers to sell their product, but producers should be able to choose those options as they see fit within their business. I disagree with electing for a specific option. If a producer wants to sell to any or all of the above, then that is there business so long as it remains within the production contract parameters. Any option to sell volume to Enbridge for example, should be a separate agreement (buy-sell agreement) as they would with any buyer.

The M13 option is reasonable if the producer would like to sell at Dawn. Alternatively, the producer should have the option to sell at the custody transfer meter as the molecules do not go to Dawn but are delivered downstream in closer proximity to end use customers. Producers who choose to sell on the standard GPA should receive the Total Gas Supply Commodity Charge for their gas sold directly to EGI as that is the Board approved rate customers pay for system gas and is the best approximation for the value of gas commodity delivered downstream of Dawn in proximity to end use customers.

Option 1 applies best to RNG producers.

Producer should be able to change its election after the contract execution to accommodate changes in business needs.

Not applicable.

Options For The Sale of Production

Thinking about Enbridge Gas' proposal that the producer make a choice of how they want to sell their production at the time they sign their agreement, which of the following statements best describes your view?

The producer should have the ability to change their election annually.	A producer should have the ability to choose more than one option at a time.	I don't have an opinion on this	Don't know	No answer
1	3	2	-	1

Again, disagree with elections at agreement time. Producers should be able to make business decisions outside of utility dictating those terms. If the Enbridge contribution (aid to construct for initial infrastructure) is tied to a specific option, that is a separate matter in my opinion.

Local producers should be able to sell all gas they produce on a variable basis as gas production can fluctuate although it is steady and fairly predictable. Producers in the Southern rate zone should have the option to transport to Dawn on M13 or sell directly to EGI on a standard GPA. Gas sold to EGI on a standard GPA should receive the Total Gas Supply Commodity Charge. EGI should make efforts to support local gas over gas transported from other jurisdictions due to the economic benefits to Ontario and the reduced carbon footprint from less transportation. EGI should where infrastructure allows attempt to accommodate all volumes of local gas and new connection requests from local producers.

Energy Transition

Enbridge Gas provided customers with the following background information on energy transition, and asked customers for their perspectives.

“Enbridge Gas is also looking at ways in which it can support its organizational, as well as federal and provincial goals to reduce greenhouse gas (GHG) emissions and achieve net zero targets.

- Enbridge Inc. targets to reduce, from its operations, GHG emission intensity by 35% by 2030 over 2018 levels, and to reach Net Zero GHG emissions by 2050
- Federal targets to reduce GHG emissions by 40-45% by 2030 over 2005 levels and to reach Net Zero GHG emissions by 2050
- Provincial target to reduce GHG emissions by 30% by 2030 over 2005 levels

There are several options that Enbridge Gas is considering in its efforts to minimize impact on the environment, which include reducing the demand for natural gas, greening the gas through the blending of Renewable Natural Gas (RNG) or Hydrogen Gas with traditional natural gas, and supporting the development of new technologies and options that may not exist today.”

Energy Transition

Thinking about your organization's goals, as well as broader climate targets, what are some ways in which Enbridge Gas can support these goals and targets?
Provide broader support for RNG such as utilities in BC and Quebec are doing.
Communicate to customers thorough leaflets, ads. Develop programs targeting residential sectors.
Partnerships with customers in development of new greener production.
Continue to play a role in the production and advancing of RNG production
Natural Gas should not be phased out globally until coal and other more carbon intensive fuels are phased out first. it will be needed as a transition fuel and currently offsets a lot of oil, propane and wood heating. Adding green Hydrogen and RNG to the natural gas stream should be encouraged in order to reduce carbon footprint. Adding as much locally produced natural gas should also be encouraged as a greener alternative to out of jurisdiction natural gas as it does not have the fuel gas shrinkage associated with compression to bring it from afar. Additionally, Ontario produced natural gas is produced by conventional means and does not have the environmental impacts associated with high volume hydraulic fracturing technics utilized in the shale gas industries. Natural gas is a lower carbon bridging fuel for the energy transition to zero carbon. Ultimately carbon sequestration will be needed to remove CO2 and new technologies need to be developed and refined to fight climate change.
If these targets are to be met producers of RNG must be able to sell their gas to the utility at a price that make projects profitable and must be for a duration that allows for reasonable capital finance rates such as 15-20 years. Cost of injection point construction needs to be addressed. See comments above.
As an RNG producer, connection to the gas pipeline for injection is very cost prohibitive. We have also seen injection stations priced differently by geographic location. Enbridge needs to make the injection stations more cost effective.

Feedback on the Engagement

Customers were provided the opportunity to share their feedback on the customer engagement.

Overall, did you have a favourable or unfavourable impression of the workbook you just completed?

Very favourable	Somewhat favourable	Somewhat unfavourable	Very unfavourable	Don't know	No answer
2	3	1	0	-	1

In this workbook, do you feel that Enbridge Gas provided …

Too little information	Just the right amount of information	Too much information	No answer
1	6	-	-

Was there any content missing that you would have liked to have seen included in this workbook?

Not necessarily, but being a rigid questionnaire, lacks flexibility in responses. As an RNG producer, we don't fit the typical mold of producer.
More on RNG.
Production section does not differentiate between RNG and locally produced natural gas. No mention of standard Gas Purchase Agreement for local producers. No mention of how producer receipt stations are budgeted or if future revenues are considered when determining cost to connect for local producers. Should EGI preform same economic analysis on how much it will make off of the local producer and discount station build costs as they do with customers for connecting to the system?
Questions presented seem disconnected from my reality as an RNG producer.

Feedback on the Engagement

Is there anything that you would still like answered?
Support to RNG developers
Should EGI preform same economic analysis on how much it will make off of the local producer and discount station build costs as they do with customers for connecting to the system? *Should EGI consider allowing local producers to build their own connection facilities?* *What is the logic behind EGI owning the connection facility but the local producer paying for it? Does the connection facility go into EGI rate base after it is paid for by the local producer?*

Next Steps

At the conclusion of the workbook:

- Customers could indicate whether they would like to be notified of how Enbridge Gas used their feedback.
- Customers were asked to confirm they would be willing to receive a follow-up call from INNOVATIVE Research Group to confirm their participation in the customer engagement.
- Customers were advised that

> “Enbridge Gas will use the findings from this consultation to ensure that its 2024-2028 plan meets customers’ needs, which will be filed to the Ontario Energy Board as part of the Enbridge Gas 2024 Rate Rebasing application in Q4 2022.”

PERFORMANCE MEASUREMENT AND SCORECARD

SEAN COLLIER, DIRECTOR OPERATIONS SERVICES
STEPHANIE FIFE, MANAGER PERFORMANCE REPORTING & ANALYTICS
TRACY LYNCH, DIRECTOR CUSTOMER CARE OPERATIONS

1. The purpose of this evidence is to demonstrate how Enbridge Gas measures and monitors performance through its OEB Scorecard (scorecard) by providing the past five historical years results related to the scorecard which includes its service quality requirements (SQR) as outlined in Section 7 of the OEB's Gas Distribution Access Rule (GDAR). In addition, this evidence supports the Company's request for a partial exemption under Section 1.5.1 of the GDAR related to certain SQR performance measures, corresponding amendments to the scorecard and a recommendation that the OEB's Chief Executive Officer review and amend these SQR performance measures in the GDAR.

2. This evidence is organized as follows:
    1. Introduction
    2. Historical Scorecard Performance
    3. Exemption Request and GDAR Review Recommendation
    4. Mitigation Plans
    5. Summary

1. Introduction

3. The scorecard is produced annually and includes measures in four categories: customer focus, operational effectiveness, public policy responsiveness, and financial performance. 2021 is the third year that Enbridge Gas is presenting the scorecard for the amalgamated utility. Enbridge Gas is providing five years of

scorecard results (2017 to 2021), at Attachment 1. The years 2019 to 2021 are for Enbridge Gas, whereas 2017 and 2018 are presented separately for the pre-amalgamated utilities.

4. SQRs are included as performance measures on the scorecard as they have been reported by both EGD and Union since the SQR measures were added to the GDAR, coming into affect on January 1, 2007.[1] The OEB found that the 2024 Rebasing proceeding is "the appropriate time to review historical performance trends and consider customer implications before making any adjustments to the performance scorecard."[2] As stated in the Filing Requirements For Natural Gas Rate Applications (Filing Requirements), the OEB may modify existing scorecards from time to time.[3]

5. Enbridge Gas was unable to meet the performance standard for four SQR measures in 2021. Those measures are:
   a) Call Answering Service Level (CASL);
   b) Abandon Rate (AR);
   c) Meter Reading Performance Measurement (MRPM); and
   d) Time to Reschedule a Missed Appointment (TRMA)

   In addition, the performance standard for MRPM was not attained in 2020 and 2019. The 100% performance standard for TRMA has historically not been met. Through the OEB's processes for compliance, the Company provided an

[1] EB-2005-0453, OEB Amendments to the Gas Distribution Access Rule, March 27, 2006, pp.1-2.
[2] EB-2021-0149, OEB Decision and Order, January 27, 2022, p.12.
[3] Filing Requirements For Natural Gas Rate Applications, February 16, 2017, p.15.

Assurance of Voluntary Compliance (AVC) in September 2022 for CASL, AR, and MRPM.

2. Historical Scorecard Performance

6. For the customer focused performance measures, the scorecard provides the results for seven performance measures related to service quality and customer satisfaction. The targets for Reconnection Response Time, Scheduled Appointments Met on Time and Customer Complaint Written Response were met or exceeded over the five-year reporting period. CASL and AR targets were achieved for 2017 to 2020, however, the targets were not met in 2021. The Utility has historically missed the 100% target on the TRMA performance measure. The Billing Accuracy measure has no specific target; however, it is a reportable audited number of the manual checks completed for billing accuracy.

7. For operational effectiveness performance measures, Enbridge Gas has demonstrated positive performance trends for five of six measures. The percentage of Emergency Calls Responded to Within One Hour continues to trend above the GDAR target. The Compression Reliability, Damages per 1000 Locate Requests and the Total Cost measures have no specific target, however, demonstrate consistent year-over-year performance. The MRPM did not attain target in 2021, 2020 or 2019.

8. Enbridge Gas is also providing the results for the Public Policy Responsiveness performance measure and the Financial Performance results for five years. Total Cumulative Cubic Meters of Natural Gas Saved (Net) is an approved result from the annual DSM Clearance proceeding, therefore the result for 2021 is not available

until the 2021 DSM Clearance proceeding is concluded.

9. Enbridge Gas has taken all reasonable steps in striving to achieve the SQR targets on a consistent basis. Factors contributing to not reaching the SQR targets in recent reporting periods include the COVID-19 pandemic, staffing issues, system integration and extreme weather events. Throughout 2020 and 2021 Enbridge Gas took proactive steps to manage through changes and challenges and meet the performance standards for all SQRs. Those steps included:
    a) Customer Communications – Communications were developed and delivered months prior to Customer Information System (CIS) integration, notifying customers of expected impacts including updated log in and payment information. Communications used multiple channels including email, the website and the Interactive Voice Response (IVR). Prior to the integration of the CIS, communication plans were shared with OEB Staff providing an opportunity for questions and comment on the integration taking place. To address meter reading performance, similar communication channels were used to assist customers in submitting meter reads to decrease the number of consecutive estimates used to produce customer bills;
    b) Digital Channels – Enbridge Gas introduced additional online self-serve options for customers in 2019, including a “chatbot” to answer less complex questions such as account balance inquiries. Following system integration all digital channels were aligned and available to all customers;
    c) Staffing – Where possible, temporary staff were hired to assist with the increase in call volumes and absenteeism. In addition, staff were redirected to focus on addressing customer concerns that were resulting in increased calls such as resolving billing issues;

d) Labour Shortage – Enbridge Gas assisted key vendors in hiring staff to address the labour shortage. In addition, Enbridge Gas worked with vendors to support retention of staff;
e) Training – Prior to the CIS integration implementation call centre staff underwent extensive training on the new system and new scripts to ensure agents were able to answer questions and resolve issues effectively; and
f) Systems Integration – Enbridge Gas continues to integrate systems and align processes in an effort to provide an efficient and consistent customer experience. Integration of systems such as CIS and the work management systems are necessary and beneficial, however, they can require an initial change for customers, can take time to transition and can create an initial learning curve for employees. Systems integration supports consistent and aligned processes for the benefit of customers.

10. Safety continues to be the top priority and a core value of Enbridge Gas. During the COVID-19 pandemic, there were periods of time when meter readers were unable to complete routes due to public health stay-at-home orders. The stay-at-home orders also led to more people being at home during the day, increasing interactions between meter readers and homeowners. There was also an increase in the number of dogs in backyards with more people being home. This led to increased safety concerns and dog bites. COVID-19 safety and quarantine periods were also impactful, as the well-being of staff that were ill and staff that could come in contact with ill co-workers was a concern. In addition, provincial guidelines and the requirement to adhere to quarantine/isolation periods that ranged between 5 to 14 days created resourcing challenges that impacted meter reading performance. To provide further context, approximately 4,000 meters can be read by one meter reader in a five-day work week, therefore if a meter reader is unable to conduct

reads for a 14-day quarantine/isolation period (10 business days) 8,000 meters could go unread.

11. Finally, extreme weather such as freezing rain, flooding and heavy snow impacted the ability to obtain meter reads as roads were too dangerous to travel on or in some cases were closed. Responding to emergencies was and continues to be a priority for Enbridge Gas, and from time-to-time field staff and dispatch staff are re-directed from customer appointments to attend emergencies impacting the ability to reschedule appointments according to the prescribed timelines.

2.1. Call Answering Service Level

12. CASL tracks the percentage of calls reaching the general inquiry number, including IVR calls that are answered within 30 seconds. The yearly performance standard for CASL is 75% with a minimum monthly standard of 40%. The 2021 annual result was 64.3%; however, Enbridge Gas did achieve the minimum monthly standard of 40% in all months. Prior to 2021, Enbridge Gas met the performance standard for CASL on a consistent basis.

13. Provided at Exhibit 1, Tab 9, Schedule 1, Enbridge Gas consolidated its CIS's in July 2021, migrating 1.6 million Union rate zone customers from the CIS in use that was approaching end of life to a single CIS on the platform in use for EGD rate zone customers. The transition of customers to the SAP CIS also introduced these customers to a new customer-facing website, online billing and IVR systems. The change resulted in a significant increase in call volumes and call complexity in 2021. The move to one CIS benefitted customers through efficiencies created by integrated and consistent processes related to call handling, billing and customer experience.

14. As part of this integration project, customers were required to update passwords and banking information and some customers experienced issues with billing data converted during system integration, all of which increased calls to the call centre. Anticipating an increase in call volumes, additional temporary employees were hired to support the transition. Also, prior to the integration, each call centre employee underwent extensive training on the SAP CIS. All the training was virtual due to the pandemic restrictions for in class training, resulting in reduced “hands-on” training and experience. Over the same period Enbridge Gas experienced a shortage of resources in the call centre due to increased illness and absences related to the COVID-19 pandemic. While Enbridge Gas added temporary staffing, adding enough temporary staff to cover all absences due to COVID-19 outbreaks was not practical. It takes up to four weeks for call centre staff to be initially trained to answer calls related to customer move and an additional two weeks of training to answer more complex calls such as billing calls or questions on changes to rates.

15. The annual call volumes prior to the pandemic in 2019 were 3,588,323 and the average call handling time was 7 minutes and 7 seconds. In 2021 the annual call volumes were 3,609,331 and the average call handling time was 8 minutes and 14 seconds. The call volumes between 2019 and 2021 did increase and may have been even higher for 2021 following CIS integration, if not for Enbridge Gas implementing enhanced web self-serve options, including an online chatbot in August 2019. From the time of integration in July 2021 to the end of that year, there were approximately 900,000 transactions completed across the digital channels (My Account, IVR and chatbot) which represents approximately half of total customer interactions which otherwise could have been calls to the call centre. The web self-service implementation is part of Enbridge Gas’s digital strategy to better meet customer expectations. Enbridge Gas’s customers can self-serve for less

complex inquiries such as viewing account balances, submitting meter readings and moves. This leaves the more complex inquiries for the call centre, and these calls tend to be lengthier.

16. Complex call types are most often in the billing category and are driven by a heightened interest in understanding and lowering gas use and changes to rates, amplified by broader customer affordability concerns. These calls often include multiple intents within the same interaction. For example, a billing call may start with an inquiry about the balance but will commonly transition to options available to make payments easier if the balance is higher than expected. As well, during the initial pandemic period of 2020 through 2021, Enbridge Gas administered the Ontario Government's COVID-19 Energy Assistance Program to support customers through pandemic lockdowns. Agents are trained to address customers' questions in an empathetic manner and offer support to customers experiencing hardship. The current metrics require agents to seek to minimize average call handle time so they can answer a higher volume of calls. A metric that incents shorter individual call times may result in a less positive customer experience for customers seeking assistance with paying bills and other complex issues.

2.2. Abandon Rate

17. AR tracks the percentage of callers who hang up while waiting for a live operator. The annual standard is not to exceed 10%. As a result of the increased call volume and call complexity, customers had a longer wait time to speak to a live operator and this impacted the AR. The 2021 result was 16%. As with the CASL measure, the 2021 result is not consistent with historical performance. The result in 2019 was 2.5% and 5.4% in 2020, exceeding the performance standard.

18. The AR was also impacted by the CIS integration in 2021 and the COVID-19 pandemic. The increase in call volumes, call handling time, and staffing issues due to illness resulted in an increase in wait times driving the increased AR.

2.3. Time to Reschedule a Missed Appointment

19. The TRMA tracks the percentage of customers contacted to reschedule work within two hours of the end of the original appointment time. Enbridge Gas has historically experienced challenges meeting the annual performance standard of 100% for the TRMA measure. The result in 2021 was 97%, consistent with previous years.

20. Efforts toward improving the TRMA target of 100% are ongoing. Enbridge Gas began to align work management systems and processes upon amalgamation in 2019 and by 2021, was able to move to one platform for the planning and scheduling of customer work. Enbridge Gas is investigating process and technology solutions that will further enhance its ability to reschedule customer appointments when required. For example, technology to ensure technicians can continue to use their cellular phones in the event of a service provider outage has been implemented and the ability to text customers to communicate that they will not be able to attend the appointment on time are being reviewed.

21. While Enbridge Gas acknowledges that prompt rescheduling of missed appointments is an important part of achieving the SQR and customer service, attainment of a performance standard of 100% is unreasonable and impractical. The 100% target does not consider factors like emergency response, human error and technical error. In the event of an emergency, technicians and dispatch team members are redirected from non-emergent customer appointments to respond to emergencies such as blowing gas or an odour call. Redirecting from customer

appointments to respond to an emergency can impact the ability of Enbridge Gas to meet a booked customer appointment and the reschedule timeline. It should be noted that the number of missed appointments that are not rescheduled within the required time represents a small percentage of total customer four-hour window appointments. For example, in 2021 there were 54 four-hour window appointments that were missed and were not rescheduled within two hours of the original appointment window end time. 54 appointments represents 0.1% of the 51,821 four-hour window appointments completed in 2021. Of the 54 appointments where Enbridge Gas did not contact the customer to reschedule within two hours of the original appointment window, there were 20 appointments that were still completed that day. In addition, Enbridge Gas consistently exceeds the Appointments Met target, demonstrating commitment to and success with overall customer service. By meeting more appointments, the Company reduces the absolute number of calls that require rescheduling, which promotes greater customer satisfaction.

2.4. Meter Reading Performance Measurement

22. MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% or less and Enbridge Gas attained 5% in 2021. The result for 2020 was 4.4% and 0.7% in 2019.

23. In 2019, the main reasons for Enbridge Gas not meeting the MRPM include:
    a) Extreme weather events such as freezing rain, polar vortex, heavy snowfall and flooding which limited the ability to travel to properties and access meters safely; and

b) A key vendor decision to no longer provide meter reading services and end its contract with Enbridge Gas, resulting in the unplanned need to hire a new vendor in an already limited market.

24. For 2020 and 2021, the pandemic presented many additional and unprecedented challenges to Enbridge Gas meeting the MRPM, such as:
    a) Enbridge Gas, like all Ontario residents and businesses, was required to follow public health guidelines during the pandemic. During the early onset of the COVID-19 pandemic and periods of lockdown, Enbridge Gas faced several challenges with meter reading and considered pausing meter reading activity due to public concerns about the safety of meter reading activity. Enbridge Gas directed its meter reading partners to ensure that all staff were working as safely as possible and to avoid close contact with the public and customers based on sensitivities. The pandemic resulted in many events beyond the control of Enbridge Gas such as closed businesses, increased customer sensitivities and access issues such as the inability to read inside meters;
    b) Extreme weather events such as freezing rain, polar vortex, heavy snowfall and flooding which limited the ability to travel to properties and access meters safely; and
    c) A new meter reading vendor was still transitioning and learning the requirements of Enbridge Gas, while also facing challenges with staffing due to the COVID-19 pandemic. Resourcing issues impacted all meter reading vendors during the pandemic and included challenges hiring staff and absences due to illness and the quarantine/isolation periods required by public health to ensure public safety.

25. The attrition rate for meter reading personnel in 2022 is 20% and the level of absenteeism is 17%, the highest that Enbridge Gas has experienced. Meter reading vendors are also experiencing hiring challenges with low applicant interest due to the physically demanding nature of the role, which also contributes to the high attrition rate adding to the challenge of achieving the staffing levels required to meet the MRPM. Weather is also an area where there is a shift to more natural weather events. In 2020 and 2021 there were over 27 different events ranging from flooding to tornadoes and severe cold and snow. Winter forecasts for 2023 call for snow, rain and record-breaking cold temperatures which will contribute to missed reads due to unsafe weather conditions, particularly in the northern area. These changes in customer behaviour, labour market challenges and weather impacts that are outside of the control of Enbridge Gas are expected to continue for the foreseeable future. These factors make it unrealistic and impractical for Enbridge Gas to be able to commit to meeting the performance standard of 0.5% in future years.

26. In addition to the challenges listed above, the MRPM is cumulative, where the total number of unread meters fluctuates as some meters are read and are deducted from the totals, while other meters remain unread from the previous month, and new meters reach their four-month timeline and are added to the current consecutive estimate results. This means that even though a percentage of meters have successfully been read, Enbridge Gas will continue to have meters that have consecutive estimates. With over 3.8 million customers, if 19,000 meters have consecutive estimates on average each month, the metric is not achieved. Once a meter has a consecutive estimate for four months or more, it will count toward the metric in a minimum of two-meter reading cycles. Unread meters being carried into the next year compound the results when added to the external challenges such as extreme weather events, COVID-19, and staffing issues. In addition, due to

increased customer sensitivity, meter access issues are contributing in the range of 1-3% of the total monthly percentage of consecutive estimates. At the current metric level, based on access issues alone, Enbridge Gas is not able to meet the metric in 2022. The cumulative impact of all of these factors makes, meeting the MRPM impossible for the year.

27. Enbridge Gas is working with customers where the meter is not accessible. Examples include sending regular emails and letters asking the customers to submit a read, working with field staff to obtain reads on all service visits and sending out personnel to knock on customers' doors to arrange access to the meter. Enbridge Gas is also working with customers impacted by the consecutive estimates to ensure that their billing is reconciled as soon as an actual read is obtained. In addition, Enbridge Gas is sending out notices where an email is available to advise customers of the adjustments which include the adjusted amount, timeframe and difference in charges. Customers are provided their bill (paper bill or eBill) 21 days before payment is required providing them with the opportunity to contact Enbridge Gas regarding their amount owing. Where the billing adjustment results in an amount owing, flexible pay arrangements are offered in the event that they need extra time to pay. Where the billing adjustment results in a credit, customers have the option to have the money returned to them automatically through their bank, an interac etransfer or a cheque.

28. Enbridge Gas is continuing work to maintain and, where necessary, improve the results of all scorecard performance measures through ongoing reporting of results, identifying the root cause for variances and implementing initiatives targeting areas where improvement can be made. Such initiatives include the implementation of automated process tools which allow Enbridge Gas to process reads into its system

faster making them available for billing to customers. Enbridge Gas is committed to continuous year-over-year performance improvement and has developed mitigation plans to aid in achieving progress.

3. Exemption Request and GDAR Review Recommendation

29. Enbridge Gas anticipates continued challenges through the rebasing period meeting the existing performance standards for the CASL, TRMA and MRPM and therefore is seeking a partial exemption from these SQR measures beginning in 2024 for the rebasing period or until the OEB orders otherwise (such as through a generic review of the GDAR, as recommended below). Enbridge Gas has made a separate application to request a similar exemption for 2023.[4] Plans have been developed and initiatives are being implemented to improve performance, however, given changes in customer behaviour and expectations and comparison with the equivalent performance standards for electric utilities, the existing targets are no longer reasonable. Enbridge Gas requests a partial exemption to replace the existing CASL, TRMA and MRPM with the modified measures set out in Attachments 2-4 and summarized as follows:

a) CASL – achieve 65% of calls reaching the general inquiry number answered within 30 seconds. This aligns with the Distribution System Code (DSC);
b) TRMA – attempt to contact customers requiring a rescheduled appointment within one business day of the original appointment window 98% of the time. This is also similar to the DSC; and
c) MRPM – achieve no more than 2% of meters with consecutive estimates for four months or more.

[4] EB-2022-0276.

Enbridge Gas aims to meet the AR measure of no more than 10% of callers hanging up while waiting for a live operator. Enbridge Gas believes the AR and remaining performance standards and measurements in the scorecard continue to be appropriate for measuring performance.

30. In the longer term and for the purpose of generic application to rate-regulated gas utilities, Enbridge Gas recommends that the OEB's Chief Executive Officer conduct a review of the GDAR pursuant to Section 44 of the OEB Act and consider amendments to the SQR performance measures for which Enbridge Gas is requesting a partial exemption in this Application.

31. Enbridge Gas submits that a generic review of the GDAR performance standards is required because:

   a) The performance standards were established more than 15 years ago and are not reflective of the current customer behaviours and expectations. For instance, customer calls are more complex in nature as customers can use web self-service options and chatbot feature for less complex inquiries;
   b) There is lack of alignment with the DSC performance standards and no allowance for force majeure relief in the GDAR;
   c) There are continuing impacts of external factors such as the pandemic, labour market and economic environment; and
   d) Planned activities to align systems and meet industry standards (such as for cyber-security) may impact metric performance.

3.1. Customer Behaviour and Expectations

32. The SQRs were added to the GDAR on January 1, 2007. The SQR performance measures are more than 15 years old and in that time, there have been notable

changes to customer behaviour and expectations. From the customer behaviour perspective, there is increased customer sensitivity to contact with meter readers and/or meter readers going onto homeowners' property which creates access issues. In addition, since the pandemic began, more customers are working from home and are now seeing readers access the meter which is causing increased customer concerns such as trespassing and accusations of meter readers stealing packages from front porches. From the customer expectation perspective, customers expect digital channels in addition to being able to reach agents by phone by calling the call centre. Companies now need to develop, support, and maintain service levels for multiple points of contact for customers. Digital channels such as websites, chatbots and IVRs allow customers to complete self-serve activities such as change of address and checking account information.

3.2. Distribution System Code Alignment

33. The DSC SQRs and the SQRs within the GDAR do not align on similar measures.

- The Rescheduling a Missed Appointment measure in the DSC is an attempt to contact the customer prior to the appointment and an attempt to reschedule within one business day compared to the GDAR requirement to reschedule within two hours of the end of the original appointment time;
- The Telephone Accessibility performance measure in the DSC is to answer 65% of calls in 30 seconds compared to CASL in the GDAR that requires 75% of calls to be answered in 30 seconds; and
- The DSC contains a force majeure provision that allows a utility to be relieved of obligations for events that are beyond its reasonable control and the GDAR is silent on force majeure.

3.3. External Factors and Planned Activities

34. External factors such as the pandemic, labour market conditions and economic factors continue to impact the ability of Enbridge Gas to meet the performance standards outlined in the GDAR. Mitigation plans have been developed and initiatives are being implemented that will assist the Company in managing outside factors; however the Company expects continued challenges with meeting existing targets. Outside factors include:
    a) The COVID-19 pandemic continues to impact the ability to meet performance standards with increased illness and absence of call centre agents and meter readers;
    b) Challenges hiring staff experienced across Ontario has impacted the ability to hire temporary and full-time employees for the call centre and for the meter reading vendor to hire full-time staff;
    c) Extreme weather events such as heavy snowfall, extreme cold, and flooding have been impactful, and this trend is likely to continue; and
    d) An increase in the natural gas bills, due to inflation, global energy shortages and federal carbon charges has resulted in an increase in customer bills resulting in an increase in calls to the call centre.

35. Enbridge Gas continues to align and integrate processes and enhance technology to better serve its customers. For example, the proposed general service rate harmonization outlined in evidence provided at Exhibit 8, Tab 2, Schedule 3 for implementation is planned for April 2025. Rate harmonization will increase calls to the call centre as customers adjust to the new rate structure, impacting the ability to meet the CASL performance standard in the first few years of the rebasing period. Also, Enbridge Gas expects increased call volumes to result from its

implementation of the mandatory Green Button program.

36. As outlined under historical scorecard performance for CASL, the increased complexity of calls has led to longer call times which impacts the number of calls that can be answered by agents. Agents typically manage multiple questions with each customer transaction with the majority of questions being about billing including how to lower usage, questions about changes to rates and affordability concerns. The focus on decreasing call handling time to meet the metric target can result in a less positive customer experience as agents work to quickly answer inquiries and move to the next call rather than taking extra time when needed to understand the entire customer experience, address concerns and respond in an empathetic manner.

4. Mitigation Plans

37. Enbridge Gas is committed to providing excellent customer service to all customers and has developed mitigation plans for the performance measures not met in 2021. The mitigation plans outline the approach to improve metric performance: the mitigation plans for 2022 were provided to the OEB as part of the Assurance of Voluntary Compliance[5] dated September 2022; the mitigation plans for the reporting year 2023 were provided in the 2023 GDAR Exemption Request Application; and the mitigation plans for 2024 and beyond are found at Attachments 2-4.

[5] EB-2022-0188, Assurance of Voluntary Compliance, September 12, 2022. https://www.oeb.ca/sites/default/files/EGI-Assurance-of-Voluntary-Compliance-20220912.pdf

4.1. Call Answering Service Level and Abandon Rate

38. To improve performance on the CASL and the AR, Enbridge Gas has identified and implemented several initiatives outlined in the mitigation plan provided at Attachment 2. The main elements include:
    a) Planning – implementing an augmented planning process to better assess and mitigate impacts from events with customer-facing impacts;
    b) Resourcing – recruiting temporary and full-time employees to assist with high call volumes at all call centre and billing locations;
    c) Digital Channel Enhancements – review and continuous improvement of systems to enhance customer experience; and
    d) Customer Service Processes – continuous improvement in response to customer surveys and internal reviews.

4.2. Time to Reschedule a Missed Appointment

39. To improve performance on the TRMA, Enbridge Gas has identified several initiatives outlined in the mitigation plan provided at Attachment 3. The main elements include:
    a) Process – align existing processes for identifying attempts to contact the customer to reschedule appointments;
    b) Technology – leverage technology to aim to improve performance measure results through additional customer contact options for appointment rescheduling;
    c) Reporting - enhanced reporting of results and corrective action process; and
    d) Communication – ongoing communication of process to reschedule appointments.

40. The mitigation plans aim to achieve a performance standard of 98% of customer appointments rescheduled within one business day for TRMA commencing in 2024.

4.3. Meter Reading Performance Measurement

41. Enbridge Gas recognizes the importance of obtaining regular meter reads and is committed to implementing a plan to reduce the consecutive estimate count. Key initiatives are outlined in the mitigation plan provided at Attachment 4. The main elements include:

   a) Consecutive estimate campaign – working with meter reading vendors to hire additional readers and conduct meter reading and communication campaigns;
   b) Inbound calls – educating customers on the importance of providing access to meters and providing assistance to read own meters;
   c) Customer outreach – targeted customer communications to engage customers to arrange for meter access and submit own meter reads;
   d) Operations engagement – field operations to support meter access efforts; and
   e) Meter reading processes – review and continuous improvement to increase attainment and efficiency.

42. The mitigation plan aims to achieve a 2% MRPM for in 2024 and for the rebasing period.

43. In addition to the above-mentioned initiatives to reduce the consecutive estimate count, Enbridge Gas is investigating an Advanced Metering Infrastructure (AMI) solution to automate its meter reading process for customers. Details on this initiative are provided at Exhibit 2, Tab 7, Schedule 2. The current meter reading

process is highly manual and can be inconvenient to customers. Further, the utility industry is overwhelmingly moving towards some form of meter automation, leading to changes in both market conditions and customer expectations. Automation is more accurate and convenient for customers while allowing operational efficiencies to be achieved for the utility and additional insight for customers as they can see further details on their gas consumption patterns.

4.4. Mitigation Plan Monitoring and Conditions of Approval

44. Enbridge Gas will monitor the success of the mitigation initiatives and the impact on metric performance to determine if adjustments need to be made to the initiatives or if new initiatives need to be added. Internally, weekly reporting and comprehensive monthly reviews will occur with the cross-functional teams responsible for metric performance. Monthly reviews will include variance explanations and management action plans focusing on continuous improvement. In addition, monthly reporting of mitigation plan progress and metric performance will be presented to Enbridge Gas senior leadership.

45. Enbridge Gas anticipates the continuation of annual SQR reporting under the Natural Gas Reporting and Record Keeping Requirements (RRR) Rule for Gas Utilities during the relief period. Enbridge Gas will provide quarterly updates to OEB taff on progress with implementing mitigation plans and metric performance for TRMA, CASL and MRPM.

5. Summary

46. Enbridge Gas is requesting a partial exemption for three of the measures on the scorecard and in the GDAR: CASL, TRMA and MRPM. Relief is needed from these GDAR targets beginning in 2024 until the OEB orders otherwise or until such time

as the OEB conducts a review of the GDAR SQR metrics to modernize the SQRs with the current business environment and customer needs, behaviours and expectations. During the partial exemption period, Enbridge Gas will work towards continuous improvement on metric performance as outlined above and in its attached mitigation plans. Enbridge Gas will monitor and track results of its efforts and report regularly to OEB staff on progress. Regardless of the current challenges with the SQR metrics, Enbridge Gas remains committed to providing a positive customer experience and continuous improvement related to all of the performance measures on the scorecard.

EGI OEB SCORECARD 2017 - 2021

#	Performance Measure	Target	Actual 2021 EGI	Actual 2020 EGI	Actual 2019 EGI	Actual 2018 EGD	Actual 2018 Union	Actual 2017 EGD	Actual 2017 Union
#	**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%	96.9%	98.9%	98.1%	97.3%	90.7%	96.2%	90.5%
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%	94.5%	98.8%	98.5%	94.7%	98.8%	94.3%	99.0%
3	**Telephone calls answered on time (call answering service level)** (# of calls answered within 30 seconds / # of calls received)	75.0%	64.3%	75.2%	79.0%	82.0%	77.6%	82.5%	79.2%
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%	100.0%	100.0%	100.0%	100.0%	100.0%	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.'		384,858 manual checks completed as per QAP	427,524 manual checks completed as per QAP	429,386 manual checks completed as per QAP	224,316 manual checks completed as per QAP	218,700 manual checks completed as per QAP	494,330 manual checks completed as per QAP	167,075 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%	16.0%	5.4%	2.50%	1.9%	2.6%	1.8%	3.4%
7	**Time to Reschedule a Missed Appointments** (% of rescheduled work within 2 hours of the end of the original appointment time)	100.0%	97.0%	97.3%	97.0%	98.7%	99.8%	96.8%	99.9%
	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%	5.0%	4.4%	0.7%	0.5%	0.4%	0.5%	0.1%
9	**% of Emergency Calls Responded within One Hour** (# of emergency calls responded within 60 minutes / # of emergency calls)	90.0%	95.2%	96.7%	96.7%	96.6%	99.3%	96.8%	99.0%
10	**Compression Reliability** % reliable for transmission compression		99.7%	99.7%	99.9%	NA	99.8%	NA	99.9%
11	**Damages per 1000 locate requests**		1.95	2.22	1.97	1.85	2.28	1.83	2.17
12	**Total Cost per Customer** ($ / Customer)		643.94	658.2	653.6	530.7	756.7	513.9	730.3
13	**Total Cost per km of Distribution Pipe** ($ / km of Distribution Pipe)		16,639.6	16,928.5	16,735.4	15,123.1	16,947.5	14,739.7	16,109.4
	PUBLIC POLICY RESPONSIVENESS (Conservation & Demand Management & Connection of Renewable Generation)								
14	**Total Cumulative Cubic Meters of Natural Gas Saved (Net)** (Millions)			1,632.2	2,075.9	807.5	1,124.5	787.2	1,182.7
	FINANCIAL PERFORMANCE (Financial Ratios)								
15	**Current Ratio** (Current Assets / Current Liabilities)		0.71	0.66	0.75	0.93	0.69	0.84	0.47
16	**Debt Ratio** (Total Debt / Total Assets)		0.41	0.40	0.40	0.49	0.51	0.47	0.49
17	**Debt to Equity Ratio** (Total Debt / Shareholders' Equity)		1.06	1.01	0.98	1.67	2.12	1.54	2.08
18	**Interest Coverage** (EBIT / Interest Charges)		2.55	2.34	2.53	2.52	2.69	1.96	2.42
19	**Financial Statement Return on Assets** (Net Income / Total Assets)		2.07%	1.97%	2.25%	2.98%	3.20%	2.27%	2.71%
20	**Financial Statement Return on Equity** (Net Income / Shareholders' Equity)		5.32%	4.96%	5.56%	10.20%	13.25%	7.39%	11.43%

Customer Care

Telephone Answer Performance

Enbridge Gas Inc.
Mitigation Plan

September 1, 2022

Mitigation Plan – Call Answering Service Level (CASL) / Abandonment Rate

Background

Call Answering Service Level (CASL) tracks the percentage of calls reaching the general inquiry number, including IVR calls that are answered within 30 seconds. Abandonment Rate tracks the percentage of callers who hang up while waiting for a live operator. In 2021, Enbridge Gas completed an integration project to bring all of its 3.8M customers into one customer information system (CIS (SAP)). This resulted in 1.6M customers moving to the SAP system and at the same time the IVR and MyAccount along with the web were integrated. As a result, customers moving to SAP had to update their password as well as their banking information. This resulted in a significant increase in calls into the contact centre. In addition, following the system change a number of billing data exceptions had to be completed, which has also resulted in increased call volumes. The COVID-19 (Covid) pandemic has also impacted the contact centres due to increased illness/absence. As a result of higher call volumes Enbridge Gas did not achieve the call answer and abandonment metrics in 2021. Based on this recent experience along with upcoming events during 2024 - 2026, Enbridge is anticipating challenges to meet the metrics and a mitigation plan has been developed.

Enbridge Gas is committed to providing excellent customer service to all customers.

Enbridge Gas is also anticipating and planning for a number of events throughout 2024-2026 that will have customer-facing impacts, including further integration work, Rebasing, Service Harmonization and the implementation of Green Button. These events are expected to generate questions from customers that will be of a complex nature, thereby impacting the contact centre operation.

To ensure Enbridge Gas achieves 65% of calls being answered within 30 seconds and an abandonment rate of 10% or lower, the following initiatives will take place through the period of 2024 to 2026.

Initiative	Description	Target Segment	Start Date	Details
Planning	Implement augmented planning and forecasting activities	All contact centre locations	Ongoing, starting in 2023	• Determine company activities for 2024 - 2026 period. • Assess external activities for 2024 - 2026 to understand further potential for customer impacts. • Review OEB Decision and Order(s) as an outcome of the Rebasing proceeding to determine effects on Call Centre • Conduct a comprehensive change impact needs assessment on the planned Green Button, Rebasing and Service Harmonization activities.

Initiative	Description	Target Segment	Start Date	Details
				• Develop a staged training plan for the full contact centre team with early start to minimize impacts. • Update process documents and prebuild tools to assist agent's proficiency in handling resulting call types. • Develop a comprehensive customer communication plan for all planned changes. • Maintain and refine agent training and tools following implementation to optimize call handling.

Resourcing	Review staffing plans with options for increased flexibility as a priority.	All contact centre locations	Ongoing	• Going into 2023, Enbridge Gas is adding permanent employees to add stability and broaden the base of call agents.
				• Enbridge Gas will continue to hire temporary agents to assist with increased call pressures in key operational periods as well as when extensive training of workforce will be needed, i.e., ahead of and throughout April 2025 when Rate and Service Harmonization is expected to go live.
				  ○ Note: Recruitment and training takes approximately 3 months before employee can answer move calls and an additional 2 weeks before an employee can answer billing related inquiries
				• Monitor and reflect changing staffing trends in forecasting and staffing plans, including recruitment, attrition, and absenteeism.
				• Augment workforce planning based on call volumes. Activities include the following.
				  ○ Weekly touchpoints to ensure metrics are on track and any further mitigation requirements
				  ○ Continuing workshops to drive optimization, identify opportunities for improved performance and maximize utilization of resources.
				  ○ Develop flexible staff strategy that can be leveraged in short term scenarios where volumes are up or staff is limited.
				  ○ Sustain coaching of agents to ensure both average handle times and call quality are in line with expectations.
				  ○ Staggered training of agents to ensure positive customer experience and minimized disruption.
				• Monitor Covid and other illness/absence related impacts. To date we continue to see significant impacts due to increased illness absence frequency and duration.

Initiative	Description	Target Segment	Start Date	Details
Telephony Systems/ System Enhancements	Review of telephony system (IVR) to continually complete enhancements to improve customer experience	IVR Telephony, MyAccount Chatbot	Ongoing	• Regular monitoring of IVR health metrics, including authentication and resolution rates, as well as overall self-serve transaction uptake to understand any trends and address any detracting pressures. • Continuous review of system enhancements to improve customer experience in customer self-service channels (MyAccount, Chatbot, IVR)
Process Improvement	Process review for continuous improvement and customer experience	All Contact Center and Billing Processes	Ongoing	• Continue to conduct Quality Assurance reviews and collect agent feedback on process improvement opportunities. • Monthly review of customer feedback to identify opportunities to improve customer experience. • Review processes with key internal stakeholders to improve customer experience.

Mitigation Plan – Monitoring Initiatives

Throughout the mitigation plan period, Enbridge Gas will monitor the success of each mitigation activity and determine if adjustments need to be made to the initiatives or if new initiatives need to be added. Enbridge Gas will have weekly check points and comprehensive monthly reviews on the progress of mitigation activities to continually improve the call answering and abandonment metrics. Customer Care will lead the reviews and engage with our Service Partners, Regulatory Affairs, Operations, and Communications.

2024 - 2026 Compliance Objectives

Call Answer Service Level (7.3.1.1)

- The yearly performance is expected to achieve 65% with a minimum monthly standard of 40%.

Abandonment Rate (7.3.1.2)

- The yearly performance is expected to normalize and not exceed 10% on average for the year.

Operations - Time to Reschedule a Missed Appointment

Enbridge Gas Inc.

Performance Mitigation Plan

September 1, 2022

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Mitigation Plan – Time to Reschedule a Missed Appointment

The Service Quality Requirement (SQR), Time to Reschedule a Missed Appointment (TRMA) measure tracks the percentage of customers contacted to reschedule work within two hours of the end of the original appointment window. Enbridge Gas experiences challenges meeting the annual performance standard of 100% for the TRMA measure. The result in 2021 was 97.0%; consistent with previous years of 97.3% in 2020 and 97.0% in 2019.

Efforts toward meeting the TRMA target of 100% are ongoing. Enbridge Gas began to align work management systems and processes upon amalgamation in 2019 and by 2021 was able to move to one platform for the planning and scheduling of customer work. Enbridge Gas is investigating process and technology solutions that will further enhance the ability to reschedule customer appointments when required. For example, technology to ensure technicians can continue to use their cellular phones in the event of a service provider outage has been implemented and the ability to text customers to communicate that they will not be able to attend the appointment on time are being reviewed.

While Enbridge Gas acknowledges that promptly rescheduling missed appointments is an important part of achieving the SQR and customer service, attainment of a perfect 100% is unreasonable and impractical. The 100% target does not consider factors like emergency response, human error or technical error. In the event of an emergency, technicians and dispatch team members are redirected from non-emergent customer appointments to respond to emergencies such as blowing gas or odour calls. Redirecting from customer appointments to respond to an emergency can impact the ability of Enbridge Gas to meet a booked customer appointment and the reschedule timeline.

Enbridge Gas is committed to providing excellent customer service to all customers and in doing so improving performance on the TRMA measure. It should be noted that the number of reschedules for missed appointment reschedules not met represents a small percentage of total customer four-hour window appointments. In 2021 this number was 54 reschedules not met of 51,821 appointments which represents less than 0.1% of four-hour window appointments. Of the 54 appointments where Enbridge Gas did not contact the customer to reschedule within two hours of the original appointment window, there were 20 appointments that were still completed that day. In addition, Enbridge Gas consistently exceeds the Appointment Met target, demonstrating commitment to and success with overall customer service. By meeting more appointments, the Company reduces the absolute number of calls that require rescheduling, which promotes greater customer satisfaction.

Enbridge Gas aims to meet a performance standard of 98% for the TRMA measure. At minimum, Enbridge Gas will attempt to contact the customer to reschedule the work within one business day of the end of the original appointment window for 2023 and thereafter.

Initiative	Description	Start Date	Details
Process	Align and enhance process for identifying attempts to contact the customer.	Q4 2022	• Document aligned process to ensure consistent customer experience for rescheduled appointments. ○ Investigate opportunities for capturing reasons for rescheduling • Communicate and reinforce process
Technology	Leverage technology to improve performance standard through additional customer	Q1 2023	• Investigate technology enablement to provide additional customer contact options (e.g., text messaging) ○ Requires process changes such as collecting mobile phone / email when appointment is booked.

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	contact options for appointment rescheduling.		○ Continued rollout of cellular technology to ensure redundancy and the ability of technicians to remain in contact in the event of a service provider outage.
Reporting	Enhanced reporting of results and corrective actions.	2022 - 2025	• Increase frequency of TRMA result reporting to weekly from monthly reporting ○ Escalate missed reschedules to Director, Operations Services ○ Include variance explanations and corrective action plans for missed reschedules
Communication	Ongoing communication of process for rescheduling.	2022 - 2025	• Annually to those with responsibilities to reschedule appointments, to ensure awareness of the compliance requirement under the GDAR.

Mitigation Plan – Monitoring Initiatives

Throughout the period of this mitigation plan, Enbridge Gas will monitor the success of each mitigation activity and determine if adjustments need to be made to the initiatives or if new initiatives need to be added. Enbridge Gas will have weekly check points and comprehensive monthly reviews on the progress of mitigation activities to improve the TRMA measure.

Customer Care

Meter Reading Performance

Enbridge Gas Inc.
Mitigation Plan

September 1, 2022

Mitigation Plan – Consecutive Estimated Meter Reads

Background

The meter reading performance metric (MRPM) has been challenging for Enbridge Gas Inc. (Enbridge Gas) to achieve for a number of reasons, including the decision of a key meter reading vendor (serving 40% of Enbridge Gas's customers) to no longer provide meter reading service and end its contract, resulting in the unplanned need to hire and onboard a new vendor at the end of 2019. Since the start of 2020, the COVID-19 (Covid) pandemic has presented many additional challenges to meeting the MRPM, such as:

- The Covid pandemic resulting in closed businesses, increased customer sensitivity over contact with meter readers, access issues such as inability to read inside meters, and during the early onset of Covid and periods of lockdown, Enbridge Gas faced several challenges around meter reading and had considered pausing meter reading activity due to questions from the public and law enforcement around the safety of meter reading activity. Enbridge Gas directed its meter reading partners to ensure that all staff were working as safely as possible and to avoid close contact with the public and customers based on the sensitivity of the Covid pandemic;

- Extreme weather events such as freezing rain, polar vortex, heavy snowfall, and flooding which limited the ability to travel to properties and access meters safely; and

- A new vendor was still transitioning and learning the business, while also facing challenges with staffing due to the Covid pandemic. Resourcing issues included challenges hiring staff and absences due to illness and the quarantine/isolation periods required by Public Health to ensure public safety.

The MRPM metric of 0.5% is a very onerous Service Quality Requirement (SQR) for Enbridge Gas to meet given its geographic reach, especially when complicated by extraordinary events such as extreme weather and the many impacts from the Covid pandemic. MRPM is a cumulative metric whereby the total number of unread meters fluctuates as some meters are read and come off of the totals, while other meters remain as unread from the previous month, and new meters reach their 4 month timeline and are added to the current consecutive estimate results. This means that even though a percentage of meters have successfully been read, Enbridge Gas will continue to have meters that have consecutive estimates. With over 3.8 million customers, if 19,000 meters have consecutive estimates on average each month the metric is not achieved. With bi-monthly meter reading, once a meter has a consecutive estimate that is 4+ months (two meter reading cycles), it will count toward the metric in a minimum of two months. At the current metric level, based on access issues alone, Enbridge Gas is not able to meet the metric. In addition, if Enbridge Gas experiences a challenging one or two months for meter reading during a year, the MRPM is so difficult to achieve that it becomes impossible to meet for the year. For example, readers have 3 days to read their routes within the billing cycle. When 1 reader becomes ill with Covid and needs to quarantine for 5-10 days, they will miss routes for 2 to 3 cycles (5000-10,000 reads). Another example impacting meter reading was the month-long Ottawa convoy protest. This made getting around the Ottawa area very difficult which resulted in approximately 26,000 meter reads missed.

Enbridge Gas recognizes the importance of conducting regular meter reads. The following steps will be taken to ensure we are continuously attaining meter readings.

Initiative	Description	Target Segment	Start Date	Details

Consecutive Estimate Campaign	Working with meter reading vendors to hire additional meter readers and conduct campaigns to obtain meter reads	All meters	ongoing	• Continuous review of staffing needs and active hiring wherever necessary.
				• Enbridge Gas assistance with recruitment activities and hiring practices
				• Longer working hours – evenings/weekend:
				  ○ Readers will take additional routes, work weekends when weather allows, and additional hours as sunlight hours extend.
				  ○ Meter reading vendors to offer various incentives for working longer hours, weekends and taking on additional routes.
				• Knocking on doors:
				  ○ When a meter reader attends a hard to access property, they will knock on the door and attempt to gain access to read the meter.
				• Door hangers:
				  ○ Notices will be left on customer doors when no contact is made asking the customer to contact us or submit their read.
				• Attain reads on secondary services:
				  ○ When attending properties to complete other services, such as battery exchanges, the meter will be read.

Inbound Calls	Call Centre will request a current read from customer on the phone	All meters	ongoing	Call Centre agents will be requesting reads from customers on the phone.
				
				Agents will ask the customer to submit a read when calling about the following:
				  ○ Move calls
				  ○ Billing calls where last read is estimated
				  ○ Meter reading inquiries
				
				Targeted IVR message for consecutive estimate accounts:
				  ○ Prompt customer to submit a read

Initiative	Description	Target Segment	Start Date	Details
Customer Outreach	Various customer outreach activities to obtain read or make appointment to attend the property	All meters	Ongoing (Annual Spring Launch)	• Targeted emails / text messages and letters to customers encouraging them to submit a meter read online. • Outbound phone calls (dialer/live agent) for 12+ consecutive estimates due to access issues so that we can arrange for access moving forward and to attain a read. • Social media - safety and access campaign: ○ reminder about dogs and allowing us access to read meters • Web messaging to encourage meter reading submissions in combination with social media safety and access campaign starting every Spring.
Operations Engagement	Work with field operations to support hard to access meters	Focus on hard to access meters	Ongoing	• Targeted meter exchange campaign for hard to access meters. • Work with Quality Assurance team to attend properties where Enbridge Gas does not have access to the meter. • Operations appointment, attain reads on properties they attend to complete other work.
Process	Review processes for meter reads	All meters	Ongoing	• Continuous review of processes to ensure increased attainment and utilization of meter reads received. • Prioritize meter reading work to ensure timely billing. • Continuous review of system functionality to allocate meter reads accurately. • Develop administration team to monitor workload efficiency, targeting work with direct meter reading impact (meter exchange, doubtful meter, crossed meter, etc.) • Continuous review of tolerance thresholds to ensure acceptance of actual meter readings. • Work with Field Operations partners to harmonize process and reduce meter work exceptions. • Increase Back Office staffing levels as needed to support Meter Reading. • Enhance system functionality to ensure timely processing of incoming field work.

Mitigation Plan – Monitoring Initiatives

Enbridge Gas will monitor the success of each mitigation activity and determine if adjustments need to be made to the initiatives or if new initiatives need to be added. Enbridge Gas will have weekly check points and comprehensive monthly reviews on the progress of mitigation activities. Customer Care will lead the reviews and engage with our Service Partners, Regulatory Affairs, Operations, and Communications.

<u>2023 - 2025 Compliance Objectives</u>

Meter Reading Performance Measurement (7.3.3.1)

This target is difficult to meet at the best of times and has been significantly impacted by increased challenges over the past two years (2020 – 2021), as a result of the Covid pandemic, including resourcing constraints and access issues, weather and safety impacts.

- With the mitigation initiatives taking place in 2023 through to 2025, the yearly performance for 2023 will improve from the 2022 results.
- The annual performance for 2023 is expected to be in the range of 2%, which will include meter reads for circumstances in which Enbridge Gas is not able to access customer meters for various reasons such as, locked gates, inside meters and customers not providing access to the property.
- During the period of this mitigation plan, Enbridge Gas will provide the OEB in Pivotal UX the meter reading results. Enbridge Gas will continue to track the number of inaccessible meters numbers and will report to the OEB upon request.

[2] EB-2021-0149, OEB Decision and Order in Enbridge Gas Application for 2020 Disposition of Deferral and Variance Account Balances and Earning Sharing Mechanism (January 27, 2022), p. 12.

FINANCIAL INFORMATION

In accordance with the Filing Requirements[1], this section of evidence and associated attachments include the required financial information.

1. Audited Financial Statements of The Utility

Enbridge Gas's historical audited financial statements are provided as follows:

- Attachment 1: Enbridge Gas Inc.'s audited consolidated financial statements for the year ended December 31, 2020
- Attachment 2: Enbridge Gas Inc.'s audited consolidated financial statements for the year ended December 31, 2021

The audited financial statements are only available on a consolidated basis.

2. Detailed Reconciliation of the Financials

A detailed reconciliation of financial results shown in the audited financial statements is provided as follows:

- Attachment 3: Reconciliation of audited EGI income (per financial statements) to corporate income for utility income determination purposes for 2019 actual results
- Attachment 4: EGI utility income for 2019 actual results
- Attachment 5: Reconciliation of audited EGI income (per financial statements) to corporate income for utility income determination purposes for 2020 actual results
- Attachment 6: EGI utility income for 2020 actual results

[1] Filing Requirements For Natural Gas Rate Applications, February 16, 2017.

- Attachment 7: Reconciliation of audited EGI income (per financial statements) to corporate income for utility income determination purposes for 2021 actual results
- Attachment 8: EGI utility income for 2021 actual results

3. Proforma Statements for Bridge Year and Test Year

Pro-forma statements for Enbridge Gas for the 2023 Bridge Year and 2024 Test Year are provided as follows:

- Attachment 9: Pro-forma Statements – EGI – 2023 and 2024

4. Annual Report and Management Discussion and Analysis (MD&A) For The Most Recent Year From Parent Company

Enbridge's 2021 Annual Report which includes the MD&A is provided as follows:

- Attachment 10: Enbridge Inc. 2021 Annual Report

5. Rating Agency Reports

Copies of the most recent rating agency reports performed by DBRS Limited (DBRS), and S&P Global Ratings are provided as follows:

- Attachment 11: DBRS Rating Report – Enbridge Gas Inc. (dated September 27, 2022)
- Attachment 12: S&P RatingsDirect – Enbridge Gas Inc. (dated February 1, 2022)

6. Prospectuses, Information circulars, etc. for recent and planned public debt or equity offerings

A copy of the prospectus for recent public debt offerings:

- Attachment 13: Short Form Base Shelf Prospectus – Enbridge Gas Inc. (dated September 8, 2021)

7. Existing Accounting Orders and List Of Any Departures From These Orders

The following are a list of the existing deferral and variance accounts for Enbridge Gas:

7.1. EGD Rate Zone

- Purchase Gas Variance Account (Account No. 179-70_)
- Transactional Services Deferral Account (Account No. 179-80_)
- Unaccounted for Gas Variance Account (Account No. 179-86_)
- Storage and Transportation Deferral Account (Account No. 179-88_)
- Gas Distribution Access Rule Impact Deferral Account (Account No. 179-20_)
- Deferred Rebate Account (Account No. 179-00_)
- Pension and OPEB Forecast Accrual vs. Actual Cash Payments Differential Variance Account (Account No. 179-36_)
- Incremental Capital Module Deferral Account (Account No. 179-500)
- Facility Carbon Charge Variance Account (Account No. 179-503)
- Customer Carbon Charge Variance Account (Account No. 179-502)
- Greenhouse Gas Emissions Administration Variance Account (Account No. 179-501)
- Average Use True-up Variance Account (Account No. 179-66_)
- Transition Impact of Accounting Changes Deferral Account (Account No. 179-02_)
- Ex-Franchise Third Party Billing Services Deferral Account (Account No. 179-08_)

- Renewable Natural Gas Injection Service Variance Account (Account No. 179-12_)
- Dawn Access Cost Deferral Account (Account No. 179-40_)
- Open Bill Revenue Variance Account (Account No. 179-48_)
- OEB Cost Assessment Variance Account (Account No. 179-94_)

7.2. Union Rate Zones

- Union South Purchase Gas Variance Account (Account No. 179-106)
- Union North West Purchase Gas Variance Account (Account No. 179-147)
- Union North East Purchase Gas Variance Account (Account No. 179-148)
- Transportation Tolls and Fuel - Union North West Operations Area (Account No. 179-145)
- Transportation Tolls and Fuel - Union North East Operations Area (Account No. 179-146)
- Spot Gas Variance Account (Account No. 179-107)
- Unabsorbed Demand Costs Variance Account (Account No. 179-108)
- Inventory Revaluation Account (Account No. 179-109)
- Upstream Transportation Optimization Deferral Account (Account No. 179-131)
- Base Service North T-Service TransCanada Capacity Account (Account No. 179-153)
- Unaccounted for Gas Volume Variance Account (Account No. 179-135)
- Unaccounted for Gas Price Variance Account (Account No. 179-141)
- Gas Distribution Access Rule Costs Deferral Account (Account No. 179-112)
- Deferral Clearing Variance Account (Account No. 179-132)
- Parkway Obligation Rate Variance Account (Account No. 179-138)
- Unauthorized Overrun Non-Compliance Account (Account No. 179-143)

- Pension and OPEB Forecast Accrual vs. Actual Cash Payments Differential Variance Account (Account No. 179-157)
- Incremental Capital Module Deferral Account (Account No. 179-159)
- Facility Carbon Charge Variance Account (Account No. 179-420)
- Customer Carbon Charge Variance Account (Account No. 179-421)
- Greenhouse Gas Emissions Administration Deferral Account (Account No. 179-422)
- Normalized Average Consumption Account (Account No. 179-133)
- OEB Cost Assessment Variance Account (Account No. 179-151)
- Short-term Storage and Other Balancing Services Deferral Account (Account No. 179-70)
- Unbundled Services Unauthorized Storage Overrun Deferral Account (Account No. 179-103)
- Brantford-Kirkwall/Parkway D Project Costs (Account No. 179-137)
- Burlington-Oakville Project Costs (Account No. 179-149)
- Dawn H/Lobo D/Bright C Compressor Project Costs (Account No. 179-144)
- Lobo C Compressor/Hamilton-Milton Pipeline Project Costs (Account No. 179-142)
- Panhandle Reinforcement Project Costs (Account No. 179-156)
- Parkway West Project Costs (Account No. 179-136)
- Sudbury Replacement Project Costs (Account No. 179-162)

7.3. Enbridge Gas

- Earnings Sharing Mechanism Deferral Account (Account No. 179-382)
- Tax Variance Deferral Account (Account No. 179-383)
- Expansion of Natural Gas Distribution Systems Variance Account (Account No. 179-380)

- Integrated Resource Planning Operating Cost Deferral Account (Account No. 179-385)
- Integrated Resource Planning Capital Cost Deferral Account (Account No. 179-386)
- Green Button Initiative Deferral Account (Account No. 179-387)
- Demand Side Management Variance Account (Account No. 179-313)
- Lost Revenue Adjustment Mechanism Variance Account (Account No. 179-314)
- Conservation Demand Management Deferral Account (Account No. 179-315)
- Demand Side Management Incentive Deferral Account (Account No. 179-316)
- Accounting Policy Changes Deferral Account (Account No. 179-381)
- Impacts Arising from the COVID-19 Emergency Deferral Account (Account No. 179-384)

Please see Exhibit 9, Tab 1, Schedule 1, Attachment 1 for a description of the existing deferral and variance accounts for more information. There are no departures from any existing accounting orders. The DSM-related deferral and variance accounts listed above are subject to OEB approval as part of the 2023 to 2027 DSM Plan[2] proceeding.

8. Departures from the Uniform System of Accounts for Class A Gas Utilities

There are no departures from the Uniform System of Accounts for Class A Gas Utilities.

[2] EB-2021-0002, Exhibit F, Tab 1, Schedule 1.

9. Change in Tax Status

Enbridge Gas or its predecessors have not changed their tax status since 2013. EGD and Union, two taxable Canadian corporations, continued as Enbridge Gas on January 1, 2019.

10. Accounting Standard Used

Enbridge Gas follows United States Generally Accepted Accounting Principals (US GAAP) for its general-purpose financial statements. Information on Enbridge Gas accounting standards is provided at Exhibit 1, Tab 8, Schedule 2.

11. Qualifying Facilities and Assets

Enbridge Gas does not have any qualifying facilities or assets (non-utility business, such as generation and energy storage facilities) and confirms this annually through its Reporting and Record Keeping Requirements (RRR) filing.

12. Enbridge Gas Tax Returns

Copies of the most recent Federal and Provincial tax returns are provided as follows:

- Attachment 14: 2021 Federal and Provincial Tax Return

ENBRIDGE GAS INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2020

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE GAS INC.

Financial Reporting
Management of Enbridge Gas Inc. (the Company) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors is responsible for all aspects related to governance of the Company. The Company does not have an Audit Committee, having received an exemption from such requirement.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with U.S. GAAP and to provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, have conducted an audit of the consolidated financial statements of the Company in accordance with Canadian generally accepted auditing standards and have issued an unqualified audit report, which is accompanying the consolidated financial statements.

"signed"	**"signed"**
Cynthia L. Hansen	**Tanya M. Ferguson**
President	Vice President, Finance

February 12, 2021

Independent auditor's report

To the Shareholders of Enbridge Gas Inc.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Inc. (the Company) as at December 31, 2020 and 2019, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America (US GAAP).

What we have audited
The Company's consolidated financial statements comprise:

- the consolidated statements of earnings for the years ended December 31, 2020 and 2019;
- the consolidated statements of comprehensive income for the years ended December 31, 2020 and 2019;
- the consolidated statements of changes in equity for the years ended December 31, 2020 and 2019;
- the consolidated statements of cash flows for the years ended December 31, 2020 and 2019;
- the consolidated statements of financial position as at December 31, 2020 and 2019; and
- the notes to the consolidated financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with US GAAP, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

pwc

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

/s/ PricewaterhouseCoopers LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Ontario
February 12, 2021

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Operating revenues		
Gas commodity and distribution	**3,631**	4,152
Storage, transportation and other	**884**	923
Total operating revenues *(Note 4)*	**4,515**	5,075
Operating expenses		
Gas commodity and distribution costs	**1,812**	2,334
Operating and administrative	**1,137**	1,109
Depreciation and amortization	**655**	638
Total operating expenses	**3,604**	4,081
Operating income	**911**	994
Other income	**56**	20
Interest expense, net *(Note 10)*	**(412)**	(400)
Earnings before income taxes	**555**	614
Income tax expense *(Note 15)*	**(58)**	(58)
Earnings	**497**	556

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Earnings	**497**	556
Other comprehensive income/(loss), net of tax *(Notes 12 and 13)*		
Change in unrealized loss on cash flow hedges	**(37)**	(37)
Reclassification to earnings of loss on cash flow hedges	**15**	4
Recognition of regulatory offset	**—**	55
Actuarial loss on other postretirement benefits (OPEB) *(Note 16)*	**(10)**	(12)
Foreign currency translation adjustment	**—**	(5)
Other comprehensive (loss)/income, net of tax	**(32)**	5
Comprehensive income	**465**	561

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Common shares *(Note 11)*		
Balance at beginning of year	**3,517**	3,030
Capital contribution	**800**	800
Return of capital	**(800)**	(313)
Balance at end of year	**3,517**	3,517
Additional paid-in capital		
Balance at beginning and end of year	**7,253**	7,253
Deficit		
Balance at beginning of year	**(720)**	(339)
Earnings	**497**	556
Common share dividends declared	**(450)**	(937)
Adoption of new accounting standard	**(2)**	—
Balance at end of year	**(675)**	(720)
Accumulated other comprehensive loss *(Note 12)*		
Balance at beginning of year	**(46)**	(51)
Other comprehensive (loss)/income, net of tax	**(32)**	5
Balance at end of year	**(78)**	(46)
Total equity	**10,017**	10,004

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Operating activities		
Earnings	**497**	556
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	**655**	638
Deferred income tax recovery	**(25)**	(31)
Net defined pension and OPEB costs	**(31)**	(17)
Loss on disposition	**—**	10
Other	**13**	5
Changes in operating assets and liabilities *(Note 18)*	**93**	116
Net cash provided by operating activities	**1,202**	1,277
Investing activities		
Capital expenditures	**(1,109)**	(1,073)
Additions to intangible assets	**(76)**	(36)
Proceeds from disposition	**—**	72
Net cash used in investing activities	**(1,185)**	(1,037)
Financing activities		
Net change in short-term borrowings	**223**	(127)
Short-term repayments to affiliate	**—**	(32)
Repayment of loans from affiliates	**(650)**	(300)
Term note issuances, net of issue costs	**1,192**	697
Term note repayments	**(400)**	—
Common share dividends	**(450)**	(937)
Return of capital	**(800)**	(313)
Capital contribution received	**800**	800
Net cash used in financing activities	**(85)**	(212)
Net (decrease)/increase in cash	**(68)**	28
Cash, cash equivalents and restricted cash at beginning of year	**77**	49
Cash at end of year	**9**	77
Supplementary cash flow information		
Cash paid for income taxes	**66**	12
Cash paid for interest, net of amounts capitalized	**385**	381
Property, plant and equipment non-cash accruals	**20**	34

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2020**	2019
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash	**9**	77
Accounts receivable and other *(Note 6)*	**1,161**	1,317
Accounts receivable from affiliates *(Note 19)*	**92**	46
Gas inventory	**659**	631
	1,921	2,071
Property, plant and equipment, net *(Note 7)*	**15,866**	15,418
Intangible assets, net *(Note 8)*	**174**	173
Deferred amounts and other assets	**2,492**	2,235
Goodwill	**4,784**	4,784
Total assets	**25,237**	24,681
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 10)*	**1,121**	898
Accounts payable and other *(Note 9)*	**1,295**	1,369
Accounts payable to affiliates *(Note 19)*	**134**	113
Current portion of long-term debt *(Note 10)*	**376**	400
	2,926	2,780
Long-term debt *(Note 10)*	**8,606**	7,815
Other long-term liabilities	**2,166**	1,999
Deferred income taxes *(Note 15)*	**1,522**	1,433
Loan from affiliate *(Note 19)*	**—**	650
	15,220	14,677
Commitments and contingencies *(Note 21)*		
Equity		
Share capital *(Note 11)*		
Common shares *(522 million shares outstanding at December 31, 2020 and 2019)*	**3,517**	3,517
Additional paid-in capital	**7,253**	7,253
Deficit	**(675)**	(720)
Accumulated other comprehensive loss *(Note 12)*	**(78)**	(46)
	10,017	10,004
Total liabilities and equity	**25,237**	24,681

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

"signed"	**"signed"**
Cynthia L. Hansen	**David G. Unruh**
Director	Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. BUSINESS OVERVIEW

The terms "we," "our," "us" and "Enbridge Gas" as used in these financial statements refer collectively to Enbridge Gas Inc. and its subsidiaries unless the context suggests otherwise. Enbridge Gas is a wholly-owned indirect subsidiary of Enbridge Inc. (Enbridge). Enbridge provides administrative and general support services to us.

Enbridge Gas is a rate-regulated natural gas distribution, storage and transmission utility, serving residential, commercial and industrial customers in Ontario. We also served areas in northern New York State through our wholly-owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence Gas), prior to its disposition on November 1, 2019.

AMALGAMATION

On January 1, 2019, Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas) amalgamated and have continued from this date as Enbridge Gas, which continues to have all of the assets, rights, contracts, liabilities and obligations of each of EGD and Union Gas, including licenses and permits.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

We are permitted to use U.S. GAAP as our primary basis of accounting for purposes of meeting our continuous disclosure obligations under an exemption granted by securities regulators in Canada.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues; estimates of revenue; expected credit losses; depreciation rates and carrying value of property, plant and equipment *(Note 7)*; amortization rates and carrying value of intangible assets *(Note 8)*; measurement of goodwill; fair value of asset retirement obligations (AROs); fair value of financial instruments *(Note 13)*; provisions for income taxes *(Note 15)*; assumptions used to measure retirement benefits and OPEB *(Note 16)*; and commitments and contingencies *(Note 21)*. Actual results could differ from these estimates.

Certain comparative figures in our consolidated financial statements have been reclassified to conform to the current year's presentation.

REGULATION

Our utility operations within Ontario are regulated by the Ontario Energy Board (OEB), while the utility operations of St. Lawrence Gas were regulated by the New York State Public Service Commission. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities.

As a result of rate regulated accounting, we have recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates and amounts collected from customers in advance of costs being incurred. Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment.

The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. The regulator's future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which we operate. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. We believe that the recovery of our regulatory assets as at December 31, 2020 is probable over the periods described in *Note 5. Regulatory Matters*.

With the approval of the regulator, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

REVENUE RECOGNITION
Revenue from contracts with customers are generally recognized upon the fulfillment of the performance obligations for the distribution, storage, transportation and sale of natural gas. For distribution and transportation service arrangements, where the services are simultaneously received and consumed by the customer, revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas. Revenues from storage services are recognized as the storage services are provided.

A significant portion of our operations are subject to regulation and, accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue under such circumstances is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator, which are accounted for under Accounting Standards Codification (ASC) 980 - Regulated Operations.

PUSH-DOWN ACCOUNTING
EGD elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted U.S. GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by EGD. Upon adopting push-down accounting, the historical cost of EGD's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

We have applied push-down accounting with respect to the accounts of Union Gas from February 27, 2017, the date upon which Enbridge acquired common control of EGD and Union Gas. The carrying values of certain assets and liabilities of Union Gas transferred to EGD have been adjusted to reflect Enbridge's historical cost as at February 27, 2017.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

We use derivative financial instruments to manage our exposure to changes in interest rates and foreign exchange rates. Hedge accounting is optional and requires us to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. There were no outstanding derivative instruments relating to fair value or net investment hedges as at December 31, 2020 and 2019.

Cash Flow Hedges

We use cash flow hedges to manage our exposure to changes in interest rates and foreign exchange rates related to our unregulated storage revenue. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities in the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a deduction from Long-term debt in the Consolidated Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

INCOME TAXES

Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge Gas or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period in which they arise.

Prior to its sale in 2019, our only foreign operation was St. Lawrence Gas. The functional currency of St. Lawrence Gas was the United States dollar (USD). The effects of translating the financial statements of St. Lawrence Gas to Canadian dollars were included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI) and were recognized in earnings upon its sale. Asset and liability accounts were translated at the exchange rates in effect on the balance sheet date, while revenues and expenses were translated using monthly average exchange rates.

CASH

We combine cash and bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements.

RECEIVABLES AND CURRENT EXPECTED CREDIT LOSSES

Accounts receivable are measured at cost. For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations.

NATURAL GAS IMBALANCES

The Consolidated Statements of Financial Position include balances as a result of differences in gas volumes received and delivered for customers. Since certain imbalances are settled in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. Most natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

GAS INVENTORY

Gas inventories primarily consist of natural gas held in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the regulators in the determination of distribution rates. The actual price of gas purchased may differ from the regulator’s approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the regulator.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest incurred during construction as authorized by the regulator. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the regulator. When grouped assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation until the last asset in the pool is disposed of. Gains and losses on the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the regulator, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the regulator.

IMPAIRMENT

We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we calculate fair value based on the discounted cash flows and write the assets down to the extent that the carrying value exceeds the fair value.

LEASES

We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach as is applied for other long-lived assets.

Lease liabilities and ROU assets require the use of judgment and estimates, which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; derivative financial instruments; and actuarial gains and losses arising from defined benefit pension plans.

INTANGIBLE ASSETS

Intangible assets consist primarily of certain software costs. We capitalize costs incurred during the application development stage of internal use software projects. Intangible assets are generally amortized on a straight line basis over their expected lives, commencing when the asset is available for use.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. When performing a qualitative assessment, we determine the drivers of fair value and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends and industry conditions. Based on our assessment of the qualitative factors, if we determine it is more likely than not that the fair value is less than its carrying amount, a quantitative goodwill impairment test is performed.

The quantitative goodwill impairment test involves determining the fair value of goodwill and comparing that value to its carrying value. If the carrying value, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the carrying value exceeds the fair value. This amount should not exceed the carrying amount of goodwill. Fair value is estimated using a discounted cash flow model technique. The determination of fair value using the discounted cash flow model technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. The cash flow projections included significant judgments and assumptions relating to revenue growth rates and expected future capital expenditure.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (ARO) associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset’s useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of our assets, it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

PENSION AND OPEB

We provide pension benefits through defined benefit and defined contribution pension plans and OPEB, including group health care and life insurance benefits through defined benefit OPEB plans.

Defined benefit pension obligation and net periodic benefit cost are estimated using the projected unit credit method, which incorporates management’s best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. The OPEB benefit obligation and net periodic benefit cost are estimated using the projected unit credit method, where benefits are attributed to years of service, taking into consideration projection of benefit costs.

We use mortality tables issued by the Canadian Institute of Actuaries (revised in 2014) to measure the benefit obligation of our pension plans.

We determine discount rates by reference to rates of high quality long-term corporate bonds with maturities that approximate the timing of future payments we anticipate making under each of the respective plans.

Funded pension plan assets are measured at fair value. The expected return on funded pension plan assets is determined using market-related values and assumptions on the invested asset mix consistent with the investment policies relating to the plan assets. The market-related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period (funded pension plans) and from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount and salary inflation experience.

The excess of the fair value of a plan's assets over the fair value of a plan's benefit obligation is recognized as Deferred amounts and other assets in the Consolidated Statements of Financial Position. The excess of the fair value of a plan's benefit obligation over the fair value of a plan's assets is recognized as Accounts payable and other and Other long-term liabilities in the Consolidated Statements of Financial Position.

Net periodic benefit cost is charged to earnings and includes:

- cost of benefits provided in exchange for employee services rendered during the year (current service cost);
- interest cost of plan obligations;
- expected return on plan assets (funded pension plans);
- amortization of prior service costs on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit OPEB plans are presented as a component of AOCI in the Consolidated Statements of Changes in Equity. Any unrecognized OPEB-related actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax. Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit pension plans, which have been permitted or are expected to be permitted by the regulator, to be recovered through future rates, are presented as a component of Deferred amounts and other assets in the Consolidated Statements of Financial Position.

We also record regulatory adjustments to reflect the difference between certain net periodic benefit costs for accounting purposes and net periodic benefit costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to earnings and OCI on an accrual basis.

For defined contribution plans, contributions made by us are expensed in the period in which the contribution occurs.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount or, if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW ACCOUNTING STANDARDS
Reference Rate Reform
Effective July 1, 2020, we adopted Accounting Standards Update (ASU) 2020-04 on a prospective basis. The new standard was issued in March 2020 to provide temporary optional guidance in accounting for reference rate reform. The new guidance provides optional expedients and exceptions for applying generally accepted accounting principles when accounting for contract modifications, hedging relationships and other transactions impacted by rate reform, subject to meeting certain criteria. ASU 2020-04 is effective until December 31, 2022. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Disclosure Effectiveness
Effective January 1, 2020, we adopted ASU 2018-13 on both a retrospective and prospective basis depending on the change. The new standard was issued to improve the disclosure requirements for fair value measurements by eliminating and modifying some disclosures, while also adding new disclosures. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Credit Losses
Effective January 1, 2020, we adopted ASU 2016-13 on a modified retrospective basis.

The new standard was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. The previous accounting treatment used the incurred loss methodology for recognizing credit losses that delayed the recognition until it was probable a loss had been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes results in more timely recognition of such losses.

Further, ASU 2018-19 was issued in November 2018 to clarify that operating lease receivables should be accounted for under the new leases standard, ASC 842, and are not within the scope of ASC 326, Financial Instruments - Credit Losses.

For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations.

The adoption of this ASU did not have a material impact on our consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES
Accounting for Income Taxes
ASU 2019-12 was issued in December 2019 with the intent of simplifying the accounting for income taxes. The accounting update removes certain exceptions to the general principles in ASC 740, as well as provides simplification by clarifying and amending existing guidance. ASU 2019-12 is effective January 1, 2021 and entities are permitted to adopt the standard early. The adoption of ASU 2019-12 is not expected to have a material impact on our consolidated financial statements.

Disclosure Effectiveness
ASU 2018-14 was issued in August 2018 to improve disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendment modifies the current guidance by adding and removing several disclosure requirements while also clarifying the guidance on current disclosure requirements. ASU 2018-14 is effective January 1, 2021 and entities are permitted to adopt the standard early. The adoption of ASU 2018-14 is not expected to have a material impact on our consolidated financial statements.

4. REVENUES

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Services

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Gas commodity and distribution revenues - residential	**2,560**	2,847
Gas commodity and distribution revenues - commercial and industrial	**1,077**	1,316
Storage revenue	**144**	140
Transportation revenue	**681**	716
Other revenues	**62**	65
Total revenue from contracts with customers	**4,524**	5,084
Other[1]	**(9)**	(9)
Total revenues	**4,515**	5,075

1 Primarily relates to the effects of rate-regulated accounting.

We disaggregate revenues into categories which represent our principal performance obligations. These revenue categories also represent the most significant revenue streams, and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Receivables	Contract Liabilities
(millions of Canadian dollars)		
Balance as at December 31, 2020	**738**	**—**
Balance as at December 31, 2019	613	65

Receivables represent an unconditional right to consideration where only the passage of time is required before payment of consideration is due, and consist of trade accounts receivable, unbilled revenue and other accrued receivable balances.

Contract liabilities represent payments received for performance obligations which have not been fulfilled under our equal monthly payment plan. Revenue recognized during the year ended December 31, 2020 included $65 million of contract liabilities which had not been fulfilled as at the beginning of the year. The increase in contract liabilities from cash received, net of amounts recognized as revenues during the year ended December 31, 2020, was nil.

Performance Obligations

	Nature of Performance Obligation
Gas commodity and distribution revenue	• Supply and delivery of natural gas to customers
Storage and transportation revenue	• Storage and transportation of natural gas on behalf of customers
Other revenue	• Other billing and service fees

We recognized a reduction of revenue of $22 million during the year ended December 31, 2020 from performance obligations satisfied in previous periods, primarily resulting from differences in actual and estimated consumption. The associated reduction in gas commodity and distribution costs was also recognized in the current year.

Payment Terms
Payments from distribution customers are received on a continuous basis based on established billing cycles. Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. Payments from storage customers are received monthly under long-term storage capacity contracts. Payments from transportation customers are received on a continuous basis based on established billing cycles or monthly under long-term transportation capacity contracts.

Revenue to be Recognized from Unfulfilled Performance Obligations
Total revenue from performance obligations expected to be fulfilled in future periods is $581 million, of which $310 million is expected to be recognized during the year ending December 31, 2021.

The performance obligations above reflect revenues expected to be recognized in future periods from unfulfilled performance obligations pursuant to contracts with customers for the purchase of natural gas distribution, storage and transportation services. Certain revenues are excluded from the amounts above under the following ASC 606 optional exemptions:

- certain revenues, such as flow-through costs charged to customers, which are recognized at the amount for which we have the right to invoice our customers; and
- revenue from contracts with customers that have an original expected duration of one year or less.

Variable consideration is also excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be reasonably estimated.

A significant portion of our operations are subject to regulation. Accordingly, the amounts above, in addition to revenues that are not regulated, only include revenue for which the underlying rate has been approved by regulation, where applicable. The revenues excluded from the amounts above could represent a significant portion of our overall revenues and revenue from contracts with customers.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE
Revenue Recognition
Revenue from contracts with customers is generally recognized upon the fulfillment of the performance obligations as described above. Distribution and transportation service revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas.

Due to regulatory mechanisms, there are circumstances where revenues recognized do not match the amounts billed. Under such circumstances, revenue is recognized in a manner that is consistent with the underlying rate setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator.

Recognition and Measurement of Revenues

Year ended December 31, *(millions of Canadian dollars)*	**2020**	2019
Revenue from products and services transferred over time[1]	**4,464**	5,019
Revenue from products transferred at a point in time[2]	**60**	65
Total revenue from contracts with customers	**4,524**	5,084

1 Revenue from distribution, storage and transportation services.
2 Primarily from Other revenues.

Performance Obligations Satisfied Over Time

For arrangements involving the distribution and transportation of natural gas, where the services are simultaneously received and consumed by the customer, we recognize revenue over time using an output method based on volumes of commodities delivered. The measurement of the volumes delivered corresponds directly to the benefits received by the customers during that period. Revenue from storage services are recognized as the services are provided.

Determination of Transaction Prices

Prices for distribution and transportation services and regulated storage services are prescribed by regulation. Fees for unregulated storage services are determined through negotiations with customers and are based on market rates.

Prices for natural gas sold are driven by market prices and the Quarterly Rate Adjustment Mechanism (QRAM) in place that allows for rates to reflect changes in natural gas prices, subject to regulatory approval.

5. REGULATORY MATTERS

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under U.S. GAAP for non-regulated entities. See *Note 2* for further discussion.

We are regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act*, (1998), which is part of a package of legislation known as the *Energy Competition Act*, (1998). This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario.

RATE APPROVALS

Our distribution rates, commencing in 2019, are set under a five-year Incentive Regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% stretch factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires us to share equally with customers any earnings in excess of 150 basis points over the annual OEB approved return on equity.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following regulatory assets and liabilities in the Consolidated Statements of Financial Position:

December 31,	**2020**	2019	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Federal carbon receivables[1]	**—**	145	2020
Demand side management program	**31**	28	2021
Purchase gas variance[2]	**—**	23	2021
Other current regulatory assets	**86**	94	2021
Total current regulatory assets[3] *(Note 6)*	**117**	290	
Long-term regulatory assets			
Deferred income taxes[4]	**1,393**	1,266	Various
Pension plan receivable[5]	**342**	222	Various
Long-term debt[6]	**334**	362	2022-2046
Accounting policy changes[7]	**169**	175	Various
Transition impact of accounting changes[8]	**53**	53	2032
Other long-term regulatory assets	**34**	12	Various
Total long-term regulatory assets[3]	**2,325**	2,090	
Total regulatory assets	**2,442**	2,380	
Current regulatory liabilities			
Purchase gas variance[2]	**153**	41	2021
Other current regulatory liabilities	**73**	176	2021
Total current regulatory liabilities[9] *(Note 9)*	**226**	217	
Long-term regulatory liabilities			
Future removal and site restoration reserves[10]	**1,455**	1,424	Various
Accelerated capital cost allowance	**43**	28	Various
Other long-term regulatory liabilities	**45**	19	Various
Total long-term regulatory liabilities[9]	**1,543**	1,471	
Total regulatory liabilities	**1,769**	1,688	

1 *The federal carbon balance is the difference between actual carbon costs and carbon costs recovered in rates, as well as the administration costs associated with the impacts of the federal carbon program requirements. This balance has been recovered from customers in the fourth quarter of 2020 in accordance with the OEB's approval.*

2 *Purchase gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. We have been granted OEB approval to refund this balance to, or collect this balance from, customers on a rolling 12 month basis as part of the QRAM process.*

3 *Current regulatory assets are included in Accounts receivable and other, while long-term regulatory assets are included in Deferred amounts and other assets.*

4 *The deferred income taxes balance represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in future regulator-approved rates and recovered from customers. The recovery period depends on the timing of the reversal of the temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded.*

5 *The pension plan balance represents the regulatory offset to our pension liability to the extent that it is expected to be included in regulator-approved future rates and recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense would be recorded in earnings and OCI.*

6 *The debt balance represents our regulatory offset to the fair value adjustment to debt acquired in Enbridge's merger with Spectra Energy Corp. (Spectra Energy) and pushed down to Enbridge Gas. The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.*

7 *The accounting policy changes deferral reflects unamortized accumulated actuarial gains/losses and past service costs incurred by Union Gas, relating to the period up to Enbridge's merger with Spectra Energy, which were previously recorded in AOCI. The amortization of this balance is recognized as a component of accrual-based pension expenses, which are included in Other income and recovered in rates, as previously approved by the OEB.*

8 *The transition impact of accounting changes balance represents our right to recover costs resulting from the adoption of the accrual basis of accounting for pension and OPEB costs upon transition to U.S. GAAP in 2012. Pursuant to the OEB rate order, the balance as at December 31, 2012 is to be collected in rates over a 20 year period, commencing in 2013.*

9 Current regulatory liabilities are included in Accounts payable and other, while long-term regulatory liabilities are included in Other long-term liabilities.

10 Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the OEB, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

OTHER ITEMS AFFECTED BY RATE REGULATION

Operating Cost Capitalization

With the approval of the OEB, we capitalize a percentage of certain operating costs. We are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate-regulated accounting, a portion of such operating costs would be charged to earnings in the year incurred.

We entered into a services contract relating to asset management initiatives. The majority of these costs were capitalized to Gas mains in accordance with regulatory approval. As at December 31, 2020, the net book value of the costs included in Gas mains, services and other in Property, plant and equipment, net was $96 million (2019 - $103 million).

Work and Asset Management Solution (WAMS) is our integrated work and asset management system. As at December 31, 2020, the net book value of the WAMS asset included in Intangible assets, net was $51 million (2019 - $60 million).

Gas Inventories

Natural gas in storage is recorded in inventory at the reference prices approved by the OEB in the determination of customers' system supply rates. Included in Gas inventory as at December 31, 2020 is $60 million (2019 - $66 million) related to storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during our off-peak months and charged to gas costs during the peak winter months. In the absence of rate-regulated accounting, these costs would be expensed as incurred, and inventory would be recorded at the lower of cost or market value.

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2020**	2019
(millions of Canadian dollars)		
Trade receivables and unbilled revenues, net[1]	**855**	857
Regulatory assets *(Note 5)*	**117**	290
Rebillables receivable	**76**	88
Gas imbalances	**54**	44
Other	**59**	38
	1,161	1,317

1 Net of allowance for expected credit losses of $45 million as at December 31, 2020 and allowance for doubtful accounts of $38 million as at December 31, 2019.

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2020**	2019
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas transmission	**2.5%**	**1,752**	1,505
Gas mains, services and other	**2.6%**	**12,476**	12,114
Compressors, meters and other operating equipment	**4.3%**	**3,235**	2,918
Storage	**2.8%**	**975**	919
Land and right-of-way[1]	**1.0%**	**361**	334
Vehicles, office furniture, equipment and other buildings and improvements	**10.7%**	**434**	506
Under construction	**—%**	**177**	223
		19,410	18,519
Accumulated depreciation		**(3,946)**	(3,490)
		15,464	15,029
Unregulated property, plant and equipment			
Gas mains, services and other	**5.6%**	**13**	13
Compressors, meters and other operating equipment	**1.3%**	**41**	40
Storage	**3.0%**	**365**	347
Land and right-of-way[1]	**1.7%**	**37**	32
Under construction	**—%**	**30**	24
		486	456
Accumulated depreciation		**(84)**	(67)
		402	389
Property, plant and equipment, net		**15,866**	15,418

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.

Depreciation expense, including amounts collected for future removal and site restoration costs, was $583 million for the year ended December 31, 2020 (2019 - $558 million).

Included within depreciation expense is $22 million for the year ended December 31, 2020 (2019 - $22 million) in incremental depreciation resulting from push-down accounting *(Note 2)*.

DISPOSITION

On November 1, 2019, we closed the sale of St. Lawrence Gas for total cash proceeds of approximately $72 million (US$55 million). A loss on disposal of approximately $10 million before tax was included in Other income in the Consolidated Statements of Earnings in 2019.

8. INTANGIBLE ASSETS

December 31,	2020	2019
(millions of Canadian dollars)		
Software and Customer Information System	**654**	592
Less: Accumulated amortization	**(480)**	(419)
Intangible assets, net	**174**	173

For the year ended December 31, 2020, the weighted average amortization rate for software and CIS was 11.8% (2019 - 13.9%).

Intangible assets include $35 million of work-in-progress as at December 31, 2020 (2019 - $16 million). Total amortization expense for intangible assets was $72 million for the year ended December 31, 2020 (2019 - $80 million). The following table presents our expected amortization expense associated with existing intangible assets for the years indicated as follows:

	2021	2022	2023	2024	2025
(millions of Canadian dollars)					
Forecast of amortization expense	64	18	16	16	16

9. ACCOUNTS PAYABLE AND OTHER

December 31,	2020	2019
(millions of Canadian dollars)		
Trade payables and accrued liabilities	**491**	464
Regulatory liabilities *(Note 5)*	**226**	217
Federal carbon program liability	**194**	140
Construction payables and contractor holdbacks	**73**	112
Gas imbalances	**54**	44
Taxes payable	**47**	114
Other	**210**	278
	1,295	1,369

10. DEBT

December 31,	Weighted Average Interest Rate[3]	Maturity	2020	2019
(millions of Canadian dollars)				
Medium-term notes	3.9 %	2021-2050	**8,485**	7,685
Debentures	9.1 %	2024-2025	**210**	210
Commercial paper and credit facility draws	0.3 %	2022	**1,121**	898
Other[1]			**(47)**	(42)
Fair value adjustment from push down accounting *(Note 2)*			**334**	362
Total debt			**10,103**	9,113
Current maturities			**(376)**	(400)
Short-term borrowings[2]			**(1,121)**	(898)
Long-term debt			**8,606**	7,815

1 Primarily unamortized discounts, premiums and debt issuance costs.
2 Weighted average interest rate - 0.3% (2019 - 2.0%).
3 Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2020.

As at December 31, 2020, all outstanding debt was unsecured.

CREDIT FACILITIES

We actively manage our bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of our external credit facility at December 31, 2020:

	Maturity	Total Facility	Draws[2]	Available
(millions of Canadian dollars)				
364 day extendible credit facility	2022[1]	**2,000**	**1,121**	**879**

1 Maturity date is inclusive of the one-year term out provision.
2 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.

On July 24, 2020, we extended our 364 extendible credit facility to July 23, 2022, inclusive of a one-year term out provision.

The credit facility carries a standby fee of 0.3% on the unused portion and the draws bear interest at market rates.

As at December 31, 2020, we have access to Enbridge's demand letter of credit facilities totaling $495 million (2019 - $495 million). As at December 31, 2020 and 2019, $14 million of letters of credit were issued by us.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2020, we completed the following long-term debt issuances totaling $1.2 billion:

Issue Date		Principal Amount
(millions of Canadian dollars)		
April 2020	2.90% medium-term notes due April 2030	$600
April 2020	3.65% medium-term notes due April 2050	$600

With proceeds from these issuances, we repaid the outstanding $650 million subordinated promissory note, as well as the related interest payable, due to Westcoast Energy Inc. on April 1, 2020. The note was presented as Loan from affiliate in the Consolidated Statements of Financial Position as at December 31, 2019.

LONG-TERM DEBT REPAYMENT

During the year ended December 31, 2020, we completed the following long-term debt repayment totaling $400 million:

Repayment Date		Principal Amount
(millions of Canadian dollars)		
November 2020	4.04% medium-term notes	$400

DEBT COVENANTS

Our credit facility agreement and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or terminations of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2020, we are in compliance with all debt covenants.

INTEREST EXPENSE

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Debentures and term notes	**380**	331
Commercial paper and credit facility draws	**17**	31
Interest on loans from affiliate	**6**	31
Other interest and finance costs	**14**	12
Capitalized interest	**(5)**	(5)
	412	400

11. SHARE CAPITAL

As at December 31, 2020, our authorized share capital consisted of an unlimited number of common shares with no par value and an unlimited number of preference shares. Our Class A and Class B common shares are held by Enbridge Energy Distribution Inc. (EEDI) and Great Lakes Basin Energy LP (GLBE), respectively. Both classes of common shares are identical in every respect, and dividends cannot be paid to one class without paying dividends to the other. As at December 31, 2020 and 2019, no preferred shares were issued and outstanding.

COMMON SHARES

	2020		2019	
December 31,	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of shares in millions)				
Class A				
Balance at beginning of year	**282**	**2,636**	233	2,373
Common shares converted from amalgamation[1]	**—**	**—**	(233)	(2,373)
Common shares issued from amalgamation[1]	**—**	**—**	282	2,373
Capital contribution	**—**	**432**	—	432
Return of capital	**—**	**(432)**	—	(169)
	282	**2,636**	282	2,636
Class B				
Balance at beginning of year	**240**	**881**	58	657
Common shares converted from amalgamation[2]	**—**	**—**	(58)	(657)
Common shares issued from amalgamation[2]	**—**	**—**	240	657
Capital contribution	**—**	**368**	—	368
Return of capital	**—**	**(368)**	—	(144)
	240	**881**	240	881
Balance at end of year	**522**	**3,517**	522	3,517

1 *On January 1, 2019, we issued to EEDI, which wholly-owned EGD and owned 1% of Union Gas, 281,881,334 Class A common shares in exchange for 232,749,988 EGD common shares and 621,866 Union Gas Class A common shares.*

2 *On January 1, 2019, we issued to GLBE, which owned 99% of Union Gas, 240,020,243 Class B common shares in exchange for 57,822,650 Union Gas common shares.*

The capital contribution and return of capital transactions to the stated capital of Class A and Class B common shares had no impact on the total shares outstanding.

12. COMPONENTS OF AOCI

Changes in AOCI for the years ended December 31, 2020 and 2019 are as follows:

	2020			
	Cash Flow Hedges	Cumulative Translation Adjustment	OPEB Adjustment	Total
(millions of Canadian dollars)				
Balance at January 1, 2020	**(42)**	**—**	**(4)**	**(46)**
Other comprehensive loss retained in AOCI	**(49)**	**—**	**(13)**	**(62)**
Other comprehensive loss reclassified to earnings	**17**	**—**	**—**	**17**
	(74)	**—**	**(17)**	**(91)**
Tax impact				
Income tax on amounts retained in AOCI	**12**	**—**	**3**	**15**
Income tax on amounts reclassified to earnings	**(2)**	**—**	**—**	**(2)**
	10	**—**	**3**	**13**
Balance at December 31, 2020	**(64)**	**—**	**(14)**	**(78)**

	2019			
	Cash Flow Hedges	Cumulative Translation Adjustment	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)				
Balance at January 1, 2019	(9)	5	(47)	(51)
Other comprehensive (loss)/income retained in AOCI[1]	(50)	(2)	58	6
Other comprehensive loss/(income) reclassified to earnings	5	(3)	—	2
	(54)	—	11	(43)
Tax impact				
Income tax on amounts retained in AOCI[1]	13	—	(15)	(2)
Income tax on amounts reclassified to earnings	(1)	—	—	(1)
	12	—	(15)	(3)
Balance at December 31, 2019	(42)	—	(4)	(46)

1 OCI for the year ended December 31, 2019 was increased by an adjustment of $74 million in respect of Enbridge Gas applying rate-regulated accounting to record a regulatory offset to certain pension liabilities. An offsetting amount of $19 million was also recorded in OCI for the related tax impact.

13. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

Our earnings, cash flows and OCI are subject to movements in natural gas prices, foreign exchange rates and interest rates (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by our customers.

Foreign Exchange Risk
Foreign exchange risk is the risk of gain or loss due to the volatility of currency exchange rates. We generate certain revenues, incur expenses and hold cash balances that are denominated in USD. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from USD exchange rate variability.

We have implemented a policy to hedge a portion of our USD denominated unregulated storage revenue exposures. Qualifying derivative instruments are used to hedge anticipated USD denominated revenues and to manage variability in cash flows.

A portion of our natural gas purchases are denominated in USD and, as a result, there is exposure to fluctuations in the exchange rate of the USD against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to customers, therefore, we have no net exposure to movements in the foreign exchange rate on natural gas purchases.

Until November 1, 2019, we held a subsidiary that generated revenues denominated in USD.

Interest Rate Risk
Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps are used to hedge against the effect of future interest rate movements. We have implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense via execution of floating-to-fixed interest rate swaps with an average swap rate of 2.3%.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have implemented a program to significantly mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating-to-fixed interest rate swaps with an average swap rate of 1.9%.

COVID-19 PANDEMIC RISK
The COVID-19 pandemic has caused significant volatility in Canada, the United States and international markets. While we have taken proactive measures to deliver energy safely and reliably during this pandemic, given the ongoing dynamic nature of the circumstances surrounding COVID-19, the impact of this pandemic on our business remains uncertain.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments.

We generally have a common practice of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce our credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2020	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Deferred amounts and other assets					
Interest rate contracts	**8**	**—**	**8**	**(1)**	**7**
	8	**—**	**8**	**(1)**	**7**
Accounts payable to affiliates					
Interest rate contracts	**(43)**	**—**	**(43)**	**—**	**(43)**
	(43)	**—**	**(43)**	**—**	**(43)**
Other long-term liabilities					
Interest rate contracts	**(1)**	**—**	**(1)**	**1**	**—**
	(1)	**—**	**(1)**	**1**	**—**
Total net derivative liability					
Interest rate contracts	**(36)**	**—**	**(36)**	**—**	**(36)**
	(36)	**—**	**(36)**	**—**	**(36)**

December 31, 2019	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable to affiliates					
Interest rate contracts	(9)	—	(9)	—	(9)
	(9)	—	(9)	—	(9)
Other long-term liabilities					
Interest rate contracts	(13)	—	(13)	—	(13)
	(13)	—	(13)	—	(13)
Total net derivative liability					
Interest rate contracts	(22)	—	(22)	—	(22)
	(22)	—	(22)	—	(22)

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.

December 31, 2020	2021	2022	2023	2024	2025	Thereafter	Total
Foreign exchange contracts - United States dollar forwards - sell *(millions of USD)*	**2**	**1**	**—**	**—**	**—**	**—**	**3**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**387**	**18**	**—**	**—**	**—**	**—**	**405**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**275**	**200**	**200**	**—**	**—**	**—**	**675**

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on our consolidated earnings and comprehensive income, before the effect of income taxes.

Year ended December 31, *(millions of Canadian dollars)*	**2020**	2019
Amount of unrealized loss recognized in OCI		
Cash flow hedges		
Interest rate contracts	**(49)**	(50)
	(49)	(50)
Amount of loss/(gain) reclassified from AOCI to earnings		
Interest rate contracts[1]	**17**	6
Foreign exchange contracts	**—**	(1)
	17	5

1 Reported within Interest expense, net in the Consolidated Statements of Earnings.

We estimate that a loss of $10 million of AOCI related to unrealized cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest and foreign exchange rates in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 13 months as at December 31, 2020.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments, as they become due. In order to manage this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under the committed credit facility and long-term debt, which includes debentures and medium-term notes and, if necessary, additional liquidity is available through intercompany transactions with our ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable us to fund all anticipated requirements. We maintain a current medium-term note shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. We also maintain a committed credit facility with a diversified group of banks and institutions. We were in compliance with all of the terms and conditions of our committed credit facility as at December 31, 2020. As a result, the credit facility is available to us and the banks are obligated to fund us under the terms of the facility.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. We are exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by our large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default of receivables. Generally, we classify receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

In July 2020, we began administering the Government of Ontario-funded COVID-19 Energy Assistance Program (CEAP) to eligible residential natural gas customers who have experienced hardships as a result of the COVID-19 pandemic. In August 2020, the CEAP was expanded to include small business and registered charity customers. Additional government assistance programs may also be administered by us in the future.

Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which generally require payment in full within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made accordingly.

Our expected credit loss is determined based on historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations, using a loss allowance matrix. This estimate is revised each reporting period to reflect current expectations. When we have determined that collection efforts are unlikely to be successful, amounts charged to the expected credit loss account are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits our exposure to credit risk related to accounts receivable, to the extent such estimates are accurate.

Entering into derivative financial instruments may also result in exposure to credit risk. We enter into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements. As at December 31, 2020, we have $8 million credit concentrations and credit exposure with Enbridge and its affiliates.

Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair values of financial instruments reflect our best estimates of fair value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. We do not have any derivative instruments classified as Level 1.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps for which observable inputs can be obtained.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivative's fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support a Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. We do not have any derivative instruments classified as Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value, including discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, we use observable market prices (interest, foreign exchange and natural gas) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread, as well as the credit default swap spreads associated with our counterparties, in our estimation of fair value.

At December 31, 2020, we had Level 2 derivative assets with a fair value of $8 million, (2019 - nil) and Level 2 derivative liabilities with a fair value of $44 million (2019 - $22 million).

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS
The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. At December 31, 2020, our long-term debt, including the current portion, had a carrying value of $8.7 billion (2019 - $7.9 billion) before debt issuance costs and fair value adjustment from push down accounting, and a fair value of $10.7 billion (2019 - $9.2 billion).

The fair value of financial assets and liabilities, other than derivative instruments and long-term debt, approximate their carrying value due to the short period to maturity.

14. LEASES

LESSEE
We incur operating lease payments related to natural gas transportation, storage and real estate assets. These lease agreements have remaining lease terms of 3 months to 17 years, some of which include options to terminate at our discretion.

For the years ended December 31, 2020 and 2019, we incurred operating lease expenses of $9 million and $7 million, respectively. Operating lease expenses are reported within Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2020 and 2019, operating lease payments made to settle lease liabilities were $9 million and $7 million, respectively. Operating lease payments are reported within Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Consolidated Statements of Financial Position Information

December 31,	**2020**	2019
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases		
Operating lease right-of-use assets, net[1]	**53**	46
Operating lease liabilities - current[2]	**6**	6
Operating lease liabilities - long-term[3]	**47**	40
Total operating lease liabilities	**53**	46
Weighted average remaining lease term		
Operating leases	**9 years**	9 years
Weighted average discount rate		
Operating leases	**3.1%**	3.3%

1 Right-of-use assets are reported within Deferred amounts and other assets in the Consolidated Statements of Financial Position.
2 Current lease liabilities are reported within Accounts payable and other and Accounts payable to affiliates in the Consolidated Statements of Financial Position.
3 Long-term lease liabilities are reported within Other long-term liabilities in the Consolidated Statements of Financial Position.

As at December 31, 2020, we have lease commitments as detailed below:

	Operating leases
(millions of Canadian dollars)	
2021	**8**
2022	**7**
2023	**7**
2024	**6**
2025	**6**
Thereafter	**27**
Total undiscounted lease payments	**61**
Less imputed interest	**(8)**
Total operating lease liabilities	**53**

LESSOR

We receive revenues from operating and sales-type leases primarily related to natural gas equipment and real estate assets. Our lease agreements have remaining lease terms of 1 month to 20 years for the year ended December 31, 2020.

As at December 31, 2020, the following table sets out future lease payments to be received under operating lease and sales-type lease contracts where we are the lessor:

	Operating leases	Sales-type leases
(millions of Canadian dollars)		
2021	**2**	**1**
2022	**1**	**1**
2023	**1**	**1**
2024	**1**	**1**
2025	**1**	**1**
Thereafter	**3**	**18**
Future lease payments to be received	**9**	**23**

15. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Earnings before income taxes	**555**	614
Canadian federal statutory income tax rate	**15%**	15%
Expected federal taxes at statutory rate	**83**	92
Increase/(decrease) resulting from:		
Provincial and state income taxes	**(13)**	29
Effects of rate-regulated accounting[1]	**(46)**	(52)
Part VI.1 tax, net of federal Part I deduction[1]	**41**	—
Non-taxable portion of loss on sale of investment to unrelated party	**—**	(1)
Other[2]	**(7)**	(10)
Income tax expense	**58**	58
Effective income tax rate	**10.5%**	9.4%

1 The provincial tax component of these items is included in Provincial and state income taxes above.
2 Includes miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals and entertainment and a change in prior year estimates arising from the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Earnings before income taxes		
Canada	**555**	638
United States	**—**	(24)
	555	614
Current income taxes		
Canada	**84**	85
United States	**(1)**	4
	83	89
Deferred income taxes		
Canada	**(25)**	(25)
United States	**—**	(6)
	(25)	(31)
Income tax expense	**58**	58

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	**2020**	2019
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(1,586)**	(1,497)
Regulatory assets	**(368)**	(335)
Deferrals	**(10)**	(17)
Pension and OPEB plans	**(13)**	(8)
Other	**(2)**	(1)
Total deferred income tax liabilities	**(1,979)**	(1,858)
Deferred income tax assets		
Future removal and site restoration reserves	**391**	373
Minimum tax credits	**40**	30
Financial instruments	**24**	15
Other	**2**	7
Total deferred income tax assets	**457**	425
Net deferred income tax liabilities	**(1,522)**	(1,433)

Enbridge Gas is subject to taxation in Canada. Prior to its disposition on November 1, 2019, we were also subject to taxation in the United States through our wholly-owned subsidiary St. Lawrence Gas. The material jurisdiction in which we are subject to potential examinations is Canada (Federal and Ontario). We are open to examination by Canadian tax authorities for 2012 to 2020 tax years, and are currently under examination for income tax matters in Canada for 2015 to 2017 tax years.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**39**	39
Gross increases for tax positions of current year	**—**	3
Gross decreases for tax positions of prior year	**(2)**	(1)
Lapses of statute of limitations	**(3)**	(2)
Unrecognized tax benefits at end of year	**34**	39

The unrecognized tax benefits as at December 31, 2020, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the years ended December 31, 2020 and 2019 included no amounts of interest and penalties. As at December 31, 2020 and 2019, interest and penalties of $1 million have been accrued.

16. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We provide pension benefits, covering substantially all employees, through contributory and non-contributory registered defined benefit and defined contribution pension plans. We also provide non-registered pension benefits for certain employees through supplemental non-contributory defined benefit pension plans.

Defined Benefit Pension Plan Benefits
Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

Defined Contribution Pension Plan Benefits
Our contributions are based on each plan participant's current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

OTHER POSTRETIREMENT BENEFIT PLANS
We provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees, through unfunded defined benefit OPEB plans.

BENEFIT OBLIGATIONS, PLAN ASSETS AND FUNDED STATUS
The following table details the changes in the benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit pension and OPEB plans:

	Pension		OPEB	
December 31,	**2020**	2019	**2020**	2019
(millions of Canadian dollars)				
Change in benefit obligation				
Benefit obligation at beginning of year	**2,331**	2,080	**170**	153
Service cost	**68**	63	**3**	2
Interest cost	**66**	72	**5**	5
Participant contributions	**15**	14	**—**	—
Actuarial loss[1]	**160**	210	**13**	15
Benefits paid	**(108)**	(108)	**(5)**	(5)
Benefit obligation at end of year[2]	**2,532**	2,331	**186**	170
Change in plan assets				
Fair value of plan assets at beginning of year	**2,108**	1,923	**—**	—
Actual return on plan assets	**152**	237	**—**	—
Employer contributions	**52**	42	**5**	5
Participant contributions	**15**	14	**—**	—
Benefits paid	**(108)**	(108)	**(5)**	(5)
Fair value of plan assets at end of year	**2,219**	2,108	**—**	—
Underfunded status at end of year	**(313)**	(223)	**(186)**	(170)
Presented as follows:				
Deferred amounts and other assets	**35**	34	**—**	—
Accounts payable and other	**(3)**	(2)	**(7)**	(7)
Other long-term liabilities	**(345)**	(255)	**(179)**	(163)
	(313)	(223)	**(186)**	(170)

1 Primarily due to decrease in the discount rate used to measure the benefit obligations.
2 For pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. The accumulated benefit obligation for our pension plans was $2.4 billion and $2.2 billion as at December 31, 2020 and 2019, respectively.

Certain of our pension plans have projected and accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets were as follows:

December 31,	**2020**	2019
(millions of Canadian dollars)		
Projected benefit obligation	**2,115**	784
Accumulated benefit obligation	**1,963**	686
Fair value of plan assets	**1,767**	593

AMOUNT RECOGNIZED IN AOCI

The amount of pre-tax AOCI relating to our OPEB plans are as follows:

December 31,	**2020**	2019
(millions of Canadian dollars)		
Net actuarial loss	**18**	5
Total amount recognized in AOCI	**18**	5

NET PERIODIC BENEFIT COST AND OTHER AMOUNTS RECOGNIZED IN COMPREHENSIVE INCOME

The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2020**	2019	**2020**	2019
(millions of Canadian dollars)				
Service cost	**68**	63	**3**	2
Interest cost[1]	**66**	72	**5**	5
Expected return on plan assets[1]	**(136)**	(129)	**—**	—
Amortization of net actuarial loss[1,2]	**20**	16	**—**	—
Net periodic benefit cost	**18**	22	**8**	7
Defined contribution benefit cost	**2**	2	**—**	—
Net pension and OPEB cost recognized in Earnings	**20**	24	**8**	7
Amount recognized in OCI:				
Adjustment for rate-regulated accounting *(Note 12)*	**—**	(74)	**—**	—
Net actuarial loss arising during the year	**—**	—	**13**	16
Total amount recognized in OCI	**—**	(74)	**13**	16
Total amount recognized in Comprehensive income	**20**	(50)	**21**	23

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.
2 Reflects amortization of net actuarial loss arising from pension plans that are recognized as long-term regulatory assets (Note 5).

ACTUARIAL ASSUMPTIONS

The weighted average assumptions made in the measurement of the benefit obligation and net periodic benefit cost of our defined benefit pension and OPEB plans are as follows:

	Pension		OPEB	
	2020	2019	**2020**	2019
Benefit obligations				
Discount rate	**2.6%**	3.1%	**2.6%**	3.1%
Rate of salary increase	**2.6%**	3.2%	**2.4%**	3.3%
Net benefit cost				
Discount rate	**3.1%**	3.8%	**3.1%**	3.8%
Rate of return on plan assets	**6.5%**	6.8%	**N/A**	N/A
Rate of salary increase	**3.2%**	3.2%	**3.3%**	3.3%

ASSUMED HEALTH CARE COST TREND RATES
The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	2020	2019
Health care cost trend rate assumed for next year	**4.0%**	4.0%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0%**	4.0%

PLAN ASSETS
We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

	Target	December 31,	
Asset Category	**Allocation**	**2020**	2019
Equity securities	**40.8%**	**46.3%**	45.7%
Fixed income securities	**35.5%**	**31.9%**	33.7%
Alternatives[1]	**23.7%**	**21.8%**	20.6%

1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the funds.

The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level:

	2020				2019			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Cash and cash equivalents	**50**	**—**	**—**	**50**	53	—	—	53
Equity securities								
Canada	**103**	**111**	**—**	**214**	92	112	—	204
Global	**—**	**813**	**—**	**813**	—	760	—	760
Fixed income securities								
Government	**125**	**249**	**—**	**374**	117	272	—	389
Corporate	**—**	**284**	**—**	**284**	—	268	—	268
Alternatives[4]	**—**	**—**	**466**	**466**	—	—	427	427
Forward currency contracts	**—**	**18**	**—**	**18**	—	7	—	7
Total pension plan assets at fair value	**278**	**1,475**	**466**	**2,219**	262	1,419	427	2,108

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

December 31,	**2020**	2019
(millions of Canadian dollars)		
Balance at beginning of year	**427**	298
Unrealized and realized gains	**(3)**	9
Purchases and settlements, net	**42**	120
Balance at end of year	**466**	427

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2021	2022	2023	2024	2025	2026-2030
(millions of Canadian dollars)						
Pension	108	109	111	113	115	599
OPEB	7	7	8	8	8	41

EXPECTED EMPLOYER CONTRIBUTIONS

In 2021, we expect to contribute approximately $39 million and $7 million to the pension plans and OPEB plans, respectively.

17. SEVERANCE COSTS

For the year ended December 31, 2020, we incurred $74 million in severance costs related to Enbridge's voluntary workforce reduction program. For the year ended December 31, 2019, we incurred $39 million in severance costs related to the amalgamation of EGD and Union Gas. Severance costs are presented in Operating and administrative expense in the Consolidated Statements of Earnings.

18. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Accounts receivable and other	**65**	(17)
Accounts receivable from affiliates	**(46)**	(24)
Regulatory assets	**156**	29
Gas inventory	**(39)**	48
Deferred amounts and other assets	**10**	(2)
Accounts payable and other	**(55)**	(45)
Accounts payable to affiliates	**(40)**	18
Regulatory liabilities	**54**	105
Other long-term liabilities	**(12)**	(8)
Assets held for sale	**—**	12
	93	116

19. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. Affiliates refer to Enbridge and companies that are either directly or indirectly owned by Enbridge.

Enbridge and its affiliates perform centralized corporate functions for us pursuant to applicable agreements, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. We reimburse Enbridge for the expenses incurred to provide these services, as well as for other expenses incurred on our behalf. In addition, we perform services and incur expenses on behalf of our affiliates, which are subsequently reimbursed. Our expenses and recoveries for these services are recorded in Operating and administrative expense in the Consolidated Statements of Earnings, and are based on the cost of actual services provided or using various allocation methodologies.

Our transactions with entities related through common or joint control and significantly influenced investees are as follows:

Year ended December 31, 2020	Operating revenues	Gas commodity and distribution costs	Operating and administrative expense	Other Income	Interest income/ (expense)
(millions of Canadian dollars)					
Enbridge Inc.	**—**	**—**	**131**	**6**	**14**
Westcoast Energy Inc.	**—**	**—**	**—**	**—**	**(6)**
Tidal Energy Marketing Inc.	**11**	**13**	**—**	**—**	**—**
Tidal Energy Marketing (U.S.) LLC	**—**	**18**	**—**	**—**	**—**
Gazifère Inc.	**26**	**—**	**—**	**—**	**—**
Énergir, L.P.	**37**	**—**	**—**	**—**	**—**
Vector Pipeline, LLC (U.S.)	**—**	**19**	**—**	**—**	**—**
NEXUS Gas Transmission, LLC	**—**	**116**	**—**	**—**	**—**
Other affiliates, net	**2**	**3**	**7**	**—**	**—**

Year ended December 31, 2019	Operating revenues	Gas commodity and distribution costs	Operating and administrative expense	Other Income	Interest income/ (expense)
(millions of Canadian dollars)					
Enbridge Inc.	—	—	99	—	7
Westcoast Energy Inc.	—	—	—	—	(24)
Tidal Energy Marketing Inc.	11	38	—	—	—
Tidal Energy Marketing (U.S.) LLC	—	37	—	—	—
Gazifère Inc.	30	—	—	—	—
Énergir, L.P.	10	—	—	—	—
Vector Pipeline, LLC (U.S.)	—	19	—	—	—
NEXUS Gas Transmission, LLC	—	114	—	—	—
Other affiliates, net	2	8	6	—	(1)

Amounts due from/(to) related parties are as follows:

December 31,	**2020**	2019
(millions of Canadian dollars)		
Westcoast Energy Inc.[1]	**—**	(656)
Enbridge Inc.[2]	**(68)**	(39)
Enbridge Employee Services Canada Inc.	**(38)**	(46)
NEXUS Gas Transmission, LLC (U.S.)	**(10)**	(10)
Enbridge Pipelines Inc.	**45**	—
Union Energy Solutions Limited Partnership	**29**	23
Other affiliates, net[3]	**7**	(2)
	(35)	(730)

1 Included a $650 million subordinated promissory note from Westcoast, which was repaid in the second quarter of 2020.
2 Includes net derivative payable balances to affiliate.
3 Includes current portion of operating lease liabilities to affiliates.

SHARE CAPITAL
During the year ended December 31, 2020, common share dividends declared on our Class A and Class B common shares were $243 million (2019 - $506 million) and $207 million (2019 - $431 million), respectively. During 2020, we also completed the return of capital transactions, and received capital contributions, as described in *Note 11. Share Capital*.

FINANCING TRANSACTION
On April 1, 2020, we repaid the outstanding $650 million subordinated promissory note, as well as the related interest payable, due to Westcoast

GAS METER SERVICES
We purchase gas meter services from Lakeside Performance Gas Services Ltd. (Lakeside), such as ongoing meter exchanges and inspections for customers in our franchise area. As of December 1, 2020, Lakeside became an affiliate. In the month of December 2020, we purchased gas meter services from Lakeside totaling $3 million, of which a portion of these costs was expensed to Operating and administrative expense and the remainder capitalized in Property, plant and equipment. We will continue purchasing these services at prevailing market prices under normal trade terms.

WHOLESALE SERVICES
We provide gas procurement and transportation services to Gazifère Inc., an affiliate, pursuant to a contract negotiated between us and approved by the OEB and Régie de l'énergie.

LEASES
We incur operating lease payments related to natural gas transportation and storage services from various affiliates. Total affiliate right-of-use assets and lease liabilities as at December 31, 2020 were $51 million (2019 - $43 million) and $51 million (2019 - $43 million), respectively. See *Note 14* for further discussion.

DERIVATIVE INSTRUMENTS
As at December 31, 2020, we had a net payable balance of $36 million (2019 - $22 million) due to Enbridge in respect of derivative instruments that they have entered into on our behalf. See *Note 13. Risk Management and Financial Instruments* for further discussion.

OTHER
Our cash balances are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

20. GUARANTEES

In the normal course of conducting business, we may enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included in our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases.

We typically enter into these arrangements to facilitate commercial transactions with third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2020, guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

21. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

At December 31, 2020, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	8,695	375	125	350	300	745	6,800
Interest obligations[2]	5,521	359	345	342	327	311	3,837
Purchase of services, pipe and other materials, including transportation[3,4]	5,922	1,436	691	536	487	466	2,306
Right-of-way commitments[5]	527	9	9	9	9	9	482
Total	20,665	2,179	1,170	1,237	1,123	1,531	13,425

1 *Includes debentures and term notes, and excludes short-term borrowings, debt discounts, debt issue costs, finance lease obligations and fair value adjustment from push down accounting. Changes to the planned funding requirements are dependent on the terms of any debt refinancing agreements. Therefore, the actual timing of future cash repayments could be materially different than presented above.*

2 *Includes debentures and term notes bearing interest at fixed rates.*

3 *Includes firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; contracts for software, consulting or advisory services, as well as customer care services.*

4 *Includes capital and operating commitments.*

5 *Right-of-way payments related to cancellable gas storage payments that are reasonably likely to occur for the remaining life of all storage reservoirs.*

ENVIRONMENTAL

We are subject to various federal, provincial and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to natural gas pipeline operations, and we are, at times, subject to environmental remediation at various contaminated sites. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with our operating activities.

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. We were named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by us for the operation of our MGP.

While these Statements of Claim were filed by the City and the School Board, they were never formally served on us. It was and remains our understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, Enbridge Gas and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with us. To our knowledge, neither the City nor the School Board has taken any steps to advance the lawsuits.

Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation, isolation and containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the U.S. for the recovery in rates of costs relating to the remediation of former MGP sites. From 2006 to 2018, the OEB approved the establishment of deferral accounts to record the costs of investigating, defending and dealing with ongoing MGP-related claims. We expect that if it is found that we must contribute to any remediation costs, either as a result of a lawsuit or government order, we would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, we believe that the ultimate outcome of these matters will not have a significant impact on our financial position.

Hamilton Contaminated Site

In April 2016, the Ontario Ministry of the Environment, Conservation and Parks (MECP), formerly the Ministry of the Environment and Climate Change, issued a Director's Order (the Order) naming us, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of Enbridge Gas in Hamilton. In May 2016, we appealed the Order, and in June 2016, the Environmental Review Tribunal (the Tribunal), on consent of the MECP's Director, stayed the application of parts of the Order. The Tribunal extended the stay of the Order several times, which has allowed the owner of the property, with the cooperation of the adjacent owners, to prepare a plan of action, including discussions with the MECP and other neighbors. On February 4, 2021, the MECP determined that we and other parties have complied with the Order and no further obligations are outstanding. Accordingly, we withdrew our appeal and the Tribunal has accepted the withdrawal and is closing its file.

OTHER LITIGATION

We are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our financial position or results of operations.

TAX MATTERS

We maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

ENBRIDGE GAS INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2021

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE GAS INC.

Financial Reporting
Management of Enbridge Gas Inc. (Enbridge Gas) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors is responsible for all aspects related to governance of Enbridge Gas. Enbridge Gas does not have an Audit Committee, having received an exemption from such requirement.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. Enbridge Gas's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with US GAAP and to provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of Enbridge Gas, have conducted an audit of the consolidated financial statements of Enbridge Gas in accordance with Canadian generally accepted auditing standards and have issued an unqualified audit report, which is accompanying the consolidated financial statements.

/s/ Cynthia L. Hansen	**/s/ Tanya M. Ferguson**
Cynthia L. Hansen	Tanya M. Ferguson
President	Vice President, Finance

February 11, 2022

Independent auditor's report

To the Shareholders of Enbridge Gas Inc.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Inc. (the Company) as at December 31, 2021 and 2020, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America (US GAAP).

What we have audited
The Company's consolidated financial statements comprise:

- the consolidated statements of earnings for the years ended December 31, 2021 and 2020;
- the consolidated statements of comprehensive income for the years ended December 31, 2021 and 2020;
- the consolidated statements of changes in equity for the years ended December 31, 2021 and 2020;
- the consolidated statements of cash flows for the years ended December 31, 2021 and 2020;
- the consolidated statements of financial position as at December 31, 2021 and 2020; and
- the notes to the consolidated financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with US GAAP, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Ontario
February 11, 2022

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Operating revenues		
Gas commodity and distribution	**3,996**	3,631
Storage, transportation and other	**897**	884
Total operating revenues *(Note 4)*	**4,893**	4,515
Operating expenses		
Gas commodity and distribution costs	**2,146**	1,812
Operating and administrative	**1,105**	1,137
Depreciation and amortization	**677**	655
Total operating expenses	**3,928**	3,604
Operating income	**965**	911
Other income	**43**	56
Interest expense, net *(Note 10)*	**(394)**	(412)
Earnings before income taxes	**614**	555
Income tax expense *(Note 15)*	**(63)**	(58)
Earnings	**551**	497

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Earnings	**551**	497
Other comprehensive income/(loss), net of tax *(Notes 12 and 13)*		
Change in unrealized gain/(loss) on cash flow hedges	**21**	(37)
Reclassification to earnings of loss on cash flow hedges	**12**	15
Actuarial gain/(loss) on other postretirement benefits (OPEB)	**22**	(10)
Other comprehensive income/(loss), net of tax	**55**	(32)
Comprehensive income	**606**	465

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Common shares *(Note 11)*		
Balance at beginning of year	**3,517**	3,517
Capital contribution	**975**	800
Return of capital	**(1,050)**	(800)
Balance at end of year	**3,442**	3,517
Additional paid-in capital		
Balance at beginning and end of year	**7,253**	7,253
Deficit		
Balance at beginning of year	**(675)**	(720)
Earnings	**551**	497
Common share dividends declared	**(200)**	(450)
Adoption of new accounting standard	**—**	(2)
Balance at end of year	**(324)**	(675)
Accumulated other comprehensive loss *(Note 12)*		
Balance at beginning of year	**(78)**	(46)
Other comprehensive income/(loss), net of tax	**55**	(32)
Balance at end of year	**(23)**	(78)
Total equity	**10,348**	10,017

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Operating activities		
Earnings	**551**	497
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	**677**	655
Deferred income tax recovery	**(15)**	(25)
Net defined pension and OPEB costs	**(24)**	(31)
Expected credit loss	**14**	15
Other	**10**	13
Changes in operating assets and liabilities *(Note 17)*	**(473)**	78
Net cash provided by operating activities	**740**	1,202
Investing activities		
Capital expenditures	**(1,308)**	(1,109)
Additions to intangible assets	**(72)**	(76)
Net cash used in investing activities	**(1,380)**	(1,185)
Financing activities		
Net change in short-term borrowings	**394**	223
Repayment of loan from affiliate	**—**	(650)
Term note issuances, net of issue costs	**896**	1,192
Term note repayments	**(375)**	(400)
Common share dividends	**(200)**	(450)
Return of capital	**(1,050)**	(800)
Capital contribution received	**975**	800
Net cash provided by/(used in) financing activities	**640**	(85)
Net change in cash	**—**	(68)
Cash at beginning of year	**9**	77
Cash at end of year	**9**	9
Supplementary cash flow information		
Cash paid/(received) for income taxes	**(5)**	66
Cash paid for interest, net of amounts capitalized	**374**	385
Property, plant and equipment non-cash accruals	**75**	20

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2021**	2020
(millions of Canadian dollars)		
Assets		
Current assets		
Cash	**9**	9
Accounts receivable and other *(Note 6)*	**1,228**	1,161
Accounts receivable from affiliates	**156**	92
Gas inventory	**897**	659
	2,290	1,921
Property, plant and equipment, net *(Note 7)*	**16,662**	15,866
Intangible assets, net *(Note 8)*	**177**	174
Deferred amounts and other assets	**2,677**	2,492
Goodwill	**4,784**	4,784
Total assets	**26,590**	25,237
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 10)*	**1,515**	1,121
Accounts payable and other *(Note 9)*	**1,458**	1,295
Accounts payable to affiliates	**113**	134
Current portion of long-term debt *(Note 10)*	**126**	376
	3,212	2,926
Long-term debt *(Note 10)*	**9,352**	8,606
Other long-term liabilities	**2,012**	2,166
Deferred income taxes *(Note 15)*	**1,666**	1,522
	16,242	15,220
Commitments and contingencies *(Note 19)*		
Equity		
Share capital *(Note 11)*		
Common shares *(522 million shares outstanding at December 31, 2021 and 2020)*	**3,442**	3,517
Additional paid-in capital	**7,253**	7,253
Deficit	**(324)**	(675)
Accumulated other comprehensive loss *(Note 12)*	**(23)**	(78)
	10,348	10,017
Total liabilities and equity	**26,590**	25,237

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

/s/ Cynthia L. Hansen	**/s/ David G. Unruh**
Cynthia L. Hansen	David G. Unruh
Director	Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. BUSINESS OVERVIEW

The terms "we", "our", "us" and "Enbridge Gas" as used in these financial statements refer collectively to Enbridge Gas Inc. and its subsidiaries unless the context suggests otherwise. Enbridge Gas is a wholly-owned indirect subsidiary of Enbridge Inc. (Enbridge). Enbridge provides administrative and general support services to us.

Enbridge Gas is a rate-regulated natural gas distribution, storage and transmission utility, serving residential, commercial and industrial customers in Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (US GAAP). Amounts are stated in Canadian dollars unless otherwise noted. We are permitted to use US GAAP as our primary basis of accounting for the purposes of meeting our continuous disclosure obligations under an exemption granted by securities regulators in Canada.

BASIS OF PRESENTATION AND USE OF ESTIMATES
The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues; estimates of revenue; expected credit losses; depreciation rates and carrying value of property, plant and equipment *(Note 7)*; amortization rates and carrying value of intangible assets *(Note 8)*; measurement of goodwill; fair value of asset retirement obligations (ARO); fair value of financial instruments *(Note 13)*; provisions for income taxes *(Note 15)*; assumptions used to measure retirement benefits and OPEB *(Note 16)*; and commitments and contingencies *(Note 19)*. Actual results could differ from these estimates.

Certain comparative figures in our consolidated financial statements have been reclassified to conform to the current year's presentation.

REGULATION
Our utility operations within Ontario are regulated by the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities.

As a result of rate-regulated accounting, we have recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates and amounts collected from customers in advance of costs being incurred. Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment.

The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. The regulator's future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which we operate. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. We believe that the recovery of our regulatory assets as at December 31, 2021 is probable over the periods described in *Note 5 - Regulatory Matters*.

With the approval of the regulator, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

REVENUE RECOGNITION

Revenue from contracts with customers is generally recognized upon the fulfillment of the performance obligations for the distribution, storage, transportation and sale of natural gas. For distribution and transportation service arrangements, where the services are simultaneously received and consumed by the customer, revenues are recorded based on regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas. Revenues from storage services are recognized as the storage services are provided.

A significant portion of our operations are subject to regulation and, accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue under such circumstances is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator, which are accounted for under Accounting Standards Codification (ASC) 980 *Regulated Operations*.

PUSH-DOWN ACCOUNTING

Enbridge Gas Distribution Inc. (EGD) elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted US GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by EGD. Upon adopting push-down accounting, the historical cost of EGD's property, plant and equipment and related accounts were adjusted by the remaining unamortized fair value adjustment.

We have applied push-down accounting with respect to the accounts of Union Gas Limited (Union Gas). The carrying values of certain assets and liabilities of Union Gas transferred to EGD have been adjusted to reflect Enbridge's historical cost as at February 27, 2017, the date upon which Enbridge acquired common control of EGD and Union Gas.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

We use derivative financial instruments to manage our exposure to changes in interest rates and foreign exchange rates. Hedge accounting is optional and requires us to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges or net investment hedges. There were no outstanding derivative instruments relating to fair value or net investment hedges as at December 31, 2021 and 2020.

Cash Flow Hedges
We use cash flow hedges to manage our exposure to changes in interest rates and foreign exchange rates related to our unregulated storage revenue. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives
We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities in the Consolidated Statements of Cash Flows.

Balance Sheet Offset
Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

Transaction Costs
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a reduction to Long-term debt in the Consolidated Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

INCOME TAXES
Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent that taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

FOREIGN CURRENCY TRANSACTIONS
Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge Gas or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated to the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the exchange rate in effect as at the balance sheet date. Exchange gains and losses resulting from the translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period in which they arise.

CASH
We combine cash and bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements.

RECEIVABLES AND CURRENT EXPECTED CREDIT LOSSES
Accounts receivable and other are measured at cost. For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations.

NATURAL GAS IMBALANCES
The Consolidated Statements of Financial Position include balances as a result of differences in gas volumes received from, and delivered for, customers. As settlement of certain imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. All natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

GAS INVENTORY
Gas inventories primarily consist of natural gas held in storage and also include costs such as storage injection and demand costs. Natural gas held in storage is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of gas purchased is deferred as a liability for future refund, or as an asset for collection as approved by the OEB.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost, including an allowance for interest incurred during construction as authorized by the regulator. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the regulator. When group assets are retired or otherwise disposed of, gains and losses are generally not reflected in earnings but are booked as an adjustment to accumulated depreciation until the last asset in the pool is disposed of. Gains and losses on the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the regulator, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the regulator.

LEASES
We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach applied for other long-lived assets.

Lease liabilities and ROU assets require the use of judgment and estimates which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily consists of costs that regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; the fair value adjustment to long-term debt; the difference between the actual cost and approved cost of natural gas reflected in rates; and actuarial gains and losses arising from defined benefit pension plans.

INTANGIBLE ASSETS

Intangible assets consist primarily of certain software costs. We capitalize costs incurred during the application development stage of internal use software projects. Intangible assets are generally amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. When performing a qualitative assessment, we determine the drivers of fair value and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, the assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends and industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value is less than its carrying amount, a quantitative goodwill impairment test is performed.

The quantitative goodwill impairment assessment involves determining the fair value of goodwill and comparing that value to its carrying value. If the carrying value, including allocated goodwill, exceeds fair value, goodwill impairment is measured at the amount by which the carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. Fair value is estimated using a discounted cash flow technique. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. Cash flow projections include significant judgments and assumptions relating to revenue growth rates and expected future capital expenditures.

IMPAIRMENT

We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we calculate fair value based on the discounted cash flows and write the assets down to the extent that the carrying value exceeds the fair value.

ASSET RETIREMENT OBLIGATIONS

ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. Fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset’s useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

PENSION AND OTHER POSTRETIREMENT BENEFITS
We provide pension benefits through defined benefit and defined contribution pension plans and OPEB, including group health care and life insurance benefits through defined benefit OPEB plans.

Defined benefit pension obligation and net periodic benefit cost are estimated using the projected unit credit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors, including discount rates and mortality. The OPEB benefit obligation and net periodic benefit cost are estimated using the projected unit credit method, where benefits are attributed to years of service, taking into consideration projection of benefit costs.

We use mortality tables issued by the Canadian Institute of Actuaries (revised in 2014) to measure the benefit obligation of our pension plans.

We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments we anticipate making under each of the respective plans.

Funded pension plan assets are measured at fair value. The expected return on funded pension plan assets is determined using market-related values and assumptions on the invested asset mix consistent with the investment policies relating to the plan assets. The market-related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period (for funded pension plans) or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount and salary inflation experience.

The excess of the fair value of a plan's assets over the fair value of a plan's benefit obligation is recognized as Deferred amounts and other assets in the Consolidated Statements of Financial Position. The excess of the fair value of a plan's benefit obligation over the fair value of a plan's assets is recognized as Accounts payable and other and Other long-term liabilities in our Consolidated Statements of Financial Position.

Net periodic benefit cost is charged to earnings and includes:

- cost of benefits provided in exchange for employee services rendered during the year (current service cost);
- interest cost of plan obligations;
- expected return on plan assets (for funded pension plans);
- amortization of prior service costs on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit OPEB plans are presented as a component of Accumulated other comprehensive loss (AOCI) in our Consolidated Statements of Changes in Equity. Any unrecognized OPEB-related actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax. Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit pension plans, which have been permitted or are expected to be permitted by the regulator, to be recovered through future rates, are presented as a component of Deferred amounts and other assets in our Consolidated Statements of Financial Position.

We also record regulatory adjustments to reflect the difference between certain net periodic benefit costs for accounting purposes and net periodic benefit costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to earnings and OCI on an accrual basis.

For defined contribution plans, contributions made by us are expensed in the period in which the contribution occurs.

COMMITMENTS AND CONTINGENCIES
Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

CHANGES IN ACCOUNTING POLICIES
There were no changes in accounting policies during the year ended December 31, 2021.

ADOPTION OF NEW ACCOUNTING STANDARDS
Accounting for Contract Assets and Liabilities from Contracts with Customers in a Business Combination
Effective November 1, 2021, we adopted Accounting Standards Update (ASU) 2021-08 on a retrospective basis beginning January 1, 2021. The new standard was issued in October 2021 to amend business combination accounting specific to contract assets and contract liabilities resulting from contracts with customers, requiring measurement in accordance with ASC 606 The ASU is also applicable to contract assets and contract liabilities from other contracts to which ASC 606 applies, such as contract liabilities from the sale of nonfinancial assets within the scope of ASC 610-20. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Income Taxes
Effective January 1, 2021, we adopted ASU 2019-12 on a prospective basis. The new standard was issued in December 2019 with the intent of simplifying the accounting for income taxes. The accounting update removes certain exceptions to the general principles in ASC 740 *Income Taxes* as well as provides simplification by clarifying and amending existing guidance. The adoption of this ASU did not have a material impact on our consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES
Disclosures About Government Assistance
ASU 2021-10 was issued in November 2021 to increase the transparency of government assistance to business entities. The ASU adds new disclosure requirements for transactions with government that are accounted for using a grant or contribution accounting model by analogy. The required disclosures include information about the nature of transactions, accounting policy applied, impacted financial statement line items and significant terms and conditions. ASU 2021-10 is effective January 1, 2022 and can be applied either prospectively or retrospectively with early adoption permitted. The adoption of ASU 2021-10 is not expected to have a material impact on our consolidated financial statements.

4. REVENUES

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Services

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Gas commodity and distribution revenues - residential	**2,778**	2,560
Gas commodity and distribution revenues - commercial and industrial	**1,208**	1,077
Storage revenue	**156**	144
Transportation revenue	**686**	681
Other revenues	**71**	62
Total revenue from contracts with customers	**4,899**	4,524
Other[1]	**(6)**	(9)
Total revenues	**4,893**	4,515

1 Primarily relates to the effects of rate-regulated accounting.

We disaggregate revenues into categories which represent our principal performance obligations. These revenue categories also represent the most significant revenue streams, and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Receivables	Contract Liabilities
(millions of Canadian dollars)		
Balance as at December 31, 2021	**824**	**17**
Balance as at December 31, 2020	738	—

Receivables represent an unconditional right to consideration where only the passage of time is required before payment of consideration is due, and consist of trade accounts receivable, unbilled revenue and other accrued receivable balances. Receivables also consist of trade accounts receivable and unbilled revenue balances for the collection of certain federal carbon levy unit rates, for which we act as an agent.

Contract liabilities represent payments received for performance obligations which have not been fulfilled under our equal monthly payment plan. The increase in contract liabilities from cash received, net of amounts recognized as revenues during the year ended December 31, 2021, was $17 million.

Performance Obligations

Revenue category	**Nature of Performance Obligation**
Gas commodity and distribution revenue	• Supply and delivery of natural gas to customers
Storage and transportation revenue	• Storage and transportation of natural gas on behalf of customers
Other revenue	• Other billing and service fees

We recognized a reduction of revenue of $15 million during the year ended December 31, 2021 from performance obligations satisfied in previous periods, primarily resulting from differences in actual and estimated consumption. The associated reduction in gas commodity and distribution costs was also recognized in the current year.

Payment Terms
Payments from distribution customers are received on a continuous basis based on established billing cycles. Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. Payments from storage customers are received monthly under long-term storage capacity contracts. Payments from transportation customers are received on a continuous basis based on established billing cycles or monthly under long-term transportation capacity contracts.

Revenue to be Recognized from Unfulfilled Performance Obligations
Total revenue from performance obligations expected to be fulfilled in future periods is $602 million, of which $309 million is expected to be recognized during the year ending December 31, 2022.

The performance obligations above reflect revenues expected to be recognized in future periods from unfulfilled performance obligations pursuant to contracts with customers for the purchase of natural gas distribution, storage and transportation services. Certain revenues are excluded from the amounts above under the following ASC 606 optional exemptions:

- revenues, such as flow-through costs charged to customers, which are recognized at the amount for which we have the right to invoice our customers; and
- revenue from contracts with customers that have an original expected duration of one year or less.

Variable consideration is also excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be reasonably estimated.

A significant portion of our operations are subject to regulation. Accordingly, the amounts above, in addition to revenues that are not regulated, only include revenue for which the underlying rate has been approved by regulation, where applicable. The revenues excluded from the amounts above could represent a significant portion of our overall revenues and revenue from contracts with customers.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE
Revenue Recognition
Revenue from contracts with customers is generally recognized upon the fulfillment of the performance obligations as described above. Distribution and transportation service revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas.

Due to regulatory mechanisms, there are circumstances where revenues recognized do not match the amounts billed. Under such circumstances, revenue is recognized in a manner that is consistent with the underlying rate setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator.

Recognition and Measurement of Revenues

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Revenue from products and services transferred over time[1]	**4,829**	4,464
Revenue from products transferred at a point in time[2]	**70**	60
Total revenue from contracts with customers	**4,899**	4,524

1 Revenue from distribution, storage and transportation services.
2 Primarily from Other revenues.

Performance Obligations Satisfied Over Time
For arrangements involving the distribution and transportation of natural gas, where the services are simultaneously received and consumed by the customer, we recognize revenue over time using an output method based on volumes of commodities delivered. The measurement of the volumes delivered corresponds directly to the benefits received by the customers during that period. Revenue from storage services are recognized as the services are provided.

Determination of Transaction Prices
Prices for distribution and transportation services and regulated storage services are prescribed by regulation. Fees for unregulated storage services are determined through negotiations with customers and are based on market rates.

Prices for natural gas sold are driven by market prices and the Quarterly Rate Adjustment Mechanism (QRAM) in place that allows for rates to reflect changes in natural gas prices, subject to regulatory approval.

5. REGULATORY MATTERS

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under US GAAP for non-regulated entities. See *Note 2 - Significant Accounting Policies* for further discussion.

We are regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act*, (1998), which is part of a package of legislation known as the *Energy Competition Act*, (1998). This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario.

RATE APPROVALS
Our distribution rates, commencing in 2019, are set under a five-year Incentive Regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% stretch factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires us to share equally with customers any earnings in excess of 150 basis points over the annual OEB approved return on equity.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following regulatory assets and liabilities in the Consolidated Statements of Financial Position:

December 31,	**2021**	2020	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Purchase gas variance[1]	**15**	—	2022
Other current regulatory assets	**67**	117	2022
Total current regulatory assets[2] *(Note 6)*	**82**	117	
Long-term regulatory assets			
Deferred income taxes[3]	**1,532**	1,393	Various
Long-term debt[4] *(Note 10)*	**307**	334	2023-2046
Purchase gas variance[1]	**215**	—	2023
Accounting policy changes[5]	**157**	169	Various
Transition impact of accounting changes[6]	**49**	53	2032
Pension plan receivable[7]	**26**	342	Various
Other long-term regulatory assets	**91**	34	Various
Total long-term regulatory assets[2]	**2,377**	2,325	
Total regulatory assets	**2,459**	2,442	
Current regulatory liabilities			
Purchase gas variance[1]	**—**	153	2021
Other current regulatory liabilities	**61**	73	2022
Total current regulatory liabilities[8] *(Note 9)*	**61**	226	
Long-term regulatory liabilities			
Future removal and site restoration reserves[9]	**1,543**	1,455	Various
Accelerated capital cost allowance	**17**	43	Various
Other long-term regulatory liabilities	**94**	45	Various
Total long-term regulatory liabilities[8]	**1,654**	1,543	
Total regulatory liabilities	**1,715**	1,769	

1 Represents the difference between the actual cost and the approved cost of natural gas reflected in rates. We have been granted OEB approval to refund this balance to, or collect this balance from, customers on a rolling 12 month basis as part of the QRAM process. As part of the January 1, 2022 QRAM application, the recovery of certain balances have been deferred into 2023.

2 Current regulatory assets are included in Accounts receivable and other, while long-term regulatory assets are included in Deferred amounts and other assets.

3 Represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in future regulator-approved rates and recovered from customers. The recovery period depends on the timing of the reversal of temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded.

4 Represents our regulatory offset to the fair value adjustment to debt acquired in Enbridge's merger with Spectra Energy Corp. (Spectra Energy) and pushed down to Enbridge Gas. The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.

5 This deferral reflects unamortized accumulated actuarial gains/losses and past service costs incurred by Union Gas, relating to the period up to Enbridge's merger with Spectra Energy, which were previously recorded in AOCI. The amortization of this balance is recognized as a component of accrual-based pension expenses, which are included in Other income and recovered in rates, as previously approved by the OEB.

6 Represents our right to recover costs resulting from the adoption of the accrual basis of accounting for pension and OPEB costs upon transition to US GAAP in 2012. Pursuant to the OEB rate order, the balance as at December 31, 2012 is to be collected in rates over a 20 year period, commencing in 2013.

7 Represents the regulatory offset to our pension liability to the extent that it is expected to be included in regulator-approved future rates and recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense would be recorded in earnings and OCI.

8 Current regulatory liabilities are included in Accounts payable and other, while long-term regulatory liabilities are included in Other long-term liabilities.

9 Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the OEB, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

OTHER ITEMS AFFECTED BY RATE REGULATION

Gas Inventories

Natural gas held in storage is recorded in inventory at the reference prices approved by the OEB in the determination of customers' system supply rates. Included in Gas inventory as at December 31, 2021 is $61 million (2020 - $60 million) related to storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during our off-peak months and charged to gas costs during the peak winter months. In the absence of rate-regulated accounting, these costs would be expensed as incurred, and inventory would be recorded at the lower of cost or market value.

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2021**	2020
(millions of Canadian dollars)		
Trade receivables and unbilled revenues, net[1]	**953**	855
Regulatory assets *(Note 5)*	**82**	117
Gas imbalances	**101**	54
Rebillables receivable	**45**	76
Other	**47**	59
	1,228	1,161

1 Net of allowance for expected credit losses of $55 million as at December 31, 2021 (2020 - $45 million).

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2021**	2020
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas transmission	2.5%	**1,854**	1,752
Gas mains, services and other	2.6%	**13,354**	12,580
Compressors, meters and other operating equipment	4.1%	**3,361**	3,246
Storage	2.7%	**1,065**	950
Land and right-of-way[1]	0.9%	**375**	361
Vehicles, office furniture, equipment and other buildings and improvements	8.4%	**453**	434
Under construction	—%	**263**	177
		20,725	19,500
Accumulated depreciation		**(4,464)**	(4,036)
		16,261	15,464
Unregulated property, plant and equipment			
Gas mains, services and other	10.2%	**13**	13
Compressors, meters and other operating equipment	1.3%	**42**	41
Storage	3.0%	**374**	365
Land and right-of-way[1]	1.5%	**38**	37
Under construction	—%	**37**	30
		504	486
Accumulated depreciation		**(103)**	(84)
		401	402
Property, plant and equipment, net		**16,662**	15,866

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.

Depreciation expense, including amounts collected for future removal and site restoration costs, was $606 million for the year ended December 31, 2021 (2020 - $583 million).

Included within depreciation expense is $22 million in incremental depreciation resulting from push-down accounting for the year ended December 31, 2021 (2020 - $22 million) *(Note 2)*.

8. INTANGIBLE ASSETS

December 31,	**2021**	2020
(millions of Canadian dollars)		
Software and Customer Information System[1]	**515**	654
Less: Accumulated amortization	**(338)**	(480)
Intangible assets, net	**177**	174

1 The weighted average amortization rate for the years ended December 31, 2021 and 2020 was 12.8% and 11.8%, respectively.

Intangible assets include $26 million of work-in-progress as at December 31, 2021 (2020 - $35 million). Amortization expense for intangible assets for the years ended December 31, 2021 and 2020 was $71 million and $72 million, respectively. The following table presents our expected amortization expense associated with existing intangible assets for the years indicated as follows:

	2022	2023	2024	2025	2026
(millions of Canadian dollars)					
Forecast of amortization expense	54	25	20	20	19

9. ACCOUNTS PAYABLE AND OTHER

December 31,	**2021**	2020
(millions of Canadian dollars)		
Trade payables and operating accrued liabilities	**638**	491
Federal carbon program liability	**242**	194
Gas imbalances	**124**	54
Taxes payable	**99**	47
Construction payables and contractor holdbacks	**88**	73
Interest payable	**87**	81
Regulatory liabilities *(Note 5)*	**61**	226
Other	**119**	129
	1,458	1,295

10. DEBT

December 31,	Weighted Average Interest Rate[3]	Maturity	**2021**	2020
(millions of Canadian dollars)				
Medium-term notes	3.8%	2022-2051	**9,010**	8,485
Debentures	9.1%	2024-2025	**210**	210
Commercial paper and credit facility draws	0.5%	2023	**1,515**	1,121
Other[1]			**(49)**	(47)
Fair value adjustment from push down accounting *(Note 2)*			**307**	334
Total debt			**10,993**	10,103
Current maturities			**(126)**	(376)
Short-term borrowings[2]			**(1,515)**	(1,121)
Long-term debt			**9,352**	8,606

1 Primarily unamortized discounts, premiums and debt issuance costs.
2 Weighted average interest rate - 0.5% (2020 - 0.3%).
3 Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2021.

As at December 31, 2021, all outstanding debt was unsecured.

CREDIT FACILITIES

We actively manage our bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of our external credit facility at December 31, 2021:

	Maturity	Total Facility	Draws[2]	Available
(millions of Canadian dollars)				
364 day extendible credit facility	2023[1]	**2,000**	**1,515**	**485**

1 Maturity date is inclusive of the one-year term out provision.
2 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.

On July 23, 2021, we extended the term out date of our 364 day extendible credit facility to July 22, 2022, with a maturity date of July 22, 2023.

The credit facility carries a standby fee of 0.1% on the unused portion and the draws bear interest at market rates.

As at December 31, 2021, we have access to Enbridge's demand letter of credit facilities totaling $1.0 billion (2020 - $495 million). As at December 31, 2021, $15 million (2020 - $14 million) of letters of credit were issued by us.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2021, we completed the following long-term debt issuances totaling $900 million:

Issue Date		Principal Amount
(millions of Canadian dollars)		
September 2021	2.35% medium-term notes due September 2031	$475
September 2021	3.20% medium-term notes due September 2051	$425

LONG-TERM DEBT REPAYMENT

During the year ended December 31, 2021, we completed the following long-term debt repayment totaling $375 million:

Repayment Date		Principal Amount
(millions of Canadian dollars)		
May 2021	2.76% medium-term notes	$200
December 2021	4.77% medium-term notes	$175

DEBT COVENANTS

Our credit facility agreement and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or terminations of the agreements may result if we were to default on payment or violate certain covenants. We were in compliance with all terms and conditions of our committed credit facility agreement and our Trust Indenture as at December 31, 2021.

INTEREST EXPENSE

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Debentures and term notes	**378**	380
Commercial paper and credit facility draws	**5**	17
Interest on loans from affiliate	**—**	6
Other interest and finance costs	**18**	14
Capitalized interest	**(7)**	(5)
	394	412

11. SHARE CAPITAL

As at December 31, 2021, our authorized share capital consisted of an unlimited number of common shares with no par value and an unlimited number of preference shares. Our Class A and Class B common shares are held by Enbridge Energy Distribution Inc. and Great Lakes Basin Energy LP, respectively. Both classes of common shares are identical in every respect, and dividends cannot be paid to one class without paying dividends to the other. As at December 31, 2021 and 2020, no preference shares were issued and outstanding.

COMMON SHARES

	2021		2020	
December 31,	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of shares in millions)				
Class A				
Balance at beginning of year	**282**	**2,636**	282	2,636
Capital contribution	**—**	**527**	—	432
Return of capital	**—**	**(567)**	—	(432)
	282	**2,596**	282	2,636
Class B				
Balance at beginning of year	**240**	**881**	240	881
Capital contribution	**—**	**448**	—	368
Return of capital	**—**	**(483)**	—	(368)
	240	**846**	240	881
Balance at end of year	**522**	**3,442**	522	3,517

The capital contribution and return of capital transactions to the stated capital of Class A and Class B common shares had no impact on the total shares outstanding.

12. COMPONENTS OF AOCI

Changes in AOCI for the year ended December 31, 2021 and 2020 are as follows:

	2021		
	Cash Flow Hedges	OPEB Adjustment	Total
(millions of Canadian dollars)			
Balance at January 1, 2021	**(64)**	**(14)**	**(78)**
Other comprehensive income retained in AOCI	**29**	**31**	**60**
Other comprehensive loss reclassified to earnings	**17**	**—**	**17**
	(18)	**17**	**(1)**
Tax impact			
Income tax on amounts retained in AOCI	**(8)**	**(9)**	**(17)**
Income tax on amounts reclassified to earnings	**(5)**	**—**	**(5)**
	(13)	**(9)**	**(22)**
Balance at December 31, 2021	**(31)**	**8**	**(23)**

	2020		
	Cash Flow Hedges	OPEB Adjustment	Total
(millions of Canadian dollars)			
Balance at January 1, 2020	(42)	(4)	(46)
Other comprehensive loss retained in AOCI	(49)	(13)	(62)
Other comprehensive loss reclassified to earnings	17	—	17
	(74)	(17)	(91)
Tax impact			
Income tax on amounts retained in AOCI	12	3	15
Income tax on amounts reclassified to earnings	(2)	—	(2)
	10	3	13
Balance at December 31, 2020	(64)	(14)	(78)

13. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

Our earnings, cash flows and other OCI are subject to movements in natural gas prices, foreign exchange rates and interest rates (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by our customers. The difference between the actual cost of natural gas purchased and the price approved by the OEB is deferred as a receivable from, or payable to, customers until it is approved for collection or refund. We have a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices, and for the establishment of rate riders required to collect or refund gas cost variances. Adjustments are subject to OEB approval.

Foreign Exchange Risk

Foreign exchange risk is the risk of gain or loss due to the volatility of currency exchange rates. We generate certain revenues, incur expenses and hold cash balances that are denominated in United States dollars (USD). As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from USD exchange rate variability.

We have implemented a policy to hedge a portion of our USD denominated unregulated storage revenue exposures. Qualifying derivative instruments are used to hedge anticipated USD denominated revenues and to manage variability in cash flows.

A portion of our natural gas purchases are denominated in USD and, as a result, there is exposure to fluctuations in the exchange rate of the USD against the Canadian dollar. Realized foreign exchange gains and losses relating to natural gas purchases are passed on to customers, therefore, we have no net exposure to movements in the foreign exchange rate on natural gas purchases.

Interest Rate Risk

Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps are used to hedge against the effect of future interest rate movements. Current floating-to-fixed interest rate swaps with an average swap rate of 2.3% expire in January 2022.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have implemented a program to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating-to-fixed interest rate swaps with an average swap rate of 1.4%

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments.

We generally have a common practice of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce our credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2021	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Deferred amounts and other assets					
Interest rate contracts	**14**	**—**	**14**	**—**	**14**
	14	**—**	**14**	**—**	**14**
Accounts payable to affiliates					
Interest rate contracts	**12**	**—**	**12**	**—**	**12**
	12	**—**	**12**	**—**	**12**
Total net derivative asset					
Interest rate contracts	**26**	**—**	**26**	**—**	**26**
	26	**—**	**26**	**—**	**26**

December 31, 2020	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Deferred amounts and other assets					
Interest rate contracts	8	—	8	(1)	7
	8	—	8	(1)	7
Accounts payable to affiliates					
Interest rate contracts	(43)	—	(43)	—	(43)
	(43)	—	(43)	—	(43)
Other long-term liabilities					
Interest rate contracts	(1)	—	(1)	1	—
	(1)	—	(1)	1	—
Total net derivative liability					
Interest rate contracts	(36)	—	(36)	—	(36)
	(36)	—	(36)	—	(36)

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.

December 31, 2021	2022	2023	2024	2025	2026	Thereafter	Total
Foreign exchange contracts - United States dollar forwards - sell *(millions of USD)*	**1**	**—**	**—**	**—**	**—**	**—**	**1**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**18**	**—**	**—**	**—**	**—**	**—**	**18**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**200**	**200**	**—**	**—**	**—**	**—**	**400**

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on our consolidated earnings and comprehensive income, before the effect of income taxes.

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Amount of unrealized gain/(loss) recognized in OCI		
Interest rate contracts	**29**	(49)
	29	(49)
Amount of loss reclassified from AOCI to earnings		
Interest rate contracts[1]	**17**	17
	17	17

1 Reported within Interest expense, net in the Consolidated Statements of Earnings.

We estimate that a gain of $1 million of AOCI related to unrealized cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest and foreign exchange rates in effect when derivative contracts, that are currently outstanding, mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 24 months as at December 31, 2021.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments, as they become due. In order to manage this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under the committed credit facility and long-term debt, which includes debentures and medium-term notes and, if necessary, additional liquidity is available through intercompany transactions with our ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable us to fund all anticipated requirements. We maintain a current medium-term note shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. We also maintain a committed credit facility with a diversified group of banks and institutions. We were in compliance with all of the terms and conditions of our committed credit facility as at December 31, 2021. As a result, the credit facility is available to us and the banks are obligated to fund us under the terms of the facility.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. We are primarily exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by our large and diversified customer base and the ability to recover an estimate for expected credit losses for utility operations through the rate-making process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default of receivables. Generally, we classify receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which generally require payment in full within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the expected credit loss, which totaled $55 million as at December 31, 2021 (December 31, 2020 - $45 million).

Our expected credit loss is determined based on historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations, using a loss allowance matrix. This estimate is revised each reporting period to reflect current expectations. When we have determined that collection efforts are unlikely to be successful, amounts charged to the expected credit loss account are applied against the impaired accounts receivable.

Entering into derivative financial instruments may also result in exposure to credit risk. We enter into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements. As at December 31, 2021, we have $26 million (December 31, 2020 - $8 million) in credit concentrations and credit exposure with Enbridge and its affiliates.

Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair values of financial instruments reflect our best estimates of fair value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. We do not have any derivative instruments classified as Level 1.

Level 2
Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps, for which observable inputs can be obtained.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable, or where the observable data does not support a significant portion of the derivative's fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support a Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. We do not have any derivative instruments classified as Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value, including discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, we use observable market prices (interest, foreign exchange and natural gas) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread, as well as the credit default swap spreads associated with our counterparties, in our estimation of fair value.

As at December 31, 2021, we had Level 2 derivative assets with a fair value of $26 million (December 31, 2020 - $8 million) and Level 2 derivative liabilities with a fair value of nil (December 31, 2020 - $44 million).

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS
The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. As at December 31, 2021, our long-term debt, including the current portion, had a carrying value of $9.2 billion (December 31, 2020 - $8.7 billion) before debt issuance costs and a fair value adjustment from push down accounting, and a fair value of $10.4 billion (December 31, 2020 - $10.7 billion).

The fair value of financial assets and liabilities, other than derivative instruments and long-term debt, approximate their carrying value due to the short period to maturity.

14. LEASES

LESSEE
We incur operating lease payments related to natural gas transportation, storage and real estate assets. These lease agreements have remaining lease terms of five months to 16 years, some of which include options to terminate at our discretion.

For the years ended December 31, 2021 and 2020, we incurred operating lease expenses of $8 million and $9 million, respectively. Operating lease expenses are reported within Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2021 and 2020, operating lease payments made to settle lease liabilities were $9 million and $9 million, respectively. Operating lease payments are reported within Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Consolidated Statements of Financial Position Information

December 31,	**2021**	2020
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases		
Operating lease right-of-use assets, net[1]	**49**	53
Operating lease liabilities - current[2]	**6**	6
Operating lease liabilities - long-term[3]	**43**	47
Total operating lease liabilities	**49**	53
Weighted average remaining lease term		
Operating leases	**8 years**	9 years
Weighted average discount rate		
Operating leases	**3.1%**	3.1%

1 Right-of-use assets are reported within Deferred amounts and other assets in the Consolidated Statements of Financial Position.
2 Current lease liabilities are reported within Accounts payable and other and Accounts payable to affiliates in the Consolidated Statements of Financial Position.
3 Long-term lease liabilities are reported within Other long-term liabilities in the Consolidated Statements of Financial Position.

As at December 31, 2021, we have lease commitments as detailed below:

	Operating leases
(millions of Canadian dollars)	
2022	**8**
2023	**7**
2024	**7**
2025	**7**
2026	**6**
Thereafter	**20**
Total undiscounted lease payments	**55**
Less imputed interest	**(6)**
Total operating lease liabilities	**49**

LESSOR

We receive revenues from operating and sales-type leases primarily related to natural gas equipment and real estate assets. Our lease agreements have remaining lease terms of five years to 20 years as at December 31, 2021.

As at December 31, 2021, the following table sets out future lease payments to be received under operating lease and sales-type lease contracts where we are the lessor:

	Operating leases	Sales-type leases
(millions of Canadian dollars)		
2022	**2**	**1**
2023	**1**	**2**
2024	**1**	**2**
2025	**1**	**2**
2026	**1**	**2**
Thereafter	**2**	**20**
Future lease payments to be received	**8**	**29**

15. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Earnings before income taxes	**614**	555
Canadian federal statutory income tax rate	**15%**	15%
Expected federal taxes at statutory rate	**92**	83
Increase/(decrease) resulting from:		
Provincial and state income taxes	**(1)**	(13)
Effects of rate-regulated accounting[1]	**(54)**	(46)
Part VI.1 tax, net of federal Part I deduction[1]	**30**	41
Other[2]	**(4)**	(7)
Income tax expense	**63**	58
Effective income tax rate	**10.3%**	10.5%

1 The provincial tax component of these items is included in Provincial and state income taxes above.
2 Includes miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals and entertainment and a change in prior year estimates arising from the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Earnings before income taxes		
Canada	**614**	555
	614	555
Current income taxes		
Canada	**78**	84
United States	**—**	(1)
	78	83
Deferred income taxes		
Canada	**(15)**	(25)
	(15)	(25)
Income tax expense	**63**	58

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(1,697)**	(1,586)
Regulatory assets	**(409)**	(368)
Deferrals	**(8)**	(10)
Pension and OPEB plans	**(14)**	(13)
Other	**(7)**	(2)
Total deferred income tax liabilities	**(2,135)**	(1,979)
Deferred income tax assets		
Future removal and site restoration reserves	**413**	391
Minimum tax credits	**44**	40
Financial instruments	**12**	24
Other	**—**	2
Total deferred income tax assets	**469**	457
Net deferred income tax liabilities	**(1,666)**	(1,522)

Enbridge Gas is subject to taxation in Canada. The material jurisdiction in which we are subject to potential examinations is Canada (Federal and Ontario). We are open to examination by Canadian tax authorities for 2012 to 2021 tax years, and are currently under examination for income tax matters in Canada for 2017 to 2018 tax years.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**34**	39
Gross decreases for tax positions of prior year	**(16)**	(2)
Lapses of statute of limitations	**(3)**	(3)
Unrecognized tax benefits at end of year	**15**	34

The unrecognized tax benefits as at December 31, 2021, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the years ended December 31, 2021 and 2020 included no amounts of interest and penalties. As at December 31, 2021 and 2020, interest and penalties of nil and $1 million have been accrued.

16. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We provide pension benefits, covering substantially all employees, through contributory and non-contributory registered defined benefit and defined contribution pension plans. We also provide non-registered pension benefits for certain employees through supplemental non-contributory defined benefit pension plans.

Defined Benefit Pension Plan Benefits
Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

Defined Contribution Pension Plan Benefits
Our contributions are based on each plan participant's current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

OTHER POSTRETIREMENT BENEFIT PLANS
We provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees, through unfunded defined benefit OPEB plans.

BENEFIT OBLIGATIONS, PLAN ASSETS AND FUNDED STATUS
The following table details the changes in the benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit pension and OPEB plans:

	Pension		OPEB	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Change in benefit obligation				
Benefit obligation at beginning of year	**2,532**	2,331	**186**	170
Service cost	**63**	68	**3**	3
Interest cost	**51**	66	**4**	5
Participant contributions	**13**	15	**—**	—
Actuarial (gain)/loss[1]	**(161)**	160	**(31)**	13
Benefits paid	**(112)**	(108)	**(5)**	(5)
Benefit obligation at end of year[2]	**2,386**	2,532	**157**	186
Change in plan assets				
Fair value of plan assets at beginning of year	**2,219**	2,108	**—**	—
Actual return on plan assets	**258**	152	**—**	—
Employer contributions	**37**	52	**5**	5
Participant contributions	**13**	15	**—**	—
Benefits paid	**(112)**	(108)	**(5)**	(5)
Fair value of plan assets at end of year	**2,415**	2,219	**—**	—
Overfunded/(underfunded) status at end of year	**29**	(313)	**(157)**	(186)
Presented as follows:				
Deferred amounts and other assets	**164**	35	**—**	—
Accounts payable and other	**(3)**	(3)	**(7)**	(7)
Other long-term liabilities	**(132)**	(345)	**(150)**	(179)
	29	(313)	**(157)**	(186)

1 Primarily due to increase in the discount rate used to measure the benefit obligations (2020 - primarily due to decrease in the discount rate used to measure the benefit obligations).
2 For pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. The accumulated benefit obligation for our pension plans was $2.2 billion and $2.4 billion as at December 31, 2021 and 2020, respectively.

Certain of our pension plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Accumulated benefit obligation	**253**	1,963
Fair value of plan assets	**181**	1,767

Certain of our pension plans have projected benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligation and fair value of plan assets were as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Projected benefit obligation	**895**	2,115
Fair value of plan assets	**760**	1,767

AMOUNT RECOGNIZED IN ACCUMULATED OTHER COMPREHENSIVE INCOME

The amount of pre-tax AOCI relating to our OPEB plans are as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Net actuarial (gain)/loss	**(13)**	18
Total amount recognized in AOCI	**(13)**	18

NET PERIODIC BENEFIT COST AND OTHER AMOUNTS RECOGNIZED IN COMPREHENSIVE INCOME

The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Service cost	**63**	68	**3**	3
Interest cost[1]	**51**	66	**4**	5
Expected return on plan assets[1]	**(131)**	(136)	**—**	—
Amortization of net actuarial loss[1,2]	**28**	20	**—**	—
Net periodic benefit cost	**11**	18	**7**	8
Defined contribution benefit cost	**2**	2	**—**	—
Net pension and OPEB cost recognized in Earnings	**13**	20	**7**	8
Amount recognized in OCI:				
Net actuarial (gain)/loss arising during the year	**—**	—	**(31)**	13
Total amount recognized in OCI	**—**	—	**(31)**	13
Total amount recognized in Comprehensive income	**13**	20	**(24)**	21

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.
2 Reflects amortization of net actuarial loss arising from pension plans that are recognized as long-term regulatory assets (Note 5).

ACTUARIAL ASSUMPTIONS
The weighted average assumptions made in the measurement of the benefit obligation and net periodic benefit cost of our defined benefit pension and OPEB plans are as follows:

	Pension		OPEB	
	2021	2020	**2021**	2020
Benefit obligations				
Discount rate	**3.2%**	2.6%	**3.2%**	2.6%
Rate of salary increase	**2.9%**	2.3%	**3.0%**	2.4%
Net benefit cost				
Discount rate	**2.6%**	3.1%	**2.6%**	3.1%
Rate of return on plan assets	**6.0%**	6.5%	**N/A**	N/A
Rate of salary increase	**2.3%**	3.2%	**2.4%**	3.3%

ASSUMED HEALTH CARE COST TREND RATES
The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	2021	2020
Health care cost trend rate assumed for next year	**4.0%**	4.0%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0%**	4.0%

PLAN ASSETS
We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

Asset Category	**Target Allocation**	December 31, **2021**	December 31, 2020
Equity securities	**40.9%**	**44.9%**	46.3%
Fixed income securities	**34.8%**	**32.2%**	31.9%
Alternatives[1]	**24.3%**	**22.9%**	21.8%

1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the funds.

The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level:

	2021				2020			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Cash and cash equivalents	**42**	**—**	**—**	**42**	50	—	—	50
Equity securities								
Canada	**110**	**123**	**—**	**233**	103	111	—	214
Global	**—**	**853**	**—**	**853**	—	813	—	813
Fixed income securities								
Government	**141**	**294**	**—**	**435**	125	249	—	374
Corporate	**—**	**300**	**—**	**300**	—	284	—	284
Alternatives[4]	**—**	**—**	**552**	**552**	—	—	466	466
Forward currency contracts	**—**	**—**	**—**	**—**	—	18	—	18
Total pension plan assets at fair value	**293**	**1,570**	**552**	**2,415**	278	1,475	466	2,219

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Balance at beginning of year	**466**	427
Unrealized and realized gains/(losses)	**49**	(3)
Purchases and settlements, net	**37**	42
Balance at end of year	**552**	466

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2022	2023	2024	2025	2026	2027-2031
(millions of Canadian dollars)						
Pension	113	115	117	119	120	628
OPEB	7	7	7	7	7	38

EXPECTED EMPLOYER CONTRIBUTIONS

In 2022, we expect to contribute approximately $41 million and $7 million to the pension plans and OPEB plans, respectively.

For the year ended December 31, 2020, we incurred $74 million in severance costs related to Enbridge's voluntary workforce reduction program. For the year ended December 31, 2021, there were no such costs incurred. Severance costs are presented in Operating and administrative expense in the Consolidated Statements of Earnings.

17. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Accounts receivable and other	**(14)**	50
Accounts receivable from affiliates	**(27)**	(46)
Regulatory assets	**(222)**	156
Gas inventory	**(242)**	(39)
Deferred amounts and other assets	**(2)**	10
Accounts payable and other	**196**	(55)
Accounts payable to affiliates	**(4)**	(40)
Regulatory liabilities	**(140)**	54
Other long-term liabilities	**(18)**	(12)
	(473)	78

18. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. Affiliates refer to Enbridge and companies that are either directly or indirectly owned by Enbridge.

Enbridge and its affiliates perform centralized corporate functions for us pursuant to applicable agreements, including legal, accounting, compliance, treasury, employee benefits, information technology and other areas, as well as certain engineering and other services. We reimburse Enbridge for the expenses incurred to provide these services as well as for other expenses incurred on our behalf. In addition, we perform services and incur expenses on behalf of our affiliates, which are subsequently reimbursed. Our expenses and recoveries for these services are recorded in Operating and administrative expense in the Consolidated Statements of Earnings, and are based on the cost of actual services provided or using various allocation methodologies.

Our transactions with entities related through common or joint control and significantly influenced investees are as follows:

Year ended December 31, 2021	Operating revenues	Gas commodity and distribution costs	Operating and administrative expense	Other Income	Interest income
(millions of Canadian dollars)					
Enbridge Inc.	**—**	**—**	**153**	**5**	**2**
Tidal Energy Marketing Inc.	**18**	**16**	**—**	**—**	**—**
Tidal Energy Marketing (U.S.) LLC	**—**	**31**	**—**	**—**	**—**
Gazifère Inc.	**30**	**—**	**—**	**—**	**—**
Énergir, L.P.[1]	**35**	**—**	**—**	**—**	**—**
Vector Pipeline, L.P.	**—**	**20**	**—**	**—**	**—**
NEXUS Gas Transmission, LLC	**—**	**111**	**—**	**—**	**—**
Lakeside Performance Gas Services Ltd.	**—**	**—**	**19**	**—**	**—**
Other affiliates, net	**2**	**3**	**9**	**—**	**—**

1 The minority interest in the parent of Energir L.P. held by a subsidiary of Enbridge was sold on December 30, 2021.

Year ended December 31, 2020	Operating revenues	Gas commodity and distribution costs	Operating and administrative expense	Other Income	Interest income/ (expense)
(millions of Canadian dollars)					
Enbridge Inc.	—	—	131	6	14
Westcoast Energy Inc.	—	—	—	—	(6)
Tidal Energy Marketing Inc.	11	13	—	—	—
Tidal Energy Marketing (U.S.) LLC	—	18	—	—	—
Gazifère Inc.	26	—	—	—	—
Énergir, L.P.	37	—	—	—	—
Vector Pipeline, L.P.	—	19	—	—	—
NEXUS Gas Transmission, LLC	—	116	—	—	—
Other affiliates, net	2	3	7	—	—

Amounts due from/(to) related parties are as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Enbridge Employee Services Canada Inc.	**(61)**	(38)
NEXUS Gas Transmission, LLC	**(9)**	(10)
Enbridge Pipelines Inc.	**35**	45
Union Energy Solutions Limited Partnership	**28**	29
Gazifère Inc.	**25**	6
Tidal Energy Marketing Inc.[3]	**19**	—
Enbridge Inc.[1]	**18**	(68)
Other affiliates, net[2,3]	**—**	1
	55	(35)

1 Includes net qualifying interest cash flow hedges receivable and net derivative receivable balances from affiliate.
2 Includes current portion of operating lease liabilities to affiliates.
3 Includes affiliate gas imbalance receivable. As at December 31, 2021 total affiliate gas imbalance receivable was $23 million (2020 - nil).

SHARE CAPITAL
During the year ended December 31, 2021, common share dividends declared on our Class A and Class B common shares were $108 million (2020 - $243 million) and $92 million (2020 - $207 million), respectively. During 2020, we also completed the return of capital transactions, and received capital contributions, as described in *Note 11 - Share Capital*.

FINANCING TRANSACTION
On April 1, 2020, we repaid the outstanding $650 million subordinated promissory note, as well as the related interest payable, due to Westcoast Energy Inc.

GAS METER SERVICES
We purchase gas meter services from Lakeside Performance Gas Services Ltd. (Lakeside), such as ongoing meter exchanges and inspections for customers in our franchise area. As of December 1, 2020, Lakeside became an affiliate. In 2021, we purchased gas meter services from Lakeside totaling $52 million, a portion of which was expensed to Operating and administrative expense and the remainder capitalized in Property, plant and equipment. We will continue purchasing these services at prevailing market prices under normal trade terms.

HYDRO EXCAVATION SERVICES
We purchase hydro excavation and specialty gas services from Ontario Excavac Inc. (OE). As of July 31, 2021, OE became an affiliate. We will continue purchasing these services at prevailing market prices under normal trade terms.

WHOLESALE SERVICES
We provide gas procurement and transportation services to Gazifère Inc., an affiliate, pursuant to a contract negotiated between us and approved by the OEB and Régie de l'énergie.

LEASES
We incur operating lease payments related to natural gas transportation and storage services from various affiliates. Total affiliate right-of-use assets and lease liabilities as at December 31, 2021 were $48 million (2020 - $51 million) and $48 million (2020 - $51 million), respectively. See *Note 14 - Leases* for further discussion.

DERIVATIVE INSTRUMENTS
As at December 31, 2021, we had a net receivable balance of $26 million (2020 - $36 million payable) due from Enbridge in respect of derivative instruments that they have entered into on our behalf. See *Note 13 - Risk Management and Financial Instruments* for further discussion.

OTHER
Our cash balances are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

19. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2021, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	9,220	125	350	300	745	650	7,050
Interest obligations[2]	5,681	370	367	351	336	300	3,957
Purchase of services, pipe and other materials, including transportation[3,4]	6,050	1,998	757	525	473	437	1,860
Right-of-way commitments[5]	668	11	11	11	11	11	613
Total	21,619	2,504	1,485	1,187	1,565	1,398	13,480

1 *Includes debentures and term notes, and excludes short-term borrowings, debt discounts, debt issuance costs, finance lease obligations and the fair value adjustment from push-down accounting. Changes to the planned funding requirements are dependent on the terms of any debt refinancing agreements. Therefore, the actual timing of future cash repayments could be materially different than presented above.*

2 *Includes debentures and term notes bearing interest at fixed rates.*

3 *Includes firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; and customer care services.*

4 *Includes capital and operating commitments.*

5 *Includes right-of-way payments related to cancellable gas storage payments that are reasonably likely to occur for the remaining life of all storage reservoirs.*

ENVIRONMENTAL

We are subject to various federal, provincial and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to natural gas pipeline operations, and we are, at times, subject to environmental remediation at various contaminated sites. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with our operating activities.

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. We were named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by us for the operation of our MGP.

While these Statements of Claim were filed by the City and the School Board, they were never formally served on us. It was and remains our understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, we entered into an agreement with the City (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with us. To our knowledge, neither the City nor the School Board has taken any steps to advance the lawsuits.

Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time, as there are a number of potential alternative remediation, isolation and containment approaches which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the US for the recovery in rates of costs relating to the remediation of former MGP sites. From 2006 to 2018, the OEB approved the establishment of deferral accounts to record the costs of investigating, defending and dealing with ongoing MGP-related claims. We expect that if it is found that we must contribute to any remediation costs, either as a result of a lawsuit or government order, we may be generally allowed to recover in rates those substantial costs not recovered through insurance or by other means. Accordingly, we believe that the ultimate outcome of these matters will not have a significant impact on our financial position.

Hamilton Contaminated Site

In April 2016, the Ontario Ministry of the Environment, Conservation and Parks (MECP), formerly the Ministry of the Environment and Climate Change, issued a Director's Order (the Order) naming us, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of ours in Hamilton. In May 2016, we appealed the Order, and in June 2016, the Environmental Review Tribunal (the Tribunal), on consent of the MECP's Director, stayed the application of parts of the Order. The Tribunal extended the stay of the Order several times, which allowed the owner of the property, with the cooperation of the adjacent owners, to prepare a plan of action, including discussions with the MECP and other neighbors. On February 4, 2021, the MECP determined that we and other parties have complied with the Order and no further obligations are outstanding. Accordingly, we withdrew our appeal, and the Tribunal has accepted the withdrawal and has closed its file.

OTHER LITIGATION

We are subject to various legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

TAX MATTERS

We maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

20. GUARANTEES

In the normal course of conducting business, we may enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries, jointly owned entities, unconsolidated entities such as equity method investees, or entities with other ownership arrangements that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included in our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases.

We typically enter into these arrangements to facilitate commercial transactions with third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2021, guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

RECONCILIATION OF AUDITED EGI INCOME (PER FINANCIAL STATEMENTS)
TO CORPORATE INCOME FOR UTILITY INCOME DETERMINATION PURPOSES
2019 ACTUAL

Line No.	Particulars ($ millions)	Audited Income (as per Financial Statements)	Corporate Income as per Utility Income Schedule	Variance	Reference
		(a)	(b)	(c)	(d)
	Operating Revenues				
1	Gas sales (commodity) and distribution	4,152.0	4,660.3		
2	Storage, transportation and other	836.0	-		
3	Transportation	-	142.0		
4	Storage	-	143.2		
5	Other operating revenue	87.0	71.5		
6	Other income	20.0	26.2		
7	Total operating revenue	5,095.0	5,043.2	(51.8)	(a)
	Operating Expenses				
8	Gas (commodity and distribution) costs	2,334.0	2,307.9	(26.1)	(b)
9	Operation and maintenance (administrative)	1,109.0	937.3	(171.7)	(c)
10	Depreciation and amortization expense	638.0	637.2	(0.8)	
11	Fixed financing costs	-	3.8	3.8	(d)
12	Municipal and other taxes	-	122.9	122.9	(e)
13	Total operating expenses	4,081.0	4,009.0	(72.0)	
14	Income before income taxes	1,014.0	1,034.2	20.2	
15	Interest and financing expenses	400.0	-	(400.0)	(f)
16	Income before income taxes	614.0	1,034.2	420.2	
17	Income taxes	58.0	-	(58.0)	(g)
18	Net Income	556.0	1,034.2	478.2	

Note: Col. b - Corporate income as reported in Exhibit 1, Tab 8, Schedule 1, Attachment 4, Column 1

a)	Audited Total Operating Revenue	5,095.0
	Eliminate affiliate transactions from non-consolidated EGI	(16.0)
	Reclassify pension related other revenue to O&M	(18.7)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue	(14.3)
	Eliminate 2019 adjustment for GSPCCDA (recorded in 2020 corporate earnings)	(3.9)
	Reclassify other expenses out of other income to O&M	(0.6)
	Correction of 2019 LBA fees (recorded in 2020 corporate earnings)	1.6
	Corporate Total Operating Revenue	5,043.2
b)	Audited Gas Costs	2,334.0
	Eliminate affiliate transactions from non-consolidated EGI	(22.0)
	Eliminate 2019 adjustment for GSPCCDA (recorded in 2020 corporate earnings)	(6.1)
	Correction of 2019 LBA fees (recorded in 2020 corporate earnings)	1.8
	Other	0.2
	Corporate Gas Costs	2,307.9
c)	Audited Operation and Maintenance	1,109.0
	Eliminate affiliate transactions from non-consolidated EGI	(16.0)
	Reclassify pension related other revenue to O&M	(18.7)
	Reclassify Municipal & Property Taxes out of O&M	(122.9)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue	(14.3)
	Reclassify other expenses out of other income to O&M	0.6
	Other	(0.5)
	Corporate Operation and Maintenance	937.3
d)	Audited Fixed Financing Costs	-
	Reclassify fixed financing costs from interest and financing expenses	3.8
	Corporate Fixed Financing Costs	3.8
e)	Audited Municipal and Other Taxes	-
	Reclassify Municipal and other taxes included within O&M costs	122.9
	Corporate Municipal and Other Taxes	122.9
f)	Audited Interest and Financing expenses	400.0
	Eliminate affiliate transactions from non-consolidated EGI	(2.0)
	Reclassify fixed financing costs from interest and financing expenses	(3.8)
	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure	(394.2)
	Corporate Interest and Financing expenses	0.0
g)	Audited Income Taxes	58.0
	Eliminate affiliate transactions from non-consolidated EGI	6.0
	Elimination of corporate income taxes which will be calculated on a utility stand-alone basis	(64.0)
	Corporate Income Taxes	-

EGI UTILITY INCOME
2019 ACTUAL

Line No.	Particulars ($ millions)	Corporate	Storage Unregulated Storage	Adjustments		Income Utility Income
		(a)	(b)	(c)		(d) =(a)-(b)+(c)
1	Gas sales and distribution	4,660.3	-	(28.8)	(1)	4,631.5
2	Transportation	142.0	(0.4)	(0.2)	(2)	142.2
3	Storage	143.2	137.0	(0.2)	(3)	6.0
4	Other operating revenue	71.5	1.2	(20.7)	(4)	49.6
5	Other income	26.2	(0.1)	(28.1)	(5)	(1.8)
6	Total operating revenue	5,043.2	137.7	(78.0)		4,827.6
7	Gas costs	2,307.9	25.0	(17.5)	(1)	2,265.3
8	Operation and maintenance	937.3	19.5	(3.2)	(6)	914.6
9	Depreciation and amortization expense	637.2	12.9	(22.6)	(7)	601.7
10	Fixed financing costs	3.8	0.0	1.0	(8)	4.7
11	Municipal and other taxes	122.9	1.5	0.0		121.4
12	Cost of service	4,009.0	58.9	(42.3)		3,907.8
13	Utility income before income taxes					919.7
14	Income tax expense					59.9
15	Utility income					859.9

Notes on Adjustments:

(1)	Reclassification of Union rate zone optimization revenue as a cost of gas reduction	(17.5)
	Elimination of distribution related 2018 accelerated CCA (Bill C97) impacts recorded in 2019, but reflected in 2018 util	4.4
	Elimination of EGD rate zone 2018 earnings sharing amounts recorded in 2019 financial results	1.7
	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(17.4)
		(28.8)
(2)	Elimination of transportation related 2018 accelerated CCA (Bill C97) impacts recorded in 2019, but reflected in 2018	0.4
	Elimination of the Union rate zone shareholder portion of net optimization activity (before tax)	(0.6)
		(0.2)
(3)	Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before tax)	(0.2)
(4)	Adjust EGD rate zone OBA costs to reflect EB-2013-0099 approved unit costs agreed to be used for determining net r	(2.0)
	Elimination of EGD rate zone Open Bill shareholder incentive	(0.1)
	Elimination of EGD rate zone shareholder portion of transactional service revenues	(1.3)
	Elimination of demand-side management incentive	(16.2)
	Elimination of EGD rate zone net revenue from ABC T-service, considered to be non-utility	(1.1)
		(20.7)
(5)	Elimination of donations	(3.0)
	Elimination of CDM Program shareholder benefit	0.2
	Elimination of non-utility costs and expenses relating to support of the EGD rate zone ABC T-service program	(0.3)
	Eliminate EGD/Union amalgamation transaction costs	(0.1)
		(3.2)
(6)	Eliminate amortization of PPD (purchase price discrepancy)	(22.5)
	Eliminate depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479)	(0.1)
		(22.6)
(7)	Interest on security deposits held during the year and included in elimination of corporate interest exp. Expense incurred to reduce bad debt. The average amount of the security deposit held during the year is applied as a reduction to the allowance for working capital in rate base	1.0
(8)	Elimination of interest income from investments not included in utility rate base	(0.3)
	Elimination of interest income from affiliates	(13.0)
	Elimination of the non-utility gain on the sale of St. Lawrence Gas	(14.8)
		(28.1)

RECONCILIATION OF AUDITED EGI INCOME (PER FINANCIAL STATEMENTS)
TO CORPORATE INCOME FOR UTILITY INCOME DETERMINATION PURPOSES
2020 ACTUAL

Line No.	Particulars ($ millions)	Audited Income (as per Financial Statements)	Corporate Income as per Utility Income Schedule	Variance	Reference
		(a)	(b)	(c)	(d)
	Operating Revenues				
1	Gas sales (commodity) and distribution	3,630.7	4,152.4		
2	Storage, transportation and other	884.0	-		
3	Transportation	-	142.4		
4	Storage	-	145.7		
5	Other operating revenue	-	63.6		
6	Other income	56.3	24.2		
7	Total operating revenue	4,571.0	4,528.3	(42.7)	(a)
	Operating Expenses				
8	Gas (commodity and distribution) costs	1,811.7	1,816.0	4.3	(b)
9	Operation and maintenance (administrative)	1,136.9	965.7	(171.2)	(c)
10	Depreciation and amortization expense	655.5	655.5	(0.0)	
11	Fixed financing costs	-	4.4	4.4	(d)
12	Municipal and other taxes	-	126.2	126.2	(e)
13	Total operating expenses	3,604.1	3,567.8	(36.3)	
14	Income before income taxes	966.9	960.4	(6.5)	
15	Interest and financing expenses	411.9	-	(411.9)	(f)
16	Income before income taxes	555.0	960.4	405.4	
17	Income taxes	57.7	-	(57.7)	(g)
18	Net Income	497.3	960.4	463.1	

Note: Col. b - Corporate income as reported in Exhibit 1, Tab 8, Schedule 1, Attachment 6, Column 1

a)	Audited Total Operating Revenue	4,571.0
	Reclassify pension related other revenue to O&M	(32.3)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue	(12.9)
	Eliminate 2019 adjustment for GSPCCDA (recorded in 2020 corporate earnings)	3.9
	Reclassify other expenses out of other income to O&M	0.2
	Eliminate correction of 2019 LBA fees (recorded in 2020 corporate earnings)	(1.6)
	Corporate Total Operating Revenue	4,528.3
b)	Audited Gas Costs	1,811.7
	Eliminate 2019 adjustment for GSPCCDA (recorded in 2020 corporate earnings)	6.1
	Eliminate correction of 2019 LBA fees (recorded in 2020 corporate earnings)	(1.8)
	Corporate Gas Costs	1,816.0
c)	Audited Operation and Maintenance	1,136.9
	Reclassify pension related other revenue to O&M	(32.3)
	Reclassify Municipal & Property Taxes out of O&M	(126.2)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue	(12.9)
	Reclassify other expenses out of other income to O&M	0.2
	Corporate Operation and Maintenance	965.7
d)	Audited Fixed Financing Costs	-
	Reclassify fixed financing costs from interest and financing expenses	4.4
	Corporate Fixed Financing Costs	4.4
e)	Audited Municipal and Other Taxes	-
	Reclassify Municipal and other taxes included within O&M costs	126.2
	Corporate Municipal and Other Taxes	126.2
f)	Audited Interest and Financing expenses	411.9
	Reclassify fixed financing costs from interest and financing expenses	(4.4)
	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure	(407.5)
	Corporate Interest and Financing expenses	(0.0)
g)	Audited Income Taxes	57.7
	Elimination of corporate income taxes which will be calculated on a utility stand-alone basis	(57.7)
	Corporate Income Taxes	-

EGI UTILITY INCOME
2020 ACTUAL

Line No.	Particulars ($ millions)	Corporate (a)	Unregulated Storage (b)	Adjustments (c)		Utility Income (d) = (a)-(b)+(c)
1	Gas sales and distribution	4,152.4	-	(33.6)	(1)	4,118.8
2	Transportation	142.4	(0.4)	(0.4)	(2)	142.3
3	Storage	145.7	139.8	(0.4)	(3)	5.6
4	Other operating revenue	63.6	0.7	(15.2)	(4)	47.7
5	Other income	24.2	(0.9)	(20.5)	(5)	4.5
6	Total operating revenue	4,528.3	139.2	(70.1)		4,318.9
7	Gas costs	1,816.0	18.7	(15.9)	(1)	1,781.3
8	Operation and maintenance	965.7	16.6	(0.8)	(6)	948.4
9	Depreciation and amortization expense	655.5	14.7	(22.6)	(7)	618.2
10	Fixed financing costs	4.4	0.0	1.0	(8)	5.4
11	Municipal and other taxes	126.2	1.6	0.0		124.6
12	Cost of service	3,567.8	51.6	(38.4)		3,477.8
13	Utility income before income taxes					841.1
14	Income tax expense					39.2
15	Utility income					801.9

Notes on Adjustments:

(1)	Reclassification of Union rate zone optimization revenue as a cost of gas reduction	(15.9)
	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(17.7)
		(33.6)
(2)	Elimination of the Union rate zone shareholder portion of net optimization activity (before tax)	(0.4)
(3)	Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before tax)	(0.4)
(4)	Adjust EGD rate zone OBA costs to reflect EB-2013-0099 approved unit costs agreed to be used for determining net re	(4.0)
	Elimination of EGD rate zone Open Bill shareholder incentive	0.3
	Elimination of EGD rate zone shareholder portion of transactional service revenues	(1.8)
	Elimination of demand-side management incentive	(8.7)
	Elimination of EGD rate zone net revenue from ABC T-service, considered to be non-utility	(1.0)
		(15.2)
(5)	Elimination of donations	(0.6)
	Elimination of non-utility costs and expenses relating to support of the EGD rate zone ABC T-service program	(0.2)
		(0.8)
(6)	Eliminate amortization of PPD (purchase price discrepancy)	(22.5)
	Eliminate depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479)	(0.1)
		(22.6)
(7)	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	1.0
(8)	Elimination of interest income from investments not included in utility rate base	0.1
	Eliminate non-utility true-up (loss) on the sale of St. Lawrence Gas	0.2
	Elimination of interest income from affiliates	(14.5)
	Elimination of the revenue indemnification received from Enbridge Inc. related to a non-utility Corporate tax planning P	(6.3)
		(20.5)

RECONCILIATION OF AUDITED EGI INCOME (PER FINANCIAL STATEMENTS)
TO CORPORATE INCOME FOR UTILITY INCOME DETERMINATION PURPOSES
2021 ACTUAL

Line No.	Particulars ($ millions)	Audited Income (as per Financial Statements)	Corporate Income (as per Utility Income Schedule)	Variance	Reference
		(a)	(b)	(c)	(d)
	Operating Revenues				
1	Gas sales and distribution	3,996.4	4,513.2		
2	Storage, transportation and other	896.7	-		
3	Transportation	-	143.0		
4	Storage	-	159.7		
5	Other operating revenue	-	64.3		
6	Other Income	42.9	7.2		
7	Total operating revenue	4,936.0	4,887.4	(48.6)	(a)
	Operating Expenses				
8	Gas Costs	2,146.2	2,146.2	-	
9	Operation and maintenance	1,105.1	938.6	(166.5)	(b)
10	Depreciation and amortization expense	676.8	676.8	-	
11	Fixed financing costs	-	6.3	6.3	(c)
12	Municipal and other taxes	-	117.9	117.9	(d)
13	Cost of service	3,928.1	3,885.8	(42.3)	
14	Income before interest and income taxes	1,007.9	1,001.6	(6.3)	
15	Interest and financing expenses	393.9	-	(393.9)	(e)
16	Income before income taxes	614.0	1,001.6	387.6	
17	Income taxes	62.9	-	(62.9)	(f)
18	Net Income	551.1	1,001.6	450.5	

Col. c - Corporate income as reported in Exhibit 1, Tab 8, Schedule 1, Attachment 8, Column b

a)	Audited Total Operating Revenue	4,936.0
	Reclassify pension related other revenue to O&M	(36.0)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue	(12.8)
	Reclassify other expenses out of other income to O&M	0.2
	Corporate Total Operating Revenue	4,887.4
b)	Audited Operation and Maintenance	1,105.1
	Reclassify pension related other revenue to O&M	(36.0)
	Reclassify Municipal & Property Taxes out of O&M	(117.9)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue	(12.8)
	Reclassify other expenses out of other income to O&M	0.2
	Corporate Operation and Maintenance	938.6
c)	Audited Fixed Financing Costs	-
	Reclassify fixed financing costs from interest and financing expenses	6.3
	Corporate Fixed Financing Costs	6.3
d)	Audited Municipal and Other Taxes	-
	Reclassify Municipal and other taxes included within O&M costs	117.9
	Corporate Municipal and Other Taxes	117.9
e)	Audited Interest and Financing expenses	393.9
	Reclassify fixed financing costs from interest and financing expenses	(6.3)
	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure	(387.6)
	Corporate Interest and Financing expenses	-
f)	Audited Income Taxes	62.9
	Elimination of corporate income taxes which will be calculated on a utility stand-alone basis	(62.9)
	Corporate Income Taxes	-

EGI UTILITY INCOME
2021 ACTUAL

Line No.	Particulars ($ millions)	Corporate	Unregulated Storage	Adjustments		Utility Income
		(a)	(b)	(c)		(d) = (a)-(b)+(c)
1	Gas sales and distribution	4,513.2	-	(32.6)	(1)	4,480.6
2	Transportation	143.0	0.4	(0.8)	(2)	142.0
3	Storage	159.7	153.6	(0.1)	(3)	6.0
4	Other operating revenue	64.3	1.8	(13.4)	(4)	49.1
5	Other income	7.2	-	(6.3)	(5)	0.9
6	Total operating revenue	4,887.4	155.8	(53.1)		4,678.5
7	Gas costs	2,146.2	20.2	(15.4)	(1)	2,110.5
8	Operation and maintenance	938.6	14.1	(4.0)	(6)	920.6
9	Depreciation and amortization expense	676.8	14.1	(22.6)	(7)	640.1
10	Fixed financing costs	6.3	0.0	0.5	(8)	6.8
11	Municipal and other taxes	117.9	1.7	-		116.2
12	Cost of service	3,885.8	50.2	(41.5)		3,794.2
13	Utility income before income taxes					884.3
14	Income tax expense					41.8
15	Utility income					842.5

Notes on Adjustments:

(1)	Reclassification of Union rate zone optimization revenue as a cost of gas reduction	(15.4)
	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(17.2)
		(32.6)
(2)	Elimination of the Union rate zone shareholder portion of net optimization activity (before tax)	(0.8)
(3)	Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before tax)	(0.1)
(4)	Adjust EGD rate zone OBA costs to reflect EB-2013-0099 approved unit costs agreed to be used for determining net revenue	(4.3)
	Elimination of EGD rate zone Open Bill shareholder incentive	0.3
	Elimination of EGD rate zone shareholder portion of transactional service revenues	(1.8)
	Elimination of demand-side management incentive	(6.9)
	Elimination of EGD rate zone net revenue from ABC T-service, considered to be non-utility	(0.8)
		(13.4)
(5)	Elimination of donations	(3.6)
	Elimination of EB-2021-0204 Assurance of Voluntary Compliance amount	(0.1)
	Elimination of non-utility costs and expenses relating to support of the EGD rate zone ABC T-service program	(0.3)
		(4.0)
(6)	Eliminate amortization of PPD (purchase price discrepancy)	(22.5)
	Eliminate depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479)	(0.1)
		(22.6)
(7)	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	0.5
(8)	Elimination of interest income from investments not included in utility rate base	(0.1)
	Elimination of interest income from affiliates	(1.6)
	Elimination of the revenue indemnification received from Enbridge Inc. related to a non-utility Corporate tax planning Part VI.1 tax transfer to EGI	(4.6)
		(6.3)

PRO-FORMA STATEMENT OF UTILITY INCOME
2023 BRIDGE YEAR

Line No.	Particulars ($ millions)		
	Operating Income		
1	Gas Sales and Distribution	5,664.5	
2	Transportation	139.6	/u
3	Storage	6.0	
4	Other Operating Revenue	63.2	
5	Interest and Property Rental	-	
6	Other Income	-	
7	Total Operating Revenue	5,873.3	/u
	Operating Cost		
8	Gas Costs	3,047.3	
9	Operation and Maintenance	1,021.7	/u
10	Depreciation and Amortization Expense	725.3	/u
11	Fixed Financing Costs	4.0	
12	Debt Redemption Premium Amortization	-	
13	Municipal and Other Taxes	122.5	
14	Cost of Service	4,920.8	/u
15	Utility Income Before Income Taxes	952.6	/u
16	Income Tax Expense	(42.1)	/u
17	Utility Income	910.4	/u

PRO-FORMA STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE BRIDGE YEAR ENDED DECEMBER 31, 2023

Line No.	Particulars ($ millions / %)			
1	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency			
2	Utility Income before Income Tax		952.6	/u
3	Less: Income Taxes		42.1	/u
4	Utility Income		910.4	/u
5	Utility Rate Base		15,640.1	/u
6	Indicated Return on Rate Base %	(line 4 / line 5)	5.821%	/u
7	Less: Required Rate of Return %		5.764%	/u
8	(Deficiency) / Sufficiency %		0.057%	/u
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	8.9	/u
10	Provision for Income Taxes		3.2	/u
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	12.1	/u
12	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency			
13	Utility Income before Income Tax		952.6	/u
14	Less: Long Term Debt Costs		402.5	/u
15	Less: Short Term Debt Costs		11.4	/u
16	Net Income before Income Taxes		538.6	/u
17	Less: Income Taxes		42.1	/u
18	Net Income Applicable to Common Equity	(line 16 - line 17)	496.5	/u
19	Common Equity		5,630.4	/u
20	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	8.660%	
21	Achieved Rate of Return on Equity %	(line 18 / line 19)	8.818%	/u
22	Resulting (Deficiency) / Sufficiency in Return on Equity %		0.158%	/u
23	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	8.9	/u
24	Provision for Income Taxes		3.2	/u
25	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	12.1	/u

PRO-FORMA STATEMENT OF UTILITY INCOME
2024 TEST YEAR

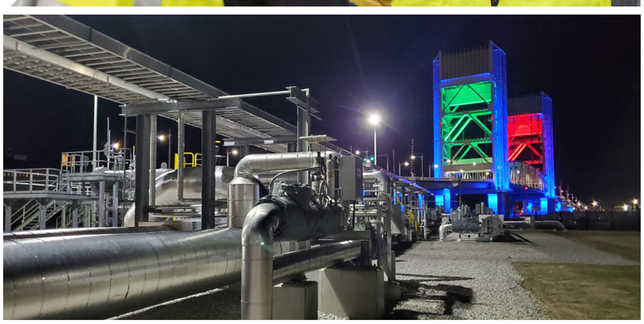
Line No.	Particulars ($ millions)		
	Operating Income		
1	Gas Sales and Distribution	5,851.6	
2	Transportation	164.7	/u
3	Storage	0.0	
4	Other Operating Revenue	64.3	
5	Interest and Property Rental	0	
6	Other Income	0	
7	Total Operating Revenue	6,080.6	/u
	Operating Cost		
8	Gas Costs	3,228.0	
9	Operation and Maintenance	1,046.0	/u
10	Depreciation and Amortization Expense	892.0	/u
11	Fixed Financing Costs	4.0	
12	Debt Redemption Premium Amortization	0.0	
13	Municipal and Other Taxes	127.2	
14	Cost of Service	5,297.2	/u
15	Utility Income Before Income Taxes	783.4	/u
16	Income Tax Expense	(43.8)	/u
17	Utility Income	739.6	/u

PRO-FORMA STATEMENT OF UTILITY
RETURN ON RATE BASE AND RETURN ON EQUITY
FOR THE TEST YEAR ENDED DECEMBER 31, 2024

Line No.	Particulars ($ millions / %)			
1.	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency			
2.	Utility Income before Income Tax		783.4	/u
3.	Less: Income Taxes		43.8	/u
4.	Utility Income		739.6	/u
5.	Utility Rate Base		16,281.1	/u
6.	Indicated Return on Rate Base %	(line 4 / line 5)	4.543%	/u
7.	Less: Required Rate of Return %		5.870%	/u
8.	(Deficiency) / Sufficiency %		-1.327%	/u
9.	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(216.1)	/u
10.	Provision for Income Taxes		(78.0)	/u
11.	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	(294.1)	/u
12.	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency			
13.	Utility Income before Income Tax		783.4	/u
14.	Less: Long Term Debt Costs		418.0	/u
15.	Less: Short Term Debt Costs		2.0	/u
16.	Net Income before Income Taxes		363.5	/u
17.	Less: Income Taxes		43.8	/u
18.	Net Income Applicable to Common Equity	(line 16 - line 17)	319.7	/u
19.	Common Equity		6,186.8	/u
20.	Approved ROE (including deadband before earning sharing) %	(OEB-approved)	8.660%	
21.	Achieved Rate of Return on Equity %	(line 18 / line 19)	5.167%	/u
22.	Resulting (Deficiency) / Sufficiency in Return on Equity %		-3.493%	/u
23.	Net Earnings (Deficiency) / Sufficiency	(line 19 x line 22)	(216.1)	/u
24.	Provision for Income Taxes		(78.0)	/u
25.	Gross Earnings (Deficiency) / Sufficiency	(line 23 / 73.5%)	(294.1)	/u

Bridge to a cleaner energy future

2021 Annual Report



ENBRIDGE®
Life Takes Energy®

Letter to Shareholders

Dear Shareholder,

Last year, global economies and the energy business continued to be challenged by the COVID-19 pandemic. However, a robust economic recovery drove energy demand and commodity prices higher, and underscored the importance of reliable, affordable energy in our lives.

Our people safely navigated COVID restrictions and supported each other and our communities. We continued to focus and deliver on our purpose – to provide the energy that people rely on every day to fuel their quality of life. We delivered record safety, operating and financial performance, and executed on key strategic priorities. At the same time, we took steps to modernize our systems, diversify our assets, and advance our net-zero emissions and diversity and inclusion targets.

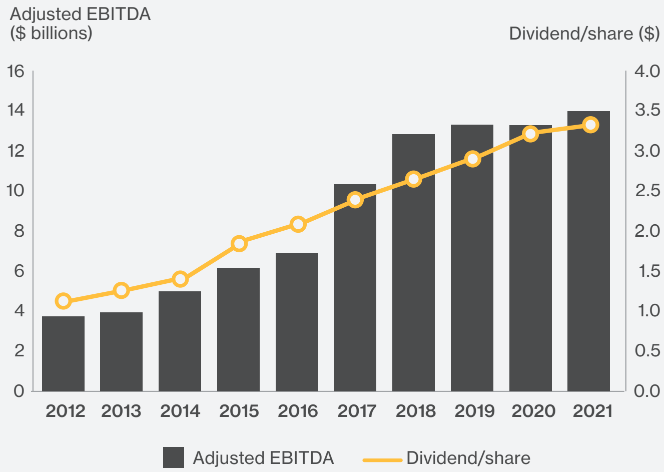
We're proud of our people and what we achieved last year – helping to further cement Enbridge's position as North America's leading energy delivery company.

In 2021, Enbridge set employee and contractor safety and system reliability records because of our strong safety culture and investments in system integrity and preventative maintenance.

Delivering on results and strategic priorities

2021 was a catalyst year for the Company. We built on our momentum to grow our conventional business, reduce emissions intensity from our existing assets and expand our low-carbon investments. We reached the top end of our external guidance range for distributable cash flow (DCF)[1] per share, increased our dividend for the 26th consecutive year – and extended that track record with another 3% dividend increase for 2022.

In 2021, Enbridge generated strong total shareholder returns of 30%. Over the last 10 years, we have grown earnings before interest taxes depreciation and amortization (adjusted EBITDA[1]) at an average annual rate of 14% by executing a $65 billion organic capital program, delivering on revenue and productivity improvements, as well as selective acquisitions that have advanced our strategies and driven further organic growth. That includes the 2017 acquisition of Spectra, which transformed the business by adding a leading natural gas utility and pipeline footprint – complementing Enbridge's irreplaceable crude oil assets and growing renewables business. Last year, Enbridge added North America's leading crude oil export platform through the acquisition of the Ingleside Energy Center, which positions the Company to play a pivotal role in global energy exports. Our disciplined investment of capital, while protecting our sector-leading financial strength, has enabled us to grow the dividend on average by 13% per year over the last 10 years, supporting robust shareholder returns.



[1] Adjusted EBITDA and DCF per share are non-GAAP measures.

In 2021, we placed $10 billion of secured capital into service – including completion of the state-of-the-art Line 3 Replacement Project, the largest capital project in Enbridge's history – and sanctioned $2 billion of new projects. These investments will contribute to cash flow growth and provide additional financial capacity in the years to come.

Engagement with Indigenous groups along the Line 3 right-of-way led to a better route, as well as tailored environmental measures to protect the land and minimize impacts. This engagement also resulted in $900 million in Indigenous business opportunities, including Indigenous workers comprising 7% of the U.S. Line 3 workforce. This valuable experience is being shared across our organization to further strengthen our lifecycle approach to Indigenous and stakeholder engagement.

> Indigenous-owned MB Customs worked on the Line 3 Replacement Program in Minnesota.

We also advanced our export strategy with the acquisition of the Ingleside Energy Center, through which we established a leading light-oil export position and platform for future organic growth. We aligned that investment with our target to reach net-zero emissions by 2050 by committing to develop an on-site solar farm that will drive net-zero Scope 1 and 2 emissions, while also contributing to Scope 3 reductions. This is a great example of how Enbridge is differentiating its approach to energy infrastructure.

> In February 2022, Enbridge and First Nation Capital Investment Partnership (FNCIP) announced plans to work together to advance a new carbon transportation and storage solution west of Edmonton called the Open Access Wabamun Carbon Hub. The proposed Wabamun Hub will tie into planned carbon capture projects, with the combined potential to abate nearly 4 million tonnes of CO_2 emissions annually.

Good progress is being made on our $10 billion commercially secured growth program, including construction of four offshore wind projects in Europe, connecting new customers to our natural gas distribution system, and modernizing our long-haul pipeline systems. We also established industry partnerships to advance our early-mover position in renewable natural gas, hydrogen, and carbon capture and storage.

Over the last several years we've worked with our customers to develop a new contract offering for our Canadian Mainline. Last year, our proposal was declined by the Canada Energy Regulator (CER), despite having support from more than 75% of our shippers. We'll continue to collaborate with our customers on two alternative options to assure a solid, long-term commercial arrangement is in place.

> The Enbridge team continued to make a positive impact in our communities – including a US$4 million contribution to the United Way – and thousands of hours of volunteering with close to 3,000 local community and Indigenous organizations. Our people stepped up to support recovery efforts following wildfires and flooding in B.C., and the same care was shown after Hurricane Ida in Louisiana.

Bridging to a cleaner energy future

Forecasts show that the demand for energy will continue to increase as populations grow and developing nations raise their standards of living. Natural gas and oil make up more than half of that energy demand today and we expect demand to remain strong for decades to come, even as renewables grow. This energy is critical for transportation, heating, cooking, manufacturing, electronics, pharmaceuticals – and more. North America has an abundant supply of oil and gas with leading environmental performance – supply that can be exported to where it's needed.

It's clear that society is moving toward a lower-carbon economy. We believe that we need to transition our energy systems prudently to ensure adequate supply of conventional energy while lowering emissions and increasing investment in low-carbon energies.

We have a solid inventory of both conventional and low-carbon opportunities, totaling about $6 billion of annual investment. On the conventional side, we'll expand and modernize gas systems, which will displace coal and support renewables growth. We'll continue to build out our LNG and export positions and invest in our gas utility. We'll also pursue capital-efficient Liquids Pipelines optimizations.

These businesses also come with embedded low-carbon opportunities. Our existing assets will support the energy transition by blending and transporting renewable natural gas and hydrogen, transporting and storing carbon, and moving more natural gas. Our Renewables business also gives us high visibility to growth, with 14 projects in construction, including solar self-power in North America and offshore wind in France.

Getting the pace of the transition right will be critical. We're taking a disciplined approach to ensure that new opportunities provide an attractive return, and we'll build on proven technologies and partner with those who can bolster our capability. This is exactly the model we used for wind and solar 20 years ago, and today Enbridge has a leading renewables platform.

Energy is needed in every aspect of daily life, and our assets provide an essential source of safe, reliable and affordable energy. Our systems have longevity because they serve the best markets and can't be replaced. We're modernizing our assets to improve efficiency and reduce emissions.

Sustaining our growth

In 2022, we're positioned to grow adjusted EBITDA and DCF per share by about 8%. We expect to exit 2022 near the bottom of our 4.5x to 5.0x debt to EBITDA range, driven by annualized contributions from Line 3 and the Ingleside terminal. We remain focused on managing costs and maximizing our financial strength and flexibility.

Our visible cash flow growth outlook and healthy balance sheet will enable the return of capital as part of our shareholder value proposition.

Over the next three years, we expect to generate $5 to $6 billion of annual investment capacity. Of that amount, $3 to $4 billion will be prioritized to low-capital intensity and utility-like investments, and the remaining $2 billion will be deployed to the next best alternatives, such as organic growth, profitable energy transition investments, share repurchases or debt reduction. The $1.5 billion share-buyback program we recently introduced creates an additional avenue to return value to shareholders.

By executing on our secured capital program, enhancing returns on our existing businesses, and deploying excess financial capacity, we estimate 5 – 7% DCF per share compound annual growth through 2024 versus 2021 results.

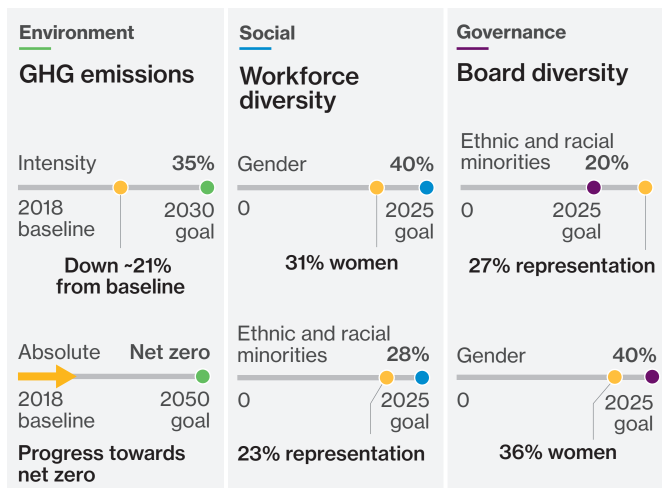
Enbridge was an early investor in low-carbon energies and is well positioned to be a North American leader. In 2021, we established a dedicated New Energy Technologies team. Through 2025, we see opportunity to invest a further $1.5 billion to advance low-carbon opportunities, in addition to the $2.5 billion in offshore wind projects already in execution.

Being a differentiated service provider

Core to our strategy is our industry-leading approach to our environmental, social and governance (ESG) performance. Our performance in these areas has and will continue to differentiate Enbridge – setting us apart as the service provider of choice for our customers, an employer of choice, a trusted partner to communities, Indigenous groups and policy makers, and a best-in-class investment.

In 2020, we introduced ESG goals, including continuing to drive industry-leading safety performance, reducing emissions to net zero, and improving diversity and inclusion. We've set ambitious goals for our ESG efforts, made them public and linked discretionary pay for all employees to progress in these areas. At our inaugural ESG Forum in September 2021, we shared detailed plans for how we're going about achieving these goals and how we've integrated them into each of our businesses.

2021 ESG performance update



Last year, we issued $3 billion in sustainability-linked financings that are tied to achievement of our ESG goals. We also further advanced our capital-allocation framework to ensure that all new investments account for carbon prices and are aligned with our emissions-reduction goals.

We're on track to reduce our emissions intensity 35% by 2030 and reach our net-zero emissions target by 2050. Additionally, we expanded emissions reporting to include new Scope 3 metrics designed to measure the emissions intensity of energy delivered and the emissions avoided through our more than two decades of investment in renewables, low-carbon fuels, and demand-side management programs. Since 2018, we have reduced our emissions intensity and absolute emissions by approximately 21% and 14%, respectively.

Through demand-side management in our Gas Distribution and Storage business unit, we've reduced emissions by nearly 55 million tCO_2e since 1995.

We're committed to industry leadership in sustainability and continuous improvement in this area. That's why we've implemented additional measures, including working with our supply chain to lower Scope 3 emissions, developing partnerships to advance low-carbon innovation within our businesses, and working proactively with organizations developing science-based guidelines for emissions targets in the midstream sector. This year's annual sustainability report will include a scenario analysis that considers the resiliency of our strategy on a net-zero pathway.

We remain steadfast in our belief that an energized work force is driven by diversity, equity and inclusion. This continues to be a priority and has been embedded in our hiring decisions and training, including mandatory training on racial justice, unconscious bias and Indigenous cultural awareness.

Prior to the pandemic, we enhanced our Workplace Mental Health initiatives to provide more resources and education on well-being – programs that proved to be critically important over the last two years. We're now advancing our efforts by raising awareness of the small actions we can take to reduce stigma, create personal well-being, and make people feel valued and appreciated.

We're deliberate about creating the right environment for our people. We conduct regular surveys and focus groups to listen to their input and ensure that we continue to evolve and meet the needs of today. Last year, we expanded our FlexWork program to give Enbridge employees more choice to balance accountabilities at work and at home.

Our highly engaged Board reflects a balance of diverse perspectives, backgrounds and experiences. Our independent Board Chair and separate Chair and CEO positions represent corporate governance best practices. Four of our directors are women, three of whom chair Board committees. Three of 11 directors self-identify as members of an ethnic or visible minority and, subject to shareholder approval of our 2022 director nominees, we expect to increase our diversity further.

Evolving our leadership and Board

There were several changes to senior leadership last year as part of development and succession planning, and we're fortunate to have strong leaders to step into new roles. This included the retirement of Bill Yardley, Executive Vice President and President, Gas Transmission and Midstream, who spent 22 years with Enbridge. Bill leaves a strong legacy and will be remembered for his passion for the business and his deep care and respect for the people around him.

In 2021, the Board welcomed three new directors: Mayank (Mike) Ashar, Gaurdie Banister and Jane Rowe; three highly qualified individuals who bring significant energy industry experience and strong skills and business judgment to the Board. We're also bringing forward two new Board candidates, Jason Few and Steven Williams, who will stand for election at our annual general meeting in May. Information about our Board directors and new candidates can be found in our Management Information Circular.

We said goodbye to Gregory Goff, Maureen Kempston-Darkes and Marcel Coutu as directors. We'd like to thank them for their valuable contributions to the Company. We'd also like to acknowledge Herb England who will be retiring at this year's meeting. As one of our longest-serving Board members, Herb has played a significant role in shaping Enbridge's strategy, and his leadership and dedication will be missed.

Our thanks

Each year our performance comes down to our people, who fulfill Enbridge's purpose while living our values of Safety, Integrity, Respect and Inclusion. We thank them for their commitment to our business.

As we look to next year, the strong demand for our systems and execution on our capital program continue to drive stable and growing cash flows. We believe that our embedded conventional and low-carbon organic growth opportunities, along with our disciplined approach to investment and increasing dividends, provide a compelling growth outlook and continued strong value proposition for our shareholders and our other important stakeholders.

Sincerely,

Greg Ebel and Al Monaco

Gregory L. Ebel
Chair, Board of Directors

Al Monaco
President & Chief Executive Officer

Calgary, Alberta
March 2, 2022

Our Board

Gregory L. Ebel

Mayank (Mike) M. Ashar

Gaurdie E. Banister Jr.

Pamela L. Carter

Susan M. Cunningham

J. Herb England

Teresa S. Madden

Al Monaco

Stephen S. Poloz

S. Jane Rowe

Dan C. Tutcher

About us

At Enbridge, our purpose is to fuel quality of life by delivering energy safely, reliably and sustainably. Whether it's oil, natural gas or renewable power, the energy we deliver helps to heat homes, feed families, fuel vehicles, power industry and benefit society in thousands of ways. The passion and innovation of our 11,000-person team has helped Enbridge become North America's leading energy delivery company.

Throughout our history, we've looked beyond the horizon to invest in modern infrastructure, resilient communities and reliable energy. We're building a bridge to a more sustainable future by meeting energy needs today and growing our low-carbon businesses for tomorrow.

While conventional energy will continue to be needed for decades to come, Enbridge is taking a balanced approach to the energy transition.

Our networks stretch across North America and we're modernizing our systems, expanding our footprint, and working toward our goal to be net zero by 2050. We're taking steps big and small to reduce emissions and accelerate the energy transition, including pursuing the potential for investment of $4 billion through 2025 in renewable power and low-carbon energy solutions such as hydrogen, renewable natural gas (RNG), and carbon capture and storage (CCS).

As we grow and evolve, we'll continue to be guided by a strong set of core values – Safety, Integrity, Respect and Inclusion – that reflect what is truly important to Enbridge.

Our core businesses

Enbridge plays a significant role in the energy value chain by connecting people to the energy they need and want.

- Gas Transmission and Midstream (GTM) transports approximately 20% of the natural gas consumed in the U.S., supplying natural gas to approximately 170 million people, as well as power generation facilities across the continent.
- Gas Distribution and Storage (GDS) has more than 3.9 million metered connections in over 300 municipalities across Ontario and Quebec and supplies energy to 75% of Ontario residents.
- Liquids Pipelines (LP) transports approximately 30% of the crude oil produced in North America to 25 refiners, connecting producers to the best markets in the U.S. Midwest, the U.S. Gulf Coast and Eastern Canada.
- Renewable Power Generation has ownership interests in more than 48 renewable energy facilities (in operation and under construction) with 2,178 megawatts (MW) of net generation capacity – enough to meet the electricity needs of nearly one million homes.
- Enbridge's recently formed New Energy Technologies team collaborates with each business unit to advance low-carbon energy infrastructure opportunities across the Company and build on Enbridge's early investments in RNG, hydrogen and CCS.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2021
or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to
Commission file number 1-10934

ENBRIDGE INC.
(Exact Name of Registrant as Specified in Its Charter)

Canada	**98-0377957**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

200, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
(Address of Principal Executive Offices) (Zip Code)
Registrant's telephone number, including area code **(403) 231-3900**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Shares	ENB	New York Stock Exchange
6.375% Fixed-to-Floating Rate Subordinated Notes Series 2018-B due 2078	ENBA	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☒	Accelerated Filer	☐
Non-Accelerated Filer	☐	Smaller reporting company	☐
Emerging growth company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. Yes ☒ No ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the registrant's common shares held by non-affiliates computed by reference to the price at which the common equity was last sold on June 30, 2021, was approximately US$77.7 billion.

As at February 4, 2022, the registrant had 2,026,274,277 common shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
Not applicable.

EXPLANATORY NOTE

Enbridge Inc., a corporation existing under the *Canada Business Corporations Act*, qualifies as a foreign private issuer in the United States of America (US) for purposes of the Securities Exchange Act of 1934, as amended (the Exchange Act). Although, as a foreign private issuer, Enbridge Inc. is not required to do so, Enbridge Inc. currently files annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K with the Securities and Exchange Commission (SEC) instead of filing the reporting forms available to foreign private issuers.

Enbridge Inc. intends to prepare and file a management proxy circular and related material under Canadian requirements. As Enbridge Inc.'s management proxy circular is not filed pursuant to Regulation 14A, Enbridge Inc. may not incorporate by reference information required by Part III of this Form 10-K from its management proxy circular. Accordingly, in reliance upon and as permitted by Instruction G(3) to Form 10-K, Enbridge Inc. will be filing an amendment to this Form 10-K containing the Part III information no later than 120 days after the end of the fiscal year covered by this Form 10-K.

GLOSSARY

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income/(loss)
ARO	Asset retirement obligations
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
BC	British Columbia
bcf/d	Billion cubic feet per day
bpd	Barrels per day
CCS	Carbon capture and storage
CER	Canada Energy Regulator, created by the Canadian Energy Regulator Act which also repealed the National Energy Board Act, on August 28, 2019
CPP Investments	Canada Pension Plan Investment Board
CTS	Competitive Toll Settlement
DAPL	Dakota Access Pipeline
Dawn	An extensive network of underground storage pools at the Tecumseh Gas Storage facility and Dawn Hub
DCP Midstream	DCP Midstream, LLC
EBITDA	Earnings before interest, income taxes and depreciation and amortization
EEP	Enbridge Energy Partners, L.P.
EIEC	Enbridge Ingleside Energy Center
EIS	Environmental Impact Statement
EMF	Éolien Maritime France SAS
Enbridge	Enbridge Inc.
Enbridge Gas	Enbridge Gas Inc.
ESG	Environment, Social and Governance
FERC	Federal Energy Regulatory Commission
Flanagan South	Flanagan South Pipeline
GHG	Greenhouse gas
H2	Hydrogen gas
IJT	International Joint Tariff
ISO	Incentive Stock Options
kbpd	Thousand barrels per day
LMCI	Land Matters Consultation Initiative
LNG	Liquefied natural gas
MATL	Montana-Alberta Tie-Line
MD&A	Management’s Discussion and Analysis
Moda	Moda Midstream Operating, LLC

MW	Megawatts
NCIB	Normal course issuer bid
NGLs	Natural gas liquids
Noverco	Noverco Inc.
NYSE	New York Stock Exchange
OBPS	Output-based pricing system
OCI	Other comprehensive income/(loss)
OEB	Ontario Energy Board
OPEB	Other postretirement benefit obligations
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSU	Performance Stock Units
RNG	Renewable natural gas
ROU	Right-of-use
RSU	Restricted Stock Units
Sabal Trail	Sabal Trail Transmission, LLC
Seaway Pipeline	Seaway Crude Pipeline System
SEP	Spectra Energy Partners, LP
Spectra Energy	Spectra Energy Corp
SPOT	Sea Port Oil Terminal
Texas Eastern	Texas Eastern Transmission, L.P.
TSX	Toronto Stock Exchange
US	United States of America
US GAAP	Generally accepted accounting principles in the United States of America
US L3R Program	United States portion of the Line 3 Replacement Program
VIE	Variable interest entities
Westcoast	Westcoast Energy Inc.

CONVENTIONS

The terms "we", "our", "us" and "Enbridge" as used in this report refer collectively to Enbridge Inc. and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge.

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars, all references to “dollars” or “$” are to Canadian dollars and all references to “US$” are to US dollars. All amounts are provided on a before tax basis, unless otherwise stated.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this Annual Report on Form 10-K to provide information about us and our subsidiaries and affiliates, including management’s assessment of our and our subsidiaries’ future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ‘‘anticipate”, “believe”, “estimate”, “expect”, “forecast”, “intend”, “likely”, “plan”, “project”, “target” and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: our corporate vision and strategy, including strategic priorities and enablers; the COVID-19 pandemic and the duration and impact thereof; energy intensity and emissions reduction targets and related Environment, Social and Governance (ESG) matters; diversity and inclusion goals; expected supply of, demand for, and prices of crude oil, natural gas, natural gas liquids (NGLs), liquified natural gas and renewable energy; energy transition; anticipated utilization of our existing assets; expected earnings before interest, income taxes and depreciation and amortization (EBITDA); expected earnings/(loss); expected future cash flows and distributable cash flow; dividend growth and payout policy; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected strategic priorities and performance of the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation and Energy Services businesses; expected costs related to announced projects and projects under construction and for maintenance; expected in-service dates for announced projects and projects under construction and for maintenance; expected capital expenditures, investment capacity and capital allocation priorities; expected equity funding requirements for our commercially secured growth program; expected future growth and expansion opportunities; expectations about our joint venture partners’ ability to complete and finance projects under construction; expected closing of acquisitions and dispositions and the timing thereof; expected benefits of transactions, including the realization of efficiencies, synergies and cost savings; expected future actions of regulators and courts; toll and rate cases discussions and filings, including Mainline System contracting; anticipated competition; United States Line 3 Replacement Program (US L3R Program), including anticipated in-service dates and capital costs; and Line 5 dual pipelines and related litigation and other matters.

Although we believe these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the COVID-19 pandemic and the duration and impact thereof; the expected supply of and demand for crude oil, natural gas, NGL and renewable energy; prices of crude oil, natural gas, NGLs and renewable energy; anticipated utilization of assets; exchange rates; inflation; interest rates; availability and price of labor and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for our projects; anticipated in-service dates; weather; the timing and closing of acquisitions and dispositions; the realization of anticipated benefits and synergies of transactions; governmental legislation; litigation; estimated future dividends and impact of our dividend policy on our future cash flows; our credit ratings; capital project funding; hedging program; expected EBITDA; expected earnings/(loss); expected future cash flows; and expected distributable cash flow. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGLs and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation, interest rates and the COVID-19 pandemic impact the economies and business environments in which we operate and may impact levels of demand for our services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-

looking statement cannot be determined with certainty, particularly with respect to expected EBITDA, expected earnings/(loss), expected future cash flows, expected distributable cash flow or estimated future dividends. The most relevant assumptions associated with forward-looking statements regarding announced projects and projects under construction, including estimated completion dates and expected capital expenditures, include the following: the availability and price of labor and construction materials; the effects of inflation and foreign exchange rates on labor and material costs; the effects of interest rates on borrowing costs; the impact of weather, customer, government, court and regulatory approvals on construction and in-service schedules and cost recovery regimes; and the COVID-19 pandemic and the duration and impact thereof.

Our forward-looking statements are subject to risks and uncertainties pertaining to the successful execution of our strategic priorities, operating performance, legislative and regulatory parameters; litigation, including with respect to the Dakota Access Pipeline (DAPL) and the Line 5 dual pipelines; acquisitions, dispositions and other transactions and the realization of anticipated benefits therefrom; our dividend policy; project approval and support; renewals of rights-of-way; weather; economic and competitive conditions; public opinion; changes in tax laws and tax rates; exchange rates; interest rates; commodity prices; political decisions; the supply of, demand for and prices of commodities; and the COVID-19 pandemic, including but not limited to those risks and uncertainties discussed in this Annual Report on Form 10-K and in our other filings with Canadian and US securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and our future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statement made in this Annual Report on Form 10-K or otherwise, whether as a result of new information, future events or otherwise. All forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP AND OTHER FINANCIAL MEASURES

Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations *(MD&A) in this Annual Report on Form 10-K makes reference to non-GAAP and other financial measures, including EBITDA. EBITDA is defined as earnings before interest, income taxes, depreciation and amortization. Management uses EBITDA to assess performance of Enbridge and to set targets. Management believes the presentation of EBITDA gives useful information to investors as it provides increased transparency and insight into the performance of Enbridge.*

The non-GAAP and other financial measures described above are not measures that have a standardized meaning prescribed by generally accepted accounting principles in the United States of America (US GAAP) and are not US GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers. A reconciliation of historical non-GAAP and other financial measures to the most directly comparable GAAP measures is set out in this MD&A and is available on our website. Additional information on non-GAAP and other financial measures may be found on our website, www.sedar.com or www.sec.gov.

PART I

ITEM 1. BUSINESS

We are a leading North American energy infrastructure company. We safely and reliably deliver the energy people need and want to fuel quality of life. Our core businesses include Liquids Pipelines, which transports approximately 30% of the crude oil produced in North America; Gas Transmission and Midstream, which transports approximately 20% of the natural gas consumed in the US; Gas Distribution and Storage, which serves approximately 75% of Ontario residents via approximately 3.8 million meter connections; and Renewable Power Generation, which generates approximately 1,766 megawatts (MW) of net renewable power in North America and Europe. Our common shares trade on the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE) under the symbol ENB. We were incorporated on April 13, 1970 under the Companies Ordinance of the Northwest Territories and were continued under the Canada Business Corporations Act on December 15, 1987.

A more detailed description of each of our businesses and underlying assets is provided below under *Business Segments.*

CORPORATE VISION AND STRATEGY

VISION

Our primary purpose as a company is to fuel quality of life by providing the energy people need and want, in a safe, clean and socially responsible way. Our vision to be the leading energy infrastructure company in North America supports this purpose. In pursuing this vision, we play a critical role in enabling the economic and social well-being of people in the areas we serve who depend on access to affordable and reliable energy of all types. Our infrastructure franchises transport, distribute, and generate energy including liquids, natural gas, renewable power, and low-carbon fuels like Renewable Natural Gas (RNG). We recognize that the energy system is changing, and we aim to bridge to that cleaner energy future by investing in low-carbon platforms while ensuring the continuity and stability that the world requires through the transition.

Our investor value proposition is founded on our ability to deliver predictable cash flows and a growing stream of dividends year-over-year through investment in, and efficient operation of, energy infrastructure assets that are strategically positioned between key supply basins and strong demand-pull markets. Our assets are underpinned by long-term contracts, regulated cost-of-service tolling frameworks, power purchase agreements, and other low-risk commercial arrangements.

We strive to be a leader in ESG; worker and public safety; emissions reduction; stakeholder relations; customer service; community investment; and employee engagement and satisfaction.

STRATEGY

An in-depth understanding of energy supply and demand fundamentals coupled with disciplined capital allocation principles has helped us become an industry leader supported by a diverse set of assets across the energy system. Our assets have reliably generated low-risk, resilient cash flows through many commodity and economic cycles, including the COVID-19 pandemic and the ensuing volatile economic recovery.

To ensure we continue to be an industry leader and value creator going forward, we maintain a robust strategic planning approach. We regularly conduct scenario and resiliency analysis on both our assets and on our business strategy. We test various value enhancement and maximization options, and we engage regularly with our Board of Directors (Board) to ensure alignment and maintain active oversight. This Board participation includes updates and discussions throughout the year and a dedicated session to Strategy Planning annually. This comprehensive approach will continue to guide investment decisions moving forward.

Predictable growth is a hallmark of our investor value proposition. We see a 5-7% compound annual growth rate in distributable cash flow per share through 2024, relative to 2021, underpinned by opportunities to advance returns in our base business and grow organically through disciplined capital allocation. Our diversified footprint allows for selective investment in both our core businesses and in emerging low carbon energy platforms such as carbon capture and storage (CCS), hydrogen gas (H2), and RNG.

In 2021, we progressed several of our strategic priorities. For example:

- Our Liquids Pipelines team delivered record mainline throughput, placed $5.6 billion of capital into service (Line 3 Replacement, Southern Access), added 90 kbpd of system expansions into Petroleum Administration for Defense Districts (PADD) III, and acquired the Ingleside Energy Center in Corpus Christi and related assets which extends our reach into global light-oil export markets.

- Our Gas Transmission and Midstream business successfully placed $3.1 billion of capital into service, completed favorable rate settlements, which added $150 million of incremental EBITDA, and continued to advance more than $2 billion of expansion opportunities.

- Our Gas Distribution and Storage utility provided uninterrupted services during the ongoing pandemic, added over 40 thousand new customers, completed 190 modernization projects, placed two RNG projects into service, and completed an H2 blending pilot.

- In Europe, Renewable Power Generation advanced construction of the 480 MW Saint Nazaire project, the 500 MW Fécamp project, and the 448 MW Calvados project, and sanctioned the Provence Grand Large floating offshore wind facility.

- We advanced our self-power strategy and commissioned two projects, Alberta Solar One on our Liquids Pipeline system and Heidlersberg on our Gas Transmission system. Ten additional self-power facilities (~100MW) were approved for future development.

- We established our New Energy Technologies team to advance our low-carbon strategy. Through several strategic partnerships, we are working to develop solutions in RNG, H2 and CCS and to accelerate global and industry-specific low-carbon objectives.

- We continued to make meaningful progress towards our ESG goals that include a 35% reduction in greenhouse gas (GHG) emissions intensity from our operations by 2030 (net zero GHG emissions by 2050) and increased representation of diverse groups within our workforce and the Board of Directors by 2025.

- We sold $1.2 billion of assets at attractive valuations, further strengthening our financial flexibility. In addition, we continued to reduce our operating costs ($1.2 billion since 2017), increasing our profitability and competitiveness.

These achievements are discussed in further detail in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.*

Looking ahead, our near-term strategic priorities remain similar to years past. As always, proactively advancing the safety of communities and assets, protecting the environment, and maintaining reliability will always be our top priorities. We are focused on enhancing the value of our existing assets in Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, and Renewable Power Generation.

We will continue to enhance base business returns, capitalize on our advantaged liquids and natural gas pipeline infrastructure, emphasizing export-driven opportunities and in-franchise organic growth, and developing low-carbon opportunities across our business.

Our key strategic priorities are summarized below:

Ensure Safe Reliable Operations
Safety and operational reliability remain the foundation of our strategy. Our commitment to safety and operational reliability means achieving and maintaining industry leadership in safety (process, public and personal) and ensuring the reliability and integrity of the systems we operate, in order to generate, transport and deliver energy while protecting people and the environment.

Enhance Returns from our Base Businesses
A key priority is to drive growth through an ongoing focus on optimization, productivity, and efficiency across all our businesses. Examples include: the application of drag-reducing agents and pump station horsepower additions to optimize throughput on our liquids system, the execution of toll settlements and rate case filings to optimize revenue within our gas transmission franchises, the expansion of low-carbon gas offerings to modernize and integrate value chains at our gas utility, and more generally, and the creation of sustainable cost savings across the organization through process improvement and/or system enhancements.

Execute the Capital Program and Grow Core Business
Successful project execution is integral to our financial performance and to the strategic positioning of our business over the long term. Our ongoing objective is to deliver our slate of secured projects (currently $9 billion through 2024) at the lowest practical cost while maintaining the highest standards for safety, quality, customer satisfaction and environmental and regulatory compliance. For a discussion of our current portfolio of capital projects, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects*.

In seeking to extend growth, we expect to have sufficient self-funding capacity of about $5 to $6 billion per year to invest in new organic growth capital without issuing any additional common equity and maintaining key credit metrics. We will remain disciplined and deploy capital towards the best uses, prioritizing balance sheet strength, investment in low capital intensity growth and regulated utility or utility-like projects. We will carefully assess our remaining investable capacity, deploying capital to the most value-enhancing opportunities available to us, including further organic growth, asset acquisitions, and share buybacks, or further deleveraging our balance sheet.

Looking ahead, we see strong utilization of our existing network and opportunities for future growth within each of our businesses. For example:

- Our liquids pipelines infrastructure will remain a vital connection between key supply basins and demand-pull markets such as the refinery hubs in the US Midwest, Eastern Canada, and the US Gulf Coast. The emergence of CCS offers the potential to provide new growth opportunities over the long term.

- Our natural gas pipelines business will seek extension and expansion opportunities driven by new load demand from gas-fired power generation, industrial growth, and coastal liquefied natural gas (LNG) plants. Looking forward, blending RNG and H2 production projects into our system will enhance asset longevity and enable us to offer a differentiated low-carbon service to customers.

- Our gas distribution utility will continue to grow through customer additions, productivity enhancements, modernization investments and facilities that blend H2 and RNG into gas supply, and expansion of our demand-side management and distributed energy programs.

- Our mature capabilities in the offshore and onshore wind sector position us well to compete for new projects across the development cycle in Europe and North America, while our multi-year program to self-power existing pipeline compressor stations represents highly visible and scalable growth.

Maintain Financial Strength and Flexibility
The maintenance of our financial strength is critical to our strategy. Our financing strategies are designed to retain strong investment-grade credit ratings to ensure that we have the financial capacity to meet our capital funding needs and the flexibility to manage capital market disruptions. Our current secured capital program, which extends to 2024, can be readily financed through internally generated cash flow and available balance sheet capacity without issuance of additional common equity and we will seek to secure new growth within our “self-funded” equity model. In addition, we continue to look at opportunities to monetize non-core assets at attractive valuations. For further discussion on our financing strategies, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources*.

Disciplined Capital Allocation
We assess the latest fundamental trends, monitor the business landscape and proactively conduct business development activities with the goal of identifying an industry-leading opportunity set for capital deployment. Opportunities are screened, analyzed and assessed using a disciplined investment framework with the objective of ensuring effective deployment of capital to achieve attractive risk-adjusted returns, while maintaining our low-risk “utility-like” business model.

All investment opportunities are evaluated based on their potential to advance our strategy, mitigate risk, support our ESG goals, and create additional financial flexibility. Our primary emphasis in the near term is on low capital-intensive opportunities to enhance returns in existing businesses (organic expansions and optimizations), modernization of our systems and utility rate-based investments. Execution risk remains high for large scale, long-duration development projects and, therefore, our focus will be on projects where we can carefully manage at-risk capital during the permitting and construction phases.

In evaluating typical investment opportunities, we also consider other potential capital allocation alternatives. Other alternatives for capital deployment depend on our current outlook and include further dividend increases, further debt reduction, and/or share re-purchases.

Adapt to Energy Transition Over Time
As the global population grows and standards of living continue to improve around the world, more energy will be needed. At the same time, our society increasingly recognizes the impacts of greenhouse gas emissions on the world’s climate. Accordingly, energy systems are being reshaped as industry participants, regulators and consumers seek to lower emissions. As a diversified energy infrastructure company, we are well positioned to play a key role in the transition to a low-emissions economy by leading the development of the future energy systems and partnering with customers on their low-carbon strategies, while at the same time working to reduce our own emissions. Furthermore, we have tested our assets for various energy transition scenarios and concluded that they are highly resilient and can be relied upon for stable cash flow generation well into the future.

We believe that diversification and innovation will play a significant role in the transition to a low-carbon future. To date, we have made large investments in natural gas infrastructure and continue to see significant opportunity in renewable energy. Our focus areas in renewable energy remain in offshore wind and utility-scale onshore projects. We are also taking a leadership role in other low-carbon platforms like CCS, H2 and RNG where we can leverage our infrastructure capability and stakeholder relationships to accelerate growth and extend the value of our existing assets. Additionally, all new investments that we make will need to have a clear path to achieve net zero emissions.

We recognize our customer's expectations of a transition to a lower-carbon economy and are working actively to be a differentiated service provider by leveraging our ESG leadership and world-class execution capabilities.

STRATEGIC ENABLERS
Our success in executing on our strategic priorities is enabled by our commitment to ESG, the quality and capabilities of our people, and the extent to which we embrace technology and innovation as a competitive advantage.

ESG
Sustainability is integral to our ability to safely and reliably deliver the energy people need and want. How well we perform as a steward of our environment; as a safe operator of essential energy infrastructure; as a diverse and inclusive employer; and as a responsible corporate citizen is inextricably linked to our ability to achieve our strategic priorities and create long-term value for all stakeholders.

Our commitment to strong ESG practices and performance has long been core to how we do business and we are proud to be recognized as a leader amongst our peers. In 2020, we set out ambitious goals[1] including:

- Net zero GHG emissions by 2050 with an interim target to reduce GHG emissions intensity 35% by 2030 compared to the 2018 baseline.
- Increased representation of diverse groups within our workforce by 2025, including representation goals of 40% women and 28% racial and ethnic groups, along with new initiatives to enhance supplier diversity.
- Strengthening diversity on our Board with representation goals of 40% women and 20% racial and ethnic groups by 2025.
- Annual safety and reliability targets that drive continuous improvement towards our goal of zero incidents, injuries, and implementation of robust cyber defense programs.

Beginning in 2021, we began linking ESG performance to incentive compensation and are making meaningful progress toward these targets by executing on specific action plans. In addition, we issued our first sustainability-linked loan and sustainability-linked bond that ties our financing to our ESG goals.

1 *All percentages or specific goals regarding inclusion, diversity, equity and accessibility are aspirational goals which we intend to achieve in a manner compliant with state, local, provincial and federal law, including, but not limited to, US federal regulations, Equal Employment Opportunity Commission, Department of Labor and Office of Federal Contract Compliance Programs.*

Enbridge aims to continuously strengthen its approach to emissions reporting and reduction and is expanding its approach to include the following additional actions:

- Ensure that investment decision making aligns with Enbridge's interim and long-term emissions reduction goals.
- Continue to proactively work with the organizations developing science-based guidelines for emissions targets in the midstream sector.
- Work with key suppliers to support the further reduction of Scope 3 emissions.
- Further develop low carbon energy partnerships to drive innovation across our business, with a focus on renewable power, renewable natural gas, hydrogen and carbon capture.

Achieving our goals will put us in a better position to successfully transition to a low-carbon, more diverse, and inclusive future.

People
Our employees are essential to our long-term success and enhancing the capability of our people to maximize their potential is a key area of focus. We value diversity, and diverse thought, and have embedded inclusive practices in our programs and approach to people management. Furthermore, we strive to maintain industry competitive compensation, flexibility, and retention programs that provide both short-term and long-term performance incentives.

Technology
Given the competitive climate of today's energy sector, we recognize the vital role technology can play in helping to achieve our strategic objectives. We're committed to pursuing innovation and technology solutions that further improve our safety performance, maximize revenues, improve efficiencies, and enable transition to new, cleaner energy solutions. Our two Technology and Innovation labs, located in Calgary and Houston, embody our commitment to technology enabled business solutions. Leveraging the benefits of technology to contribute to safety, reliability and the profitability of assets has become entrenched in our everyday operations.

We provide annual progress updates related to the above initiatives, along with our assumptions and other relevant information, in our annual Sustainability Report which can be found at https://www.enbridge.com/sustainability-reports. ***Unless otherwise specifically stated, none of the information contained on, or connected to, the Enbridge website, including our annual Sustainability Report, is incorporated by reference in, or otherwise part of, this Annual Report on Form 10-K***.

BUSINESS SEGMENTS

Our activities are carried out through five business segments: Liquids Pipelines; Gas Transmission and Midstream; Gas Distribution and Storage; Renewable Power Generation; and Energy Services, as discussed below.

LIQUIDS PIPELINES

Liquids Pipelines consists of pipelines and terminals in Canada and the US that transport and export various grades of crude oil and other liquid hydrocarbons.

MAINLINE SYSTEM

The Mainline System is comprised of the Canadian Mainline and the Lakehead System. The Canadian Mainline is a common carrier pipeline system which transports various grades of crude oil and other liquid hydrocarbons within western Canada and from western Canada to the Canada/US border near Gretna, Manitoba and Neche, North Dakota and from the US/Canada border near Port Huron, Michigan and Sarnia, Ontario to eastern Canada and the northeastern US. The Canadian Mainline includes six adjacent pipelines with a combined operating capacity of approximately 3.1 million barrels per day (mmbpd) that connect with the Lakehead System at the Canada/US border, as well as five pipelines that deliver crude oil and refined products into eastern Canada and the northeastern US. We have operated, and frequently expanded, the Canadian Mainline since 1949. The Lakehead System is the portion of the Mainline System in the US. It is an interstate common carrier pipeline system regulated by the Federal Energy Regulatory Commission (FERC) and is the primary transporter of crude oil and liquid petroleum from western Canada to the US.

Tolling Framework

The Competitive Toll Settlement (CTS) which governed tolls paid for products shipped on the Canadian Mainline, with the exception of Lines 8 and 9 which are tolled on a separate basis, expired on June 30, 2021. The CTS was a 10-year negotiated agreement and provided for a Canadian Local Toll (CLT) for deliveries within western Canada, as well as an International Joint Tariff (IJT) for crude oil shipments originating in western Canada, on the Canadian Mainline, and delivered into the US, via the Lakehead System, and into eastern Canada. The IJT tolls were denominated in US dollars.

On December 19, 2019, we submitted an application to the Canada Energy Regulator (CER) to implement contracting on our Canadian Mainline System. On November 26, 2021, the CER denied the application on the basis that, among other things, contracting as proposed would result in a significant change to access the Canadian Mainline and potentially inequitable outcomes to some shippers and non-shippers without a compelling justification.

Effective July 1, 2021, the Mainline System is on Interim Tolls which will remain in effect until new tolls are approved by the CER. In accordance with the terms of the CTS, Interim Tolls are equal to the CTS exit tolls on June 30, 2021 and are subject to finalization and adjustment applicable to the interim period, if any. We are currently exploring, with customers and other stakeholders, alternatives that may include: a modified and extended CTS, a new incentive rate-making agreement, or a cost-of-service rate-making structure. Any negotiated settlement would require CER approval before implementation. New tolling framework clarity is expected by 2023.

Shippers continue to nominate volumes on a monthly basis and we continue to allocate capacity to maximize the efficiency of the Mainline System.

Local tolls for service on the Lakehead System are not affected by Interim Tolls and continue to be established pursuant to the Lakehead System’s existing toll agreements, as described below. Under Interim Tolls, the Canadian Mainline’s share of the toll relating to pipeline transportation of a batch from any western Canada receipt point to the US border is equal to the toll applicable to that batch’s US delivery point less the Lakehead System’s local toll to that delivery point. While on Interim Tolls, we will continue to refer to this amount as the Canadian Mainline IJT Residual Benchmark Toll which is denominated in US dollars.

Lakehead System Local Tolls

Transportation rates are governed by the FERC for deliveries from the Canada/US border near Neche, North Dakota, Clearbrook, Minnesota and other points to principal delivery points on the Lakehead System. The Lakehead System periodically adjusts these transportation rates as allowed under the FERC's index methodology and tariff agreements, the main components of which are index rates and the Facilities Surcharge Mechanism. Index rates, the base portion of the transportation rates for the Lakehead System, are subject to an annual inflationary adjustment which cannot exceed established ceiling rates as approved by the FERC. The Facilities Surcharge Mechanism allows the Lakehead System to recover costs associated with certain shipper-requested projects through an incremental surcharge in addition to the existing base rates and is subject to annual adjustment on April 1 of each year. To the extent that the Lakehead System transportation rates materially under-recover the Lakehead System cost of service, an application can be made with the FERC to seek approval to increase the rates in order to bring recoveries in-line with costs.

On May 21, 2021, we filed a cost-of-service application to raise our base rates effective July 1, 2021. On June 30, 2021, the FERC issued an order to accept the rates subject to refund. This matter is currently in the FERC settlement process.

REGIONAL OIL SANDS SYSTEM

The Regional Oil Sands System includes five intra-Alberta long-haul pipelines; the Athabasca Pipeline, Waupisoo Pipeline, Woodland Pipeline, Wood Buffalo Extension/Athabasca Twin pipeline system and the Norlite Pipeline System (Norlite), as well as two large terminals: the Athabasca Terminal located north of Fort McMurray, Alberta and the Cheecham Terminal, located south of Fort McMurray, Alberta. The Regional Oil Sands System also includes numerous laterals and related facilities which currently provide access for oil sands production from twelve producing oil sands projects.

The combined capacity of the intra-Alberta long-haul pipelines is approximately 1,090 kbpd to Edmonton and 1,370 kbpd into Hardisty, with Norlite providing approximately 218 kbpd of diluent capacity into the Fort McMurray region. We have a 50% interest in the Woodland Pipeline and a 70% interest in Norlite. The Regional Oil Sands System is anchored by long-term agreements with multiple oil sands producers that provide cash flow stability and also include provisions for the recovery of some of the operating costs of this system.

GULF COAST AND MID-CONTINENT

Gulf Coast includes Seaway Crude Pipeline System (Seaway Pipeline), Flanagan South Pipeline (Flanagan South), Spearhead Pipeline, Gray Oak Pipeline and the Enbridge Ingleside Energy Center (EIEC), as well as the Mid-Continent System (Cushing Terminal).

We have a 50% interest in the 1,078-kilometer (670-mile) Seaway Pipeline, including the 805-kilometer (500-mile), 30-inch diameter long-haul system between Cushing, Oklahoma and Freeport, Texas, as well as the Texas City Terminal and Distribution System which serve refineries in the Houston and Texas City areas. Total aggregate capacity on the Seaway Pipeline system is approximately 950 kbpd. Seaway Pipeline also includes 8.8 million barrels of crude oil storage tank capacity on the Texas Gulf Coast.

Flanagan South is a 950-kilometer (590-mile), 36-inch diameter interstate crude oil pipeline that originates at our terminal at Flanagan, Illinois, a delivery point on the Lakehead System, and terminates in Cushing, Oklahoma. Flanagan South has a capacity of approximately 600 kbpd.

Spearhead Pipeline is a long-haul pipeline that delivers crude oil from Flanagan, Illinois, a delivery point on the Lakehead System, to Cushing, Oklahoma. The Spearhead pipeline has a capacity of approximately 193 kbpd.

The Gray Oak pipeline is a 1,368-kilometer (850-mile) crude oil system, which runs from the Permian Basin in West Texas to the US Gulf Coast. The Gray Oak pipeline has an expected average annual capacity of 900 kbpd and transports light crude oil. We have an effective 22.8% interest in the pipeline. Initial in-service for the pipeline commenced in November 2019 with full service achieved in the second quarter of 2020.

The Mid-Continent System is comprised of storage terminals at Cushing, Oklahoma (Cushing Terminal), consisting of over 80 individual storage tanks ranging in size from 78 to 570 thousand barrels. Total storage shell capacity of Cushing Terminal is approximately 20 million barrels. A portion of the storage facilities are used for operational purposes, while the remainder are contracted to various crude oil market participants for their term storage requirements. Contract fees include fixed monthly storage fees, throughput fees for receiving and delivering crude to and from connecting pipelines and terminals, as well as blending fees.

In October 2021, we acquired a 100 percent operating interest in the Ingleside Energy Center (renamed the Enbridge Ingleside Energy Center (EIEC)), located near Corpus Christi, Texas. This terminal is comprised of 15.6 million barrels of storage and 1.5 million barrels per day of export capacity. We also acquired a 20% interest in the 670-kbpd Cactus II Pipeline, a 100% interest in the 300-kbpd Viola pipeline, and a 100% interest in the 350-thousand-barrel Taft Terminal.

OTHER

Other includes Southern Lights Pipeline, Express-Platte System, Bakken System and Feeder Pipelines and Other.

Southern Lights Pipeline is a single stream 180 kbpd 16/18/20-inch diameter pipeline that ships diluent from the Manhattan Terminal near Chicago, Illinois to three western Canadian delivery facilities, located at the Edmonton and Hardisty terminals in Alberta and the Kerrobert terminal in Saskatchewan. Both the Canadian portion of Southern Lights Pipeline and the US portion of Southern Lights Pipeline receive tariff revenues under long-term contracts with committed shippers. Southern Lights Pipeline capacity is 90% contracted with the remaining 10% of the capacity assigned for shippers to ship uncommitted volumes.

The Express-Platte System consists of the Express pipeline and the Platte pipeline, and crude oil storage of approximately 5.6 million barrels. It is an approximate 2,736-kilometer (1,700-mile) long crude oil transportation system, which begins at Hardisty, Alberta, and terminates at Wood River, Illinois. The 310 kbpd Express pipeline carries crude oil to US refining markets in the Rocky Mountains area, including Montana, Wyoming, Colorado and Utah. The 145 to 164 kbpd Platte pipeline, which interconnects with the Express pipeline at Casper, Wyoming, transports crude oil predominantly from the Bakken shale and western Canada to refineries in the midwest. Express pipeline capacity is typically committed under long-term take-or-pay contracts with shippers. A small portion of Express pipeline capacity and all of the Platte pipeline capacity is used by uncommitted shippers who pay only for the pipeline capacity they actually use in a given month.

The Bakken System consists of the North Dakota System and the Bakken Pipeline System. The North Dakota System services the Bakken in North Dakota and is comprised of a crude oil gathering and interstate pipeline transportation system. The gathering system provides delivery to Clearbrook, Minnesota for service on the Lakehead system or a variety of interconnecting pipeline and rail export facilities. The interstate portion of the system has both US and Canadian components that extend from Berthold, North Dakota into Cromer, Manitoba.

Tariffs on the US portion of the North Dakota System are governed by the FERC. The Canadian portion is categorized as a Group 2 pipeline, and as such, its tolls are regulated by the CER on a complaint basis. Tolls on the interstate pipeline system are based on long-term take-or-pay agreements with anchor shippers.

We have an effective 27.6% interest in the Bakken Pipeline System, which connects the Bakken formation in North Dakota to markets in eastern PADD II and the US Gulf Coast. The Bakken Pipeline System consists of the DAPL from the Bakken area in North Dakota to Patoka, Illinois, and the Energy Transfer Crude Oil Pipeline from Patoka, Illinois to Nederland, Texas. Current capacity is 750 kbpd of crude oil with the potential to be expanded through additional pumping horsepower. The Bakken Pipeline System is anchored by long-term throughput commitments from a number of producers.

Feeder Pipelines and Other includes a number of liquids storage assets and pipeline systems in Canada and the US.

Key assets included in Feeder Pipelines and Other are the Hardisty Contract Terminal and Hardisty Storage Caverns located near Hardisty, Alberta, a key crude oil pipeline hub in western Canada and the Southern Access Extension (SAX) pipeline which originates in Flanagan, Illinois and delivers to Patoka, Illinois. We have an effective 65% interest in the 300 kbpd SAX pipeline of which the majority of its capacity is commercially secured under long-term take-or-pay contracts with shippers.

Feeder Pipelines and Other also includes Patoka Storage, the Toledo pipeline system and the Norman Wells (NW) System. Patoka Storage is comprised of four storage tanks with 480 thousand barrels of shell capacity located in Patoka, Illinois. The 101 kbpd Toledo pipeline system connects with the Lakehead System and delivers to Ohio and Michigan. The 45 kbpd NW System transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta and has a cost-of-service rate structure based on established terms with shippers.

COMPETITION

Competition to our liquids pipelines network comes primarily from infrastructure or logistics alternatives that transport liquid hydrocarbons from production basins in, which we operate, to markets in Canada, the US and internationally. Competition from existing and proposed pipelines is based primarily on access to supply, end use markets, the cost of transportation, contract structure and the quality and reliability of service. Additionally, volatile crude price differentials and insufficient pipeline capacity on either our or competitors' pipelines can make transportation of crude oil by rail competitive, particularly to markets not currently served by pipelines.

We believe that our liquids pipelines systems will continue to provide competitive and attractive options to producers in the Western Canadian Sedimentary Basin (WCSB), North Dakota, and more recently the Permian Basin, due to our market access, competitive tolls and flexibility through our multiple delivery and storage points. We also employ long-term agreements with shippers, which mitigates competition risk by ensuring consistent supply to our liquids pipelines network. Our current complement of growth projects to expand market access and to enhance capacity on our pipeline system will provide additional competitive solutions for liquids transportation. We have a proven track record of successfully executing projects to meet the needs of our customers.

SUPPLY AND DEMAND

We have an established and successful history of being the largest transporter of crude oil to the US, the world’s largest market for crude oil. While US demand for Canadian crude oil production will support the use of our infrastructure for the foreseeable future, North American and global crude oil supply and demand fundamentals are shifting, and we have a role to play in this transition by developing long-term transportation options that enable the efficient flow of crude oil from supply regions to end-user markets, both domestic and global.

The COVID-19 pandemic had a significant negative impact on the crude oil market in 2020 with decreased demand from the economic slowdown and government imposed mobility restrictions. However, 2021 has seen global crude oil demand recover to levels close to pre-pandemic highs. International prices have strengthened to multi-year highs as global demand has outpaced the return of supply as publicly traded producers have adopted a more disciplined approach to capital allocation for new drilling.

Our Mainline System throughput, as measured at the Canada/US border at Gretna, Manitoba ended the year delivering 3.1 million barrels per day, as the Line 3 Replacement program has come into service. Refinery demand in the upper Midwest PADD II market has been strong given the economic recovery and enhanced mobility demand. On the US Gulf Coast, lower supply of heavy crude from Latin America and the Middle East is driving increased demand for Canadian heavy crude.

Global crude oil demand in most base case forecasts is expected to grow into the next decade, primarily driven by emerging economies in regions outside the Organization for Economic Cooperation and Development (OECD), such as India and China. In North America, demand growth for transportation fuels is expected to moderate over time due to vehicle fuel efficiency improvement and increasing sales of electric vehicles.

New supply to meet this growing demand will primarily come from Organization of the Petroleum Exporting Countries (OPEC) countries and North America. Growth in supply from OPEC will be led by Saudi Arabia and the United Arab Emirates with their significant low cost reserves and could be supplemented by the return of sanctioned Iranian production. Growth in North America will be driven by the Permian Basin which is a large and cost competitive light crude oil resource base. In addition, heavy crude oil growth is expected from the WCSB as additional egress availability will support expansion of existing projects and some potential new greenfield facilities.

The combination of long term demand growth in non-OECD nations, domestic demand contraction over time, and continued production growth in the Permian Basin and WCSB highlights the importance of our strategic asset footprint and reinforces the need for additional export oriented infrastructure. We are well positioned to meet these evolving supply and demand fundamentals through expansion of system capacity for incremental access to the US Gulf Coast, and through further development of our new Enbridge Ingleside Energy Center in Corpus Christi, the largest crude oil export facility in North America.

Opposition to fossil fuel development in conjunction with evolving consumer preferences and new technology could underpin accelerated energy transition scenarios impacting long term supply and demand of crude oil. We continue to closely monitor the evolution of all of these factors to be able to pro-actively adapt our business to help meet our customers' and society's energy needs.

Progress on the development and construction of our commercially secured growth projects is discussed in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects.*

GAS TRANSMISSION AND MIDSTREAM

Gas Transmission and Midstream consists of our investments in natural gas pipelines and gathering and processing facilities in Canada and the US, including US Gas Transmission, Canadian Gas Transmission, US Midstream and other assets.

US GAS TRANSMISSION
US Gas Transmission includes ownership interests in Texas Eastern Transmission, L.P. (Texas Eastern), Algonquin Gas Transmission, LLC (Algonquin), Maritimes & Northeast (M&N) (US and Canada), East Tennessee Natural Gas, LLC (East Tennessee), Gulfstream Natural Gas System, L.L.C. (Gulfstream), Sabal Trail Transmission (Sabal Trail), NEXUS Gas Transmission Pipeline (NEXUS), Valley Crossing Pipeline, LLC. (Valley Crossing), Southeast Supply Header (SESH), Vector Pipeline L.P. (Vector) and certain other gas pipeline and storage assets. The US Gas Transmission business primarily provides transmission and storage of natural gas through interstate pipeline systems for customers in various regions of the northeastern, southern and midwestern US.

The Texas Eastern natural gas transmission system extends from supply and demand centers in the Gulf Coast region of Texas and Louisiana to supply and demand centers in Ohio, Pennsylvania, New Jersey and New York. Texas Eastern's onshore system has a peak day capacity of 13.09 billion cubic feet per day (bcf/d) of natural gas on approximately 13,807-kilometers (8,579-miles) of pipeline and associated compressor stations. Texas Eastern is also connected to four affiliated storage facilities that are partially or wholly-owned by other entities within the US Gas Transmission business.

The Algonquin natural gas transmission system connects with Texas Eastern’s facilities in New Jersey and extends through New Jersey, New York, Connecticut, Rhode Island and Massachusetts where it connects to M&N US. The system has a peak day capacity of 3.09 bcf/d of natural gas on approximately 1,820-kilometers (1,131-miles) of pipeline with associated compressor stations.

M&N US has a peak day capacity of 0.83 bcf/d of natural gas on approximately 552-kilometers (343-miles) of mainline interstate natural gas transmission system, including associated compressor stations, which extends from northeastern Massachusetts to the border of Canada near Baileyville, Maine. M&N Canada has a peak day capacity 0.55 bcf/d on approximately 885-kilometers (550-miles) of interprovincial natural gas transmission mainline system that extends from Goldboro, Nova Scotia to the US border near Baileyville, Maine. We have a 78% interest in M&N US and M&N Canada.

East Tennessee’s natural gas transmission system has a peak day capacity of 1.86 bcf/d of natural gas, crosses Texas Eastern’s system at two locations in Tennessee and consists of two mainline systems totaling approximately 2,456-kilometers (1,526-miles) of pipeline in Tennessee, Georgia, North Carolina and Virginia, with associated compressor stations. East Tennessee has a LNG storage facility in Tennessee and also connects to the Saltville storage facilities in Virginia.

Gulfstream is an approximately 1,199-kilometer (745-mile) interstate natural gas transmission system with associated compressor stations. Gulfstream has a peak day capacity of 1.31 bcf/d of natural gas from Mississippi, Alabama, Louisiana and Texas, crossing the Gulf of Mexico to markets in central and southern Florida. We have a 50% interest in Gulfstream.

Sabal Trail is an approximately 832-kilometer (517-mile) pipeline that provides firm natural gas transportation. Facilities include a pipeline, laterals and various compressor stations. The pipeline infrastructure is located in Alabama, Georgia and Florida, and adds approximately 1.0 bcf/d of capacity enabling the access of onshore gas supplies. We have a 50% interest in Sabal Trail.

NEXUS is an approximately 414-kilometer (257-mile) interstate natural gas transmission system with associated compressor stations. NEXUS transports natural gas from our Texas Eastern system in Ohio to our Vector interstate pipeline in Michigan, with peak day capacity of 1.4 bcf/d. Through its interconnect with Vector, NEXUS provides a connection to Dawn Hub, the largest integrated underground storage facility in Canada and one of the largest in North America, located in southwestern Ontario adjacent to the Greater Toronto Area. We have a 50% interest in NEXUS.

Valley Crossing is an approximately 285-kilometer (177-mile) intrastate natural gas transmission system, with associated compressor stations. The pipeline infrastructure is located in Texas and provides market access of up to 2.6 bcf/d of design capacity to the Comisión Federal de Electricidad, Mexico's state-owned utility.

SESH is an approximately 462-kilometer (287-mile) natural gas transmission system with associated compressor stations. SESH extends from the Perryville Hub in northeastern Louisiana where the shale gas production of eastern Texas, northern Louisiana and Arkansas, along with conventional production, is reached from six major interconnections. SESH extends to Alabama, interconnecting with 14 major north-south pipelines and three high-deliverability storage facilities and has a peak day capacity of 1.1 bcf/d of natural gas. We have a 50% interest in SESH.

Vector is an approximately 560-kilometer (348-mile) pipeline travelling between Joliet, Illinois in the Chicago area and Ontario. Vector can deliver 1.745 bcf/d of natural gas, of which 455 million cubic feet per day (mmcf/d) is leased to NEXUS. We have a 60% interest in Vector.

Transmission and storage services are generally provided under firm agreements where customers reserve capacity in pipelines and storage facilities. The vast majority of these agreements provide for fixed reservation charges that are paid monthly regardless of the actual volumes transported on the pipelines, plus a small variable component that is based on volumes transported, injected or withdrawn, which is intended to recover variable costs.

Interruptible transmission and storage services are also available where customers can use capacity if it exists at the time of the request and are generally at a higher toll than long-term contracted rates. Interruptible revenues depend on the amount of volumes transported or stored and the associated rates for this service. Storage operations also provide a variety of other value-added services including natural gas parking, loaning and balancing services to meet customers' needs.

CANADIAN GAS TRANSMISSION

Canadian Gas Transmission is comprised of Westcoast Energy Inc.'s (Westcoast) British Columbia (BC) Pipeline, Alliance Pipeline and other minor midstream gas gathering pipelines.

BC Pipeline has a peak day capacity of 3.6 bcf/d of natural gas on approximately 2,950-kilometers (1,833-miles) of transmission pipeline in BC and Alberta that includes associated mainline compressor stations. It provides cost-of-service based natural gas transmission services.

Alliance Pipeline is an approximately 3,000-kilometer (1,864-mile) integrated, high-pressure natural gas transmission pipeline with approximately 860-kilometers (534-miles) of lateral pipelines and related infrastructure. It transports liquids-rich natural gas from northeast BC, northwest Alberta and the Bakken area in North Dakota to the Alliance Chicago gas exchange hub downstream of the Aux Sable NGL extraction and fractionation plant at Channahon, Illinois. The system has a peak day capacity of 1.8 bcf/d of natural gas. We have a 50% interest in Alliance Pipeline.

The majority of transportation services provided by Canadian Gas Transmission are under firm agreements, which provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipeline, plus a small variable component that is based on volumes transported to recover variable costs. Canadian Gas Transmission also provides interruptible transmission services where customers can use capacity if it is available at the time of request. Payments under these services are based on volumes transported.

US MIDSTREAM
US Midstream includes a 42.7% interest in each of Aux Sable Liquid Products LP and Aux Sable Midstream LLC, and a 50% interest in Aux Sable Canada LP (collectively, Aux Sable). Aux Sable Liquid Products LP owns and operates an NGL extraction and fractionation plant at Channahon, Illinois, outside Chicago, near the terminus of Alliance Pipeline. Aux Sable also owns facilities connected to Alliance Pipeline that facilitate delivery of liquids-rich natural gas for processing at the Aux Sable plant. These facilities include the Palermo Conditioning Plant and the Prairie Rose Pipeline in the Bakken area of North Dakota, owned and operated by Aux Sable Midstream US; and Aux Sable Canada's interests in the Montney area of BC, comprising the Septimus Pipeline. Aux Sable Canada also owns a facility which processes refinery/upgrader offgas in Fort Saskatchewan, Alberta.

US Midstream also includes a 50% investment in DCP Midstream, LLC (DCP Midstream), which indirectly owns approximately 57% of DCP Midstream, LP, including limited partner and general partner interests. DCP Midstream, LP is a master limited partnership, with a diversified portfolio of assets, engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; producing, fractionating, transporting, storing and selling NGLs; and recovering and selling condensate. DCP Midstream, LP owns and operates more than 36 plants and approximately 90,123-kilometers (56,000-miles) of natural gas and natural gas liquids pipelines, with operations in nine states across major producing regions.

OTHER
Other consists primarily of our offshore assets. Enbridge Offshore Pipelines is comprised of 11 natural gas gathering and FERC regulated transmission pipelines and four oil pipelines. These pipelines are located in four major corridors in the Gulf of Mexico, extending to deepwater developments, and include almost 2,100-kilometers (1,300-miles) of underwater pipe and onshore facilities with total capacity of approximately 6.5 bcf/d.

COMPETITION
Our natural gas transmission and storage businesses compete with similar facilities that serve our supply and market areas in the transmission and storage of natural gas. The principal elements of competition are location, rates, terms of service, flexibility and reliability of service.

The natural gas transported in our business competes with other forms of energy available to our customers and end-users, including electricity, coal, propane, fuel oils, nuclear and renewable energy. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, levels of business activity, long-term economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Competition exists in all markets that our businesses serve. Competitors include interstate/interprovincial and intrastate/intraprovincial pipelines or their affiliates and other midstream businesses that transport, gather, treat, process and market natural gas or NGLs. Because pipelines are generally the most efficient mode of transportation for natural gas over land, the most significant competitors of our natural gas pipelines are other pipeline companies.

SUPPLY AND DEMAND
Our gas transmission assets make up one of the largest natural gas transportation networks in North America, driving connectivity between prolific supply basins and major demand centers within the continent. Our systems have been integral to the transition in supply and demand markets over the last decade and will continue to play a part as the energy landscape evolves.

In 2010, natural gas production in each of the Appalachian and Permian basins were less than 5.0 bcf/d each. Today, these regions produce more than 47.5 bcf/d of natural gas on a combined basis. Improved technology and increased shale gas drilling have increased the supply of low-cost natural gas. As well, there has been and continues to be a corresponding increase in demand for our natural gas infrastructure in North America. Through a series of expansions and reversals on our core systems, combined with the execution of greenfield projects and strategic acquisitions, we have been able to meet the needs of producers and consumers alike. Our US Gas Transmission systems were initially designed to transport natural gas from the Gulf Coast to the supply starved northeast markets. Our asset base now has the capability to transport diverse bi-directional supply to the northeast, southeast, midwest, Gulf Coast and LNG markets on a fully subscribed and highly utilized basis.

The northeast market continues its role as a predominantly supply constrained region with steady demand. The bi-directional capabilities offered by our US Gas Transmission system allows us to deliver in an efficient manner to our regional customers. The region has seen an increase in natural gas supply due to the development of the Marcellus and Utica shales in the Appalachia region.

The southeast market is linked to multiple, highly liquid supply pools that include the Marcellus and Utica shale developments, offering consistent supply and stable pricing to a growing population of end-use customers across our multiple systems under long term, utility-like arrangements.

With connectivity to Appalachian and western Canadian supply through our systems, the midwest market has access to two of the lowest cost gas producing regions on the continent. As demand in the region is expected to continue to grow by approximately 2.0 bcf/d over the next two decades, maintaining this link will remain important. Flexibility in supply for this market is especially critical to maintaining liquidity and price stability as natural gas continues to replace coal-fired generation.

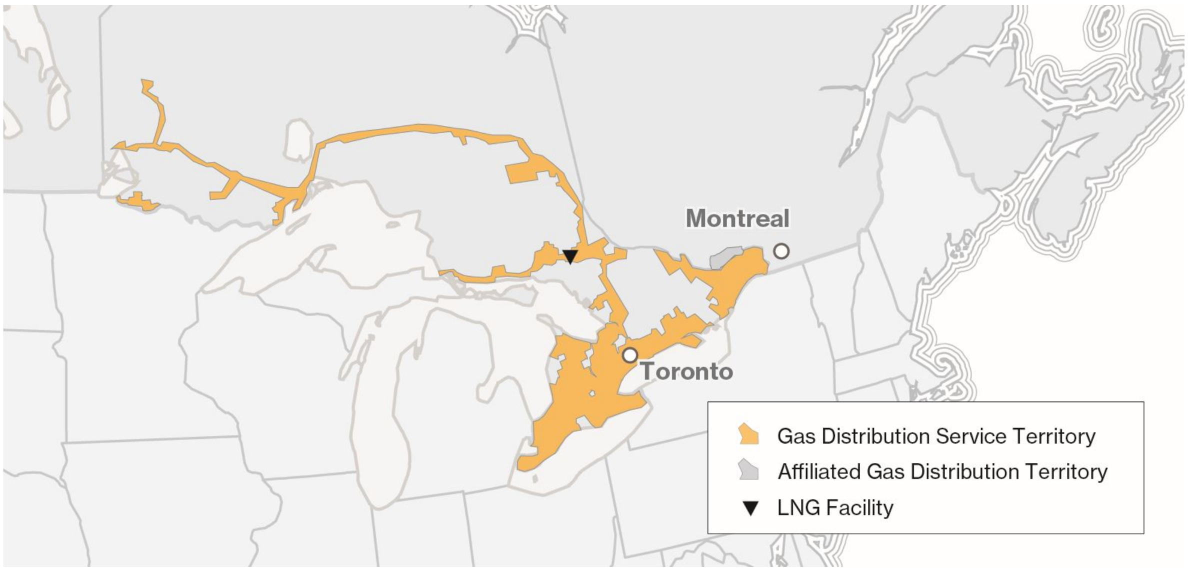
Gulf Coast demand growth is being driven by an increase in the volume of LNG exports, an ongoing wave of gas-intensive petrochemical facilities, along with power generation and additional pipeline exports to Mexico. Demand to these markets in the region is anticipated to grow by more than 23.0 bcf/d through 2040. The Gulf Coast market has been the beneficiary of low cost capacity on our assets as the relationship between supply and market centers has shifted. Such cost-effective capacity is difficult to access or replicate, offering existing shippers and transporters stability of capacity and utilization. Tide-water market access and proximity to Mexico continue to make this region a platform of global trade as pipeline and LNG exports continue their growth trajectory. The US exported over 11 bcf/d of natural gas to LNG markets, primarily from the Gulf Coast region, at the end of 2021.

Western Canada, not unlike other supply hubs, is a source of low-cost supply seeking access to premium markets in North America and globally. One of the few vital links to demand centers in the pacific northwest are our own systems in the region, which are highly utilized.

Global energy demand is expected to increase approximately 27% by 2040, according to the International Energy Agency, driven primarily by economic growth in non-OECD countries. Natural gas will play an important role in meeting this energy demand as gas consumption is anticipated to grow by approximately 23% during this period as one of the world's fastest growing energy sources. North American exports will play a significant part in meeting global demand, underscoring the ability of our assets to remain highly utilized by shippers, and highlighting the need for incremental transportation solutions across North America. In response to these global fundamentals, we believe we are well positioned to provide value-added solutions to shippers. Opposition to natural gas development, including new pipeline projects, has been increasing in recent years. This may challenge continued growth of the North American gas market and the ability to efficiently connect supply and demand. We are responding to the need for regional infrastructure with additional investments in Canadian and US gas transportation facilities. Progress on the development and construction of our commercially secured growth projects is discussed in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects.*

GAS DISTRIBUTION AND STORAGE

Gas Distribution and Storage consists of our natural gas utility operations, the core of which is Enbridge Gas Inc. (Enbridge Gas), which serves residential, commercial and industrial customers throughout Ontario. This business segment also includes natural gas distribution activities in Québec and previously included an investment in Noverco Inc. (Noverco) which was sold on December 30, 2021. Please refer to Part II. *Item 8. Financial Statements and Supplementary data - Note 8 - Acquisitions and Dispositions* for further details.



ENBRIDGE GAS

Enbridge Gas is a rate-regulated natural gas distribution utility with storage and transmission services that has been in operation for 173 years. Enbridge Gas serves approximately 75% of Ontario residents via approximately 3.8 million residential, commercial and industrial meter connections.

There are three principal interrelated aspects of the natural gas distribution business in which Enbridge Gas is directly involved: Distribution, Transportation and Storage.

In 2021, Enbridge Gas implemented a voluntary RNG pilot program, whereby customers can voluntarily contribute towards the incremental cost of low carbon RNG to displace regular natural gas, and a pilot project which allows regular natural gas to be blended with H2, in an isolated portion of the existing distribution system, in an effort to gain insight into the use of H2 as a method for decarbonizing natural gas for the purpose of reducing GHG emissions.

Distribution
Enbridge Gas' principal source of revenue arises from distribution of natural gas to customers. The services provided to residential, small commercial and industrial heating customers are primarily on a general service basis, without a specific fixed term or fixed price contract. The services provided to larger commercial and industrial customers are usually on an annual contract basis under firm or interruptible service contracts. Under a firm contract, Enbridge Gas is obligated to deliver natural gas to the customer up to a maximum daily volume. The service provided under an interruptible contract is similar to that of a firm contract, except that it allows for service interruption at Enbridge Gas' option primarily to meet seasonal or peak demands. The Ontario Energy Board (OEB) approves rates for both contract and general services. The distribution system consists of approximately 147,000-kilometers (91,342-miles) of pipelines that carry natural gas from the point of local supply to customers.

Customers have a choice with respect to natural gas supply. Customers may purchase and deliver their own natural gas to points upstream of the distribution system or directly into Enbridge Gas' distribution system, or, alternatively, they may choose a system supply option, whereby customers purchase natural gas from Enbridge Gas' supply portfolio. To acquire the necessary volume of natural gas to serve its customers, Enbridge Gas maintains a diversified natural gas supply portfolio, acquiring supplies on a delivered basis in Ontario, as well as acquiring supply from multiple supply basins across North America.

Transportation
Enbridge Gas contracts for firm transportation service, primarily with TransCanada Pipelines Limited (TransCanada), Vector and NEXUS, to meet its annual natural gas supply requirements. The transportation service contracts are not directly linked with any particular source of natural gas supply. Separating transportation contracts from natural gas supply allows Enbridge Gas flexibility in obtaining its own natural gas supply and accommodating the requests of its direct purchase customers for assignment of TransCanada capacity. Enbridge Gas forecasts the natural gas supply needs of its customers, including the associated transportation and storage requirements.

In addition to contracting for transportation service, Enbridge Gas offers firm and interruptible transportation services on its own Dawn-Parkway pipeline system. Enbridge Gas' transmission system consists of approximately 5,500-kilometers (3,418-miles) of high-pressure pipeline and five mainline compressor stations and has an effective peak daily demand capacity of 7.6 bcf/d. Enbridge Gas' transmission system also links an extensive network of underground storage pools at the Tecumseh Gas Storage facility and Dawn Hub (collectively, Dawn) to major Canadian and US markets, and forms an important link in moving natural gas from western Canada and US supply basins to central Canadian and northeastern US markets.

As the supply of natural gas in areas close to Ontario continues to grow, there is an increased demand to access these diverse supplies at Dawn and transport them along the Dawn-Parkway pipeline system to markets in Ontario, eastern Canada and the northeastern US. Enbridge Gas delivered 1,943 bcf of gas through its distribution and transmission system in 2021. A substantial amount of Enbridge Gas' transportation revenue is generated by fixed annual demand charges, with the average length of a long-term contract being approximately 15 years and the longest remaining contract term being 19 years.

Storage
Enbridge Gas' business is highly seasonal as daily market demand for natural gas fluctuates with changes in weather, with peak consumption occurring in the winter months. Utilization of storage facilities permits Enbridge Gas to take delivery of natural gas on favorable terms during off-peak summer periods for subsequent use during the winter heating season. This practice permits Enbridge Gas to minimize the annual cost of transportation of natural gas from its supply basins, assists in reducing its overall cost of natural gas supply and adds a measure of security in the event of any short-term interruption of transportation of natural gas to Enbridge Gas' franchise areas.

Enbridge Gas' storage facility at Dawn is located in southwestern Ontario, and has a total working capacity of approximately 281 bcf in 34 underground facilities located in depleted gas fields. Dawn is the largest integrated underground storage facility in Canada and one of the largest in North America. Approximately 180 bcf of the total working capacity is available to Enbridge Gas for utility operations. Enbridge Gas also has storage contracts with third parties for 21 bcf of storage capacity.

Dawn offers customers an important link in the movement of natural gas from western Canadian and US supply basins to markets in central Canada and the northeast US. Dawn's configuration provides flexibility for injections, withdrawals and cycling. Customers can purchase both firm and interruptible storage services at Dawn. Dawn offers customers a wide range of market choices and options with easy access to upstream and downstream markets. During 2021, Dawn provided services such as storage, balancing, gas loans, transport, exchange and peaking services to over 200 counterparties.

A substantial amount of Enbridge Gas' storage revenue is generated by fixed annual demand charges, with the average length of a long-term contract being approximately four years and the longest remaining contract term being 15 years.

NOVERCO

Noverco is a holding company that wholly-owns Énergir, LP (Énergir), formerly known as Gaz Metro Limited Partnership, a natural gas distribution company operating in Québec, with interests in subsidiary companies operating gas transmission, gas distribution and power distribution businesses in Québec and Vermont. Énergir serves approximately 525,000 residential and industrial customers and is regulated by the Québec Régie de l'énergie and the Vermont Public Utility Commission. Noverco also holds an investment in our common shares. We owned an equity interest in Noverco through ownership of 38.9% of its common shares and an investment in its preferred shares. On December 30, 2021, we sold our 38.9% non-operating minority ownership interest in Noverco to Trencap L.P. for $1.1 billion in cash.

GAZIFÈRE

We wholly own Gazifère, a natural gas distribution company that serves approximately 44,000 customers in western Québec, a market not served by Énergir. Gazifère is regulated by the Québec Régie de l'énergie.

COMPETITION

Enbridge Gas' distribution system is regulated by the OEB and is subject to regulation in a number of areas, including rates. Enbridge Gas is not generally subject to third-party distribution competition within its franchise areas.

Enbridge Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include weather, price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation including the federal carbon pricing law, governmental regulations, the ability to convert to alternative fuels and other factors.

SUPPLY AND DEMAND

We expect that demand for natural gas in North America will continue to see steady annual growth over the long term with continued growth in peak day demands, however there are risks to the natural gas market that may challenge its growth prospects. Evolving customer preferences for lower-carbon fuels and more efficient technologies, combined with increasing opposition to natural gas development in North America, may reduce the markets' ability to efficiently deploy capital to connect supply and demand. We monitor these factors closely to be able to develop our business strategy to align with shifts in customer preferences.

We expect demand for natural gas connections in Ontario to maintain its recent growth profile due to continued population growth and with competitively priced natural gas expected to continue to provide a significant price advantage relative to alternate energy options, even with increasing carbon charges. Specific interest in natural gas connections is expected to come from communities that are not currently serviced by natural gas in Ontario.

Enbridge Gas continues to focus on promoting conservation and energy efficiency by undertaking activities focused on reducing natural gas consumption through various demand side management programs offered across all markets and sourcing supply with a smaller carbon footprint. In addition to our existing RNG programs, we are also expanding our efforts in other low-carbon supply sourcing such as Responsibly Sourced Natural Gas, and Hydrogen Gas.

The storage and transportation marketplace continues to respond to changing natural gas supply dynamics, including a recovering supply environment which was negatively impacted by the global pandemic.

Over the past decade, growth in the North American gas supply landscape, driven mainly by the development of unconventional gas resources in the Montney, Permian, Marcellus and Utica supply basins, has resulted in lower annual commodity prices and narrower seasonal price spreads. Unregulated storage values are primarily determined by the difference in value between winter and summer natural gas prices. Storage values have been relatively stable as North American natural gas supply and demand slowly returned to a more balanced position.

RENEWABLE POWER GENERATION

Renewable Power Generation consists primarily of investments in wind and solar assets, as well as geothermal, waste heat recovery, and transmission assets. In North America, assets are primarily located in the provinces of Alberta, Saskatchewan, Ontario, and Québec and in the states of Colorado, Texas, Indiana and West Virginia. We are also developing several solar self-power projects along our oil and gas rights-of-way in North America. In Europe, we hold equity interests in operating offshore wind facilities in the coastal waters of the United Kingdom and Germany, as well as interests in several offshore wind projects under construction and active development in France. Further, we are pursuing new European offshore wind development opportunities through Maple Power Ltd., a joint venture in which we hold a 50% interest.

Combined Renewable Power Generation investments represent approximately 2,178 MW of net generation capacity. Of this amount, approximately:

- 1,392 MW is generated by North American wind facilities;
- 255 MW is generated by European offshore wind facilities;
- 309 MW will be generated by the Saint-Nazaire, Fécamp and Calvados Offshore Wind projects, all of which are currently under construction;
- 6 MW will be generated by the Provence Grand Large Floating Offshore Wind project, which secured funding in 2021 and continues to prepare onshore construction; and
- 93 MW is generated by North American solar facilities in operation, with an additional 97 MW in projects in early construction and under-construction.

The vast majority of the power produced from these facilities is sold under long-term Power Purchase Agreements (PPAs).

Renewable Power Generation also includes our 25% interest in the East-West Tie, a 450-MW transmission line in northwestern Ontario, which is currently under construction and is expected to reach commercial operation in the first half of 2022.

JOINT VENTURES / EQUITY INVESTMENTS

The investments in the Canadian wind and solar assets (excluding self-power) and two of the US renewable assets are held within a joint venture in which we maintain a 51% interest and which we manage and operate.

We also own interests in European offshore wind facilities through the following joint ventures:

- a 24.9% interest in Rampion Offshore Wind, located in the United Kingdom;
- a 25.4% interest in Hohe See Offshore and its subsequent expansion, located in Germany;
- a 25.5% interest in the Saint-Nazaire Offshore Wind project, under construction in France;
- a 25% interest in the Provence Grande Large Floating Offshore Wind project, in pre-construction in France;
- a 17.9% interest in the Fécamp Offshore Wind project, under construction in France; and
- a 21.7% interest in the Calvados Offshore Wind project, in pre-construction in France.

The ownership interest percentages in the Saint-Nazaire, Fécamp, and Calvados Offshore Wind projects reflect the sale of 49% of an entity that holds our 50% interest in Éolien Maritime France SAS (EMF) to the Canada Pension Plan Investment Board (CPP Investments) which closed in the first half of 2021.

COMPETITION

Renewable Power Generation operates in the North American and European power markets, which are subject to competition and supply and demand fundamentals for power in the jurisdictions in which they operate. The majority of revenue is generated pursuant to long-term PPAs (or has been substantially hedged). As such, the financial performance is not significantly impacted by fluctuating power prices arising from supply/demand imbalances or the actions of competing facilities during the term of the applicable contracts. However, the renewable energy sector includes large utilities, small independent power producers and private equity investors, which are expected to aggressively compete for new project development opportunities and for the right to supply customers when contracts expire.

To grow in an environment of heightened competition, we strategically seek opportunities to collaborate with well-established renewable power developers and financial partners and to target regions with commercial constructs consistent with our low risk business model. In addition, we bring to bear the expertise of completing and delivering large scale infrastructure projects.

SUPPLY AND DEMAND
The renewable power generation network in North America and Europe is expected to grow significantly over the next 20 years due to the replacement of older fossil fuel-based sources of electricity generation in support of announced governmental carbon emissions reduction targets. Any additional governmental actions toward reducing emissions and/or increasing electrification will further accelerate renewable electricity demand growth and electrification across all sectors.

On the demand side, North American economic growth over the longer term and the continued electrification and transition to low-carbon strategies within the residential, transportation and industrial sectors are expected to drive growing electricity demand. Furthermore, voluntary GHG emissions targets are becoming increasingly expected by stakeholders, which is driving significant demand from corporate electricity end-users for clean electricity and environmental attributes. However, continued efficiency gains are expected to make the economy less energy-intensive and temper overall demand growth.

On the supply side in North America, legislation is accelerating the retirement of aging coal-fired generation, while generation from conventional nuclear power is also forecast to decline. As a result, North America requires significant new generation capacity from preferred technologies. Gas-fired and renewable energy facilities, including solar and wind (which make up the bulk of our renewable power assets), are generally the preferred sources to replace coal-fired generation due to their low carbon intensities.

The falling capital and operating costs of wind and solar, combined with their improving capacity factors, are expected to continue the ongoing trend of making renewable energy more competitive and support investment over the long-term, regardless of available government incentives. Generation from renewable sources is expected to double over the next two decades in North America. Aside from the construction of new wind and solar facilities, other growth opportunities include repowering projects to increase output from, and extending the project-life of, our existing facilities.

In Europe, the renewable energy outlook is robust. Demand for electricity is expected to gradually increase over the next two decades, driven by electrification of transportation and buildings. Energy efficiency gains will temper, but not eliminate, demand growth. Renewable power will play a significant role in the United Kingdom's ability to meet their aggressive low-carbon and renewable energy targets, particularly offshore wind.

On the supply side, the International Energy Agency expects coal to fall by more than 90% from 2020 levels, while nuclear falls by one-third, by 2040. Over the same period, it anticipates power generation from renewable sources will more than double, including installed (onshore and offshore) wind more than doubling and photovoltaics solar power nearly tripling. We, through our European joint ventures, continue to invest in offshore wind projects in the United Kingdom, France and Germany, and to explore opportunities, to meet the growing demand.

ENERGY SERVICES

The Energy Services businesses in Canada and the US provide physical commodity marketing and logistical services to North American refiners, producers, and other customers.

Energy Services is primarily focused on servicing customers across the value chain and capturing value from quality, time, and location price differentials when opportunities arise. To execute these strategies, Energy Services transports and stores on both Enbridge-owned and third party assets using a combination of contracted long-term and short-term pipeline, storage, railcar, and truck capacity agreements.

COMPETITION
Energy Services' earnings are primarily generated from arbitrage opportunities which, by their nature, can be replicated by competitors. An increase in market participants entering into similar arbitrage strategies could have an impact on our earnings. Efforts to mitigate competition risk include diversification of the marketing business by transacting at the majority of major hubs in North America and establishing long-term relationships with clients and pipelines.

ELIMINATIONS AND OTHER

Eliminations and Other includes operating and administrative costs that are not allocated to business segments and the impact of foreign exchange hedge settlements. Eliminations and Other also includes new business development activities and corporate investments.

REGULATION

GOVERNMENT REGULATION
Pipeline Regulation
Our Liquids Pipelines and Gas Transmission and Midstream assets are subject to numerous operational rules and regulations mandated by governments or applicable regulatory authorities, breaches of which could result in fines, penalties, operating restrictions and an overall increase in operating and compliance costs.

In the US, our interstate pipeline operations are subject to pipeline safety laws and regulations administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA), an agency within the United States Department of Transportation. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. These laws and regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines and to operate them at permissible pressures.

PHMSA continues to review existing regulations and establish new regulations to support safety standards that are designed to improve and expand operations integrity management processes. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will impose additional costs on new pipeline projects as well as on existing operations. In this climate of increasingly stringent regulation, pipeline failure or failures to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by PHMSA, which would reduce available capacity on our pipelines. Should any of these risks materialize, it may have an adverse effect on our operations, capital expenditures, earnings, cash flows, financial condition and competitive advantage.

Our ability to establish transportation and storage rates on our US interstate natural gas facilities are subject to regulation by the FERC, whose rulings and policies could have an adverse impact on the ability of such pipeline and storage assets to recover their respective full cost of operating, including a reasonable rate of return. Regulatory or administrative actions by FERC such as rate proceedings, applications to certify construction of new facilities, and depreciation and amortization policies can affect our business, including decreasing tariff rates and revenues and increasing our costs of doing business.

In Canada, our pipeline operations are subject to pipeline safety regulations administered by the CER or provincial regulators. Applicable legislation and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our pipelines. Among other obligations, this regulatory framework imposes requirements to monitor and maintain the integrity of our pipelines.

As in the US, several legislative changes addressing pipeline safety in Canada have recently been enacted. The changes evidence an increased focus on the implementation of management systems to address key areas such as emergency management, integrity management, safety, security and environmental protection. Other legislative changes have created authority for the CER to impose administrative monetary penalties for non-compliance with the regulatory regime it administers, as well as to impose financial requirements for future abandonment and major pipeline releases.

A key component of pipeline safety and reliability is the approach to integrity management that uses reliability targets and safety case assessments. A long history of extensive inline inspection has provided detailed knowledge of the assets in our pipeline systems. Our pipelines are assessed and maintained, in a proactive manner, such that the probability of a release is sufficiently low and that our reliability targets are met. Furthermore, the integrity management program has an independent step to check the results of our integrity assessments to validate the effectiveness of the program and to ensure that the operational risk remains as low as reasonably practicable throughout the integrity inspection and assessment cycle. As inspection technology, pipeline materials and construction practices improve with time, and new data on threats and pipeline condition are gathered, our methods of maintaining fitness for service evolves, with a strong focus on continual improvement in every aspect of integrity management.

Our pipelines also face economic regulation risk. Broadly defined, economic regulation risk is the risk that governments or regulatory agencies change or reject proposed or existing commercial arrangements or policies, including permits and regulatory approvals for both new and existing projects or agreements, upon which future and current operations are dependent. Our Mainline System and other liquids pipelines and gas transmission facilities are subject to the actions of various regulators, including the CER and the FERC, with respect to the tariffs and tolls of those pipelines. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable permits and tariff structure or changes in interpretations of existing regulations by courts or regulators, could have an adverse effect on our revenues and earnings.

Gas Distribution and Storage

Our gas distribution and storage utility operations are regulated by the OEB and the Québec Régie de l'énergie, among others. To the extent that the regulators' future actions are different from current expectations, the timing and amount of recovery or refund of amounts recorded on the Consolidated Statements of Financial Position, or amounts that would have been recorded on the Consolidated Statements of Financial Position in the absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

Enbridge Gas' distribution rates, commencing in 2019, are set under a five-year incentive regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% productivity factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas to share equally with customers any earnings in excess of 150 basis points over the annual OEB approved return on equity (ROE).

We retain dedicated professional staff and maintain strong relationships with customers, intervenors and regulators. This strong regulatory relationship continued in 2021 following OEB Decisions and Orders approving Phase 2 of Enbridge Gas' application for 2021 rates and Phase 1 of Enbridge Gas' application for 2022 rates. The Phase 2 Decision and Order approved the funding of $124 million in 2021 discrete incremental capital investment requested through the incremental capital module, while the Phase 1 Decision and Order approved 2022 base rate escalation under the price cap mechanism.

Enbridge Gas continues to develop opportunities to support a low-carbon future in Ontario. In 2021, we received OEB approval of an Integrated Resource Planning (IRP) framework. The framework requires Enbridge Gas to consider facility and non-pipe demand and/or supply side alternatives (IRP alternatives) to address systems needs of its regulated operations, where certain parameters have been met. The framework will also allow Enbridge Gas to pursue an IRP alternative (or combination of IRP and facility alternative) where it is found to be 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.

Renewable Power Generation

Renewable Power Generation is subject to numerous operational rules and regulations mandated by governments or applicable regulatory authorities, breaches of which could result in fines, penalties, operating restrictions and an overall increase in operating and compliance costs.

The North American Reliability Council (NERC) is an international regulatory authority responsible for establishing and enforcing Reliability Standards to reduce risks to the reliability and security of the grid in Canada, the United States, and Mexico. It is subject to oversight from the FERC and provincial governments in Canada. The FERC has authority over many markets in the US and is tasked with ensuring safe, reliable, and secure interstate transmission of electricity, natural gas, and oil. This includes establishing reliability standards and determining certain pricing aspects of transmission development and access, among others. NERC and FERC standards and pricing decisions are also updated from time to time and could impact our operations, capital expenditures, earnings, and cash flows, though some of these impacts could be positive for our business.

At the US federal level, our Renewable Power Generation assets are subject to legislation overseen by the US Fish and Wildlife Service, which is aimed at reducing the impact of development and human activity on wildlife, along with other federal environmental permitting legislation. These federal environmental laws are subject to change from time to time which could require Enbridge to obtain new permits, update practices, or amend operations and operating expenditures.

In Canada, the Federal Government does not generally regulate the electricity sector though it has imposed a federal carbon price on other sectors via its output-based pricing system (OBPS) and may seek to impose emissions standards on the electricity sector in the future.

Our Renewable Power Generation assets in France and Germany each have federal policies in place and are subject to directives and regulations established and enforced by the European Union (EU). These include the Renewable Energy Directive (RED II most recently passed set targets through 2030), the European Green Deal, and ongoing work on financing mechanisms and transmission directives and programs. The EU is also responsible for establishing environmental protection rules and permitting standards. All of these are subject to change from time to time, which could impact our operations and related expenditures; however the EU’s general direction is to facilitate increased renewable power integration to its grid.

The United Kingdom (UK) government is responsible for establishing renewable energy and carbon pricing policies for the entire UK, as well as long-term electricity sector planning and procurement mechanisms and structure for auctions that are administered at the national level, e.g., England, Scotland, within the UK. Each country within the UK is also responsible for establishing its own environmental and permitting regulations. This process is still ongoing following Brexit and in some cases continues to result in more volatile merchant power prices; however, expanded interconnectors to Europe and policies aimed at increasing domestic renewable capacity are in progress.

Energy Services

Energy Services is regulated by government authorities in the areas of commodity trading, import and export compliance and the transportation of commodities. Non-compliance with governing rules and regulations could result in fines, penalties and operating restrictions. These consequences would have an adverse effect on operations, earnings, cash flows, financial condition and competitive advantage. Energy Services retains dedicated professional staff and has a robust regulatory compliance program to mitigate these potential risks associated with the business.

In the US, commodity marketing is regulated by the Commodity Futures Trading Commission, the SEC, the Federal Trade Commission, the various commodity exchanges, the US Department of Justice and state regulators. The interstate marketing of electricity and natural gas is also regulated by the FERC. The provincial and territorial securities regulators similarly regulate commodity marketing within Canada and are members of the Canadian Securities Administrators. In addition, the Regional Transmission Organizations and Independent System Operators in both US and Canada regulate commodity marketing. These various regulators enforce, among other things, the prohibition of market manipulation, fraud and disruptive trading. To mitigate risks related to commodity trading, Energy Services has implemented a robust regulatory compliance program that includes targeted training.

The export of natural gas out of Alberta is regulated by the Alberta Energy Regulator. The import and export of commodities between Canada and the US is subject to regulation by the CER and the US Department of Energy, as well as customs authorities. In particular, import and export permits are required, with associated regular reporting requirements. Breaches of such import and export rules could result in an inability to perform day to day operations, and therein negatively impact the earnings of the business.

The transportation of crude oil and natural gas liquids by railcar or truck is regulated by the US Department of Transportation, Transport Canada and provincial regulation. Each jurisdiction requires compliance with security, safety, emergency management, and environmental laws and regulations related to ground transportation of commodities. Risks associated with transportation of crude or natural gas liquids include unplanned releases. In the event of a release, remediation of the affected area would be required. Energy Services engages third parties, such as the Emergency Response Assistance Canada, Chemical Transportation Emergency Center and Canadian Transport Emergency Center to assist in such remediation.

ENVIRONMENTAL REGULATION

Pipeline Regulation

Our Liquids Pipelines and Gas Transmission and Midstream assets are subject to numerous federal, state and provincial environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, water discharge and waste. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits and other approvals.

In particular, in the US, compliance with major Clean Air Act regulatory programs is likely to cause us to incur significant capital expenditures to obtain permits, evaluate off-site impacts of our operations, install pollution control equipment, and otherwise assure compliance. Some states in which we operate are implementing new emissions limits to comply with 2008 ozone standards regulated under the National Ambient Air Quality Standards. In 2015, the ozone standards were lowered even further from 75 parts per billion (ppb) to 70 ppb, which may require states to implement additional emissions regulations. The precise nature of these compliance obligations at each of our facilities has not been finally determined and may depend in part on future regulatory changes. In addition, compliance with new and emerging environmental regulatory programs may significantly increase our operating costs compared to historical levels.

In the US, climate change action is evolving at federal, state and regional levels. The Supreme Court decision in Massachusetts v. Environmental Protection Agency in 2007 established that GHG emissions were pollutants subject to regulation under the Clean Air Act. Pursuant to federal regulations, we are currently subject to an obligation to report our GHG emissions at our largest emitting facilities but are not generally subject to limits on emissions of GHGs. The new US presidential administration has also announced that policies designed to combat climate change and reduce GHG emissions will be a key legislative and regulatory priority, and thus stricter emissions limits and air quality enforcement actions are likely. In addition, a number of states have joined regional GHG initiatives, and a number are developing their own programs that would mandate reductions in GHG emissions. Public interest groups and regulatory agencies are increasingly focusing on the emission of methane associated with natural gas development and transmission as a source of GHG emissions. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business are highly uncertain.

For its part, Canada has reaffirmed its strong preference for a harmonized approach on climate action with that of the US. In 2019, the Government of Canada implemented a federal system of carbon pricing. The pricing applies to provinces and territories that do not have a carbon pricing system in place that meets the federal benchmark. The Canadian Net-Zero Emissions Accountability Act, which received royal assent in April 2021, requires national targets for the reduction of GHG emissions in Canada be set, with the objective of attaining net-zero emissions by 2050. As of April 2021, the federal carbon price was raised to $40 per tonne. This will increase to $65 per tonne in 2023 and rise to $170 per tonne of carbon dioxide equivalent in 2030.

Due to the speculative outlook regarding any US federal and state policies, we cannot estimate the potential effect of proposed GHG policies on our future consolidated results of operations, financial position or cash flows. However, such legislation or regulation could materially increase our operating costs, require material capital expenditures or create additional permitting, which could delay proposed construction projects.

Gas Distribution and Storage

Our Gas Distribution and Storage operations, facilities and workers are subject to municipal, provincial and federal legislation which regulate the protection of the environment and the health and safety of workers. Environmental legislation primarily includes regulation of spills and emissions to air, land and water; hazardous waste management; the assessment and management of contaminated sites; protection of environmentally sensitive areas, and species at risk and their habitat; and the reporting and reduction of GHG emissions.

Gas distribution system operation, as with any industrial operation, has the potential risk of abnormal or emergency conditions, or other unplanned events that could result in releases or emissions exceeding permitted levels. These events could result in injuries to workers or the public, adverse impacts to the environment, property damage and/or regulatory infractions including orders and fines. We could also incur future liability for soil and groundwater contamination associated with past and present site activities.

In addition to gas distribution, we also operate storage facilities and a small volume of oil and brine production in southwestern Ontario. Environmental risk associated with these facilities has the potential for unplanned releases. In the event of a release, remediation of the affected area would be required. There would also be potential for fines, orders or charges under environmental legislation, and potential third-party liability claims by any affected landowners.

The gas distribution system and our other operations must maintain environmental approvals and permits from regulators to operate. As a result, these assets and facilities are subject to periodic inspections and/or audits. Annual reports, such as Annual Written Summary Reports for Environmental Compliance Approvals (ECAs) are submitted to the Ontario Ministry of the Environment, Conservation and Parks (MECP) and other regulators to demonstrate we are in good standing with our environmental requirements. Failure to maintain regulatory compliance could result in operational interruptions, fines, and/or orders for additional pollution control technology or environmental mitigation. As environmental requirements and regulations become more stringent, the cost to maintain compliance and the time required to obtain approvals is expected to increase.

As in previous years, in 2021, we reported operational GHG emissions, including emissions from stationary combustion, flaring, venting and fugitive sources to Environment and Climate Change Canada (ECCC), the Ontario MECP, and a number of voluntary reporting programs. In accordance with the provincial GHG regulations, stationary combustion and flaring emissions related to storage and transmission operations were verified in detail by a third-party accredited verifier with no material discrepancies found.

Enbridge Gas utilizes emissions data management processes and systems to help with the data capture and mandatory and voluntary reporting needs. Quantification methodologies and emission factors will continually be updated in our systems as required. Enbridge Gas continues to work with industry associations to refine quantification methodologies and emissions factors, as well as best management practices to minimize emissions.

In October 2018, the federal government confirmed that Ontario is subject to the federal government's carbon pricing program, otherwise known as the Federal Carbon Pricing Backstop Program. This program consists of two components: a carbon charge levied on fossil fuels, including natural gas, and an OBPS.

The federal carbon charge took effect on April 1, 2019 at a rate of 3.91 cents/cubic meter (m3) of natural gas and is applicable to the majority of customers. Enbridge Gas is registered as a natural gas distributor with the Canada Revenue Agency and remits the federal carbon charge on a monthly basis. The charge increases annually on April 1 of each year by 1.96 cents/m3, rising up to 9.79 cents/m3 in 2022. In December 2020, the federal government announced plans to increase the federal carbon price by $15 per tonne each year in 2023, rising to $170 per tonne of carbon dioxide equivalent in 2030. Enbridge Gas estimates that this will equate to a federal carbon charge on natural gas of approximately 33.31 cents/m3 in 2030. Enbridge Gas applies for approval from the OEB on an annual basis to pass through federal carbon charges.

The OBPS component came into effect on January 1, 2019. Under OBPS, a registered facility has a compliance obligation for the portion of their emissions that exceeds their annual facility emissions limit, which is calculated based on the sector specific output-based standard and annual production. Enbridge Gas is registered with ECCC as an emitter in the OBPS program and has an annual compliance obligation associated with the combustion and flaring emissions associated with its natural gas pipeline transmission system. As a registered facility under OBPS, Enbridge Gas submitted an annual report along with the required verification report from an accredited third-party verifier who found no material misstatements. Enbridge Gas is required to remit payment for facility emissions that exceed its annual facility emissions limit. Due to COVID-19, ECCC delayed the payment deadline for the 2019 compliance obligation from December 15, 2020 to April 15, 2021. Enbridge Gas made payment for the 2019 compliance obligation in March 2021 and for the 2020 compliance obligation in November 2021.

In September 2020, Ontario and the federal government announced that the federal government has accepted that Ontario's Emission Performance Standards (EPS) will replace the federal OBPS for industrial facilities. In March 2021, the federal government announced that the federal OBPS will stand down in Ontario at the end of 2021 and Ontario will transition to the EPS effective January 1, 2022. In September 2021, the Greenhouse Gas Pollution Pricing Act was amended to remove Ontario as a covered province effective January 1, 2022. Beginning January 1, 2022, Enbridge Gas will have a compliance obligation under the EPS program for its facility-related emissions, as well as the federal carbon charge for its customer-related emissions.

HUMAN CAPITAL RESOURCES

WORKFORCE SIZE AND COMPOSITION

As at December 31, 2021, we had approximately 10,900 regular employees, including approximately 1,500 unionized employees across our North American operations. This total rises to nearly 13,000 if temporary employees and contractors are included. We have a strong preference for direct employment relationships but where we have collectively bargained-for employees, we have mature working relationships with our labor unions and the parties have traditionally committed themselves to the achievement of renewal agreements without a work stoppage.

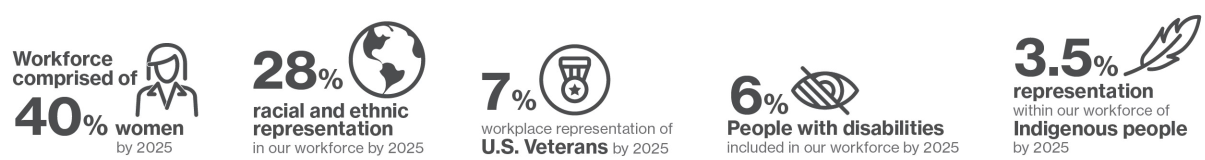
SAFETY

We believe all injuries, incidents and occupational illnesses are preventable. Our overall focus on employee and contractor safety, including through the COVID-19 pandemic, continues to result in strong performance compared against industry benchmarks and we are actively engaged in continuous improvement exercises as we pursue our goal of zero incidents.

DIVERSITY AND INCLUSION

To ensure our workforce is reflective of the communities where we operate, we have pursued efforts to increase the representation of women, underrepresented ethnic and racial groups, people with disabilities and veterans. In 2021 we set diversity representation goals and shared these goals with employees and external stakeholders. Consistent with our culture, we remain committed to open, two-way dialogue related to our goals, enhancing transparency and accountability for all stakeholders.

Diversity Representation Goals



In 2021, we added Inclusion to our core values of Safety, Integrity and Respect to demonstrate this commitment. We are building an organization where people feel safe and welcome and have the opportunity to thrive and grow based on merit. As part of our evolving ESG strategy, we created a tighter link between our success and the workforce related ESG measures – including safety, emissions reduction efforts and diversity & inclusion – that enable it. As a result, beginning in 2021, key metrics in these areas are embedded in our scorecards and directly impact compensation.

PRODUCTIVITY AND DEVELOPMENT

We continually invest in our people's personal and professional development because we recognize their success is our success. Every year, employees are provided access to a range of development and re-skilling opportunities through a variety of channels, including: extensive catalog of self-directed learning (10,000+ external courses plus proprietary Enbridge University courses); on-the-job learning opportunities and rotational assignments; curated leadership development programs; educational reimbursement; and developmental relationships with mentors through our formal mentor-protégé matching program.

EXECUTIVE OFFICERS

The following table sets forth information regarding our executive officers as at February 11, 2022:

Name	Age	Position
Al Monaco	62	President & Chief Executive Officer
Vern D. Yu	55	Executive Vice President & Chief Financial Officer
Colin K. Gruending	52	Executive Vice President & President, Liquids Pipelines
Cynthia L. Hansen	57	Executive Vice President & President, Gas Distribution and Storage
Byron C. Neiles	56	Executive Vice President, Corporate Services
Robert R. Rooney	65	Executive Vice President & Chief Legal Officer
William T. Yardley	57	Executive Vice President & President, Gas Transmission and Midstream
Matthew Akman	54	Senior Vice President, Strategy, Power & New Energy Technologies
Allen C. Capps	51	Senior Vice President, Corporate Development & Energy Services

Al Monaco was appointed President and Chief Executive Officer on October 1, 2012. Mr. Monaco is also a member of the Enbridge Board of Directors.

Vern D. Yu was appointed Executive Vice President and Chief Financial Officer on October 1, 2021, with oversight for all of Enbridge's financial affairs including investor relations, financial reporting, financial planning, treasury, tax, insurance, risk and audit management functions as well as implementation of our ERP transformation system. Previously, Mr. Yu served as Executive Vice President and President, Liquids Pipelines and prior to that served as President and Chief Operating Officer for Liquids Pipelines and as Executive Vice President and Chief Development Officer. Effective March 1, 2022, Mr. Yu will be appointed as Executive Vice President, Corporate Development and Chief Financial Officer.

Colin K. Gruending was appointed Executive Vice President and President, Liquids Pipelines on October 1, 2021. Mr. Gruending is responsible for the overall leadership and operations of Enbridge's Liquids Pipelines business. Previously, he served as our Executive Vice President and Chief Financial Officer and as Senior Vice President, Corporate Development and Investment Review.

Cynthia L. Hansen was appointed Executive Vice President and President, Gas Distribution and Storage, on June 1, 2019. Ms. Hansen is responsible for the overall leadership and operations of Enbridge Gas, following the amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas), as well as Gazifère. Previously, our Executive Vice President, Utilities and Power Operations, Ms. Hansen is also the Executive Sponsor for Asset and Work Management Transformation across Enbridge, working with other business unit leaders. Effective March 1, 2022, Ms. Hansen will be appointed as the Executive Vice President and President of Gas Transmission and Midstream and Michele E. Harradence will be appointed as Senior Vice President and President, Gas Distribution and Storage. Ms. Harradence most recently held the role of Senior Vice President and Chief Operations Officer, Gas Transmission and Midstream.

Byron C. Neiles was appointed Executive Vice President, Corporate Services on May 2, 2016. Mr. Neiles has oversight of our information technology, human resources, real estate, supply chain management, safety, environment, land & right-of-way, and public affairs, communications and sustainability functions.

Robert R. Rooney was appointed Executive Vice President and Chief Legal Officer on February 1, 2017. Mr. Rooney leads our legal, ethics and compliance, security and aviation teams across the organization.

William T. Yardley was named Executive Vice President and President, Gas Transmission and Midstream on February 27, 2017. Mr. Yardley was previously President of Spectra Energy Corp's (Spectra Energy) US Transmission and Storage business, leading the business development, project execution, operations and environment, health and safety efforts associated with Spectra Energy’s US portfolio of assets. Mr. Yardley will retire on May 31, 2022.

Matthew Akman was appointed Senior Vice President, Strategy & Power on June 1, 2019 and he is currently Senior Vice President, Strategy, Power & New Energy Technologies. He is responsible for the corporate strategic planning process and all renewable power operations and development globally, as well as for our New Energy Technologies team formed in 2021. Mr. Akman joined Enbridge in early 2016 as our head of Corporate Strategy and also previously held responsibilities for Corporate Development and Investor Relations.

Allen C. Capps was appointed Senior Vice President, Corporate Development and Energy Services in September 2020. He is responsible for capital allocation, investment review, corporate business development including Mergers & Acquisitions and Energy Services. Prior to assuming his current role, Mr. Capps served as Senior Vice President, Corporate Development and Investment Review. Mr. Capps has also served as Senior Vice President and Chief Accounting Officer and before that Vice President and Controller of Spectra Energy. Effective March 1, 2022, Mr. Capps will be appointed as the Senior Vice President and Chief Commercial Officer of Gas Transmission & Midstream.

ADDITIONAL INFORMATION

Additional information about us is available on our website at www.enbridge.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. The aforementioned information is made available in accordance with legal requirements and is not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K. We make available free of charge, through our website, annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as well as proxy statements, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Reports, proxy statements and other information filed with the SEC may also be obtained through the SEC’s website (www.sec.gov).

ENBRIDGE GAS INC.
Additional information about Enbridge Gas can be found in its annual information form, financial statements and management's discussion and analysis (MD&A) for the year ended December 31, 2021, which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to Enbridge Gas and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ENBRIDGE PIPELINES INC.
Additional information about Enbridge Pipelines Inc. (EPI) can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2021, which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to EPI and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

WESTCOAST ENERGY INC.
Additional information about Westcoast can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2021, which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to Westcoast and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ITEM 1A. RISK FACTORS

The following risk factors could materially and adversely affect our business, operations, financial results, market price or value of our securities. This list is not exhaustive, and we place no priority or likelihood based on order of presentation or grouping under sub-captions.

RISKS RELATED TO CLIMATE CHANGE

Climate change risks could adversely affect our business, operations and financial results, and these effects could be material.
Climate change presents both physical and transition risks to our organization. A summary of these risks is discussed below. Given the interconnected nature of climate impacts, however, we also discuss these risks within the context of other risks impacting Enbridge throughout Item 1A - *Risk Factors*. Climate change and its associated impacts may increase our exposure to, and magnitude of, the other risks identified in Item 1A - *Risk Factors*. Our business, financial condition, results of operations, cash flows, reputation, access to and cost of capital or insurance, business plans or strategy may all be adversely impacted as a result of climate change and its associated impacts.

PHYSICAL RISKS
Physical risks relate to the physical impacts of climate change. These risks could damage our assets or affect the safety and reliability of our operations.

Climate change could result in extreme variability in weather patterns, such as increased frequency and severity of extreme weather events, heavy snowfall, heavy rainfall, floods, landslides, fires, hurricanes, tropical storms, ice storms, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Our assets and operations are exposed to potential interruption or damage from these kinds of events, and we may also experience reduced access to our assets or increased risk of loss of life or injury or damage to property and the environment. We have experienced operational interruptions and damage to our assets from such weather events in the past, and we expect to experience climate related physical risks in the future, potentially with increasing frequency or severity. Operational risk is intensified by changing climate and more extreme weather events. Any of these physical risks could result in substantial losses for which our insurance may not be sufficient or available and for which we may bear a part or all of the cost.

TRANSITION RISKS
Transition risks relate to the transition to a lower-emission economy, which may increase our cost of operations, impact our business plans, and influence stakeholder decisions about our company, each of which could adversely impact our strategic plan, business, operations or financial results. These transition risks include:

Policy and legal risks
Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on reducing GHG emissions, promoting adaptation to climate change, transitioning to a low-carbon economy, and disclosure of climate-related matters. Such policies, laws and regulations vary at the federal, state, provincial and municipal levels in which Enbridge operates and can be highly variable and subject to change. It is expected that further investments will be required to meet new regulatory requirements. In addition, in recent years there has been an increase in climate and disclosure-related litigation against governments as well as companies involved in the energy industry. There is no assurance that our company will not be impacted by such litigation.

Technology risks
Our success in executing our strategic plan, including our role in the transition to a lower-carbon economy, and attaining our GHG emissions reduction goals and targets, depends, in part, on technology (including technology still under development), innovation and continued diversification with renewable power and other low carbon energy infrastructure as well as modernization of our infrastructure to reduce GHG emissions. Achieving our GHG emissions reductions goals and targets could require significant capital expenditures and resources, with the potential that the costs required to achieve our goals and targets materially differ from our original estimates and expectations. Similarly, there is a risk that emissions reduction technology – like battery storage, CCS or direct air capture – do not materialize as expected, making it more difficult to reduce emissions.

Market risks
Climate change concerns, increase in demand for low-carbon and zero-emissions energy, alternative and new energy sources and technologies, changing customer behavior and reduced energy consumption could impact the demand for our services or securities. The pace and scale of the transition to a lower carbon economy may pose a climate-related transition risk if Enbridge diversifies either too quickly or too slowly. Similarly, uncertainty in market signals, such as abrupt and unexpected shifts in energy costs and demands, including due to climate change concerns, can impact revenue through reduced throughput volumes on our pipeline transportation systems.

Reputational risks
We have long been committed to strong ESG practices and performance, and in November 2020, we introduced a set of ESG goals to strengthen transparency and accountability. We have set GHG emissions reduction goals and a strategic priority to adapt to the energy transition over time. If we are not able to achieve our GHG emissions reduction goals, we are not able to meet future climate, emissions or other reporting requirements of regulators, or we are not able to meet or manage current and future expectations and issues important to investors or other stakeholders, including those related to climate change, it could negatively impact our reputation and our business, operations or financial results.

RISKS RELATED TO OPERATIONAL DISRUPTION OR CATASTROPHIC EVENTS

Pipeline operations involve numerous risks that may adversely affect our business, financial results and the environment.
Operation of complex pipeline systems, gathering, treating, storing and processing operations involves many risks, hazards and uncertainties.

These operational risks include adverse weather conditions, natural disasters, accidents, the breakdown or failure of equipment or processes, and the performance of the facilities below expected levels of capacity and efficiency and catastrophic events. Climate change presents physical risks relating to the physical impacts of climate change, which can affect the safety and reliability of our operations. Climate change could result in extreme variability in weather patterns, such as increased frequency and severity of extreme weather events, extreme hot and cold weather, heavy snowfall, heavy rainfall, floods, landslides, fires, hurricanes, tropical storms, ice storms, rising mean temperature and sea levels, and long-term changes in precipitation patterns.

Our assets and operations are exposed to potential interruption or damage from these kinds of events, and we may also experience reduced access to our assets, increased risk of loss of life or injury, damage to our property and our assets, environmental pollution or impairment of our operations. These kinds of events could also result in rupture or release of product from our pipeline systems and facilities. Such events could result in substantial losses for which insurance may not be sufficient or available and for which we may bear a part or all of the cost. Operational risk is also intensified by changing climate and more extreme weather events.

An environmental incident is an event that may cause environmental harm and could lead to an increased cost of operating and insuring our assets, thereby negatively impacting earnings. An environmental incident could have lasting reputational impacts and could impact our ability to work with various stakeholders. For pipeline and storage assets located near populated areas, including residential communities, commercial business centers, industrial sites and other public gathering locations, the level of damage resulting from these events could be greater.

We have experienced such events in the past, including in 2010 on Lines 6A and 6B of the Lakehead System; in October 2018 at the BC Pipeline T-South system; in January 2019, August 2019 and May 2020 at the Texas Eastern Pipeline; impacts from the winter storm in February 2021 in Texas and from wildfires in July 2021 and flooding in November 2021 in BC. We have incurred and expect to continue to incur significant costs in preparing for or responding to operational risks and events. We expect to continue to experience climate related physical risks, potentially with increasing frequency and severity, and we cannot guarantee that we will not experience catastrophic or other events in the future. In addition, we could be subject to litigation and significant fines and penalties from regulators in connection with any such events.

A service interruption could have a significant impact on our operations, and negatively impact financial results, relationships with stakeholders and our reputation.
A service interruption due to a major power disruption, curtailment of commodity supply, operational incident, availability of gas supply or distribution or other reasons could have a significant impact on our operations and negatively impact financial results, relationships with stakeholders, our reputation or the safety of our end customers. Service interruptions that impact our crude oil and natural gas transportation services can negatively impact shippers' operations and earnings as they are dependent on our services to move their product to market or fulfill their own contractual arrangements. We have experienced, and may again experience, service interruptions including in connection with the kinds of operational incidents referred to in the previous risk factor.

Our operations involve safety risks to the public and to our workers and contractors.
Several of our pipelines and distribution systems and related assets are operated in close proximity to populated areas and a major incident could result in injury or loss of life to members of the public. In addition, given the natural hazards inherent in our operations, our workers and contractors are subject to personal safety risks. A public safety incident or an injury or loss of life to our workers or contractors, which we have experienced in the past and, despite the precautions we take, may experience in the future, could result in reputational damage to us, material repair costs or increased costs of operating and insuring our assets.

Cyber-attacks or security breaches could adversely affect our business, operations or financial results.
Our business is dependent upon information systems and other digital technologies for controlling our plants, pipelines and other assets, processing transactions and summarizing and reporting results of operations. The secure processing, maintenance and transmission of information is critical to our operations. A security breach of our network or systems, or the network or systems of our third-party vendors, could result in improper operation of our assets, potentially including delays in the delivery or availability of our customers' products, contamination or degradation of the products we transport, store and distribute, or releases of hydrocarbon products for which we could be held liable. Furthermore, we and some of our vendors collect and store sensitive data in the ordinary course of our business, including personal information of our employees and residential gas distribution customers as well as our proprietary business information and that of our customers, suppliers, investors and other stakeholders.

Cybersecurity risks have increased in recent years as a result of the proliferation of new technologies and the increased sophistication, magnitude and frequency of cyber-attacks and data security breaches, as well as due to international and national political factors. Because of the critical nature of our infrastructure and our use of information systems and other digital technologies to control our assets, we face a heightened risk of cyber-attacks. New cybersecurity regulations have been recently implemented resulting in additional regulatory oversight and compliance requirements.

During the normal course of business, we have experienced and expect to continue to experience attempts to gain unauthorized access, compromise our information systems or to disrupt our operations through cyber-attacks or security breaches, although none to our knowledge have had a material adverse effect on our business, operations or financial results. Despite our security measures, our information systems or those of our vendors are expected to become the target of further cyber-attacks or security breaches which could compromise our systems, affect our ability to correctly record, process and report transactions, result in the loss of information, or cause operational disruption. As a result of a cyber-attack or security breach, we could also be liable under laws that protect the privacy of personal information, subject to regulatory penalties, incur additional costs for remediation, litigation or other costs, all of which could materially adversely affect our reputation, business, operations or financial results.

Pandemics, epidemics or disease outbreaks, such as the COVID-19 pandemic, may adversely affect local and global economies and our business, operations or financial results.
Disruptions caused by pandemics, epidemics or disease outbreaks, in locations in which we operate or globally, could materially adversely affect our business, operations, financial results and forward-looking expectations.

In response to the rapid global spread of COVID-19, governments continue to enact emergency measures to combat the spread of the virus. These measures include restrictions on business activity and travel, as well as requirements to isolate or quarantine. Certain of our operations and projects have been deemed essential services in critical infrastructure sectors and are currently exempt from certain business activity restrictions. COVID-19 and government responses have interrupted business activities and supply chains, disrupted travel, and contributed to significant volatility in the financial and commodity markets.

Given the ongoing and dynamic nature of the COVID-19 pandemic, further impacts will depend on future developments and factors outside of our control, which are uncertain, evolving and cannot be predicted, including new information which may emerge concerning the severity or duration of this pandemic (including new COVID-19 strains and the efficacy of vaccines) and actions taken by governments and others to contain or end the COVID-19 pandemic or its impact. Such developments include disruptions, which have had or may have an adverse effect on our customers, suppliers, regulators, business, operations and financial results.

There can be no assurance that our strategies to address potential disruptions will mitigate these risks or the adverse impacts to our business, operations and financial results. In addition, disruptions related to the COVID-19 pandemic have had, or could continue to have, the effect of heightening many of the other risks described in this Item 1A. *Risk Factors*.

Terrorist attacks and threats, escalation of military activity in response to these attacks or acts of war, and other civil unrest or activism could adversely affect our business, operations or financial results.

Terrorist attacks and threats (which may take the form of cyber-attacks), escalation of military activity or acts of war, or other civil unrest or activism may have significant effects on general economic conditions and may cause fluctuations in consumer confidence and spending and market liquidity, each of which could adversely affect our business. Future terrorist attacks, rumors or threats of war, actual conflicts involving the US, or Canada, or military or trade disruptions may significantly affect our operations and those of our customers. Strategic targets, such as energy related assets, may be at greater risk of future attacks than other targets in the US and Canada. In addition, increased environmental activism against pipeline construction and operation could potentially result in work delays, reduced demand for our products and services, increased legislation or denial or delay of permits and rights-of-way. Finally, the disruption or a significant increase in energy prices could result in government-imposed price controls. It is possible that any of these occurrences, or a combination of them, could adversely affect our business, operations or financial results.

RISKS RELATED TO OUR BUSINESS AND INDUSTRY

There are utilization risks with respect to our assets.

With respect to our Liquids Pipelines assets, we may be exposed to throughput risk on the Canadian Mainline depending upon the tolling framework we adopt for that system, and we are exposed to throughput risk under certain tolling agreements applicable to other liquids pipelines assets, such as the Lakehead System. A decrease in volumes transported can directly and adversely affect our revenues and earnings. Factors such as changing market fundamentals, capacity bottlenecks, regulatory restrictions, maintenance and operational incidents on our system and upstream or downstream facilities and increased competition can all impact the utilization of our assets. Market fundamentals, such as commodity prices and price differentials, weather, gasoline price and consumption, alternative and new energy sources and technologies, and global supply disruptions outside of our control can impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on our pipelines.

With respect to our Gas Transmission and Midstream assets, gas supply and demand dynamics continue to change due to shifts in regional production and consumption. These shifts can lead to fluctuations in commodity prices and price differentials, resulting in oversupply of pipeline takeaway capacity in some areas and an adverse effect to the utilization of our systems. Other factors affecting system utilization include operational incidents, regulatory restrictions, system maintenance, and increased competition.

With respect to our Gas Distribution and Storage assets, customers are billed on both a fixed charge and volumetric basis and our ability to collect the total revenue requirement (the cost of providing service, including a reasonable return to the utility) depends on achieving the forecast distribution volume established in the rate-making process. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Weather is a significant driver of delivery volumes, given that a significant portion of our Gas Distribution customer base uses natural gas for space heating. Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continue to place downward pressure on consumption. In addition, conservation efforts by customers may further contribute to a decline in annual average consumption. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Even in those circumstances where we attain our respective total forecast distribution volume, our Gas Distribution business may not earn its expected ROE due to other forecast variables, such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector. Our Gas Distribution business remains at risk for the actual versus forecast large volume contract commercial and industrial volumes.

With respect to our Renewable Power Generation assets, earnings from these assets are highly dependent on weather and atmospheric conditions as well as continued operational availability of these energy producing assets. While the expected energy yields for Renewable Power Generation projects are predicted using long-term historical data, wind and solar resources are subject to natural variation from year-to-year and from season-to-season. Any prolonged reduction in wind or solar resources at any of the Renewable Power Generation facilities could lead to decreased earnings and cash flows for us. Additionally, inefficiencies or interruptions of Renewable Power Generation facilities due to operational disturbances or outages resulting from weather conditions or other factors, could also impact earnings.

Our assets vary in age and were constructed over many decades which may cause our inspection, maintenance or repair costs to increase in the future.
Our pipelines vary in age and were constructed over many decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have changed over time. Depending on the era of construction, some assets require more frequent inspections, which could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our business, operations or financial results.

Competition may result in a reduction in demand for our services, fewer project opportunities or assumption of risk that results in weaker or more volatile financial performance than expected.
We face competition from competing carriers available to ship western Canadian liquid hydrocarbons to markets in Canada, the US and internationally and from proposed pipelines that seek to access markets currently served by our liquids pipelines. Competition among existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets. We also face competition from alternative storage facilities. Our natural gas transmission and storage businesses compete with similar facilities that serve our supply and market areas in the transmission and storage of natural gas. The natural gas transported in our business competes with other forms of energy available to our customers and end-users, including electricity, coal, propane, fuel oils, and renewable energy. Renewable Power Generation business faces competition in the procurement of long-term power purchase agreements and from other fuel sources in the markets in which we operate. Competition in all of our businesses, including competition for new project development opportunities, could have a negative impact on our business, financial condition or results of operations.

Execution of our projects subjects us to various regulatory, operational and market risks that may affect our financial results.
Our ability to successfully bring our secured capital growth program into service is exposed to risks including:

- the ability to obtain or amend necessary approvals and permits from governments and regulatory agencies on a timely basis and with acceptable terms and conditions and to maintain those issued approvals and permits and satisfy the terms and conditions imposed therein;
- opposition by third parties, physical protests, interference with or damage to our property or infrastructure, litigation or increased execution and stakeholder engagement complexity;
- new or incremental changes in federal, state, provincial and local laws and regulations after projects are sanctioned;
- inflationary pressures on labor, materials and equipment, which have decreased price predictability;
- bottlenecked global supply chains and logistics, which have increased delivery times of materials and equipment;
- timely acquisition or renewal of rights-of-way or land rights with acceptable terms and conditions;
- extreme weather events (e.g. hurricanes, forest fires, floods); or
- contractor or supplier non-performance, weather, geological or other factors beyond our control.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated cost.

New projects may not achieve their expected investment return, which could affect our financial results, reputation and hinder our ability to secure future projects. Recent projects that have experienced various degrees of impacts include the US L3R Program that was placed into service in the third quarter of 2021, Line 5 projects (tunnel and reroute), Texas Eastern Modernization, East-West Tie and Offshore Wind. For additional discussion of specific proceedings that could affect our operations and financial results, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates.*

Changing expectations from stakeholders regarding ESG practices and climate change or erosion of stakeholder trust or confidence could damage our reputation and influence actions or decisions about our company and industry and have negative impacts on our business, operations or financial results.

Companies across all sectors and industries are facing changing expectations or increasing scrutiny from stakeholders related to their approach to ESG matters of greatest relevance to their business and to their stakeholders. For energy companies, climate change, safety, stakeholder and Indigenous relations remain primary focus areas, while other environmental elements such as biodiversity are ascendant; changing expectations of our practices and performance across these and other ESG areas may impose additional costs or create exposure to new or additional risks.

Our operations, projects and growth opportunities require us to have strong relationships with key stakeholders, including local communities, Indigenous groups and communities and other groups directly impacted by our activities, as well as governments and government agencies, investor advocacy groups, institutional investors, investment funds, financial institutions, insurers and others, which are increasingly focused on ESG practices.

Enhanced public awareness of climate change has driven an increase in demand for low-carbon and zero-emissions energy. Enbridge has a long history of diversifying its portfolio of businesses to align with the mix of energy that people need and want. However, the pace and scale of the transition to a lower emissions economy may pose a climate-related transition risk if Enbridge diversifies either too quickly or too slowly. Similarly, unexpected shifts in energy demands, including due to climate changes concerns, can impact revenue through reduced throughput volumes on our pipeline transportation system.

We have long been committed to strong ESG practices, performance and reporting, and in late 2020 introduced a set of ESG goals to strengthen transparency and accountability. The goals include increasing diversity and inclusion within our organization and reducing emissions from our operations to net zero by 2050, with corporate and business unit action plans aligned to our strategic priority to adapt to the energy transition over time. Given elevated long-term risks associated with climate change, there have also been efforts in recent years by the investment community, including increased engagement with companies on climate change and decreasing the carbon intensity of their portfolios. If we are not able to achieve our GHG emissions reduction goals, are not able to meet future climate, emissions or other reporting requirements of regulators, or are not able to meet or manage current and future expectations or issues important to investors or other stakeholders including those related to climate change, it could negatively impact stakeholder trust and confidence, our reputation, and our business, operations or financial results, including:

- loss of business;
- loss of ability to secure growth opportunities;
- delays in project execution;
- legal action, such as the legal challenges to the operation of Line 5 in Michigan and Wisconsin;
- increased regulatory oversight;
- loss of ability to obtain and maintain necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms;

- impediments on our ability to acquire or renew rights-of-way or land rights on a timely basis and on acceptable terms;
- changing investor sentiment regarding investment in the oil and gas industry or our company;
- restricted access to and cost of capital and insurance; and
- loss of ability to hire and retain top talent.

We are also exposed to the risk of higher costs, delays, project cancellations, new restrictions or the cessation of operations of existing pipelines due to increasing pressure on governments and regulators. Recent judicial decisions have increased the ability of groups to make claims and oppose projects in regulatory and legal forums. In addition to issues raised by groups focused on particular project impacts, we and others in the energy and pipeline businesses are facing organized opposition to oil and gas extraction and shipment of oil and gas products.

Our forecasted assumptions may not materialize as expected, including on our expansion projects, acquisitions and divestitures.
We evaluate expansion projects, acquisitions and divestitures on an ongoing basis. Planning and investment analysis is highly dependent on accurate forecasting assumptions and to the extent that these assumptions do not materialize, financial performance may be lower or more volatile than expected. Volatility and unpredictability in the economy, both locally and globally, and changes in cost estimates, project scoping and risk assessment could result in a loss of our profits. Similarly, uncertainty in market signals, such as abrupt and unexpected shifts in energy costs and demands, as we saw in 2020 resulting from the COVID-19 pandemic, have impacted, and may in the future impact, revenue through reduced throughput volumes on our pipeline transportation system.

Our insurance coverage may not be sufficient to cover our losses in the event of an accident, natural disaster or other hazardous event.
Our operations are subject to many hazards inherent in our industry. Our assets may experience physical damage as a result of an accident or natural disaster. These hazards can also cause, and in some cases have caused, personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage, and suspension of operations. We maintain a comprehensive insurance program for us, our subsidiaries and certain of our affiliates to mitigate the financial impacts arising from these hazards. This program includes insurance coverage in types and amounts and with terms and conditions that are generally consistent with coverage customary for our industry; however, insurance does not cover all events in all circumstances.

In the unlikely event that multiple insurable incidents that in the aggregate exceed coverage limits occur within the same insurance period, the total insurance coverage will be allocated among our entities on an equitable basis based on an insurance allocation agreement among us and our subsidiaries. Additionally, even with insurance, if any natural disaster or other hazardous event leads to a catastrophic interruption in operations, we may not be able to restore operations without significant interruption.

We are exposed to the credit risk of our customers.
We are exposed to the credit risk of our customers in the ordinary course of our business. Generally, our customers are rated investment-grade, are otherwise considered creditworthy or provide us security to satisfy credit concerns. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in our customers' creditworthiness. It is possible that customer payment defaults, if significant, could adversely affect our earnings and cash flows.

Our risk management policies cannot eliminate all risks. In addition, any non-compliance with our risk management policies could adversely affect our business, operations or financial results.
We use financial derivatives to manage risks associated with changes in foreign exchange rates, interest rates, commodity prices and our share price to reduce volatility of our cash flows. Based on our risk management policies, all of our financial derivatives are associated with an underlying asset, liability and/or forecasted transaction and not intended for speculative purposes.

These policies cannot, however, eliminate all risk including unauthorized trading. Although this activity is monitored independently by our risk management function, we can provide no assurance that we will detect and prevent all unauthorized trading and other violations, particularly if deception, collusion or other intentional misconduct is involved, and any such violations could adversely affect our business, operations or financial results.

Our business requires the retention and recruitment of a skilled and diverse workforce, and difficulties in recruiting and retaining our workforce could result in a failure to implement our business plans.
Our operations and management require the retention and recruitment of a skilled and diverse workforce, including engineers, technical personnel and other professionals. We and our affiliates compete with other companies in the energy industry, and for some jobs the broader labor market, for this skilled workforce. If we are unable to retain current employees and/or recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

Our transformation projects may fail to fully deliver anticipated results.
We launched projects starting in 2016 to transform various processes, capabilities and reporting systems infrastructure to continuously improve effectiveness and efficiency across the organization and are subject to transformation project risk with respect to these projects. Such projects, some of which will continue beyond 2022, are subject to transformation project risk. Transformation project risk is the risk that modernization projects carried out by us and our subsidiaries do not fully deliver anticipated results due to insufficiently addressing the risks associated with project execution and change management. This could result in negative financial, operational and reputational impacts.

Our business is undergoing significant changes driven by technological advancements and the energy transition, which could impact our strategic plan, business, operations or financial results.
Our success in executing our strategic plan, including our role in the transition to a low-carbon economy, and attaining our GHG emissions reduction goals and targets depends, in part, on technology (including technology still under development), innovation and continued diversification with renewable power and other low carbon energy infrastructure as well as modernization of our infrastructure to reduce GHG emissions, all of which could require significant capital expenditures and resources. Public policy relating to climate change can drive investment in lower-emissions technologies which could impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on our pipelines.

Our Liquids Pipelines growth rate and results may be directly and indirectly affected by commodity prices and government policy.
This intervention had a negligible impact on the Mainline System throughput, as enough inventory existed to meet refinery customer needs and service our favorable markets. Wide commodity price basis between Western Canada and global tidewater markets have negatively impacted producer netbacks and margins in the past years that largely resulted from pipeline infrastructure takeaway capacity from producing regions in Western Canada and North Dakota which are operating at capacity. A protracted long-term outlook for low crude oil prices could result in delay or cancellation of future projects. Effective December 31, 2021, the Government of Alberta lifted the oil production curtailment that was imposed in December 2018.

The tight conventional oil plays of Western Canada, the Permian basin, and the Bakken region of North Dakota have short cycle break-even time horizons, typically less than 24 months, and high decline rates that can be well managed through active hedging programs and are positioned to react quickly to market signals. Accordingly, during periods of comparatively low prices, drilling programs, unsupported by hedging programs, will be reduced and as such supply growth from tight oil basins may be lower, which may impact volumes on our pipeline systems.

Our Energy Services and Gas Transmission and Midstream results may be adversely affected by commodity price volatility.
Within our US Midstream assets, through our investments in DCP Midstream and Aux Sable, we are engaged in the businesses of gathering, treating and processing natural gas and natural gas liquids. The financial results of these businesses are directly impacted by changes in commodity prices.

Energy Services generates margin by capitalizing on quality, time and location differentials when opportunities arise. Lower commodity prices due to changing market conditions could limit margin opportunities and impede Energy Services' ability to cover capacity commitments.

We rely on access to short-term and long-term capital markets to finance capital requirements and support liquidity needs, and cost effective access to those markets can be affected, particularly if we or our rated subsidiaries are unable to maintain an investment-grade credit rating.
A significant portion of our consolidated asset base is financed with debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations and to fund investments originally financed through debt. Our senior unsecured long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us or our rated subsidiaries below investment-grade, our borrowing costs would increase, perhaps significantly. Consequently, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources could decrease.

We maintain revolving credit facilities to provide back-up for commercial paper programs for borrowings and/or letters of credit at various entities. These facilities typically include financial covenants and failure to maintain these covenants at a particular entity could preclude that entity from issuing commercial paper or letters of credit or borrowing under the revolving credit facility, which could affect cash flows or restrict business. Furthermore, if our short-term debt rating were to be downgraded, access to the commercial paper market could be significantly limited. Although this would not affect our ability to draw under our credit facilities, borrowing costs could be significantly higher.

If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be affected. An inability to access capital may limit our ability to pursue enhancements or acquisitions that we may otherwise rely on for future growth. Any downgrade or other event negatively affecting the credit ratings of our subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could increase our need to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing the liquidity and borrowing availability of the consolidated group.

RISKS RELATED TO GOVERNMENT REGULATION AND LEGAL RISKS

Many of our operations are regulated and failure to secure timely regulatory approval for our proposed projects, or loss of required approvals for our existing operations, could have a negative impact on our business, operations or financial results.
The nature and degree of regulation and legislation affecting energy companies in Canada and the US have changed significantly in recent years.

In Canada, the passing of the Canadian Energy Regulator Act and the Impact Assessment Act under Bill C-69, which came into force on August 28, 2019, adds steps in the regulatory process and extends overall timelines associated with regulatory approvals for new projects which trigger a federal impact assessment. Changes to the BC regulatory framework have also been made, including a new Environmental Assessment Act, which came into force in December 2019, affecting provincially-regulated projects in a similar manner as those that are federally-regulated. Within the US and in Canada, pipelines companies continue to face opposition from anti-pipeline activists, Indigenous and tribal groups and communities, citizens, environmental groups and politicians concerned with either the safety of pipelines or environmental effects. In the US, several federal agencies made changes to regulations that were designed to streamline permitting, including changes that the Environmental Protection Agency made in June 2020 to regulations implementing Section 401 of the Clean Water Act and the July 2020 Council on Environmental Quality revisions to regulations implementing the National Environmental Policy Act. These and many other regulations adopted during the previous US presidential administration are not only being challenged in multiple courts, but have now been expressly targeted for rollback by the new US administration, which is expected to modify or reverse the regulations.

These actions could adversely impact permitting of a wide range of energy projects. We may not be able to obtain or maintain all required regulatory approvals for our operating assets or development projects. If there is a delay in obtaining any required regulatory approvals, if we fail to obtain or comply with them, or if laws or regulations change or are administered in a more stringent manner, the operations of facilities or the development of new facilities could be prevented, delayed or become subject to additional costs.

Our operations are subject to numerous environmental laws and regulations, including those relating to climate change and GHG emissions and climate-related disclosure, as well as internal initiatives to reduce GHG emissions, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans, or expose us to environmental liabilities.

We are subject to numerous environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste.

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting GHG emissions, promoting adaptation to climate change and the transition to a low-carbon economy, and disclosure of climate-related matters. Such policies, laws and regulations vary at the federal, state, and provincial levels in which Enbridge operates and can be highly variable and subject to change. International multilateral agreements, the obligations adopted thereunder, increasing physical impacts of climate change, changing political and public opinion and legal challenges concerning the adequacy of climate-related policy brought against governments and corporations, among other factors, are expected to accelerate the implementation of these measures.

Enbridge is required to adhere to a number of implicit and explicit carbon-pricing mechanisms. These mechanisms may present climate-related transition risk to our business strategy, impacting both commodity demand and the overall energy mix we deliver.

Failure to comply with environmental laws and regulations and failure to secure permits necessary for our operations may result in the imposition of fines, penalties and injunctive measures affecting our operating assets. In addition, changes in environmental laws and regulations or the enactment of new environmental laws or regulations, including those related to climate change and GHG emissions, could result in a material increase in our cost of compliance with such laws and regulations, such as costs to monitor and report our emissions and install new emission controls to reduce emissions. We may not be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities. Efforts to regulate or restrict GHG emissions could also drive down demand for the products we transport.

We may not be able to obtain or maintain all required environmental regulatory approvals and permits for our operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals or permits, if we fail to obtain or comply with them, or if environmental laws or regulations change or are administered in a more stringent manner, the operations of facilities or the development of new facilities could be prevented, delayed or become subject to additional costs. We expect that costs we incur to comply with environmental regulations in the future may have a significant effect on our earnings and cash flows.

In November 2020, we set new ESG goals for the future related to GHG emissions reduction. Our ability to achieve these goals depends on many factors, including our ability to reduce emissions from our operations through modernization and innovation, reduce the emissions intensity of the electricity we buy, invest in renewables and low carbon energy and balance residual emissions through carbon offset credits. The cost associated with our GHG emissions reduction goals could be significant. There is also a risk that some or all of the expected benefits and opportunities of achieving the various GHG emissions reduction and energy transition goals may fail to materialize, may cost more to achieve or may not occur within the anticipated time periods. Similarly, there is a risk that emissions reduction technology – like battery storage or direct air capture – do not materialize as expected making it more difficult to reduce emissions. Failure to achieve our emissions targets could result in reputational harm, changing investor sentiment regarding investment in Enbridge or a negative impact on access to and cost of capital, including penalties associated with our sustainability-linked bond offerings.

Our operations are subject to operational regulation and other requirements, including compliance with easements and other land tenure documents, and failure to comply with applicable regulations and other requirements could have a negative impact on our reputation, business, operations or financial results.

Operational risks relate to compliance with applicable operational rules and regulations mandated by governments, applicable regulatory authorities, or other requirements that may be found in easements or other agreements that provide a legal basis for our operations, breaches of which could result in fines, penalties, awards of damages, operating restrictions (including shutdown of lines) and an overall increase in operating and compliance costs. We do not own all of the land on which our pipelines, facilities and other assets are located and we obtain the rights to construct and operate our pipelines and other assets from third parties or government entities. In addition, some of our pipelines, facilities and other assets cross Indigenous lands pursuant to rights-of-way or other land tenure interests. Our loss of these rights could have an adverse effect on our reputation, operations and financial results. Regulator scrutiny over our assets and operations has the potential to increase operating costs or limit future projects. Regulatory enforcement actions issued by regulators for non-compliant findings can increase operating costs and negatively impact reputation. Potential regulatory changes and legal challenges could have an impact on our future earnings from existing operations and the cost related to the construction of new projects. Regulators' future actions may differ from current expectations, or future legislative changes may impact the regulatory environments in which we operate. While we seek to mitigate operational regulation risk by actively monitoring and consulting on potential regulatory requirement changes with the respective regulators directly, or through industry associations, and by developing response plans to regulatory changes or enforcement actions, such mitigation efforts may be ineffective or insufficient. While we believe the safe and reliable operation of our assets and adherence to existing regulations is the best approach to managing operational regulatory risk, the potential remains for regulators or other government officials to make unilateral decisions that could disrupt our operations or have an adverse financial impact on us.

Our operations are subject to economic regulation and failure to secure regulatory approval for our proposed or existing commercial arrangements could have a negative impact on our business, operations or financial results.
Our liquids pipelines, gas transmission and gas distribution assets face economic regulation risk. Broadly defined, economic regulation risk is the risk that governments or regulatory agencies change or reject proposed or existing commercial arrangements or policies, including permits and regulatory approvals for both new and existing projects or agreements, upon which future and current operations are dependent. Our Mainline System, other liquids pipelines and gas transmission assets are subject to the actions of various regulators, including the CER and the FERC, with respect to the tariffs and tolls of those pipelines. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable permits and tariff structure or changes in interpretations of existing regulations by courts or regulators such as with respect to Mainline Contracting, could have an adverse effect on our revenues and earnings.

We could be subject to changes in our tax rates, the adoption of new US, Canadian or international tax legislation or exposure to additional tax liabilities.
We are subject to taxes in the US, Canada and numerous foreign jurisdictions. Due to economic and political conditions, tax rates in various jurisdictions may be subject to significant change. Our effective tax rates could be affected by changes in the mix of earnings in countries with differing statutory tax rates, changes in the valuation of deferred tax assets and liabilities, or changes in tax laws or their interpretation. In particular, we are anticipating interest deductibility rules to be tabled in Canada, possible new tax legislation to be passed in the US and a minimum tax rate to be introduced on a global basis for OECD countries. All of these measures could cause our effective tax rate to increase.

We are also subject to the examination of our tax returns and other tax matters by the US Internal Revenue Service, the Canada Revenue Agency and other tax authorities and governmental bodies. We regularly assess the likelihood of an adverse outcome resulting from these examinations to determine the adequacy of our provision for taxes. There can be no assurance as to the outcome of these examinations. If our effective tax rates were to increase, particularly in the US or Canada, or if the ultimate determination of our taxes owed is for an amount in excess of amounts previously accrued, our financial condition and operating results could be materially adversely affected.

We are involved in numerous legal proceedings, the outcomes of which are uncertain, and resolutions adverse to us could adversely affect our financial results.
We are subject to numerous legal proceedings. In recent years there has been an increase in climate and disclosure-related litigation against governments as well as companies involved in the energy industry. There is no assurance that we will not be impacted by such litigation. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with assurance. It is reasonably possible that the final resolution of some of the matters in which we are involved could require additional expenditures, in excess of established reserves, over an extended period of time and in a range of amounts that could adversely affect our financial results or affect our reputation. Refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates* for a discussion of certain legal proceedings with recent developments.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Descriptions of our properties and maps depicting the locations of our liquids and natural gas systems are included in Part 1. *Item 1. Business.*

In general, our systems are located on land owned by others and are operated under easements and rights-of-way, licenses, leases or permits that have been granted by private land-owners, First Nations, Native American Tribes, public authorities, railways or public utilities. Our liquids pipeline systems have pumping stations, tanks, terminals and certain other facilities that are located on land that is owned by us and/or used by us under easements, licenses, leases or permits. Additionally, our natural gas pipeline systems have natural gas compressor stations, of which the vast majority are located on land that is owned by us, with the remainder used by us under easements, leases or permits.

Titles to Enbridge owned properties or affiliate entities may be subject to encumbrances in some cases. We believe that none of these burdens should materially detract from the value of these properties or materially interfere with their use in the operation of our business.

ITEM 3. LEGAL PROCEEDINGS

We are involved in various legal and administrative proceedings and litigation arising in the ordinary course of business. The outcome of these matters is not predictable at this time. However, we believe that the ultimate resolution of these matters will not have a material adverse effect on our financial condition, results of operations or cash flows in future periods. Refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates* for discussion of certain legal proceedings with recent developments.

SEC regulations require the disclosure of any proceeding under environmental laws to which a governmental authority is a party unless the registrant reasonably believes it will not result in monetary sanctions over a certain threshold. Given the size of our operations, we have elected to use a threshold of US$1 million for the purposes of determining proceedings requiring disclosure.

The Minnesota Department of Natural Resources (DNR) issued an Administrative Penalty Order on September 16, 2021 due to an uncontrolled groundwater flow at Clearbrook. The groundwater flow was stopped in January 2022 after diligently implementing the steps required under the remedial action plan. We have also provided all required information to date. A contested case was not sought in this matter; instead, the penalty and mitigation amounts will be paid as directed for the Clearbrook site. A separate US$2.75 million escrow account is being established for any potential future monitoring and mitigation. In total, Enbridge will direct US$3.3 million to address this matter. With work complete at Clearbrook and a second site, Enbridge continues to work with the DNR towards a corrective action plan for the final location, including ongoing restoration, monitoring, and mitigation for all three sites.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

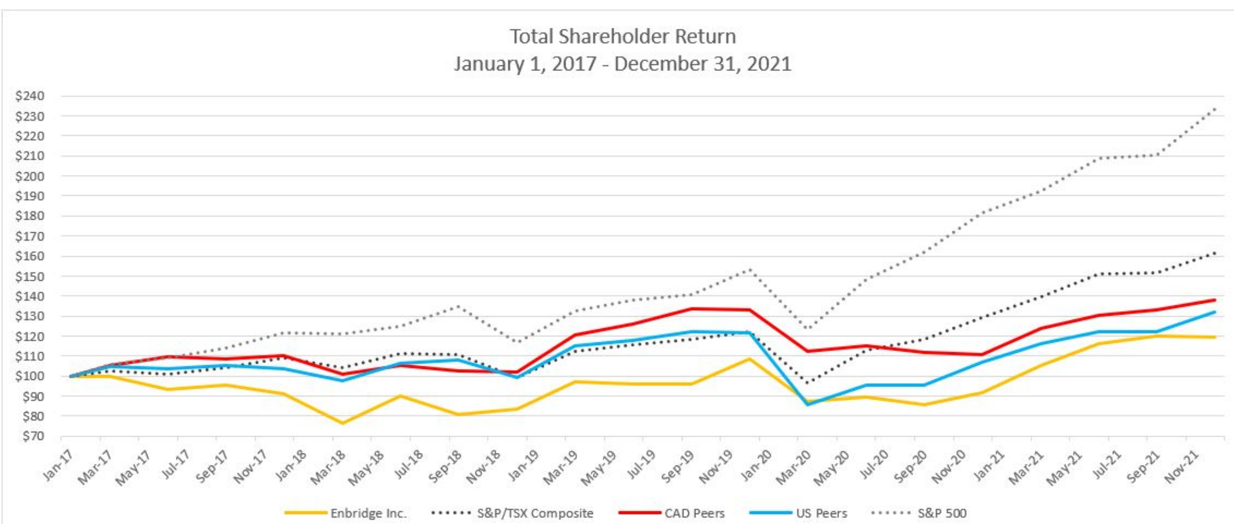
Common Stock
Enbridge common stock is traded on the TSX and NYSE under the symbol “ENB.” As at February 4, 2022, there were 80,754 registered shareholders of record of Enbridge common stock. A substantially greater number of holders of Enbridge common stock are "street name" or beneficial holders, whose shares are held by banks, brokers and other financial institutions.

Securities Authorized for Issuance Under Equity Compensation Plans
The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021.

Recent Sales of Unregistered Equity Securities
None.

Issuer Purchases of Equity Securities
None.

Total Shareholder Return
The following graph reflects the comparative changes in the value from January 1, 2017 through December 31, 2021 of $100 invested in (1) Enbridge Inc.’s common shares traded on the TSX, (2) the S&P/TSX Composite index, (3) the S&P 500 index, (4) our US peer group (comprising CNP, D, DTE, DUK, EPD, ET, KMI, MMP, NEE, NI, OKE, PAA, PCG, SO, SRE and WMB) and (5) our Canadian peer group (comprising CU, FTS, PPL and TRP). The amounts included in the table were calculated assuming the reinvestment of dividends at the time dividends were paid.



	January 1, 2017	December 31, 2017	2018	2019	2020	2021
Enbridge Inc.	100.00	91.20	83.64	108.32	91.84	119.50
S&P/TSX Composite	100.00	109.10	99.40	122.14	128.98	161.34
S&P 500 Index	100.00	121.83	116.49	153.17	181.35	233.41
US Peers[1]	100.00	103.37	99.41	121.77	107.12	131.86
Canadian Peers	100.00	110.39	101.93	133.27	110.56	138.14

1 For the purpose of the graph, it was assumed that CAD:US dollar conversion ratio remained at 1:1 for the years presented.

ITEM 6. [Reserved]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with "Forward-Looking Information" and "Non-GAAP and Other Financial Measures", Part I. *Item 1A. Risk Factors* and our consolidated financial statements and the accompanying notes included in Part II. *Item 8. Financial Statements and Supplementary Data* of this Annual Report on Form 10-K.

This section of our Annual Report on Form 10-K discusses 2021 and 2020 items and year-over-year comparisons between 2021 and 2020. For discussion of 2019 items and year-over-year comparisons between 2020 and 2019, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* of our Annual Report on Form 10-K for the year ended December 31, 2020.

RECENT DEVELOPMENTS

ACQUISITION OF MODA MIDSTREAM OPERATING, LLC

On October 12, 2021, we acquired Moda Midstream Operating, LLC (Moda) for $3.7 billion (US$3.0 billion) of cash plus potential contingent payments dependent on performance of the assets (the Acquisition). Moda owns and operates a vertically-integrated crude export system of pipeline and storage assets on the US Gulf Coast, including the EIEC located near Corpus Christi, Texas. EIEC, North America's largest crude export terminal, controls 15.6 million barrels of storage and 1.6 million barrels per day (mmbpd) of export capacity and volumes are underpinned by 925- thousand barrels per day (kbpd) of long-term take-or-pay vessel loading contracts and 15.3 million barrels of long-term storage contracts. The Acquisition aligns with and advances our US Gulf Coast export strategy and connectivity to low-cost and long-lived reserves in the Permian and Eagle Ford basins.

NORMAL COURSE ISSUER BID

On December 31, 2021, we announced that the Toronto Stock Exchange (TSX) had approved our normal course issuer bid (NCIB) to purchase, for cancellation, up to 31,062,331 of the outstanding common shares of Enbridge to an aggregate amount of up to $1.5 billion, subject to certain restrictions on the number of common shares that may be purchased on a single day.

Purchases under the NCIB may be made through the facilities of the TSX, the New York Stock Exchange (NYSE) and other designated exchanges and alternative trading systems, commencing on January 5, 2022 and continuing until January 4, 2023, when the bid expires, or such earlier date on which Enbridge has either acquired the maximum number of common shares allowable under the NCIB or otherwise decide not to make any further repurchases under the NCIB. The maximum number of common shares that Enbridge may repurchase for cancellation represents approximately 1.53% of the 2,026,085,179 common shares issued and outstanding as at December 22, 2021.

MAINLINE SYSTEM CONTRACTING

On December 19, 2019, we submitted an application to the Canada Energy Regulator (CER) to implement contracting on our Canadian Mainline System. On November 26, 2021, the CER denied the application on the basis that, among other things, contracting as proposed would result in a significant change to access the Canadian Mainline and potentially inequitable outcomes to some shippers and non-shippers without a compelling justification.

We are currently exploring with customers and other stakeholders alternatives that may include: a modified and extended Competitive toll Settlement (CTS), a new incentive rate-making agreement or a cost-of-service rate-making structure. Any negotiated settlement would require CER approval before implementation.

In accordance with the terms of the CTS, which expired on June 30, 2021, the tolls in place on June 30, 2021 will continue on an interim basis, subject to finalization and adjustment applicable to the interim period, if any.

GAS TRANSMISSION AND MIDSTREAM RATE PROCEEDINGS

Texas Eastern Transmission

Texas Eastern Transmission, LP (Texas Eastern) filed a rate case on July 30, 2021. On August 31, 2021 the Federal Energy Regulatory Commission (FERC) issued an order rejecting the July 30, 2021 filing in its entirety noting the proposed US federal income tax rate in the filing was not known and measurable ("August 2021 Order"). Additionally, the August 31, 2021 order directed Texas Eastern to show cause that its reservation charge crediting process is in accordance with FERC policy.

In response to the August 2021 Order, on September 30, 2021 Texas Eastern responded to the show cause directive and filed a new rate case using the current US federal income tax rate. On October 29, 2021, the FERC issued an order accepting and suspending tariff records, subject to refund, conditions, and establishing hearing procedures for the new rate case filed on September 30, 2021.

Texas Eastern also filed for rehearing of the August 2021 Order. On January 20, 2022 the FERC issued an "Order Addressing Arguments Raised On Rehearing And Setting Aside Prior Order, In Part" ("January 2022 Order"). The January 2022 Order set aside the August 2021 Order, and accepted and suspended Texas Eastern's proposed rates from its initial rate case filing to be effective upon motion on February 1, 2022, subject to refund, conditions, and the outcome of hearing proceedings. In addition, the January 2022 Order directed Texas Eastern to remove its proposed income tax adjustment and include the actual tax rate in the computation of its rates when it files to motion the suspended rates into effect.

Finally, the FERC left to the discretion of the Chief Administrative Law Judge whether to consolidate the two rate case proceedings.

East Tennessee

East Tennessee Natural Gas, LLC (ETNG) filed a rate case in the second quarter of 2020 and an agreement in principle was reached with shippers in April 2021. A Stipulation and Agreement was filed on May 21, 2021, approved by the FERC on September 10, 2021 and was effective on November 1, 2021.

Maritimes & Northeast Pipeline

The US portion of Maritimes & Northeast Pipeline filed a rate case in the second quarter of 2020 and an agreement in principle was reached with shippers in December 2020. A Stipulation and Agreement was filed on February 17, 2021, approved by the FERC on April 30, 2021 and was effective on June 1, 2021. In December 2021, the CER approved interim rates for the Canadian portion of Maritimes & Northeast Pipeline effective January 1, 2022, which were based on the negotiated 2022 rates in the 2022-2023 settlement agreement and unanimously supported by shippers. A decision from the CER on the 2022-2023 settlement agreement is expected in the first quarter of 2022.

Alliance Pipeline
The US portion of Alliance Pipeline filed a rate case in the second quarter of 2020 and an agreement in principle was reached with shippers in January 2021. A Stipulation and Agreement was filed on March 31, 2021, approved by the FERC on July 15, 2021 and was effective on September 1, 2021.

British Columbia (BC) Pipeline
The settlement agreement for our BC Pipeline system expired in December 2021. The CER has approved 2022 interim tolls for BC Pipeline and settlement agreement negotiations are ongoing, with an expected agreement to be reached in the first half of 2022.

GAS DISTRIBUTION AND STORAGE RATE APPLICATIONS

2021 Rate Application
Enbridge Gas Inc.'s (Enbridge Gas) rate applications are filed in two phases. As part of an Ontario Energy Board (OEB) Decision and Order issued in November 2020, Phase 1 of the application for 2021 rates (the 2021 Application), exclusive of 2021 capital investment funding requested through the incremental capital module (ICM) mechanism, was approved on an interim basis effective January 1, 2021. Through a subsequent OEB Rate Order issued in June 2021, Phase 2 of the 2021 Application, inclusive of funding for $124 million of requested 2021 ICM amounts, was approved effective July 1, 2021, and interim rates in effect for 2021 were made final. The 2021 Application, which represented the third year of a five-year term, was filed in accordance with the parameters of the Enbridge Gas OEB approved Price Cap Incentive Regulation (IR) rate setting mechanism.

2022 Rate Application
In June 2021, Enbridge Gas filed Phase 1 of the application with the OEB for the setting of rates for 2022 (the 2022 Application). The 2022 Application was filed in accordance with the parameters of the Enbridge Gas OEB approved Price Cap IR rate setting mechanism which represents the fourth year of a five-year term. In October 2021, the OEB approved a Phase 1 Settlement Proposal and Interim Rate Order effective January 1, 2022. Phase 2 of the 2022 Application addressing ICM funding requirements was filed in October 2021, with a decision from the OEB expected in the second quarter of 2022.

FINANCING UPDATE

We completed long-term debt issuances totaling US$3.9 billion and $3.2 billion during the year ended December 31, 2021, including an inaugural US$1.0 billion 12-year sustainability-linked senior notes issuance in June 2021 and an inaugural $1.1 billion Canadian 12-year sustainability-linked medium-term notes issuance in September 2021. We renewed approximately $8.0 billion of our five-year credit facilities, extending the maturity date out to July 2026. We also extended approximately $10.0 billion of our 364-day extendible credit facilities to July 2022, which includes a one-year term out provision to July 2023.

Our 2021 financing activities, in combination with the asset monetization activities noted below, provide significant liquidity that we expect will enable us to fund our current portfolio of capital projects without requiring access to the capital markets for the next 12 months should market access be restricted or pricing is unattractive. Refer to *Liquidity and Capital Resources*.

On January 19, 2022, we closed a $750 million private placement offering of non-call 10-year fixed-to-fixed subordinated notes which mature on January 19, 2082. The net proceeds from the offering will be used to redeem the Preference Shares, Series 17 at par on March 1, 2022.

On February 10, 2022 we renewed our three year $1.0 billion sustainability-linked credit facility, extending the maturity date out to July 2025.

Credit Rating Action
On June 1, 2021, Moody's Investors Service (Moody's) upgraded the credit ratings of Enbridge Inc., including our senior unsecured and issuer ratings, to Baa1 from Baa2. Moody's also upgraded the credit ratings of our subsidiaries: Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Limited Partnership (EELP), Spectra Energy Partners, LP (SEP) and Texas Eastern. The outlooks of all five entities are stable.

ENERGY TRANSITION

Given the priority we are placing on low carbon investments and energy transition, we have established a dedicated New Energy Technologies team. This team will extend the capabilities we have built over the last 20 years of renewable investments and will establish priorities and co-ordinate strategy across our business units. The team will also develop new partnerships to enable access to new technology, complementary assets and skills.

During 2021, the Alberta Solar One and Heidlersburg solar self-power projects were placed into service. We also started the construction process on 10 additional solar self-power projects in Wisconsin, Illinois, Pennsylvania, Kentucky, Ohio and Minnesota, together capable of generating more than 97 megawatts (MW) MW of emissions-free electricity. These projects will provide clean power to our liquids and natural gas pipeline right-of-way and support scope 1 and 2 emission targets.

ASSET MONETIZATION

Éolien Maritime France SAS
On March 18, 2021, we sold 49% of an entity that holds our 50% interest in Éolien Maritime France SAS (EMF) to the Canada Pension Plan Investment Board (CPP Investments). CPP Investments will fund their 49% share of all ongoing future development capital. Through our investment in EMF, we own equity interests in three French offshore wind projects, including Saint-Nazaire (25.5%), Fécamp (17.9%) and Calvados (21.7%). The Calvados Offshore Wind Project reached a positive final investment decision in February 2021 and all three projects are now considered commercially secured and are under construction.

Noverco Inc.
On December 30, 2021, we sold our 38.9% non-operating minority ownership interest in Noverco Inc. (Noverco) to Trencap L.P. for $1.1 billion in cash.

RESULTS OF OPERATIONS

	Year ended December 31,		
	2021	2020	2019
(millions of Canadian dollars, except per share amounts)			
Segment earnings before interest, income taxes and depreciation and amortization[1]			
Liquids Pipelines	**7,897**	7,683	7,681
Gas Transmission and Midstream	**3,671**	1,087	3,371
Gas Distribution and Storage	**2,117**	1,748	1,747
Renewable Power Generation	**508**	523	111
Energy Services	**(313)**	(236)	250
Eliminations and Other	**356**	(113)	429
Earnings before interest, income taxes and depreciation and amortization[1]	**14,236**	10,692	13,589
Depreciation and amortization	**(3,852)**	(3,712)	(3,391)
Interest expense	**(2,655)**	(2,790)	(2,663)
Income tax expense	**(1,415)**	(774)	(1,708)
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(125)**	(53)	(122)
Preference share dividends	**(373)**	(380)	(383)
Earnings attributable to common shareholders	**5,816**	2,983	5,322
Earnings per common share	**2.87**	1.48	2.64
Diluted earnings per common share	**2.87**	1.48	2.63

1 Non-GAAP financial measures.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Year ended December 31, 2021 compared with year ended December 31, 2020

Earnings Attributable to Common Shareholders increased by $2.2 billion due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, unrealized net gain of $53 million ($40 million after-tax) in 2021, compared with an unrealized net loss of $122 million ($92 million after-tax) in 2020 reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions, as well as manage the exposure to movements in commodity prices;
- an impairment loss of $111 million ($83 million after-tax) in 2021 to our investment in the PennEast pipeline project after a decision by project partners to cease development, compared to a combined impairment loss of $615 million ($452 million after-tax) in 2020 to our investments in Southeast Supply Header (SESH) and Steckman Ridge, LP (Steckman);
- a gain of $303 million ($298 million after-tax) resulting from the sale of our investment in Noverco;
- employee severance, transition and transformation costs of $147 million ($112 million after-tax) in 2021, compared to $339 million ($256 million after-tax) in 2020 primarily related to our voluntary workforce reduction program offered in the second quarter of 2020;
- the absence in 2021 of a non-cash impairment to the carrying value of our investment in DCP Midstream, LLC (DCP Midstream) of $1.7 billion ($1.3 billion after-tax) and a $324 million loss ($244 million after-tax) resulting from our share of asset and goodwill impairments recognized by DCP Midstream, both recognized in 2020; and

- the absence in 2021 of a $159 million loss ($119 million after-tax) recorded in 2020 to reflect the Texas Eastern rate case settlement that re-established the Excess Accumulated Deferred Income Tax (EDIT) regulated liability that was previously eliminated in December 2018; partially offset by
- a non-cash, unrealized derivative fair value net gain of $197 million ($150 million after-tax) in 2021, compared with a net gain of $856 million ($646 million after-tax) in 2020, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks.

The non-cash, unrealized derivative fair value gains and losses discussed above generally arise as a result of a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price risks. This program creates volatility in reported short-term earnings through the recognition of unrealized non-cash gains and losses on financial derivative instruments used to hedge these risks. Over the long-term, we believe our hedging program supports the reliable cash flows and dividend growth upon which our investor value proposition is based.

After taking into consideration the factors above, the remaining $657 million increase in earnings attributable to common shareholders is primarily explained by the following significant business factors:

- stronger contributions from our Liquids Pipelines segment due to increased volumes enabled by incremental Line 3 capacity placed into service in the fourth quarter of 2021 and a higher Mainline International Joint Tariff (IJT) Benchmark Toll, partially offset by the recognition of a provision against the interim Mainline IJT for barrels shipped between July 1, 2021 and December 31, 2021;
- increased earnings from our Gas Distribution and Storage segment due to increased rates and customer base;
- higher equity earnings from our Aux Sable and DCP Midstream joint ventures in our Gas Transmission and Midstream; and
- lower interest expense for the first nine months of 2021 due to favourable interest rates on short-term borrowings, and the impact of a weaker US dollar currency that positively impacted the translation of interest payments on US dollar denominated debt.

The business factors above were partially offset by the following:

- decreased earnings from our Energy Services segment due to the significant compression of location and quality differentials in certain markets, fewer storage opportunities due to market backwardation, adverse impacts from the major winter storm experienced across the US Midwest during February 2021 and fewer opportunities to achieve profitable transportation margins on facilities in which Energy Services holds capacity obligations;
- the net unfavorable effect of translating US dollar EBITDA to Canadian dollars at a lower average exchange rate in 2021 compared to the same period in 2020;
- the absence in 2021 of the recognition of revenue in 2020 from a rate settlement on Texas Eastern, partially offset by increased revenue due to the absence of pressure restrictions that existed on the Texas Eastern system in 2020; and
- higher depreciation expense on new assets placed into service throughout 2021, including the US L3R Program, placed into service early in the fourth quarter and the EIEC, acquired in mid-October.

REVENUES

We generate revenues from three primary sources: transportation and other services, gas distribution sales and commodity sales.

Transportation and other services revenues of $16.2 billion, $16.2 billion and $16.6 billion for the years ended December 31, 2021, 2020 and 2019, respectively, were earned from our crude oil and natural gas pipeline transportation businesses and also include power generation revenues from our portfolio of renewable and power generation assets. For our transportation assets operating under market-based arrangements, revenues are driven by volumes transported and the corresponding tolls for transportation services. For assets operating under take-or-pay contracts, revenues reflect the terms of the underlying contract for services or capacity. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator and, in most cost-of-service based arrangements, are reflective of our cost to provide the service plus a regulator-approved rate of return.

Gas distribution sales revenues of $4.0 billion, $3.7 billion and $4.2 billion for the years ended December 31, 2021, 2020 and 2019, respectively, were recognized in a manner consistent with the underlying rate-setting mechanism mandated by the regulator. Revenues generated by the gas distribution businesses are primarily driven by volumes delivered, which vary with weather and customer composition and utilization, as well as regulator-approved rates. The cost of natural gas is passed through to customers through rates and does not ultimately impact earnings due to its flow-through nature.

Commodity sales revenues of $26.9 billion, $19.3 billion and $29.3 billion for the years ended December 31, 2021, 2020 and 2019, respectively, were generated primarily through our Energy Services operations. Energy Services includes the contemporaneous purchase and sale of crude oil, natural gas, power and Natural Gas Liquids (NGLs) to generate a margin, which is typically a small fraction of gross revenue. While sales revenue generated from these operations are impacted by commodity prices, net margins and earnings are relatively insensitive to commodity prices and reflect activity levels which are driven by differences in commodity prices between locations, grades and points in time, rather than on absolute prices. Any residual commodity margin risk is closely monitored and managed. Revenues from these operations depend on activity levels, which vary from year-to-year depending on market conditions and commodity prices.

Our revenues also include changes in unrealized derivative fair value gains and losses related to foreign exchange and commodity price contracts used to manage exposures from movements in foreign exchange rates and commodity prices. The mark-to-market accounting creates volatility and impacts the comparability of revenues in the short-term, but we believe over the long-term, the economic hedging program supports reliable cash flows.

BUSINESS SEGMENTS

LIQUIDS PIPELINES

	2021	2020	2019
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**7,897**	7,683	7,681

1 Non-GAAP financial measure.

Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was negatively impacted by $335 million due to certain unusual, infrequent or other non-operating factors, primarily explained by a non-cash, unrealized gain of $120 million in 2021 compared with an unrealized gain of $545 million in 2020 reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks.

The factor above was partially offset by the following:

- a property tax settlement receipt of $57 million in 2021 related to the resolution of Minnesota property tax appeals for the tax years 2012 through 2018; and
- the absence in 2021 of $30 million of asset impairment losses recognized in 2020.

After taking into consideration the factors above, the remaining $549 million increase is primarily explained by the following factors:

- higher Mainline system ex-Gretna average throughput of 2.8 million barrels per day (mmbpd) in 2021 as compared to 2.6 mmbpd in 2020 driven by the rebounding demand for crude oil and related products as economies continue to recover from the impacts of the COVID-19 pandemic;
- incremental L3R capacity that came into service October 2021 further supporting demand growth and the implementation of full L3R surcharge of US$0.93 per barrel beginning October 2021 compared to the Canadian L3R program US$0.20 per barrel;
- a higher average IJT Benchmark Toll on our Mainline System of US$4.27 in 2021, compared with US$4.24 in 2020;
- a higher foreign exchange hedge rate used to lock-in US dollar denominated Canadian Mainline revenue; and
- higher equity income from our investment in the Seaway Crude Pipeline System driven by increased volumes.

The positive business factors above were partially offset by the following:

- the recognition of a provision in the fourth quarter against the interim Mainline IJT for barrels shipped between July 1, 2021 and December 31, 2021; and
- the net unfavorable effect of translating US dollar EBITDA to Canadian dollars at a lower average exchange rate in 2021 versus 2020.

GAS TRANSMISSION AND MIDSTREAM

	2021	2020	2019
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**3,671**	1,087	3,371

1 Non-GAAP financial measure.

Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was positively impacted by $2.6 billion due to certain unusual, infrequent or other non-operating factors primarily explained by the following:

- an impairment loss of $111 million in 2021 to our investment in the PennEast pipeline project after a decision by project partners to cease development, compared to a combined impairment loss of $615 million in 2020 to our investments in SESH and Steckman;
- the absence in 2021 of a $1.7 billion non-cash impairment to the carrying value of our investment in DCP Midstream and a $324 million loss resulting from our share of asset and goodwill impairments recognized by DCP Midstream, both recognized in 2020;
- the absence in 2021 of a $159 million loss recorded in 2020 to reflect the Texas Eastern rate case settlement that re-established the EDIT regulated liability that was previously eliminated in December 2018; partially offset by
- a negative impact in equity earnings of $44 million in 2021, compared with a positive impact of $22 million in 2020 relating to changes in the mark-to-market value of derivative financial instruments within our equity method investee, DCP Midstream.

After taking into consideration the factors above, we saw a $45 million decrease to EBITDA that is primarily explained by the following business factors:

- the net unfavorable effect of translating US dollar EBITDA at a lower Canadian to US dollar average exchange rate in 2021, compared to the same period in 2020; and
- the absence in 2021 of the recognition of revenue in 2020 that related to the settlement of interim rates collected from shippers on Texas Eastern, retroactive to June 1, 2019.

The factors above were partially offset by the following positive factors:

- higher commodity prices benefiting equity earnings from our Aux Sable and DCP Midstream joint ventures;
- increased revenue due to the absence of pressure restrictions that existed on the Texas Eastern system in 2020; and
- a full year of contributions from the Atlantic Bridge Phase III project after it commenced service in January of 2021.

GAS DISTRIBUTION AND STORAGE

	2021	2020	2019
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**2,117**	1,748	1,747

1 Non-GAAP financial measure.

Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was positively impacted by $338 million due to certain unusual, infrequent or other non-operating factors primarily explained by the following:

- a gain of $303 million resulting from the sale of our investment in Noverco; and
- a non-cash, unrealized gain of $14 million in 2021, compared with a loss of $10 million in 2020, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks.

After taking into consideration the positive factors above, the remaining $31 million increase is primarily explained by the following significant business factors:

- higher distribution charges resulting from increases in rates and customer base; and
- higher storage revenue, mainly relating to storage optimization activities.

The positive business factors above were partially offset by the following factors:

- higher operating and administrative costs largely related to operational, pipeline integrity and safety costs; and
- when compared with the normal weather forecast embedded in rates, weather was warmer in both 2021 and 2020, negatively impacting EBITDA in both years. Warmer than normal weather in 2021 negatively impacted 2021 EBITDA by approximately $55 million, while the warmer than normal weather in 2020 negatively impacted 2020 EBITDA by approximately $33 million.

RENEWABLE POWER GENERATION

	2021	2020	2019
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**508**	523	111

1 Non-GAAP financial measure.

Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was negatively impacted by $15 million primarily explained by the following significant business factors:

- weaker wind resources at Canadian and United States wind facilities and the effects from the Texas winter storm in February 2021; and
- the absence in 2021 of reimbursements received in 2020 at certain Canadian wind facilities resulting from a change in operator; partially offset by
- the sale of a 49% interest of an entity that holds our 50% interest in EMF.

ENERGY SERVICES

	2021	2020	2019
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization[1]	**(313)**	(236)	250

1 Non-GAAP financial measure.

EBITDA from Energy Services is dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was positively impacted by $164 million due to certain unusual, infrequent or other non-operating factors, primarily explained by a non-cash, unrealized net gain of $53 million in 2021, compared with a loss of $122 million in 2020, reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions, as well as manage the exposure to movements in commodity prices.

After taking into consideration the positive factors above, the remaining $241 million decrease is primarily explained by the following significant business factors:

- significant compression of location and quality differentials in certain markets;
- limited storage opportunities in 2021 due to market backwardation compared to favorable storage opportunities in 2020;
- fewer opportunities to achieve profitable transportation margins on facilities in which Energy Services holds capacity obligations; and
- adverse impacts from the major winter storm experienced across the US Midwest during February 2021.

ELIMINATIONS AND OTHER

	2021	2020	2019
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization[1]	**356**	(113)	429

1 Non-GAAP financial measure.

Eliminations and Other includes operating and administrative costs which are not allocated to business segments and the impact of foreign exchange hedge settlements. Eliminations and Other also includes the impact of new business development activities and corporate investments.

Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was positively impacted by $24 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- employee severance, transition and transformation costs of $87 million in 2021 compared with $279 million in 2020 primarily related to our voluntary workforce reduction program offered in the second quarter of 2020;
- the absence in 2021 of a non-cash loss of $74 million in 2020 relating to the recognition of a corporate guarantee obligation; and
- the absence in 2021 of a loss of $43 million in 2020 relating to the write-down of certain investments in emerging energy and other technologies; partially offset by
- a non-cash, unrealized gain of $55 million in 2021 compared with a gain of $318 million in 2020 reflecting net fair value gains and losses arising from the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk.

After taking into consideration the factors above, the remaining $445 million increase is primarily explained by realized gains related to settlements under our enterprise-wide foreign exchange risk management program which substantially offset the foreign currency exposures realized within our business segments' results.

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

The following table summarizes the status of our commercially secured projects, organized by business segment:

	Enbridge's Ownership Interest	Estimated Capital Cost[1]	Expenditures to Date[2]	Status[2]	Expected In-Service Date
(Canadian dollars, unless stated otherwise)					
LIQUIDS PIPELINES					
1. US Line 3 Replacement Program	100 %	US$4.0 billion	US$4.1 billion	Complete	In-service
2. Southern Access Expansion	100 %	US$0.5 billion	US$0.5 billion	Complete	In-service
3. Other - US	100 %	US$0.1 billion	US$0.1 billion	Complete	In-service
GAS TRANSMISSION AND MIDSTREAM					
4. T-South Reliability & Expansion Program	100 %	$1.0 billion	$0.9 billion	Complete	In-service
5. Spruce Ridge Project	100 %	$0.4 billion	$0.4 billion	Complete	In-service
6. Texas Eastern Modernization	100 %	US$0.4 billion	No significant expenditures to date	Pre-construction	2024 - 2026
7. Appalachia to Market II	100 %	US$0.1 billion	No significant expenditures to date	Pre-construction	2025
8. Other - US[3]	Various	US$0.6 billion	US$0.4 billion	Various stages	2021 - 2023
GAS DISTRIBUTION AND STORAGE					
9. System Enhancement Projects[4]	100 %	$0.4 billion	$0.1 billion	Various stages	2021 - 2023
10. Storage Enhancements	100 %	$0.1 billion	No significant expenditures to date	Under construction	2H - 2022
11. Natural Gas Expansion Program[5]	100 %	$0.1 billion	No significant expenditures to date	Pre-construction	2022 - 2027
RENEWABLE POWER GENERATION					
12. East-West Tie Line	25.0 %	$0.2 billion	$0.2 billion	Under construction	1H - 2022
13. Solar Self-Power Projects[6]	100 %	US$0.2 billion	No significant expenditures to date	Pre-construction	2022 - 2023
14. Saint-Nazaire France Offshore Wind Project[7]	25.5 %	$0.9 billion (€0.6 billion)	$0.5 billion (€0.3 billion)	Under construction	2H - 2022
15. Provence Grand Large Floating Offshore Wind Project[8]	25.0 %	$0.1 billion (€0.1 billion)	No significant expenditures to date	Pre-construction	2023
16. Fécamp Offshore Wind Project[9]	17.9 %	$0.7 billion (€0.5 billion)	$0.3 billion (€0.2 billion)	Under construction	2023
17. Calvados Offshore Wind Project[9]	21.7 %	$0.9 billion (€0.6 billion)	$0.1 billion (€0.1 billion)	Pre-construction	2024

1 These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect our share of joint venture projects.

2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to December 31, 2021.

3 Includes the US$0.1 billion Texas Eastern Middlesex Extension placed into service in September of 2021 and the US$0.1 billion Cameron Extension Project placed into service in November of 2021.

4 Includes the $0.1 billion London Line Replacement Project placed into service in December of 2021. Total estimated capital cost consists of site restoration work expected to be completed in 2022.
5 Represents Phase 2 of the Natural Gas Expansion Program (the Program) and the estimated capital cost is presented net of the maximum funding assistance we expect to receive from the Government of Ontario. The expected in-service dates represent the expected completion dates of the leave to construct requirements.
6 Self-Power Projects consists of solar self-power projects along our liquids and gas transmission systems. All 10 projects will be located at existing pump and/or compressor stations.
7 Reflects the sale of 49% of an entity that holds our 50% interest in EMF to CPP Investments that closed in the first quarter of 2021. Our equity contribution is $0.15 billion, with the remainder of the project financed through non-recourse project level debt.
8 Reflects the sale of 50% of an entity that holds our 50% interest in Provence Grand Large to CPP Investments. Our equity contribution is $0.05 billion, with the remainder of the project financed through non-recourse project level debt for each project.
9 Each project reflects the sale of 49% of an entity that holds our 50% interest in EMF to CPP Investments that closed in the first quarter of 2021. Our equity contribution is $0.1 billion, with the remainder of the project financed through non-recourse project level debt.

Risks related to the development and completion of growth projects are described under Part I. *Item 1A. Risk Factors.*

LIQUIDS PIPELINES

The following commercially secured growth projects were placed into service in 2021:

- **United States Line 3 Replacement Program** – replacement of the existing Line 3 crude oil pipeline between Neche, North Dakota and Superior, Wisconsin is now complete and in-service. The US L3R Program supports the safety and operational reliability of the Mainline System, enhances system flexibility and allows us to optimize throughput on the mainline. The US L3R Program restored the original capacity of 760 kbpd and brought the total Mainline System operating capacity to approximately 3.1 mmbpd.

- **Southern Access Expansion** – expansion of our existing Southern Access crude oil pipeline from 996 kbpd to approximately 1,200 kbpd.

GAS TRANSMISSION AND MIDSTREAM

The following commercially secured growth projects were placed into service in 2021:

- **Atlantic Bridge Phase III** – an expansion of the Algonquin natural gas transmission systems which transports 133 million cubic feet per day (mmcf/d) of natural gas to the New England region. The third and final phase of Atlantic Bridge fully commenced service in January 2021 with the Weymouth compressor station being brought online.

- **T-South Reliability & Expansion Program** – a natural gas pipeline expansion of Westcoast's BC Pipeline in southern BC that provides improved compressor reliability and additional capacity of approximately 190 mmcf/d into the Huntington/Sumas market at the US/Canada border.

- **Spruce Ridge Project** – a natural gas pipeline expansion of Westcoast's BC Pipeline in northern BC. The project provides additional capacity of up to 402 mmcf/d.

The following commercially secured growth projects are currently in pre-construction stages:

- **Texas Eastern Modernization Phase II –** this program is the modernization of compression facilities in Pennsylvania and New Jersey to increase safety and reliability and reduce associated greenhouse gas emissions at multiple sites on our Texas Eastern system. The program will be completed in stages over a period of years beginning in 2024.

- **Appalachia to Market II** - the expansion is designed to deliver 55 MDth per day on the Texas Eastern pipeline from the Appalachia supply basin in Southwest Pennsylvania to existing local distribution company customers in New Jersey beginning in late 2025. The project is a brown-field expansion and upgrade of existing Texas Eastern facilities in Pennsylvania.

GAS DISTRIBUTION AND STORAGE

The following commercially secured growth project was placed into service in 2021:

- **System Enhancement Projects** – The London Line Replacement Project replaced two existing pipelines known collectively as the London Line and included the construction of approximately 90.5-kilometers of natural gas pipeline and ancillary facilities in southern Ontario.

The following commercially secured growth projects are currently in various stages of construction:

- **System Enhancement Project** – The Lake Shore Kipling Oshawa Loop (KOL) Replacement Project is a replacement of approximately 4.5-kilometers of natural gas pipeline and ancillary facilities of the Cherry to Bathurst segment of the KOL along Lake Shore Boulevard in the City of Toronto. The St. Laurent Ottawa North Replacement Project is a replacement of approximately 16-kilometers of natural gas pipeline in the City of Ottawa. The first two phases of this project have already been completed. Phases 3 and 4 represent approximately 11.4-kilometers of pipeline.

- **Storage Enhancements** – Storage Enhancements are part of a larger delta pressuring project to increase deliverability and storage capacity at Enbridge Gas' storage facilities. The additional deliverability and storage capacity will be sold as part of Enbridge Gas' unregulated storage portfolio.

- **Natural Gas Expansion Program** – The Program was created under the Access to Natural Gas Act, 2018 to help expand access to natural gas to areas of Ontario that currently do not have access to the natural gas distribution system. Under Phase 2 of the Program, we will be provided up to $214 million in funding assistance to deliver 25 community expansion and two economic development projects throughout Ontario.

RENEWABLE POWER GENERATION

The following commercially secured growth projects are currently in various stages of construction:

- **East-West Tie Line** – a transmission project that will parallel an existing double-circuit, 230 kilovolt transmission line that connects the Wawa Transformer Station to the Lakehead Transformer Station near Thunder Bay, Ontario, including a connection midway in Marathon, Ontario.

- **Solar Self-Power Projects** – 10 solar self-power projects under development in Wisconsin, Illinois, Pennsylvania, Kentucky, Ohio and Minnesota, with a combined estimate of 97 MW of emissions-free generating capacity. These projects will provide clean power directly to our liquids and natural gas pipeline rights-of-way.

- **Saint-Nazaire France Offshore Wind Project** – a wind project located off the west coast of France that is expected to generate approximately 480-MW. Project revenues are backed by a 20-year fixed price power purchase agreement (PPA) with added power production protection.

- **Provence Grand Large Floating Offshore Wind Project** – a floating offshore wind facility off the southern coast of France that secured funding in 2021 and continues to prepare onshore construction and is expected to generate approximately 24-MW. Project revenues are underpinned by a 20-year fixed price PPA.

- **Fécamp Offshore Wind Project** – an offshore wind project located off the northwest coast of France and is expected to generate approximately 500-MW. Project revenues are underpinned by a 20-year fixed price PPA.
- **Calvados Offshore Wind Project** – an offshore wind project located off the northwest coast of France that is expected to generate approximately 448-MW. Project revenues are underpinned by a 20-year fixed price power purchase agreement.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

The following projects have been announced by us, but have not yet met our criteria to be classified as commercially secured:

LIQUIDS PIPELINES

- **Sea Port Oil Terminal Project** – the Sea Port Oil Terminal (SPOT) project consists of onshore and offshore facilities, including a fixed platform located approximately 30 miles off the coast of Brazoria County, Texas. SPOT is designed to load very large crude carriers at rates of approximately 85,000 barrels per hour, or up to approximately 2 million bpd. Along with Enterprise Products Partners, L.P., we announced our intent to jointly develop and market SPOT, and we will work to finalize an equity participation agreement. The agreement will allow us to purchase an ownership interest in SPOT, subject to SPOT receiving a deep-water port license.
- **Enbridge Houston Oil Terminal** – the terminal is expected to have an ultimate capability of up to 15 million barrels of storage, access to crude oil from all major North American production basins and will be fully integrated with the Seaway Crude Pipeline System to allow for access to Houston-area refineries, existing export facilities, the SPOT project and other facilities in the future.

GAS TRANSMISSION AND MIDSTREAM

- **Rio Bravo Pipeline** – the Rio Bravo Pipeline is designed to transport up to 4.5 billion cubic feet per day (bcf/d) of natural gas from the Agua Dulce supply area to NextDecade Corporation's (NextDecade) Rio Grande liquefied natural gas (LNG) export facility in the Port of Brownsville, Texas. We have executed a precedent agreement with NextDecade under which we will provide firm transportation capacity on the Rio Bravo Pipeline to NextDecade's Rio Grande LNG export facility for a term of at least 20 years. Construction of the pipeline will be subject to the Rio Grande LNG export facility reaching a final investment decision.

- **Ridgeline Expansion Project Opportunity** – We are working on a potential expansion of the ETNG system which would provide additional natural gas for the Tennessee Valley Authority (TVA) to support the replacement of an existing coal-fired power plant as it continues to transition its generation mix towards lower-carbon fuels. The TVA environmental review scoping process has begun for this proposed plant; TVA published a Notice of Intent on the Federal Register on June 15, 2021 to initiate their review process. Several options to replace the retiring coal-fired generation would be assessed in TVA's Environmental Impact Statement (EIS). Should the onsite natural gas option of building a combined cycle plant be selected through TVA's review, we would deliver on the required expansion of the East Tennessee system. ETNG's proposed project would consist of the installation of additional pipeline primarily along the ETNG system, the installation of one electric-powered compressor station and solar facilities behind the meter, as well as other design features all contributing to minimizing greenhouse gas emissions. Should TVA's environmental assessment determine that the natural gas solution of building an onsite combined cycle plant is the optimal supply source, and pending the approval and receipt of all necessary permits, construction of the pipeline would begin in 2025 with a target in-service date of fall 2026.

- **Valley Crossing Expansion Project** – On January 10, 2022, we executed a precedent agreement with Texas LNG Brownsville LLC (Texas LNG) under which, via an expansion of our Valley Crossing Pipeline, we will provide 0.72 bcf/d firm transportation capacity to Texas LNG's proposed LNG liquefaction and export facility in the Port of Brownsville, Texas for a term of at least 20 years. Expansion of the pipeline will be subject to Texas LNG's export facility reaching a final investment decision.

- **Texas Eastern Venice Extension Project** - a reversal and expansion of Texas Eastern's Line 40 from its existing New Roads compressor station to a new delivery point with the proposed Gator Express pipeline just south of Texas Eastern's Larose compressor station. The project is expected to deliver 1.26 bcf/d of feed gas to Venture Global's proposed Plaquemines LNG export facility located in Plaquemine Parish, Louisiana. The expansion will be subject to the Plaquemines LNG export facility reaching a final investment decision.

We also have a portfolio of additional projects under development that have not yet progressed to the point of securement.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to our growth strategy, particularly in light of the significant number and size of capital projects currently secured or under development. Access to timely funding from capital markets could be limited by factors outside our control including, but not limited to, financial market volatility resulting from economic and political events both inside and outside North America. To mitigate such risks, we actively manage financial plans and strategies to ensure we maintain sufficient liquidity to meet routine operating and future capital requirements. In the near term, we generally expect to utilize cash from operations together with commercial paper issuance and/or credit facility draws and the proceeds of capital market offerings to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. We target to maintain sufficient liquidity through securement of committed credit facilities with a diversified group of banks and financial institutions to enable us to fund all anticipated requirements for approximately one year without accessing the capital markets.

Material contractual obligations arising in the normal course of business primarily consist of long-term contracts, annual debt maturities and related interest obligations, rights-of-way and leases. See Part II. *Item 8. Financial Statements and Supplementary data - Note 18 - Debt and Note 27 - Leases* for amounts outstanding at December 31, 2021, related to debt and leases.

Long-term contracts are contracts that we have signed for the purchase of services, pipe and other materials totaling $5.9 billion which are expected to be paid over the next five years. Long-term contracts also consists of the following purchase obligations: gas transportation and storage contracts, firm capacity payments and gas purchase commitments, transportation, service and product purchase obligations, and power commitments.

Our financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives. Our current financing plan does not include any issuances of additional common equity. On January 19, 2022, we closed a $750 million private placement offering of non-call 10-year fixed-to-fixed subordinated notes which mature on January 19, 2082. The net proceeds from the offering will be used to redeem the Preference Shares, Series 17 at par on March 1, 2022.

CAPITAL MARKET ACCESS

We ensure ready access to capital markets, subject to market conditions, through maintenance of shelf prospectuses that allow for issuance of long-term debt, equity and other forms of long-term capital when market conditions are attractive. In accordance with our funding plan, we completed the following long-term debt issuances totaling US$3.9 billion and $3.2 billion in 2021:

Entity	Issuance Date	Type of Issuance	Amount
(in millions of Canadian dollars, unless stated otherwise)			
Enbridge Inc.	February 2021	Floating rate senior-notes	US$500
Enbridge Inc.	June 2021	Sustainability-linked senior notes	US$1,000
Enbridge Inc.	June, October 2021	Senior notes	US$2,000
Enbridge Inc.	September 2021	Medium-term notes	$1,100
Enbridge Inc.	September 2021	Sustainability-linked medium-term	$400
Enbridge Gas Inc.	September 2021	Medium-term notes	$900
Enbridge Pipelines Inc.	May 2021	Medium-term notes	$800
Spectra Energy Partners, LP[1]	September 2021	Senior notes	US$400

1 Issued through Texas Eastern, a wholly-owned operating subsidiary of SEP.

Credit Facilities, Ratings and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, we maintain ready access to funds through committed bank credit facilities and actively manage our bank funding sources to optimize pricing and other terms. The following table provides details of our committed credit facilities at December 31, 2021:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2022-2026	**9,137**	**7,837**	**1,300**
Enbridge (U.S.) Inc.	2023-2026	**6,948**	**4,845**	**2,103**
Enbridge Pipelines Inc.	2023	**3,000**	**667**	**2,333**
Enbridge Gas Inc.	2023	**2,000**	**1,515**	**485**
Total committed credit facilities		**21,085**	**14,864**	**6,221**

1 Maturity date is inclusive of the one-year term out option for certain credit facilities.
2 Includes facility draws and commercial paper issuances that are back-stopped by credit facilities.

On February 10, 2021, Enbridge Inc. entered into a three year, revolving, extendible, sustainability-linked credit facility for $1.0 billion with a syndicate of lenders and concurrently terminated our one year, revolving, syndicated credit facility for $3.0 billion.

On July 22 and 23, 2021, we renewed approximately $8.0 billion of our five-year credit facilities, extending the maturity date out to July 2026. We also extended approximately $10.0 billion of our 364-day extendible credit facilities to July 2022, which includes a one-year term out provision to July 2023.

On February 10, 2022 we renewed our three year $1.0 billion sustainability-linked credit facility, extending the maturity date out to July 2025.

In addition to the committed credit facilities noted above, we maintain $1.3 billion of uncommitted demand letter of credit facilities, of which $854 million was unutilized as at December 31, 2021. As at December 31, 2020, we had $849 million of uncommitted demand letter of credit facilities, of which $533 million was unutilized.

As at December 31, 2021, our net available liquidity totaled $6.5 billion (2020 - $12.7 billion), consisting of available credit facilities of $6.2 billion (2020 - $12.3 billion) and unrestricted Cash and cash equivalents of $286 million (2020 - $452 million) as reported in the Consolidated Statements of Financial Position.

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions, whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2021, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

Cash flow growth, proceeds from non-core asset dispositions, ready access to liquidity from diversified sources and a stable business model have enabled us to manage our credit profile. We actively monitor and manage key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to EBITDA.

On June 1, 2021, Moody's upgraded the credit ratings of Enbridge Inc., including our senior unsecured and issuer ratings, to Baa1 from Baa2. Moody's also upgraded the credit ratings of our subsidiaries: EEP, EELP, SEP and Texas Eastern. The outlooks of all five entities are stable.

There are no material restrictions on our cash. Total Restricted cash of $34 million, as reported on the Consolidated Statements of Financial Position, primarily includes cash collateral and future pipeline abandonment costs collected and held in trust. Cash and cash equivalents held by certain subsidiaries may not be readily accessible for alternative use by us.

Excluding current maturities of long-term debt, as at December 31, 2021 and 2020, we had a negative working capital position of $3.1 billion and $3.7 billion, respectively. In both periods, the major contributing factor to the negative working capital position was the current liabilities associated with our growth capital program.

To address this negative working capital position, we maintain significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due.

SOURCES AND USES OF CASH

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Operating activities	**9,256**	9,781	9,398
Investing activities	**(10,657)**	(5,177)	(4,658)
Financing activities	**1,236**	(4,770)	(4,745)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**(5)**	(20)	44
Net increase/(decrease) in cash and cash equivalents and restricted cash	**(170)**	(186)	39

Significant sources and uses of cash for the years ended December 31, 2021 and 2020 are summarized below:

Operating Activities
Typically, the primary factors impacting cash flow from operating activities year-over-year include changes in our operating assets and liabilities in the normal course due to various factors, including the impact of fluctuations in commodity prices and activity levels on working capital within our business segments, the timing of tax payments, as well as timing of cash receipts and payments generally. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 28. Changes in Operating Assets and Liabilities.* Cash provided by operating activities is also impacted by changes in earnings and certain unusual, infrequent and other non-operating factors, as discussed under *Results of Operations.*

Investing Activities
We continue with the execution of our growth capital program which is further described in *Growth Projects - Commercially Secured Projects*. The timing of project approval, construction and in-service dates impacts the timing of cash requirements.

A summary of additions to property, plant and equipment for the years ended December 31, 2021, 2020 and 2019 is set out below:

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Liquids Pipelines	**4,051**	2,032	2,548
Gas Transmission and Midstream	**2,353**	2,066	1,695
Gas Distribution and Storage	**1,343**	1,134	1,100
Renewable Power Generation	**16**	81	23
Energy Services	**1**	2	2
Eliminations and Other	**54**	90	124
Total capital expenditures	**7,818**	5,405	5,492

2021
The increase in cash used in investing activities primarily resulted from the following factors:
- Our acquisition of Moda on October 12, 2021 and higher capital expenditures related to the completion of the US L3R Program, partially offset by higher proceeds received from dispositions in 2021 compared with 2020 due to the sale of our interest in Noverco on December 30, 2021.

2020
The increase in cash used in investing activities primarily resulted from the following factors:
- Lower proceeds from asset dispositions in 2020 compared with 2019, primarily due to the sale of the federally regulated portion of our Canadian natural gas gathering and processing businesses assets on December 31, 2019.

- The factor above was partially offset by lower contributions to the Gray Oak Holdings LLC equity investment in 2020, higher return of capital primarily from equity investments in Seaway Crude Holdings LLC, MarEn Bakken Company LLC, Gray Oak Holdings LLC and Enbridge Renewable Infrastructure Investments S.a.r.l., and lower net cash invested in affiliate loans in 2020 compared with 2019.

Financing Activities
Cash provided by and used in financing activities primarily relates to issuances and repayments of external debt, as well as transactions with our common and preference shareholders relating to dividends, share issuances and share redemptions. Cash from financing activities is also impacted by changes in distributions to, and contributions from, noncontrolling interests.

2021
The increase in cash provided by financing activities primarily resulted from the following factors:
- Increased issuances of long-term debt, commercial paper and credit facility draws and short-term borrowings, along with lower repayments of long-term debt in 2021 compared to 2020.
- The factors above were partially offset by the redemption of Westcoast Energy Inc.'s (Westcoast) preferred shares in 2021 and increased common share dividend payments primarily due to the increase in our common share dividend rate.

2020
Cash used in financing activities in 2020 was consistent with 2019 due to the following factors:
- Increased commercial paper and credit facility draws, increased short-term borrowings and lower repayments of long-term debt in 2020 compared with 2019, partially offset by lower issuances of long-term debt.
- The absence in 2020 of the redemption of Westcoast's preferred shares in 2019.
- The above factors were partially offset by increased common share dividend payments primarily due to the increase in our common share dividend rate.

OFF-BALANCE SHEET ARRANGEMENTS
We enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Part II. *Item 8. Financial Statements and Supplementary Data - Note 31 Guarantees* for further discussion of guarantee arrangements.

Most of the guarantee arrangements that we enter into enhance the credit standings of certain subsidiaries, non-consolidated entities or less than 100%-owned entities, enabling them to conduct business. As such, these guarantee arrangements involve elements of performance and credit risk which are not included on our Consolidated Statements of Financial Position. The possibility of us having to honor our contingencies is largely dependent upon the future operations of our subsidiaries, investees and other third parties, or the occurrence of certain future events. Issuance of these guarantee arrangements is not required for the majority of our operations.

We do not have material off-balance sheet financing entities or structures, except for guarantee arrangements and financings entered into by our equity investments. For additional information on these commitments, see Part II. *Item 8. Financial Statements and Supplementary Data - Note 30 Commitments and Contingencies* and *Note 31 Guarantees*.

We do not have material off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Preference Share Issuances

Since July 2011, we have issued 315 million preference shares for gross proceeds of approximately $7.9 billion with the following characteristics:

	Gross Proceeds	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars, unless otherwise stated)						
Series A	$125 million	5.50 %	$1.37500	$25	—	—
Series B	$457 million	3.42 %	$0.85360	$25	June 1, 2022	Series C
Series C[5]	$43 million	3-month treasury bill plus 2.40%	—	$25	June 1, 2022	Series B
Series D	$450 million	4.46 %	$1.11500	$25	March 1, 2023	Series E
Series F	$500 million	4.69 %	$1.17224	$25	June 1, 2023	Series G
Series H	$350 million	4.38 %	$1.09400	$25	September 1, 2023	Series I
Series J	US$200 million	4.89 %	US$1.22160	US$25	June 1, 2022	Series K
Series L	US$400 million	4.96 %	US$1.23972	US$25	September 1, 2022	Series M
Series N	$450 million	5.09 %	$1.27152	$25	December 1, 2023	Series O
Series P	$400 million	4.38 %	$1.09476	$25	March 1, 2024	Series Q
Series R	$400 million	4.07 %	$1.01825	$25	June 1, 2024	Series S
Series 1	US$400 million	5.95 %	US$1.48728	US$25	June 1, 2023	Series 2
Series 3	$600 million	3.74 %	$0.93425	$25	September 1, 2024	Series 4
Series 5	US$200 million	5.38 %	US$1.34383	US$25	March 1, 2024	Series 6
Series 7	$250 million	4.45 %	$1.11224	$25	March 1, 2024	Series 8
Series 9	$275 million	4.10 %	$1.02424	$25	December 1, 2024	Series 10
Series 11	$500 million	3.94 %	$0.98452	$25	March 1, 2025	Series 12
Series 13	$350 million	3.04 %	$0.76076	$25	June 1, 2025	Series 14
Series 15	$275 million	2.98 %	$0.74576	$25	September 1, 2025	Series 16
Series 17	$750 million	5.15 %	$1.28750	$25	March 1, 2022	Series 18
Series 19	$500 million	4.90 %	$1.22500	$25	March 1, 2023	Series 20

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board of Directors. With the exception of Series A and Series C Preference Shares, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Series 17 and Series 19 Preference Shares contain a feature where the fixed dividend rate, when reset every five years, will not be less than 5.15% and 4.90%, respectively. No other series of Preference Shares has this feature.*

2 *Series A Preference Shares may be redeemed any time at our option. For all other series of Preference Shares, we may at our option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.*

4 *With the exception of Series A Preference Shares, after the redemption and conversion option dates, holders may elect to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/number of days in a year) x three-month Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14), 2.7% (Series 16), 4.1% (Series 18) or 3.2% (Series 20); or US$25 x (number of days in quarter/ number of days in a year) x three-month US Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).*

5 *The floating quarterly dividend amount for the Series C Preference Shares was increased to $0.15501 from $0.15349 on March 1, 2021, was increased to $0.15753 from $0.15501 on June 1, 2021, was increased to $0.16081 from $0.15753 on September 1, 2021 and was decreased to $0.15719 from $0.16081 on December 1, 2021, due to reset on a quarterly basis following the issuance thereof.*

PREFERENCE SHARE REDEMPTION

We intend to exercise our right to redeem all of our outstanding cumulative redeemable minimum rate reset preference shares, Series 17, on March 1, 2022 at a price of $25 per Series 17 share, together with all accrued and unpaid dividends, if any.

Dividends

We have paid common share dividends in every year since we became a publicly traded company in 1953. In December 2021, we announced a 3% increase in our quarterly dividend to $0.86 per common share, or $3.44 annualized, effective with the dividend payable on March 1, 2022, thereby making a dividend increase for 27 straight years.

For the years ended December 31, 2021 and 2020, total dividends paid were $6.8 billion and $6.6 billion, respectively, all of which were paid in cash and reflected in financing activities.

On December 6, 2021, our Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2022 to shareholders of record on February 15, 2022.

	Dividend per share
Common Shares[1]	$0.86000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.21340
Preference Shares, Series C[2]	$0.15719
Preference Shares, Series D	$0.27875
Preference Shares, Series F	$0.29306
Preference Shares, Series H	$0.27350
Preference Shares, Series J	US$0.30540
Preference Shares, Series L	US$0.30993
Preference Shares, Series N	$0.31788
Preference Shares, Series P	$0.27369
Preference Shares, Series R	$0.25456
Preference Shares, Series 1	US$0.37182
Preference Shares, Series 3	$0.23356
Preference Shares, Series 5	US$0.33596
Preference Shares, Series 7	$0.27806
Preference Shares, Series 9	$0.25606
Preference Shares, Series 11	$0.24613
Preference Shares, Series 13	$0.19019
Preference Shares, Series 15	$0.18644
Preference Shares, Series 17	$0.32188
Preference Shares, Series 19	$0.30625

1 The quarterly dividend per common share was increased 3% to $0.86 from $0.835, effective March 1, 2022.

2 The quarterly dividend per share paid on Series C was increased to $0.15501 from $0.15349 on March 1, 2021, was increased to $0.15753 from $0.15501 on June 1, 2021, was increased to $0.16081 from $0.15753 on September 1, 2021 and was decreased to $0.15719 from $0.16081 on December 1, 2021, due to reset on a quarterly basis following the date of issuance of the Series C Preference Shares.

SUMMARIZED FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, SEP and EEP (the Partnerships), pursuant to which Enbridge fully and unconditionally guaranteed, on a senior unsecured basis, the payment obligations of the Partnerships with respect to the outstanding series of notes issued under the respective indentures of the Partnerships. Concurrently, the Partnerships entered into a subsidiary guarantee agreement pursuant to which they fully and unconditionally guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. The Partnerships have also entered into supplemental indentures with Enbridge pursuant to which the Partnerships have issued full and unconditional guarantees, on a senior unsecured basis, of senior notes issued by Enbridge subsequent to January 22, 2019. As a result of the guarantees, holders of any of the outstanding guaranteed notes of the Partnerships (the Guaranteed Partnership Notes) are in the same position with respect to the net assets, income and cash flows of Enbridge as holders of Enbridge's outstanding guaranteed notes (the Guaranteed Enbridge Notes), and vice versa. Other than the Partnerships, Enbridge subsidiaries (including the subsidiaries of the Partnerships, collectively, the Subsidiary Non-Guarantors), are not parties to the subsidiary guarantee agreement and have not otherwise guaranteed any of Enbridge's outstanding series of senior notes.

Consenting SEP notes and EEP notes under Guarantee

SEP Notes[1]	EEP Notes[2]
4.750% Senior Notes due 2024	5.875% Notes due 2025
3.500% Senior Notes due 2025	5.950% Notes due 2033
3.375% Senior Notes due 2026	6.300% Notes due 2034
5.950% Senior Notes due 2043	7.500% Notes due 2038
4.500% Senior Notes due 2045	5.500% Notes due 2040
	7.375% Notes due 2045

1 As at December 31, 2021, the aggregate outstanding principal amount of SEP notes was approximately US$3.2 billion.
2 As at December 31, 2021, the aggregate outstanding principal amount of EEP notes was approximately US$2.4 billion.

Enbridge Notes under Guarantees

US Dollar Denominated[1]	Canadian Dollar Denominated[2]
Floating Rate Senior Notes due 2022	4.850% Senior Notes due 2022
Floating Rate Senior Notes due 2023	3.190% Senior Notes due 2022
2.900% Senior Notes due 2022	3.940% Senior Notes due 2023
4.000% Senior Notes due 2023	3.940% Senior Notes due 2023
0.550% Senior Notes due 2023	3.950% Senior Notes due 2024
3.500% Senior Notes due 2024	2.440% Senior Notes due 2025
2.500% Senior Notes due 2025	3.200% Senior Notes due 2027
4.250% Senior Notes due 2026	6.100% Senior Notes due 2028
1.600% Senior Notes due 2026	2.990% Senior Notes due 2029
3.700% Senior Notes due 2027	7.220% Senior Notes due 2030
3.125% Senior Notes due 2029	7.200% Senior Notes due 2032
2.500% Sustainability-linked Senior Notes due 2033	3.100% Sustainability-linked Senior Notes due 2033
4.500% Senior Notes due 2044	5.570% Senior Notes due 2035
5.500% Senior Notes due 2046	5.750% Senior Notes due 2039
4.000% Senior Notes due 2049	5.120% Senior Notes due 2040
3.400% Senior Notes due 2051	4.240% Senior Notes due 2042
	4.570% Senior Notes due 2044
	4.870% Senior Notes due 2044
	4.100% Senior Notes due 2051
	4.560% Senior Notes due 2064

1 As at December 31, 2021, the aggregate outstanding principal amount of the Enbridge US dollar denominated notes was approximately US$11 billion.
2 As at December 31, 2021, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately $9.2 billion.

Rule 3-10 of the US Securities and Exchange Commission's (SEC) Regulation S-X provides an exemption from the reporting requirements of the Securities Exchange Act of 1934, as amended (Exchange Act) for fully consolidated subsidiary issuers of guaranteed securities and subsidiary guarantors and allows for summarized financial information in lieu of filing separate financial statements for each of the Partnerships.

The following Summarized Combined Statement of Earnings and the Summarized Combined Statements of Financial Position combines the balances of EEP, SEP and Enbridge.

Summarized Combined Statement of Earnings

	Year ended December 31, 2021
(millions of Canadian dollars)	
Operating loss	**(64)**
Earnings	**4,970**
Earnings attributable to common shareholders	**4,604**

Summarized Combined Statements of Financial Position

	December 31, 2021	December 31, 2020
(millions of Canadian dollars)		
Accounts receivable from affiliates	**3,442**	2,108
Short-term loans receivable from affiliates	**4,947**	4,926
Other current assets	**605**	375
Long-term loans receivable from affiliates	**51,983**	43,217
Other long-term assets	**3,732**	4,237
Accounts payable to affiliates	**1,982**	1,267
Short-term loans payable to affiliates	**2,891**	4,117
Other current liabilities	**8,110**	5,628
Long-term loans payable to affiliates	**41,370**	32,035
Other long-term liabilities	**41,353**	41,353

The Guaranteed Enbridge Notes and the Guaranteed Partnership Notes are structurally subordinated to the indebtedness of the Subsidiary Non-Guarantors in respect of the assets of those Subsidiary Non-Guarantors.

Under US bankruptcy law and comparable provisions of state fraudulent transfer laws, a guarantee can be voided, or claims may be subordinated to all other debts of that guarantor if, among other things, the guarantor, at the time the indebtedness evidenced by its guarantee or, in some states, when payments become due under the guarantee:

- received less than reasonably equivalent value or fair consideration for the incurrence of the guarantee and was insolvent or rendered insolvent by reason of such incurrence;
- was engaged in a business or transaction for which the guarantor’s remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they mature.

The guarantees of the Guaranteed Enbridge Notes contain provisions to limit the maximum amount of liability that the Partnerships could incur without causing the incurrence of obligations under the guarantee to be a fraudulent conveyance or fraudulent transfer under US federal or state law.

Each of the Partnerships is entitled to a right of contribution from the other Partnership for 50% of all payments, damages and expenses incurred by that Partnership in discharging its obligations under the guarantees for the Guaranteed Enbridge Notes.

Under the terms of the guarantee agreement and applicable supplemental indentures, the guarantees of either of the Partnerships of any Guaranteed Enbridge Notes will be unconditionally released and discharged automatically upon the occurrence of any of the following events:

- any direct or indirect sale, exchange or transfer, whether by way of merger, sale or transfer of equity interests or otherwise, to any person that is not an affiliate of Enbridge, of any of Enbridge’s direct or indirect limited partnership of other equity interests in that Partnership as a result of which the Partnership ceases to be a consolidated subsidiary of Enbridge;
- the merger of that Partnership into Enbridge or the other Partnership or the liquidation and dissolution of that Partnership;
- the repayment in full or discharge or defeasance of those Guaranteed Enbridge Notes, as contemplated by the applicable indenture or guarantee agreement;

- with respect to EEP, the repayment in full or discharge or defeasance of each of the consenting EEP notes listed above;
- with respect to SEP, the repayment in full or discharge or defeasance of each of the consenting SEP notes listed above; or
- with respect to any series of Guaranteed Enbridge Notes, with the consent of holders of at least a majority of the outstanding principal amount of that series of Guaranteed Enbridge Notes.

The guarantee obligations of Enbridge of the Guaranteed Partnership Notes will terminate with respect to any series of Guaranteed Partnership Notes if that series is discharged or defeased.

The Partnerships also guarantee the obligations of Enbridge under its existing credit facilities**.**

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

Michigan Line 5 Dual Pipelines - Straits of Mackinac Easement
In 2019, the Michigan Attorney General filed a complaint in the Michigan Ingham County Circuit Court (the Court) that requests the Court to declare the easement granted in 1953 that we have for the operation of Line 5 in the Straits of Mackinac (the Straits) to be invalid and to prohibit continued operation of Line 5 in the Straits “as soon as possible after a reasonable notice period to allow orderly adjustments by affected parties”. On December 15, 2021, we removed the case to the US District Court in the Western District of Michigan (US District Court), where it was assigned to Judge Janet T. Neff. The removal of the Attorney General’s case to federal court follows a November 16, 2021 ruling (further described below) which held that the similar (and now dismissed) 2020 lawsuit brought by the Governor to force Line 5’s shutdown raised important federal issues that should be heard in federal court. On December 21, 2021, the Attorney General made a request to file a remand motion and on December 28, 2021, we responded to her request to file that motion. On January 5, 2022, the court issued an Order allowing the Attorney General to file a motion to remand the 2019 case. The Attorney General’s motion and brief was filed on January 14, 2022, and our response is due on February 11, 2022. The motion is expected to be fully briefed by March 2022.

On November 13, 2020, the Governor of Michigan and the Director of the Michigan Department of Natural Resources notified us that the State of Michigan (the State) was revoking and terminating the easement granted in 1953 that allows Line 5 to operate across the Straits. The notice demanded that the portion of Line 5 that crosses the Straits must be shut down by May 2021. On November 24, 2020, we filed in the US District Court for the Western District of Michigan a Notice of Removal, which removed the State’s November Complaint to federal court, and a Complaint for Declaratory and Injunctive Relief that requests the US District Court to enjoin the Governor from taking any action to prevent or impede the operation of Line 5. US District Court Judge Neff was assigned to the cases and on November 16, 2021, Judge Neff issued an order denying the State’s motion to remand its 2020 case back to Ingham County Circuit Court ,finding that the case should remain in federal court. Judge Neff also ruled in our favor on our motion for additional briefing and granted the Government of Canada’s motion to file a supplemental brief, which reiterated that the 1977 Transit Pipelines Treaty between the US and Canada had been invoked in October and that the matter is of great importance to Canada. Subsequently, the Governor voluntarily dismissed the State’s lawsuit on November 30, 2021.

Our lawsuit to prohibit the Governor of Michigan and Director of the Michigan Department of Natural Resources from interfering with the operation of Line 5, remains in federal court. On November 30, 2021 the State made a request to Judge Neff to file a motion to dismiss the complaint. On the same date, we made a request to file a motion for summary judgment. Briefing on these motions began on January 18, 2022 and is scheduled to be complete by April 2022.

In 2021, we completed the engineering and design phase of the Great Lakes Tunnel Project and we have begun the process of hiring a contractor to construct the tunnel. We continue to actively pursue state and federal regulatory permits from the US Army Corps of Engineers (Army Corps), the Michigan Department of Environment, Great Lakes & Energy (EGLE) and the Michigan Public Service Commission (MPSC). The EGLE permits were granted in the first quarter of 2021; one of the EGLE permits was challenged by the Bay Mills Indian Community. Dispositive motions are fully briefed and with the Administrative Law Judge for decision.

On June 23, 2021, the Army Corps announced they would proceed with an EIS for the Great Lakes Tunnel Project to replace Line 5 at the Straits. On June 23, 2021, we issued a statement stating that construction on this project would be delayed due to the EIS.

In the MPSC contested case proceeding, testimony has been filed, and the hearing took place during January 2022, with briefing scheduled to be complete by March 2022.

Dakota Access Pipeline
We own an effective interest of 27.6% in the Bakken Pipeline System, which is inclusive of DAPL. The Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe filed lawsuits in 2016 with the US Court for the District of Columbia (the District Court) contesting the lawfulness of the Army Corps easement for DAPL, including the adequacy of the Army Corps' environmental review and tribal consultation process. The Oglala Sioux and Yankton Sioux Tribes also filed lawsuits alleging similar claims in 2018.

On June 14, 2017, the District Court found the Army Corps' environmental review to be deficient and ordered the Army Corps to conduct further study concerning spill risks from DAPL. In August 2018, the Army Corps completed on remand the further environmental review ordered by the District Court and reaffirmed the issuance of the easement for DAPL. All four plaintiff Tribes subsequently amended their complaints to include claims challenging the adequacy of the Army Corps' August 2018 remand decision.

On March 25, 2020, in response to amended complaints from the Tribes, the District Court found the Army Corps' environmental review on remand was deficient and ordered the Army Corps to prepare an EIS to address unresolved controversy pertaining to potential spill impacts resulting from DAPL. On July 6, 2020, the District Court issued an order vacating the Army Corps' easement for DAPL and ordering that the pipeline be shut down by August 5, 2020. Dakota Access, LLC and the Army Corps appealed the decision and filed a motion for a stay pending appeal with the US Court of Appeals for the District of Columbia Circuit. On August 5, 2020, the US Court of Appeals stayed the District Court's July 6 order to shut down and empty the pipeline, but did not stay the District Court's March 25 order requiring the Army Corps to prepare an EIS or the District Court's July 6 order vacating the DAPL easement.

On January 26, 2021, the US Court of Appeals affirmed the District Court's decision, holding that the Army Corps is required to prepare an EIS and that the Army Corps' easement for DAPL is vacated. Dakota Access, LLC has since filed a petition asking the US Supreme Court to review the decision that an EIS is required. The US Court of Appeals also determined that, absent considering the closure of DAPL in the context of an injunction proceeding, the District Court could not order DAPL's operations to cease. While not an issue before the US Court of Appeals, the US Court of Appeals also recognized that the Army Corps could consider whether to allow DAPL to continue to operate in the absence of an easement. On September 20, 2021, DAPL requested that the US Supreme Court review the US Court of Appeals decision. That request, opposed by the US Government and the Tribes, remands pending.

On May 21, 2021, the District Court dismissed the plaintiff Tribes' request for an injunction enjoining DAPL from operating until the Army Corps has completed its EIS. The right of the plaintiff Tribes to appeal the denial of the injunction request expired on July 20, 2021. The Army Corps earlier indicated that it did not intend, at that time, to exercise its authority to bar DAPL's continued operation, notwithstanding the absence of an easement and that it anticipates completing its EIS by March 2022.

On July 22, 2021, the Army Corps filed a notice with the District Court advising that the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a notice asserting violations of federal safety regulations resulting from the operation of DAPL. The Army Corps stated that it would consider PHMSA's notice as part of its ongoing consideration of whether and how the Army Corps will enforce its rights on property crossed by the pipeline and in the context of the ongoing EIS. The Army Corps also granted the request from the Tribes to extend the EIS completion date to September 2022.

OTHER LITIGATION
We and our subsidiaries are involved in various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

TAX MATTERS
We and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

CRITICAL ACCOUNTING ESTIMATES

Our consolidated financial statements are prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP), which require management to make estimates, judgments and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. In making judgments and estimates, management relies on external information and observable conditions, where possible, supplemented by internal analysis as required. We believe our most critical accounting policies and estimates discussed below have an impact across the various segments of our business.

Business Combinations
We apply the provisions of Accounting Standards Codification (ASC) 805 *Business Combinations* in accounting for our acquisitions. The acquired long-lived assets, intangible assets and assumed liabilities are recorded at their estimated fair values at the date of acquisition. Goodwill represents the excess of the purchase price over the fair value of net assets. While we use our best estimates and assumptions to accurately value assets acquired and liabilities assumed at the date of acquisition, as well as any contingent consideration, our estimates are inherently uncertain and subject to refinement. During the measurement period, which may be up to one year from the acquisition date, we record adjustments to the assets acquired and liabilities assumed with the corresponding offset to goodwill. Upon the conclusion of the measurement period or final determination of values of assets acquired or liabilities assumed, whichever comes first, any subsequent adjustments are recorded to our consolidated statements of operations.

Accounting for business combinations requires significant judgment, estimates and assumptions at the acquisition date. In developing estimates of fair values at the acquisition date, we utilize a variety of factors including market data, historical and future expected cash flows, growth rates and discount rates. The subjective nature of our assumptions increases the risk associated with estimates surrounding the projected performance of the acquired entity.

Goodwill Impairment
Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired.

We perform our impairment assessment annually on April 1 at the reporting unit level. Reporting units are determined by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends, and industry conditions. Based on our assessment of the qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than it's carrying amount, a quantitative goodwill impairment assessment is performed.

The quantitative goodwill impairment assessment involves determining the fair value of our reporting units and comparing those values to the carrying value of each corresponding reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. Fair value of our reporting units is estimated using a combination of discounted cash flow models and earnings multiples techniques. The determination of fair value using the discounted cash flow model technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. The cash flow projections include significant judgments and assumptions relating to discount rates and expected future capital expenditures. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multipliers for reporting units.

Our most recent annual assessment of the goodwill balance was performed on April 1, 2021. As at April 1, 2021, our reporting units were equivalent to our reportable segments. We performed a quantitative goodwill impairment assessment for the Gas Transmission and Midstream reporting unit and qualitative assessments for the Liquids Pipelines and Gas Distribution and Storage reporting units. Our goodwill impairment assessments did not result in an impairment charge. Also, we did not identify any indicators of goodwill impairment during the remainder of 2021.

Asset Impairment

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, business climate, legal or regulatory changes, or other factors indicate we may not recover the carrying amount of our assets. We continually monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we will assess the fair value of the asset. An impairment loss is recognized when the carrying amount of the asset exceeds its fair value.

With respect to equity method investments, we assess at each balance sheet date whether there is objective evidence that the investment is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is objective evidence of impairment, we determine whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the investment.

Asset fair value is determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires the use of projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes to these projections and assumptions could result in revisions to the evaluation of the recoverability of the asset and the recognition of an impairment loss in the Consolidated Statements of Earnings.

Assets Held for Sale
We classify assets as held for sale when management commits to a formal plan to actively market an asset or a group of assets and when management believes it is probable the sale of the assets will occur within one year. We measure assets classified as held for sale at the lower of their carrying value and their estimated fair value less costs to sell.

Regulatory Accounting
Certain of our businesses are subject to regulation by various authorities, including but not limited to, the CER, the FERC, the Alberta Energy Regulator, La Régie de l'energie du Québec and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities. Key determinants in the ratemaking process are:

- Costs of providing service, including operating costs, capital invested, depreciation expense and taxes;
- Allowed rate of return, including the equity component of the capital structure and related income taxes;
- Interest costs on the debt component of the capital structure; and
- Contract and volume throughput assumptions.

The allowed rate of return is determined in accordance with the applicable regulatory model and may impact our profitability. The rates for a number of our projects are based on a cost-of-service recovery model that follows the regulators' authoritative guidance. Under the cost-of-service tolling methodology, we calculate tolls based on forecast volumes and cost. A difference between forecast and actual results causes an over or under recovery in any given year. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or expected to be paid to cover future abandonment costs in relation to the CER's Land Matters Consultation Initiative (LMCI) and for future removal and site restoration costs as approved by the OEB.

To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates.

As at December 31, 2021 and 2020, our regulatory assets totaled $5.9 billion and $5.6 billion, respectively, and regulatory liabilities totaled $3.4 billion and $3.4 billion, respectively.

Depreciation

Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2021 and 2020, of $100.1 billion and $94.6 billion, respectively, is charged in accordance with two primary methods. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of our assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by our pipelines as well as the demand for crude oil and natural gas and the integrity of our systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of our business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

Pension and Other Postretirement Benefits

We use certain assumptions relating to the calculation of defined benefit pension and other postretirement liabilities and net periodic benefit costs. These assumptions comprise management's best estimates of expected return on plan assets, future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments anticipated to be made under each of the respective plans. The expected return on plan assets is determined using market-related values and assumptions on the asset mix consistent with the investment policy relating to the assets and their projected returns. The assumptions are reviewed annually by our independent actuaries. Actual results that differ from results based on assumptions are amortized over future periods and, therefore, could materially affect the expense recognized and the recorded obligation in future periods.

The following sensitivity analysis identifies the impact on the December 31, 2021 Consolidated Financial Statements of a 0.5% change in key pension and other postretirement benefit obligations (OPEB) assumptions:

	Canada		United States	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Pension				
Decrease in discount rate	378	31	70	5
Decrease in expected return on assets	—	21	—	5
Decrease in rate of salary increase	(71)	(15)	(6)	(2)
OPEB				
Decrease in discount rate	21	1	8	—
Decrease in expected return on assets	N/A	N/A	—	1

Contingent Liabilities
Provisions for claims filed against us are determined on a case-by-case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on our financial results and certain subsidiaries and investments are detailed in Part II. *Item 8. Financial Statements and Supplementary Data - Note 30. Commitments and Contingencies*. In addition, any unasserted claims that later may become evident could have a material impact on our financial results and certain subsidiaries and investments.

Asset Retirement Obligations
Asset Retirement Obligations (ARO) associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. The discount rates used to estimate the present value of the expected future cash flows for the year ended December 31, 2021 ranged from 0.9% to 9.0% (2020 - 1.8% to 9.0%). ARO is added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

In 2009, the CER issued a decision related to the LMCI, which required holders of an authorization to operate a pipeline under the CER Act to file a proposed process and mechanism to set aside funds to pay for future abandonment costs in respect of the sites in Canada used for the operation of a pipeline. The CER's decision stated that while pipeline companies are ultimately responsible for the full costs of abandoning pipelines, abandonment costs are a legitimate cost of providing service and are recoverable from the users of the pipeline upon approval by the CER. Following the CER's final approval of the collection mechanism and the set-aside mechanism for LMCI, we began collecting and setting aside funds to cover future abandonment costs effective January 1, 2015. The funds collected are held in trust in accordance with the CER decision. The funds collected from shippers are reported within Transportation and other services revenues and Restricted long-term investments. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense and Other long-term liabilities.

The Minnesota Public Utilities Commission (MPUC), in its June 28, 2018 decision granting the Line 3 Replacement Project's Certificate of Need, required Enbridge to establish and fund a decommissioning trust (Decommissioning Trust Fund) for the purpose of funding the cost of retiring Line 3 Replacement Project assets at the end of their useful lives. Further to the Certificate of Need decision, in late 2021 the MPUC established a process for the purpose of determining the terms and conditions of the Decommissioning Trust Fund. Enbridge anticipates this MPUC process to be completed in 2022, with a decision from the MPUC in the second half of 2022. Enbridge expects to recover contributions necessary to fund the Decommissioning Trust Fund from its shippers through rates.

CHANGES IN ACCOUNTING POLICIES

Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 3. Changes in Accounting Policies*.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk
We generate certain revenues, incur expenses and hold a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

We employ financial derivative instruments to hedge foreign currency denominated earnings exposure. A combination of qualifying and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses and to manage variability in cash flows. We hedge certain net investments in US dollar denominated investments and subsidiaries using foreign currency derivatives and US dollar denominated debt.

Interest Rate Risk
Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt within the Board of Directors approved policy limit of a maximum of 30% of floating rate debt as a percentage of total debt outstanding. We primarily use qualifying derivative instruments to manage interest rate risk. Pay fixed-receive floating interest rate swaps may be used to hedge against the effect of future interest rate movements. We have implemented a program to mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 3.9%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of changes in market interest rates. Pay floating-receive fixed interest rate swaps are used, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in fair value via execution of fixed to floating interest rate swaps. As at December 31, 2021, we do not have any pay floating-receive fixed interest rate swaps outstanding.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have established a program including some of our subsidiaries to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 2.0%.

Commodity Price Risk
Our earnings and cash flows are exposed to changes in commodity prices as a result of our ownership interests in certain assets and investments, as well as through the activities of our energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. We employ financial and physical derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. We use primarily non-qualifying derivative instruments to manage commodity price risk.

Equity Price Risk
Equity price risk is the risk of earnings fluctuations due to changes in our share price. We have exposure to our own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. We use equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted share units. We use a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

Market Risk Management
We have a Risk Policy to minimize the likelihood that adverse cash flow impacts arising from movements in market prices will exceed a defined risk tolerance. We identify and measure all material market risks including commodity price risks, interest rate risks, foreign exchange risk and equity price risk using a standardized measurement methodology. Our market risk metric consolidates the exposure after accounting for the impact of offsetting risks and limits the consolidated cash flow volatility arising from market related risks to an acceptable approved risk tolerance threshold. Our market risk metric is Cash Flow at Risk (CFaR).

CFaR is a statistically derived measurement used to measure the maximum cash flow loss that could potentially result from adverse market price movements over a one month holding period for price sensitive non-derivative exposures and for derivative instruments we hold or issue as recorded on the Consolidated Statements of Financial Position as at December 31, 2021. CFaR assumes that no further mitigating actions are taken to hedge or otherwise minimize exposures and the selection of a one month holding period reflects the mix of price risk sensitive assets at Enbridge. As a practical matter, a large portion of Enbridge’s exposure could be hedged or unwound in a much shorter period if required to mitigate the risks.

The consolidated CFaR policy limit for Enbridge is 3.5% of its forward 12 month normalized cash flow. At December 31, 2021 and 2020 CFaR was $103 million and $128 million or 0.9% and 1.2%, respectively, of estimated 12 month forward normalized cash flow.

LIQUIDITY RISK
Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. We also maintain current shelf prospectuses with securities regulators which enables ready access to either the Canadian or US public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2021. As a result, all credit facilities are available to us and the banks are obligated to fund and have been funding us under the terms of the facilities.

CREDIT RISK
Entering into derivative instruments may result in exposure to credit risk from the possibility that a counterparty will default on its contractual obligations. In order to mitigate this risk, we enter into risk management transactions primarily with institutions that possess strong investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated through maintenance and monitoring of credit exposure limits and contractual requirements, netting arrangements, and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

We generally have a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our financial derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit events and reduce our credit risk exposure on financial derivative asset positions outstanding with the counterparties in those circumstances.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects our best estimates of market value based on generally accepted valuation techniques or models and is supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enbridge Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated statements of financial position of Enbridge Inc. and its subsidiaries (together, the Company) as of December 31, 2021 and 2020, and the related consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2021, including the related notes (collectively referred to as the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

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Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

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Goodwill impairment assessment

As described in Notes 2 and 16 to the consolidated financial statements, the Company's goodwill balance was $32,775 million at December 31, 2021. As disclosed by management, an annual goodwill impairment assessment is performed at the reporting unit level as of April 1 of each year, or more frequently if events or circumstances indicate that the carrying value of goodwill may be impaired. Management has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. In making the qualitative assessment, management considers macroeconomic trends, changes to regulatory environments, capital accessibility, operating income trends, and changes to industry conditions. The quantitative goodwill impairment assessment involves determining the fair value of the Company's reporting units and comparing those values to the carrying value of each reporting unit, including goodwill. Fair value is estimated using a combination of discounted cash flow and earnings multiples techniques. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, expected future capital expenditures and working capital levels. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multipliers for reporting units. In the current year, the quantitative goodwill impairment assessment was performed for the Gas Transmission and Midstream (Gas Transmission) reporting unit, while the qualitative goodwill impairment assessments were performed for the Liquids Pipelines and Gas Distribution and Storage reporting units.

The principal considerations for our determination that performing procedures relating to the goodwill impairment assessment is a critical audit matter are the significant judgment required by management when (i) developing the significant assumptions related to operating income trends used in the qualitative assessment for all reporting units outside of the Gas Transmission reporting unit, and (ii) developing such significant assumptions as discount rates, projected operating income, expected future capital expenditures and earnings multipliers used to estimate the fair value of the Gas Transmission reporting unit. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures to evaluate the reasonableness of management's significant assumptions used in the qualitative assessment and the quantitative assessment of the Gas Transmission reporting unit. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing the procedures and evaluating the audit evidence obtained over the quantitative assessment.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's goodwill impairment assessment, including controls over (i) the development of significant assumptions related to operating income trends used in the qualitative assessment and (ii) the determination of the fair value estimate of the Gas Transmission reporting unit. These procedures also included, among others (i) evaluating the reasonableness of significant assumptions used by management in the qualitative assessment of the Company's reporting units, specifically those related to operating income trends and (ii) testing management's process for developing the fair value estimate of the Gas Transmission reporting unit. Testing management's process for developing the fair value estimate of the Gas Transmission reporting unit included evaluating the appropriateness of the discounted cash flow and the earnings multiples models; testing the completeness, accuracy, and relevance of underlying data used in the models; and evaluating the reasonableness of significant assumptions used by management in determining the fair value estimate including discount rates, projected operating income, expected future capital expenditures and earnings multipliers.

Assessing the reasonableness of projected operating income and its trends, and expected future capital expenditures, involved evaluating whether these significant assumptions were reasonable considering the current and past performance of the Company's reporting units, external industry data, and evidence obtained in other areas of the audit. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of management's discounted cash flow and earnings multiples models and evaluating the reasonableness of assumptions used in the models, specifically discount rates and earnings multipliers.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 11, 2022

We have served as the Company's auditor since 1949.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars, except per share amounts)			
Operating revenues			
Commodity sales	**26,873**	19,259	29,309
Gas distribution sales	**4,026**	3,663	4,205
Transportation and other services	**16,172**	16,165	16,555
Total operating revenues *(Note 4)*	**47,071**	39,087	50,069
Operating expenses			
Commodity costs	**26,608**	18,890	28,802
Gas distribution costs	**2,094**	1,779	2,202
Operating and administrative	**6,712**	6,749	6,991
Depreciation and amortization	**3,852**	3,712	3,391
Impairment of long-lived assets	**—**	—	423
Total operating expenses	**39,266**	31,130	41,809
Operating income	**7,805**	7,957	8,260
Income from equity investments *(Note 13)*	**1,711**	1,136	1,503
Impairment of equity investments *(Note 13)*	**(111)**	(2,351)	—
Other income/(expense)			
Net foreign currency gain	**286**	181	477
Gain/(loss) on dispositions	**319**	(17)	(300)
Other	**374**	74	258
Interest expense *(Note 18)*	**(2,655)**	(2,790)	(2,663)
Earnings before income taxes	**7,729**	4,190	7,535
Income tax expense *(Note 25)*	**(1,415)**	(774)	(1,708)
Earnings	**6,314**	3,416	5,827
Earnings attributable to noncontrolling interests	**(125)**	(53)	(122)
Earnings attributable to controlling interests	**6,189**	3,363	5,705
Preference share dividends	**(373)**	(380)	(383)
Earnings attributable to common shareholders	**5,816**	2,983	5,322
Earnings per common share attributable to common shareholders *(Note 6)*	**2.87**	1.48	2.64
Diluted earnings per common share attributable to common shareholders *(Note 6)*	**2.87**	1.48	2.63

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Earnings	**6,314**	3,416	5,827
Other comprehensive income/(loss), net of tax			
Change in unrealized gain/(loss) on cash flow hedges	**162**	(457)	(437)
Change in unrealized gain on net investment hedges	**49**	102	281
Other comprehensive income/(loss) from equity investees	**(12)**	(1)	40
Excluded components of fair value hedges	**(5)**	5	—
Reclassification to earnings of loss on cash flow hedges	**235**	198	127
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**21**	13	13
Reclassification to earnings of gain on equity investees	**(62)**	—	—
Actuarial gain/(loss) on pension and OPEB	**394**	(167)	(96)
Foreign currency translation adjustments	**(507)**	(853)	(3,035)
Other comprehensive income/(loss), net of tax	**275**	(1,160)	(3,107)
Comprehensive income	**6,589**	2,256	2,720
Comprehensive income attributable to noncontrolling interests	**(95)**	(22)	(7)
Comprehensive income attributable to controlling interests	**6,494**	2,234	2,713
Preference share dividends	**(373)**	(380)	(383)
Comprehensive income attributable to common shareholders	**6,121**	1,854	2,330

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 21)*			
Balance at beginning and end of year	**7,747**	7,747	7,747
Common shares *(Note 21)*			
Balance at beginning of year	**64,768**	64,746	64,677
Shares issued on exercise of stock options	**31**	22	69
Balance at end of year	**64,799**	64,768	64,746
Additional paid-in capital			
Balance at beginning of year	**277**	187	—
Stock-based compensation	**28**	30	34
Repurchase of noncontrolling interest	**—**	—	65
Options exercised	**(23)**	(21)	(61)
Change in reciprocal interest	**98**	76	117
Other	**(15)**	5	32
Balance at end of year	**365**	277	187
Deficit			
Balance at beginning of year	**(9,995)**	(6,314)	(5,538)
Earnings attributable to controlling interests	**6,189**	3,363	5,705
Preference share dividends	**(373)**	(380)	(383)
Common share dividends declared	**(6,818)**	(6,612)	(6,125)
Dividends paid to reciprocal shareholder	**8**	17	18
Modified retrospective adoption of *ASU 2016-13 Financial Instruments - Credit Losses*	**—**	(66)	—
Other	**—**	(3)	9
Balance at end of year	**(10,989)**	(9,995)	(6,314)
Accumulated other comprehensive income/(loss) *(Note 23)*			
Balance at beginning of year	**(1,401)**	(272)	2,672
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**305**	(1,129)	(2,992)
Other	**—**	—	48
Balance at end of year	**(1,096)**	(1,401)	(272)
Reciprocal shareholding			
Balance at beginning of year	**(29)**	(51)	(88)
Change in reciprocal interest	**29**	22	37
Balance at end of year	**—**	(29)	(51)
Total Enbridge Inc. shareholders' equity	**60,826**	61,367	66,043
Noncontrolling interests *(Note 20)*			
Balance at beginning of year	**2,996**	3,364	3,965
Earnings attributable to noncontrolling interests	**125**	53	122
Other comprehensive loss attributable to noncontrolling interests, net of tax			
Change in unrealized loss on cash flow hedges	**(15)**	(6)	(7)
Foreign currency translation adjustments	**(15)**	(25)	(108)
	(30)	(31)	(115)
Comprehensive income attributable to noncontrolling interests	**95**	22	7
Distributions	**(271)**	(300)	(254)
Contributions	**15**	23	12
Redemption of noncontrolling interests	**(293)**	(112)	(300)
Repurchase of noncontrolling interest	**—**	—	(65)
Other	**—**	(1)	(1)
Balance at end of year	**2,542**	2,996	3,364
Total equity	**63,368**	64,363	69,407
Dividends paid per common share	**3.34**	3.24	2.95

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Operating activities			
Earnings	**6,314**	3,416	5,827
Adjustments to reconcile earnings to net cash provided by operating activities:			
Depreciation and amortization	**3,852**	3,712	3,391
Deferred income tax expense *(Note 25)*	**1,091**	447	1,156
Unrealized derivative fair value gain, net *(Note 24)*	**(173)**	(756)	(1,751)
Income from equity investments	**(1,711)**	(1,136)	(1,503)
Distributions from equity investments	**1,630**	1,392	1,804
Impairment of long-lived assets	**—**	—	423
Impairment of equity investments	**111**	2,351	—
(Gain)/loss on dispositions	**(319)**	(6)	254
Other	**77**	268	56
Changes in operating assets and liabilities *(Note 28)*	**(1,616)**	93	(259)
Net cash provided by operating activities	**9,256**	9,781	9,398
Investing activities			
Capital expenditures	**(7,818)**	(5,405)	(5,492)
Long-term investments and restricted long-term investments	**(640)**	(487)	(1,159)
Distributions from equity investments in excess of cumulative earnings	**533**	705	417
Additions to intangible assets	**(275)**	(215)	(200)
Acquisitions	**(3,785)**	(24)	—
Proceeds from dispositions	**1,263**	265	2,110
Affiliate loans, net	**65**	(16)	(314)
Other	**—**	—	(20)
Net cash used in investing activities	**(10,657)**	(5,177)	(4,658)
Financing activities			
Net change in short-term borrowings	**394**	223	(127)
Net change in commercial paper and credit facility draws	**2,960**	1,542	825
Debenture and term note issues, net of issue costs	**8,032**	5,230	6,176
Debenture and term note repayments	**(2,264)**	(4,463)	(4,668)
Contributions from noncontrolling interests	**15**	23	12
Distributions to noncontrolling interests	**(271)**	(300)	(254)
Common shares issued	**5**	5	18
Preference share dividends	**(367)**	(380)	(383)
Common share dividends	**(6,766)**	(6,560)	(5,973)
Redemption of preferred shares held by subsidiary *(Note 20)*	**(415)**	—	(300)
Other	**(87)**	(90)	(71)
Net cash provided by/(used in) financing activities	**1,236**	(4,770)	(4,745)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**(5)**	(20)	44
Net increase/(decrease) in cash and cash equivalents and restricted cash	**(170)**	(186)	39
Cash and cash equivalents and restricted cash at beginning of year	**490**	676	637
Cash and cash equivalents and restricted cash at end of year	**320**	490	676
Supplementary cash flow information			
Cash paid for income taxes	**489**	524	571
Cash paid for interest, net of amount capitalized	**2,427**	2,538	2,738
Property, plant and equipment non-cash accruals	**831**	801	730

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2021**	2020
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**286**	452
Restricted cash	**34**	38
Accounts receivable and other *(Note 9)*	**6,862**	5,258
Accounts receivable from affiliates	**107**	66
Inventory *(Note 10)*	**1,670**	1,536
	8,959	7,350
Property, plant and equipment, net *(Note 11)*	**100,067**	94,571
Long-term investments *(Note 13)*	**13,324**	13,818
Restricted long-term investments *(Note 14)*	**630**	553
Deferred amounts and other assets	**8,613**	8,446
Intangible assets, net *(Note 15)*	**4,008**	2,080
Goodwill *(Note 16)*	**32,775**	32,688
Deferred income taxes *(Note 25)*	**488**	770
Total assets	**168,864**	160,276
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 18)*	**1,515**	1,121
Accounts payable and other *(Note 17)*	**9,767**	9,228
Accounts payable to affiliates	**90**	22
Interest payable	**693**	651
Current portion of long-term debt *(Note 18)*	**6,164**	2,957
	18,229	13,979
Long-term debt *(Note 18)*	**67,961**	62,819
Other long-term liabilities	**7,617**	8,783
Deferred income taxes *(Note 25)*	**11,689**	10,332
	105,496	95,913
Commitments and contingencies *(Note 30)*		
Equity		
Share capital *(Note 21)*		
Preference shares	**7,747**	7,747
Common shares *(2,026 outstanding at December 31, 2021 and 2020)*	**64,799**	64,768
Additional paid-in capital	**365**	277
Deficit	**(10,989)**	(9,995)
Accumulated other comprehensive loss *(Note 23)*	**(1,096)**	(1,401)
Reciprocal shareholding	**—**	(29)
Total Enbridge Inc. shareholders’ equity	**60,826**	61,367
Noncontrolling interests *(Note 20)*	**2,542**	2,996
	63,368	64,363
Total liabilities and equity	**168,864**	160,276

Variable Interest Entities (VIE) *(Note 12)*
The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
INDEX

1. BUSINESS OVERVIEW

The terms "we," "our," "us" and "Enbridge" as used in this report refer collectively to Enbridge Inc. and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge.

Enbridge is a publicly traded energy transportation and distribution company. We conduct our business through five business segments: Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation, and Energy Services. These reporting segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES
Liquids Pipelines consists of pipelines and terminals in Canada and the United States (US) that transport various grades of crude oil and other liquid hydrocarbons, including the Mainline System, Regional Oil Sands System, Gulf Coast and Mid-Continent, Southern Lights Pipeline, Express-Platte System, Bakken System, and Feeder Pipelines and Other. This segment also includes Moda Midstream Operating, LLC (Moda) which was acquired on October 12, 2021 *(Note 8)* and is a component of Gulf Coast and Mid-Continent.

GAS TRANSMISSION AND MIDSTREAM
Gas Transmission and Midstream consists of our investments in natural gas pipelines and gathering and processing facilities in Canada and the US, including US Gas Transmission, Canadian Gas Transmission, US Midstream and Other.

GAS DISTRIBUTION AND STORAGE
Gas Distribution and Storage consists of our natural gas utility operations, the core of which is Enbridge Gas Inc. (Enbridge Gas), which serves residential, commercial and industrial customers located throughout Ontario. This business segment also includes natural gas distribution activities in Québec and an investment in Noverco Inc. (Noverco). We sold our investment in Noverco to Trencap L.P. on December 30, 2021 *(Note 13)*.

RENEWABLE POWER GENERATION
Renewable Power Generation consists primarily of investments in wind and solar assets, as well as geothermal, waste heat recovery and transmission assets. In North America, assets are primarily located in the provinces of Alberta, Saskatchewan, Ontario and Québec, and in the states of Colorado, Texas, Indiana and West Virginia. We also have offshore wind assets in operation and under development in the United Kingdom, Germany and France.

ENERGY SERVICES
Our Energy Services businesses in Canada and the US undertake physical commodity marketing activity and logistical services to manage our volume commitments on various pipeline systems. Energy Services also provides energy marketing services to North American refiners, producers and other customers.

ELIMINATIONS AND OTHER
In addition to the business segments noted above, Eliminations and Other includes operating and administrative costs that are not allocated to business segments as well as a foreign exchange hedging program. Eliminations and Other also includes new business development activities and corporate investments.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (US GAAP). Amounts are stated in Canadian dollars unless otherwise noted. As a Securities and Exchange Commission (SEC) registrant, we are permitted to use US GAAP for the purposes of meeting both our Canadian and US continuous disclosure requirements.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: variable consideration included in revenue *(Note 4);* carrying values of regulatory assets and liabilities *(Note 7)*; purchase price allocations *(Note 8)*; unbilled revenues; expected credit losses; depreciation rates and carrying value of property, plant and equipment *(Note 11)*; amortization rates and carrying value of intangible assets *(Note 15)*; measurement of goodwill *(Note 16)*; fair value of asset retirement obligations (ARO) *(Note 19)*; valuation of stock-based compensation *(Note 22)*; fair value of financial instruments *(Note 24)*; provisions for income taxes *(Note 25)*; assumptions used to measure retirement benefits and OPEB *(Note 26)*; commitments and contingencies *(Note 30)*; and estimates of losses related to environmental remediation obligations *(Note 30)*. Actual results could differ from these estimates.

Certain comparative figures in our consolidated financial statements have been reclassified to conform to the current year's presentation.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include our accounts and accounts of our subsidiaries and VIEs for which we are the primary beneficiary. A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity’s operations through voting rights or do not substantively participate in the gains and losses of the entity. Upon inception of a contractual agreement, we perform an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a VIE. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity’s economic performance and the obligation to absorb losses or the right to receive benefits from the VIE entity that could potentially be significant to the VIE. Where we conclude that we are the primary beneficiary of a VIE, we consolidate the accounts of that VIE. We assess all variable interests in the entity and use our judgment when determining if we are the primary beneficiary. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. We assess the primary beneficiary determination for a VIE on an ongoing basis if there are changes in the facts and circumstances related to a VIE. If an entity is determined to not be a VIE, the voting interest entity model is applied, where an investor holding the majority voting rights consolidates the entity. The consolidated financial statements also include the accounts of any limited partnerships where we represent the general partner and, based on all facts and circumstances, control such limited partnerships, unless the limited partner has substantive participating rights or substantive kick-out rights. For certain investments where we retain an undivided interest in assets and liabilities, we record our proportionate share of assets, liabilities, revenues and expenses.

All significant intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests. Investments and entities over which we exercise significant influence are accounted for using the equity method.

REGULATION

Certain parts of our businesses are subject to regulation by various authorities including, but not limited to, the Canada Energy Regulator (CER), the Federal Energy Regulatory Commission (FERC), the Alberta Energy Regulator, the Ontario Energy Board (OEB) and La Régie de l'energie du Québec. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or expected to be paid to cover future abandonment costs in relation to the CER's Land Matters Consultation Initiative (LMCI). Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates. We believe that the recovery of our regulatory assets as at December 31, 2021 is probable over the periods described in *Note 7 - Regulatory Matters*.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component, which are both capitalized based on rates set out in a regulatory agreement. The corresponding impact on earnings is included in Interest expense for the interest component and Other income/(expense) for the equity component. In the absence of rate regulation, we would capitalize interest using a capitalization rate based on our cost of borrowing, whereas the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation relating to the equity component would not be recognized.

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains and losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

With the approval of regulators, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

For certain regulated operations to which US GAAP guidance for phase-in plans applies, negotiated depreciation rates recovered in transportation tolls may be less than the depreciation expense calculated in accordance with US GAAP in early years of long-term contracts but recovered in future periods when tolls exceed depreciation. Depreciation expense on such assets is recorded in accordance with US GAAP and no regulatory asset is recorded.

REVENUE RECOGNITION

For businesses that are not rate-regulated, revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured. Customer creditworthiness is assessed prior to agreement signing, as well as throughout the contract duration. Certain revenues from liquids and gas pipeline businesses are recognized under the terms of committed delivery contracts rather than the cash tolls received.

Long-term take-or-pay contracts, under which shippers are obligated to pay fixed amounts ratably over the contract period regardless of volumes shipped, may contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry. We recognize revenues associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Certain offshore pipeline transportation contracts require us to provide transportation services for the life of the underlying producing fields. Under these arrangements, shippers pay us a fixed monthly toll for a defined period of time which may be shorter than the estimated reserve life of the underlying producing fields, resulting in a contract period which extends past the period of cash collection. Fixed monthly toll revenues are recognized ratably over the committed volume made available to shippers throughout the contract period, regardless of when cash is received.

For the years ended December 31, 2021, 2020 and 2019, cash received net of revenue recognized for contracts under make-up rights and similar deferred revenue arrangements was $127 million, $292 million and $169 million, respectively.

For rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators. Natural gas utility revenues are recorded based on regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas.

Our Energy Services segment enters into commodity purchase and sale arrangements that are recorded on a gross basis as the related contracts are not held for trading purposes and we are acting as the principal in the transactions.

Our largest non-affiliated customer accounted for approximately 13.5% of our third-party revenues for the year ended December 31, 2021 and 13.6% for the year ended December 31, 2020. No non-affiliated customer exceeded 10% of our third-party revenues for the year ended December 31, 2019.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are used primarily to economically hedge foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Commodity sales, Transportation and other services revenue, Commodity costs, Operating and administrative expense, Net foreign currency gain/(loss) and Interest expense.

Derivatives in Qualifying Hedging Relationships
We use derivative financial instruments to manage our exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to our share price. Hedge accounting is optional and requires us to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges or net investment hedges.

Cash Flow Hedges
We use cash flow hedges to manage our exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to our share price. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Fair Value Hedges
We may use fair value hedges to hedge the fair value of debt instruments. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged risk of the asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged risk of the asset or liability ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item.

Net Investment Hedges
Gains and losses arising from the translation of our net investment in foreign operations from their functional currencies to Enbridge's Canadian dollar presentation currency are included in cumulative translation adjustments (CTA), a component of OCI. We currently have designated a portion of our US dollar denominated debt, as well as a portfolio of foreign exchange forward contracts in prior periods, as a hedge of our net investment in US dollar denominated investments and subsidiaries. As a result, the change in fair value of the foreign currency derivatives as well as the translation of US dollar denominated debt are reflected in OCI. Amounts recognized previously in Accumulated other comprehensive income/(loss) (AOCI) are reclassified to earnings when there is a reduction of the hedged net investment resulting from the disposal of a foreign operation.

Classification of Derivatives
We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities in the Consolidated Statements of Cash Flows.

Balance Sheet Offset
Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a reduction to Long-term debt in the Consolidated Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

EQUITY INVESTMENTS

Equity investments over which we exercise significant influence, but do not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for our proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to, and decreased for distributions received from, the investee. To the extent an equity investee undertakes activities necessary to commence its planned principal operations, we capitalize interest costs associated with the investment during such period.

RESTRICTED LONG-TERM INVESTMENTS

Long-term investments that are restricted as to withdrawal or usage, for the purposes of the CER's LMCI, are presented as Restricted long-term investments in the Consolidated Statements of Financial Position.

OTHER INVESTMENTS

Generally, we classify equity investments in entities over which we do not exercise significant influence and that do not have readily determinable fair values as other investments measured using the fair value measurement alternative (FVMA). These investments are recorded at cost minus impairment, if any, plus or minus the impact of observable price changes occurring in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the FVMA are reviewed for impairment each reporting period and written down to their fair value if objective evidence of impairment is identified. Equity investments with readily determinable fair values are measured at fair value through earnings. Dividends received from investments in equity securities are recognized in earnings when the right to receive payment is established.

Investments in debt securities are classified as available-for-sale and measured at fair value through OCI.

NONCONTROLLING INTERESTS

Noncontrolling interests represent ownership interests attributable to third parties in certain consolidated subsidiaries. The portion of equity not owned by us in such entities is reflected as Noncontrolling interests within the equity section of the Consolidated Statements of Financial Position.

INCOME TAXES

Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent that taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated to the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the exchange rate in effect as at the balance sheet date. Exchange gains and losses resulting from the translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period in which they arise.

Gains and losses arising from the translation of foreign operations' functional currencies to our Canadian dollar presentation currency are included in the CTA component of AOCI and are recognized in earnings upon sale of the foreign operation. Asset and liability accounts are translated at the exchange rates in effect as at the balance sheet date, while revenues and expenses are translated using monthly average exchange rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

RESTRICTED CASH

Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific commercial arrangements, are presented as Restricted cash in the Consolidated Statements of Financial Position.

LOANS AND RECEIVABLES

Affiliate long-term notes receivable are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized. Accounts receivable and other are measured at cost. Interest income is recognized in earnings as it is earned with the passage of time.

CURRENT EXPECTED CREDIT LOSSES

For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations. Other loan receivables and applicable off-balance sheet commitments utilize a discounted cash flow methodology which calculates the current expected credit losses based on historical default probability rates associated with the credit rating of the counterparty and the related term of the loan or commitment, adjusted for forward-looking information and management expectations.

NATURAL GAS IMBALANCES

The Consolidated Statements of Financial Position include balances as a result of differences in gas volumes received from, and delivered for, customers. As settlement of certain imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. Most natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

INVENTORY

Inventory is comprised of natural gas held in storage by Enbridge Gas, crude oil and natural gas held primarily by businesses in the Energy Services segment and materials and supplies. Natural gas held in storage by Enbridge Gas is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of gas purchased is deferred as a liability for future refund, or as an asset for collection as approved by the OEB. Other inventory is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, other commodities inventory is recorded to Commodity costs in the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value. Materials and supplies inventory is recorded at the lower of average cost or net realizable value.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. We capitalize interest incurred during construction for non-rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component.

Two primary methods of depreciation are utilized. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in-service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting for property, plant and equipment is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are generally not reflected in earnings but are booked as an adjustment to accumulated depreciation.

LEASES

We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach applied for other long-lived assets.

Lease liabilities and ROU assets require the use of judgment and estimates which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily consists of costs that regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; the fair value adjustment to long-term debt; actual cost of removal of previously retired or decommissioned plant assets; and actuarial gains and losses arising from defined benefit pension plans.

INTANGIBLE ASSETS

Intangible assets consist primarily of certain software costs, customer relationships and emission allowances. We capitalize costs incurred during the application development stage of internal use software projects. Customer relationships represent the underlying relationship from long-term agreements with customers that are capitalized upon acquisition. Intangible assets are generally amortized on a straight-line basis over their expected lives, commencing when the asset is available for use, with the exception of emission allowances, which are not amortized as they will be used to satisfy compliance obligations as they come due.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, the assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends and industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed.

The quantitative goodwill impairment assessment involves determining the fair value of our reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. The fair value of our reporting units is estimated using a combination of discounted cash flow and earnings multiples techniques. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. Cash flow projections include significant judgments and assumptions relating to discount rates and expected future capital expenditures. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multipliers for reporting units.

The allocation of goodwill to held-for-sale and disposed businesses is based on the relative fair value of businesses included in the relevant reporting unit.

On April 1, 2021, we performed a quantitative goodwill impairment assessment for the Gas Transmission and Midstream reporting unit and qualitative assessments for the Liquids Pipelines and Gas Distribution and Storage reporting units. Our goodwill impairment assessments did not result in an impairment charge. Also, we did not identify any indicators of goodwill impairment during the remainder of 2021.

IMPAIRMENT
We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds its expected undiscounted cash flows, we will calculate fair value based on the discounted cash flows and write the asset down to the extent that the carrying value exceeds the fair value.

With respect to investments in debt securities and equity investments, we assess at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is objective evidence of impairment, we value the expected discounted cash flows using observable market inputs. We determine whether the decline below carrying value is other-than-temporary for equity method investments or is due to a credit loss for investments in debt securities. If the decline is determined to be other-than-temporary for equity method investments or is due to a credit loss for investments in debt securities, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

ASSET RETIREMENT OBLIGATIONS
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. Fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

PENSION AND OTHER POSTRETIREMENT BENEFITS
We sponsor defined benefit and defined contribution pension plans, and defined benefit OPEB plans, which provide group health care, life insurance benefits and other postretirement benefits.

Defined benefit pension obligation and net periodic benefit cost are estimated using the projected unit credit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors, including discount rates and mortality. The OPEB benefit obligation and net periodic benefit cost are estimated using the projected unit credit method, where benefits are attributed to years of service, taking into consideration projection of benefit costs.

We use mortality tables issued by the Society of Actuaries in the US (revised in 2021) and the Canadian Institute of Actuaries (revised in 2014) to measure the benefit obligations of our US pension plans (the US Plans) and our Canadian pension plans (the Canadian Plans), respectively.

We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments we anticipate making under each of the respective plans.

Funded pension and OPEB plan assets are measured at fair value. The expected return on funded pension and OPEB plan assets is determined using market-related values and assumptions on the invested asset mix consistent with the investment policies relating to the plan assets. The market-related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period (for funded pension and OPEB plans) or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount and salary inflation experience.

The excess of the fair value of a plan's assets over the fair value of a plan's benefit obligation is recognized as Deferred amounts and other assets in the Consolidated Statements of Financial Position. The excess of the fair value of a plan's benefit obligation over the fair value of a plan's assets is recognized as Accounts payable and other and Other long-term liabilities in the Consolidated Statements of Financial Position.

Net periodic benefit cost is charged to earnings and includes:

- cost of benefits provided in exchange for employee services rendered during the year (current service cost);
- interest cost of plan obligations;
- expected return on plan assets (for funded pension and OPEB plans);
- amortization of prior service costs on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit pension plans for our non-utility operations and from defined benefit OPEB plans are presented as a component of AOCI in the Consolidated Statements of Changes in Equity. Any unrecognized actuarial gains and losses and prior service costs and credits related to those plans that arise during the period are recognized as a component of OCI, net of tax. Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit pension plans for our utility operations, which have been permitted or are expected to be permitted by the regulators, to be recovered through future rates, are presented as a component of Deferred amounts and other assets in the Consolidated Statements of Financial Position.

Our utility operations also record regulatory adjustments to reflect the difference between certain net periodic benefit costs for accounting purposes and net periodic benefit costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to earnings and OCI on an accrual basis.

For defined contribution plans, contributions made by us are expensed in the period in which the contribution occurs.

STOCK-BASED COMPENSATION

Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISO granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Additional paid-in capital. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest one-third annually from the grant date. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of Enbridge’s shares with an offset to Accounts payable and other or to Other long-term liabilities. The value of the PSUs is also dependent on our performance relative to performance targets set out under the plan.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense costs incurred for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations, taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies’ clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new information and are included in Accounts payable and other and Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in the Consolidated Statements of Financial Position.

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

CHANGES IN ACCOUNTING POLICIES
There were no changes in accounting policies during the year ended December 31, 2021.

ADOPTION OF NEW ACCOUNTING STANDARDS
Accounting for Contract Assets and Liabilities from Contracts with Customers in a Business Combination
Effective November 1, 2021, we adopted Accounting Standards Update (ASU) 2021-08 on a retrospective basis beginning January 1, 2021. The new standard was issued in October 2021 to amend business combination accounting specific to contract assets and contract liabilities resulting from contracts with customers, requiring measurement in accordance with Accounting Standards Codification (ASC) 606. The ASU is also applicable to contract assets and contract liabilities from other contracts to which ASC 606 applies, such as contract liabilities from the sale of nonfinancial assets within the scope of ASC 610-20. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Reference Rate Reform
For eligible hedging relationships existing as at January 1, 2021 and prospectively, we have applied the optional expedient in ASU 2020-04 whereby the modification of the hedging instrument does not result in an automatic hedging relationship de-designation. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Clarifying Interaction Between Equity Securities, Equity Method Investments and Derivatives
Effective January 1, 2021, we adopted ASU 2020-01 on a prospective basis. The new standard was issued in January 2020 and clarifies that observable transactions should be considered for the purpose of applying the measurement alternative in accordance with ASC 321 *Investments - Equity Securities* immediately before the application or upon discontinuance of the equity method of accounting. Furthermore, the ASU clarifies that forward contracts or purchased options on equity securities are not out of scope of ASC 815 *Derivatives and Hedging* guidance only because, upon the contracts' exercise, the equity securities could be accounted for under the equity method of accounting or fair value option. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Income Taxes
Effective January 1, 2021, we adopted ASU 2019-12 on a prospective basis. The new standard was issued in December 2019 with the intent of simplifying the accounting for income taxes. The accounting update removes certain exceptions to the general principles in ASC 740 *Income Taxes* as well as provides simplification by clarifying and amending existing guidance. The adoption of this ASU did not have a material impact on our consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES
Disclosures About Government Assistance
ASU 2021-10 was issued in November 2021 to increase the transparency of government assistance to business entities. The ASU adds new disclosure requirements for transactions with government that are accounted for using a grant or contribution accounting model by analogy. The required disclosures include information about the nature of transactions, accounting policy applied, impacted financial statement line items and significant terms and conditions. ASU 2021-10 is effective January 1, 2022 and can be applied either prospectively or retrospectively with early adoption permitted. The adoption of ASU 2021-10 is not expected to have a material impact on our consolidated financial statements.

Accounting for Certain Lessor Leases with Variable Lease Payments
ASU 2021-05 was issued in July 2021 to amend lessor accounting for certain leases with variable lease payments that do not depend on a reference index or a rate and would have resulted in the recognition of a loss at lease commencement if classified as a sales-type or a direct financing lease. The ASU amends the classification requirements of such leases for lessors to result in an operating lease classification. ASU 2021-05 is effective January 1, 2022 and can be applied either retrospectively or prospectively with early adoption permitted. The adoption of ASU 2021-05 is not expected to have a material impact on our consolidated financial statements.

Accounting for Modifications or Exchanges of Certain Equity-Classified Contracts
ASU 2021-04 was issued in May 2021 to clarify issuer accounting for modifications or exchanges of freestanding equity-classified written call options that remain equity classified after modification or exchange. The ASU requires an issuer to determine the accounting for the modification or exchange based on the economic substance of the modification or exchange. ASU 2021-04 is effective January 1, 2022 and should be applied prospectively. The adoption of ASU 2021-04 is not expected to have a material impact on our consolidated financial statements.

Accounting for Convertible Instruments and Contracts in an Entity's Own Equity
ASU 2020-06 was issued in August 2020 to simplify accounting for certain financial instruments. The ASU eliminates the current models that require separation of beneficial conversion and cash conversion features from convertible instruments and simplifies the derivative scope exception guidance pertaining to equity classification of contracts in an entity's own equity. The ASU also introduces additional disclosures for convertible debt and freestanding instruments that are indexed to and settled in an entity's own equity. The ASU amends the diluted earnings per share guidance, including the requirement to use if-converted method for all convertible instruments and an update for instruments that can be settled in either cash or shares. ASU 2020-06 is effective January 1, 2022 and should be applied on a full or modified retrospective basis. The adoption of ASU 2020-06 is not expected to have a material impact on our consolidated financial statements.

4. REVENUE

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Products and Services

Year ended December 31, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	**9,492**	**4,364**	**676**	**—**	**—**	**—**	**14,532**
Storage and other revenue	**147**	**255**	**246**	**—**	**—**	**—**	**648**
Gas gathering and processing revenue	**—**	**49**	**—**	**—**	**—**	**—**	**49**
Gas distribution revenue	**—**	**—**	**4,026**	**—**	**—**	**—**	**4,026**
Electricity and transmission revenue	**—**	**—**	**—**	**177**	**—**	**—**	**177**
Total revenue from contracts with customers	**9,639**	**4,668**	**4,948**	**177**	**—**	**—**	**19,432**
Commodity sales	**—**	**—**	**—**	**—**	**26,873**	**—**	**26,873**
Other revenue[1,2]	**375**	**42**	**13**	**336**	**—**	**—**	**766**
Intersegment revenue	**567**	**1**	**19**	**(1)**	**44**	**(630)**	**—**
Total revenue	**10,581**	**4,711**	**4,980**	**512**	**26,917**	**(630)**	**47,071**

Year ended December 31, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	9,161	4,523	674	—	—	—	14,358
Storage and other revenue	94	274	203	—	—	—	571
Gas gathering and processing revenue	—	27	—	—	—	—	27
Gas distribution revenue	—	—	3,663	—	—	—	3,663
Electricity and transmission revenue	—	—	—	198	—	—	198
Total revenue from contracts with customers	9,255	4,824	4,540	198	—	—	18,817
Commodity sales	—	—	—	—	19,259	—	19,259
Other revenue[1,2]	584	44	17	389	—	(23)	1,011
Intersegment revenue	584	2	12	—	24	(622)	—
Total revenue	10,423	4,870	4,569	587	19,283	(645)	39,087

Year ended December 31, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	9,082	4,477	743	—	—	—	14,302
Storage and other revenue	109	268	201	—	—	—	578
Gas gathering and processing revenue	—	423	—	—	—	—	423
Gas distribution revenue	—	—	4,210	—	—	—	4,210
Electricity and transmission revenue	—	—	—	180	—	—	180
Commodity sales	—	4	—	—	—	—	4
Total revenue from contracts with customers	9,191	5,172	5,154	180	—	—	19,697
Commodity sales	—	—	—	—	29,305	—	29,305
Other revenue[1,2]	659	30	9	387	(2)	(16)	1,067
Intersegment revenue	369	5	16	—	71	(461)	—
Total revenue	10,219	5,207	5,179	567	29,374	(477)	50,069

1 *Includes mark-to-market gains from our hedging program for the year ended December 31, 2021 of $59 million, (2020 - $265 million, 2019 - $346 million).*
2 *Includes revenues from lease contracts. Refer to* Note 27 - Leases*.*

We disaggregate revenue into categories which represent our principal performance obligations within each business segment. These revenue categories represent the most significant revenue streams in each segment and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Contract Receivables	Contract Assets	Contract Liabilities
(millions of Canadian dollars)			
Balance as at December 31, 2021	**2,369**	**213**	**1,898**
Balance as at December 31, 2020	2,042	226	1,815

Contract receivables represent the amount of receivables derived from contracts with customers.

Contract assets represent the amount of revenue which has been recognized in advance of payments received for performance obligations we have fulfilled (or partially fulfilled) and prior to the point in time at which our right to the payment is unconditional. Amounts included in contract assets are transferred to accounts receivable when our right to the consideration becomes unconditional.

Contract liabilities represent payments received for performance obligations which have not been fulfilled. Contract liabilities primarily relate to make-up rights and deferred revenue. Revenue recognized during the year ended December 31, 2021 included in contract liabilities at the beginning of the period is $305 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2021 were $397 million.

Performance Obligations

Segment	Nature of Performance Obligation
Liquids Pipelines	• Transportation and storage of crude oil and natural gas liquids (NGLs)
Gas Transmission and Midstream	• Transportation, storage, gathering, compression and treating of natural gas • Transportation of NGLs • Sale of crude oil, natural gas and NGLs
Gas Distribution and Storage	• Supply and delivery of natural gas • Transportation of natural gas • Storage of natural gas
Renewable Power Generation	• Generation and transmission of electricity • Delivery of electricity from renewable energy generation facilities

There was no material revenue recognized in the year ended December 31, 2021 from performance obligations satisfied in previous periods.

Payment Terms

Payments are received monthly from customers under long-term transportation, commodity sales, and gas gathering and processing contracts. Payments from Gas Distribution and Storage customers are received on a continuous basis based on established billing cycles.

Certain contracts in the US offshore business provide for us to receive a series of fixed monthly payments (FMPs) for a specified period which is less than the period during which the performance obligations are satisfied. As a result, a portion of the FMPs are recorded as contract liabilities. The FMPs are not considered to be a financing arrangement because the payments are scheduled to match the production profiles of offshore oil and gas fields, which generate greater revenue in the initial years of their productive lives.

Revenue to be Recognized from Unfulfilled Performance Obligations

Total revenue from performance obligations expected to be fulfilled in future periods is $59.8 billion, of which $7.4 billion is expected to be recognized during the year ended December 31, 2022.

The revenues excluded from the amounts above based on optional exemptions available under ASC 606, as explained below, represent a significant portion of our overall revenues and revenues from contracts with customers. Certain revenues such as flow-through operating costs charged to shippers are recognized at the amount for which we have the right to invoice our customers and are excluded from the amounts of revenue to be recognized in the future from unfulfilled performance obligations above. Variable consideration is excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. Additionally, the effect of escalation on certain tolls which are contractually escalated for inflation has not been reflected in the amounts above as it is not possible to reliably estimate future inflation rates. Revenues for periods extending beyond the current rate settlement term for regulated contracts where the tolls are periodically reset by the regulator are excluded from the amounts above since future tolls remain unknown. Finally, revenues from contracts with customers which have an original expected duration of one year or less are excluded from the amounts above.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE

Long-Term Transportation Agreements

For long-term transportation agreements, significant judgments pertain to the period over which revenue is recognized and whether the agreement provides for make-up rights for the shippers. Transportation revenue earned from firm contracted capacity arrangements is recognized ratably over the contract period. Transportation revenue from interruptible or volumetric-based arrangements is recognized when services are performed.

Variable Consideration

Revenue from arrangements subject to variable consideration is recognized only to the extent that it is probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved. Uncertainties associated with variable consideration relate principally to differences between estimated and actual volumes and prices. These uncertainties are resolved each month when actual volumes are sold or transported and actual tolls and prices are determined.

During the year ended December 31, 2021, revenue for the Canadian Mainline has been recognized in accordance with the terms of the Competitive Tolling Settlement (CTS), which expired on June 30, 2021. The tolls in place on June 30, 2021 continue on an interim basis until a new commercial arrangement is implemented and are subject to finalization and adjustment applicable to the interim period, if any. Due to the uncertainty of adjustment to tolling pursuant to a CER decision and potential customer negotiations, interim toll revenue recognized during the year ended December 31, 2021 is considered variable consideration.

Recognition and Measurement of Revenue

Year ended December 31, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	**—**	**—**	**70**	**—**	**70**
Revenue from products and services transferred over time[1]	**9,639**	**4,668**	**4,878**	**177**	**19,362**
Total revenue from contracts with customers	**9,639**	**4,668**	**4,948**	**177**	**19,432**

Year ended December 31, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	—	—	60	—	60
Revenue from products and services transferred over time[1]	9,255	4,824	4,480	198	18,757
Total revenue from contracts with customers	9,255	4,824	4,540	198	18,817

Year ended December 31, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	—	4	65	—	69
Revenue from products and services transferred over time[1]	9,191	5,168	5,089	180	19,628
Total revenue from contracts with customers	9,191	5,172	5,154	180	19,697

1 *Revenue from crude oil and natural gas pipeline transportation, storage, natural gas gathering, compression and treating, natural gas distribution, natural gas storage services and electricity sales.*

Performance Obligations Satisfied Over Time

For arrangements involving the transportation and sale of petroleum products and natural gas where the transportation services or commodities are simultaneously received and consumed by the shipper or customer, we recognize revenue over time using an output method based on volumes of commodities delivered or transported. The measurement of the volumes transported or delivered corresponds directly to the benefits received by the shippers or customers during that period.

Determination of Transaction Prices

Prices for transportation and gas processing services are determined based on the capital cost of the facilities, pipelines and associated infrastructure required to provide such services plus a rate of return on capital invested that is determined either through negotiations with customers or through regulatory processes for those operations that are subject to rate regulation.

Prices for commodities sold are determined by reference to market price indices plus or minus a negotiated differential and in certain cases a marketing fee.

Prices for natural gas sold and distribution services provided by regulated natural gas distribution operations are prescribed by regulation.

5. SEGMENTED INFORMATION

Segmented information for the years ended December 31, 2021, 2020 and 2019 is as follows:

Year ended December 31, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**10,581**	**4,711**	**4,980**	**512**	**26,917**	**(630)**	**47,071**
Commodity and gas distribution costs	**(25)**	**—**	**(2,147)**	**—**	**(27,174)**	**644**	**(28,702)**
Operating and administrative	**(3,431)**	**(1,877)**	**(1,143)**	**(180)**	**(48)**	**(33)**	**(6,712)**
Income/(loss) from equity investments	**759**	**813**	**42**	**101**	**—**	**(4)**	**1,711**
Impairment of equity investments	**—**	**(111)**	**—**	**—**	**—**	**—**	**(111)**
Other income/(expense)	**13**	**135**	**385**	**75**	**(8)**	**379**	**979**
Earnings/(loss) before interest, income tax expense and depreciation and amortization	**7,897**	**3,671**	**2,117**	**508**	**(313)**	**356**	**14,236**
Depreciation and amortization							**(3,852)**
Interest expense							**(2,655)**
Income tax expense							**(1,415)**
Earnings							**6,314**
Capital expenditures[1]	**4,051**	**2,420**	**1,343**	**16**	**1**	**54**	**7,885**
Total property, plant and equipment, net	**52,530**	**27,028**	**16,904**	**3,315**	**23**	**267**	**100,067**

Year ended December 31, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	10,423	4,870	4,569	587	19,283	(645)	39,087
Commodity and gas distribution costs	(20)	—	(1,810)	(2)	(19,450)	613	(20,669)
Operating and administrative	(3,331)	(1,859)	(1,091)	(191)	(67)	(210)	(6,749)
Income/(loss) from equity investments	558	479	9	94	(3)	(1)	1,136
Impairment of equity investments	—	(2,351)	—	—	—	—	(2,351)
Other income/(expense)	53	(52)	71	35	1	130	238
Earnings/(loss) before interest, income tax expense and depreciation and amortization	7,683	1,087	1,748	523	(236)	(113)	10,692
Depreciation and amortization							(3,712)
Interest expense							(2,790)
Income tax expense							(774)
Earnings							3,416
Capital expenditures[1]	2,033	2,130	1,134	81	2	90	5,470
Total property, plant and equipment, net	48,799	25,745	16,079	3,495	24	429	94,571

Year ended December 31, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	10,219	5,207	5,179	567	29,374	(477)	50,069
Commodity and gas distribution costs	(29)	—	(2,354)	(2)	(29,091)	472	(31,004)
Operating and administrative	(3,298)	(2,232)	(1,149)	(189)	(44)	(79)	(6,991)
Impairment of long-lived assets	(21)	(105)	—	(297)	—	—	(423)
Income/(loss) from equity investments	780	682	4	31	8	(2)	1,503
Other income/(expense)	30	(181)	67	1	3	515	435
Earnings before interest, income tax expense and depreciation and amortization	7,681	3,371	1,747	111	250	429	13,589
Depreciation and amortization							(3,391)
Interest expense							(2,663)
Income tax expense							(1,708)
Earnings							5,827
Capital expenditures[1]	2,548	1,753	1,100	23	2	124	5,550
Total property, plant and equipment, net	48,783	25,268	15,622	3,658	24	368	93,723

1 Includes allowance for equity funds used during construction.

The measurement basis for preparation of segmented information is consistent with the significant accounting policies *(Note 2)*.

GEOGRAPHIC INFORMATION

Revenues[1]

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Canada	**20,474**	16,453	19,954
US	**26,597**	22,634	30,115
	47,071	39,087	50,069

1 Revenues are based on the country of origin of the product or service sold.

Property, Plant and Equipment[1]

December 31,	**2021**	2020
(millions of Canadian dollars)		
Canada	**47,102**	46,499
US	**52,965**	48,072
	100,067	94,571

1 Amounts are based on the location where the assets are held.

6. EARNINGS PER COMMON SHARE

BASIC

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by our pro-rata weighted average interest in our own common shares of approximately 2 million as at December 31, 2021, 5 million as at December 31, 2020, and 6 million as at December 31, 2019, resulting from our reciprocal investment in Noverco. On December 30, 2021, we closed the sale of our non-operating minority ownership of Noverco. Refer to *Note 13 - Long-term Investments* for more information.

DILUTED

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

Weighted average shares outstanding used to calculate basic and diluted earnings per share are as follows:

December 31,	**2021**	2020	2019
(number of shares in millions)			
Weighted average shares outstanding	**2,023**	2,020	2,017
Effect of dilutive options	**2**	1	3
Diluted weighted average shares outstanding	**2,025**	2,021	2,020

For the years ended December 31, 2021, 2020 and 2019, 18.6 million, 29.8 million and 17.8 million, respectively, of anti-dilutive stock options with a weighted average exercise price of $52.89, $51.42 and $53.56, respectively, were excluded from the diluted earnings per common share calculation.

7. REGULATORY MATTERS

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under US GAAP for non-regulated entities. See *Note 2 - Significant Accounting Policies* for further discussion. Our significant regulated businesses and the related accounting impacts are described below.

Under the current authorized rate structure for certain operations, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of temporary differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since most of these temporary differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of the related assets.

LIQUIDS PIPELINES

Canadian Mainline

Canadian Mainline includes the Canadian portion of our mainline system and is subject to regulation by the CER. Tolls, excluding Lines 8 and 9, are governed by the 10-year CTS which expired on June 30, 2021 *(Note 4).* The CTS established a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on our Lakehead System. Under the CTS, we have recognized a regulatory asset of $2.1 billion as at December 31, 2021 (2020 - $1.9 billion) to offset deferred income taxes, as a CER rate order governing flow-through income tax treatment permits future recovery. No other material regulatory assets or liabilities are recognized under the terms of the CTS.

Southern Lights Pipeline

The US and Canadian portions of the Southern Lights Pipeline are regulated by the FERC and CER, respectively. Shippers on the Southern Lights Pipeline are subject to long-term transportation contracts under a cost-of-service toll methodology. Toll adjustments are filed annually with the regulators and provide for the recovery of allowable operating and debt financing costs, plus a pre-determined after-tax return on equity (ROE) of 10%.

GAS TRANSMISSION AND MIDSTREAM

British Columbia Pipeline and Maritimes & Northeast Canada

British Columbia (BC) Pipeline and Maritimes & Northeast (M&N) Canada are regulated by the CER. Rates are approved by the CER through negotiated toll settlement agreements based on cost-of-service. Both our BC Pipeline and M&N Canada systems operate under the terms of their respective negotiated toll settlements, which stipulate an allowable ROE and the continuation and establishment of certain deferral and variance accounts. As both settlement agreements expired in December 2021, we are currently operating under CER-approved interim tolls and negotiating the terms of new toll settlements for periods beginning in 2022.

US Gas Transmission

Most of our US gas transmission and storage services are regulated by the FERC and may also be subject to the jurisdiction of various other federal, state and local agencies. The FERC regulates natural gas transmission in US interstate commerce including the establishment of rates for services, while rates for intrastate commerce and/or gathering services are regulated by the state gas commissions. Cost-of-service is the basis for the calculation of regulated tariff rates, although the FERC also allows the use of negotiated and discounted rates within contracts with shippers that may result in a rate that is above or below the FERC-regulated recourse rate for that service.

GAS DISTRIBUTION AND STORAGE

Enbridge Gas

Enbridge Gas' distribution rates, commencing in 2019, are set under a five-year Incentive Regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% stretch factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas to share equally with customers any earnings in excess of 150 basis points over the annual OEB approved ROE.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following regulatory assets and liabilities in the Consolidated Statements of Financial Position:

December 31,	**2021**	2020	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Under-recovery of fuel costs	**114**	86	2022
Other current regulatory assets	**145**	146	2022
Total current regulatory assets[1] *(Note 9)*	**259**	232	
Long-term regulatory assets			
Deferred income taxes[2]	**4,176**	3,890	Various
Long-term debt[3]	**398**	429	2023-2046
Negative salvage[4]	**243**	246	Various
Purchase gas variance	**215**	—	2023
Accounting policy changes[5]	**157**	169	Various
Pension plan receivable[6]	**78**	402	Various
Other long-term regulatory assets	**339**	261	Various
Total long-term regulatory assets[1]	**5,606**	5,397	
Total regulatory assets	**5,865**	5,629	
Current regulatory liabilities			
Purchase gas variance	**—**	153	2021
Other current regulatory liabilities	**106**	117	2022
Total current regulatory liabilities[7]	**106**	270	
Long-term regulatory liabilities			
Future removal and site restoration reserves[8]	**1,543**	1,455	Various
Regulatory liability related to US income taxes[9]	**895**	941	2050-2072
Pipeline future abandonment costs *(Note 14)*	**649**	578	Various
Other long-term regulatory liabilities	**234**	150	Various
Total long-term regulatory liabilities[7]	**3,321**	3,124	
Total regulatory liabilities	**3,427**	3,394	

1 Current regulatory assets are included in Accounts receivable and other, while long-term regulatory assets are included in Deferred amounts and other assets.

2 Represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in future regulator-approved rates and recovered from customers. The recovery period depends on the timing of the reversal of temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded.

3 Represents our regulatory offset to the fair value adjustment to debt acquired in our merger with Spectra Energy Corp. (Spectra Energy). The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.

4 The negative salvage balance represents the recovery in future rates of the actual cost of removal of previously retired or decommissioned plant assets, as approved by the FERC.

5 This deferral reflects unamortized accumulated actuarial gains/losses and past service costs incurred by Union Gas Limited, relating to the period up to our merger with Spectra Energy, which were previously recorded in AOCI. The amortization of this balance is recognized as a component of accrual-based pension expenses, which are included in Other income/(expense) and recovered in rates, as previously approved by the OEB.

6 Represents the regulatory offset to our pension liability to the extent that it is expected to be included in regulator-approved future rates and recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense would be recorded in earnings and OCI.

7 Current regulatory liabilities are included in Accounts payable and other, while long-term regulatory liabilities are included in Other long-term liabilities.

8 Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the OEB, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

9 The regulatory liability related to US income taxes resulted from the US tax reform legislation dated December 22, 2017. These balances will be refunded to customers in accordance with the respective rate settlements approved by the FERC.

8. ACQUISITIONS AND DISPOSITIONS

ACQUISITION

Moda Midstream Operating, LLC

On October 12, 2021, through a wholly-owned US subsidiary, we acquired all of the outstanding membership interests in Moda for $3.7 billion (US$3.0 billion) of cash plus potential contingent payments of up to US$150 million dependent on performance of the assets (the Acquisition). The Acquisition is also subject to customary closing and working capital adjustments. Moda owns and operates a light crude export platform with very large crude carrier capability. The Acquisition aligns with and advances our US Gulf Coast export strategy and enables connectivity to low-cost and long-lived reserves in the Permian and Eagle Ford basins.

We accounted for the Acquisition using the acquisition method as prescribed by ASC 805 *Business Combinations*. In accordance with valuation methodologies described in ASC 820 *Fair Value Measurements*, the acquired assets and assumed liabilities were recorded at their estimated fair values as at the date of acquisition.

The following table summarizes the estimated preliminary fair values that were assigned to the net assets of Moda:

(millions of Canadian dollars)	October 12, 2021
Fair value of net assets acquired:	
Current assets	**62**
Property, plant and equipment (a)	**1,480**
Long-term investments (b)	**427**
Intangible assets (c)	**1,781**
Current liabilities	**59**
Long-term liabilities	**17**
Goodwill (d)	**268**
Purchase price:	
Cash	**3,755**
Contingent consideration (e)	**187**
	3,942

a) Due to the specialized nature of Moda's property, plant and equipment, which includes groups of assets configured for use as storage facilities, pipelines and export terminals, the depreciated replacement cost approach was adopted as the primary valuation methodology. In determining replacement cost, both indirect costing using relevant inflation indices and direct costing using relevant market quotes were utilized. Adjustments were then applied for physical deterioration as well as functional and economic obsolescence. The fair value of land was determined using a market approach, which is based on rents and offerings for comparable properties.

b) Long-term investments represent Moda's 20% equity interest in Cactus II Pipeline, LLC (Cactus II). The fair value of Cactus II was determined using the discounted cash flow method. The discounted cash flow method is an income-based approach to valuation which estimates the present value of future projected benefits from the investment.

c) Intangible assets consist primarily of customer relationships associated with long-term take-or-pay contracts. Fair value was determined using an income-based approach by estimating the present value of the after-tax earnings attributable to the contracts, including earnings associated with expected renewal terms, and will be amortized on a straight-line basis over an expected useful life of 10 years.

d) Goodwill is primarily attributable to uncontracted future revenues, existing assembled assets that cannot be duplicated at the same cost by a new entrant, and enhanced scale and geographic diversity which provide greater optionality and platforms for future growth. The goodwill balance recognized has been assigned to our Liquids Pipelines segment and is tax deductible over 15 years.

e) We agreed to pay additional contingent consideration of up to US$150 million to Moda's former membership interest holders if Moda's monthly volumes of crude oil loaded onto a vessel equal or exceed specified throughput levels. These performance requirements terminate the earlier of December 31, 2023 or the date the final contingent payment is made. The US$150 million of contingent consideration recognized in the purchase price represents the fair value of contingent consideration at the date of acquisition. As at December 31, 2021, there were no changes to the amount of contingent consideration recognized.

Acquisition-related expenses incurred were approximately $21 million for the year ended December 31, 2021 and are included in Operating and administrative expense in the Consolidated Statements of Earnings.

Upon completion of the Acquisition, we began consolidating Moda. For the period beginning October 12, 2021 through to December 31, 2021, Moda generated approximately $80 million in operating revenues and $9 million in earnings attributable to common shareholders.

Our supplemental pro forma consolidated financial information for the years ended December 31, 2021 and 2020, including the results of operations for Moda as if the Acquisition had been completed on January 1, 2020, are as follows:

Year ended December 31,	2021	2020
(unaudited; millions of Canadian dollars)		
Operating revenues	**47,339**	39,435
Earnings attributable to common shareholders[1,2]	**5,771**	2,938

1 Acquisition-related expenses of $21 million (after-tax $16 million) were excluded from earnings attributable to common shareholders for the year ended December 31 2021 and deducted for the year ended December 31, 2020.

2 Includes the amortization of fair value adjustments recorded for acquired property, plant and equipment, long-term investments and intangible assets of $193 million and $207 million (after-tax of $145 million and $155 million) for the years ended December 31, 2021 and 2020, respectively.

DISPOSITIONS

Line 10 Crude Oil Pipeline

In the first quarter of 2018, we satisfied the condition as set out in our agreements for the sale of our Line 10 crude oil pipeline (Line 10), which originates near Hamilton, Ontario and terminates at West Seneca, New York. Our subsidiaries, Enbridge Pipelines Inc. and Enbridge Energy Partners, L.P. (EEP), owned the Canadian and US portions of Line 10, respectively, and the related assets were included in our Liquids Pipelines segment. The transaction closed on June 1, 2020. No gain or loss on disposition was recorded.

Montana-Alberta Tie Line
In the fourth quarter of 2019, we committed to a plan to sell the Montana-Alberta Tie Line (MATL) transmission asset, a 345 kilometer transmission line from Great Falls, Montana to Lethbridge, Alberta. MATL was included in our Renewable Power Generation segment. The purchase and sale agreement was signed in January 2020.

Upon the reclassification and subsequent remeasurement of MATL assets as held for sale, a loss of $297 million was included within Impairment of long-lived assets in the Consolidated Statements of Earnings for the year ended December 31, 2019.

On May 1, 2020, we closed the sale of MATL for cash proceeds of approximately $189 million. After closing adjustments, a gain on disposal of $4 million was included in Other income/(expense) in the Consolidated Statements of Earnings.

Ozark Gas Transmission
In the first quarter of 2020, we agreed to sell our Ozark Gas Transmission and Ozark Gas Gathering assets (Ozark assets). The Ozark assets are composed of a transmission system that extends from southeastern Oklahoma through Arkansas to southeastern Missouri, and a fee-based gathering system that accesses Fayetteville Shale and Arkoma production. These assets were included in our Gas Transmission and Midstream segment.

On April 1, 2020, we closed the sale of the Ozark assets for cash proceeds of approximately $63 million. After closing adjustments, a gain on disposal of $1 million was included in Other income/(expense) in the Consolidated Statements of Earnings.

Canadian Natural Gas Gathering and Processing Businesses
On July 4, 2018, we entered into agreements to sell our Canadian natural gas gathering and processing businesses to Brookfield Infrastructure Partners L.P. and its institutional partners for a cash purchase price of approximately $4.3 billion, subject to customary closing adjustments. Separate agreements were entered into for those facilities currently governed by provincial regulations and those governed by federal regulations (collectively, Canadian Natural Gas Gathering and Processing Businesses assets); these assets were part of our Gas Transmission and Midstream segment.

On October 1, 2018, we closed the sale of the provincially regulated facilities. On December 31, 2019, we closed the sale of the federally regulated facilities for proceeds of approximately $1.7 billion. After closing adjustments, a loss on disposal of $268 million before tax was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2019. As these assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit to these assets using a relative fair value approach.

St. Lawrence Gas Company, Inc.
In August 2017, we entered into an agreement to sell the issued and outstanding shares of St. Lawrence Gas Company, Inc. (St. Lawrence Gas). St. Lawrence Gas assets were included in the Gas Distribution and Storage segment. On November 1, 2019, we closed the sale of St. Lawrence Gas for cash proceeds of approximately $72 million. After closing adjustments, a loss on disposal of $10 million was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2019.

Enbridge Gas New Brunswick
In December 2018, we entered into an agreement for the sale of Enbridge Gas New Brunswick Limited Partnership and Enbridge Gas New Brunswick Inc. (collectively, EGNB). EGNB assets were a part of our Gas Distribution and Storage segment. On October 1, 2019, we closed the sale of EGNB to Liberty Utilities (Canada) LP, a wholly-owned subsidiary of Algonquin Power and Utilities Corp., for cash proceeds of approximately $331 million. After closing adjustments, a loss on disposal of $3 million was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2019.

As EGNB assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit to these assets using a relative fair value approach. As such, allocated goodwill of $133 million was included in assets subsequently disposed.

9. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2021**	2020
(millions of Canadian dollars)		
Trade receivables and unbilled revenues[1]	**4,957**	3,923
Short-term portion of derivative assets *(Note 24)*	**529**	323
Regulatory assets *(Note 7)*	**259**	232
Taxes receivable	**407**	374
Other	**710**	406
	6,862	5,258

1 Net of allowance for expected credit losses of $87 million as at December 31, 2021 and $70 million as at December 31, 2020.

10. INVENTORY

December 31,	**2021**	2020
(millions of Canadian dollars)		
Natural gas	**953**	710
Crude oil	**624**	744
Other	**93**	82
	1,670	1,536

11. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2021**	2020
(millions of Canadian dollars)			
Pipelines	2.8 %	**62,997**	57,459
Facilities and equipment	3.1 %	**34,331**	30,149
Land and right-of-way[1]	2.3 %	**3,320**	2,896
Gas mains, services and other	2.7 %	**13,606**	12,813
Storage	2.4 %	**3,099**	2,936
Wind turbines, solar panels and other	4.0 %	**4,912**	4,877
Other	8.2 %	**1,507**	1,558
Under construction	— %	**2,268**	5,762
Total property, plant and equipment		**126,040**	118,450
Total accumulated depreciation		**(25,973)**	(23,879)
Property, plant and equipment, net		**100,067**	94,571

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.

Depreciation expense for the years ended December 31, 2021, 2020 and 2019 was $3.5 billion, $3.4 billion and $3.0 billion, respectively.

IMPAIRMENT

Access Northeast Project

In 2019, we announced that we terminated the agreements with Eversource Energy and National Grid USA Service Company, Inc. related to the Access Northeast project. As a result, we recognized an impairment loss of $105 million for the year ended December 31, 2019, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings. Access Northeast is part of our Gas Transmission and Midstream segment.

Impairment charges were based on the amount by which the carrying values of the assets exceeded fair value, determined using expected discounted future cash flows.

12. VARIABLE INTEREST ENTITIES

CONSOLIDATED VARIABLE INTEREST ENTITIES

Our consolidated VIEs consist of legal entities where we are the primary beneficiary. We are the primary beneficiary when our variable interest(s) provide us with (i) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (ii) the obligation to absorb losses of the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. We determine whether we are the primary beneficiary of a VIE by considering qualitative and quantitative factors, including, but not limited to: decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties.

The following table includes assets to be used to settle liabilities of our consolidated VIEs and liabilities of our consolidated VIEs for which creditors do not have recourse to our general credit as the primary beneficiary. These assets and liabilities are included in the Consolidated Statements of Financial Position.

December 31,	**2021**[1]	2020[1]
(millions of Canadian dollars)		
Assets		
Cash and cash equivalents	**247**	215
Restricted cash	**4**	1
Accounts receivable and other	**99**	65
Inventory	**9**	7
	359	288
Property, plant and equipment, net	**3,052**	3,201
Long-term investments	**16**	14
Restricted long-term investments	**101**	84
Deferred amounts and other assets	**2**	3
Intangible assets, net	**108**	115
	3,638	3,705
Liabilities		
Accounts payable and other	**84**	52
Other long-term liabilities	**182**	175
Deferred income taxes	**5**	5
	271	232
	3,367	3,473

1 *Excludes assets and liabilities of EEP and Spectra Energy Partners, L.P. (SEP) following the subsidiary guarantees agreement entered on January 22, 2019. See Part II.* Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Summarized Financial Information.

We do not have obligations to provide additional financial support to any of our consolidated VIEs.

UNCONSOLIDATED VARIABLE INTEREST ENTITIES

We currently hold interests in several non-consolidated VIEs where we are not the primary beneficiary as we do not have the power to direct the activities of the VIEs that most significantly impact the VIEs' economic performance. These interests include investments in limited partnerships that are assessed to be VIEs due to the limited partners not having substantive kick-out rights or participating rights. The power to direct the activities of a majority of these non-consolidated limited partnership VIEs is shared amongst the partners. Each partner has representatives that make up an executive committee that makes significant decisions for the VIE and none of the partners may make significant decisions unilaterally.

The carrying amount of these VIEs and our estimated maximum exposure to loss as at December 31, 2021 and 2020 are presented below:

December 31, 2021	Carrying Amount of the VIE	Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.[1]	**113**	**195**
EIH S.á r.l.[2, 8]	**38**	**664**
Enbridge Renewable Infrastructure Investments S.á r.l.[3]	**54**	**2,121**
Rampion Offshore Wind Limited[5]	**450**	**508**
Vector Pipeline L.P.[6]	**189**	**374**
Other[4,7]	**210**	**426**
	1,054	**4,288**

December 31, 2020	Carrying Amount of the VIE	Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.[1]	106	187
Éolien Maritime France SAS[2, 8]	96	949
Enbridge Renewable Infrastructure Investments S.á r.l.[3]	100	2,516
PennEast Pipeline Company, LLC[4]	116	371
Rampion Offshore Wind Limited[5]	599	650
Vector Pipeline L.P.[6]	201	390
Other[7]	133	361
	1,351	5,424

1 At December 31, 2021 and 2020, the maximum exposure to loss includes guarantees by us for our respective share of the VIE's borrowing on a bank credit facility.

2 At December 31, 2021, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the three French offshore wind projects for which we would be liable in the event of default by the VIE and an outstanding affiliate loan receivable for $73 million held by us as at December 31, 2021. On March 18, 2021, Enbridge Renewable Infrastructure Holdings S.á r.l. (ERIH) closed the sale of 49% of its interest in EIH S.á r.l. to the Canada Pension Plan Investment Board (CPP Investments).

3 At December 31, 2021 and 2020, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the project for which we would be liable in the event of default by the VIE and an outstanding affiliate loan receivable for $807 million and $904 million held by us as at December 31, 2021 and 2020, respectively.

4 At December 31, 2021, the maximum exposure to loss is limited to our equity investment and at December 31, 2020, the maximum exposure to loss includes the remaining expected contributions to the joint venture.

5 At December 31, 2021 and 2020, the maximum exposure to loss includes our parental guarantees that have been committed in project contracts in which we would be liable for in the event of default by the VIE.

6 At December 31, 2021 and 2020, the maximum exposure to loss includes the carrying value of outstanding affiliate loans receivable for $80 million and $84 million held by us as at December 31, 2021 and 2020, respectively, and an outstanding credit facility for $105 million as at December 31, 2021 and 2020.

7 At December 31, 2021, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the project for which we would be liable in the event of default by the VIE.

8 At December 31, 2020, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the project for which we would be liable for in the event of default by the VIE and an outstanding affiliate loan receivable for $132 million held by us as at December 31, 2020. In relation to the sale of 49% of EIH S.á r.l.'s interest to CPP Investments, Eolien Maritime France SAS is now reported under EIH S.á r.l. in 2021.

We do not have an obligation to and did not provide any additional financial support to the VIEs during the years ended December 31, 2021 and 2020.

13. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2021**	2020
(millions of Canadian dollars)			
EQUITY INVESTMENTS			
Liquids Pipelines			
MarEn Bakken Company LLC[1]	75.0%	**1,728**	1,795
Gray Oak Holdings LLC[2]	35.0%	**469**	502
Seaway Crude Holdings LLC	50.0%	**2,634**	2,668
Illinois Extension Pipeline Company, L.L.C.[3]	65.0%	**593**	623
Cactus II Pipeline, LLC[4]	20.0%	**434**	—
Other	30.0% - 43.8%	**71**	73
Gas Transmission and Midstream			
Alliance Pipeline[5]	50.0%	**504**	269
Aux Sable[6]	42.7% - 50.0%	**238**	251
DCP Midstream, LLC[7]	50.0%	**397**	331
Gulfstream Natural Gas System, L.L.C.	50.0%	**1,180**	1,175
Nexus Gas Transmission, LLC	50.0%	**1,724**	1,745
PennEast Pipeline Company, LLC	20.0%	**12**	116
Sabal Trail Transmission, LLC	50.0%	**1,464**	1,510
Southeast Supply Header, LLC	50.0%	**82**	84
Steckman Ridge, LP	50.0%	**88**	90
Vector Pipeline[8]	60.0%	**189**	201
Offshore - various joint ventures	22.0% - 74.3%	**309**	338
Other	33.3%	**2**	4
Gas Distribution and Storage			
Noverco Common Shares[9]	38.9%	**—**	156
Other	47.6% - 50%	**20**	13
Renewable Power Generation			
EIH S.a.r.l.[10]	51.0%	**38**	96
Enbridge Renewable Infrastructure Investments S.a.r.l.	51.0%	**54**	100
Rampion Offshore Wind Limited	24.9%	**450**	599
NextBridge Infrastructure LP	25.0%	**186**	122
Other	12.0% - 50.0%	**93**	74
Eliminations and Other			
Other	42.7% - 50.0%	**23**	32
OTHER LONG-TERM INVESTMENTS			
Gas Distribution and Storage			
Noverco Preferred Shares[9]		**—**	567
Renewable Power Generation			
Emerging Technologies and Other		**32**	32
Eliminations and Other			
Other[11]		**310**	252
		13,324	13,818

1 Owns 49% interest in Bakken Pipeline Investments L.L.C., which owns 75% of the Bakken Pipeline System resulting in a 27.6% effective interest in the Bakken Pipeline System.
2 Owns 65% interest in Gray Oak Pipeline, LLC resulting in a 22.8% effective interest in Gray Oak Pipeline, LLC.
3 Owns the Southern Access Extension Project.
4 In October 2021 we acquired an effective 20.0% interest in Cactus II Pipeline, LLC through the acquisition of Moda Midstream Operating, LLC. See Note 8 - Acquisitions and Dispositions for further discussion.
5 Includes Alliance Pipeline Limited Partnership in Canada and Alliance Pipeline L.P. in the US.
6 Includes Aux Sable Canada LP in Canada and Aux Sable Liquid Products LP and Aux Sable Midstream LLC in the US.

7 Our ownership in DCP Midstream, LLC (DCP Midstream) holds an interest of 56.5% in DCP Midstream, LP.
8 Includes Vector Pipeline Limited Partnership in Canada and Vector Pipeline L.P. in the US.
9 On December 30, 2021, we sold our 38.9% common share and preferred share interest of Noverco Inc.
10 On March 18, 2021, we sold 49% of EIH S.a.r.l., an entity that holds our 50% interest in Éolien Maritime France SAS (EMF), to the CPP Investments. This resulted in a 25.5% effective interest in EMF. Through our investment in EMF, we own equity interests in three French offshore wind projects, including Saint-Nazaire (25.5%), Fécamp (17.9%) and Calvados (21.7%).
11 Includes investments held and valued at fair value through net income.

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date. As at December 31, 2021, this basis difference was $2.5 billion (2020 - $2.4 billion), of which $730 million (2020 - $657 million) was amortizable.

For the years ended December 31, 2021, 2020 and 2019, distributions received from equity investments were $2.2 billion, $2.1 billion and $2.2 billion, respectively.

Summarized combined financial information of our interest in unconsolidated equity investments (presented at 100%) is as follows:

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Operating revenues	**19,891**	13,987	15,687
Operating expenses	**16,514**	12,223	13,153
Earnings	**2,952**	2,306	3,016
Earnings attributable to Enbridge	**1,711**	1,136	1,503

December 31,	**2021**	2020
(millions of Canadian dollars)		
Current assets	**3,581**	3,136
Non-current assets	**44,497**	45,955
Current liabilities	**3,678**	3,539
Non-current liabilities	**16,950**	19,639
Noncontrolling interests	**3,786**	3,810

Noverco Inc.
On June 7, 2021, IPL System Inc., a wholly owned subsidiary of Enbridge, entered into a purchase and sale agreement to sell its 38.9% common share and preferred share interest in Noverco to Trencap L.P. for $1.1 billion in cash.

On December 30, 2021, we closed the sale of Noverco for cash proceeds of $1.1 billion. After closing adjustments, a gain on disposal of $303 million before tax was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2021. Noverco was previously included in our Gas Distribution and Storage segment.

IMPAIRMENT OF EQUITY INVESTMENTS
PennEast Pipeline Company, LLC
PennEast Pipeline Company, LLC (PennEast) is a joint venture formed to develop a natural gas transmission pipeline to serve local distribution companies and power generators in Southeastern Pennsylvania and New Jersey, is owned 20% by Enbridge, and is recorded as an equity method investment. In the third quarter of 2021, PennEast determined further development of the project was no longer viable and development of the project was ceased. As a result, we recorded an other-than-temporary impairment loss of $111 million on our investment for the year ended December 31, 2021 based on the estimated fair value of our share of the net assets. The carrying value of this investment as at December 31, 2021 and 2020 was $12 million and $116 million, respectively.

Steckman Ridge, LP
Steckman Ridge, LP (Steckman Ridge) is engaged in the storage of natural gas, is owned 50% by Enbridge and is recorded as an equity method investment. During the year ended December 31, 2020, Steckman Ridge's forecasted performance was adjusted for the expectation that future available capacity will be re-contracted at lower than expected rates and an other than temporary impairment loss on our investment of $221 million for the year ended December 31, 2020 was recorded based on a discounted cash flow analysis. The carrying value of this investment as at December 31, 2021 and 2020 was $88 million and $90 million, respectively.

Southeast Supply Header, L.L.C.
Southeast Supply Header, L.L.C. (SESH) provides natural gas transmission services from east Texas and northern Louisiana to the southeast markets of the Gulf Coast. SESH is owned 50% by Enbridge and is recorded as an equity method investment. The forecasted performance of SESH was revised during the year ended December 31, 2020 to reflect downward revisions to future negotiated rates as well as higher than expected available capacity levels, caused primarily by a significant contract expiry. An other than temporary impairment loss on our investment of $394 million for the year ended December 31, 2020 was recorded based on a discounted cash flow analysis. The carrying value of this investment as at December 31, 2021 and 2020 was $82 million and $84 million, respectively.

DCP Midstream, LLC
DCP Midstream, a 50% owned equity method investment of Enbridge, holds an equity interest in DCP Midstream, LP. A decline in the market price of DCP Midstream, LP's publicly traded units during the first quarter of 2020 resulted in an other than temporary impairment loss on our investment in DCP Midstream of $1.7 billion for the year ended December 31, 2020. In addition, we incurred losses of $324 million through our equity earnings pick up in relation to asset and goodwill impairment losses recorded by DCP Midstream, LP. The carrying value of our investment in DCP Midstream as at December 31, 2021 and 2020 was $397 million and $331 million, respectively.

Our investments in PennEast, Steckman, SESH and DCP Midstream form part of our Gas Transmission and Midstream segment. The impairment losses were recorded within Impairment of Equity Investments in the Consolidated Statements of Earnings.

14. RESTRICTED LONG-TERM INVESTMENTS

Effective January 1, 2015, we began collecting and setting aside funds to cover future pipeline abandonment costs for all CER regulated pipelines as a result of the CER's regulatory requirements under LMCI. The funds collected are held in trusts in accordance with the CER decision. The funds collected from shippers are reported within Transportation and other services revenues on the Consolidated Statements of Earnings and Restricted long-term investments on the Consolidated Statements of Financial Position. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense on the Consolidated Statements of Earnings and Other long-term liabilities on the Consolidated Statements of Financial Position.

We routinely invest excess cash and various restricted balances in securities such as commercial paper, bankers acceptances, corporate debt securities, Canadian equity securities, treasury bills and money market securities in the US and Canada.

As at December 31, 2021 and 2020, we had restricted long-term investments held in trust and classified as available-for-sale of $630 million and $553 million, respectively. The cost basis of our debt securities classified as available-for-sale and recorded as part of our restricted long-term investment balance was $383 million and $322 million as at December 31, 2021 and 2020, respectively. Within Other long-term liabilities we had estimated future abandonment costs related to LMCI of $649 million and $578 million as at December 31, 2021 and 2020, respectively *(Note 7)*.

15. INTANGIBLE ASSETS

December 31, 2021	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	12.0 %	**2,067**	**(1,148)**	**919**
Power purchase agreements	4.5 %	**63**	**(21)**	**42**
Project agreement[1]	4.0 %	**152**	**(27)**	**125**
Customer relationships	8.5 %	**2,532**	**(215)**	**2,317**
Other intangible assets	3.9 %	**475**	**(116)**	**359**
Under development	— %	**246**	**—**	**246**
		5,535	**(1,527)**	**4,008**

December 31, 2020	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	10.5 %	2,043	(1,299)	744
Power purchase agreements	4.5 %	63	(18)	45
Project agreement[1]	4.0 %	153	(21)	132
Customer relationships	5.0 %	724	(139)	585
Other intangible assets	2.7 %	456	(96)	360
Under development	— %	214	—	214
		3,653	(1,573)	2,080

1 Represents a project agreement acquired from the merger of Enbridge and Spectra Energy.

For the years ended December 31, 2021, 2020 and 2019, our amortization expense related to intangible assets totaled $348 million, $294 million and $296 million, respectively. Our expected amortization expense associated with existing intangible assets for each of the years 2022 to 2026 is $492 million.

16. GOODWILL

(millions of Canadian dollars)	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Energy Services	Consolidated
Balance at January 1, 2020	7,951	19,844	5,356	2	33,153
Foreign exchange and other	(123)	(364)	—	—	(487)
Acquisition	—	—	22	—	22
Balance at December 31, 2020[1,2]	7,828	19,480	5,378	2	32,688
Foreign exchange and other	**(55)**	**(145)**	**—**	**—**	**(200)**
Acquisition[3]	**268**	**—**	**19**	**—**	**287**
Balance at December 31, 2021[1,2]	**8,041**	**19,335**	**5,397**	**2**	**32,775**

1 Gross cost of goodwill as at December 31, 2021 and 2020 was $34.4 billion and $34.3 billion, respectively.
2 Accumulated impairment as at December 31, 2021 and 2020 was $1.6 billion.
3 In 2021, we recorded $268 million of goodwill related to the acquisition of Moda. See Note 8 - Acquisitions and Dispositions for further discussion.

17. ACCOUNTS PAYABLE AND OTHER

December 31,	**2021**	2020
(millions of Canadian dollars)		
Trade payables and operating accrued liabilities	**4,470**	3,497
Dividends payable	**1,773**	1,728
Current deferred credits	**853**	978
Construction payables and contractor holdbacks	**844**	855
Current derivative liabilities *(Note 24)*	**717**	896
Taxes payable	**478**	622
Other	**632**	652
	9,767	9,228

18. DEBT

December 31,	Weighted Average Interest Rate[9]	Maturity	**2021**	2020
(millions of Canadian dollars)				
Enbridge Inc.				
US dollar senior notes	3.2 %	2022 - 2051	**10,992**	8,536
Medium-term notes	3.9 %	2022 - 2064	**8,123**	8,323
Sustainability-linked bonds	1.1 %	2033	**2,363**	—
Fixed-to-fixed subordinated term notes[1]	5.8 %	2080	**1,263**	1,274
Fixed-to-floating rate subordinated term notes[2]	5.8 %	2023 - 2028	**6,442**	6,477
Floating rate notes[3]		2022 - 2023	**1,579**	956
Commercial paper and credit facility draws	1.0 %	2022 - 2026	**7,837**	8,719
Other[4]			**5**	5
Enbridge (U.S.) Inc.				
Commercial paper and credit facility draws	0.4 %	2023 - 2026	**4,845**	492
Other[4]			**7**	7
Enbridge Energy Partners, L.P.				
Senior notes	6.5 %	2025 - 2045	**3,095**	3,886
Enbridge Gas Inc.				
Medium-term notes	3.8 %	2022 - 2051	**9,010**	8,485
Debentures	9.1 %	2024 - 2025	**210**	210
Commercial paper and credit facility draws	0.5 %	2023	**1,515**	1,121
Enbridge Pipelines (Southern Lights) L.L.C.				
Senior notes	4.0 %	2040	**949**	1,038
Enbridge Pipelines Inc.				
Medium-term notes[5]	4.0 %	2022 - 2051	**5,575**	4,775
Debentures	8.2 %	2024	**200**	200
Commercial paper and credit facility draws	0.7 %	2023	**667**	1,278
Enbridge Southern Lights LP				
Senior notes	4.0 %	2040	**240**	257
Spectra Energy Capital, LLC				
Senior notes	7.0 %	2032 - 2038	**218**	220
Spectra Energy Partners, LP				
Senior notes	3.9 %	2022 - 2048	**8,451**	8,332
Westcoast Energy Inc.				
Medium-term notes	4.5 %	2022 - 2041	**1,475**	1,625
Debentures	8.1 %	2025 - 2026	**275**	275
Fair value adjustment			**667**	750
Other[6]			**(363)**	(344)
Total debt[7]			**75,640**	66,897
Current maturities			**(6,164)**	(2,957)
Short-term borrowings[8]			**(1,515)**	(1,121)
Long-term debt			**67,961**	62,819

1 *For the initial 10 years, the notes carry a fixed interest rate. Subsequently, the interest rate will be set to equal to the Five-Year US Treasury Rate plus a margin of 5.31% from years 10 to 30 and a margin of 6.06% from years 30 to 60.*
2 *For the initial 10 years, the notes carry a fixed interest rate. Subsequently, the interest rate will be floating and set to equal to the Canadian Dollar Offered Rate (CDOR) or the London Interbank Offered Rate (LIBOR) plus a margin. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.*
3 *The notes carry an interest rate equal to the three-month LIBOR plus a margin of 50 basis points and Secured Overnight Financing Rate (SOFR) plus a margin of 40 basis points.*
4 *Primarily finance lease obligations.*
5 *Included in medium-term notes is $100 million with a maturity date of 2112.*
6 *Primarily unamortized discounts, premiums and debt issuance costs.*
7 *2021 - $36 billion and US$31 billion; 2020 - $35 billion and US$24 billion. Totals exclude capital lease obligations, unamortized discounts, premiums and debt issuance costs and fair value adjustment.*
8 *Weighted average interest rates on outstanding commercial paper were 0.5% as at December 31, 2021 (2020 - 0.3%).*
9 *Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2021.*

As at December 31, 2021, all outstanding debt was unsecured.

CREDIT FACILITIES

The following table provides details of our committed credit facilities as at December 31, 2021:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2022-2026	**9,137**	**7,837**	**1,300**
Enbridge (U.S.) Inc.	2023-2026	**6,948**	**4,845**	**2,103**
Enbridge Pipelines Inc.	2023	**3,000**	**667**	**2,333**
Enbridge Gas Inc.	2023	**2,000**	**1,515**	**485**
Total committed credit facilities		**21,085**	**14,864**	**6,221**

1 Maturity date is inclusive of the one-year term out option for certain credit facilities.
2 Includes facility draws and commercial paper issuances that are back-stopped by credit facilities.

On February 10, 2021, Enbridge Inc. entered into a three year, revolving, extendible, sustainability-linked credit facility for $1.0 billion with a syndicate of lenders and concurrently terminated our one year, revolving, syndicated credit facility for $3.0 billion.

On February 25, 2021, two term loans with an aggregate total of US$500 million were repaid with proceeds from a floating rate notes issuance.

On July 22 and 23, 2021, we renewed approximately $8.0 billion of our five-year credit facilities, extending the maturity date out to July 2026. We also extended approximately $10.0 billion of our 364-day extendible credit facilities to July 2022, which includes a one-year term out provision to July 2023.

On February 10, 2022 we renewed our three year $1.0 billion sustainability-linked credit facility, extending the maturity date out to July 2025.

In addition to the committed credit facilities noted above, we maintain $1.3 billion of uncommitted demand letter of credit facilities, of which $854 million was unutilized as at December 31, 2021. As at December 31, 2020, we had $849 million of uncommitted demand letter of credit facilities, of which $533 million was unutilized.

Our credit facilities carry a weighted average standby fee of 0.1% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and we have the option to extend such facilities, which are currently scheduled to mature from 2022 to 2026.

As at December 31, 2021 and 2020, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $11.3 billion and $9.9 billion, respectively, were supported by the availability of long-term committed credit facilities and, therefore, have been classified as long-term debt.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2021, we completed the following long-term debt issuances totaling US$3.9 billion and $3.2 billion:

Company	Issue Date		Principal Amount
(millions of Canadian dollars unless otherwise stated)			
Enbridge Inc.			
	February 2021	Floating rate senior-notes due February 2023[1]	US$500
	June 2021	2.50% Sustainability-linked senior notes due August 2033	US$1,000
	June 2021	3.40% senior notes due August 2051	US$500
	September 2021	3.10% Sustainability-linked medium-term notes due September 2033	$1,100
	September 2021	4.10% medium-term notes due September 2051	$400
	October 2021	0.55% senior notes due October 2023	US$500
	October 2021	1.60% senior notes due October 2026	US$500
	October 2021	3.40% senior notes due August 2051	US$500
Enbridge Gas Inc.			
	September 2021	2.35% medium-term notes due September 2031	$475
	September 2021	3.20% medium-term notes due September 2051	$425
Enbridge Pipelines Inc.			
	May 2021	2.82% medium-term notes due May 2031	$400
	May 2021	4.20% medium-term notes due May 2051	$400
Spectra Energy Partners, LP			
	September 2021	2.50% senior notes due September 2031[2]	US$400

1 Notes carry an interest rate equal to the SOFR plus a margin of 40 basis points.
2 Issued through Texas Eastern Transmission, LP, a wholly-owned operating subsidiary of SEP.

On January 19, 2022, we closed a $750 million private placement offering of non-call 10-year fixed-to-fixed subordinated notes which mature on January 19, 2082. The net proceeds from the offering will be used to redeem the Preference Shares, Series 17 at par on March 1, 2022.

LONG-TERM DEBT REPAYMENTS

During the year ended December 31, 2021, we completed the following long-term debt repayments totaling $1.1 billion and US$914 million, respectively:

Company	Repayment Date		Principal Amount
(millions of Canadian dollars unless otherwise stated)			
Enbridge Inc.			
	February 2021	4.26% medium-term notes	$200
	March 2021	3.16% medium-term notes	$400
Enbridge Energy Partners, L.P.			
	June 2021	4.20% senior notes	US$600
Enbridge Gas Inc.			
	May 2021	2.76% medium-term notes	$200
	December 2021	4.77% medium-term notes	$175
Enbridge Pipelines (Southern Lights) L.L.C.			
	June and December 2021	3.98% senior notes	US$64
Enbridge Southern Lights LP			
	June and December 2021	4.01% senior notes	$16
Spectra Energy Partners, LP			
	March 2021	4.60% senior notes	US$250
Westcoast Energy Inc.			
	October 2021	3.88% medium-term notes	$150

DEBT COVENANTS

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2021, we were in compliance with all debt covenants.

INTEREST EXPENSE

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Debentures and term notes	**2,850**	2,913	2,783
Commercial paper and credit facility draws	**70**	123	273
Amortization of fair value adjustment	**(50)**	(54)	(67)
Capitalized interest	**(215)**	(192)	(326)
	2,655	2,790	2,663

19. ASSET RETIREMENT OBLIGATIONS

Our ARO relate mostly to the retirement of pipelines, renewable power generation assets and obligations related to right-of way agreements and contractual leases for land use.

The discount rates used to estimate the present value of the expected future cash flows for the year ended December 31, 2021 ranged from 0.9% to 9.0% (2020 - 1.8% to 9.0%).

A reconciliation of movements in our ARO liabilities is as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Obligations at beginning of year	**496**	520
Liabilities disposed	**—**	—
Liabilities incurred	**—**	—
Liabilities settled	**(67)**	(30)
Change in estimate and other	**70**	—
Foreign currency translation adjustment	**(3)**	(6)
Accretion expense	**6**	12
Obligations at end of year	**502**	496
Presented as follows:		
Accounts payable and other	**160**	56
Other long-term liabilities	**342**	440
	502	496

20. NONCONTROLLING INTERESTS

NONCONTROLLING INTERESTS

The following table provides additional information regarding Noncontrolling interests as presented in our Consolidated Statements of Financial Position:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Algonquin Gas Transmission, L.L.C	**377**	384
Maritimes & Northeast Pipeline, L.L.C	**546**	558
Renewable energy assets	**1,503**	1,646
Westcoast Energy Inc.[1]	**116**	408
	2,542	2,996

1 Includes nil and 12 million cumulative redeemable preferred shares as at December 31, 2021 and 2020, respectively.

Westcoast Energy Inc. Preferred Shares Redemption

On March 20, 2019, Westcoast Energy Inc. (Westcoast) exercised its right to redeem all of its outstanding 5.5% Cumulative Redeemable First Preferred Shares, Series 7 (Series 7 Shares) and all of its outstanding 5.6% Cumulative Redeemable First Preferred Shares, Series 8 (Series 8 Shares) at a price of $25 per Series 7 Share and $25 per Series 8 Share, respectively, for a total payment of $300 million. In addition, payment of $4 million was made for all accrued and unpaid dividends. As a result, we recorded a $300 million decrease in Noncontrolling interests for the year ended December 31, 2019.

On January 15, 2021, Westcoast redeemed its Cumulative Five-Year Minimum Rate Reset Redeemable First Preferred Shares, Series 10 with a par value of $115 million. The par value of $115 million was included in Accounts payable and other in the Consolidated Statements of Financial Position as at December 31, 2020.

On October 15, 2021, Westcoast redeemed its Cumulative Five-Year Minimum Rate Reset Redeemable First Preferred Shares, Series 12 with a par value of $300 million. As a result, we recorded a decrease of $293 million, which represents the par value less related issuance costs, in Noncontrolling interests for the year ended December 31, 2021.

21. SHARE CAPITAL

Our authorized share capital consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

COMMON SHARES

	2021		2020		2019	
December 31,	Number Shares	Amount	Number Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)						
Balance at beginning of year	**2,026**	**64,768**	2,025	64,746	2,022	64,677
Shares issued on exercise of stock options	**—**	**31**	1	22	3	69
Balance at end of year	**2,026**	**64,799**	2,026	64,768	2,025	64,746

PREFERENCE SHARES

	2021		2020		2019	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)						
Preference Shares, Series A	**5**	**125**	5	125	5	125
Preference Shares, Series B	**18**	**457**	18	457	18	457
Preference Shares, Series C	**2**	**43**	2	43	2	43
Preference Shares, Series D	**18**	**450**	18	450	18	450
Preference Shares, Series F	**20**	**500**	20	500	20	500
Preference Shares, Series H	**14**	**350**	14	350	14	350
Preference Shares, Series J	**8**	**199**	8	199	8	199
Preference Shares, Series L	**16**	**411**	16	411	16	411
Preference Shares, Series N	**18**	**450**	18	450	18	450
Preference Shares, Series P	**16**	**400**	16	400	16	400
Preference Shares, Series R	**16**	**400**	16	400	16	400
Preference Shares, Series 1	**16**	**411**	16	411	16	411
Preference Shares, Series 3	**24**	**600**	24	600	24	600
Preference Shares, Series 5	**8**	**206**	8	206	8	206
Preference Shares, Series 7	**10**	**250**	10	250	10	250
Preference Shares, Series 9	**11**	**275**	11	275	11	275
Preference Shares, Series 11	**20**	**500**	20	500	20	500
Preference Shares, Series 13	**14**	**350**	14	350	14	350
Preference Shares, Series 15	**11**	**275**	11	275	11	275
Preference Shares, Series 17	**30**	**750**	30	750	30	750
Preference Shares, Series 19	**20**	**500**	20	500	20	500
Issuance costs		**(155)**		(155)		(155)
Balance at end of year		**7,747**		7,747		7,747

Characteristics of the preference shares are as follows:

(Canadian dollars unless otherwise stated)	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
Preference Shares, Series A	5.50 %	$1.37500	$25	—	—
Preference Shares, Series B	3.42 %	$0.85360	$25	June 1, 2022	Series C
Preference Shares, Series C[5]	3-month treasury bill plus 2.40%	—	$25	June 1, 2022	Series B
Preference Shares, Series D	4.46 %	$1.11500	$25	March 1, 2023	Series E
Preference Shares, Series F	4.69 %	$1.17224	$25	June 1, 2023	Series G
Preference Shares, Series H	4.38 %	$1.09400	$25	September 1, 2023	Series I
Preference Shares, Series J	4.89 %	US$1.22160	US$25	June 1, 2022	Series K
Preference Shares, Series L	4.96 %	US$1.23972	US$25	September 1, 2022	Series M
Preference Shares, Series N	5.09 %	$1.27152	$25	December 1, 2023	Series O
Preference Shares, Series P	4.38 %	$1.09476	$25	March 1, 2024	Series Q
Preference Shares, Series R	4.07 %	$1.01825	$25	June 1, 2024	Series S
Preference Shares, Series 1	5.95 %	US$1.48728	US$25	June 1, 2023	Series 2
Preference Shares, Series 3	3.74 %	$0.93425	$25	September 1, 2024	Series 4
Preference Shares, Series 5	5.38 %	US$1.34383	US$25	March 1, 2024	Series 6
Preference Shares, Series 7	4.45 %	$1.11224	$25	March 1, 2024	Series 8
Preference Shares, Series 9	4.10 %	$1.02424	$25	December 1, 2024	Series 10
Preference Shares, Series 11	3.94 %	$0.98452	$25	March 1, 2025	Series 12
Preference Shares, Series 13	3.04 %	$0.76076	$25	June 1, 2025	Series 14
Preference Shares, Series 15	2.98 %	$0.74576	$25	September 1, 2025	Series 16
Preference Shares, Series 17	5.15 %	$1.28750	$25	March 1, 2022	Series 18
Preference Shares, Series 19	4.90 %	$1.22500	$25	March 1, 2023	Series 20

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board of Directors. With the exception of Series A and Series C Preference Shares, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Series 17 and Series 19 Preference Shares contain a feature where the fixed dividend rate, when reset every five years, will not be less than 5.15% and 4.90%, respectively. No other series of Preference Shares has this feature.*

2 *Series A Preference Shares may be redeemed any time at our option. For all other series of Preference Shares, we may at our option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.*

4 *With the exception of Series A Preference Shares, after the redemption and conversion option dates, holders may elect to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/number of days in a year) x three-month Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14), 2.7% (Series 16), 4.1% (Series 18) or 3.2% (Series 20); or US$25 x (number of days in quarter/ number of days in a year) x three-month US Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).*

5 *The floating quarterly dividend amount for the Series C Preference Shares was increased to $0.15501 from $0.15349 on March 1, 2021, was increased to $0.15753 from $0.15501 on June 1, 2021, was increased to $0.16081 from $0.15753 on September 1, 2021 and was decreased to $0.15719 from $0.16081 on December 1, 2021, due to reset on a quarterly basis following the issuance thereof.*

PREFERENCE SHARE REDEMPTION

We intend to exercise our right to redeem all of our outstanding cumulative redeemable minimum rate reset preference shares, Series 17, on March 1, 2022 at a price of $25 per Series 17 share, together with all accrued and unpaid dividends, if any.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of our shareholders in connection with any takeover offer. Rights issued under the plan become exercisable when a person and any related parties acquires or announces its intention to acquire 20% or more of our outstanding common shares without complying with certain provisions set out in the plan or without approval of our Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase our common shares at a 50% discount to the market price at that time.

22. STOCK OPTION AND STOCK UNIT PLANS

We maintain three long-term incentive compensation plans: the ISO Plan, the PSU Plan and the RSU Plan. Total stock-based compensation expense recorded for the years ended December 31, 2021, 2020 and 2019 was $157 million, $145 million and $117 million, respectively. Disclosure of activity and assumptions for material stock-based compensation plans are included below.

INCENTIVE STOCK OPTIONS

Certain key employees are granted ISOs to purchase common shares at the grant date market price. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

December 31, 2021	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars; weighted average exercise price in Canadian dollars)				
Options outstanding at beginning of year	**35,494**	**48.65**		
Options granted	**4,072**	**43.86**		
Options exercised[1]	**(4,142)**	**41.85**		
Options cancelled or expired	**(1,407)**	**50.74**		
Options outstanding at end of year	**34,017**	**49.28**	**5.7**	**128**
Options vested at end of year[2]	**22,029**	**49.84**	**4.5**	**64**

1 *The total intrinsic value of ISOs exercised during the years ended December 31, 2021, 2020 and 2019 was $24 million, $13 million and $58 million, respectively, and cash received on exercise was $2 million, $4 million and $1 million, respectively.*

2 *The total fair value of ISOs exercised during the years ended December 31, 2021, 2020 and 2019 was $25 million, $30 million and $32 million, respectively.*

Weighted average assumptions used to determine the fair value of ISOs granted using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2021**	2020	2019
Fair value per option *(Canadian dollars)*[1]	**4.10**	4.01	4.37
Valuation assumptions			
Expected option term *(years)*[2]	**6**	6	5
Expected volatility[3]	**25.5 %**	18.3 %	19.9 %
Expected dividend yield[4]	**7.6 %**	5.9 %	6.1 %
Risk-free interest rate[5]	**0.7 %**	1.3 %	2.0 %

1 *Options granted to US employees are based on NYSE prices. The option value and assumptions shown are based on a weighted average of the US and the Canadian options. The fair values per option for the years ended December 31, 2021, 2020 and 2019 were $3.91, $3.75 and $4.04, respectively, for Canadian employees and US$3.65, US$3.62 and US$4.09, respectively, for US employees.*
2 *The expected option term is six years based on historical exercise practice and five years for retirement eligible employees.*
3 *Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.*
4 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*
5 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the US Treasury Bond Yields.*

Compensation expense recorded for the years ended December 31, 2021, 2020 and 2019 for ISOs was $16 million, $24 million and $32 million, respectively. As at December 31, 2021, unrecognized compensation expense related to non-vested stock-based compensation arrangements granted under the ISO Plan was $11 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE STOCK UNITS

Under PSU awards for certain key employees, cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if our performance fails to meet threshold performance levels, to a maximum of two if we perform within the highest range of the performance targets. The performance multiplier is derived through a calculation of our Total Shareholder Return percentile rank, in each case relative to a specified peer group of companies and our distributable cash flow per share, adjusted for unusual, non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2021 expense, a multiplier of 0.5 was used for 2021 PSU grants, 0.5 for 2020 PSU grants and 1.3 for the 2019 PSU grants.

December 31, 2021	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**3,056**		
Units granted	**1,895**		
Units cancelled	**(76)**		
Units matured[1]	**(1,664)**		
Dividend reinvestment	**218**		
Units outstanding at end of year	**3,429**	**1.1**	**181**

1 *The total amount paid during the years ended December 31, 2021, 2020 and 2019 for PSUs was $70 million, $14 million and $19 million, respectively.*

Compensation expense recorded for the years ended December 31, 2021, 2020 and 2019 for PSUs was $56 million, $76 million and $40 million, respectively. As at December 31, 2021, unrecognized compensation expense related to non-vested PSUs was $31 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Under RSU awards, cash awards are paid to certain of our employees vesting in equal installments on each of the first, second and third anniversaries of the grant date. Share settled awards are given to certain senior management employees following a three year maturity period. RSU holders receive cash or shares equal to our weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2021	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**2,453**		
Units granted	**1,514**		
Units cancelled	**(75)**		
Units matured[1]	**(1,433)**		
Dividend reinvestment	**246**		
Units outstanding at end of year	**2,705**	**1.1**	**129**

1 The total amount paid during the years ended December 31, 2021, 2020 and 2019 for RSUs was $72 million, $27 million and $34 million, respectively.

Compensation expense recorded for the years ended December 31, 2021, 2020 and 2019 for RSUs was $85 million, $44 million and $41 million, respectively. As at December 31, 2021, unrecognized compensation expense related to non-vested RSUs was $62 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

23. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

Changes in AOCI attributable to our common shareholders for the years ended December 31, 2021, 2020 and 2019 are as follows:

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance at January 1, 2021	**(1,326)**	**5**	**(215)**	**568**	**66**	**(499)**	**(1,401)**
Other comprehensive income/(loss) retained in AOCI	**238**	**(5)**	**49**	**(492)**	**(12)**	**520**	**298**
Other comprehensive (income)/loss reclassified to earnings							
Interest rate contracts[1]	**296**	**—**	**—**	**—**	**—**	**—**	**296**
Commodity contracts[2]	**1**	**—**	**—**	**—**	**—**	**—**	**1**
Foreign exchange contracts[3]	**5**	**—**	**—**	**—**	**—**	**—**	**5**
Other contracts[4]	**2**	**—**	**—**	**—**	**—**	**—**	**2**
Equity investment disposal	**—**	**—**	**—**	**—**	**(66)**	**—**	**(66)**
Amortization of pension and OPEB actuarial loss and prior service costs[5]	**—**	**—**	**—**	**—**	**—**	**28**	**28**
Other	**17**	**—**	**—**	**(20)**	**3**	**—**	**—**
	559	**(5)**	**49**	**(512)**	**(75)**	**548**	**564**
Tax impact							
Income tax on amounts retained in AOCI	**(61)**	**—**	**—**	**—**	**—**	**(126)**	**(187)**
Income tax on amounts reclassified to earnings	**(69)**	**—**	**—**	**—**	**4**	**(7)**	**(72)**
	(130)	**—**	**—**	**—**	**4**	**(133)**	**(259)**
Balance at December 31, 2021	**(897)**	**—**	**(166)**	**56**	**(5)**	**(84)**	**(1,096)**

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance at January 1, 2020	(1,073)	—	(317)	1,396	67	(345)	(272)
Other comprehensive income/(loss) retained in AOCI	(591)	5	115	(828)	(2)	(221)	(1,522)
Other comprehensive (income)/loss reclassified to earnings							
Interest rate contracts[1]	253	—	—	—	—	—	253
Foreign exchange contracts[3]	5	—	—	—	—	—	5
Other contracts[4]	(2)	—	—	—	—	—	(2)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	—	—	—	—	—	17	17
	(335)	5	115	(828)	(2)	(204)	(1,249)
Tax impact							
Income tax on amounts retained in AOCI	140	—	(13)	—	1	54	182
Income tax on amounts reclassified to earnings	(58)	—	—	—	—	(4)	(62)
	82	—	(13)	—	1	50	120
Balance at December 31, 2020	(1,326)	5	(215)	568	66	(499)	(1,401)

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2019	(770)	(598)	4,323	34	(317)	2,672
Other comprehensive income/(loss) retained in AOCI	(599)	320	(2,927)	34	(124)	(3,296)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	157	—	—	—	—	157
Commodity contracts[2]	(1)	—	—	—	—	(1)
Foreign exchange contracts[3]	5	—	—	—	—	5
Other contracts[4]	(3)	—	—	—	—	(3)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	—	—	—	—	17	17
	(441)	320	(2,927)	34	(107)	(3,121)
Tax impact						
Income tax on amounts retained in AOCI	169	(39)	—	6	28	164
Income tax on amounts reclassified to earnings	(31)	—	—	—	(4)	(35)
	138	(39)	—	6	24	129
Other	—	—	—	(7)	55	48
Balance at December 31, 2019	(1,073)	(317)	1,396	67	(345)	(272)

1 *Reported within Interest expense in the Consolidated Statements of Earnings.*
2 *Reported within Transportation and other services revenue, Commodity sales revenue, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*
3 *Reported within Transportation and other services revenue and Net foreign currency gain in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*
5 *These components are included in the computation of net benefit costs and are reported within Other income/(expense) in the Consolidated Statements of Earnings.*

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

Our earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price (collectively, market risks). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

We generate certain revenues, incur expenses and hold a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

We employ financial derivative instruments to hedge foreign currency denominated earnings exposure. A combination of qualifying and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses and to manage variability in cash flows. We hedge certain net investments in US dollar denominated investments and subsidiaries using foreign currency derivatives and US dollar denominated debt.

Interest Rate Risk
Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt within the Board of Directors approved policy limit of a maximum of 30% of floating rate debt as a percentage of total debt outstanding. We primarily use qualifying derivative instruments to manage interest rate risk. Pay fixed-receive floating interest rate swaps may be used to hedge against the effect of future interest rate movements. We have implemented a program to mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 3.9%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of changes in market interest rates. Pay floating-receive fixed interest rate swaps are used, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in fair value via execution of fixed to floating interest rate swaps. As at December 31, 2021, we do not have any pay floating-receive fixed interest rate swaps outstanding.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have established a program including some of our subsidiaries to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 2.0%.

Commodity Price Risk
Our earnings and cash flows are exposed to changes in commodity prices as a result of our ownership interests in certain assets and investments, as well as through the activities of our energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. We employ financial and physical derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. We use primarily non-qualifying derivative instruments to manage commodity price risk.

Equity Price Risk
Equity price risk is the risk of earnings fluctuations due to changes in our share price. We have exposure to our own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. We use equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted share units. We use a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments.

We generally have a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our financial derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit events and reduce our credit risk exposure on financial derivative asset positions outstanding with the counterparties in those circumstances.

The following table summarizes the maximum potential settlement amounts in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2021	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)							
Accounts receivable and other							
Foreign exchange contracts	**—**	**—**	**—**	**259**	**259**	**(41)**	**218**
Interest rate contracts	**64**	**—**	**—**	**—**	**64**	**—**	**64**
Commodity contracts	**—**	**—**	**—**	**204**	**204**	**(129)**	**75**
Other contracts	**—**	**—**	**—**	**2**	**2**	**—**	**2**
	64	**—**	**—**	**465**	**529**	**(170)**	**359**
Deferred amounts and other assets							
Foreign exchange contracts	**—**	**—**	**—**	**240**	**240**	**(61)**	**179**
Interest rate contracts	**88**	**—**	**—**	**—**	**88**	**(1)**	**87**
Commodity contracts	**—**	**—**	**—**	**29**	**29**	**(13)**	**16**
Other contracts	**—**	**—**	**—**	**3**	**3**	**—**	**3**
	88	**—**	**—**	**272**	**360**	**(75)**	**285**
Accounts payable and other							
Foreign exchange contracts	**(15)**	**—**	**(112)**	**(176)**	**(303)**	**41**	**(262)**
Interest rate contracts	**(150)**	**—**	**—**	**—**	**(150)**	**—**	**(150)**
Commodity contracts	**(14)**	**—**	**—**	**(250)**	**(264)**	**129**	**(135)**
Other contracts	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	(179)	**—**	**(112)**	**(426)**	**(717)**	**170**	**(547)**
Other long-term liabilities							
Foreign exchange contracts	**—**	**—**	**—**	**(423)**	**(423)**	**61**	**(362)**
Interest rate contracts	**(1)**	**—**	**—**	**(23)**	**(24)**	**1**	**(23)**
Commodity contracts	**(17)**	**—**	**—**	**(67)**	**(84)**	**13**	**(71)**
Other contracts	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	(18)	**—**	**—**	**(513)**	**(531)**	**75**	**(456)**
Total net derivative asset/(liability)							
Foreign exchange contracts	**(15)**	**—**	**(112)**	**(100)**	**(227)**	**—**	**(227)**
Interest rate contracts	**1**	**—**	**—**	**(23)**	**(22)**	**—**	**(22)**
Commodity contracts	**(31)**	**—**	**—**	**(84)**	**(115)**	**—**	**(115)**
Other contracts	**—**	**—**	**—**	**5**	**5**	**—**	**5**
	(45)	**—**	**(112)**	**(202)**	**(359)**	**—**	**(359)**

December 31, 2020	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)							
Accounts receivable and other							
Foreign exchange contracts	—	—	—	180	180	(28)	152
Interest rate contracts	—	—	—	—	—	—	—
Commodity contracts	—	—	—	143	143	(81)	62
Other contracts	—	—	—	—	—	—	—
	—	—	—	323	323	(109)	214
Deferred amounts and other assets							
Foreign exchange contracts	14	—	—	452	466	(218)	248
Interest rate contracts	56	—	—	—	56	(25)	31
Commodity contracts	—	—	—	39	39	(9)	30
Other contracts	—	—	—	—	—	—	—
	70	—	—	491	561	(252)	309
Accounts payable and other							
Foreign exchange contracts	(5)	—	(29)	(151)	(185)	28	(157)
Interest rate contracts	(423)	—	—	(2)	(425)	—	(425)
Commodity contracts	(2)	—	—	(278)	(280)	81	(199)
Other contracts	(1)	—	—	(3)	(4)	—	(4)
	(431)	—	(29)	(434)	(894)	109	(785)
Other long-term liabilities							
Foreign exchange contracts	—	—	(87)	(673)	(760)	218	(542)
Interest rate contracts	(218)	—	—	(23)	(241)	25	(216)
Commodity contracts	(1)	—	—	(57)	(58)	9	(49)
Other contracts	—	—	—	—	—	—	—
	(219)	—	(87)	(753)	(1,059)	252	(807)
Total net derivative asset/(liability)							
Foreign exchange contracts	9	—	(116)	(192)	(299)	—	(299)
Interest rate contracts	(585)	—	—	(25)	(610)	—	(610)
Commodity contracts	(3)	—	—	(153)	(156)	—	(156)
Other contracts	(1)	—	—	(3)	(4)	—	(4)
	(580)	—	(116)	(373)	(1,069)	—	(1,069)

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.

	2021							2020
As at December 31,	2022	2023	2024	2025	2026	Thereafter	Total	Total
Foreign exchange contracts - US dollar forwards - purchase *(millions of US dollars)*	**2,508**	**—**	**—**	**—**	**—**	**—**	**2,508**	3,522
Foreign exchange contracts - US dollar forwards - sell *(millions of US dollars)*	**9,245**	**5,596**	**4,346**	**3,174**	**2,574**	**492**	**25,427**	17,859
Foreign exchange contracts - British pound (GBP) forwards - sell *(millions of GBP)*	**28**	**29**	**30**	**30**	**28**	**32**	**177**	265
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**104**	**92**	**91**	**86**	**85**	**343**	**801**	885
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**72,500**	**—**	**—**	**—**	**—**	**—**	**72,500**	72,500
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**395**	**47**	**35**	**30**	**26**	**64**	**597**	4,635
Interest rate contracts - long-term pay fixed rate *(millions of Canadian dollars)*	**2,363**	**1,784**	**1,132**	**—**	**—**	**—**	**5,279**	5,396
Equity contracts *(millions of Canadian dollars)*	**20**	**26**	**21**	**—**	**—**	**—**	**67**	62
Commodity contracts - natural gas *(billions of cubic feet)*	**165**	**18**	**5**	**11**	**—**	**—**	**199**	173
Commodity contracts - crude oil *(millions of barrels)*	**12**	**—**	**—**	**—**	**—**	**—**	**12**	15
Commodity contracts - power *(megawatt per hour (MW/H)*	**(43)**	**(43)**	**(43)**	**(43)**	**—**	**—**	**(43)** [1]	(35) [1]

1 Total is an average net purchase/(sell) of power.

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges and net investment hedges on our consolidated earnings and consolidated comprehensive income, before the effect of income taxes:

	2021	2020	2019
(millions of Canadian dollars)			
Amount of unrealized gain/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**(29)**	(1)	(19)
Interest rate contracts	**252**	(595)	(559)
Commodity contracts	**(28)**	2	(25)
Other contracts	**1**	(3)	10
Fair value hedges			
Foreign exchange contracts	**(5)**	5	—
Net investment hedges			
Foreign exchange contracts	**—**	13	2
	191	(579)	(591)
Amount of (gain)/loss reclassified from AOCI to earnings			
Foreign exchange contracts[1]	**5**	5	5
Interest rate contracts[2]	**296**	253	157
Commodity contracts[3]	**1**	—	(1)
Other contracts[4]	**2**	(2)	(3)
	304	256	158

1 Reported within Transportation and other services revenues and Net foreign currency gain/(loss) in the Consolidated Statements of Earnings.
2 Reported within Interest expense in the Consolidated Statements of Earnings.
3 Reported within Transportation and other services revenue, Commodity sales revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.
4 Reported within Operating and administrative expenses in the Consolidated Statements of Earnings.

We estimate that a loss of $47 million from AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 36 months as at December 31, 2021.

Fair Value Derivatives

For interest rate derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is included in Interest expense in the Consolidated Statements of Earnings.

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Unrealized gain/(loss) on derivative	**8**	(116)
Unrealized gain/(loss) on hedged item	**(15)**	133
Realized loss on derivative	**(41)**	(12)
Realized gain on hedged item	**45**	—

Non-Qualifying Derivatives

The following table presents the unrealized gains and losses associated with changes in the fair value of our non-qualifying derivatives:

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**92**	902	1,626
Interest rate contracts[2]	**2**	(25)	178
Commodity contracts[3]	**71**	(114)	(62)
Other contracts[4]	**8**	(7)	9
Total unrealized derivative fair value gain/(loss), net	**173**	756	1,751

1 *For the respective annual periods, reported within Transportation and other services revenue (2021 - $98 million gain; 2020 - $533 million gain; 2019 - $930 million gain) and Net foreign currency gain/(loss) (2021 - $6 million loss; 2020 - $369 million gain; 2019 - $696 million gain) in the Consolidated Statements of Earnings.*

2 *Reported as an increase within Interest expense in the Consolidated Statements of Earnings.*

3 *For the respective annual periods, reported within Transportation and other services revenue (2021 - $9 million gain; 2020 - $2 million loss; 2019 - $26 million loss), Commodity sales (2021 - $160 million gain; 2020 - $321 million loss; 2019 - $544 million loss), Commodity costs (2021 - $105 million loss; 2020 - $207 million gain; 2019 - $459 million gain) and Operating and administrative expense (2021 - $7 million gain; 2020 - $2 million gain; 2019 - $49 million gain) in the Consolidated Statements of Earnings.*

4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. We also maintain current shelf prospectuses with securities regulators which enables ready access to either the Canadian or US public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2021. As a result, all credit facilities are available to us and the banks are obligated to fund and have been funding us under the terms of the facilities.

CREDIT RISK

Entering into derivative instruments may result in exposure to credit risk from the possibility that a counterparty will default on its contractual obligations. In order to mitigate this risk, we enter into risk management transactions primarily with institutions that possess strong investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated through maintenance and monitoring of credit exposure limits and contractual requirements, netting arrangements, and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

We have credit concentrations and credit exposure, with respect to derivative instruments, in the following counterparty segments:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Canadian financial institutions	**424**	481
US financial institutions	**130**	99
European financial institutions	**181**	28
Asian financial institutions	**30**	167
Other[1]	**122**	97
	887	872

1 Other is comprised of commodity clearing house and physical natural gas and crude oil counterparties.

As at December 31, 2021, we provided letters of credit totaling nil in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant International Swaps and Derivatives Association agreements. We held no cash collateral on derivative asset exposures as at December 31, 2021 and December 31, 2020.

Gross derivative balances have been presented without the effects of collateral posted. Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates, and are reflected at fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Within Enbridge Gas, credit risk is mitigated by the utilities' large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default on receivables. Generally, we classify and provide for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects our best estimates of market value based on generally accepted valuation techniques or models and is supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 instruments consist primarily of exchange traded derivatives used to mitigate the risk of crude oil price fluctuations.

Level 2
Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts, as well as commodity swaps for which observable inputs can be obtained.

We have also categorized the fair value of our held to maturity preferred share investment and long-term debt as Level 2. The fair value of our held to maturity preferred share investment is primarily based on the yield of certain Government of Canada bonds. The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power contracts and NGL and natural gas contracts, basis swaps, commodity swaps, power and energy swaps, as well as physical forward commodity contracts. We do not have any other financial instruments categorized in Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, we use observable market prices (interest, foreign exchange, commodity and share price) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread as well as the credit default swap spreads associated with our counterparties in our estimation of fair value.

We have categorized our derivative assets and liabilities measured at fair value as follows:

December 31, 2021	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**259**	**—**	**259**
Interest rate contracts	**—**	**64**	**—**	**64**
Commodity contracts	**38**	**71**	**95**	**204**
Other contracts	**—**	**2**	**—**	**2**
	38	**396**	**95**	**529**
Long-term derivative assets				
Foreign exchange contracts	**—**	**240**	**—**	**240**
Interest rate contracts	**—**	**88**	**—**	**88**
Commodity contracts	**—**	**21**	**8**	**29**
Other contracts	**—**	**3**	**—**	**3**
	—	**352**	**8**	**360**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(303)**	**—**	**(303)**
Interest rate contracts	**—**	**(150)**	**—**	**(150)**
Commodity contracts	**(52)**	**(66)**	**(146)**	**(264)**
Other contracts	**—**	**—**	**—**	**—**
	(52)	**(519)**	**(146)**	**(717)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(423)**	**—**	**(423)**
Interest rate contracts	**—**	**(24)**	**—**	**(24)**
Commodity contracts	**—**	**(19)**	**(65)**	**(84)**
Other contracts	**—**	**—**	**—**	**—**
	—	**(466)**	**(65)**	**(531)**
Total net financial asset/(liability)				
Foreign exchange contracts	**—**	**(227)**	**—**	**(227)**
Interest rate contracts	**—**	**(22)**	**—**	**(22)**
Commodity contracts	**(14)**	**7**	**(108)**	**(115)**
Other contracts	**—**	**5**	**—**	**5**
	(14)	**(237)**	**(108)**	**(359)**

December 31, 2020	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	180	—	180
Interest rate contracts	—	—	—	—
Commodity contracts	43	33	67	143
Other contracts	—	—	—	—
	43	213	67	323
Long-term derivative assets				
Foreign exchange contracts	—	466	—	466
Interest rate contracts	—	56	—	56
Commodity contracts	1	24	14	39
Other contracts	—	—	—	—
	1	546	14	561
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(185)	—	(185)
Interest rate contracts	—	(425)	—	(425)
Commodity contracts	(39)	(18)	(223)	(280)
Other contracts	—	(4)	—	(4)
	(39)	(632)	(223)	(894)
Long-term derivative liabilities				
Foreign exchange contracts	—	(760)	—	(760)
Interest rate contracts	—	(241)	—	(241)
Commodity contracts	(1)	(8)	(49)	(58)
Other contracts	—	—	—	—
	(1)	(1,009)	(49)	(1,059)
Total net financial asset/(liability)				
Foreign exchange contracts	—	(299)	—	(299)
Interest rate contracts	—	(610)	—	(610)
Commodity contracts	4	31	(191)	(156)
Other contracts	—	(4)	—	(4)
	4	(882)	(191)	(1,069)

The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments were as follows:

December 31, 2021	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	**(19)**	**Forward gas price**	**3.12**	**9.05**	**4.49**	**$/mmbtu[2]**
Crude	**3**	**Forward crude price**	**76.02**	**98.99**	**91.73**	**$/barrel**
Power	**(60)**	**Forward power price**	**31.00**	**125.13**	**76.23**	**$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**(56)**	**Forward gas price**	**2.65**	**9.25**	**4.63**	**$/mmbtu[2]**
Crude	**24**	**Forward crude price**	**68.66**	**97.00**	**87.97**	**$/barrel**
	(108)					

1 Financial and physical forward commodity contracts are valued using a market approach valuation technique.
2 One million British thermal units (mmbtu).

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of our Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices, and for option contracts, price volatility. Changes in forward commodity prices could result in significantly different fair values for our Level 3 derivatives. Changes in price volatility would change the value of the option contracts. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of price volatility.

Changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(191)**	(69)
Total gain/(loss)		
Included in earnings[1]	**(39)**	(123)
Included in OCI	**(29)**	2
Settlements	**151**	(1)
Level 3 net derivative liability at end of period	**(108)**	(191)

1 Reported within Transportation and other services revenue, Commodity costs and Operating and administrative expenses in the Consolidated Statements of Earnings.

There were no transfers into or out of Level 3 as at December 31, 2021 or 2020.

NET INVESTMENT HEDGES

We have designated a portion of our US dollar denominated debt, as well as a portfolio of foreign exchange forward contracts, as a hedge of our net investment in US dollar denominated investments and subsidiaries.

During the years ended December 31, 2021 and 2020, we recognized unrealized foreign exchange gains of $49 million and $117 million, respectively, on the translation of US dollar denominated debt and an unrealized gain on the change in fair value of our outstanding foreign exchange forward contracts of nil and $13 million, respectively, in OCI. During the years ended December 31, 2021 and 2020, we recognized a realized loss of nil and $15 million, respectively, in OCI associated with the settlement of foreign exchange forward contracts. No realized gains or losses associated with the settlement of US dollar denominated debt that had matured during the period were recognized in OCI during the years ended December 31, 2021 and 2020.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

Certain long-term investments in other entities with no actively quoted prices are classified as FVMA investments and are recorded at cost less impairment. The carrying value of FVMA investments totaled $52 million as at December 31, 2021 and 2020.

We have Restricted long-term investments held in trust totaling $630 million and $553 million as at December 31, 2021 and 2020, respectively, which are recognized at fair value.

As at December 31, 2021 and 2020, our long-term debt had a carrying value of $74.4 billion and $66.1 billion, respectively, before debt issuance costs and a fair value of $82.0 billion and $75.1 billion, respectively. We also have non-current notes receivable carried at book value and recorded in Deferred amounts and other assets in the Consolidated Statements of Financial Position. As at December 31, 2021 and 2020, the non-current notes receivable had a carrying value of $1.0 billion and $1.1 billion, respectively, which also approximates their fair value.

The fair value of other financial assets and liabilities other than derivative instruments, other long-term investments, restricted long-term investments and long-term debt approximate their cost due to the short period to maturity.

25. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Earnings before income taxes	**7,729**	4,190	7,535
Canadian federal statutory income tax rate	**15%**	15%	15%
Expected federal taxes at statutory rate	**1,159**	629	1,130
Increase/(decrease) resulting from:			
Provincial and state income taxes[1]	**228**	288	415
Foreign and other statutory rate differentials[2]	**134**	(53)	129
Effects of rate-regulated accounting[3]	**(139)**	(145)	(63)
Foreign allowable interest deductions[4]	**—**	(4)	(29)
Part VI.1 tax, net of federal Part I deduction[5]	**73**	76	78
US Minimum Tax[6]	**—**	44	67
Non-taxable portion of gain on sale of investment[7]	**(23)**	—	—
Valuation allowance[8]	**5**	(6)	26
Intercorporate investments[9]	**—**	—	(14)
Noncontrolling interests	**(17)**	(8)	(13)
Other	**(5)**	(47)	(18)
Income tax expense	**1,415**	774	1,708
Effective income tax rate	**18.3%**	18.5%	22.7%

1 *The change in provincial and state income taxes from 2020 to 2021 reflects the 2020 impact of state tax apportionment and rate changes in both the US and Canada offset by the increase in earnings from US and Canadian operations in 2021.*
2 *The change in foreign and other statutory rate differentials from 2020 to 2021 reflects the increase in earnings from US operations partially offset by higher rate benefits from foreign operations.*
3 *The amount in 2019 included the federal component of the tax benefit of the write-off of regulatory assets.*
4 *The decrease in foreign allowable interest deductions from 2019 to 2021 was due to changes in the related loan portfolio.*
5 *Part VI.1 tax is a tax levied on preferred share dividends paid in Canada.*
6 *There was no US Minimum Tax in 2021 as a result of tax losses from bonus tax depreciation.*
7 *The amount in 2021 relates to the federal impact of the gain on sale of the investment in Noverco.*
8 *The increase in 2021 is due to the federal component of the tax effect of a valuation allowance on additional deferred tax assets that are not more likely than not to be realized.*
9 *The amount in 2019 relates to the federal component of changes in assertions regarding the manner of recovery of intercorporate investments such that deferred tax related to outside basis temporary differences was required to be recorded for MATL.*

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	2021	2020	2019
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**3,399**	2,789	3,560
US	**3,336**	407	3,115
Other	**994**	994	860
	7,729	4,190	7,535
Current income taxes			
Canada	**162**	165	347
US	**80**	64	107
Other	**82**	98	98
	324	327	552
Deferred income taxes			
Canada	**344**	378	490
US	**741**	66	672
Other	**6**	3	(6)
	1,091	447	1,156
Income tax expense	**1,415**	774	1,708

COMPONENTS OF DEFERRED INCOME TAXES

Deferred income tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	2021	2020
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(8,721)**	(7,786)
Investments	**(6,097)**	(4,649)
Regulatory assets	**(1,245)**	(1,156)
Other	**(208)**	(127)
Total deferred income tax liabilities	**(16,271)**	(13,718)
Deferred income tax assets		
Financial instruments	**315**	518
Pension and OPEB plans	**110**	251
Loss carryforwards	**3,081**	2,005
Other	**1,648**	1,461
Total deferred income tax assets	**5,154**	4,235
Less valuation allowance	**(84)**	(79)
Total deferred income tax assets, net	**5,070**	4,156
Net deferred income tax liabilities	**(11,201)**	(9,562)
Presented as follows:		
Total deferred income tax assets	**488**	770
Total deferred income tax liabilities	**(11,689)**	(10,332)
Net deferred income tax liabilities	**(11,201)**	(9,562)

A valuation allowance has been established for certain loss and credit carryforwards, and outside basis temporary differences on investments that reduce deferred income tax assets to an amount that will more likely than not be realized.

As at December 31, 2021, we recognized the benefit of unused tax loss carryforwards of $1.9 billion (2020 - $2.6 billion) in Canada which expire in 2026 and beyond.

As at December 31, 2021, we recognized the benefit of unused tax loss carryforwards of $11.0 billion (2020 - $5.8 billion) in the US. Unused tax loss carryforwards of $3.5 billion (2020 - $2.4 billion) begin to expire in 2023, and unused tax loss carryforwards of $7.5 billion (2020 - $3.4 billion) have no expiration.

We have not provided for deferred income taxes on the difference between the carrying value of substantially all of our foreign subsidiaries and their corresponding tax basis as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such, these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying values of the investments and their tax bases is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries were $4.3 billion and $5.5 billion for the periods December 31, 2021 and 2020, respectively. If such earnings are remitted, in the form of dividends or otherwise, we may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

Enbridge and certain of our subsidiaries are subject to taxation in Canada, the US and other foreign jurisdictions. The material jurisdictions in which we are subject to potential examinations include the US (Federal) and Canada (Federal, Alberta and Ontario). We are open to examination by Canadian tax authorities for the 2012 to 2021 tax years and by US tax authorities for the 2018 to 2021 tax years. We are currently under examination for income tax matters in Canada for the 2014 to 2018 tax years. We are not currently under examination for income tax matters in any other material jurisdiction where we are subject to income tax.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**121**	129
Gross increases for tax positions of current year	**1**	1
Gross decreases for tax positions of prior year	**(26)**	(1)
Change in translation of foreign currency	**(1)**	(3)
Lapses of statute of limitations	**(19)**	(5)
Unrecognized tax benefits at end of year	**76**	121

The unrecognized tax benefits as at December 31, 2021, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Interest and penalties included in income taxes for the years ended December 31, 2021 and 2020 were a $5 million recovery and $3 million expense, respectively. As at December 31, 2021 and 2020, interest and penalties of $12 million and $17 million, respectively, have been accrued.

26. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We sponsor Canadian and US contributory and non-contributory registered defined benefit and defined contribution pension plans, which provide benefits covering substantially all employees. The Canadian Plans provide defined benefit and defined contribution pension benefits to our Canadian employees. The US Plans provide defined benefit pension benefits to our US employees. We also sponsor supplemental non-contributory defined benefit pension plans, which provide non-registered benefits for certain employees in Canada and the US.

Defined Benefit Pension Plan Benefits

Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

Defined Contribution Pension Plan Benefits

Our contributions are based on each plan participant's current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

Benefit Obligations, Plan Assets and Funded Status

The following table details the changes in the projected benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit pension plans:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Change in projected benefit obligation				
Projected benefit obligation at beginning of year	**4,855**	4,446	**1,243**	1,230
Service cost	**139**	148	**44**	44
Interest cost	**101**	128	**17**	31
Participant contributions	**28**	31	**—**	—
Actuarial (gain)/loss[1]	**(329)**	292	**(21)**	95
Benefits paid	**(194)**	(190)	**(84)**	(128)
Foreign currency exchange rate changes	**—**	—	**(11)**	(23)
Other	**—**	—	**(4)**	(6)
Projected benefit obligation at end of year[2]	**4,600**	4,855	**1,184**	1,243
Change in plan assets				
Fair value of plan assets at beginning of year	**4,077**	3,827	**1,062**	1,104
Actual return on plan assets	**505**	288	**151**	83
Employer contributions	**120**	121	**43**	27
Participant contributions	**28**	31	**—**	—
Benefits paid	**(194)**	(190)	**(84)**	(128)
Foreign currency exchange rate changes	**—**	—	**(8)**	(18)
Other	**—**	—	**(4)**	(6)
Fair value of plan assets at end of year[3]	**4,536**	4,077	**1,160**	1,062
Underfunded status at end of year	**(64)**	(778)	**(24)**	(181)
Presented as follows:				
Deferred amounts and other assets	**250**	35	**98**	—
Accounts payable and other	**(9)**	(9)	**(4)**	(3)
Other long-term liabilities	**(305)**	(804)	**(118)**	(178)
	(64)	(778)	**(24)**	(181)

1 *Primarily due to increase in the discount rate used to measure the benefit obligations (2020 - primarily due to decrease in the discount rate used to measure the benefit obligations).*

2 *The accumulated benefit obligation for our Canadian pension plans was $4.3 billion and $4.5 billion as at December 31, 2021 and 2020, respectively. The accumulated benefit obligation for our US pension plans was $1.1 billion and $1.2 billion as at December 31, 2021 and 2020, respectively.*

3 *Assets in the amount of $13 million (2020 - $11 million) and $84 million (2020 - $59 million), related to our Canadian and United States non-registered supplemental pension plan obligations, are held in grantor trusts and rabbi trusts that, in accordance with federal tax regulations, are not restricted from creditors. These assets are committed for the future settlement of benefit obligations included in the underfunded status as at the end of the year, however they are excluded from plan assets for accounting purposes.*

Certain of our pension plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Accumulated benefit obligation	**440**	4,094	**115**	1,207
Fair value of plan assets	**247**	3,621	**—**	1,062

Certain of our pension plans have projected benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Projected benefit obligation	**1,272**	4,434	**121**	1,243
Fair value of plan assets	**1,020**	3,621	**—**	1,062

Amount Recognized in Accumulated Other Comprehensive Income

The amount of pre-tax AOCI relating to our pension plans are as follows:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Net actuarial loss	**226**	542	**92**	233
Prior service credit	**—**	—	**(1)**	(1)
Total amount recognized in AOCI[1]	**226**	542	**91**	232

1 Excludes amounts related to cumulative translation adjustment.

Net Periodic Benefit Cost and Other Amounts Recognized in Comprehensive Income

The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our pension plans are as follows:

	Canada			US		
Year ended December 31,	**2021**	2020	2019	**2021**	2020	2019
(millions of Canadian dollars)						
Service cost	**139**	148	149	**44**	44	45
Interest cost[1]	**101**	128	139	**17**	31	41
Expected return on plan assets[1]	**(252)**	(260)	(245)	**(73)**	(88)	(78)
Amortization/settlement of net actuarial loss[1]	**54**	42	41	**11**	1	2
Amortization/curtailment of prior service credit[1]	**—**	—	—	**—**	(1)	(1)
Net periodic benefit (credit)/cost	**42**	58	84	**(1)**	(13)	9
Defined contribution benefit cost	**7**	6	8	**—**	—	—
Net pension (credit)/cost recognized in Earnings	**49**	64	92	**(1)**	(13)	9
Amount recognized in OCI:						
Effect of plan combination	**—**	—	—	**—**	—	(6)
Amortization/settlement of net actuarial loss	**(25)**	(21)	(26)	**(11)**	(1)	(2)
Amortization/curtailment of prior service credit	**—**	—	—	**—**	1	1
Net actuarial (gain)/loss arising during the year	**(291)**	118	115	**(99)**	100	8
Total amount recognized in OCI	**(316)**	97	89	**(110)**	100	1
Total amount recognized in Comprehensive income	**(267)**	161	181	**(111)**	87	10

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.

Actuarial Assumptions

The weighted average assumptions made in the measurement of the projected benefit obligation and net periodic benefit cost of our pension plans are as follows:

	Canada			US		
	2021	2020	2019	**2021**	2020	2019
Projected benefit obligation						
Discount rate	**3.2 %**	2.6 %	3.0 %	**2.6 %**	2.2 %	3.0 %
Rate of salary increase	**2.9 %**	2.3 %	3.2 %	**2.8 %**	2.7 %	2.9 %
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.3 %**	4.3 %	4.5 %
Net periodic benefit cost						
Discount rate	**2.6 %**	3.0 %	3.8 %	**2.2 %**	3.0 %	3.9 %
Rate of return on plan assets	**6.2 %**	6.8 %	7.0 %	**7.3 %**	7.9 %	8.0 %
Rate of salary increase	**2.3 %**	3.2 %	3.2 %	**2.7 %**	2.9 %	2.9 %
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.3 %**	4.5 %	4.5 %

OTHER POSTRETIREMENT BENEFIT PLANS

We sponsor funded and unfunded defined benefit OPEB Plans, which provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees.

Benefit Obligations, Plan Assets and Funded Status

The following table details the changes in the accumulated postretirement benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit OPEB plans:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Change in accumulated postretirement benefit obligation				
Accumulated postretirement benefit obligation at beginning of year	**321**	293	**254**	288
Service cost	**6**	5	**1**	2
Interest cost	**7**	8	**3**	7
Participant contributions	**—**	—	**8**	4
Actuarial (gain)/loss[1]	**(51)**	21	**(69)**	17
Benefits paid	**(9)**	(6)	**(22)**	(28)
Plan amendments	**—**	—	**—**	(33)
Foreign currency exchange rate changes	**—**	—	**(3)**	(4)
Other	**—**	—	**1**	1
Accumulated postretirement benefit obligation at end of year	**274**	321	**173**	254
Change in plan assets				
Fair value of plan assets at beginning of year	**—**	—	**188**	188
Actual return on plan assets	**—**	—	**22**	14
Employer contributions	**9**	6	**6**	12
Participant contributions	**—**	—	**8**	4
Benefits paid	**(9)**	(6)	**(22)**	(28)
Foreign currency exchange rate changes	**—**	—	**(3)**	(3)
Other	**—**	—	**2**	1
Fair value of plan assets at end of year	**—**	—	**201**	188
Overfunded/(underfunded) status at end of year	**(274)**	(321)	**28**	(66)
Presented as follows:				
Deferred amounts and other assets	**—**	—	**71**	19
Accounts payable and other	**(12)**	(13)	**—**	(6)
Other long-term liabilities	**(262)**	(308)	**(43)**	(79)
	(274)	(321)	**28**	(66)

1 Primarily due to increase in the discount rate used to measure the benefit obligations (2020 - primarily due to decrease in the discount rate used to measure the benefit obligations).

Certain of our OPEB plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Accumulated benefit obligation	**274**	321	**94**	191
Fair value of plan assets	**—**	—	**51**	106

Amount Recognized in Accumulated Other Comprehensive Income

The amount of pre-tax AOCI relating to our OPEB plans are as follows:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Net actuarial (gain)/loss	**(35)**	15	**(104)**	(7)
Prior service credit	**(1)**	(1)	**(37)**	(44)
Total amount recognized in AOCI[1]	**(36)**	14	**(141)**	(51)

1 Excludes amounts related to cumulative translation adjustment.

Net Periodic Benefit Cost and Other Amounts Recognized in Comprehensive Income

The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our OPEB plans are as follows:

	Canada			US		
Year ended December 31,	**2021**	2020	2019	**2021**	2020	2019
(millions of Canadian dollars)						
Service cost	**6**	5	5	**1**	2	2
Interest cost[1]	**7**	8	10	**3**	7	10
Expected return on plan assets[1]	**—**	—	—	**(10)**	(12)	(12)
Amortization/settlement of net actuarial gain[1]	**—**	(1)	(7)	**(1)**	(1)	—
Amortization/curtailment of prior service credit[1]	**—**	—	(1)	**(7)**	(2)	(2)
Net periodic benefit (credit)/cost recognized in Earnings	**13**	12	7	**(14)**	(6)	(2)
Amount recognized in OCI:						
Amortization/settlement of net actuarial gain	**—**	1	7	**1**	1	—
Amortization/curtailment of prior service credit	**—**	—	1	**7**	2	2
Net actuarial (gain)/loss arising during the year	**(50)**	21	15	**(80)**	15	(8)
Prior service credit	**—**	—	—	**—**	(33)	—
Total amount recognized in OCI	**(50)**	22	23	**(72)**	(15)	(6)
Total amount recognized in Comprehensive income	**(37)**	34	30	**(86)**	(21)	(8)

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.

Actuarial Assumptions
The weighted average assumptions made in the measurement of the accumulated postretirement benefit obligation and net periodic benefit cost of our OPEB plans are as follows:

	Canada			US		
	2021	2020	2019	**2021**	2020	2019
Accumulated postretirement benefit obligation						
Discount rate	**3.2 %**	2.6 %	3.1 %	**2.4 %**	2.0 %	2.8 %
Net periodic benefit cost						
Discount rate	**2.6 %**	3.1 %	3.8 %	**2.0 %**	2.8 %	4.0 %
Rate of return on plan assets	**N/A**	N/A	N/A	**6.0 %**	6.7 %	6.7 %

Assumed Health Care Cost Trend Rates
The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Canada		US	
	2021	2020	**2021**	2020
Health care cost trend rate assumed for next year	**4.0 %**	4.0 %	**7.0 %**	6.8 %
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0 %**	4.0 %	**4.5 %**	4.5 %
Year that the rate reaches the ultimate trend rate	**N/A**	N/A	**2037**	2037

PLAN ASSETS
We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

	Canada			US		
	Target	December 31,		**Target**	December 31,	
Asset Category	**Allocation**	**2021**	2020	**Allocation**	**2021**	2020
Equity securities	**43.8 %**	**46.7 %**	47.2 %	**45.0 %**	**52.5 %**	55.6 %
Fixed income securities	**28.9 %**	**29.8 %**	29.6 %	**20.1 %**	**18.4 %**	17.2 %
Alternatives[1]	**27.3 %**	**23.5 %**	23.2 %	**34.9 %**	**29.1 %**	27.2 %

1 *Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the funds.*

Pension Plans

The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level:

	Canada				US			
	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
December 31, 2021								
Cash and cash equivalents	**180**	**—**	**—**	**180**	**10**	**—**	**—**	**10**
Equity securities								
Canada	**198**	**228**	**—**	**426**	**—**	**—**	**—**	**—**
US	**1**	**—**	**—**	**1**	**—**	**—**	**—**	**—**
Global	**—**	**1,693**	**—**	**1,693**	**—**	**609**	**—**	**609**
Fixed income securities								
Government	**258**	**459**	**—**	**717**	**—**	**86**	**—**	**86**
Corporate	**—**	**453**	**—**	**453**	**—**	**118**	**—**	**118**
Alternatives[4]	**—**	**—**	**1,064**	**1,064**	**—**	**—**	**337**	**337**
Forward currency contracts	**—**	**2**	**—**	**2**	**—**	**—**	**—**	**—**
Total pension plan assets at fair value	**637**	**2,835**	**1,064**	**4,536**	**10**	**813**	**337**	**1,160**
December 31, 2020								
Cash and cash equivalents	213	—	—	213	5	—	—	5
Equity securities								
Canada	178	188	—	366	—	—	—	—
US	2	—	—	2	—	—	—	—
Global	—	1,556	—	1,556	—	590	—	590
Fixed income securities								
Government	207	378	—	585	—	75	—	75
Corporate	—	410	—	410	—	103	—	103
Alternatives[4]	—	—	912	912	—	—	289	289
Forward currency contracts	—	33	—	33	—	—	—	—
Total pension plan assets at fair value	600	2,565	912	4,077	5	768	289	1,062

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of pension plan assets classified as Level 3 in the fair value hierarchy were as follows:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Balance at beginning of year	**912**	852	**289**	276
Unrealized and realized gains/(losses)	**77**	(27)	**38**	7
Purchases and settlements, net	**75**	87	**10**	6
Balance at end of year	**1,064**	912	**337**	289

OPEB Plans

The following table summarizes the fair value of plan assets for our US funded OPEB plans recorded at each fair value hierarchy level:

	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)				
December 31, 2021				
Cash and cash equivalents	**4**	**—**	**—**	**4**
Equity securities				
US	**—**	**39**	**—**	**39**
Global	**—**	**75**	**—**	**75**
Fixed income securities				
Government	**47**	**6**	**—**	**53**
Corporate	**—**	**8**	**—**	**8**
Alternatives[4]	**—**	**—**	**22**	**22**
Total OPEB plan assets at fair value	**51**	**128**	**22**	**201**
December 31, 2020				
Equity securities				
US	—	35	—	35
Global	—	79	—	79
Fixed income securities				
Government	38	6	—	44
Corporate	—	8	—	8
Alternatives[4]	—	—	22	22
Total OPEB plan assets at fair value	38	128	22	188

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives includes investments in private debt, private equity, infrastructure and real estate.

Changes in the net fair value of US funded OPEB plan assets classified as Level 3 in the fair value hierarchy were as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Balance at beginning of year	**22**	18
Unrealized and realized gains	**2**	1
Purchases and settlements, net	**(2)**	3
Balance at end of year	**22**	22

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2022	2023	2024	2025	2026	2027-2031
(millions of Canadian dollars)						
Pension						
Canada	197	203	208	212	217	1,163
US	80	78	78	76	77	374
OPEB						
Canada	12	12	12	13	13	67
US	17	15	14	13	12	51

EXPECTED EMPLOYER CONTRIBUTIONS

In 2022, we expect to contribute approximately $110 million and $4 million to the Canadian and US pension plans, respectively, and $12 million and $6 million to the Canadian and US OPEB plans, respectively.

RETIREMENT SAVINGS PLANS

In addition to the pension and OPEB plans discussed above, we also have defined contribution employee savings plans available to US employees. Employees may participate in a matching contribution where we match a certain percentage of before-tax employee contributions of up to 6.0% of eligible pay per pay period. For the years ended December 31, 2021, 2020 and 2019, pre-tax employer matching contribution costs were $27 million each year, respectively.

27. LEASES

LESSEE

We incur operating lease expenses related primarily to real estate, pipelines, storage and equipment. Our operating leases have remaining lease terms of 5 months to 25 years as at December 31, 2021.

For the years ended December 31, 2021 and 2020, we incurred operating lease expenses of $95 million and $107 million, respectively. Operating lease expenses are reported under Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2021 and 2020, operating lease payments to settle lease liabilities were $118 million and $133 million, respectively. Operating lease payments are reported under Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Statements of Financial Position Information

	December 31, 2021	December 31, 2020
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases[1]		
Operating lease right-of-use assets, net[2]	**645**	**708**
Operating lease liabilities - current[3]	**92**	**80**
Operating lease liabilities - long-term[3]	**612**	**681**
Total operating lease liabilities	**704**	**761**
Finance leases		
Finance lease right-of-use assets, net[4]	**49**	**57**
Finance lease liabilities - current[5]	**13**	**11**
Finance lease liabilities - long-term[3]	**33**	**42**
Total finance lease liabilities	**46**	**53**
Weighted average remaining lease term		
Operating leases	**12 years**	13 years
Finance leases	**7 years**	7 years
Weighted average discount rate		
Operating leases	**4.1 %**	4.1 %
Finance leases	**3.8 %**	3.8 %

1 *Affiliate right-of-use assets, current lease liabilities and long-term lease liabilities as at December 31, 2021 were $51 million (December 31, 2020 - $65 million), $5 million (December 31, 2020 - $5 million) and $47 million (December 31, 2020 - $52 million), respectively.*

2 *Operating lease right-of-use assets are reported under Deferred amounts and other assets in the Consolidated Statements of Financial Position.*

3 *Current operating lease liabilities and long-term operating and finance lease liabilities are reported under Accounts payable and other and Other long-term liabilities, respectively, in the Consolidated Statements of Financial Position.*

4 *Finance lease right-of-use assets are reported under Property, plant and equipment, net in the Consolidated Statements of Financial Position.*

5 *Current finance lease liabilities are reported under Current portion of long-term debt in the Consolidated Statements of Financial Position.*

As at December 31, 2021, our operating and finance lease liabilities are expected to mature as follows:

	Operating leases	Finance leases
(millions of Canadian dollars)		
2022	**117**	**15**
2023	**98**	**13**
2024	**91**	**9**
2025	**84**	**2**
2026	**72**	**1**
Thereafter	**455**	**11**
Total undiscounted lease payments	**917**	**51**
Less imputed interest	**(213)**	**(5)**
Total	**704**	**46**

LESSOR

We receive revenues from operating leases primarily related to natural gas and crude oil storage and processing facilities, rail cars, and wind power generation assets. Our operating leases have remaining lease terms of 1 month to 30 years as at December 31, 2021.

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Operating lease income	**263**	265
Variable lease income	**333**	361
Total lease income[1]	**596**	626

1 Lease income is recorded under Transportation and other services in the Consolidated Statements of Earnings.

As at December 31, 2021, the following table sets out future lease payments to be received under operating lease contracts where we are the lessor:

	Operating leases
(millions of Canadian dollars)	
2022	**235**
2023	**215**
2024	**205**
2025	**196**
2026	**191**
Thereafter	**1,938**
Future lease payments	**2,980**

28. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Accounts receivable and other	**(1,228)**	1,546	(547)
Accounts receivable from affiliates	**(38)**	8	6
Inventory	**(118)**	(254)	(24)
Deferred amounts and other assets	**(195)**	(586)	133
Accounts payable and other	**(63)**	(770)	63
Accounts payable to affiliates	**52**	1	(24)
Interest payable	**43**	31	(41)
Other long-term liabilities	**(69)**	117	175
	(1,616)	93	(259)

29. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

We provide transportation services to several significantly influenced investees which we record as transportation and other services revenue. We also purchase and sell natural gas and crude oil with several of our significantly influenced investees. These revenues and costs are recorded as commodity sales and commodity costs. We contract for firm transportation services to meet our annual natural gas supply requirements which we record as gas distribution costs.

Our transactions with significantly influenced investees are as follows:

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Transportation and other services	**149**	133	140
Commodity sales	**20**	21	107
Operating and administrative[1]	**292**	252	241
Commodity costs[2]	**790**	518	773
Gas distribution costs	**131**	135	133

1 During the years December 31, 2021, 2020 and 2019, we had Operating and administrative costs from the Seaway Crude Pipeline System of $389 million, $342 million and $327 million, respectively. These costs are a result of an operational contract where we utilize capacity on Seaway Crude Pipeline System assets for use in our Liquids Pipelines business. The costs are offset by recoveries recorded on expenses incurred by us on behalf of our significantly influenced investees of $104 million, $94 million and $86 million for the years ended December 31, 2021, 2020 and 2019.

2 During the years December 31, 2021, 2020 and 2019, we had Commodity costs from the Aux Sable Canada LP. of $447 million, $91 million and $272 million, respectively.

LONG-TERM NOTES RECEIVABLE FROM AFFILIATES

As at December 31, 2021, amounts receivable from affiliates include a series of loans totaling $954 million ($1,108 million as at December 31, 2020), which require quarterly or semi-annual interest payments at annual interest rates ranging from 3% to 8%. Interest income recognized from these notes totaled $39 million, $44 million and $40 million for the years ended December 31, 2021, 2020 and 2019, respectively. The amounts receivable from affiliates are included in Deferred amounts and other assets in the Consolidated Statements of Financial position.

30. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2021, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	73,809	6,164	7,910	4,559	4,357	11,007	39,812
Interest obligations[2]	36,044	2,531	2,389	2,229	2,073	1,925	24,897
Purchase of services, pipe and other materials, including transportation[3]	7,876	2,945	1,010	736	561	607	2,017
Maintenance agreements	346	41	20	20	21	21	223
Right-of-ways commitments	1,249	35	35	35	36	37	1,071
Total	119,324	11,716	11,364	7,579	7,048	13,597	68,020

1 Includes debentures, term notes, commercial paper and credit facility draws based on the facility's maturity date and excludes short-term borrowings, debt discounts, debt issuance costs, finance lease obligations and fair value adjustment. We have the ability under certain debt facilities to call and repay the obligations prior to scheduled maturities. Therefore, the actual timing of future cash repayments could be materially different than presented above.

2 Includes debentures and term notes bearing interest at fixed, floating and fixed-to-floating rates.

3 Includes capital and operating commitments. Consists primarily of gas transportation and storage contracts, firm capacity payments and gas purchase commitments, transportation, service and product purchase obligations, and power commitments.

ENVIRONMENTAL
We are subject to various Canadian and US federal, state and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and Enbridge and its affiliates are, at times, subject to environmental remediation at various sites where we operate. We manage this environmental risk through appropriate environmental policies, programs and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with our operating activities.

AUX SABLE
On October 14, 2016, an amended claim was filed against Aux Sable by a counterparty to an NGL supply agreement. On January 5, 2017, Aux Sable filed a Statement of Defence with respect to this claim.

On November 27, 2019, the counterparty filed an amended amended claim providing further particulars of its claim against Aux Sable, increasing its damages claimed, and adding defendants Aux Sable Liquid Products Inc. and Aux Sable Extraction LLC (general partners of the previously existing defendants). Aux Sable filed an amended Statement of Defence responding to the amended amended claim on January 31, 2020.

While the final outcome of this action cannot be predicted with certainty, at this time management believes that the ultimate resolution of this action will not have a material impact on our consolidated financial position or results of operations.

TAX MATTERS
We and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATION
We and our subsidiaries are involved in various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

31. GUARANTEES

In the normal course of conducting business, we may enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries, jointly owned entities, unconsolidated entities such as equity method investees, or entities with other ownership arrangements that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases.

We typically enter into these arrangements to facilitate commercial transactions with third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2021 guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

32. QUARTERLY FINANCIAL DATA (UNAUDITED)

	Q1	Q2	Q3	Q4	Total
(unaudited; millions of Canadian dollars, except per share amounts)					
2021					
Operating revenues	**12,187**	**10,948**	**11,466**	**12,470**	**47,071**
Operating income	**2,548**	**1,816**	**1,388**	**2,053**	**7,805**
Earnings	**2,014**	**1,521**	**814**	**1,965**	**6,314**
Earnings attributable to controlling interests	**1,992**	**1,484**	**780**	**1,933**	**6,189**
Earnings attributable to common shareholders	**1,900**	**1,394**	**682**	**1,840**	**5,816**
Earnings per common share					
Basic	**0.94**	**0.69**	**0.34**	**0.91**	**2.87**
Diluted	**0.94**	**0.69**	**0.34**	**0.91**	**2.87**
2020					
Operating revenues	12,013	7,956	9,110	10,008	39,087
Operating income	1,513	2,098	2,095	2,251	7,957
Earnings/(loss)	(1,364)	1,777	1,104	1,899	3,416
Earnings/(loss) attributable to controlling interests	(1,333)	1,741	1,084	1,871	3,363
Earnings/(loss) attributable to common shareholders	(1,429)	1,647	990	1,775	2,983
Earnings/(loss) per common share					
Basic	(0.71)	0.82	0.49	0.88	1.48
Diluted	(0.71)	0.82	0.49	0.88	1.48

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and US securities law. As at December 31, 2021, an evaluation was carried out under the supervision of and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of our disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by us in reports that we file with or submit to the SEC and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rules of the SEC and the Canadian Securities Administrators. Our internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external reporting purposes in accordance with US GAAP.

Our internal control over financial reporting includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Our internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with our policies and procedures.

Our management assessed the effectiveness of our internal control over financial reporting as at December 31, 2021, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management concluded that we maintained effective internal control over financial reporting as at December 31, 2021.

The effectiveness of our internal control over financial reporting as at December 31, 2021 has been audited by PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm appointed by our shareholders. As stated in their *Report of Independent Registered Public Accounting Firm* which appears in *Item 8. Financial Statements and Supplementary Data*, they expressed an unqualified opinion on the effectiveness of our internal control over financial reporting as at December 31, 2021.

Changes in Internal Control Over Financial Reporting
During the three months ended December 31, 2021, there has been no material change in our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

NORMAL COURSE ISSUER BID

On December 31, 2021, we announced that the TSX had approved our NCIB to purchase, for cancellation, up to 31,062,331 of the outstanding common shares of Enbridge to an aggregate amount of up to $1.5 billion, subject to certain restrictions on the number of common shares that may be purchased on a single day.

Purchases under the NCIB may be made through the facilities of the TSX, the NYSE and other designated exchanges and alternative trading systems, commencing on January 5, 2022 and continuing until January 4, 2023, when the bid expires, or such earlier date on which Enbridge has either acquired the maximum number of common shares allowable under the NCIB or otherwise decide not to make any further repurchases under the NCIB. The maximum number of common shares that Enbridge may repurchase for cancellation represents approximately 1.53% of the 2,026,085,179 common shares issued and outstanding as at December 22, 2021.

A copy of our notice of intention to make a normal course issuer bid may be obtained, free of charge, by contacting Investor Relations by email, phone or mail at:

Email: investor.relations@enbridge.com
Phone Within North America: 1-800-481-2804
Phone Outside North America: 1-403-231-3960
Mail: Enbridge Inc. Investor Relations, 200, 425 – 1st Street S.W., Calgary, Alberta, Canada T2P 3L8

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors of Registrant
The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021. This information will also be disclosed in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

Executive Officers of Registrant
The information regarding executive officers is included in Part I. *Item 1. Business - Executive Officers.*

Code of Ethics for Chief Executive Officer and Senior Financial Officers
The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021. This information will also be disclosed in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021. This information will also be disclosed in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021. This information will also be disclosed in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021. This information will also be disclosed in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021. This information will also be disclosed in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Enbridge Inc.:

Report of Independent Registered Public Accounting Firm (PCAOB ID 271)
Consolidated Statements of Earnings
Consolidated Statements of Comprehensive Income
Consolidated Statements of Changes in Equity
Consolidated Statements of Cash Flows
Consolidated Statements of Financial Position
Notes to the Consolidated Financial Statements

All schedules are omitted because they are not required or because the required information is included in the Consolidated Financial Statements or Notes.

(b) Exhibits:

Reference is made to the “Index of Exhibits” following Item 16. *Form 10-K Summary*, which is hereby incorporated into this Item.

ITEM 16. FORM 10-K SUMMARY

Not applicable.

INDEX OF EXHIBITS

Each exhibit identified below is included as a part of this annual report. Exhibits included in this filing are designated by an asterisk ("*"); all exhibits not so designated are incorporated by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan arrangement.

Exhibit No.		Name of Exhibit
3.1		Articles of Continuance of the Corporation, dated December 15, 1987 (incorporated by reference to Exhibit 2.1(a) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.2		Certificate of Amendment, dated August 2, 1989, to the Articles of the Corporation (incorporated by reference to Exhibit 2.1(b) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.3		Articles of Amendment of the Corporation, dated April 30, 1992 (incorporated by reference to Exhibit 2.1(c) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.4		Articles of Amendment of the Corporation, dated July 2, 1992 (incorporated by reference to Exhibit 2.1(d) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.5		Articles of Amendment of the Corporation, dated August 6, 1992 (incorporated by reference to Exhibit 2.1(e) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.6		Articles of Arrangement of the Corporation dated December 18, 1992, attaching the Arrangement Agreement, dated December 15, 1992 (incorporated by reference to Exhibit 2.1(f) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.7		Certificate of Amendment of the Corporation (notarial certified copy), dated December 18, 1992 (incorporated by reference to Exhibit 2.1(g) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.8		Articles of Amendment of the Corporation, dated May 5, 1994 (incorporated by reference to Exhibit 2.1(h) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.9		Certificate of Amendment, dated October 7, 1998 (incorporated by reference to Exhibit 2.1(i) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.10		Certificate of Amendment, dated November 24, 1998 (incorporated by reference to Exhibit 2.1(j) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.11		Certificate of Amendment, dated April 29, 1999 (incorporated by reference to Exhibit 2.1(k) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.12		Certificate of Amendment, dated May 5, 2005 (incorporated by reference to Exhibit 2.1(l) to Enbridge's Registration Statement on Form S-8 filed August 5, 2005)
3.13		Certificate of Amendment, dated May 11, 2011 (incorporated by reference to Exhibit 3.13 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.14		Certificate of Amendment, dated September 28, 2011 (incorporated by reference to Exhibit 3.14 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.15		Certificate of Amendment, dated November 21, 2011 (incorporated by reference to Exhibit 3.15 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.16		Certificate of Amendment, dated January 16, 2012 (incorporated by reference to Exhibit 3.16 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.17		Certificate of Amendment, dated March 27, 2012 (incorporated by reference to Exhibit 3.17 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)

3.18		Certificate of Amendment, dated April 16, 2012 (incorporated by reference to Exhibit 3.18 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.19		Certificate of Amendment, dated May 17, 2012 (incorporated by reference to Exhibit 3.19 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.20		Certificate of Amendment, dated July 12, 2012 (incorporated by reference to Exhibit 3.20 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.21		Certificate of Amendment, dated September 11, 2012 (incorporated by reference to Exhibit 3.21 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.22		Certificate of Amendment, dated December 3, 2012 (incorporated by reference to Exhibit 3.22 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.23		Certificate of Amendment, dated March 25, 2013 (incorporated by reference to Exhibit 3.23 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.24		Certificate of Amendment, dated June 4, 2013 (incorporated by reference to Exhibit 3.24 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.25		Certificate of Amendment, dated September 25, 2013 (incorporated by reference to Exhibit 3.25 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.26		Certificate of Amendment, dated December 10, 2013 (incorporated by reference to Exhibit 3.26 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.27		Certificate of Amendment, dated March 10, 2014 (incorporated by reference to Exhibit 3.27 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.28		Certificate of Amendment, dated May 20, 2014 (incorporated by reference to Exhibit 3.28 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.29		Certificate of Amendment, dated July 15, 2014 (incorporated by reference to Exhibit 3.29 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.30		Certificate of Amendment, dated September 19, 2014 (incorporated by reference to Exhibit 3.30 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.31		Certificate of Amendment, dated November 22, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 1, 2016)
3.32		Certificate of Amendment, dated December 15, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 16, 2016)
3.33		Certificate of Amendment, dated July 13, 2017 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed July 13, 2017)
3.34		Certificate of Amendment, dated September 25, 2017 (incorporated by reference to Exhibit 3.34 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
3.35		Certificate of Amendment, dated December 7, 2017 (incorporated by reference to Exhibit 3.35 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
3.36		Certificate of Amendment, dated February 27, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed March 1, 2018)
3.37		Certificate of Amendment, dated April 9, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed April 12, 2018)
3.38		Certificate of Amendment, dated April 10, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed April 12, 2018)
3.39		Certificate and Articles of Amendment, dated July 6, 2020 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed July 8, 2020)
3.40	*	General By-Law No. 1 of Enbridge Inc.
3.41		By-Law No. 2 of Enbridge Inc. (incorporated by reference to Enbridge's Current Report on Form 6-K filed December 5, 2014)

4.1		Form of Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas to be dated February 25, 2005 (incorporated by reference to Exhibit 7.1 to Enbridge's Registration Statement on Form F-10 filed February 4, 2005)
4.2		First Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated March 1, 2012 (incorporated by reference to Exhibit 7.3 to Enbridge's Registration Statement on Form F-10 filed May 11, 2012)
4.3		Second Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated December 19, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 20, 2016)
4.4		Third Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated July 14, 2017 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed July 14, 2017)
4.5		Fourth Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated March 1, 2018 (incorporated by reference to Enbridge's Current Report on Form 8-K filed March 1, 2018)
4.6		Fifth Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated April 12, 2018 (incorporated by reference to Enbridge's Current Report on Form 8-K filed April 12, 2018)
4.7		Sixth Supplemental Indenture between Enbridge Inc., Spectra Energy Partners, LP (as guarantor), Enbridge Energy Partners, L.P. (as guarantor) and Deutsche Bank Trust Company Americas, dated May 13, 2019 (incorporated by reference to Enbridge's Registration Statement on Form S-3 filed May 17, 2019)
4.8		Seventh Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated July 8, 2020 (incorporated by reference to Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed July 8, 2020)
4.9		Eighth Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated June 28, 2021 (incorporated by reference to Exhibit 4.4 to Enbridge's Current Report on Form 8-K filed June 28, 2021)
4.10		Shareholder Rights Plan Agreement between Enbridge Inc. and Computershare Trust Company of Canada dated as of November 9, 1995 and Amended and Restated as of May 5, 2020 (incorporated by reference to Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed May 6, 2020).
4.11		Description of Securities Registered Under Section 12 of the Securities Exchange Act, as amended (incorporated by reference to Exhibit 4.9 to Enbridge's Form 10-K filed February 14, 2020)
		Certain instruments defining the rights of holders of long-term debt securities of the Registrant and its subsidiaries are omitted pursuant to Item 601(b)(4)(iii) of Regulation S-K. The Registrant hereby undertakes to furnish to the SEC, upon request, copies of any such instruments.
10.1		Enbridge Pipelines Inc. Competitive Toll Settlement dated July 1, 2011 (incorporated by reference to Exhibit 10.1 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.2		Sixteenth Supplemental Indenture dated as of January 22, 2019 between Enbridge Energy Partners, L.P. and US Bank National Association, as trustee (incorporated by reference as Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.3		Seventeenth Supplemental Indenture dated as of January 22, 2019 between Enbridge Energy Partners, L.P., Enbridge Inc. and US Bank National Association, as trustee (incorporated by reference as Exhibit 4.2 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.4		Seventh Supplemental Indenture dated as of January 22, 2019 between Spectra Energy Partners, LP, Enbridge Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference as Exhibit 4.3 to Enbridge's Current Report on Form 8-K filed January 24, 2019)

10.5		Eighth Supplemental Indenture dated as of January 22, 2019 between Spectra Energy Partners, LP, Enbridge Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference as Exhibit 4.4 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.6		Subsidiary Guarantee Agreement dated as of January 22, 2019 between Spectra Energy Partners, LP and Enbridge Energy Partners, L.P. (incorporated by reference as Exhibit 4.5 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.7	+	Form of Executive Employment Agreement (pre-2014) (incorporated by reference to Exhibit 10.2 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.8	+	Form of Executive Employment Agreement (2014-2016) (incorporated by reference to Exhibit 10.3 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.9	+	Form of Executive Employment Agreement (2017) (incorporated by reference to Exhibit 10.4 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.10	+	Executive Employment Agreement between Enbridge Employee Services, Inc. and William T. Yardley, dated July 25, 2018 (incorporated by reference to Exhibit 10.1 to Enbridge's Form 8-K filed July 27, 2018)
10.11	+	Form of Director Indemnity Agreement (2015) (incorporated by reference to Exhibit 10.11 to Enbridge's Annual Report on Form 10-K filed February 15, 2019)
10.12	+	Enbridge Inc. 2019 Long Term Incentive Plan (incorporated by reference to Appendix A to Enbridge's Proxy Statement on Schedule 14A for Enbridge's Annual Meeting of Shareholders (File No. 001-15254) filed March 27, 2019)
10.13		Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement (2021) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 7, 2021)
10.14		Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (2021) (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 7, 2021)
10.15		Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2021 Share-settled) (incorporated by reference to Exhibit 10.3 to Enbridge's Form 10-Q filed May 7, 2021)
10.16		Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2021 Cash-settled) (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 7, 2021)
10.17		Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit - Energy Marketers Grant Notice and Restricted Stock Unit Award Agreement (2021) (incorporated by reference to Exhibit 10.5 to Enbridge's Form 10-Q filed May 7, 2021)
10.18	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement (2020) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 7, 2020)
10.19	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (2020) (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 7, 2020)
10.20	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2020 Share-settled) (incorporated by reference to Exhibit 10.3 to Enbridge's Form 10-Q filed May 7, 2020)
10.21	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2020 Cash-settled) (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 7, 2020)
10.22	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 10, 2019)
10.23	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (incorporated by reference to Exhibit 10.5 to Enbridge's Form 10-Q filed May 10, 2019)

10.24	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.6 to Enbridge's Form 10-Q filed May 10, 2019)
10.25	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit - Energy Marketers Grant Notice and Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.7 to Enbridge's Form 10-Q filed May 10, 2019)
10.26	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement - Retention Award Version (incorporated by reference to Exhibit 10.8 to Enbridge's Form 10-Q filed August 2, 2019)
10.27	+	Enbridge Inc. Incentive Stock Option Plan (2007), as amended and restated (2011) (incorporated by reference to Exhibit 10.13 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.28	+	Enbridge Inc. Incentive Stock Option Plan (2007), as amended and restated (2011 and 2014) (incorporated by reference to Exhibit 10.14 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.29	+	Enbridge Inc. Incentive Stock Option Plan (2007), as revised (incorporated by reference to Exhibit 10.15 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.30		Enbridge Inc. Directors' Compensation Plan dated February 9, 2021, effective April 1, 2021 (incorporated by reference to Exhibit 10.6 to Enbridge's Form 10-Q filed May 7, 2021)
10.31	+	Enbridge Inc. Directors' Compensation Plan dated February 11, 2020, effective January 1, 2020 (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed July 29, 2020),
10.32	+	Enbridge Inc. Directors' Compensation Plan dated February 14, 2018 Amended Effective February 12, 2019 (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 10, 2019)
10.33	+	Enbridge Inc. Directors' Compensation Plan dated February 14, 2018, effective January 1, 2018 (incorporated by reference as Exhibit 10.3 to Enbridge's Form 10-Q filed May 10, 2018)
10.34		Enbridge Inc. Directors' Compensation Plan, November 3, 2015, effective January 1, 2016 (incorporated by reference as Exhibit 10.16 to Enbridge's Form 10-K filed February 16, 2018)
10.35	+	Enbridge Inc. Short Term Incentive Plan (As Amended and Restated Effective January 1, 2019) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 10, 2019)
10.36	+	The Enbridge Supplemental Pension Plan, As Amended and Restated Effective January 1, 2018 (incorporated by reference as Exhibit 10.1 to Enbridge's Quarterly Report on Form 10-Q filed May 10, 2018)
10.37	+	Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.20 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.38	+	Amendment 1 and Amendment 2 to the Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.21 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.39	+	Third Amendment to The Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference as Exhibit 10.2 to Enbridge's Quarterly Report on Form 10-Q filed May 10, 2018)
10.40	+	Spectra Energy Corp Directors' Savings Plan, as amended and restated (incorporated by reference to Exhibit 10.22 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)

10.41	+	Spectra Energy Corp Executive Savings Plan, as amended and restated (incorporated by reference to Exhibit 10.23 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.42	+	Spectra Energy Executive Cash Balance Plan, as amended and restated (incorporated by reference to Exhibit 10.24 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.43	+	Omnibus Amendment, dated June 20, 2014, to Spectra Energy Corp Executive Savings Plan, Spectra Energy Corp Executive Cash Balance Plan and Spectra Energy Corp 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.25 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.44	+	Form of Spectra Energy Corp Stock Option Agreement (Nonqualified Stock Options) (2016) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.45	+	Spectra Energy Corp 2007 Long-Term Incentive Plan (as amended and restated) (incorporated by reference to Exhibit 10.32 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.46	+	Second Amendment to the Spectra Energy Corp Executive Savings Plan (As Amended and Restated Effective May 1, 2012) (incorporated by reference to Exhibit 10.36 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.47	+	Second Amendment to the Spectra Energy Corp Executive Cash Balance Plan (As Amended and Restated Effective May 1, 2012) (incorporated by reference to Exhibit 10.37 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
21.1	*	Subsidiaries of the Registrant
22.1	*	Subsidiary Guarantors
23.1	*	Consent of PricewaterhouseCoopers LLP
24.1		Powers of Attorney (included on the signature page of the Annual Report)
31.1	*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	*	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	*	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	*	Inline XBRL Document Set for the consolidated financial statements and accompanying notes in Part II. Item 8 "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K
104	*	Cover Page Interactive Date File – the cover page XBRL tags are embedded within the Inline XBRL document (included in Exhibit 101).

SIGNATURES

POWER OF ATTORNEY

Each person whose signature appears below appoints Robert R. Rooney, Vern D. Yu and Karen K. L. Uehara, and each of them, any of whom may act without the joinder of the other, as their true and lawful attorneys-in-fact and agents, with full power of substitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report of Enbridge on Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or would do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them or their or his or her substitute and substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE INC.
(Registrant)

Date:	February 11, 2022	By:	**/s/ Al Monaco**
			Al Monaco President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 11, 2022 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ Al Monaco
Al Monaco
President, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ Vern D. Yu
Vern D. Yu
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Patrick R. Murray
Patrick R. Murray
Senior Vice President and Chief Accounting Officer
(Principal Accounting Officer)

/s/ Gregory L. Ebel
Gregory L. Ebel
Chairman of the Board of Directors

/s/ Mayank (Mike) M. Ashar
Mayank (Mike) M. Ashar
Director

/s/ Gaurdie E. Banister
Gaurdie E. Banister
Director

/s/ Pamela L. Carter
Pamela L. Carter
Director

/s/ Susan M. Cunningham
Susan M. Cunningham
Director

/s/ J. Herb England
J. Herb England
Director

/s/ Teresa S. Madden
Teresa S. Madden
Director

/s/ Stephen S. Poloz
Stephen S. Poloz
Director

/s/ S. Jane Rowe
S. Jane Rowe
Director

/s/ Dan C. Tutcher
Dan C. Tutcher
Director

Investor information

Investor inquiries

If you have inquiries regarding the following:

- The latest news releases or investor presentations
- Any investment-related inquiries

Please contact Enbridge Investor Relations
Toll-free: 1-800-481-2804
investor.relations@enbridge.com

Enbridge Inc.
200, 425 – 1 Street S.W.
Calgary, Alberta, Canada T2P 3L8

Annual Meeting

The Annual Meeting of Shareholders will be held on May 4, 2022 at 1:30 p.m. MDT. Due to the COVID-19 pandemic, the Meeting will be held virtually via live audio webcast. A replay will be available on enbridge.com. Webcast details will be available on the Company's website closer to the Meeting date.

Registrar and Transfer Agent

For information relating to shareholdings, dividends, direct dividend deposit and lost certificates, please contact:

Computershare Trust Company of Canada
100 University Avenue, 8th Floor
Toronto, Ontario M5J 2Y1

Toll-free North America: 1-866-276-9479
Outside North America: 1-514-982-8696
computershare.com/enbridge

Auditors

PricewaterhouseCoopers LLP

2022 Enbridge Inc. Common Share Dividends

	Q1	Q2	Q3	Q4
Dividend	$0.86	$ – [2]	$ – [2]	$ – [2]
Payment date	Mar 01	Jun 01	Sep 01	Dec 01
Record date[1]	Feb 15	May 13	Aug 15	Nov 15

[1] Dividend record dates for Common Shares are generally February 15, May 15, August 15 and November 15 in each year unless the 15th falls on a Saturday or Sunday.

[2] Amount will be announced as declared by the Board of Directors.

Common and Preference Shares

The Common Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange and in the United States on the New York Stock Exchange under the trading symbol "ENB." The Preference Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbols:

Series A – ENB.PR.A
Series B – ENB.PR.B
Series C – ENB.PR.C
Series D – ENB.PR.D
Series F – ENB.PR.F
Series H – ENB.PR.H
Series J – ENB.PR.U
Series L – ENB.PF.U
Series N – ENB.PR.N
Series P – ENB.PR.P
Series R – ENB.PR.T
Series 1 – ENB.PR.V
Series 3 – ENB.PR.Y
Series 5 – ENB.PF.V
Series 7 – ENB.PR.J
Series 9 – ENB.PF.A
Series 11 – ENB.PF.C
Series 13 – ENB.PF.E
Series 15 – ENB.PF.G
Series 19 – ENB.PF.K

Forward-looking information

This Annual Report includes references to forward-looking information, including with regards to the supply of and demand for energy, energy transition and low-carbon energy, ESG goals, growth opportunities and outlook, financial guidance and investment capacity. By its nature, this information involves certain assumptions and expectations about future outcomes, so we remind you it is subject to risks and uncertainties that affect our business. The more significant factors and risks that might affect our future outcomes are listed and discussed in the "Forward-looking information" and Risk Factors sections of our Form 10-K and Management's Discussion and Analysis, included in this Annual Report and available on both sedar.com and sec.gov.

Non-GAAP measures

This Annual Report makes reference to non-GAAP financial measures and non-GAAP ratios, including EBITDA, adjusted EBITDA and distributable cash flow (DCF) per share. Management believes the presentation of these metrics gives useful information to investors and shareholders as they provide increased transparency and insight into the performance of Enbridge. EBITDA represents earnings before interest, tax, depreciation and amortization. Adjusted EBITDA represents EBITDA adjusted for unusual, infrequent or other non-operating factors. Management uses EBITDA and adjusted EBITDA to set targets and to assess the performance of the Company and its business units. DCF is defined as cash flow provided by operating activities before the impact of changes in operating assets and liabilities (including changes in environmental liabilities) less distributions to non-controlling interests, preference share dividends and maintenance capital expenditures, and further adjusted for unusual, infrequent or other non-operating factors. Management uses DCF to assess the performance of the Company and to set its dividend payout target. Debt to EBITDA is a non-GAAP ratio used as a liquidity measure to indicate the amount of adjusted earnings available to pay debt (as calculated on a GAAP basis) before covering interest, tax, depreciation and amortization. Adjusted earnings is a non-GAAP financial measure that represents earnings attributable to common shareholders adjusted for unusual, infrequent or other non-operating factors included in adjusted EBITDA, as well as adjustments for unusual, infrequent or other non-operating factors in respect of depreciation and amortization expense, interest expense, income taxes and noncontrolling interests on a consolidated basis.

Our non-GAAP metrics described above are not measures that have standardized meaning prescribed by generally accepted accounting principles (GAAP) in the United States of America and are not U.S. GAAP measures. Therefore, these metrics may not be comparable with similar measures presented by other issuers. A reconciliation of historical non-GAAP financial measures to the most directly comparable GAAP measures is available on the Company's website. Additional information on non-GAAP financial measures and non-GAAP ratios may be found in the Company's earnings news releases or in additional information on the Company's website, sedar.com and sec.gov. Reconciliations of forward-looking non-GAAP financial measures to comparable GAAP measures are not available due to the challenges and impracticability with estimating some items, particularly certain contingent liabilities and non-cash unrealized derivative fair value losses and gains which are subject to market variability. Because of these challenges, reconciliations of forward-looking non-GAAP financial measures are not available without unreasonable effort.

Front cover

Images from across Enbridge's business.

Enbridge is committed to reducing its impact on the environment in every way, including the production of this publication. This report was printed entirely on FSC® Certified paper containing post-consumer waste fiber.

RECYCLED
Paper made from recycled material
FSC® C015495

MORNINGSTAR | DBRS

Rating Report
Enbridge Gas Inc.

DBRS Morningstar
September 27, 2022

Contents

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Senior Unsecured Notes	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On September 21, 2022, DBRS Limited (DBRS Morningstar) confirmed the Issuer Rating and Senior Unsecured Notes rating of Enbridge Gas Inc. (EGI or the Company) at "A" and the Company's Commercial Paper rating at R-1 (low). All trends are Stable. The rating confirmations reflect the following considerations:

1. EGI maintained a stable business risk profile as it is in the fourth year of the five-year price-cap incentive regulations (IR) ending at the end of 2023. The IR framework for EGI has been stable and DBRS Morningstar does not expect any material changes during this IR period.

2. EGI's financial performance remained solid, with improved credit metrics for the 12 months ended June 30, 2022. Furthermore, DBRS Morningstar expects the credit metrics to improve modestly over the medium term as a result of rate base growth and synergy realization (see below).

3. EGI's liquidity remained solid despite a significant increase in the Purchase Gas Variance Account (PGVA), which captures the difference between actual and forecast natural gas prices. As of June 30, 2022, the PGVA balance was $780 million. The recovery of the PGVA balance was approved by the Ontario Energy Board (OEB). However, the recovery period extends to 24 months, instead of 12 months. At the end of June 2022, approximately $380 million of EGI's $2.0 billion credit facility was available. In August 2022, the Company's liquidity improved considerably as EGI issued $650 million in long-term debt, which was partially used to paydown the Company's short-term indebtedness. DBRS Morningstar expects that, as in the past, in the event that EGI requires more liquidity to finance its natural gas inventory for the winter distribution, its parent, Enbridge Inc. (rated BBB (high) with a Stable trend by DBRS Morningstar), will step in and provide temporary liquidity.

The Company's ratings are supported by a stable regulatory framework in Ontario and a very large and economically strong base of approximately 3.8 million customers across the province—the largest in Canada and one of the largest in North America. This large customer base is one of the key factors allowing EGI to achieve operating efficiency under the price-cap IR. Good synergy was realized in the past three years from the amalgamation of Enbridge Gas Distribution Inc. (EGD) with Union Gas Limited

(Union Gas), and DBRS Morningstar expects significant synergy to be achieved through 2023. EGI's reliability and the flexibility of its natural gas supply have improved significantly, compared with stand-alone EGD, as a result of the significant addition of Union Gas's storage facilities. The ratings incorporate EGI's exposure to volume risk and the potential regulatory lag in the recovery of natural gas costs when the price of natural gas increases substantially.

Although EGI will likely generate substantial free cash flow deficits over the next few years because of its major capital projects (which DBRS Morningstar estimates to be between $1.4 billion and $1.5 billion for new projects and system upgrades) and a high dividend payout ratio. Funding of cash flow deficits has been with new debt issued by EGI and equity injections from the parent. DBRS Morningstar expects EGI to continue to fund its future capital expenditures (capex) in such a way that the capital structure will be maintained in line with the regulatory capital structure of 64% debt and 36% equity. As a result, DBRS Morningstar does not expect the financing of EGI's capex to have a material impact on its credit metrics in the medium term.

DBRS Morningstar does not expect any positive rating actions in the near term. However, it could take a negative rating action should the following events occur: (1) an adverse regulatory change that would have a negative impact on EGI's business risk profile, or (2) a significant deterioration of EGI's credit metrics on a sustained basis that would no longer support the current ratings. DBRS Morningstar considers these scenarios unlikely.

Financial Information

Enbridge Gas Inc.	6M June 30	6M June 30	12M June 30	Year ended December 31		
Key Credit Metrics	**2022**	**2021**	**2022**	**2021**	**2020**	**2019**
Cash flow-to-debt (%)	15.0	14.8	12.0	11.4	12.1	12.7
Total debt in capital structure (%)	49.9	50.1	49.9	50.8	49.4	48.4
Total debt in capital structure (excl. goodwill) (%)	64.3	66.2	64.3	65.8	65.1	64.3
EBIT interest coverage (times (x))	3.34	3.20	2.49	2.41	2.36	2.55

Issuer Description

Enbridge Gas Inc is a regulated natural gas distributor with connections to approximately 3.8 million meters serving residential, commercial, and industrial customers across Ontario. Other operations include regulated transportation services as well as regulated and unregulated storage services in Ontario. Enbridge Inc. owns 100% of EGI (54% directly and 46% indirectly).

Rating Considerations

Strengths

1. Low-risk regulated operations

Almost all of EGI's assets are regulated and operate under the OEB-approved, five-year price-cap IR plan from 2019 through 2023. The IR plan provides the Company with the following benefits: (A) relatively predictable earnings and cash flow through a formula (see the Regulatory Update section); (B) full recovery of gas supply costs with quarterly adjustments, subject to regulatory review; (C) annual updates for certain costs to be passed through to customers and a reasonable mechanism for capex recovery;

and (D) a mechanism for sharing earnings with customers, which provides incentives for operational efficiency.

2. Strong franchise area with a very large customer base

EGI is currently the largest regulated natural gas distributor in Canada and is one of the largest in North America, serving approximately 3.8 million residential, commercial, and industrial customers across Ontario. The Company's service area is viewed as economically strong compared with other service areas in Canada. EGI's large customer base provides it with the size and scale to operate efficiently during the five-year price-cap IR plan. EGI's large size also allows it to maintain a good degree of flexibility with its capex planning.

3. Sizable storage assets provide additional rate base and cash flow

As at June 30, 2022, EGI owned approximately 281 billion cubic feet (bcf; 276 bcf in 2021) of natural gas underground storage capacity facilities located at the Dawn Hub, the largest natural gas storage hub in Canada, which acts as a gateway for Western Canadian and Appalachian natural gas supply. EGI's storage facilities are strategically connected to major pipelines that transport natural gas to major Canadian and U.S. markets. The majority of EGI's storage assets is in the regulated rate base. In addition, nonregulated storage assets have generated strong cash flows that reflect high demand in Ontario. DBRS Morningstar estimates that cash flow from nonregulated storage activities accounts for approximately 8% to 10% of EGI's consolidated cash flow.

Challenges

1. Volume risk

For EGI's residential and small commercial customers, weather risk remains significant, as forecast volumes (based on normalized weather) are built into the Company's base rates, while actual usage varies with the weather. Therefore, colder-than-normal weather in any given year generally results in higher earnings, while the reverse is true for periods of warmer-than-normal weather. For EGI's large industrial customers, volume consumption is sensitive to the economy. However, the volume risk is partially mitigated through the Company's firm contracts with larger commercial and industrial customers where charges are based on demand. Further, the weather forecast is conducted annually to reflect the latest weather patterns.

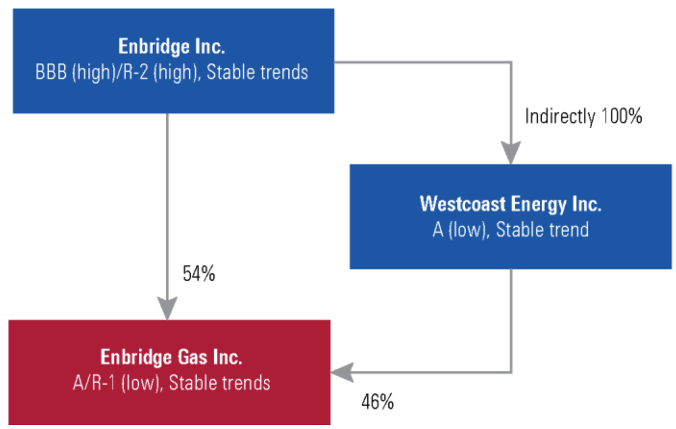
2. Managing operating costs under the price-cap IR plan

EGI is in the fourth year of its five-year price-cap IR plan. Managing operating costs is particularly important for the Company to achieve or exceed the allowed ROE. A significant increase in operating costs can have a negative impact on EGI's earnings and cash flow, and consequently on its credit metrics. Earnings below the allowed ROE will not be recovered from customers unless the actual ROE is 300 basis points (bps) below the allowed ROE, at which point the Company can request a regulatory review.

3. Potential regulatory lag

EGI faces a potential regulatory lag in the recovery of natural gas costs. Although the Company can pass natural gas costs on to customers with quarterly adjustments, the potential for a regulatory lag still exists. If natural gas costs increase substantially within a short period of time, the Company may have to recover such costs over a longer time frame than it normally does. In addition, EGI could also face regulatory lag with respect to major projects if capital spending amounts are beyond those that can be funded through base rates and if these capital projects do not qualify for recovery through the Incremental Capital Module (ICM) mechanism (see the Regulatory Update section).

Simplified Organizational Structure



Note: EGI represented approximately 13% of the consolidated EBITDA of Enbridge Inc. in 12 months ended March 31, 2022.

Enbridge Inc.: It is a diversified energy company with the following segments: Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation, and Energy Services (see DBRS Morningstar's rating report dated July 27, 2022, for details).

Westcoast Energy Inc.: In addition to owning a 46% interest in EGI, Westcoast Energy Inc. also owns (1) the federally regulated B.C. Pipeline natural gas transmission system and (2) a 78% interest in the federally regulated Maritime & Northeast Pipeline Limited Partnership, a natural gas transmission system in Eastern Canada (see DBRS Morningstar's rating report dated June 29, 2022, for details).

Earnings and Outlook

Enbridge Gas Inc.	6M June 30	6M June 30	12M June 30	Year ended December 31		
(CAD millions)	**2022**	**2021**	**2022**	**2021**	**2020**	**2019**
Gas commodity and distribution revenues	2,982	2,260	4,718	3,996	3,631	4,252
Storage, transportation, and other revenues	512	474	935	897	884	923
Total Revenue	**3,494**	**2,734**	**5,653**	**4,893**	**4,515**	**5,075**
Gas commodity & distribution costs	1,927	1,257	2,816	2,146	1,812	2,334
Operating & administrative expenses	549	504	1,150	1,105	1,063	1,070
Depreciation & amortization expenses	337	340	674	677	655	638
Total operating costs	**2,813**	**2,101**	**4,640**	**3,928**	**3,530**	**4,042**
Operating Income	**681**	**633**	**1,013**	**965**	**985**	**1,033**
Gross interest expense	204	198	407	401	417	405
Capitalized interest	(4)	(3)	(8)	(7)	(5)	(5)
Interest expense, net	**200**	**195**	**399**	**394**	**412**	**400**
Operating Income Before Other Income	**481**	**438**	**614**	**571**	**573**	**633**
Other income (expense), net	38	16	65	43	56	30
Operating Profit Before Taxes	**519**	**454**	**679**	**614**	**629**	**663**
Income taxes	(46)	(53)	(56)	(63)	78	71
Net income before extraordinary items	**473**	**401**	**623**	**551**	**551**	**592**
Extraordinary items	0	0	0	0	(54)	(36)
Reported net income	**473**	**401**	**623**	**551**	**497**	**556**

YE2021 Summary

- Operating income in 2021 increased modestly from 2020, largely reflecting (1) the absence of employee severance, transition, and transformation costs in 2021; (2) synergy realized from the amalgamation; and (3) increases in rates and customer base.

H1 2022 Summary

- The increase in operating income in H1 2022 compared with the same period in 2021 reflected (1) colder weather in the first half of 2022, (2) higher distribution charges resulting from increases in rates and customer base, and (3) synergies realized from the amalgamation. However, the increase in the operating income was partially offset by higher operating expenses largely driven by the timing of expenditures.

Outlook

- Assuming normal weather, DBRS Morningstar expects EGI's operating income to continue to increase modestly throughout the deferred rebasing period, reflecting the continued growth in the rate base and customer base as well as the potential synergy to be realized from the amalgamation.
- However, because EGI's annual rate changes are based on a price-cap formula and operating efficiency, any materially unexpected increase in operating costs can have a negative impact on EGI's operating income.

Financial Profile

Enbridge Gas Inc.	6M June 30	6M June 30	12M June 30	Year ended December 31		
(CAD millions)	**2022**	**2021**	**2022**	**2021**	**2020**	**2019**
Operating cash flow	**798**	**732**	**1,279**	**1,213**	**1,163**	**1,190**
Capital expenditures (incl. intangible assets)	(619)	(452)	(1,472)	(1,380)	(1,109)	(1,185)
Dividends paid	(687)	(626)	(1,311)	(1,250)	(1,250)	(1,250)
Free cash flow (bef. work. cap. changes)	**(508)**	**(421)**	**(1,504)**	**(1,417)**	**(1,272)**	**(1,169)**
Changes in noncash working capital items	16	332	(789)	(473)	116	93
Gross free cash flow	**(492)**	**(89)**	**(2,293)**	**(1,890)**	**(1,179)**	**(1,053)**
Cash extraordinary items	0	0	0	0	(54)	(29)
Proceeds on sale of inv. & other activities (net)	12	0	12	0	0	72
Net free cash flow	**(480)**	**(89)**	**(2,281)**	**(1,890)**	**(1,233)**	**(1,010)**
Change in debt & equivalents	230	89	1,056	915	1,015	570
Change in note payable – affiliate	0	0	0	0	(650)	(332)
Change in equity & equivalents	500	0	1,475	975	800	800
Change in cash & marketable securities	250	0	(250)	0	68	(28)
Funding sources	**480**	**89**	**2,281**	**1,890**	**1,233**	**1,010**
Total debt in capital structure (%) [1]	64.3	66.2	64.3	65.8	65.1	64.3
Cash flow/total debt (%)	15.0	14.8	12.0	11.4	12.1	12.7
EBIT interest coverage (x)	3.34	3.20	2.49	2.41	2.36	2.55
Dividends/cash flow (%)	86.1	85.5	102.5	103.1	106.1	105.0

1 Excluding goodwill.

Summary

- All credit metrics remained solid in the last twelve months (LTM) ended June 30, 2022, reflecting relatively stable cash flow and reasonable debt leverage.
- The debt-to-capital ratio, excluding goodwill, has remained relatively stable since the amalgamation and has stayed at the low end of DBRS Morningstar's "A" rating range. This capital structure level is consistent with the regulatory capital structure of 36% equity/64% debt.
- The cash flow-to-debt ratio for the LTM ended June 30, 2022, improved modestly from 2021 because of higher cash flow for H1 2022 compared with H1 2021.
- EBIT-interest coverage for the LTM ended June 30, 2022, continued to benefit from solid operating income for the period.
- EGI has generated substantial free cash flow deficits for the last couple of years as a result of a large capex program in 2020 and 2021 (averaging $1.35 billion each year). Most of growth capex was spent on growth capital projects that were approved by the regulator (see below).
- DBRS Morningstar notes the dividend/cash flow ratio has increased since 2018. This increase combined with large growth projects caused EGI to require substantial external funds to finance its cash flow deficits.
- However, EGI's financing plan has been to maintain the debt-to-capital ratio in line with the regulatory capital structure of 64% debt/36% equity.

Outlook

- DBRS Morningstar expects EGI to continue to generate free cash flow deficits over the next couple of years because of its large capex and a high dividend payout. Capex for 2022 and 2023 is estimated to be between $1.4 billion and $1.5 billion each year. A substantial amount of capex each year will be for system upgrades and new capital projects, such as the Lake Shore Kipling Oshawa Loop Replacement Project (Lakeshore KOL Replacement Project), Natural Gas Expansion Project and Panhandle Regional Expansion Project (see the Capital Projects section).
- DBRS Morningstar does not expect EGI to change its financing strategy of maintaining the debt-to-capital ratio (excluding goodwill) at or near the current level throughout the deferred rebasing period.
- Assuming normal weather, DBRS Morningstar expects EGI's cash flow-to-debt and EBIT-interest coverage ratios to improve modestly over the medium term, reflecting expected operating efficiency and incremental cash flow from a growing rate base.

Liquidity and Long-Term Debt Maturities

Credit Facilities				As at June 30, 2022
(CAD millions)	**Total Facilities**	**Drawn**[1]	**Available**	**Maturity**
Enbridge Gas Inc.[1]	2,000	1,620	380	2023

1 Includes facility draws and commercial paper issuances, net of discount, that are backed by the external credit facility.

Summary

- Liquidity remains solid, supported by predictable cash flow from operations and the availability of sizable credit facilities.
- The $2.0 billion Revolving Term Credit Facility is used to backstop a commercial paper program of $2.0 billion. In August 2022, EGI completed a $650 million dual-tranche offering of 10-year and 30-year notes. The debt issuance is not expected to have any material impact on EGI's credit metrics because most net proceeds were used to pay down the Company's short-term indebtedness.
- DBRS Morningstar notes in the event where there is extremely cold weather and gas prices are rising sharply, the Company would have to seek temporary support from its parent, Enbridge Inc. Currently, EGI has access to Enbridge Inc.'s letter of credit facilities totalling $2.0 billion.

Debt Maturities

As at June 30, 2022 (CAD millions)	**2022**	**2023**	**2024**	**2025**	**2026**	**2027+**	**Total**
EGI medium-term notes and debentures	0	350	300	745	650	7,050	9,095

Summary

- The refinancing risk in the next four years is manageable because the medium-term notes and debentures due in each of these years are modest and within the financing capability of the Company.
- EGI is subject to the issue test covenant in the indenture, which states that its total consolidated funded obligations (namely total indebtedness, including any guarantee that has a maturity term longer than 18 months) will not exceed 75% of total consolidated capitalization. EGI is also subject to an EBIT-to-interest covenant of 2.0 times, based on EBIT for 12 consecutive months and the annual pro forma interest requirements for all debt with a maturity term longer than 18 months:
  - The covenant does not apply to debt issuances for debt refinancing.
  - The Company was in compliance with the covenant as at June 30, 2022.

Regulatory Update

EGI 2022 Rate Application

- EGI filed its application in two phases. Phase 1 was filed in June 2021 for the setting of rates for 2022. In October 2021, the OEB approved a Phase 1 Settlement proposal and Interim Rate Order effective January 1, 2022. In April 2022, the OEB issued its decision on Phase 2, which was filed in October 2021, addressing ICM funding requirements. The OEB decision approved $127 million of EGI's capital funding, which was incorporated into final rates, effective July 1, 2022.

EGI 2023 Rate Application

- In June 2022, EGI filed for Phase 1 of the application for setting rates for 2023 (the 2023 Application). EGI expects to receive an OEB decision on Phase 1 of the 2023 Application in the second half of 2022. EGI does not anticipate its 2023 capital investment to require incremental funding during the final year of its Price Cap IR term (see below).

Amalgamation

On August 30, 2018, the OEB issued its decision on the application for the amalgamation of EGI and Union Gas. The OEB’s major key determinations in the decision were, among others, as follows:

- The rebasing year is deferred until 2024. The Company asked for a 10-year deferred rebasing period, but the OEB allowed for only five years. DBRS Morningstar believes the five-year rebasing period is credit positive because shorter periods have more certainty regarding cost recovery and forecasts.
- The annual rate change during the deferred rebasing period is based on a price-cap index (PCI), where PCI growth is driven by an inflation factor using the Gross Domestic Product Implicit Price Index's Final Domestic Demand index as the inflation factor, less a productivity factor of zero and a stretch factor of 0.3%. The stretch factor is used in incentive regulation to measure the efficiency of utilities (the actual costs/forecast costs), with superior performance having a lower stretch factor.
- The earnings sharing mechanism during the 2019–23 period will be on a 50:50 basis between EGI and its ratepayers for all earnings in excess of 150 bps over the allowed ROE. This means earnings in excess of up to 150 bps will be retained by EGI.
- All capex in excess of the OEB-defined materiality threshold will be recovered through an ICM mechanism, subject to the ICM eligibility criteria during the deferred rebasing term (see the next section).
- EGI continues to pass through costs associated with Y-factors. The Y-factors are costs related to gas commodity and upstream transportation costs, demand-side management cost changes, lost revenue adjustment mechanism changes for the contract market, and normalized average consumption/average use.
- The Z-factor materiality threshold will be set at $5.5 million on a revenue requirement basis.
- During the deferred rebasing period, EGI will continue to purchase market-based storage services to meet the needs of legacy EGD's in-franchise customers. This will mean that legacy Union Gas customers continue to benefit from the sale of market-based storage until issues of rate harmonization are considered.

ICM Mechanism

- ICM is an OEB funding mechanism for significant capital projects, for which a utility requires rate recovery in advance of its next regularly scheduled cost of service (COS; rebasing) application.
- The test for ICM eligibility is that a capital project is not only part of a capital project that is incremental to the materiality threshold (defined below) but must also be driven by capital spending requirements that are extraordinary and unanticipated.
- Materiality means the amount of capital spending must exceed the OEB-defined threshold (which represents a utility's financial capacities underpinned by existing rates, including growth). Any incremental capital amounts approved for rate recovery must fit within the total eligible incremental capital amount and must clearly have a significant influence on the operation of the utility. In addition, to be eligible for ICM, the amount of capital spending must meet the need and prudence criteria. Need means the total amount of capital spending must be for discrete projects and must be outside of the base upon which the rates are derived. Prudence means the utility's decision to incur the costs must represent the most cost-effective option for ratepayers.

Capital Project - Significant Commercially Secured Projects (Between 2022 and 2027, all approved by OEB)

- Storage Enhancement: This project is part of a larger delta-pressuring project to increase deliverability and storage capacity at EGI's storage facilities. The additional deliverability and storage capacity will be sold as part of the Company's unregulated storage portfolio. The estimated capital cost is $80 million.
- Lake Shore KOL Replacement Project: The replacement project of approximately 4.5 kilometres of natural gas pipeline and ancillary facilities of the Cherry to Bathurst Streets segment of the Kipling Oshawa Loop along Lake Shore Boulevard in the City of Toronto. The project is expected to be placed into service in Q4 2022. The estimated capital cost is $130 million.
- Natural Gas Expansion Program (NGEP): Under Phase 2 of the NGEP, EGI will be provided up to $214 million in funding assistance to deliver 25 community expansion and two economic development projects throughout Ontario. The estimated capital cost is $121 million (net of maximum funding assistance).
- Panhandle Regional Expansion: Expansion of the Panhandle Transmission System, which supplies natural gas from the Dawn Hub to customers in Southern Ontario, west of Dawn, consists of construction of the Panhandle Loop and Leamington interconnects, and is expected to receive a full COS-regulated return upon OEB approval. In-service dates are targeted for November 2023 and November 2024. The estimated capital cost is $314 million.

ESG Factors

There are currently no environmental, social, or governance (ESG) factors affecting the ratings of EGI.

* A Relevant Effect means that the impact of the applicable ESG risk factor has not changed the rating or rating trend on the issuer.
A Significant Effect means that the impact of the applicable ESG risk factor has changed the rating or trend on the issuer.
If any factor is proposed to have a Significant Effect, this should be reflected in the Press Release

ESG Factor		ESG Credit Consideration Applicable to the Credit Analysis: Y/N		Extent of the Effect on the ESG Factor on the Credit Analysis: Relevant (R) or Significant (S)*
Environmental		**Overall:**	N	N
	Emissions, Effluents, and Waste	Do we consider that the costs or risks for the issuer or its clients result, or could result, in changes to an issuerÆs financial, operational, and/or reputational standing?	N	N
	Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs and/or will such costs increase over time affecting the long term credit profile?	N	N
	Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?	N	N
	Land Impact and Biodiversity	Is there a financial risk to the issuer for failing to effectively manage land conversion, rehabilitation, land impact, or biodiversity activities?	N	N
	Climate and Weather Risks	In the near term, will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact? In the long term, will the issuer's or client's business activities and infrastructure be materially affected financially by a 2C rise in temperature?	N	N
Social		**Overall:**	N	N
	Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services could pose a financial or regulatory risk to the issuer?	N	N
	Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts that could result in a material financial or operational impact?	N	N
		Do violations of rights create a potential liability that can negatively affect the issue's financial wellbeing or reputation?	N	N
		Human Capital and Human Rights:	N	N
	Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?	N	N
	Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could it result, in financial penalties or client attrition to the issuer?	N	N
	Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?	N	N
	Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?	N	N
	Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	N	N
Governance		**Overall:**	N	N
	Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	N	N
		Are there any political risks that could impact the issuer's financial position or its reputation?	N	N
		Bribery, Corruption, and Political Risks:	N	N
	Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	N	N
	Corporate / Transaction Governance	Does the issuer's corporate structure allow for appropriate board and audit independence?	N	N
		Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	N	N
		Does the Board and/or management have a formal framework to assess climate-related financial risks to the issuer?	N	N
		Corporate / Transaction Governance:	N	N
	Institutional Strength, Governance, and Transparency (Governments Only)	Compared with other governments, do institutional arrangements provide a similar degree of accountability, transparency, and effectiveness?	N	N
		Are regulatory and oversight bodies protected from inappropriate political influence?	N	N
		Are government officials exposed to public scrutiny and held to high ethical standards of conduct?	N	N
		Institutional Strength, Governance, and Transparency (Governments Only):	N	N
		Consolidated ESG Criteria Output:	N	N

Balance Sheet

Enbridge Gas Inc.							
Balance Sheet (CAD millions)	June 30	Dec. 31	Dec. 31		June 30	Dec. 31	Dec. 31
Assets	**2022**	**2021**	**2020**	**Liabilities & Equity**	**2022**	**2021**	**2020**
Cash and cash equivalents	9	9	9	Short-term borrowings	1,620	1,515	1,121
Accounts receivable and other	1,447	1,228	1,161	Accounts payable	1,360	1,458	1,295
Accounts receivable from affiliates	170	156	92	A/P to affiliates	354	113	134
Gas inventory	658	897	659	Ltd. due in one year	0	126	376
Total Current Assets	**2,284**	**2,290**	**1,921**	**Current Liabilities**	**3,334**	**3,212**	**2,926**
Property, plant, and equipment	16,974	16,662	15,866	Long-term debt	9,343	9,352	8,606
Deferred amounts and other assets	3,049	2,677	2,492	Other long-term liabilities	2,118	2,012	2,166
Intangible assets	180	177	174	Deferred income taxes	1,774	1,666	1,522
Goodwill	4,784	4,784	4,784	Common equity	10,702	10,348	10,017
Total Assets	**27,271**	**26,590**	**25,237**	Total Liab. & Equity	27,271	26,590	25,237

Rating History

	Current	**2021**	**2020**	**2019***
Issuer Rating	A	A	A	A
Senior Unsecured Notes	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

*Note: EGI was formed in January 2019 after the amalgamation of EGD and Union Gas.

Previous Action

- Ratings confirmation, September 20, 2021.

Commercial Paper Limit

- $2.0 billion.

Previous Report

- Enbridge Gas Inc.: Rating Report, October 5, 2021.

Note:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrsmorningstar.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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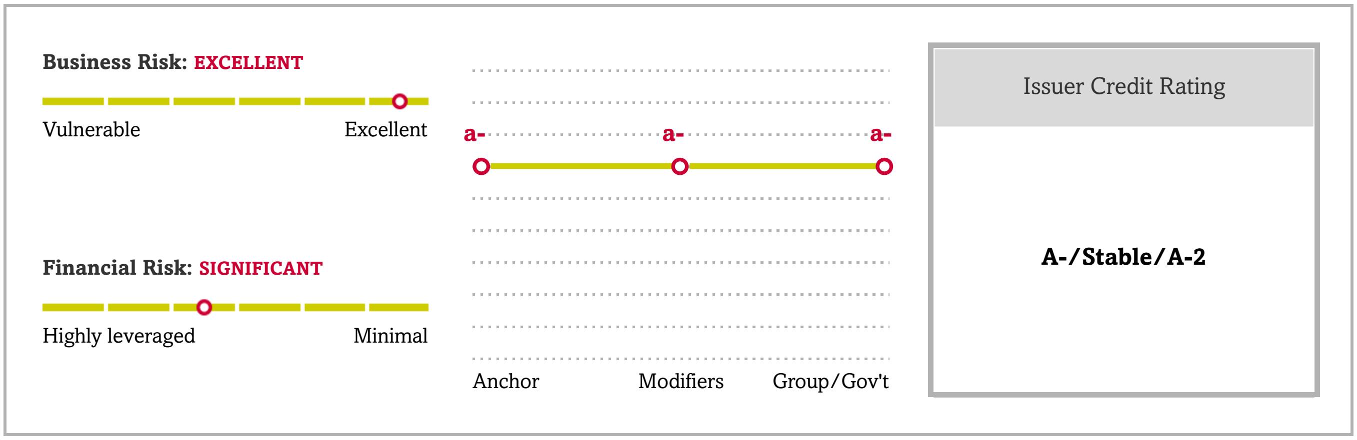
Table Of Contents

Enbridge Gas Inc.



Credit Highlights

Overview

Key strengths	Key risks
Enbridge Gas Inc. (EGI) is a low-risk, rate-regulated natural gas distribution and transmission company.	EGI operates only in Ontario and therefore has limited geographic and regulatory diversification.
About two-thirds of EGI's distribution revenue comes from residential and small business customers, providing stable cash flows.	EGI has negative discretionary cash flow linked with increasing capital expenditure activities, indicating external funding needs.
Commodity costs are passed through to customers and recovered through a quarterly adjustment mechanism, limiting EGI's exposure to commodity risk.	

We expect EGI's financial measures to remain within its financial risk profile category through 2023. This includes a projected funds from operations (FFO) to debt ratio of about 11% through 2023. In addition, we anticipate EGI's capital expenditures to remain elevated during 2022, largely reflecting new customer connections and system replacement projects such as the Lake Shore and St. Laurent natural gas pipeline replacement projects.

Additionally, as in prior years, we expect in 2022 EGI will realize positive synergies from the amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Ltd. (Union Gas), by continuing to integrate operations and optimizing storage and transmission assets.

Large capital spending primarily results in negative discretionary cash flow over our outlook period. EGI continues to have large capital expenditures through the 2022-2023 outlook period. They are about 2x its depreciation cost, which we expect will lead to negative discretionary cash flow over our forecast period, resulting in external funding needs.

EGI lacks geographic and regulatory diversity. EGI operates only in Ontario. It is the largest gas distributor in Ontario and serves virtually all of Ontario with approximately 3.8 million residential, commercial, and industrial customers. However, compared with other utilities, EGI lacks geographic and regulatory diversity, making it reliant on the Ontario Energy Board (OEB) and its regulation to sustain its credit quality.

Outlook

The stable outlook on EGI reflects S&P Global Ratings' expectation that the company will continue to focus on and generate stable and predictable cash flows from its regulated gas distribution operation. We expect that EGI will continue to benefit from modest growth in new customers, the integration of EGD and Union Gas operations and assets, and the timely and on-budget completion of capital programs. This leads to estimated FFO to debt of 11%-12% during our two-year outlook period.

The stable outlook also reflects our view that Enbridge Inc. (Enbridge), the parent, will maintain FFO to debt of 15%-17% in 2022. Furthermore, the stable outlook on EGI reflects our expectation that both the utility's insulation features and Enbridge's strategy to preserve the utilities' credit strength will not change.

Downside scenario

We could lower the ratings on EGI if the utility's financial measures deteriorate, with FFO to debt approaching 10% with no prospects of improvement.

Alternatively, we could lower the ratings on EGI if we lower our ratings on Enbridge. This could happen if Enbridge's consolidated adjusted FFO to debt falls below 13% or debt to EBITDA is sustained above 5x.

Upside scenario

Although unlikely, we could upgrade EGI over the next 18-24 months if we also upgrade Enbridge, and if EGI's stand-alone credit profile (SACP) indicates a higher SACP.

EGI could warrant a higher SACP if it improves its financial measures with FFO to debt consistently above 13%. An upgrade at the parent level would require Enbridge to maintain FFO to debt above 17% and adjusted debt to EBITDA of about 4x while maintaining its current level of asset mix and cash-flow stability.

Our Base-Case Scenario

Assumptions

- Stable and predictable cash flows from its regulated gas distribution operation, also benefiting from modest new customer growth.
- Stable regulatory regime in Ontario with no material adverse regulatory decisions.
- EGI will primarily operate under inflation-indexed rates throughout 2022 and 2023, before starting a new rate application cycle in 2024.
- The annual revenue increases through 2023 will be subject to a productivity stretch factor constraint of 0.3%, which reduces the annual revenue increases by the equivalent amount.
- All earnings exceeding 150 basis points over the OEB-approved return on equity will be shared equally between EGI and its ratepayers.
- EGI will earn close to its authorized return on equity.
- EGI will operate at or close to its authorized capital structure of 64%/36% debt to equity for the duration of the

outlook period.

- Natural gas cost and the federal carbon levy remain a pass-through to ratepayers.
- Annual capital expenditure estimated to be about C$1.4 billion to C$1.6 billion between 2022 and 2024.
- Dividends of about C$200 million in 2021 and estimated to range from C$525 to C$575 million in each of 2022, 2023, and 2024.

Key metrics

	--Fiscal year end Dec. 31 --			
	2019a	**2020a**	**2021e**	**2022f**
FFO to debt (%)	13.1	11.3	11-12	11-12
FFO cash interest coverage (x)	4.2	3.9	4.0-4.5	4.0-4.5

*All figures adjusted by S&P Global Ratings. a--Actual. e--Estimate. f--Forecast.

Company Description

EGI operates as a rate-regulated natural gas distribution utility company in Ontario, Canada. The company was formed through the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Ltd. in 2019. The company also owns and operates regulated and nonregulated natural gas storage facilities in Ontario. EGI's distribution rates are set under a five-year incentive regulation framework using a price cap mechanism, and it serves about 3.8 million customers.

Peer Comparison

Table 1

Enbridge Gas Inc.--Peer Comparison

Industry Sector: Gas

	Enbridge Gas Inc.	**CU Inc.**	**Energir Inc.**	**Washington Gas Light Co.**
Ratings as of Jan. 24, 2022	A-/Stable/A-2	A-/Stable/A-2	--/--/--	A-/Stable/A-2
	--Fiscal year ended Dec. 31, 2020--	**--Fiscal year ended Dec. 31, 2020--**	**--Fiscal year ended Sep. 30, 2021--**	**--Fiscal year ended Dec. 31, 2020--**
(Mil.)	**C$**	**C$**	**C$**	**$**
Revenue	4,515.0	2,730.0	2,434.2	1,234.3
EBITDA	1,575.0	1,421.0	796.9	370.7
Funds from operations (FFO)	1,117.5	1,045.5	577.5	307.6
Interest expense	404.5	389.7	145.6	76.0
Cash interest paid	391.5	376.5	143.7	66.0
Cash flow from operations	1,204.5	1,058.5	438.8	226.9
Capital expenditure	1,180.0	782.0	581.5	389.8
Free operating cash flow (FOCF)	24.5	276.5	(142.7)	(162.9)

Table 1

Enbridge Gas Inc.--Peer Comparison (cont.)				
Discretionary cash flow (DCF)	(1,225.5)	(149)	(668.2)	(262.9)
Cash and short-term investments	9.0	78.0	46.8	0.0
Debt	9,912.2	8,516.9	4,178.8	1,899.8
Equity	10,017.0	4,816.0	2,151.5	1,855.9
Adjusted ratios				
EBITDA margin (%)	34.9	52.1	32.7	30.0
Return on capital (%)	4.7	6.8	6.1	6.0
EBITDA interest coverage (x)	3.9	3.6	5.5	4.9
FFO cash interest coverage (x)	3.9	3.8	5.0	5.7
Debt/EBITDA (x)	6.3	6.0	5.2	5.1
FFO/debt (%)	11.3	12.3	13.8	16.2
Cash flow from operations/debt (%)	12.2	12.4	10.5	11.9
FOCF/debt (%)	0.2	3.2	(3.4)	(8.6)
DCF/debt (%)	(12.4)	(1.7)	(16.0)	(13.8)

N.M.--Not meaningful

Business Risk

Our assessment of EGI's business risk reflects our view of OEB's regulatory framework, which underpins the utility's predictable and steady cash flow. In our view, the regulatory process is transparent, consistent, and predictable. These factors collectively support EGI's timely recovery of prudently spent capital and operating expenses. In addition, the federal carbon levy is a flow-through cost to customers, and gas commodity costs are recovered through a quarterly adjustment mechanism from ratepayers, limiting EGI's exposure to commodity risk.

Further supporting our view is EGI's large customer base. EGI serves almost all of Ontario's gas distribution network with about 3.8 million customers, most of whom are residential and small business customers. As such, we expect EGI's cash flows to remain stable. However, demand for natural gas in the residential customer class can vary due to weather-driven fluctuations that can result in some cash flow volatility. Our favorable view of EGI's business risk is slightly offset by the company's limited geographic footprint and exposure to a single regulatory regime.

Financial Risk

We assess EGI's financial measures using our low volatility financial benchmark table relative to the typical industrial issuer. This reflects the company's lower-risk regulated gas distribution operation and effective management of regulatory risk. EGI has a large capital program--about 2x that of depreciation expense--that will result in negative discretionary cash flow and continually rely on external financing to fund its capital programs.

Under our base-case scenario, which includes a stable regulatory environment with no material adverse regulatory decisions, we expect capital spending of about C$1.3 billion-C$1.6 billion through 2022; net dividend payments of about C$200 million in 2021 and C$500-C$550 million in 2022 and 2023; and FFO to debt of about 11%-12% between 2021 and 2023.

Financial summary

Table 2

Enbridge Gas Inc.--Financial Summary				
Industry Sector: Gas				
	--Fiscal year ended Dec. 31--			
	2020	**2019**	**2018**	**2017**
(Mil. C$)				
Revenue	4,515.0	5,075.0	5,297.0	3,292.0
EBITDA	1,575.0	1,639.0	1,551.0	750.0
Funds from operations (FFO)	1,117.5	1,239.5	1,190.0	532.0
Interest expense	404.5	394.5	391.0	220.0
Cash interest paid	391.5	387.5	394.0	214.0
Cash flow from operations	1,204.5	1,277.5	1,725.0	558.0
Capital expenditure	1,180.0	1,104.0	1,288.0	794.0
Free operating cash flow (FOCF)	24.5	173.5	437.0	(236)
Discretionary cash flow (DCF)	(1,225.5)	(1,076.5)	(996.0)	(896)
Cash and short-term investments	9.0	77.0	17.0	20.0
Gross available cash	9.0	77.0	17.0	20.0
Debt	9,912.2	9,435.1	9,120.6	4,789.9
Equity	10,017.0	10,004.0	9,893.0	3,309.0
Adjusted ratios				
EBITDA margin (%)	34.9	32.3	29.3	22.8
Return on capital (%)	4.7	5.3	7.5	5.6
EBITDA interest coverage (x)	3.9	4.2	4.0	3.4
FFO cash interest coverage (x)	3.9	4.2	4.0	3.5
Debt/EBITDA (x)	6.3	5.8	5.9	6.4
FFO/debt (%)	11.3	13.1	13.0	11.1
Cash flow from operations/debt (%)	12.2	13.5	18.9	11.6
FOCF/debt (%)	0.2	1.8	4.8	(4.9)
DCF/debt (%)	(12.4)	(11.4)	(10.9)	(18.7)

N.M.--Not meaningful

Reconciliation

Table 3

Enbridge Gas Inc.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

	--Fiscal year ended Dec. 31, 2020--						
Enbridge Gas Inc. reported amounts (mil. C$)							
	Debt	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	10,103	1,566	911	398	1,575	1,202	1,185
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(66.00)	--	--
Cash interest paid	--	--	--	--	(385.00)	--	--
Reported lease liabilities	53.00	--	--	--	--	--	--
Operating leases	--	9.00	1.53	1.53	(1.53)	7.47	--
Postretirement benefit obligations/deferred compensation	424.15	--	--	--	--	--	--
Accessible cash and liquid investments	(9.00)	--	--	--	--	--	--
Capitalized interest	--	--	--	5.00	(5.00)	(5.00)	(5.00)
Nonoperating income (expense)	--	--	11.00	--	--	--	--
Debt: Other	(659.00)	--	--	--	--	--	--
Total adjustments	(190.85)	9.00	12.53	6.53	(457.53)	2.47	(5.00)
S&P Global Ratings' adjusted amounts							
	Debt	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	9,912	1,575	924	405	1,117	1,204	1,180

Liquidity

In our assessment, EGI's liquidity is adequate. We expect liquidity sources will cover uses by more than 1.1x in the next 12 months. We also expect that in the event of a 10% EBITDA decline, the company's sources of funds would still exceed its uses. In our opinion, EGI has strong relationships with its banks and generally prudent financial risk management. In the event of unexpected financial stress, we believe the utility would scale back on its capital expenditures and has the flexibility to suspend dividend payments to preserve its liquidity.

Principal liquidity sources

- Cash of about C$8 million as of Sept. 30, 2021;
- Committed credit facilities availability of about C$2 billion;
- Cash FFO of about C$1.2 billion; and
- Working capital inflows of about C$31 million.

Principal liquidity uses

- Debt maturities of about C$1.51 billion as of Sept. 30, 2021;
- Assumed maintenance capital spending of about C$1.0 billion over the next 12 months; and
- Net dividends of about C$444 million.

Debt maturities

- 2022: C$125 million
- 2023: C$350 million
- 2024: C$300 million
- 2025: C$745 million

Environmental, Social, And Governance

ESG Credit Indicators

E-1	**E-2**	E-3	E-4	E-5	S-1	**S-2**	S-3	S-4	S-5	G-1	**G-2**	G-3	G-4	G-5

ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1-5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary "ESG Credit Indicators: Definition And Applications," published Oct. 13, 2021.

ESG factors have no material influence on our credit rating analysis of EGI.

Group Influence

We view EGI as an insulated subsidiary within the Enbridge group. This is because EGI is incorporated as separate legal entity with financial performance and funding that are highly independent from the group, including issuing long- and short-term debt, maintaining its own separate credit facilities, and not commingling its funds, assets, or cash flows with the rest of the group. In addition, there is a strong economic basis for Enbridge to preserve EGI's credit strength, and we do not expect a default of the other group entities within Enbridge to directly lead to a default at EGI.

Issue Ratings--Subordination Risk Analysis

Capital structure

As of Sept. 30, 2021, EGI's capital structure consists of about C$1.21 billion of short-term debt in outstanding commercial paper and about C$9.7 billion of senior unsecured long-term debt.

Analytical conclusions

We rate EGI's senior unsecured debt at 'A-', the same as the issuer credit rating (ICR) on EGI because the debt is issued by a qualifying investment-grade regulated utility. The rating on the commercial paper is 'A-2' reflecting our 'A-'

ICR on EGI.

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** bbb+
- **Entity status within group:** Insulated (no impact)

Issuer Credit Rating: A-/Stable/A-2

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Significant

- Cash flow/Leverage: Significant

Anchor: a-

Modifiers

- Diversification/Portfolio effect: Neutral
- Capital structure: Neutral
- Financial policy: Neutral
- Liquidity: Adequate
- Management and governance: Satisfactory
- Comparable rating analysis: Neutral

Stand-alone credit profile: a-

- Group credit profile: bbb+
- Entity status within group: Insulated (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of February 1, 2022)*

Enbridge Gas Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	A-
Issuer Credit Ratings History	
02-Jan-2019	A-/Stable/A-2
Related Entities	
Enbridge Energy L.P.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+
Enbridge Energy Partners L.P.	
Issuer Credit Rating	BBB+/Stable/NR
Senior Unsecured	BBB+
Enbridge Inc.	
Issuer Credit Rating	
Foreign Currency	BBB+/Stable/A-2
Local Currency	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Preferred Stock *Canada National Scale Preferred Share*	P-2(Low)
Preferred Stock	BBB-
Senior Unsecured	BBB+
Subordinated	BBB-
Enbridge Pipelines Inc.	
Issuer Credit Rating	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	BBB+

Ratings Detail (As Of February 1, 2022)*(cont.)	
Spectra Energy Capital LLC	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Spectra Energy Corp.	
Issuer Credit Rating	BBB+/Stable/--
Spectra Energy Partners L.P.	
Issuer Credit Rating	BBB+/Stable/NR
Senior Unsecured	BBB+
Texas Eastern Transmission L.P.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+
Westcoast Energy Inc.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock *Canada National Scale Preferred Share*	P-2(Low)
Preferred Stock	BBB-
Senior Unsecured	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

Base Shelf Prospectus

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

This short form prospectus has been filed under legislation in each of the provinces of Canada that permits certain information about these securities to be determined after this prospectus has become final and that permits the omission from this short form prospectus of that information. The legislation requires the delivery to purchasers of a prospectus supplement containing the omitted information within a specified period of time after agreeing to purchase any of these securities.

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. The securities offered hereby have not been and will not be registered under the United States Securities Act of 1933, as amended, and, subject to certain exceptions, may not be offered or sold in the United States of America. See "Plan of Distribution".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. *Copies of the documents incorporated herein by reference may be obtained on request without charge from the Corporate Secretary of Enbridge Gas Inc., 500 Consumers Road, Toronto, Ontario, M2J 1P8 (telephone 416-758-7976), and are also available electronically at www.sedar.com.*

SHORT FORM BASE SHELF PROSPECTUS

NEW ISSUE **September 8, 2021**

ENBRIDGE GAS INC.
$2,000,000,000
MEDIUM TERM NOTES
(UNSECURED)

Enbridge Gas Inc. (the "**Corporation**") may from time to time issue medium term notes (the "**Notes**") due not less than one year from the date of issue at prices and on terms determined at the time of issue, in an aggregate principal amount of up to $2.0 billion (or the equivalent in foreign currencies) during the 25 month period that this short form base shelf prospectus (the "**Prospectus**"), including any amendments hereto, remains valid. As of the date of this Prospectus, approximately $8,285 million principal amount of Notes and $210 million principal amount of debentures of the Corporation have been issued to the public by predecessors of the Corporation, Enbridge Gas Distribution Inc. ("**EGD**") and Union Gas Limited ("**Union Gas**"), and are outstanding. The up to $2.0 billion principal amount of Notes offered hereunder is in addition to such previously issued Notes. The Notes will be issued under a trust indenture and will be direct, unsecured obligations of the Corporation ranking equally and *pari passu*, except as to redemption and/or sinking fund provisions, with all other unsecured and unsubordinated indebtedness of the Corporation.

The specific variable terms of any offering of Notes, including the aggregate principal amount offered, price to the public (at par, discount or a premium), currency, dates of issue, delivery and maturity, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof) and interest payment date(s), redemption provisions (if redeemable), proceeds to the Corporation, the agents' commission and the name of the registrar and paying agent, will be established at the time of the offering and sale of the Notes and set forth, along with any other material information not contained in this Prospectus, in a pricing supplement (a "**Pricing Supplement**") or other prospectus supplement which will accompany this Prospectus and any amendment hereto. The Corporation may set forth in a Pricing Supplement or other prospectus supplement specific variable terms of the Notes which are not within the options and parameters set forth in this Prospectus. Notes will be interest-bearing.

All information permitted under applicable laws to be omitted from this Prospectus will be contained in one or more prospectus supplements or Pricing Supplements, as applicable, which will be delivered to purchasers together with this Prospectus. Each prospectus supplement or Pricing Supplement, as applicable, will be incorporated by reference into this Prospectus for the purposes of securities legislation as of the date of the prospectus supplement or Pricing Supplement, as applicable, and only for the purposes of the distribution of the securities to which the prospectus supplement or Pricing Supplement, as applicable, pertains.

There is no market through which these securities may be sold and purchasers may not be able to resell securities purchased under this Prospectus. This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities and the extent of issuer regulation. See "*Risk Factors*".

In the opinion of counsel to the Corporation and counsel to the Agents (as defined below), the Notes offered hereby, if issued on the date hereof, would be qualified investments under the *Income Tax Act* (Canada) for certain investors as referred to under the heading "*Eligibility for Investment*".

RATES ON APPLICATION

The Notes will be offered severally by TD Securities Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., National Bank Financial Inc., RBC Dominion Securities Inc. and Scotia Capital Inc. or other investment dealers selected from time to time by the Corporation, acting as agents of the Corporation or underwriters retained by the Corporation (individually, an "**Agent**" and collectively, the "**Agents**") in Canada, subject to confirmation by the Corporation pursuant to a selling agency agreement referred to under the heading "*Plan of Distribution"*. The Corporation will pay to each Agent through whom any Note is sold a commission, as determined in accordance with Schedule "A" of the selling agency agreement or such other commission as the Corporation and the Agent may determine from time to time but which will not exceed 0.50% of the principal amount of any Note, unless the Corporation and the Agent otherwise agree. The Notes may also be purchased from time to time by any of the Agents, as principal, at such prices and with such commissions as may be agreed between the Corporation and any such Agents, for resale to the public at prices to be negotiated with each purchaser, which prices may vary during the distribution period and as between purchasers. Each Agent's compensation will be increased or decreased by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the aggregate price paid by the Agent, acting as principal, to the Corporation. In connection with any offering of Notes and subject to applicable laws, the Agents may over-allot or effect transactions which stabilize or maintain the market price of the Notes offered at a level above that which might otherwise prevail in the open market. See "*Plan of Distribution*". The Corporation may also offer the Notes directly to purchasers, pursuant to applicable statutory exemptions or discretionary exemptions, in which case no commissions will be paid to the Agents.

Under applicable securities legislation in Canada, the Corporation may be considered to be a connected issuer of each of the Agents, as each is a directly or indirectly wholly-owned or majority-owned subsidiary or affiliate of a Canadian or international financial institution which has extended a credit facility to the Corporation upon which the Corporation may draw from time to time. See "*Plan of Distribution*".

The offering of Notes is subject to approval of certain legal matters on behalf of the Corporation by McCarthy Tétrault LLP and on behalf of the Agents by Dentons Canada LLP.

The head and registered office of the Corporation is located at 500 Consumers Road, Toronto, Ontario, M2J 1P8.

TABLE OF CONTENTS

ABOUT THIS PROSPECTUS

In this Prospectus and in any Pricing Supplement or other prospectus supplement, unless otherwise specified or the context otherwise requires, all dollar amounts are expressed in Canadian dollars. Unless otherwise indicated, all financial information included and incorporated by reference in this Prospectus or included in any Pricing Supplement or other prospectus supplement is determined using United States generally accepted accounting principles ("**U.S. GAAP**"). Except as set forth under "*Description of Notes*", and unless the context otherwise requires, all references in this Prospectus and any Pricing Supplement or other prospectus supplement to "Enbridge Gas", the "Corporation", "we", "us" and "our" mean Enbridge Gas Inc. and its subsidiaries, partnership interests and joint venture investments.

This Prospectus provides a general description of the Notes that we may offer. Each time we sell Notes under this Prospectus, we will provide you with a Pricing Supplement or other prospectus supplement that will contain specific information about the terms of that offering. The Pricing Supplement or other prospectus supplement may also add, update or change information contained in this Prospectus. Before investing in any Notes, you should read both this Prospectus and any applicable Pricing Supplement or other prospectus supplement together with the additional information described below under "*Documents Incorporated by Reference*".

We take responsibility only for the information contained in or incorporated by reference in this Prospectus or any applicable Pricing Supplement or prospectus supplement. We have not authorized anyone to provide you with different or additional information. We are not making an offer of the Notes in any jurisdiction where the offer is not permitted by law. You should bear in mind that although the information contained in, or incorporated by reference in, this Prospectus is accurate as of the date on the front of such documents, such information may also be amended, supplemented or updated by the subsequent filing of additional documents deemed by law to be or otherwise incorporated by reference into this Prospectus and by any subsequently filed prospectus amendments.

DOCUMENTS INCORPORATED BY REFERENCE

The following documents, filed with the securities commission or similar regulatory authority in each of the provinces of Canada, are specifically incorporated by reference in, and form an integral part of, this Prospectus provided that such documents are not incorporated by reference to the extent that their contents are modified or superseded by a statement contained in this Prospectus or in any other subsequently filed document that is also incorporated by reference in this Prospectus:

(a) consolidated financial statements of the Corporation as at and for the years ended December 31, 2020 and 2019 and the auditors' report thereon;

(b) management's discussion and analysis of financial condition and results of operations of the Corporation for the year ended December 31, 2020;

(c) unaudited interim consolidated financial statements of the Corporation as at June 30, 2021 and for the three- and six-month periods then ended;

(d) management's discussion and analysis of financial condition and results of operations of the Corporation as at June 30, 2021 and for the three- and six- month periods then ended; and

(e) annual information form of the Corporation dated February 12, 2021 for the year ended December 31, 2020 (the "**AIF**").

Any documents of the type referred to above, any annual or interim financial statements and related management's discussion and analysis, any material change reports (except confidential material change reports), any business acquisition reports and any exhibits to interim unaudited financial statements which contain updated earnings coverage calculations filed by the Corporation with the various securities commissions or similar authorities in Canada after the date of this Prospectus and prior to the expiry of the term of this Prospectus shall be deemed to be incorporated by reference into this Prospectus. These documents will be available through the Internet on the System for Electronic Document Analysis and Retrieval (SEDAR) which can be accessed at www.sedar.com

Upon a new annual information form and the related annual financial statements and management's discussion and analysis being filed by the Corporation with and, where required, accepted by the applicable securities regulatory authorities during the term of this Prospectus, the previous annual information form, the previous annual financial statements, all interim financial statements and accompanying management's discussion and analysis, material change reports and business acquisition reports filed by the Corporation prior to the commencement of the financial year of the Corporation in respect of which the new annual information form is filed shall be deemed no longer to be incorporated into this Prospectus for purposes of future offers and sales of Notes hereunder. Upon interim financial statements and the accompanying management's discussion and analysis being filed by the Corporation with the applicable securities regulatory authorities during the term of this Prospectus, all interim financial statements and the accompanying management's discussion and analysis filed prior to the new interim financial statements shall be deemed no longer to be incorporated into this Prospectus for purposes of future offers and sales of Notes hereunder.

Any statement contained in this Prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded, for purposes of this Prospectus, to the extent that a statement contained herein or in any other subsequently filed document which also is or is deemed to be incorporated by reference herein modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of such a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute part of this Prospectus.

Any "template version" of any "marketing materials" (as such terms are defined in National Instrument 41-101 - *General Prospectus Requirements*) filed by the Corporation after the date of a Pricing Supplement or prospectus supplement and before the termination of the distribution of Notes offered pursuant to such Pricing Supplement or prospectus supplement (together with this Prospectus) will be deemed to be incorporated by reference into such Pricing Supplement or prospectus supplement for the purposes of the distribution of Notes to which the Pricing Supplement or prospectus supplement pertains.

A Pricing Supplement or other prospectus supplement containing the specific terms of an offering of Notes will be delivered to purchasers of such Notes together with this Prospectus and will be deemed to be incorporated by reference into this Prospectus as of the date of such supplement solely for the purposes of the offering of the Notes offered thereunder.

Updated earnings coverage ratios will be filed quarterly with the applicable securities regulatory authorities, either as exhibits to the Corporation's unaudited interim and audited annual financial statements or as prospectus supplements and will be deemed to be incorporated by reference into this Prospectus for the purposes of the offering of the Notes.

FORWARD LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this Prospectus to provide potential investors with information about the Corporation and its subsidiaries and affiliates, including management's assessment of the Corporation's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as “anticipate”, “expect”, ‘‘project’’, “estimate”, “forecast”, “plan”, “intend”, “target”, “believe”, “likely”, “continue”, “should”, “could”, “may”, “predict”, “will”, “potential” and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this Prospectus include, but are not limited to, statements with respect to: the expected use of proceeds; expected credit ratings; the COVID-19 pandemic and the duration and impact thereof; expected supply of and demand for natural gas; prices of natural gas; expected costs; available funding assistance; in-service dates related to announced projects and projects under construction, including additional community expansion projects; expected future decisions and actions of regulators and the timing and impact thereof; anticipated sources of financing and liquidity and the sufficiency thereof; plans to settle current liabilities and obligations; expected refinancing of long-term debt; expected capital expenditures and the timing thereof; and the Corporation’s assessment of the potential impact of the various risk factors identified or incorporated by reference under the heading "*Risk Factors*”.

Although the Corporation believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the COVID-19 pandemic and the duration and impact thereof; the expected supply of and demand for natural gas and other commodities and sources of energy; prices for natural gas and alternative sources of energy; storage of natural gas; exchange rates; inflation; interest rates; the availability of capital on satisfactory terms; the availability and price of labour and construction materials; operational reliability; maintenance of support and regulatory approvals for the Corporation’s projects; litigation; anticipated in-service dates; weather; expected earnings/(loss); expected earnings before interest, income taxes and depreciation and amortization (“**EBITDA**”); and estimated future dividends. Assumptions regarding the expected supply of and demand for natural gas and the prices of natural gas are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Corporation’s services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Corporation operates, may impact levels of demand for the Corporation’s services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected EBITDA, expected earnings/(loss) or estimated future dividends. The most relevant assumptions associated with forward-looking statements on expected capital expenditures include: the availability and price of labour and construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; the impact of weather and customer, government and regulatory approvals on construction and in-service schedules and cost recovery regimes; and the COVID-19 pandemic and the duration and impact thereof.

The Corporation’s forward-looking statements are subject to risks, uncertainties and assumptions pertaining to the realization of anticipated benefits and synergies of projects and transactions, operating performance, regulatory parameters, changes in regulations applicable to the Corporation’s businesses, litigation, project approval and support, weather, economic and competitive conditions, public opinion, access to and cost of capital, operational dependence on third parties, changes in tax law and tax rates, exchange rates, interest rates, commodity prices, and supply of and demand for commodities and other alternative energy. These risks and uncertainties include, but are not limited to, those risks, uncertainties and assumptions discussed herein, in the AIF and in the Corporation’s other filings with Canadian securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and the Corporation’s future course of action depends on management’s assessment of all information available at the relevant time. Except to the extent required by applicable law, the Corporation assumes no obligation to publicly update or revise any forward-looking statements made in this Prospectus or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to the Corporation or persons acting on the Corporation’s behalf, are expressly qualified in their entirety by these cautionary statements.

THE CORPORATION

The Corporation is a rate-regulated natural gas distribution utility with storage and transmission services. The Corporation’s distribution system carries natural gas from the point of local supply to customers and consists of approximately 146,000 kilometers of main and service pipelines supported by the Corporation’s storage and compression assets. The Corporation serves approximately 3.8 million residential, commercial and industrial customers across Ontario.

EGD and Union Gas were amalgamated on January 1, 2019, under the name "Enbridge Gas Inc.". Enbridge Energy Distribution Inc. ("**EEDI**") and Great Lakes Basin Energy L.P. ("**GLBE**"), both indirect wholly owned subsidiaries of Enbridge Inc. ("**Enbridge**"), own all of the issued and outstanding common shares of the Corporation. The Corporation continues to have all of the assets, rights, contracts, liabilities and obligations of each of EGD and Union Gas, including licenses and permits. The Corporation's head and registered office is located at 500 Consumers Road, North York, Ontario, M2J 1P8.

EGD was incorporated in 1848 by *Special Act, II Victoria Cap. XIV*, of the Province of Canada. By letters patent dated September 30, 1954, EGD was continued under the *Corporations Act, 1953* (Ontario) and was subject to the *Business Corporations Act* (Ontario). EGD changed its name from The Consumers' Gas Company Ltd. to Enbridge Gas Distribution Inc. on July 25, 2002. EGD's head and registered office was located at 500 Consumers Road, North York, Ontario, M2J 1P8.

Union Gas was incorporated under the laws of the Province of Ontario by letters patent dated December 19, 1911 and was subject to the *Business Corporations Act* (Ontario). Pursuant to a certificate of amalgamation dated January 1, 1998, Union Gas amalgamated with Centra Gas Ontario Inc. Union Gas's head office and registered office was located at 50 Keil Drive North, Chatham, Ontario, N7M 5M1.

EGD and Union Gas were both indirect wholly owned subsidiaries of Enbridge. EEDI, itself an indirect wholly owned subsidiary of Enbridge, owned all of the issued and outstanding common shares of EGD and 1% of the issued and outstanding common shares of Union Gas. GLBE, itself an indirect wholly owned subsidiary of Enbridge, owned the remaining 99% of the issued and outstanding common shares of Union Gas.

USE OF PROCEEDS

The aggregate principal amount of the Notes offered under this Prospectus shall not exceed $2.0 billion in Canadian currency or the equivalent thereof in foreign currencies. The net proceeds to be received by the Corporation from the sale from time to time of Notes under this Prospectus will be the issue price thereof less any commissions and expenses paid in connection therewith. The net proceeds cannot be estimated as at the date hereof since the amount thereof will depend on the terms and conditions of the Notes and the extent to which Notes are issued under this Prospectus. Unless otherwise specified in a Pricing Supplement or other prospectus supplement, the net proceeds from the sale of the Notes will be added to the general funds of the Corporation to be used for general corporate purposes, which may include reducing outstanding indebtedness and financing capital expenditures, investments and working capital requirements of the Corporation. The Corporation may, from time to time, issue debt instruments and incur additional indebtedness otherwise than through the issue of Notes pursuant to this Prospectus.

The net proceeds to be received by the Corporation from the sale of Notes from time to time under this Prospectus are not expected to be applied to fund any specific project. The Corporation's overall corporate strategy and major initiatives supporting its strategy are summarized in the Corporation's management's discussion and analysis for the year ended December 31, 2020, as modified or superseded by information contained in the Corporation's management's discussion and analysis as at June 30, 2021 and for the three- and six- month periods then ended and any subsequent periods, incorporated herein by reference.

PLAN OF DISTRIBUTION

Pursuant to the terms of a selling agency agreement (the "**Agency Agreement**") dated as of September 8, 2021 between the Corporation and the Agents, the Agents are or will be authorized, as agents of the Corporation for this purpose only, to solicit offers to purchase Notes, directly or through other Canadian investment dealers. The Corporation will pay each Agent through whom any Note is sold a commission, as set forth in Schedule "A" of the Agency Agreement, unless the Corporation and the Agent otherwise agree.

The Agency Agreement also provides that Notes may be purchased from time to time by any of the Agents as underwriter or principal, at a price to be agreed between the Corporation and the Agent, for resale to other dealers or purchasers at prices to be negotiated with each such dealer or purchaser. Such resale prices may vary during the distribution period and as between purchasers. The Corporation will pay to each Agent through whom any Note is sold a commission as determined in accordance with Schedule "A" of the Agency Agreement or such other commission as the Corporation and the Agent may determine from time to time but which will not exceed 0.50% of the principal amount of any Note, unless the Corporation and the Agent otherwise agree. The Agents' compensation will be increased or decreased by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the aggregate price paid by the Agent, acting as underwriter or principal, to the Corporation.

The Corporation may also offer the Notes directly to purchasers, pursuant to applicable statutory exemptions or discretionary exemptions, at prices and upon terms negotiated between the purchaser and the Corporation, in which case no commission will be paid to the Agents.

The Notes have not been and will not be registered under the *United States Securities Act of 1933*, as amended (the "**U.S. Securities Act**"), and may not be offered, sold or delivered in the United States or to, or for the account or benefit of, U.S. persons (as defined in Regulation S under the U.S. Securities Act) except in certain transactions exempt from the registration requirements of the U.S. Securities Act, including, if contemplated in the applicable Pricing Supplement or other prospectus supplement, transactions under Rule 144A under the U.S. Securities Act. The Agents have severally agreed that they will not offer or sell the Notes in the United States, except in such an exempt transaction. In addition, until 40 days after the commencement of the offering of any Notes, an offer or sale of any such Notes within the United States by any dealer (whether or not participating in the offering) may violate the registration requirements of the U.S. Securities Act if such offer or sale is made otherwise than in accordance with an applicable exemption from the registration requirements of the U.S. Securities Act.

In connection with any offering of Notes, and subject to applicable laws, the Agents may over-allot or effect transactions which stabilize or maintain the market price of the Notes offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Agents may purchase and sell Notes from time to time in the secondary market but are not obligated to do so. There can be no assurance that there will be a secondary market for the Notes. The offering price and other selling terms for such sales in the secondary market may, from time to time, be varied by the Agents.

The Corporation and, if applicable, the Agents, reserve the right to reject any offer to purchase Notes in whole or in part. The Corporation also reserves the right to withdraw, cancel or modify the offering of Notes hereunder without notice.

Under applicable securities legislation in Canada, the Corporation may be considered to be a connected issuer of each of the Agents, as each is a directly or indirectly wholly-owned or majority-owned subsidiary or affiliate of a Canadian or international financial institution which has extended a credit facility to the Corporation upon which the Corporation may draw from time to time (all such institutions being, collectively, the "**Banks**"). As at September 3, 2021 the Corporation had no outstanding unsecured indebtedness to the lenders under the Corporation's unsecured credit facilities. However, as at September 3, 2021, approximately $2,000 million of the Corporation's unsecured credit facility is used as a backstop to support outstanding commercial paper balances. The Corporation is in compliance with the terms of its unsecured credit facility and there have been no waivers of breaches thereunder. There has been no material adverse change to the financial position of the Corporation since the indebtedness was incurred. The principal purpose of the credit facility is to finance the Corporation's near-term growth capital expenditures and to support repayment obligations under its commercial paper program; however, the Corporation may incur additional indebtedness to the Banks under the credit facility and net proceeds received pursuant to this offering may be used, directly or indirectly, to reduce that indebtedness. None of the Banks was involved in the decision to offer the Notes and none will be involved in the determination of the terms of the distribution of the Notes. As a consequence of the sale of the Notes through any Agent from time to time under this Prospectus, the Corporation will pay a commission to each Agent through which a Note is sold.

DESCRIPTION OF NOTES

The following description of the Notes is a summary of their material attributes and characteristics. Certain of the capitalized terms used but not defined in this section have the meanings set out in Schedule A hereto. The terms and conditions set forth in this section will apply to each Note unless otherwise specified in the applicable Pricing Supplement or other prospectus supplement. For further particulars of the terms of the Notes, reference should be made to the Indenture (as defined below).

General

The Notes will be issued under a trust indenture dated as of July 11, 2019 between the Corporation and Computershare Trust Company of Canada, as trustee (the "**Trustee**"), as the same may be supplemented and amended from time to time (the "**Indenture**").

The Notes offered hereunder will be debentures of a single series under the Indenture. The Indenture permits the issuance thereunder from time to time of additional Notes of this series, and of debentures in one or more other series ("**Debentures**"), without limitation as to aggregate principal amount. The Notes will be direct unsecured obligations of the Corporation ranking equally and *pari passu*, except as to redemption and/or sinking fund provisions, with all other unsecured and unsubordinated indebtedness of the Corporation.

The specific terms of any offering of Notes, including the aggregate principal amount offered, price to the public (at par, discount or a premium), currency, dates of issue, delivery and maturity, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof), interest payment date(s), redemption provisions, if any, proceeds to the Corporation, the Agents' commission and the name of the registrar and paying agent, will be established at the time of the offering and sale of the Notes and set forth in a Pricing Supplement or other prospectus supplement which will accompany this Prospectus and any amendment hereto. The Corporation may set forth in a Pricing Supplement or other prospectus supplement specific variable terms of the Notes which are not within the options and parameters set forth in this Prospectus.

Term and Denomination

The Notes will have maturities of not less than one year from the date of issue, will bear interest at a fixed or floating rate and will be issuable in fully registered form in denominations of $1,000 and integral multiples thereof with the minimum subscription being $5,000 or in each case the approximate equivalent amount thereof in a foreign currency.

Fixed and Floating Rate Notes

Notes may be issued as a fixed rate Note (a "**Fixed Rate Note**") or a floating rate Note (a "**Floating Rate Note**") or as a Note that is a Fixed Rate Note for a portion of its term and a Floating Rate Note for a portion of its term, all as specified in the applicable Pricing Supplement or other prospectus supplement.

Notes will bear interest from and including their date of issue or from and including the last interest payment date to which interest has been paid, whichever is later, to, but excluding the date of maturity or redemption, if applicable; provided that, in respect of the first interest payment after the issuance thereof, each Note will bear interest from and including the later of the date of such Note and the last interest payment date preceding the issuance of such Note. Unless otherwise provided for in the applicable Pricing Supplement or other prospectus supplement, interest on Fixed Rate Notes will be payable semi-annually on the interest payment dates specified in the Notes and in the applicable Pricing Supplement or other prospectus supplement and at maturity or redemption, if applicable. Interest on Floating Rate Notes will be payable on the interest reset dates specified in the Note and in the applicable Pricing Supplement or other prospectus supplement and at maturity or redemption, if applicable. Unless otherwise provided for in the applicable Pricing Supplement or other prospectus supplement, interest shall be payable semi-annually in arrears and in equal instalments on each applicable interest payment date.

Global Notes

Unless otherwise specified in the applicable Pricing Supplement or other prospectus supplement, all Notes denominated in Canadian or United States dollars will be represented in either (i) the form of fully registered global Notes or (ii) the form of one or more uncertificated global Notes (each, a "**Global Note**") held by, or on behalf of, CDS Clearing & Depository Services Inc. or a successor (the "**Depository**") as custodian of the Global Notes (for its participants as defined below) and registered in the name of the Depository or its nominee. Except as described below, no purchaser of a Note will be entitled to a certificate or other instrument from the Corporation or the Depository evidencing the purchaser's ownership of the Note. Instead, the Notes will be represented only in book-entry form. Beneficial interests in the Global Notes, constituting ownership of the Notes, will be represented through book-entry accounts of institutions (including the Agents) acting on behalf of beneficial owners, as direct and indirect participants of the Depository ("**participants**"). Each purchaser of a Note represented by a Global Note will receive a customer confirmation of purchase from the Agent or Agents from whom the Note is purchased in accordance with the practices and procedures of the selling Agent or Agents. The practices of the Agents may vary but generally customer confirmations are issued promptly after execution of a customer order. The Depository will be responsible for establishing and maintaining book-entry accounts for its participants having interests in Global Notes.

Currently, the Depository only allows depository eligibility for securities denominated in Canadian or United States dollars. Any Notes denominated in a currency other than Canadian or United States dollars will be represented by Notes in definitive form ("**Definitive Notes**") until such time as the Depository allows depository eligibility for issues of securities denominated in such currencies.

If the Depository notifies the Corporation that it is unwilling or unable to continue as depository in connection with the Global Notes, or if at any time the Depository ceases to be a clearing agency or otherwise ceases to be eligible to be a depository and the Corporation and the Trustee are unable to locate a qualified successor, or if an event of default has occurred and is continuing with respect to the Notes, or if the Corporation elects to terminate the book-entry system, beneficial owners of Notes represented by Global Notes will receive Definitive Notes. Beneficial owners of Notes represented by Global Notes may also receive Definitive Notes if the Trustee gives notice pursuant to the Indenture that an event of default has occurred and is continuing with respect to the Notes. In addition, if provided in the applicable Pricing Supplement or other prospectus supplement, Notes may be issued in the form of Definitive Notes.

Payment of Interest and Principal

The Depository or its nominee, as the registered owner of a Global Note, will be considered the sole owner of such Note for the purposes of receiving payments of interest and principal on the Note and for all other purposes under the Indenture and the Note.

The Corporation understands that the Depository or its nominee, upon receipt of any payment of interest or principal in respect of a Global Note, will credit participants' accounts on the date interest or principal is payable, with payments in amounts proportionate to their respective beneficial interests in the principal amount of such Global Note as shown on the records of the Depository or its nominee. The Corporation also understands that payments of interest and principal by participants to the owners of beneficial interests in such Global Note held through such participants will be governed by standing instructions and customary practices. The responsibility and liability of the Corporation in respect of Notes represented by a Global Note is limited to making payment of any interest and principal due on such Global Note to the Depository or its nominee in the currency and in the manner described in the Global Note.

Transfer of Notes

Transfers of beneficial ownership of Notes represented by Global Notes will be effected through records maintained by the Depository or its nominee (with respect to interests of participants) and on the records of participants (with respect to interests of Persons other than participants). Beneficial owners who are not participants in the Depository's book-entry system, but who desire to purchase, sell or otherwise transfer ownership of or other interest in Global Notes, may do so only through participants in the Depository's book-entry system.

The ability of a beneficial owner of an interest in a Note represented by a Global Note to pledge the Note or otherwise take action with respect to such owner's interest in a Note represented by a Global Note (other than through a participant) may be limited due to the lack of a physical certificate.

The registered holder of a Definitive Note may transfer or exchange such Note at the principal office of the Trustee or other registrar in Calgary, Alberta or at such other place or places as may from time to time be designated by the Corporation with the approval of the Trustee. Definitive Notes may be exchanged for Notes (other than Notes represented by the Global Note) of the same or other authorized form or denomination or denominations of the same aggregate principal amount of the Notes, bearing the same interest rate and of the same maturity date. Reasonable charges, including a sum sufficient to cover any tax or other governmental charge payable, may be imposed by the Trustee or other registrar in connection with the exchange or transfer of Notes.

Redemption and Purchase of Notes

Notes will not be redeemable by the Corporation or repayable at the option of the holder prior to maturity unless otherwise specified in the applicable Pricing Supplement or other prospectus supplement.

The Corporation may at any time when not in default under the Indenture purchase Notes in the market (which shall include purchases from or through an investment dealer or a firm holding membership on a recognized stock exchange) or by tender to all holders of Notes or by private contract, at any price not exceeding the redemption price, if any, plus accrued and unpaid interest and costs of purchase. Notes redeemed or purchased by the Corporation will be cancelled and may not be reissued.

Covenants

In addition to other covenants, the Indenture contains, with respect to the Notes issued thereunder, covenants substantially to the following effect:

Negative Covenant

So long as any Debentures (including the Notes) remain outstanding, the Corporation will not create, assume or otherwise have outstanding any Security Interest, except for Permitted Encumbrances, on or over its assets (present or future) in respect of any Indebtedness of any Person unless, in the opinion of legal counsel to the Corporation, the obligations of the Corporation in respect of all Debentures (including Notes) then outstanding shall be secured equally and rateably therewith, provided that such covenant shall not hinder or prevent the sale of any property or asset of the Corporation.

Issue Test

So long as any Debentures (including Notes) remain outstanding, the Corporation will not issue or become liable for (other than to a Subsidiary) any Funded Obligations, unless the aggregate principal amount of Consolidated Funded Obligations does not exceed 75% of the Total Consolidated Capitalization.

Covenants of the Corporation under the Union Gas Indenture

The Corporation has assumed all obligations of Union Gas under, and is subject to certain covenants pursuant to, the trust indenture dated as of August 1, 1968, between Union Gas and CIBC Mellon Trust Company (the "**Union Gas Trustee**"), as amended and supplemented from time to time (the "**Union Gas Indenture**"), providing for the issuance by Union Gas of medium term notes ("**Union Gas Notes**"). Defined terms used in this subsection shall have the meanings ascribed thereto in Schedule B hereto.

The Union Gas Indenture contains, among others, a covenant substantially to the effect that, so long as any Union Gas Notes are outstanding, the Corporation will not create or suffer to exist any mortgage, pledge, charge or other encumbrance (whether fixed or floating) on any of its assets (including, without limitation, oil, natural gas and related hydrocarbons in place or in storage and rights in respect thereof) to secure any obligation unless at the same time it shall, in the opinion of counsel, secure or cause to be secured equally and rateably with such obligation all of the Union Gas Notes then outstanding by the same instrument or by other instruments in form and substance satisfactory to such counsel; provided that this covenant shall not apply to (a) First Mortgage Bonds; (b) Purchase Money Mortgages; (c) liens not related to the borrowing of money incurred or arising by operation of law in the ordinary course of business; or (d) security given other than on fixed assets, in the ordinary course of business and for the purpose of carrying on the same, to any bank or other lender to secure any indebtedness other than Funded Obligations; for this purpose natural gas placed in underground storage in excess of the quantity thereof carried on the books of the Corporation as base pressure gas, shall not be deemed to be fixed assets.

The Corporation is also subject to a covenant to the effect that so long as any Union Gas Notes issued between June 8, 1998 and July 20, 2006 are outstanding and remain subject to the provisions of the Union Gas Indenture, the Corporation will not: (i) issue or become liable for, or permit any Consolidated Subsidiary to issue or become liable for, any additional Funded Obligations; (ii) sell or otherwise dispose of any Funded Obligations of a Consolidated Subsidiary held by the Corporation; (iii) permit any Consolidated Subsidiary to sell or otherwise dispose of, except to the Corporation, any Funded Obligations of the Corporation or of another Consolidated Subsidiary held by it; or (iv) sell or otherwise dispose of, or permit any Consolidated Subsidiary to sell or otherwise dispose of, any shares of a Consolidated Subsidiary, or permit any Consolidated Subsidiary to issue any additional shares, except to the Corporation or to a wholly-owned Consolidated Subsidiary; unless after giving effect to any action referred to in (i) through (iv) of the foregoing paragraph, the amount of Available Earnings for any 12 consecutive calendar months of the 23 calendar months immediately preceding the effective date of such action shall not be less than two times the amount of Consolidated Interest Requirements.

Covenants of the Corporation under the EGD Indenture

The Corporation has assumed all obligations of EGD, and is subject to certain covenants pursuant to the, trust indenture dated October 9, 1996, between EGD and CIBC Mellon Trust Company of Canada (the "**EGD Trustee**"), as amended and supplemented from time to time (the "**EGD Indenture**"), providing for the issuance by EGD of medium term notes ("**EGD Notes**"). Defined terms used in this subsection shall have the meanings ascribed thereto in Schedule C hereto.

The EGD Indenture contains, among others, covenants substantially to the effect that so long as any of the EGD Notes issued pursuant to the EGD Indenture are outstanding, it will not:

(a) except from time to time to secure First Mortgage Bonds, mortgage, pledge or charge or otherwise encumber any of its assets to secure any obligations unless at the same time it shall, in the opinion of counsel to the Corporation, secure equally and rateably with such obligations all of the EGD Notes then outstanding by the same instrument or by other instrument in form and substance satisfactory to such counsel; provided that this shall not apply to (i) Permitted Prior Charges, (ii) Purchase Money Obligations, (iii) security given in the ordinary course of business and for the purpose of carrying on the same, to any bank or banks or others, to secure any obligation repayable on demand or maturing, including any right of extension or renewal, within 18 months of the date when such obligation is incurred provided such security is not given on fixed assets, or (iv) Permitted Encumbrances;

(b) permit any Restricted Subsidiary to create, incur or guarantee any indebtedness, except indebtedness to or of the Corporation or to a trustee in support of a guarantee of indebtedness of the Corporation; provided that this shall not apply to (i) Permitted Prior Charges, (ii) Purchase Money Obligations, or (iii) indebtedness incurred in the ordinary course of business and for the purpose of carrying on the same, to any bank or banks or others, repayable on demand or maturing, including any right of extension or renewal, within 18 months of the date when such indebtedness is incurred, provided such security is not given on fixed assets;

(c) dispose of any indebtedness of a Restricted Subsidiary held by or for the Corporation;

(d) permit any Restricted Subsidiary to issue any shares if, as a result of such issue, such Restricted Subsidiary ceases to qualify as such; or

(e) create or issue any additional notes unless the Consolidated Net Earnings of the Corporation for any period of 12 consecutive calendar months of the 23 calendar months next preceding the date of application to the EGD Trustee for certification of such additional notes, which shall have been selected by the Corporation, shall have been at least two times the annual interest requirements in respect of all Funded Obligations of the Corporation to be outstanding after the issue of such additional notes and after any retirements of Funded Obligations to be made out of the proceeds thereof or retirement whereof has been otherwise provided for and in respect of which proof has been afforded to the EGD Trustee satisfactory to it that adequate provision has been made assuring that such Funded Obligations will be retired within 45 days after the issue of such additional notes; provided that the provisions of this covenant (e) shall not apply to the creation and issue of additional notes for the purpose of refunding any notes previously issued provided that (except in the case of refunding all of the notes) the aggregate principal amount of the additional notes does not exceed the aggregate principal amount of the notes to be refunded.

Modifications

The rights of the holders of Notes under the Indenture may be modified. For that purpose, among others, the Indenture contains provisions making binding upon all holders of Notes, resolutions passed at meetings of such noteholders by the affirmative votes of not less than 66 ⅔% of the principal amount of such Notes present or represented by proxy at such meeting or instruments in writing signed by the holders of not less than 66⅔% of the principal amount of all such outstanding Notes. In certain cases, modification will require separate assent by the holders of the required percentages of Notes of each series or tranche outstanding under the Indenture or otherwise. Reference is made to the Indenture for detailed provisions relating to voting and meetings of noteholders.

CREDIT RATINGS

The Corporation's senior unsecured indebtedness currently has a rating of A by DBRS Limited (DBRS Morningstar) ("**DBRS**") and A- by S&P Global Ratings ("**S&P**" and, together with DBRS, the "**Rating Agencies**"). The rating outlook from each of DBRS and S&P is stable. These ratings are subject to change at any time at the sole discretion of the Rating Agencies. We expect that at the date of issuance of any Notes, such Notes will be assigned the same ratings by these Rating Agencies. The Rating Agencies' ratings for debt instruments range from a high of AAA to a low of D for DBRS and in the case of S&P, from a high of AAA to a low of D.

DBRS's credit ratings are on a long term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. The "A" rating is the third highest of ten rating categories for long term debt. Long-term obligations rated "A" are of good credit quality. The capacity for the payment of financial obligations is considered substantial, and may be vulnerable to future events, but qualifying negative factors are considered manageable. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. The "high" and "low" grades are not used for the AAA and D categories.

S&P's credit ratings are on a long term debt rating scale that ranges from AAA to D, representing the range from highest to lowest quality of such securities rated. The ''A'' rating is the third highest of ten rating categories for long term debt. An obligation rated "A" exhibits a strong capacity to meet financial commitments. However, it is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

Credit ratings are intended to provide investors with an independent measure of credit quality of any issue of securities and are indicators of the likelihood of payment and of the capacity of a company to meet its financial commitment on the rated obligation in accordance with the terms of the rated obligation. The credit ratings assigned to the Notes by the Rating Agencies are not recommendations to buy, sell or hold the Notes inasmuch as such ratings do not comment as to market price or suitability for a particular investor, and may be revised or withdrawn entirely at any time by a rating agency. Credit ratings may not reflect the potential impact of all risks on the value of the Notes. In addition, real or anticipated changes in the rating assigned to the Notes will generally affect the market value of the Notes. There can be no assurance that a rating will remain in effect for a given period of time or that a rating will not be revised or withdrawn entirely by a rating agency in the future. The lowering of any rating of the Notes may negatively affect the quoted market price, if any, of such Notes. See "*Risk Factors*".

The Corporation made payments to the Rating Agencies in connection with the assignment of ratings on the long-term debt and commercial paper of the Corporation and will make payments to the Rating Agencies in connection with the confirmation of such ratings for purposes of this Prospectus or any offering of the Notes hereunder. Other than those payments made in respect of credit ratings, no additional payments have been made to any of the Rating Agencies for any other services provided to the Corporation during the past two years.

EARNINGS COVERAGE RATIOS

The following earnings coverage ratios for the Corporation have been calculated on a consolidated basis for the respective 12 month periods ended June 30, 2021 and December 31, 2020, and are derived from unaudited financial information for the 12 month period ended June 30, 2021 and audited financial information for the 12 month period ended December 31, 2020, in each case prepared in accordance with U.S. GAAP.

The earnings coverage ratio gives pro forma effect to the issuance or repayment by the Corporation, from time to time, of debt. The earnings coverage ratio for the 12-month period ended December 31, 2020 gives pro forma effect to the early redemption by the Corporation on May 3, 2021 of $200,000,000 aggregate principal amount of 2.76% medium term note debentures, series 11 maturing June 2, 2021.

Adjustments for normal course issuances and repayments of long-term debt subsequent to June 30, 2021 and December 31, 2020 would not materially affect the ratios and, as a result, have not been made. The earnings coverage ratios set forth below do not purport to be indicative of earnings coverage ratios for any future periods and do not give pro forma effect to the issue of any Notes pursuant to this Prospectus.

	Twelve Month Period Ended	
	June 30, 2021	**December 31, 2020**
Earnings coverage[(1)]	2.6 times	2.4 times

Note:

(1) Earnings coverage on a net earnings basis is equal to earnings attributable to the Corporation plus net interest expense and income taxes divided by net interest expense plus capitalized interest.

The Corporation evaluates its performance using a variety of measures. The earnings coverage discussed above is not defined under U.S. GAAP and, therefore, should not be considered in isolation or as an alternative to, or more meaningful than, earnings as determined in accordance with U.S. GAAP as an indicator of the Corporation's financial performance or liquidity. This measure is not necessarily comparable to a similarly titled measure of another company.

The Corporation's interest requirements amounted to approximately $407 million for the 12 months ended June 30, 2021. The Corporation's earnings before interest and income tax for the 12 months ended June 30, 2021 were approximately $1,052 million, which is 2.6 times the Corporation's interest requirements for this period.

The Corporation's interest requirements amounted to approximately $411 million for the 12 months ended December 31, 2020. The Corporation's earnings before interest and income taxes for the 12 months ended December 31, 2020 were approximately $967 million, which is 2.4 times the Corporation's interest requirements for this period.

ELIGIBILITY FOR INVESTMENT

In the opinion of McCarthy Tétrault LLP, as counsel to the Corporation and Dentons Canada LLP, as counsel to the Agents, the Notes, if acquired on the date hereof, would be qualified investments on such date under the *Income Tax Act* (Canada) and the regulations thereunder (the "**Tax Act**") for a trust governed by a registered retirement savings plan ("**RRSP**"), registered retirement income fund ("**RRIF**"), registered education savings plan ("**RESP**"), deferred profit sharing plan (other than a trust governed by a deferred profit sharing plan for which the employer is the Corporation or an entity which does not deal at arm's length with the Corporation), registered disability savings plan ("**RDSP**") or tax-free savings account ("**TFSA**") (each, a "**Deferred Plan**") provided that, at the time of such acquisition, the Notes have an investment grade rating from a prescribed credit rating agency as contemplated under "*Credit Ratings*" above and provided that, at that time, the Notes are issued as part of a single issue of debt of at least $25 million or, if the Notes are issued under a debt issuance program under which debt obligations are issued on a continuous basis, the Corporation has issued and outstanding debt under the program of at least $25 million.

Notwithstanding that the Notes may be a qualified investment for a trust governed by a RRSP, RRIF, RESP, RDSP or TFSA, the annuitant of a RRSP or RRIF, the subscriber of an RESP or the holder of a TFSA or RDSP, as the case may be, will be subject to a penalty tax on such Notes held in the RRSP, RRIF, RESP, RDSP or TFSA if such Notes are a "prohibited investment" within the meaning of the Tax Act. The Notes will generally be a "prohibited investment" if the annuitant of the RRSP or RRIF, the subscriber of the RESP or the holder of the TFSA or RDSP does not deal at arm's length with the Corporation for the purposes of the Tax Act or the annuitant of the RRSP or RRIF, the subscriber of a RESP or the holder of the TFSA or RDSP has a "significant interest", within the meaning of the Tax Act, in the Corporation. Annuitants of a RRSP or RRIF, the subscriber of a RESP or a holder of a TFSA or RDSP should consult with their own tax advisors as to whether the Notes will be prohibited investments in their particular circumstances.

Prospective purchasers who intend to hold Notes in a Deferred Plan should consult their own tax advisors regarding their particular circumstances.

INTERESTS OF EXPERTS

Certain legal matters in connection with the issuance of the Notes will be passed upon on behalf of the Corporation by McCarthy Tétrault LLP and on behalf of the Agents by Dentons Canada LLP. Each of the partners and associates of McCarthy Tétrault LLP as a group, and the partners and associates of Dentons Canada LLP as a group, beneficially own, directly or indirectly, not more than 1% of the outstanding securities of each class of the Corporation.

In connection with the audit of the consolidated financial statements of the Corporation as at and for the year ended December 31, 2020, which are incorporated by reference in this Prospectus, PricewaterhouseCoopers LLP has advised that it is independent within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Ontario.

RISK FACTORS

In addition to the risk factors set forth below, additional risk factors are discussed in the AIF and in the Corporation's management's discussion and analysis of financial condition and results of operations for the year ended December 31, 2020, which risk factors are incorporated herein by reference. Prospective purchasers of Notes should consider carefully the risk factors set forth below as well as other information contained in and incorporated by reference in this Prospectus, and in any applicable Pricing Supplement or other prospectus supplement before purchasing the Notes offered hereby.

Credit Ratings

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to the Notes are not a recommendation to purchase, hold or sell the Notes, because ratings do not comment as to market price or suitability for a particular investor. There is no assurance that these ratings will remain in effect for any given period of time or that these ratings will not be revised or withdrawn entirely in the future by the relevant rating agency. Real or anticipated changes in credit ratings on the Notes may affect the market value of the Notes. In addition, real or anticipated changes in credit ratings can affect the cost at which the Corporation can access the debt market.

Lack of Public Market for the Notes

This Prospectus qualifies new issues of Notes for which there is no existing trading market. The Corporation does not intend to list the Notes on any securities exchange or to arrange for any quotation system to quote the Notes. There can be no assurance as to the liquidity of any trading market for the Notes or that a trading market for any of the Notes will develop. Even if a trading market develops for the Notes, those Notes could trade at prices that may be higher or lower than their initial offering prices. The market price for the Notes may be affected by prevailing interest rates, the Corporation's results of operations and financial position, the ratings assigned to the Notes or the Corporation, changes in general market conditions, fluctuations in the market for equity or debt securities and numerous other factors beyond the control of the Corporation.

Interest Rate Risks

Prevailing interest rates will affect the market price or value of the Notes. The market price or value of the Notes will decline as prevailing interest rates for comparable debt instruments rise and increase as prevailing interest rates for comparable debt instruments decline.

No Recourse

The obligations of the Corporation under the Indenture shall not be personally binding upon any of the Corporation's shareholders, officers or directors and any recourse against the Corporation or any of these other parties in any manner in respect of any indebtedness, obligation or liability of the Corporation arising under the Indenture, if any, shall be limited to and satisfied only out of the assets of the Corporation.

Foreign Currency Risks

An investment in Notes that are denominated or payable in currency other than Canadian dollars entails significant risks that are not associated with a similar investment in a security denominated in Canadian dollars. Such risks include, without limitation, the possibility of significant changes in rates of exchange between the Canadian dollar and the applicable foreign currency unit, the possibility of the imposition or modification of foreign exchange controls by either the Canadian or foreign governments and potential illiquidity in the secondary market. These risks will vary depending upon the currency or currencies involved and where appropriate, will be more fully described in a Pricing Supplement or other prospectus supplement.

This Prospectus does not describe all the risks of an investment in the Notes denominated or payable other than in Canadian dollars and prospective investors should consult their own financial and legal advisor as to the risk entailed with respect thereto. Notes denominated in other than Canadian dollars are not appropriate investments for investors who are unfamiliar with foreign currency transactions.

The Notes will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. A judgment by a Canadian court relating to any Notes may be awarded only in Canadian currency and such judgment may be based on a rate of exchange in existence on a day other than the day of payment.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus, the accompanying prospectus supplement or Pricing Supplement relating to the securities purchased by a purchaser and any amendment thereto. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus, the accompanying prospectus supplement or Pricing Supplement relating to the securities purchased by a purchaser and any amendment thereto contains a misrepresentation or is not delivered to the purchaser, provided that such remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province of residence. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province of residence for the particulars of these rights or consult with a legal adviser.

CERTIFICATE OF ENBRIDGE GAS INC.

Dated: September 8, 2021

This short form prospectus, together with the documents incorporated in this prospectus by reference, will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of each of the provinces of Canada.

(signed) *Cynthia L. Hansen*
Cynthia L. Hansen
President

(signed) *Tanya M. Ferguson*
Tanya M. Ferguson
Vice President, Finance

On behalf of the Board of Directors

(signed) *James E. Sanders*
James E. Sanders
Director

(signed) *David G. Unruh*
David G. Unruh
Director

CERTIFICATE OF THE AGENTS

Dated: September 8, 2021

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated in this prospectus by reference will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of each of the provinces of Canada.

TD Securities Inc.

(signed) *Mark Laing*
Per: Mark Laing

BMO Nesbitt Burns Inc.

(signed) *Katryne Mann*
Per: Katryne Mann

CIBC World Markets Inc.

(signed) *Sean Gilbert*
Per: Sean Gilbert

Desjardins Securities Inc.

(signed) *Ryan Godfrey*
Per: Ryan Godfrey

HSBC Securities (Canada) Inc.

(signed) *David W. Loh*
Per: David W. Loh

National Bank Financial Inc.

(signed) *Tushar Kittur*
Per: Tushar Kittur

RBC Dominion Securities Inc.

(signed) *James Wetmore*
Per: James Wetmore

Scotia Capital Inc.

(signed) *Patrick Breithaupt*
Per: Patrick Breithaupt

SCHEDULE A
DEFINITIONS – ENBRIDGE GAS INDENTURE

The Indenture contains, among others, definitions substantially to the following effect:

"***Consolidated Funded Obligations***" means the aggregate amount of all Funded Obligations of the Corporation and its Subsidiaries arrived at on a consolidated basis in accordance with GAAP.

"***Consolidated Net Tangible Assets***" means, on any date, all consolidated assets of the Corporation as shown in a consolidated balance sheet of the Corporation for such date, less the aggregate of the following amounts reflected upon such balance sheet:

(a) all goodwill, deferred assets, trademarks, copyrights and other similar intangible assets;

(b) to the extent not already deducted in computing such assets and without duplication, depreciation, depletion, amortization, reserves and any other account which reflects a decrease in the value of an asset or a periodic allocation of the cost of an asset; provided that no deduction shall be made under this (b) to the extent that such account reflects a decrease in value or periodic allocation of the cost of any asset referred to in (a) above;

(c) minority interests;

(d) non cash current assets; and

(e) Non-Recourse Assets to the extent of the outstanding Non-Recourse Debt financing such assets.

"***Consolidated Shareholders' Equity***" means, on any date, the total amount of shareholders' equity of the Corporation determined on a consolidated basis in accordance with GAAP as the same would be set forth in a consolidated balance sheet of the Corporation.

"***Financial Instrument Obligations***" means obligations arising under:

(a) any interest swap agreement, forward rate agreement, floor, cap or collar agreement, futures or options, insurance or other similar agreement or arrangement, or any combination thereof, entered into or guaranteed by the Corporation where the subject matter of the same is interest rates or the price, value, or amount payable thereunder is dependent or based upon the interest rates or fluctuations in interest rates in effect from time to time (but, for certainty, shall exclude conventional floating rate debt);

(b) any currency swap agreement, cross currency agreement, forward agreement, floor, cap or collar agreement, futures or options, insurance or other similar agreement or arrangement, or any combination thereof, entered into or guaranteed by the Corporation where the subject matter of the same is currency exchange rates or the price, value or amount payable thereunder is dependent or based upon currency exchange rates or fluctuations in currency exchange rates as in effect from time to time; and

(c) any agreement for the making or taking of Petroleum Substances, any commodity swap agreement, floor, cap or collar agreement or commodity future or option or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the Corporation where the subject matter of the same is Petroleum Substances or the price, value or amount payable thereunder is dependent or based upon the price of Petroleum Substances or fluctuations in the price of Petroleum Substances;

to the extent of the net amount due or accruing due by the Corporation thereunder.

"***Funded Obligations***" means all Indebtedness created, assumed or guaranteed which matures by its terms on, or is renewable at the option of the obligor to, a date more than 18 months after the date of the original creation, assumption or guarantee thereof, but excluding, in any event, Non-Recourse Debt and Subordinated Debt.

"***GAAP***" means generally accepted accounting principles which are in effect from time to time in Canada, including those accounting principles generally accepted in the United States of America from time to time, which Canadian corporations are permitted to use in Canada pursuant to Canadian law.

"***Indebtedness***" means, with respect to a Person, all items of indebtedness in respect of any amounts borrowed and all Purchase Money Obligations which, in accordance with GAAP, would be recorded in the financial statements of the Person as at the date as of which Indebtedness is to be determined, and in any event including, without duplication:

(a) obligations secured by any Security Interest existing on property owned subject to such Security Interest, whether or not the obligations secured thereby shall have been assumed; and

(b) guarantees, indemnities, endorsements (other than endorsements for collection in the ordinary course of business) or other contingent liabilities in respect of obligations of another Person for indebtedness of that other Person in respect of any amounts borrowed by them,

but excluding, in any event, Non-Recourse Debt.

"***Non-Recourse Assets***" means the assets created, developed, constructed or acquired with or in respect of which Non-Recourse Debt has been incurred and any and all receivables, inventory, equipment, chattel paper, intangibles and other rights or collateral arising from or connected with the assets created, developed, constructed or acquired (and, for certainty, shall include the shares or other ownership interests of a single purpose entity which holds only such assets and other rights and collateral arising from or connected therewith) and to which recourse of the lender of such Non-Recourse Debt (or any agent, trustee, receiver or other Person acting on behalf of such lender) in respect of such indebtedness is limited in all circumstances (other than in respect of false or misleading representations or warranties).

"***Non-Recourse Debt***" means any indebtedness in respect of any amounts borrowed, Purchase Money Obligations, obligations secured by a Security Interest existing on property owned subject to Security Interest (whether or not the obligations secured thereby shall have been assumed) and guarantees, indemnities, endorsements (other than endorsements for collection in the ordinary course of business) or other contingent obligations in respect of obligations of another Person for indebtedness of that other Person in respect of any amounts borrowed by them and, in each case, incurred to finance the creation, development, construction or acquisition of assets and any increases in or extensions, renewals or refundings of any such indebtedness, liabilities and obligations, provided that the recourse of the lender thereof or any agent, trustee, receiver or other Person acting on behalf of the lender in respect of such indebtedness, liabilities and obligations or any judgment in respect thereof is limited in all circumstances (other than in respect of false or misleading representations or warranties) to the assets created, developed, constructed or acquired in respect of which such indebtedness, liabilities and obligations has been incurred and to any receivables, inventory, equipment, chattel paper, intangibles and other rights or collateral arising from or connected with the assets created, developed, constructed or acquired (and, for certainty, shall include the shares or other ownership interests of a single purpose entity which holds only such assets and other rights and collateral arising from or connected therewith) and to which the lender has recourse.

"***Permitted Encumbrance***" means as at any particular time any of the following Security Interests or other encumbrances on the property or any part of the property of the Corporation:

(a) any Security Interest existing as of the date of the first issuance by the Corporation of Debentures issued pursuant to the Indenture, or arising thereafter pursuant to contractual commitments entered into prior to such issuance;

(b) any Security Interest created, incurred or assumed to secure any Purchase Money Obligation;

(c) any Security Interest created, incurred or assumed to secure any Non-Recourse Debt;

(d) any Security Interest in favour of any Subsidiary;

(e) any Security Interest on property of a corporation which Security Interest exists at the time such corporation is merged into, or amalgamated or consolidated with, the Corporation, or such property is otherwise acquired by the Corporation;

(f) each Excluded Sale and Leaseback, as such term is defined in the trust indenture made as of October 9, 1996 between the Corporation (formerly, The Consumers' Gas Company Ltd.) and BNY Trust Company of Canada (as successor to indenture trustee to The R-M Trust Company), as amended, modified and supplemented to the date hereof and as the same may be further amended, modified, supplemented or restated from time to time;

(g) any Security Interest securing any Indebtedness to any bank or banks or other lending institution or institutions incurred in the ordinary course of business and for the purpose of carrying on the same, repayable on demand or maturing within 18 months of the date when such Indebtedness is incurred or the date of any renewal or extension thereof;

(h) any Security Interest in respect of:

(i) liens for taxes and assessments not at the time overdue or any liens securing workmen's compensation assessments, unemployment insurance or other social security obligations; provided, however, that if any such obligations are then overdue the Corporation, shall be prosecuting an appeal or proceedings for review with respect to which it shall have secured a stay in the enforcement of any such obligations,

(ii) any liens for specified taxes and assessments which are overdue but the validity of which is being contested at the time by the Corporation in good faith,

(iii) any liens or rights of distress reserved in or exercisable under any lease for rent and for compliance with the terms of such lease,

(iv) any obligations or duties, affecting the property of the Corporation to any municipality or governmental, statutory or public authority, with respect to any franchise, grant, licence or permit and any defects in title to structures or other facilities arising solely from the fact that such structures or facilities are constructed or installed on lands held by the Corporation under government permits, leases or other grants, which obligations, duties and defects in the aggregate do not materially impair the use of such property, structures or facilities for the purpose for which they are held by the Corporation,

(v) any deposits or liens in connection with contracts, bids, tenders or expropriation proceedings, surety or appeal bonds, costs of litigation when required by law, public and statutory obligations, liens or claims incidental to current construction, builders', mechanics', labourers', materialmen's, warehousemen's, carriers' and other similar liens,

(vi) the right reserved to or vested in any municipality or governmental or other public authority by any statutory provision or by the terms of any lease, license, franchise, grant or permit, that affects any land, to terminate any such lease, license, franchise, grant or permit or to require annual or other periodic payments as a condition to the continuance thereof,

(vii) any undetermined or inchoate liens and charges incidental to the current operations of the Corporation that have not at the time been filed against the Corporation; provided, however, that if any such lien or charge shall have been filed, the Corporation shall be prosecuting an appeal or proceedings for review with respect to which it shall have secured a stay in the enforcement of any such lien or charge,

(viii) any Security Interest the validity of which is being contested at the time by the Corporation in good faith or payment of which has been provided for by deposit with the Trustee of an amount in cash sufficient to pay the same in full,

(ix) any easements, rights of way and servitudes (including, without in any way limiting the generality of the foregoing, easements, rights of way and servitudes for railways, sewers, dykes, drains, gas and water mains or electric light and power or telephone and telegraph conduits, poles, wires and cables) that in the opinion of the Corporation will not in the aggregate materially and adversely impair the use or value of the land concerned for the purpose for which it is held by the Corporation,

(x) any security to a public utility or any municipality or governmental or other public authority when required by such utility or other authority in connection with the operations of the Corporation,

(xi) cash or marketable debt securities pledged to secure Financial Instrument Obligations;

(xii) any liens and privileges arising out of judgments or awards with respect to which the Corporation shall be prosecuting an appeal or proceedings for review and with respect to which it shall have secured a stay of execution pending such appeal or proceedings for review, and

(xiii) any other liens of a nature similar to the foregoing which do not in the opinion of the Corporation materially impair the use of the property subject thereto or the operation of the business of the Corporation, or the value of such property for the purpose of such business;

(i) any other Security Interest if the amount of Indebtedness secured pursuant to this clause (i) does not exceed 5% of the Consolidated Net Tangible Assets; and

(j) any extension, renewal, alteration or replacement (or successive extensions, renewals, alterations or replacements), in whole or in part, of any Security Interest referred to in the foregoing clauses (a) through (h) inclusive, provided the extension, renewal, alteration or replacement of such Security Interest is limited to all or any part of the same property that secured the Security Interest extended, renewed, altered or replaced (plus improvements on such property) and the principal amount of the Indebtedness secured thereby is not increased.

"***Person***" means any natural person, sole proprietorship, corporation, partnership (general or limited, including master limited), limited liability company, trust, joint venture, joint stock company, unincorporated association, unincorporated syndicate, unincorporated organization, or other entity or association, and, where the context requires, any of the foregoing in its capacity as trustee, executor, administrator or other legal representative.

"***Petroleum Substances***" means crude oil, crude bitumen, synthetic crude oil, petroleum, natural gas, natural gas liquids, related hydrocarbons and any and all other substances, whether liquid, solid or gaseous, whether hydrocarbons or not, produced or producible in association with any of the foregoing, including hydrogen sulphide and sulphur.

"***Purchase Money Obligation***" means any monetary obligation created or assumed as part of the purchase price of real or tangible personal property, whether or not secured, any extensions, renewals or refundings of any such obligation, provided that the principal amount of such obligation outstanding on the date of such extension, renewal or refunding is not increased and further provided that any security given in respect of such obligation shall not extend to any property other than the property acquired in connection with which such obligation was created or assumed and fixed improvements, if any, erected or constructed thereon.

"***Security Interest***" means any assignment by way of security, mortgage, charge, pledge, lien, encumbrance, title retention agreement (including, without limitation, the interest of a lessor of goods under a lease for a term of more than one year) or other security interest whatsoever, howsoever created or arising, fixed or floating, perfected or not, which secures payment or performance of an obligation, but, for certainty, shall exclude factoring or other similar absolute assignments of accounts receivable.

"***Subordinated Debt***" means any Indebtedness which matures by its terms on, or is renewable at the option of the obligor to, a date more than 18 months after the date of the original creation or assumption thereof and which by its terms, operation of law or otherwise, provides that in the event of:

(a) any insolvency, bankruptcy, receivership, liquidation, composition or other similar proceeding relating to the Corporation or its property; or

(b) any proceedings for the liquidation, dissolution or other winding up of the Corporation, voluntary or involuntary, whether or not involving insolvency or bankruptcy proceedings; or

(c) any assignment by the Corporation for the benefit of the creditors; or

(d) any other marshalling of the assets of the Corporation for distribution to the creditors of the Corporation;

then and in any such event the principal of, premium, if any, and interest on, the Debentures is to be first paid in full before any payment or distribution, whether in cash or other property, shall be made on account of any such obligation; and in respect of which the Trustee has received an opinion of Counsel to the effect that such Indebtedness constitutes Subordinated Debt.

"***Subsidiary***" means, with respect to any Person:

(a) any corporation of which at least a majority of the outstanding shares having by the terms thereof ordinary voting power to elect a majority of the board of directors of such corporation (irrespective of whether at the time shares of any other class or classes of such corporation might have voting power by reason of the happening of any contingency, unless the contingency has occurred and then only for as long as it continues) is at the time directly, indirectly or beneficially owned or controlled by such Person or one or more of its Subsidiaries, or by such Person and one or more of its Subsidiaries;

(b) any partnership of which, at the time, such Person or one or more of its Subsidiaries, or such Person and one or more of its Subsidiaries: (i) directly, indirectly or beneficially own or control more than 50% of the income, capital, beneficial or ownership interests (however designated) thereof; and (ii) is a general partner, in the case of limited partnerships, or is a partner or has authority to bind the partnership, in all other cases; or

(c) any other Person of which at least a majority of the income, capital, beneficial or ownership interests (however designated) are at the time directly, indirectly or beneficially owned or controlled by such Person, or one or more of its Subsidiaries, or such Person and one or more of its Subsidiaries.

"***Total Consolidated Capitalization***" means, without duplication, the sum of:

(a) Consolidated Shareholders' Equity;

(b) the amount of preferred share capital;

(c) the principal amount of Consolidated Funded Obligations;

(d) the principal amount of Subordinated Debt;

(e) the accumulated provision for deferred income tax; and

(f) the amount of any non-controlling interests;

as determined for the Corporation on a consolidated basis in accordance with GAAP.

SCHEDULE B
DEFINITIONS – UNION GAS INDENTURE

The Union Gas Indenture contains, among others, definitions substantially to the following effect:

"***Available Earnings***" for any specified period means the income for such period from all sources of the Corporation and Consolidated Subsidiaries (but excluding from the computation thereof any gains or losses on the sale, disposal or revaluation of capital assets or investments to the extent that the net consolidated gain or loss thereon exceeds $25,000 in any fiscal year of the Corporation) computed on a consolidated basis after charging or making provision acceptable to the Corporation's auditors for:

(a) depreciation on depreciable properties, plant and equipment and depletion;

(b) natural gas development costs to the extent actually charged on the books of account against revenue;

(c) all other expenses of operation and administration; and

(d) minority interests in the earnings of Consolidated Subsidiaries,

but before charging or making provision for:

(e) interest on Funded Obligations and on any other indebtedness that since the end of the specified period has been or is about to be refunded by the issue of Funded Obligations;

(f) amortization of discount and expense in respect of Funded Obligations; and

(g) taxes on income,

all in accordance with generally accepted accounting practice and reported upon by the Corporation's auditors without, in their opinion, material adverse qualification.

"***Consolidated Interest Requirements***" means an amount equal to one year's interest on all Funded Obligations of the Corporation and Consolidated Subsidiaries to be outstanding immediately after the proposed action in respect of which the computation is being made, determined on a consolidated basis in accordance with generally accepted accounting practice.

"***Consolidated Subsidiary***" means at any time: (a) any Subsidiary that is engaged in the business of transmitting, storing and/or distributing natural gas; and (b) any other Subsidiary which the Corporation shall have designated as a Consolidated Subsidiary by certified resolution delivered to the Union Gas Trustee.

"***First Mortgage Bonds***" means all first mortgage bonds or other first mortgage obligations of the Corporation, whether heretofore or hereafter issued, secured by a first fixed and specific charge on substantially all the fixed assets of the Corporation, whether or not also secured by a floating charge or by any other security.

"***Funded Obligations***" means all indebtedness created, assumed or guaranteed which is not payable on demand and which by its terms matures, or is renewable at the option of the debtor to a date, more than 18 months after the date such indebtedness was created, assumed, guaranteed or last renewed.

"***Purchase Money Mortgages***" means any mortgage, lien or other encumbrance on property, assumed or given back as part of, or created or arising by operation of law to secure the whole or part of, the purchase price of such property, or affecting any property of a corporation at the time of its amalgamation with the Corporation, and any extension, renewal or replacement thereof on the same property if the principal amount of the indebtedness secured thereby is not increased.

"***Subsidiary***" means any corporation the majority of the shares of capital stock of which at the time outstanding, having under ordinary circumstances (not dependent upon the happening of a contingency) voting power to elect a majority of directors of such corporation, is owned directly or indirectly by the Corporation or by one or more of its other Subsidiaries or by the Corporation in conjunction with one or more of its other Subsidiaries.

SCHEDULE C
DEFINITIONS – EGD INDENTURE

The EGD Indenture contains, among others, definitions substantially to the following effect:

"***Attributable Debt***" means, as to any particular lease under which any person is at the time liable and at any date as of which the amount thereof is to be determined, the lesser of (i) the fair market value of the property (as determined by the directors) subject to such lease, and (ii) the total net amount of rent required to be paid by such person under such lease during the remaining term thereof (including any period for which such lease has been extended), discounted from the respective due dates thereof to such date at a rate of interest per annum equal to the weighted average interest rate of all unsecured and unsubordinated indebtedness of the Corporation. The net amount of rent required to be paid under any such lease for any such period shall be the aggregate amount of the rent payable by the lessee with respect to such period after excluding amounts required to be paid on account of maintenance and repairs, insurance, taxes, assessment, water rates and similar charges. In the case of any lease which is terminable by the lessee upon the payment of a penalty, such net amount shall also include the amount of such penalty, but no rent shall be considered as required to be paid under such lease subsequent to the first date upon which it may be so terminated.

"***Consolidated Net Earnings***" for any specified period of 12 months means the net earnings of the Corporation on a consolidated basis for such period (excluding gains or losses on the disposal of investments or fixed assets in each case in excess of $50,000 in the aggregate and other non-recurring items in excess of $50,000 in the aggregate) before deductions for income taxes, interest on Funded Obligations of the Corporation, dividends on preferred shares of the Corporation which have been deducted to calculate net earnings, amortization of debt premium, discount and expense and the cost, whether or not amortized, of conversion of facilities and appliances of the Corporation and its customers to the use of natural gas, all as determined in accordance with generally accepted accounting principles and reported on by the Corporation's auditors without, in their opinion, material adverse qualification: provided that if, within or after the period for which Consolidated Net Earnings is being determined but at or prior to the issuance of the additional notes in respect of which such determination is being made, the Corporation or any company, a portion of the net earnings (losses) of which are included in determining Consolidated Net Earnings acquires (a) any assets, or (b) an interest in any other company which would thereafter permit the inclusion in Consolidated Net Earnings of the Corporation's equity in the net earnings (losses) of such other company, then Consolidated Net Earnings may be determined as if such assets or interest had been acquired prior to and owned throughout such period if net earnings (losses) from such assets or interest can be determined or estimated for such period in accordance with generally accepted accounting principles.

"***Consolidated Net Tangible Assets***" means, on any date, the aggregate amount of assets after deducting therefrom (i) all current liabilities, and (ii) all goodwill, trade names, trademarks, patents, organization expenses and other like intangibles of the Corporation and its consolidated subsidiaries, all as set forth on the most recent balance sheet of the Corporation and its consolidated subsidiaries and determined in accordance with generally accepted accounting principles.

"***Excluded Sale and Leaseback***" means any Sale and Leaseback in respect of which:

(a) the lease is for a period, including renewal rights, of not in excess of three years, or

(b) an amount equal to the greater of the net proceeds of the sale of the property leased pursuant to such arrangement and the fair market value of such property (as determined by the directors) is applied within 180 days after the sale has been completed to:

   (i) the retirement, otherwise than by payment at maturity or pursuant to any mandatory sinking fund payment or any mandatory prepayment provision, of Funded Obligations of the Corporation or a Restricted Subsidiary, or

   (ii) the purchase of other property having a fair market value (as determined by the directors) at least equal to the fair market value (as so determined) of the property leased in such Sale and Leaseback, or

(c) such Sale and Leaseback is entered into prior to, at the time of, or within 180 days after the acquisition of the property which is subject thereto, or

(d) the only parties are the Corporation and its Restricted Subsidiaries.

"***First Mortgage Bonds***" means all first mortgage bonds or other first mortgage obligations of the Corporation, whether heretofore or hereafter issued, secured by a first fixed and specific charge on substantially all the fixed assets of the Corporation (whether or not also secured by floating charge or by any other security) and includes, without limitation, the first mortgage bonds of the Corporation outstanding from time to time under a Deed of Trust and Mortgage dated as of November 1, 1954, (and deeds supplemental thereto) made between the Corporation and The Toronto General Trusts Corporation (succeeded by Montreal Trust Company of Canada), as trustee.

"***Funded Obligations***" means any indebtedness, whether by way of bonds, debentures, debenture stock, notes or otherwise, whether secured or unsecured, the due date of payment of which, including any right of extension or renewal, is 18 months or more after the date of issue or incurring thereof but does not include Purchase Money Obligations or Permitted Prior Charges.

"***Permitted Encumbrances***" means security, deposits, pledges or other obligations in respect of:

(a) workers' compensation laws, unemployment insurance laws or similar legislation;

(b) good faith deposits in connection with bids, tenders, contracts (other than for the repayment of money borrowed), surety or appeal bonds, costs of litigation when required by law, or deposits to secure public or statutory obligations;

(c) liens imposed by law, such as labourers' or other employees', carriers', warehousemen's, mechanics', materialmen's and vendors' liens;

(d) liens arising out of judgements or awards against the Corporation or a Restricted Subsidiary with respect to which the Corporation or such Restricted Subsidiary at the time shall be prosecuting an appeal or proceedings for review and with respect to which it shall have secured a stay of execution pending such appeal or proceedings for review;

(e) liens for taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by the Corporation or a Restricted Subsidiary in good faith;

(f) liens or rights of distress reserved in or exercisable under any lease for rent or for compliance with the terms of such lease;

(g) any encumbrance arising by reason of any transaction permitted by Article 8 entered into by the Corporation or a Restricted Subsidiary;

(h) any other liens not related to the borrowing of money or the obtaining of advances or credit incurred or arising by operation of law in the ordinary course of business of the Corporation or a Restricted Subsidiary; and

(i) any other liens of a nature similar to the foregoing which do not in the opinion of the Corporation or a Restricted Subsidiary impair the use of the property subject thereto for the purposes for which it is held by the Corporation or such Restricted Subsidiary.

"***Permitted Prior Charges***" means Sale and Leasebacks and security for obligations, except First Mortgage Bonds, of the Corporation or any of its Restricted Subsidiaries, provided that the aggregate amount of the Attributable Debt of the Corporation and its Restricted Subsidiaries of all Sale and Leasebacks, excepting Excluded Sale and Leasebacks, and all obligations of the Corporation and its Restricted Subsidiaries so secured does not exceed the greater of 5% of Consolidated Net Tangible Assets of the Corporation and 10% of Shareholders' Equity of the Corporation.

"***Purchase Money Obligations***" means any mortgages, hypothecs, charges, vendors' privileges, vendors' liens or other encumbrances upon property (and the indebtedness represented thereby) given or assumed or arising by operation of law, to provide or secure the whole or any part of the consideration for the acquisition of such property and includes renewals, refundings and extensions not in excess of the principal amount thereof immediately prior to such renewal, refunding or extension.

"***Restricted Subsidiary***" means any corporation, company or organization, more than 50% of the outstanding shares of each class of the capital stock of which having attached to them voting rights under all circumstances are owned by the Corporation and/or one or more Restricted Subsidiary, provided the Corporation shall have, by resolution of its directors, designated such corporation, company or organization as a Restricted Subsidiary and more than 50% of the outstanding shares of each such class of the capital stock thereof are still owned by the Corporation and/or one or more Restricted Subsidiary.

"***Sale and Leaseback***" means any transaction with any bank, insurance company or other lender or investor, or to which any such bank, insurance company, lender or investor is a party, providing for the leasing by the Corporation or a Restricted Subsidiary of any property, real or personal, moveable or immovable, which has been or is to be sold or transferred by the Corporation or such Restricted Subsidiary to such bank, insurance company, lender or investor in contemplation of such leasing.

"***Shareholders' Equity***" means, on any date, the total amount of shareholders' equity of the Corporation and its consolidated subsidiaries including deferred income tax liabilities, all as set forth in the most recent consolidated balance sheet of the Corporation and its consolidated subsidiaries and determined in accordance with generally accepted accounting principles.

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **canada.ca/taxes** or Guide T4012, T2 Corporation – Income Tax Guide.

Identification

Business number (BN) 001 10520 5140 RC0002

Corporation's name
002 ENBRIDGE GAS INC.

Address of head office
Has this address changed since the last time we were notified? .... 010 Yes [ ] No [X]
If **yes**, complete lines 011 to 018.
011 500 CONSUMERS ROAD
012
City: 015 NORTH YORK
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal or ZIP code: 018 M2J 1P8

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? .... 020 Yes [ ] No [X]
If **yes**, complete lines 021 to 028.
021 c/o MANAGER TAX REPORTING
022 P.O.BOX 650
023
City: 025 SCARBOROUGH
Province, territory, or state: 026 ON
Country (other than Canada): 027 CA
Postal or ZIP code: 028 M1K 5E3

Location of books and records (if different from head office address)
Has this address changed since the last time we were notified? .... 030 Yes [ ] No [X]
If **yes**, complete lines 031 to 038.
031 500 CONSUMERS ROAD
032
City: 035 NORTH YORK
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal or ZIP code: 038 M2J 1P8

040 **Type of corporation at the end of the tax year** (tick one)
- [ ] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [X] 4 Corporation controlled by a public corporation
- [ ] 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change .... 043 Year Month Day

To which tax year does this return apply?
Tax year start (Year Month Day): 060 2021-01-01
Tax year-end (Year Month Day): 061 2021-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? .... 063 Yes [ ] No [X]
If **yes**, provide the date control was acquired .... 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? .... 066 Yes [ ] No [X]

Is the corporation a professional corporation that is a member of a partnership? .... 067 Yes [ ] No [X]

Is this the first year of filing after:
Incorporation? .... 070 Yes [ ] No [X]
Amalgamation? .... 071 Yes [ ] No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? .... 072 Yes [ ] No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? .... 076 Yes [ ] No [X]

Is this the final return up to dissolution? .... 078 Yes [ ] No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 Yes [X] No [ ]
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? .... 082 Yes [ ] No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
- [ ] 1 Exempt under paragraph 149(1)(e) or (l)
- [ ] 2 Exempt under paragraph 149(1)(j)
- [ ] 4 Exempt under other paragraphs of section 149

Do not use this area
095 096 898

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	170	X	29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171	X	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173		50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Does the corporation earn income from one or more Internet web pages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any resource-related deductions?	212	X	12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or a provincial credit union tax reduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243	X	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244	X	45
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit?	253		T1131
Is the corporation claiming a film or video production services tax credit?	254		T1177
Is the corporation claiming a Canadian journalism labour tax credit?	272		58
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		Yes	No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 486210 Pipeline Transportation of Natural Gas

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	NAT GAS SALES & TRAN	285	97.630 %
286	OTHER	287	1.500 %
288	INVESTMENT REVENUE	289	0.870 %

		Yes	No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 Year Month Day

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 Yes ☐ No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300		278,746,590	A
Deduct:				
Charitable donations from Schedule 2	311	3,311,345		
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine made before March 22, 2017, from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325	223,821,161		
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Employer deduction for non-qualified securities	352			
Subtotal		227,132,506 ▶	227,132,506	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			51,614,084	C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		51,614,084	
Taxable income for the year from a personal services business				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income eligible for the small business deduction from Schedule 7 . . . . . **400** ______ A

Taxable income from line 360 on page 3, **minus** 100/28 (3.57143) of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . . . **410** ______ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction

Taxable capital business limit reduction

Amount C ______ x **415** *** ______ D = ... ______ E
11,250

Passive income business limit reduction

Adjusted aggregate investment income from Schedule 7**** . **417** ______ – 50,000 = . . ______ F

Amount C ______ x Amount F ______ = ... ______ G
100,000

The greater of amount E and amount G **422** ______ H

Reduced business limit (amount C **minus** amount H) (if negative, enter "0") . . . . . **426** ______ I

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below) . . . . . ______ J

Reduced business limit after assignment (amount I **minus** amount J) . . . . . **428** ______ K

Small business deduction – Amount A, B, C, or K, whichever is the least . . . . ______ x 19 % = **430** ______

Enter amount from line 430 at amount J on page 8.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**** Enter the total adjusted aggregate investment income of the corporation and all associated corporations for each tax year that ended in the preceding calendar year. Each corporation with such income has to file a Schedule 7. For a corporation's first tax year that starts after 2018, this amount is reported at line 744 of the corresponding Schedule 7. Otherwise, this amount is the total of all amounts reported at line 745 of the corresponding Schedule 7 of the corporation for each tax year that ended in the preceding calendar year.

Specified corporate income and assignment under subsection 125(3.2)

	L1 Name of corporation receiving the income and assigned amount	L Business number of the corporation receiving the assigned amount **490**	M Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column L [3] **500**	N Business limit assigned to corporation identified in column L [4] **505**
1.				
			Total **510** ______	Total **515** ______

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income (other than specified farming or fishing income of the corporation for the year) from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
   (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
   (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or
   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column M in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 426.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3				A
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		B		
Amount 13K from Part 13 of Schedule 27		C		
Personal services business income	432	D		
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least		E		
Aggregate investment income from line 440 on page 6*		F		
Subtotal (**add** amounts B to F)		►		G
Amount A **minus** amount G (if negative, enter "0")				H
General tax reduction for Canadian-controlled private corporations – Amount H **multiplied** by 13 %				I

Enter amount I on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3			51,614,084	J
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		K		
Amount 13K from Part 13 of Schedule 27		L		
Personal services business income	434	M		
Subtotal (**add** amounts K to M)		►		N
Amount J **minus** amount N (if negative, enter "0")			51,614,084	O
General tax reduction – Amount O **multiplied** by 13 %			6,709,831	P

Enter amount P on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ________ x 30 2 / 3 % = ... ________ A

Foreign non-business income tax credit from line 632 on page 8 . . . . ________ B

Foreign investment income from Schedule 7 . . . . **445** ________ x 8 % = ________ C

Subtotal (amount B **minus** amount C) (if negative, enter "0") ________ ▶ ________ D

Amount A **minus** amount D (if negative, enter "0") . . . . ________ E

Taxable income from line 360 on page 3 . . . . ________ F

Amount from line 400, 405, 410, or 428 on page 4, whichever is the least . . . . ________ G

Foreign non-business income tax credit from line 632 on page 8 . . . . ________ x 75 / 29 = ________ H

Foreign business income tax credit from line 636 on page 8 . . ________ x 4 = ________ I

Subtotal (**add** amounts G to I) ________ ▶ ________ J

Subtotal (amount F **minus** amount J) ________ K x 30 2 / 3 % = ________ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9) . . . . ________ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . **450** ________ N

Refundable dividend tax on hand

Refundable dividend tax on hand (RDTOH) at the end of the previous tax year	460			
Dividend refund for the previous tax year	465			
Net RDTOH transferred on an amalgamation or the wind-up of a subsidiary	480			
Subtotal (line 460 **minus** line 465 **plus** line 480)				A
General rate income pool (GRIP) at the end of the previous tax year (from line 100 of Schedule 53)				B
Total eligible dividends paid in the previous tax year (from line 300 of Schedule 53)		C		
Total excessive eligible dividend designation in the previous tax year (from line 310 of Schedule 53)		D		
Subtotal (amount C **minus** amount D) (if negative, enter "0")		▶		E
Net GRIP at the end of the previous tax year (amount B **minus** amount E) (if negative, enter "0")		F		
GRIP transferred on an amalgamation or the wind-up of a subsidiary (total of lines 230 and 240 of Schedule 53)		G		
Subtotal (amount F **plus** amount G)		▶		H
Amount H **multiplied** by 38 1 / 3 %				I
Eligible refundable dividend tax on hand (ERDTOH) at the end of the previous tax year (for the first tax year starting after 2018, amount A or I, whichever is less, otherwise, use line 530 of the preceding tax year)	520			J
Non-eligible refundable dividend tax on hand (NERDTOH) at the end of the previous tax year (for the first tax year starting after 2018, amount A **minus** amount I, otherwise, use line 545 of the preceding tax year) (if negative, enter "0")	535			K
Part IV tax payable on taxable dividends from connected corporations (amount 2G from Schedule 3)		L		
Part IV tax payable on eligible dividends from non-connected corporations (amount 2J from Schedule 3)		M		
Subtotal (amount L **plus** amount M)		▶		N
Net ERDTOH transferred on an amalgamation or the wind-up of a subsidiary	525			O
ERDTOH dividend refund for the previous tax year	570			P
Refundable portion of Part I tax (from line 450 on page 6)				Q
Part IV tax before deductions (amount 2A from Schedule 3)		R		
Part IV tax allocated to ERDTOH (amount N)		S		
Part IV tax reduction due to Part IV.1 tax payable (amount 4D of Schedule 43)		T		
Subtotal (amount R **minus** total of amounts S and T)		▶		U
Net NERDTOH transferred on an amalgamation or the wind-up of a subsidiary	540			V
NERDTOH dividend refund for the previous tax year	575			W
38 1/3% of the total losses applied against Part IV tax (amount 2D from Schedule 3)				X
Part IV tax payable allocated to NERDTOH, net of losses claimed (amount U **minus** amount X) (if negative enter “0”)				Y
NERDTOH at the end of the tax year (total of amounts K, Q, V, and Y **minus** amount W) (if negative, enter "0")	545			
Part IV tax payable allocated to ERDTOH, net of losses claimed (amount N **minus** the amount, if any, by which amount X exceeds amount U) (if negative, enter "0")				Z
ERDTOH at the end of the tax year (total of amounts J, O, and Z **minus** amount P) (if negative, enter "0")	530			

Dividend refund

38 1/3% of total eligible dividends paid in the tax year (amount 3A from Schedule 3)		AA
ERDTOH balance at the end of the tax year (line 530)		BB
Eligible dividend refund (amount AA or BB, whichever is less)		CC
38 1/3% of total non-eligible taxable dividends paid in the tax year (amount 3B from Schedule 3)	76,666,667	DD
NERDTOH balance at the end of the tax year (line 545)		EE
Non-eligible dividend refund (amount DD or EE, whichever is less)		FF
Amount DD **minus** amount EE (if negative, enter "0")	76,666,667	GG
Amount BB **minus** amount CC (if negative, enter "0")		HH
Additional non-eligible dividend refund (amount GG or HH, whichever is less)		II
Dividend refund – Amount CC **plus** amount FF **plus** amount II		JJ

Enter amount JJ on line 784 on page 9.

Part I tax

Base amount Part I tax – Taxable income (from line 360 on page 3) **multiplied** by 38 %	550	19,613,352	A

Additional tax on personal services business income (section 123.5)

Taxable income from a personal services business	555		x 5 % =	560		B
Recapture of investment tax credit from Schedule 31				602		C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6				D
Taxable income from line 360 on page 3		E		
Deduct:				
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least		F		
Net amount (amount E **minus** amount F)		▶		G

Refundable tax on CCPC's investment income – 10 2 / 3 % of whichever is less: amount D or amount G	604		H
Subtotal (**add** amounts A, B, C, and H)		19,613,352	I

Deduct:

Small business deduction from line 430 on page 4			J		
Federal tax abatement	608	5,161,408			
Manufacturing and processing profits deduction from Schedule 27	616				
Investment corporation deduction	620				
Taxed capital gains 624					
Federal foreign non-business income tax credit from Schedule 21	632				
Federal foreign business income tax credit from Schedule 21	636				
General tax reduction for CCPCs from amount I on page 5	638				
General tax reduction from amount P on page 5	639	6,709,831			
Federal logging tax credit from Schedule 21	640				
Eligible Canadian bank deduction under section 125.21	641				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652	183,994			
Subtotal		12,055,233	▶	12,055,233	K

Part I tax payable – Amount I **minus** amount K	7,558,119	L

Enter amount L on line 700 on page 9.

Privacy notice

Personal information (including the SIN) is collected for the purposes of the administration or enforcement of the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties, or other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 047 on Info Source at **canada.ca/cra-info-source**.

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 8	700	7,558,119
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	63,948,903
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		71,507,022

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 MJ
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	11,257,514	
Total tax payable	770	82,764,536	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from amount JJ on page 7	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit (Form T1131)	796	
Film or video production services tax credit (Form T1177)	797	
Canadian journalism labour tax credit from Schedule 58	798	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	90,257,217
Total credits	890	90,257,217 ▶ 90,257,217 B

Balance (amount A **minus** amount B) -7,492,681

Refund code 894 1 Refund 7,492,681

If the result is negative, you have a **refund**.
If the result is positive, you have a **balance owing**.
Enter the amount above on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance owing

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 Yes ☐ No ☐

If this return was prepared by a tax preparer for a fee, provide their EFILE number 920

Certification

I, 950 Wedel (Last name) 951 Andrew (First name) 954 DIRECTOR TAX REPORTING (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2022-10-25 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (403) 231-5963 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 Yes ☒ No ☐

958 ______ Name of other authorized person 959 ______ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

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SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	2,291,556,000	1,921,082,000
	Total tangible capital assets	2008	+	21,228,969,000	19,895,965,000
	Total accumulated amortization of tangible capital assets	2009	–	4,567,281,000	4,029,979,000
	Total intangible capital assets	2178	+	5,298,949,000	5,438,888,000
	Total accumulated amortization of intangible capital assets	2179	–	338,088,000	480,938,000
	Total long-term assets	2589	+	2,676,218,000	2,491,783,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	26,590,323,000	25,236,801,000
	Liabilities				
	Total current liabilities	3139	+	3,211,822,000	2,925,447,000
	Total long-term liabilities	3450	+	13,029,230,000	12,293,725,000
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	16,241,052,000	15,219,172,000
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	10,349,271,000	10,017,629,000
	Total liabilities and shareholder equity	3640	=	26,590,323,000	25,236,801,000
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	-324,355,000	-675,007,000

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	4,818,904,000	4,440,900,000
	Cost of sales	8518	–	2,146,176,000	1,811,693,000
	Gross profit/loss	8519	=	2,672,728,000	2,629,207,000
	Cost of sales	8518	+	2,146,176,000	1,811,693,000
	Total operating expenses	9367	+	2,175,920,000	2,204,274,000
	Total expenses (mandatory field)	9368	=	4,322,096,000	4,015,967,000
	Total revenue (mandatory field)	8299	+	4,935,857,000	4,571,012,000
	Total expenses (mandatory field)	9368	–	4,322,096,000	4,015,967,000
	Net non-farming income	9369	=	613,761,000	555,045,000
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	613,761,000	555,045,000
	Total – other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	77,525,000	82,999,000
	Future (deferred) income tax provision	9995	–	-14,578,000	-25,296,000
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	550,814,000	497,342,000

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax Year End Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, General Index of Financial Information (GIFI) and T4012, T2 Corporation – Income Tax Guide.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . 095 Yes [X] No [ ]

Is the accountant connected* with the corporation? . . . . . 097 Yes [X] No [ ]

Note
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Completed an auditor's report . . . . . 1 [ ]
Completed a review engagement report . . . . . 2 [ ]
Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . 099 Yes [ ] No [ ]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]
Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . 101 Yes [X] No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . 104 Yes [ ] No [X]
Is re-evaluation of asset information mentioned in the notes? . . . . . 105 Yes [ ] No [X]
Is contingent liability information mentioned in the notes? . . . . . 106 Yes [X] No [ ]
Is information regarding commitments mentioned in the notes? . . . . . 107 Yes [X] No [ ]
Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . 108 Yes [ ] No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** Yes [X] No [ ]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**	12,000,000	**231**	21,000,000
Other	**235**		**236**	22,000,000

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** Yes [ ] No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . **255** Yes [ ] No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** Yes [ ] No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** Yes [ ] No [X]

If **yes**, you have to maintain a separate reconciliation.

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. BUSINESS OVERVIEW

The terms "we", "our", "us" and "Enbridge Gas" as used in these financial statements refer collectively to Enbridge Gas Inc. and its subsidiaries unless the context suggests otherwise. Enbridge Gas is a wholly- owned indirect subsidiary of Enbridge Inc. (Enbridge). Enbridge provides administrative and general support services to us.

Enbridge Gas is a rate-regulated natural gas distribution, storage and transmission utility, serving residential, commercial and industrial customers in Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (US GAAP). Amounts are stated in Canadian dollars unless otherwise noted. We are permitted to use US GAAP as our primary basis of accounting for the purposes of meeting our continuous disclosure obligations under an exemption granted by securities regulators in Canada.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities (Note 5); unbilled revenues; estimates of revenue; expected credit losses; depreciation rates and carrying value of property, plant and equipment (Note 7); amortization rates and carrying value of intangible assets (Note 8); measurement of goodwill; fair value of asset retirement obligations (ARO); fair value of financial instruments (Note 13); provisions for income taxes (Note 15); assumptions used to measure retirement benefits and OPEB (Note 16); and commitments and contingencies (Note 19). Actual results could differ from these estimates.

Certain comparative figures in our consolidated financial statements have been reclassified to conform to the current year's presentation.

REGULATION

Our utility operations within Ontario are regulated by the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities.

As a result of rate-regulated accounting, we have recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates and amounts collected from customers in advance of costs being incurred.

Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment.

The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. The regulator's future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which we operate. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. We believe that the recovery of our regulatory assets as at December 31, 2021 is probable over the periods described in Note 5 - Regulatory Matters.
With the approval of the regulator, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.
REVENUE RECOGNITION
Revenue from contracts with customers is generally recognized upon the fulfillment of the performance obligations for the distribution, storage, transportation and sale of natural gas. For distribution and transportation service arrangements, where the services are simultaneously received and consumed by the customer, revenues are recorded based on regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas. Revenues from storage services are recognized as the storage services are provided.
A significant portion of our operations are subject to regulation and, accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue under such circumstances is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator, which are accounted for under Accounting Standards Codification (ASC) 980 Regulated Operations.
PUSH-DOWN ACCOUNTING
Enbridge Gas Distribution Inc. (EGD) elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted US GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by EGD. Upon adopting push-down accounting, the historical cost of EGD's property, plant and equipment and related accounts were adjusted by the remaining unamortized fair value adjustment.
We have applied push-down accounting with respect to the accounts of Union Gas Limited (Union Gas). The carrying values of certain assets and liabilities of Union Gas transferred to EGD have been adjusted to reflect Enbridge's historical cost as at February 27, 2017, the date upon which Enbridge acquired common control of EGD and Union Gas.
DERIVATIVE INSTRUMENTS AND HEDGING
Derivatives in Qualifying Hedging Relationships
We use derivative financial instruments to manage our exposure to changes in interest rates and foreign exchange rates. Hedge accounting is optional and requires us to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges or net investment hedges. There were no outstanding derivative instruments relating to fair value or net investment hedges as at December 31, 2021 and 2020.
Cash Flow Hedges

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

We use cash flow hedges to manage our exposure to changes in interest rates and foreign exchange rates related to our unregulated storage revenue. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities in the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a reduction to Long-term debt in the Consolidated Statements of Financial Position.

These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

INCOME TAXES

Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent that taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

FOREIGN CURRENCY TRANSACTIONS

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge Gas or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated to the functional currency using the exchange rate prevailing at the date of the transaction.

Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the exchange rate in effect as at the balance sheet date. Exchange gains and losses resulting from the translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period in which they arise.

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

CASH
We combine cash and bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements.
RECEIVABLES AND CURRENT EXPECTED CREDIT LOSSES
Accounts receivable and other are measured at cost. For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations.
NATURAL GAS IMBALANCES
The Consolidated Statements of Financial Position include balances as a result of differences in gas volumes received from, and delivered for, customers. As settlement of certain imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. All natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.
GAS INVENTORY
Gas inventories primarily consist of natural gas held in storage and also include costs such as storage injection and demand costs. Natural gas held in storage is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of gas purchased is deferred as a liability for future refund, or as an asset for collection as approved by the OEB.
PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost, including an allowance for interest incurred during construction as authorized by the regulator. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred.
Expenditures for project development are capitalized if they are expected to have future benefit.
The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the regulator. When group assets are retired or otherwise disposed of, gains and losses are generally not reflected in earnings but are booked as an adjustment to accumulated depreciation until the last asset in the pool is disposed of. Gains and losses on the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the regulator, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the regulator.
LEASES
We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

assets are assessed for impairment using the same approach applied for other long-lived assets.

Lease liabilities and ROU assets require the use of judgment and estimates which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily consists of costs that regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; the fair value adjustment to long-term debt; the difference between the actual cost and approved cost of natural gas reflected in rates; and actuarial gains and losses arising from defined benefit pension plans.

INTANGIBLE ASSETS

Intangible assets consist primarily of certain software costs. We capitalize costs incurred during the application development stage of internal use software projects. Intangible assets are generally amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. When performing a qualitative assessment, we determine the drivers of fair value and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, the assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends and industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value is less than its carrying amount, a quantitative goodwill impairment test is performed.

The quantitative goodwill impairment assessment involves determining the fair value of goodwill and comparing that value to its carrying value. If the carrying value, including allocated goodwill, exceeds fair value, goodwill impairment is measured at the amount by which the carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. Fair value is estimated using a discounted cash flow technique. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. Cash flow projections include significant judgments and assumptions relating to revenue growth rates and expected future capital expenditures.

IMPAIRMENT

We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we calculate fair value based on the discounted cash flows and write the assets down to the extent that the carrying value exceeds the fair value.

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

ASSET RETIREMENT OBLIGATIONS
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. Fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.
PENSION AND OTHER POSTRETIREMENT BENEFITS
We provide pension benefits through defined benefit and defined contribution pension plans and OPEB, including group health care and life insurance benefits through defined benefit OPEB plans.
Defined benefit pension obligation and net periodic benefit cost are estimated using the projected unit credit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors, including discount rates and mortality. The OPEB benefit obligation and net periodic benefit cost are estimated using the projected unit credit method, where benefits are attributed to years of service, taking into consideration projection of benefit costs.
We use mortality tables issued by the Canadian Institute of Actuaries (revised in 2014) to measure the benefit obligation of our pension plans.
We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments we anticipate making under each of the respective plans.
Funded pension plan assets are measured at fair value. The expected return on funded pension plan assets is determined using market-related values and assumptions on the invested asset mix consistent with the investment policies relating to the plan assets. The market-related values reflect estimated return on investments consistent with long-term historical averages for similar assets.
Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period (for funded pension plans) or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount and salary inflation experience.
The excess of the fair value of a plan's assets over the fair value of a plan's benefit obligation is recognized as Deferred amounts and other assets in the Consolidated Statements of Financial Position. The excess of the fair value of a plan's benefit obligation over the fair value of a plan's assets is recognized as Accounts payable and other and Other long-term liabilities in our Consolidated Statements of Financial Position.
Net periodic benefit cost is charged to earnings and includes:
.   cost of benefits provided in exchange for employee services rendered during the year (current service cost);.   interest cost of plan obligations;
.   expected return on plan assets (for funded pension plans);
.   amortization of prior service costs on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
.   amortization of cumulative unrecognized net actuarial gains and losses

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit OPEB plans are presented as a component of Accumulated other comprehensive loss (AOCI) in our Consolidated Statements of Changes in Equity. Any unrecognized OPEB-related actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax. Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit pension plans, which have been permitted or are expected to be permitted by the regulator, to be recovered through future rates, are presented as a component of Deferred amounts and other assets in our Consolidated Statements of Financial Position.

We also record regulatory adjustments to reflect the difference between certain net periodic benefit costs for accounting purposes and net periodic benefit costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to earnings and OCI on an accrual basis.

For defined contribution plans, contributions made by us are expensed in the period in which the contribution occurs.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

CHANGES IN ACCOUNTING POLICIES

There were no changes in accounting policies during the year ended December 31, 2021.

ADOPTION OF NEW ACCOUNTING STANDARDS

Accounting for Contract Assets and Liabilities from Contracts with Customers in a Business Combination

Effective November 1, 2021, we adopted Accounting Standards Update (ASU) 2021-08 on a retrospective basis beginning January 1, 2021. The new standard was issued in October 2021 to amend business combination accounting specific to contract assets and contract liabilities resulting from contracts with customers, requiring measurement in accordance with ASC 606 The ASU is also applicable to contract assets and contract liabilities from other contracts to which ASC 606 applies, such as contract liabilities from the sale of nonfinancial assets within the scope of ASC 610-20. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Income Taxes

Effective January 1, 2021, we adopted ASU 2019-12 on a prospective basis. The new standard was issued in December 2019 with the intent of simplifying the accounting for income taxes. The accounting update removes certain exceptions to the general principles in ASC 740 Income Taxes as well as provides simplification by clarifying and amending existing guidance. The adoption of this ASU did not have a material impact on our consolidated financial

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

statements.
FUTURE ACCOUNTING POLICY CHANGES
Disclosures About Government Assistance
ASU 2021-10 was issued in November 2021 to increase the transparency of government assistance to business entities. The ASU adds new disclosure requirements for transactions with government that are accounted for using a grant or contribution accounting model by analogy. The required disclosures include information about the nature of transactions, accounting policy applied, impacted financial statement line items and significant terms and conditions. ASU 2021-10 is effective January 1, 2022 and can be applied either prospectively or retrospectively with early adoption permitted. The adoption of ASU 2021-10 is not expected to have a material impact on our consolidated financial statements.
(millions of Canadian dollars)
Gas commodity and distribution revenues - residential 2,778 2,560
Gas commodity and distribution revenues - commercial and industrial 1,208 1,077Storage revenue 156 144
Transportation revenue 686 681
Other revenues 71 62
Total revenue from contracts with customers 4,899 4,524
Other1 (6) (9)
Total revenues 4,893 4,515
1 Primarily relates to the effects of rate-regulated accounting.
We disaggregate revenues into categories which represent our principal performance obligations. These revenue categories also represent the most significant revenue streams, and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.
Contract Balances
Contract
Receivables Liabilities
(millions of Canadian dollars)
Balance as at December 31, 2021 824 17
Balance as at December 31, 2020 738 -
Receivables represent an unconditional right to consideration where only the passage of time is required before payment of consideration is due, and consist of trade accounts receivable, unbilled revenue and other accrued receivable balances. Receivables also consist of trade accounts receivable and unbilled revenue balances for the collection of certain federal carbon levy unit rates, for which we act as an agent.
Contract liabilities represent payments received for performance obligations which have not been fulfilled under our equal monthly payment plan. The increase in contract liabilities from cash received, net of amounts recognized as revenues during the year ended December 31, 2021, was $17 million.
Performance Obligations
Revenue category Nature of Performance Obligation
Gas commodity and distribution revenue . Supply and delivery of natural gas to customers Storage and transportation revenue . Storage and transportation of natural gas on behalfof customers
Other revenue . Other billing and service fees

We recognized a reduction of revenue of $15 million during the year ended December 31, 2021 from performance obligations satisfied in previous periods, primarily resulting from differences in actual and estimated consumption. The associated reduction in gas commodity and distribution costs was also

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

recognized in the current year.

Payment Terms

Payments from distribution customers are received on a continuous basis based on established billing cycles. Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. Payments from storage customers are received monthly under long-term storage capacity contracts. Payments from transportation customers are received on a continuous basis based on established billing cycles or monthly under long-term transportation capacity contracts.

Revenue to be Recognized from Unfulfilled Performance Obligations

Total revenue from performance obligations expected to be fulfilled in future periods is $602 million, of which $309 million is expected to be recognized during the year ending December 31, 2022.

The performance obligations above reflect revenues expected to be recognized in future periods from unfulfilled performance obligations pursuant to contracts with customers for the purchase of natural gas distribution, storage and transportation services. Certain revenues are excluded from the amounts above under the following ASC 606 optional exemptions:

. revenues, such as flow-through costs charged to customers, which are recognized at the amount for which we have the right to invoice our customers; and

. revenue from contracts with customers that have an original expected duration of one year or less.

Variable consideration is also excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be reasonably estimated.

A significant portion of our operations are subject to regulation. Accordingly, the amounts above, in addition to revenues that are not regulated, only include revenue for which the underlying rate has been approved by regulation, where applicable. The revenues excluded from the amounts above could represent a significant portion of our overall revenues and revenue from contracts with customers.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE

Revenue Recognition

Revenue from contracts with customers is generally recognized upon the fulfillment of the performance obligations as described above. Distribution and transportation service revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas. Due to regulatory mechanisms, there are circumstances where revenues recognized do not match the amounts billed. Under such circumstances, revenue is recognized in a manner that is consistent with the underlying rate setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator.

Recognition and Measurement of Revenues

Year ended December 31, 2021 2020

1 Revenue from distribution, storage and transportation services.

2 Primarily from Other revenues.

Performance Obligations Satisfied Over Time

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

For arrangements involving the distribution and transportation of natural gas, where the services are simultaneously received and consumed by the customer, we recognize revenue over time using an output method based on volumes of commodities delivered. The measurement of the volumes delivered corresponds directly to the benefits received by the customers during that period. Revenue from storage services are recognized as the services are provided.

Determination of Transaction Prices

Prices for distribution and transportation services and regulated storage services are prescribed by regulation. Fees for unregulated storage services are determined through negotiations with customers and are based on market rates.

Prices for natural gas sold are driven by market prices and the Quarterly Rate Adjustment Mechanism (QRAM) in place that allows for rates to reflect changes in natural gas prices, subject to regulatory approval.

5. REGULATORY MATTERS

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under US GAAP for non-regulated entities. See Note 2 - Significant Accounting Policies for further discussion.

We are regulated by the OEB pursuant to the provisions of the Ontario Energy Board Act, (1998), which is part of a package of legislation known as the Energy Competition Act, (1998). This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario.

RATE APPROVALS

Our distribution rates, commencing in 2019, are set under a five-year Incentive Regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% stretch factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires us to share equally with customers any earnings in excess of 150 basis points over the annual OEB approved return on equity.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following regulatory assets and liabilities in the Consolidated Statements of Financial Position:

December 31, 2021 2020

Recovery/Refund Period Ends

(millions of Canadian dollars)

Current regulatory assets Purchase gas variance1

Other current regulatory assets

15

67

- 2022

117 2022

Total current regulatory assets2 (Note 6) 82 117

Long-term regulatory assets

Deferred income taxes3 1,532 1,393 Various

Long-term debt4 (Note 10) 307 334 2023-2046

Purchase gas variance1 215 - 2023

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

Accounting policy changes5 157 169 Various
Transition impact of accounting changes6 49 53 2032
Pension plan receivable7 26 342 Various
Other long-term regulatory assets 91 34 Various
Total long-term regulatory assets2 2,377 2,325
Total regulatory assets 2,459 2,442
Current regulatory liabilities
Purchase gas variance1 - 153 2021
Other current regulatory liabilities 61 73 2022
Total current regulatory liabilities8 (Note 9) 61 226
Long-term regulatory liabilities
Future removal and site restoration reserves9 1,543 1,455 Various
Accelerated capital cost allowance 17 43 Various
Other long-term regulatory liabilities 94 45 Various
Total long-term regulatory liabilities8 1,654 1,543
Total regulatory liabilities 1,715 1,769

1 Represents the difference between the actual cost and the approved cost of natural gas reflected in rates. We have been granted OEB approval to refund this balance to, or collect this balance from, customers on a rolling 12 month basis as part of the QRAM process. As part of the January 1, 2022 QRAM application, the recovery of certain balances have been deferred into 2023.2 Current regulatory assets are included in Accounts receivable and other, while long-term regulatory assets are included in Deferred amounts and other assets.

3 Represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in future regulator- approved rates and recovered from customers. The recovery period depends on the timing of the reversal of temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded.

4 Represents our regulatory offset to the fair value adjustment to debt acquired in Enbridge's merger with Spectra Energy Corp. (Spectra Energy) and pushed down to Enbridge Gas. The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.

5 This deferral reflects unamortized accumulated actuarial gains/losses and past service costs incurred by Union Gas, relating to the period up to Enbridge's merger with Spectra Energy, which were previously recorded in AOCI. The amortization of this balance is recognized as a component of accrual-based pension expenses, which are included in Other income and recovered in rates, as previously approved by the OEB.

6 Represents our right to recover costs resulting from the adoption of the accrual basis of accounting for pension and OPEB costs upon transition to US GAAP in 2012. Pursuant to the OEB rate order, the balance as at December 31, 2012 is to be collected in rates over a 20 year period, commencing in 2013.

7 Represents the regulatory offset to our pension liability to the extent that it is expected to be included in regulator-approved future rates and recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense would be recorded in earnings and OCI.

8 Current regulatory liabilities are included in Accounts payable and other, while long-term regulatory liabilities are included in Other long-term liabilities.

9 Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the OEB, to fund future costs

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

OTHER ITEMS AFFECTED BY RATE REGULATION

Gas Inventories

Natural gas held in storage is recorded in inventory at the reference prices approved by the OEB in the determination of customers' system supply rates. Included in Gas inventory as at December 31, 2021 is
$61 million (2020 - $60 million) related to storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during our off-peak months and charged to gas costs during the peak winter months. In the absence of rate-regulated accounting, these costs would be expensed as incurred, and inventory would be recorded at the lower of cost or market value.

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	2021	2020
(millions of Canadian dollars)		
Trade receivables and unbilled revenues, net1	953	855
Regulatory assets (Note 5)	82	117
Gas imbalances	101	54
Rebillables receivable	45	76
Other	47	59
	1,228	1,161

1 Net of allowance for expected credit losses of $55 million as at December 31, 2021 (2020 - $45 million).

7. PROPERTY, PLANT AND EQUIPMENT

December 31,

Weighted Average
Depreciation Rate 2021 2020

(millions of Canadian dollars)
Regulated property, plant and equipment Gas transmission
Gas mains, services and other
Compressors, meters and other operating equipment Storage
Land and right-of-way1
Vehicles, office furniture, equipment and other buildings and improvements
Under construction
2.5%
2.6%
4.1%
2.7%
0.9%
8.4%
-%
1,854
1,752
13,354 12,580
3,361 3,246
1,065 950
375 361

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

453 434
263 177
20,725 19,500
Accumulated depreciation (4,464) (4,036)
16,261 15,464
Unregulated property, plant and equipment
Gas mains, services and other 10.2% 13 13
Compressors, meters and other operating equipment 1.3% 42 41
Storage 3.0% 374 365
Land and right-of-way1 1.5% 38 37
Under construction -% 37 30
504 486
Accumulated depreciation (103) (84)
401 402
Property, plant and equipment, net 16,662 15,866
1 The measurement of weighted average depreciation rate excludes non-depreciable assets.
Depreciation expense, including amounts collected for future removal and site restoration costs, was
$606 million for the year ended December 31, 2021 (2020 - $583 million).
Included within depreciation expense is $22 million in incremental depreciation resulting from push-down accounting for the year ended December 31, 2021 (2020 - $22 million) (Note 2).
8. INTANGIBLE ASSETS
December 31, 2021 2020
(millions of Canadian dollars)
Software and Customer Information System1
Less: Accumulated amortization 515
(338) 654
(480)
Intangible assets, net 177 174
1 The weighted average amortization rate for the years ended December 31, 2021 and 2020 was 12.8% and 11.8%, respectively.
Intangible assets include $26 million of work-in-progress as at December 31, 2021 (2020 - $35 million). Amortization expense for intangible assets for the years ended December 31, 2021 and 2020 was
$71 million and $72 million, respectively. The following table presents our expected amortization expense associated with existing intangible assets for the years indicated as follows:
2022 2023 2024 2025 2026
(millions of Canadian dollars)
Forecast of amortization expense 54 25 20 20 19

9. ACCOUNTS PAYABLE AND OTHER
December 31, 2021 2020

10. DEBT
December 31,

Weighted Average
Interest Rate3 Maturity 2021 2020

(millions of Canadian dollars)
Medium-term notes 3.8% 2022-2051 9,010 8,485
Debentures 9.1% 2024-2025 210 210
Commercial paper and credit facility draws 0.5% 2023 1,515

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

1,121Other1 (49) (47)
Fair value adjustment from push down accounting (Note 2) 307
334Total debt 10,993 10,103
Current maturities (126) (376)
Short-term borrowings2 (1,515) (1,121)
Long-term debt 9,352 8,606
1 Primarily unamortized discounts, premiums and debt issuance costs.
2 Weighted average interest rate - 0.5% (2020 - 0.3%).
3 Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2021.
As at December 31, 2021, all outstanding debt was unsecured.
CREDIT FACILITIES
We actively manage our bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of our external credit facility at December 31, 2021:Total
Maturity Facility Draws2 Available
1 Maturity date is inclusive of the one-year term out provision.
2 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.
On July 23, 2021, we extended the term out date of our 364 day extendible credit facility to July 22, 2022, with a maturity date of July 22, 2023. The credit facility carries a standby fee of 0.1% on the unused portion and the draws bear interest at market rates.
As at December 31, 2021, we have access to Enbridge's demand letter of credit facilities totaling $1.0 billion (2020 - $495 million). As at December 31, 2021, $15 million (2020 - $14 million) of letters of credit were issued by us.
LONG-TERM DEBT ISSUANCES
During the year ended December 31, 2021, we completed the following long-term debt issuances totaling$900 million:

Issue Date
(millions of Canadian dollars)

Principal Amount

September 2021 2.35% medium-term notes due September 2031 $475
September 2021 3.20% medium-term notes due September 2051 $425
LONG-TERM DEBT REPAYMENT
During the year ended December 31, 2021, we completed the following long-term debt repayment totaling$375 million:

Repayment Date
(millions of Canadian dollars)

Principal Amount

May 2021 2.76% medium-term notes $200
December 2021 4.77% medium-term notes $175

DEBT COVENANTS
Our credit facility agreement and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or terminations of the agreements may result if we were to default on payment or violate certain covenants. We were in compliance with all terms and conditions of our committed credit facility agreement and our Trust

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

Indenture as at December 31, 2021.

INTEREST EXPENSE

Year ended December 31,	2021	2020
(millions of Canadian dollars)		
Debentures and term notes	378	380
Commercial paper and credit facility draws	5	17
Interest on loans from affiliate	-	6
Other interest and finance costs	18	14
Capitalized interest	(7)	(5)
	394	412

11. SHARE CAPITAL

As at December 31, 2021, our authorized share capital consisted of an unlimited number of common shares with no par value and an unlimited number of preference shares. Our Class A and Class B common shares are held by Enbridge Energy Distribution Inc. and Great Lakes Basin Energy LP, respectively. Both classes of common shares are identical in every respect, and dividends cannot be paid to one class without paying dividends to the other. As at December 31, 2021 and 2020, no preference shares were issued and outstanding.

COMMON SHARES

2021 2020

December 31,

Number of shares Amount

Number of shares Amount

(millions of Canadian dollars; number of shares in millions)

Class A

Balance at beginning of year Capital contribution

Return of capital

282

-

-

2,636

527

(567)

282

-

-

2,636

432

(432)

282 2,596 282 2,636

Class B

Balance at beginning of year	240	881	240	881
Capital contribution	-	448	-	368
Return of capital	-	(483)	-	(368)
	240	846	240	881
Balance at end of year	522	3,442	522	3,517

The capital contribution and return of capital transactions to the stated capital of Class A and Class B common shares had no impact on the total

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

shares outstanding.
12. COMPONENTS OF AOCI

Changes in AOCI for the year ended December 31, 2021 and 2020 are as follows:
Cash Flow

2021
OPEB

Hedges Adjustment Total
(millions of Canadian dollars)
Balance at January 1, 2021
Other comprehensive income retained in AOCI Other comprehensive loss reclassified to earnings (64)29
17 (14)
31
- (78)
60
17
Tax impact
Income tax on amounts retained in AOCI Income tax on amounts reclassified to earnings (18)
(8)
(5) 17
(9)
- (1)
(17)
(5)
(13) (9) (22)
Balance at December 31, 2021 (31) 8 (23)
2020
Cash Flow
Hedges OPEB
Adjustment
Total
(millions of Canadian dollars)
Balance at January 1, 2020 (42) (4) (46)
Other comprehensive loss retained in AOCI (49) (13) (62)
Other comprehensive loss reclassified to earnings 17 - 17
(74) (17) (91)
Tax impact
Income tax on amounts retained in AOCI 12 3 15
Income tax on amounts reclassified to earnings (2) - (2)
10 3 13
Balance at December 31, 2020 (64) (14) (78)

13. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS
MARKET RISK
Our earnings, cash flows and other OCI are subject to movements in natural gas prices, foreign exchange rates and interest rates (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.
The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

the risks noted below.
Natural Gas Price Risk
Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by our customers. The difference between the actual cost of natural gas purchased and the price approved by the OEB is deferred as a receivable from, or payable to, customers until it is approved for collection or refund. We have a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices, and for the establishment of rate riders required to collect or refund gas cost variances. Adjustments are subject to OEB approval.
Foreign Exchange Risk
Foreign exchange risk is the risk of gain or loss due to the volatility of currency exchange rates. We generate certain revenues, incur expenses and hold cash balances that are denominated in United States dollars (USD). As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from USD exchange rate variability.
We have implemented a policy to hedge a portion of our USD denominated unregulated storage revenue exposures. Qualifying derivative instruments are used to hedge anticipated USD denominated revenues and to manage variability in cash flows.
A portion of our natural gas purchases are denominated in USD and, as a result, there is exposure to fluctuations in the exchange rate of the USD against the Canadian dollar. Realized foreign exchange gains and losses relating to natural gas purchases are passed on to customers, therefore, we have no net exposure to movements in the foreign exchange rate on natural gas purchases.
Interest Rate Risk
Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps are used to hedge against the effect of future interest rate movements. Current floating-to-fixed interest rate swaps with an average swap rate of 2.3% expire in January 2022.
Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have implemented a program to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating-to-fixed interest rate swaps with an average swap rate of 1.4%
TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments.
We generally have a common practice of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce our credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

December 31, 2021

Derivative Instruments Used as Cash Flow Hedges

Non-Qualifying
Derivative Instruments

Total Gross Derivative Instruments as
Presented

Amounts Available for
Offset

Total Net Derivative Instruments

(millions of Canadian dollars)
Deferred amounts and other assets
Interest rate contracts
14
-
14
-
14
14 - 14 - 14
Accounts payable to affiliates
Interest rate contracts
12
-
12
-
12
12 - 12 - 12
Total net derivative asset
Interest rate contracts
26
-
26
-
26
26 - 26 - 26
December 31, 2020 Derivative Instruments Used as Cash
Flow Hedges
Non-Qualifying
Derivative Instruments Total Gross Derivative Instruments as
Presented
Amounts Available for
Offset
Total Net Derivative Instruments
(millions of Canadian dollars)
Deferred amounts and other assets
Interest rate contracts 8 - 8 (1) 7
8 - 8 (1) 7
Accounts payable to affiliates
Interest rate contracts (43) - (43) - (43)
(43) - (43) - (43)
Other long-term liabilities

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

Interest rate contracts (1) - (1) 1 -
(1) - (1) 1 -
Total net derivative liability
Interest rate contracts (36) - (36) - (36)
(36) - (36) - (36)

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.
December 31, 2021 2022 2023 2024 2025 2026 Thereafter
TotalForeign exchange contracts - United
1
18
200
-
- 200
-
-
-
-
-
-
-
-
-
-
-
-
1
18
400
States dollar forwards - sell (millions of
USD)
Interest rate contracts - short-term
borrowings (millions of Canadian dollars)
Interest rate contracts - long-term debt
(millions of Canadian dollars)
The Effect of Derivative Instruments on the Consolidated Statements of
Earnings and Comprehensive Income
The following table presents the effect of cash flow hedges on our consolidated earnings and comprehensive income, before the effect of income taxes.
Year ended December 31, 2021 2020
(millions of Canadian dollars)
Amount of unrealized gain/(loss) recognized in OCI
Interest rate contracts
29
(49)
29 (49)
Amount of loss reclassified from AOCI to earnings
Interest rate contracts1
17
17
17 17
1 Reported within Interest expense, net in the Consolidated Statements of Earnings.
We estimate that a gain of $1 million of AOCI related to unrealized cash flow

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest and foreign exchange rates in effect when derivative contracts, that are currently outstanding, mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 24 months as at December 31, 2021.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments, as they become due. In order to manage this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under the committed credit facility and long-term debt, which includes debentures and medium-term notes and, if necessary, additional liquidity is available through intercompany transactions with our ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable us to fund all anticipated requirements. We maintain a current medium-term note shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. We also maintain a committed credit facility with a diversified group of banks and institutions. We were in compliance with all of the terms and conditions of our committed credit facility as at December 31, 2021. As a result, the credit facility is available to us and the banks are obligated to fund us under the terms of the facility.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. We are primarily exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by our large and diversified customer base and the ability to recover an estimate for expected credit losses for utility operations through the rate-making process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default of receivables. Generally, we classify receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which generally require payment in full within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the expected credit loss, which totaled $55 million as at December 31, 2021 (December 31, 2020 - $45 million). Our expected credit loss is determined based on historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations, using a loss allowance matrix. This estimate is revised each reporting period to reflect current expectations. When we have determined that collection efforts are unlikely to be successful, amounts charged to the expected credit loss account are applied against the impaired accounts receivable.

Entering into derivative financial instruments may also result in exposure to credit risk. We enter into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements. As at December 31, 2021, we have $26 million (December 31, 2020 - $8 million) in credit concentrations and credit

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

exposure with Enbridge and its affiliates.
Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, our non-performance risk is considered in the valuation.
FAIR VALUE MEASUREMENTS
Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair values of financial instruments reflect our best estimates of fair value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.
FAIR VALUE OF FINANCIAL INSTRUMENTS
We categorize our derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.
Level 1
Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. We do not have any derivative instruments classified as Level 1.
Level 2
Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps, for which observable inputs can be obtained.
Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable, or where the observable data does not support a significant portion of the derivative's fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support a Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. We do not have any derivative instruments classified as Level 3.
We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value, including discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, we use observable market prices (interest, foreign exchange and natural gas) and volatility as primary inputs to these valuation

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

techniques. Finally, we consider our own credit default swap spread, as well as the credit default swap spreads associated with our counterparties, in our estimation of fair value.

As at December 31, 2021, we had Level 2 derivative assets with a fair value of $26 million (December 31, 2020 - $8 million) and Level 2 derivative liabilities with a fair value of nil (December 31, 2020 - $44 million).

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. As at December 31, 2021, our long-term debt, including the current portion, had a carrying value of $9.2 billion (December 31, 2020 - $8.7 billion) before debt issuance costs and a fair value adjustment from push down accounting, and a fair value of
$10.4 billion (December 31, 2020 - $10.7 billion).

The fair value of financial assets and liabilities, other than derivative instruments and long-term debt, approximate their carrying value due to the short period to maturity.

14. LEASES

LESSEE

We incur operating lease payments related to natural gas transportation, storage and real estate assets. These lease agreements have remaining lease terms of five months to 16 years, some of which include options to terminate at our discretion.

For the years ended December 31, 2021 and 2020, we incurred operating lease expenses of $8 million and $9 million, respectively. Operating lease expenses are reported within Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2021 and 2020, operating lease payments made to settle lease liabilities were $9 million and $9 million, respectively. Operating lease payments are reported within Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Consolidated Statements of Financial Position Information
December 31, 2021 2020
(millions of Canadian dollars, except lease term and discount rate)
Operating leases
Operating lease right-of-use assets, net1
Operating lease liabilities - current2 Operating lease liabilities - long-term3
49
6
43
53
6
47
Total operating lease liabilities 49 53
Weighted average remaining lease term
Operating leases 8 years 9 years
Weighted average discount rate
Operating leases 3.1% 3.1%

1 Right-of-use assets are reported within Deferred amounts and other assets in the Consolidated Statements of Financial Position.
2 Current lease liabilities are reported within Accounts payable and other and Accounts payable to affiliates in the Consolidated Statements of Financial Position.
3 Long-term lease liabilities are reported within Other long-term liabilities in the Consolidated Statements of Financial Position.

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

As at December 31, 2021, we have lease commitments as detailed below:
Operating leases
(millions of Canadian dollars)
2022 8
2023 7
2024 7
2025 7
2026 6
Thereafter 20
Total undiscounted lease payments 55
Less imputed interest (6)
Total operating lease liabilities 49
LESSOR
We receive revenues from operating and sales-type leases primarily related to natural gas equipment and real estate assets. Our lease agreements have remaining lease terms of five years to 20 years as at December 31, 2021.
As at December 31, 2021, the following table sets out future lease payments to be received under operating lease and sales-type lease contracts where we are the lessor:Operating leases Sales-type leases
(millions of Canadian dollars)
2022 2 1
2023 1 2
2024 1 2
2025 1 2
2026 1 2
Thereafter 2 20
Future lease payments to be received 8 29

15. INCOME TAXES
INCOME TAX RATE RECONCILIATION
Year ended December 31, 2021 2020
(millions of Canadian dollars)
Earnings before income taxes
Canadian federal statutory income tax rate 614
15% 555
15%
Expected federal taxes at statutory rate 92 83
Increase/(decrease) resulting from:
Provincial and state income taxes (1) (13)
Effects of rate-regulated accounting1 (54) (46)
Part VI.1 tax, net of federal Part I deduction1 30 41
Other2 (4) (7)
Income tax expense 63 58
Effective income tax rate 10.3% 10.5%
1 The provincial tax component of these items is included in Provincial and state income taxes above.
2 Includes miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals and entertainment and a change in prior year estimates arising from the filing of tax returns in respect of the prior year.
COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES
Year ended December 31, 2021 2020
(millions of Canadian dollars)
Earnings before income taxes
Canada
614

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

555
614 555
Current income taxes
Canada United States
78
-
84
(1)
78 83
Deferred income taxes
Canada
(15)
(25)
(15) (25)
Income tax expense 63 58

COMPONENTS OF DEFERRED INCOME TAXES
Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:December 31, 2021
2020
(millions of Canadian dollars)
Deferred income tax liabilities
Property, plant and equipment (1,697) (1,586)
Regulatory assets (409) (368)
Deferrals (8) (10)
Pension and OPEB plans (14) (13)
Other (7) (2)
Total deferred income tax liabilities (2,135) (1,979)
Deferred income tax assets
Future removal and site restoration reserves 413 391
Minimum tax credits 44 40
Financial instruments 12 24
Other - 2
Total deferred income tax assets 469 457
Net deferred income tax liabilities (1,666) (1,522)
Enbridge Gas is subject to taxation in Canada. The material jurisdiction in which we are subject to potential examinations is Canada (Federal and Ontario). We are open to examination by Canadian tax authorities for 2012 to 2021 tax years, and are currently under examination for income tax matters in Canada for 2017 to 2018 tax years.
UNRECOGNIZED TAX BENEFITS
Year ended December 31, 2021 2020
(millions of Canadian dollars)
Unrecognized tax benefits at beginning of year
Gross decreases for tax positions of prior year Lapses of statute of limitations 34(16)
(3) 39
(2)
(3)
Unrecognized tax benefits at end of year 15 34
The unrecognized tax benefits as at December 31, 2021, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the years ended December 31, 2021 and 2020 included no amounts of interest and penalties. As at December 31, 2021 and 2020, interest and penalties of nil and $1 million have been accrued.

16. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We provide pension benefits, covering substantially all employees, through contributory and non- contributory registered defined benefit and defined contribution pension plans. We also provide non- registered pension benefits for certain employees through supplemental non-contributory defined benefit pension plans.

Defined Benefit Pension Plan Benefits

Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

Defined Contribution Pension Plan Benefits

Our contributions are based on each plan participant's current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

OTHER POSTRETIREMENT BENEFIT PLANS

We provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees, through unfunded defined benefit OPEB plans.

BENEFIT OBLIGATIONS, PLAN ASSETS AND FUNDED STATUS

The following table details the changes in the benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit pension and OPEB plans:

(millions of Canadian dollars)

Change in benefit obligation				
Benefit obligation at beginning of year	2,532	2,331	186	170
Service cost	63	68	3	3
Interest cost	51	66	4	5
Participant contributions	13	15	-	-
Actuarial (gain)/loss1	(161)	160	(31)	13
Benefits paid	(112)	(108)	(5)	(5)
Benefit obligation at end of year2	2,386	2,532	157	186
Change in plan assets				
Fair value of plan assets at beginning of year	2,219	2,108	-	-
Actual return on plan assets	258	152	-	-
Employer contributions	37	52	5	5
Participant contributions	13	15	-	-
Benefits paid	(112)	(108)	(5)	(5)
Fair value of plan assets at end of year	2,415	2,219	-	-
Overfunded/(underfunded) status at end of year	29	(313)	(157)	(186)

Presented as follows:

Deferred amounts and other assets

164

35

-

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

-
Accounts payable and other (3) (3) (7) (7)
Other long-term liabilities (132) (345) (150) (179)
29 (313) (157) (186)
1 Primarily due to increase in the discount rate used to measure the benefit obligations (2020 - primarily due to decrease in the discount rate used to measure the benefit obligations).
2 For pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. The accumulated benefit obligation for our pension plans was $2.2 billion and
$2.4 billion as at December 31, 2021 and 2020, respectively.

Certain of our pension plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:
December 31, 2021 2020
(millions of Canadian dollars)
Accumulated benefit obligation 253 1,963
Fair value of plan assets 181 1,767
Certain of our pension plans have projected benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligation and fair value of plan assets were as follows:
December 31, 2021 2020
(millions of Canadian dollars)
Projected benefit obligation 895 2,115
Fair value of plan assets 760 1,767
AMOUNT RECOGNIZED IN ACCUMULATED OTHER COMPREHENSIVE INCOME
The amount of pre-tax AOCI relating to our OPEB plans are as follows:
December 31, 2021 2020
(millions of Canadian dollars)
Net actuarial (gain)/loss (13) 18
Total amount recognized in AOCI (13) 18
NET PERIODIC BENEFIT COST AND OTHER AMOUNTS RECOGNIZED IN COMPREHENSIVE INCOME
The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our pension and OPEB plans are as follows:Pension OPEB
Year ended December 31, 2021 2020 2021 2020
(millions of Canadian dollars)
Service cost 63 68 3 3
Interest cost1 51 66 4 5
Expected return on plan assets1 (131) (136) - -
Amortization of net actuarial loss1,2 28 20 - -
Net periodic benefit cost 11 18 7 8
Defined contribution benefit cost 2 2 - -
Net pension and OPEB cost recognized in Earnings
Amount recognized in OCI:
Net actuarial (gain)/loss arising during the year 13
- 20
- 7
(31) 8
13
Total amount recognized in OCI - - (31) 13
Total amount recognized in Comprehensive income 13 20 (24) 21
1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

2   Reflects amortization of net actuarial loss arising from pension plans that are recognized as long-term regulatory assets (Note 5).
ACTUARIAL ASSUMPTIONS
The weighted average assumptions made in the measurement of the benefit obligation and net periodic benefit cost of our defined benefit pension and OPEB plans are as follows:
Benefit obligations
Discount rate   3.2%   2.6%   3.2%   2.6%
Rate of salary increase   2.9%   2.3%   3.0%   2.4%
Net benefit cost
Discount rate   2.6%   3.1%   2.6%   3.1%
Rate of return on plan assets   6.0%   6.5%   N/A   N/A
Rate of salary increase   2.3%   3.2%   2.4%   3.3%
ASSUMED HEALTH CARE COST TREND RATES
The assumed rates for the next year used to measure the expected cost of benefits are as follows:2021   2020
Health care cost trend rate assumed for next year   4.0%   4.0%
Rate to which the cost trend is assumed to decline (ultimate trend rate)
4.0%   4.0%
PLAN ASSETS
We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.
The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.
The asset allocation targets and major categories of plan assets are as follows:Target   December 31,
Asset Category   Allocation   2021   2020
1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the funds.
The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level: 2021   2020
December 31,   Level 11 Level 22 Level 33   Total   Level 11 Level 22 Level 33   Total
(millions of Canadian dollars) Cash and cash equivalents Equity securities
Canada Global
Fixed income securities Government Corporate
Alternatives4
Forward currency contracts   42   -   -
42   50   -   -
50

110	123	-	233	103	111	-	214
-	853	-	853	-	813	-	813
141	294	-	435	125	249	-	374
-	300	-	300	-	284	-	284
-	-	552	552	-	-	466	466
-	-	-	-	-	18	-	18

Total pension plan assets at fair value   293   1,570   552   2,415

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

278 1,475 466 2,219

1 Level 1 assets include assets with quoted prices in active markets for identical assets.

2 Level 2 assets include assets with significant observable inputs.

3 Level 3 assets include assets with significant unobservable inputs.

4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:December 31, 2021 2020

(millions of Canadian dollars)

Balance at beginning of year Unrealized and realized gains/(losses)

Purchases and settlements, net 466

49

37 427

(3)

42

Balance at end of year 552 466

EXPECTED BENEFIT PAYMENTS

Year ending December 31, 2022 2023 2024 2025 2026

2027-2031(millions of Canadian dollars)

Pension 113 115 117 119 120 628

OPEB 7 7 7 7 7 38

EXPECTED EMPLOYER CONTRIBUTIONS

In 2022, we expect to contribute approximately $41 million and $7 million to the pension plans and OPEB plans, respectively.

For the year ended December 31, 2020, we incurred $74 million in severance costs related to Enbridge's voluntary workforce reduction program. For the year ended December 31, 2021, there were no such costs incurred. Severance costs are presented in Operating and administrative expense in the Consolidated Statements of Earnings.

17. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31, 2021 2020

(millions of Canadian dollars)

Accounts receivable and other (14) 50

Accounts receivable from affiliates (27) (46)

Regulatory assets (222) 156

Gas inventory (242) (39)

Deferred amounts and other assets (2) 10

Accounts payable and other 196 (55)

Accounts payable to affiliates (4) (40)

Regulatory liabilities (140) 54

Other long-term liabilities (18) (12)

(473) 78

18. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. Affiliates refer to Enbridge and companies that are either directly or indirectly owned by Enbridge.

Enbridge and its affiliates perform centralized corporate functions for us pursuant to applicable agreements, including legal, accounting, compliance, treasury, employee benefits, information technology and other areas, as well as certain engineering and other services. We reimburse Enbridge for the expenses incurred to provide these services as well as for other expenses incurred on our behalf. In addition, we perform services and incur expenses on behalf of our affiliates, which are subsequently reimbursed. Our expenses

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

and recoveries for these services are recorded in Operating and administrative expense in the Consolidated Statements of Earnings, and are based on the cost of actual services provided or using various allocation methodologies.

Our transactions with entities related through common or joint control and significantly influenced investees are as follows:

Year ended December 31, 2021

Operating revenues

Gas commodity and distribution costs

Operating and administrative expense

Other Income

Interest income

(millions of Canadian dollars)
Enbridge Inc. - - 153 5 2
Tidal Energy Marketing Inc. 18 16 - - -
Tidal Energy Marketing (U.S.) LLC - 31 - - -
Gazifère Inc. 30 - - - -
Énergir, L.P.1 35 - - - -
Vector Pipeline, L.P. - 20 - - -
NEXUS Gas Transmission, LLC - 111 - - -
Lakeside Performance Gas Services Ltd. - - 19 - -
Other affiliates, net 2 3 9 - -
1 The minority interest in the parent of Energir L.P. held by a subsidiary of Enbridge was sold on December 30, 2021.

Operating

Gas commodity and distribution

Operating and administrative

Other

Interest income/

Year ended December 31, 2020 revenues costs expense Income (expense)(millions of Canadian dollars)
Enbridge Inc. - - 131 6 14
Westcoast Energy Inc. - - - - (6)
Tidal Energy Marketing Inc. 11 13 - - -
Tidal Energy Marketing (U.S.) LLC - 18 - - -
Gazifère Inc. 26 - - - -
Énergir, L.P. 37 - - - -
Vector Pipeline, L.P. - 19 - - -
NEXUS Gas Transmission, LLC - 116 - - -
Other affiliates, net 2 3 7 - -
Amounts due from/(to) related parties are as follows:

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

December 31,	2021	2020
(millions of Canadian dollars)		
Enbridge Employee Services Canada Inc.	(61)	(38)
NEXUS Gas Transmission, LLC	(9)	(10)
Enbridge Pipelines Inc.	35	45
Union Energy Solutions Limited Partnership	28	29
Gazifère Inc.	25	6
Tidal Energy Marketing Inc.3	19	-
Enbridge Inc.1	18	(68)
Other affiliates, net2,3	-	1
	55	(35)

1 Includes net qualifying interest cash flow hedges receivable and net derivative receivable balances from affiliate.
2 Includes current portion of operating lease liabilities to affiliates.
3 Includes affiliate gas imbalance receivable. As at December 31, 2021 total affiliate gas imbalance receivable was $23 million (2020 - nil).

SHARE CAPITAL

During the year ended December 31, 2021, common share dividends declared on our Class A and Class B common shares were $108 million (2020 - $243 million) and $92 million (2020 - $207 million), respectively. During 2020, we also completed the return of capital transactions, and received capital contributions, as described in Note 11 - Share Capital.

FINANCING TRANSACTION

On April 1, 2020, we repaid the outstanding $650 million subordinated promissory note, as well as the related interest payable, due to Westcoast Energy Inc.

GAS METER SERVICES

We purchase gas meter services from Lakeside Performance Gas Services Ltd. (Lakeside), such as ongoing meter exchanges and inspections for customers in our franchise area. As of December 1, 2020, Lakeside became an affiliate. In 2021, we purchased gas meter services from Lakeside totaling $52 million, a portion of which was expensed to Operating and administrative expense and the remainder capitalized in Property, plant and equipment. We will continue purchasing these services at prevailing market prices under normal trade terms.

HYDRO EXCAVATION SERVICES

We purchase hydro excavation and specialty gas services from Ontario Excavac Inc. (OE). As of July 31, 2021, OE became an affiliate. We will continue purchasing these services at prevailing market prices under normal trade terms.

WHOLESALE SERVICES

We provide gas procurement and transportation services to Gazifère Inc., an affiliate, pursuant to a contract negotiated between us and approved by the OEB and Régie de l'énergie.

LEASES

We incur operating lease payments related to natural gas transportation and storage services from various affiliates. Total affiliate right-of-use assets and lease liabilities as at December 31, 2021 were
$48 million (2020 - $51 million) and $48 million (2020 - $51 million), respectively. See Note 14 - Leasesfor further discussion.

DERIVATIVE INSTRUMENTS

As at December 31, 2021, we had a net receivable balance of $26 million (2020 - $36 million payable) due from Enbridge in respect of derivative instruments that they have entered into on our behalf. See Note 13 - Risk Management and Financial Instruments for further discussion.

OTHER

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

Our cash balances are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

19. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2021, we have commitments as detailed below:

Less than
Total 1 year 2 years 3 years 4 years 5 years
Thereafter(millions of Canadian dollars)
Annual debt maturities1 9,220 125 350 300 745 650
7,050
Interest obligations2 5,681 370 367 351 336 300
3,957
Purchase of services, pipe and other materials, including transportation3,4
6,050
1,998
757
525
473
437
1,860
Right-of-way commitments5 668 11 11 11 11 11 613
Total 21,619 2,504 1,485 1,187 1,565 1,398 13,480

1 Includes debentures and term notes, and excludes short-term borrowings, debt discounts, debt issuance costs, finance lease obligations and the fair value adjustment from push-down accounting. Changes to the planned funding requirements are dependent on the terms of any debt refinancing agreements. Therefore, the actual timing of future cash repayments could be materially different than presented above.

2 Includes debentures and term notes bearing interest at fixed rates.

3 Includes firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; and customer care services.

4 Includes capital and operating commitments.

5 Includes right-of-way payments related to cancellable gas storage payments that are reasonably likely to occur for the remaining life of all storage reservoirs.

ENVIRONMENTAL

We are subject to various federal, provincial and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to natural gas pipeline operations, and we are, at times, subject to environmental remediation at various contaminated sites. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with our operating activities.

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. We were named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by us for the operation of our MGP.

While these Statements of Claim were filed by the City and the School Board, they were never formally served on us. It was and remains our understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences.

Rather than litigate, we entered into an agreement with the City (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with us. To our knowledge, neither the City nor the School Board has taken any steps to advance the lawsuits.

Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time, as there are a number of potential alternative remediation, isolation and containment approaches which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the US for the recovery in rates of costs relating to the remediation of former MGP sites. From 2006 to 2018, the OEB approved the establishment of deferral accounts to record the costs of investigating, defending and dealing with ongoing MGP-related claims. We expect that if it is found that we must contribute to any remediation costs, either as a result of a lawsuit or government order, we may be generally allowed to recover in rates those substantial costs not recovered through insurance or by other means. Accordingly, we believe that the ultimate outcome of these matters will not have a significant impact on our financial position.

Hamilton Contaminated Site

In April 2016, the Ontario Ministry of the Environment, Conservation and Parks (MECP), formerly the Ministry of the Environment and Climate Change, issued a Director's Order (the Order) naming us, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of ours in Hamilton. In May 2016, we appealed the Order, and in June 2016, the Environmental Review Tribunal (the Tribunal), on consent of the MECP's Director, stayed the application of parts of the Order. The Tribunal extended the stay of the Order several times, which allowed the owner of the property, with the cooperation of the adjacent owners, to prepare a plan of action, including discussions with the MECP and other neighbors. On February 4, 2021, the MECP determined that we and other parties have complied with the Order and no further obligations are outstanding. Accordingly, we withdrew our appeal, and the Tribunal has accepted the withdrawal and has closed its file.

OTHER LITIGATION

We are subject to various legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

TAX MATTERS

We maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

General Index of Financial Information

Notes to the financial statements

20. GUARANTEES

In the normal course of conducting business, we may enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries, jointly owned entities, unconsolidated entities such as equity method investees, or entities with other ownership arrangements that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included in our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases.

We typically enter into these arrangements to facilitate commercial transactions with third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2021, guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- Use this schedule to reconcile the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 Corporation – Income Tax Guide.
- All legislative references are to the Income Tax Act.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			550,814,000	A
Add:				
Provision for income taxes – current	101	77,525,000		
Provision for income taxes – deferred	102	-14,578,000		
Amortization of tangible assets	104	676,834,000		
Charitable donations and gifts from Schedule 2	112	2,559,673		
Scientific research expenditures deducted per financial statements	118	1,400,674		
Non-deductible meals and entertainment expenses	121	254,763		
Non-deductible company pension plans	124	30,135,912		
Reserves from financial statements – balance at the end of the year	126	202,351		
Subtotal of additions		774,334,373	774,334,373	
Add:				
Debt issue expense	208	4,005,578		

Other additions:

	1 Description 605	2 Amount 295
1	GST ON NON-DEDUCTIBLE EXPENSES	28,366
2	DEFERRAL ACCOUNT- ADDITION	9,967,449
3	Book loss from QET	5,951
4	Amortization ACDA	12,033,400
5	2021 Co-op Tax Credit	125,400
6	Capital Sales Lease Back	562,233
	Total of column 2	22,722,799

Total of column 2	296	22,722,799		
Subtotal of other additions	199	26,728,377	26,728,377	D
Total additions	500	801,062,750	801,062,750	
Amount A **plus** line 500			1,351,876,750	B
Deduct:				
Gain on disposal of assets per financial statements	401	32,681		
Capital cost allowance from Schedule 8	403	857,929,276		
SR&ED expenditures claimed in the year on line 460 from Form T661	411	601,454		
Reserves from financial statements – balance at the beginning of the year	414	6,369,524		
Contributions to deferred income plans from Schedule 15	417	45,625,809		
Subtotal of deductions		910,558,744	910,558,744	
Deduct:				
Canadian development expenses from Schedule 12	340	154,873		
Canadian oil and gas property expenses from Schedule 12	342	81,211		

Other deductions:

	1 Description 705	2 Amount 395
1	PAYMENT OUT OF THE EBP PLAN	364,250

	1 Description 705	2 Amount 395
2	COST OF CUTTING OFF INACTIVE SERVICES & MAINS	58,667,763
3	AMORTIZATION OF DEBT ISSUE COSTS & DISCOUNTS	4,352,665
4	ALBION EASEMENT DEDUCTION	6,982
5	Overhead capitalized for regulatory purposes	87,203,434
6	Interest under construction capitalized for regulatory purpo	6,652,860
7	Expenses in NBV (Small items: fencing,landscaping)	86,894
8	Stock based compensation	0
9	Income allocation from QET	5,042
10	Part V1.1 tax reimbrusement	4,636,296
11	Non-deductible Interest	359,146
	Total of column 2	162,335,332

Total of column 2	396	162,335,332	
Subtotal of other deductions	499	162,571,416	162,571,416 E
Total deductions	510	1,073,130,160	1,073,130,160

Net income (loss) for income tax purposes (amount B **minus** line 510) . . . . 278,746,590 C
Enter amount C on line 300 of the T2 return.

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Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees
  - the Ontario, Nova Scotia, and British Columbia food donation tax credits for farmers
  - the eligible amount of gifts of certified cultural property
  - the eligible amount of gifts of certified ecologically sensitive land or
  - the additional deduction for gifts of medicine made before March 22, 2017
- All legislative references are to the federal Income Tax Act, unless stated otherwise.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts can be carried forward for 5 years except for gifts of certified ecologically sensitive land made after February 10, 2014, which can be carried forward for 10 years.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1).
- Subsection 110.1(1.2) provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift made before March 22, 2017, to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File this schedule with your T2 Corporation Income Tax Return.
- For more information, see the T2 Corporation – Income Tax Guide.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
AVAILABLE UPON REQUEST	2,559,673
Subtotal	2,559,673
Add: Total donations of less than $100 each	
Total donations in current tax year	2,559,673

Part 1 – Charitable donations

	Line	Federal		Québec	Alberta
Charitable donations at the end of the previous tax year		751,672	1A	751,672	751,672
Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year (amount 1A **minus** line 239)	240	751,672		751,672	751,672
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year (include this amount on line 112 of Schedule 1, Net Income (Loss) for Income Tax Purposes)	210	2,559,673		2,559,673	2,559,673
Subtotal (line 250 **plus** line 210)		2,559,673	1B	2,559,673	2,559,673
Subtotal (line 240 **plus** amount 1B)		3,311,345	1C	3,311,345	3,311,345
Adjustment for an acquisition of control	255				
Total charitable donations available (amount 1C **minus** line 255)		3,311,345	1D	3,311,345	3,311,345
Amount applied in the current year against taxable income (cannot be more than amount 2H in Part 2) (enter this amount on line 311 of the T2 return)	260	3,311,345		3,311,345	3,311,345
Charitable donations closing balance (amount 1D **minus** line 260)	280				

The amount of qualifying donations for the Ontario community food program donation tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2013) . . . **262** ________

Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %) . . . ________ 1

Enter amount 1 on line 420 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Ontario income tax otherwise payable or amount 1. For more information, see section 103.1.2 of the Taxation Act, 2007 (Ontario).

The amount of qualifying donations for the Nova Scotia food bank tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2015) . . . **263** ________

Nova Scotia food bank tax credit for farmers (amount on line 263 **multiplied** by 25 %) . . . ________ 2

Enter amount 2 on line 570 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Nova Scotia income tax otherwise payable or amount 2. For more information, see section 50A of the Nova Scotia Income Tax Act.

The amount of qualifying gifts for the British Columbia farmers' food donation tax credit included in the amount on line 260 (for donations made after February 16, 2016, and before January 1, 2024) . . . **265** ________

British Columbia farmers' food donation tax credit (amount on line 265 **multiplied** by 25 %) . . . ________ 3

Enter amount 3 on line 683 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the British Columbia income tax otherwise payable or amount 3. For more information, see section 20.1 of the British Columbia Income Tax Act.

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2020-12-31	751,672	751,672	751,672
2nd prior year	2019-12-31			
3rd prior year	2018-12-31			
4th prior year	2017-12-31			
5th prior year	2016-12-31			
6th prior year*	2015-12-31			
7th prior year	2014-12-31			
8th prior year	2013-12-31			
9th prior year	2012-12-31			
10th prior year	2011-12-31			
11th prior year	2010-12-31			
12th prior year	2009-12-31			
13th prior year	2008-12-31			
14th prior year	2007-12-31			
15th prior year	2006-12-31			
16th prior year	2006-09-30			
17th prior year	2005-09-30			
18th prior year	2004-09-30			
19th prior year	2003-09-30			
20th prior year	2002-09-30			
21st prior year*	2001-09-30			
Total (to line A)		751,672	751,672	751,672

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes Note 1 **multiplied** by 75 %				209,059,943 2A
Taxable capital gains arising in respect of gifts of capital property included in Part 1 Note 2		225		
Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01)		227		
The amount of the recapture of capital cost allowance in respect of charitable donations	230			
Proceeds of disposition, **less** outlays and expenses Note 2	2B			
Capital cost Note 2	2C			
Amount 2B or 2C, whichever is less	235			
Amount on line 230 or 235, whichever is less			2D	
Subtotal (**add** lines 225, 227, and amount 2D)			2E	
Amount 2E **multiplied** by 25 %				2F
Subtotal (amount 2A **plus** amount 2F)				209,059,943 2G
Maximum allowable deduction for charitable donations (enter amount 1D from Part 1, amount 2G, or net income for tax purposes, whichever is the least)				3,311,345 2H

Note 1: For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

Note 2: This amount must be prorated by the following calculation, eligible amount of the gift **divided** by the proceeds of disposition of the gift.

Part 3 – Gifts of certified cultural property

	Line	Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			3A		
Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year (amount 3A **minus** line 439)	440				
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450				
Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1)	410				
Subtotal (line 450 **plus** line 410)			3B		
Subtotal (line 440 **plus** amount 3B)			3C		
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			3D		
Gifts of certified cultural property closing balance (amount 3C **minus** amount 3D)	480				

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2020-12-31			
2nd prior year	2019-12-31			
3rd prior year	2018-12-31			
4th prior year	2017-12-31			
5th prior year	2016-12-31			
6th prior year*	2015-12-31			
7th prior year	2014-12-31			
8th prior year	2013-12-31			
9th prior year	2012-12-31			
10th prior year	2011-12-31			
11th prior year	2010-12-31			
12th prior year	2009-12-31			
13th prior year	2008-12-31			
14th prior year	2007-12-31			
15th prior year	2006-12-31			
16th prior year	2006-09-30			
17th prior year	2005-09-30			
18th prior year	2004-09-30			
19th prior year	2003-09-30			
20th prior year	2002-09-30			
21st prior year*	2001-09-30			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 4 – Gifts of certified ecologically sensitive land

	Line	Federal	Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year	4A			
Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539			
Gifts of certified ecologically sensitive land at the beginning of the current tax year (amount 4A **minus** line 539)	540			
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land (include this amount on line 112 of Schedule 1)	520			
Subtotal (line 550 **plus** line 520)	4B			
Subtotal (line 540 **plus** amount 4B)	4C			
Adjustment for an acquisition of control	555			
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560			
Subtotal (line 555 **plus** line 560)	4D			
Gifts of certified ecologically sensitive land closing balance (amount 4C **minus** amount 4D)	580			

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donation and gifts expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date . . . .

Alberta

Year of origin:		Federal	Québec	Alberta
1st prior year	2020-12-31			
2nd prior year	2019-12-31			
3rd prior year	2018-12-31			
4th prior year	2017-12-31			
5th prior year	2016-12-31			
6th prior year*	2015-12-31			
7th prior year	2014-12-31			
8th prior year	2013-12-31			
9th prior year	2012-12-31			
10th prior year	2011-12-31			
11th prior year*	2010-12-31			
12th prior year	2009-12-31			
13th prior year	2008-12-31			
14th prior year	2007-12-31			
15th prior year	2006-12-31			
16th prior year	2006-09-30			
17th prior year	2005-09-30			
18th prior year	2004-09-30			
19th prior year	2003-09-30			
20th prior year	2002-09-30			
21st prior year*	2001-09-30			
Total				

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, that are included on line *6th prior year* and gifts that are included on line *11th prior year* expire automatically in the current year.

The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to distinguish the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years, from the portion that expires in the current tax year.

For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, that are included on line *6th prior year* and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 5 – Additional deduction for gifts of medicine

	Line	Federal		Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year			5A		
Additional deduction for gifts of medicine expired after five tax years*	639				
Additional deduction for gifts of medicine at the beginning of the current tax year (amount 5A **minus** line 639)	640				
Additional deduction for gifts of medicine made before March 22, 2017 transferred on an amalgamation or the wind-up of a subsidiary	650				
Additional deduction for gifts of medicine made before March 22, 2017:					
Proceeds of disposition	602				
Cost of gifts of medicine made before March 22, 2017	601				
Subtotal (line 602 **minus** line 601)			5B		
Amount 5B **multiplied** by 50 %			5C		
Eligible amount of gifts	600				

Federal

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 **610** ______

Québec

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 ______

Alberta

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 ______

where:

a is the **lesser** of line 601 and amount 5C

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

	Line	Federal		Québec	Alberta
Subtotal (line 650 **plus** line 610)			5D		
Subtotal (line 640 **plus** amount 5D)			5E		
Adjustment for an acquisition of control	655				
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660				
Subtotal (line 655 **plus** line 660)			5F		
Additional deduction for gifts of medicine closing balance (amount 5E **minus** amount 5F)	680				

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2020-12-31			
2nd prior year	2019-12-31			
3rd prior year	2018-12-31			
4th prior year	2017-12-31			
5th prior year	2016-12-31			
6th prior year*	2015-12-31			
7th prior year	2014-12-31			
8th prior year	2013-12-31			
9th prior year	2012-12-31			
10th prior year	2011-12-31			
11th prior year	2010-12-31			
12th prior year	2009-12-31			
13th prior year	2008-12-31			
14th prior year	2007-12-31			
15th prior year	2006-12-31			
16th prior year	2006-09-30			
17th prior year	2005-09-30			
18th prior year	2004-09-30			
19th prior year	2003-09-30			
20th prior year	2002-09-30			
21st prior year*	2001-09-30			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income (enter this amount on line 255 of form CO-17)		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2020-12-31	
2nd prior year	2019-12-31	
3rd prior year	2018-12-31	
4th prior year	2017-12-31	
5th prior year	2016-12-31	
6th prior year*	2015-12-31	
7th prior year	2014-12-31	
8th prior year	2013-12-31	
9th prior year	2012-12-31	
10th prior year	2011-12-31	
11th prior year	2010-12-31	
12th prior year	2009-12-31	
13th prior year	2008-12-31	
14th prior year	2007-12-31	
15th prior year	2006-12-31	
16th prior year	2006-09-30	
17th prior year	2005-09-30	
18th prior year	2004-09-30	
19th prior year	2003-09-30	
20th prior year	2002-09-30	
21st prior year*	2001-09-30	
Total		

* These gifts expired in the current year.

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Schedule 3

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83
  - deductible dividends under subsection 138(6)
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (a.1), (b) or (d)
  - taxable dividends paid in the tax year that qualify for a dividend refund (see page 3)
- All legislative references are to the federal Income Tax Act.
- The calculations in this schedule apply only to private or subject corporations (as defined in subsection 186(3)).
- A payer corporation is **connected** with a recipient corporation at any time in a tax year, if at that time the recipient corporation meets either of the following conditions:
  - it controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b)
  - it owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation
- If you need more space, continue on a separate schedule.
- File this schedule with your T2 Corporation Income Tax Return.
- Column A1 – Enter "X" if dividends were received from a foreign source.
  Column F1 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H, I, I.1 and L **only if** the payer corporation is **connected.**

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing columns J, K and L use the **special calculations provided in the notes**.

	A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYYMMDD 220	E Non-taxable dividends under section 83 230
1	IPL SYSTEM INC.		1	89641 7342 RC0001	2021-12-31	
					Total of column E (enter amount on line 402 of Schedule 1)	

Part 1 – Dividends received in the tax year (continued)

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1),(b), or (d)note 1 **240**	F1	G Eligible dividends included in column F **242**	H Total taxable dividends paid by **connected** payer corporation (for tax year in column D) **250**
1				

	I Dividend refund of the **connected** payer corporation (for tax year in column D)note 2 **260**	I.1 Dividend refund of the **connected** payer corporation from its eligible refundable dividend tax on hand (ERDTOH) (for tax year in column D) notes 2 and 5	J Part IV tax for eligible dividends. Dividends (from column G) **multiplied** by 38 1/3%note 3 **265**	K Part IV tax before deductions. Dividends (from column F) **multiplied** by 38 1/3%note 4 **275**	L Part IV tax before deductions on taxable dividends received from **connected** corporations notes 2 and 5 **280**
1					

Total of column L (enter amount on line 2E in Part 2)

Taxable dividends received from connected corporations (total amounts from column F with code 1 in column B) . . . . ______ 1A

Taxable dividends received from non-connected corporations (total amounts from column F with code 2 in column B) . . . . ______ 1B

Subtotal (amount 1A **plus** amount 1B, include this amount on line 320 of the T2 return) ______ 1C

Eligible dividends received from connected corporations (total amounts from column G with code 1 in column B) . . . . ______ 1D

Eligible dividends received from non-connected corporations (total amounts from column G with code 2 in column B) . . . . ______ 1E

Part IV tax before deductions on taxable dividends received from connected corporations (total amounts from column K with code 1 in column B) . . . . ______ 1F

Part IV tax before deductions on taxable dividends received from non-connected corporations (total amounts from column K with code 2 in column B) . . . . ______ 1G

Subtotal (amount 1F **plus** amount 1G) ______ ▶ ______ 1H

Part IV tax on eligible dividends received from connected corporations (total amounts from column J with code 1 in column B) . . . . ______ 1I

Part IV tax on eligible dividends received from non-connected corporations (total amounts from column J with code 2 in column B) . . . . ______ 1J

Subtotal (amount 1I **plus** amount 1J) ______ ▶ ______ 1K

Part IV tax before deductions on taxable dividends (other than eligible dividends) (amount 1H **minus** amount 1K) . . . . ______ 1L

1 If taxable dividends are received, enter the amount in column F, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column K (and column J, if applicable). Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable. For column L, you only have to estimate the payer's dividend refund from its eligible refundable dividend tax on hand (ERDTOH) (column I.1).

3 For eligible dividends received from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by column G.

4 For taxable dividends received from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by column F.

5 For taxable dividends received from connected corporations (with a tax year starting after 2018), Part IV tax on dividends is equal to: total of amounts CC and II of the connected payer corporation (on page 7 of the T2 return) divided by column H multiplied by column F. If there is no dividend refund (or estimated dividend refund) to the connected payer corporation from its ERDTOH for paying the taxable dividends, enter "0" in column L.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received before deductions (amount 1H in part 1) . . . . ____ 2A

Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43) . . . . . **320** ____

Subtotal (amount 2A **minus** line 320) ____ ▶ ____ 2B

Current-year non-capital loss claimed to reduce Part IV tax . . . . **330** ____

Non-capital losses from previous years claimed to reduce Part IV tax . . . . **335** ____

Current-year farm loss claimed to reduce Part IV tax . . . . **340** ____

Farm losses from previous years claimed to reduce Part IV tax . . . . **345** ____

Total losses applied against Part IV tax (total of lines 330 to 345) ____ 2C

Amount 2C **multiplied** by 38 1 / 3 % . . . . ____ 2D

Part IV tax payable (amount 2B **minus** amount 2D, if negative enter "0") . . . . **360** ____

(enter amount on line 712 of the T2 return)

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

Part IV tax before deductions on taxable dividends received from connected corporations (total of column L in part 1) . . . . ____ 2E

Amount 4A from Schedule 43 . . . . ____ 2F

Part IV tax payable on taxable dividends received from connected corporations (amount 2E **minus** amount 2F, if negative enter "0") . . . . ____ 2G

(enter at amount L on page 7 of the T2 return)

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

Part IV tax on eligible dividends received from non-connected corporations (amount 1J in part 1) . . . . ____ 2H

Amount 4C from Schedule 43 . . . . ____ 2I

Part IV tax payable on eligible dividends received from non-connected corporations (amount 2H **minus** amount 2I, if negative enter "0") . . . . ____ 2J

(enter at amount M on page 7 of the T2 return)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the recipient corporation with which you are connected, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	L Name of recipient corporation with which you are connected **400**	M Business number **410**	N Tax year-end of recipient corporation in which the dividends in column O were received YYYYMMDD **420**	O Taxable dividends paid to recipient corporations with which you are connected **430**	P Eligible dividends included in column O **440**
1	ENBRIDGE ENERGY DISTRIBUTION INC.	89641 6948 RC0001	2021-12-31	108,020,000	
2	GREAT LAKES BASIN ENERGY LP	80581 5461 RC0001	2021-12-31	91,980,000	
				200,000,000 (Total of column O)	(Total of column P)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund (continued)

Total taxable dividends paid in the tax year to other than connected corporations		450	
Eligible dividends included in line 450	455		
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column O **plus** line 450)		460	200,000,000
Total eligible dividends paid in the tax year (total of column P **plus** line 455)		465	
Total non-eligible taxable dividends paid in the tax year (line 460 **minus** line 465)		470	200,000,000

Complete this part to determine the following amounts in order to calculate the dividend refund.

Line 465 **multiplied** by 38 1 / 3 % (enter at amount AA on page 7 of the T2 return)		3A
Line 470 **multiplied** by 38 1 / 3 % (enter at amount DD on page 7 of the T2 return)	76,666,667	3B

Part 4 – Total dividends paid in the tax year

Complete this part **if** the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			200,000,000	
Other dividends paid in the tax year (total of 510 to 540)				
Total dividends paid in the tax year		500	200,000,000	
Dividends paid out of capital dividend account	510			
Capital gains dividends	520			
Dividends paid on shares described in subsection 129(1.2)	530			
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540			
Subtotal (total of lines 510 to 540)		►		4A
Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount 4A)			200,000,000	4B

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Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the federal Income Tax Act, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the T2 Corporation – Income Tax Guide.
- File this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the federal Income Tax Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes			278,746,590	1A
Net capital losses deducted in the year (enter as a positive amount)		1B		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)		1C		
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)	223,821,161	1D		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		1E		
Employer deduction for non-qualified securities – Paragraph 110(1)(e)		1F		
Subtotal (total of amounts 1B to 1F)	223,821,161	▶	223,821,161	1G
Subtotal (amount 1A **minus** amount 1G; if positive, enter "0"				1H
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions				1I
Subtotal (amount 1H **minus** amount 1I)				1J
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)				1K
Current-year non-capital loss (amount 1J **plus** amount 1K; if positive, enter "0") If amount 1L is negative, enter it on line 110 as a positive.				1L

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year		1M		
Non-capital loss expired **(note 1)**	100			
Non-capital losses at the beginning of the tax year (amount 1M **minus** line 100)	102		▶	
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary **(note 2)** corporation	105			
Current-year non-capital loss (from amount 1L)	110			
Subtotal (line 105 **plus** line 110)			▶	1N
Subtotal (line 102 **plus** amount 1N)				1O

Note 1: A non-capital loss expires after **20 tax years** and an allowable business investment loss becomes a net capital loss after **10 tax years**.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Other adjustments (includes adjustments for an acquisition of control)	150			
Section 80 – Adjustments for forgiven amounts	140			
Subsection 111(10) – Adjustments for fuel tax rebate				
Non-capital losses of previous tax years applied in the current tax year Enter line 130 on line 331 of the T2 return.	130			
Current and previous years non-capital losses applied against current-year taxable dividends subject to Part IV tax **(note 3)**	135			
Subtotal (total of lines 150, 140, 130 and 135)			▶	1P
Non-capital losses before any request for a carryback (amount 1O **minus** amount 1P)				1Q

Request to carry back non-capital loss to:

First previous tax year to reduce taxable income	901			
Second previous tax year to reduce taxable income	902			
Third previous tax year to reduce taxable income	903			
First previous tax year to reduce taxable dividends subject to Part IV tax	911			
Second previous tax year to reduce taxable dividends subject to Part IV tax	912			
Third previous tax year to reduce taxable dividends subject to Part IV tax	913			
Total of requests to carry back non-capital losses to previous tax years (total of lines 901 to 913)			▶	1R
Closing balance of non-capital losses to be carried forward to future tax years (amount 1Q **minus** amount 1R)			180	

Note 3: Line 135 is the total of lines 330 and 335 from Schedule 3, Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200			
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205			
Subtotal (line 200 **plus** line 205)			▶	2A
Other adjustments (includes adjustments for an acquisition of control)	250			
Section 80 – Adjustments for forgiven amounts	240			
Subtotal (line 250 **plus** line 240)			▶	2B
Subtotal (amount 2A **minus** amount 2B)				2C
Current-year capital loss (from the calculation on Schedule 6, Summary of Dispositions of Capital Property)			210	
Unused non-capital losses from the 11th previous tax year **(note 4)**			2D	
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year **(note 5)**			2E	
Enter amount 2D or 2E, whichever is less	215			
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000			220	
Subtotal (amount 2C **plus** line 210 **plus** line 220)				2F

Note
If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220.

Note 4: Determine the amount of the non-capital loss from the **11th previous tax year**, and enter the part of the non-capital loss that was not deducted in the previous 11 years.

Note 5: Enter the amount of the ABILs from the **11th previous tax year**. Enter the full amount on amount 2E.

Part 2 – Capital losses (continued)

Capital losses from previous tax years applied against the current-year net capital gain **(note 6)**			225		
Capital losses before any request for a carryback (amount 2F **minus** line 225)					2G

Request to carry back capital loss to (note 7):

	Capital gain (100%)		Amount carried back (100%)		
First previous tax year		951			
Second previous tax year	15,805,947	952			
Third previous tax year		953			
Subtotal (total of lines 951 to 953)				▶	2H
Closing balance of capital losses to be carried forward to future tax years (amount 2G **minus** amount 2H) **(note 8)**				280	

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current tax year, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **divide** this amount by 2. The result represents the 50% inclusion rate.

Note 8: Capital losses can be carried forward indefinitely.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year		3A		
Farm loss expired **(note 9)**	300			
Farm losses at the beginning of the tax year (amount 3A **minus** line 300)	302		▶	
Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation	305			
Current-year farm loss (amount 1K in Part 1)	310			
Subtotal (line 305 **plus** line 310)			▶	3B
Subtotal (line 302 **plus** amount 3B)				3C
Other adjustments (includes adjustments for an acquisition of control)	350			
Section 80 – Adjustments for forgiven amounts	340			
Farm losses of previous tax years applied in the current tax year Enter line 330 on line 334 of the T2 Return.	330			
Current and previous years farm losses applied against current-year taxable dividends subject to Part IV tax **(note 10)**	335			
Subtotal (total of lines 350, 340, 330 and 335)			▶	3D
Farm losses before any request for a carryback (amount 3C **minus** amount 3D)				3E

Request to carry back farm loss to:

First previous tax year to reduce taxable income	921			
Second previous tax year to reduce taxable income	922			
Third previous tax year to reduce taxable income	923			
First previous tax year to reduce taxable dividends subject to Part IV tax	931			
Second previous tax year to reduce taxable dividends subject to Part IV tax	932			
Third previous tax year to reduce taxable dividends subject to Part IV tax	933			
Subtotal (total of lines 921 to 933)			▶	3F
Closing balance of farm losses to be carried forward to future tax years (amount 3E **minus** amount 3F)			380	

Note 9: A farm loss expires after **20 tax years**.

Note 10: Line 335 is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business			485		
(line 485 ______ – $2,500) **divided** by 2		4A			
Amount 4A or $ 15,000 , whichever is less		▶		4B	
			2,500	4C	
Subtotal (amount 4B **plus** amount 4C)			2,500 ▶	2,500	4D
Current-year restricted farm loss (line 485 **minus** amount 4D)					4E

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			4F		
Restricted farm loss expired **(note 11)**	400				
Restricted farm losses at the beginning of the tax year (amount 4F **minus** line 400)	402		▶		
Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	405				
Current-year restricted farm loss (from amount 4E)	410				
Enter line 410 on line 233 of Schedule 1, Net Income (Loss) for Income Tax Purposes.					
Subtotal (line 405 **plus** line 410)			▶		4G
Subtotal (line 402 **plus** amount 4G)					4H
Restricted farm losses from previous tax years applied against current farming income	430				
Enter line 430 on line 333 of the T2 return.					
Section 80 – Adjustments for forgiven amounts	440				
Other adjustments	450				
Subtotal (total of lines 430 to 450)			▶		4I
Restricted farm losses before any request for a carryback (amount 4H **minus** amount 4I)					4J

Request to carry back restricted farm loss to:

First previous tax year to reduce farming income	941				
Second previous tax year to reduce farming income	942				
Third previous tax year to reduce farming income	943				
Subtotal (total of lines 941 to 943)			▶		4K
Closing balance of restricted farm losses to be carried forward to future tax years (amount 4J **minus** amount 4K)			480		

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 11: A restricted farm loss expires after **20 tax years**.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			5A		
Listed personal property loss expired **(note 12)**	500				
Listed personal property losses at the beginning of the tax year (amount 5A **minus** line 500)	502		▶		
Current-year listed personal property loss (from Schedule 6)			510		
Subtotal (line 502 **plus** line 510)					5B
Listed personal property losses from previous tax years applied against listed personal property gains Enter line 530 on line 655 of Schedule 6.	530				
Other adjustments	550				
Subtotal (line 530 **plus** line 550)			▶		5C
Listed personal property losses remaining before any request for a carryback (amount 5B **minus** amount 5C)					5D

Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains	961				
Second previous tax year to reduce listed personal property gains	962				
Third previous tax year to reduce listed personal property gains	963				
Subtotal (total of lines 961 to 963)			▶		5E
Closing balance of listed personal property losses to be carried forward to future tax years (amount 5D **minus** amount 5E)			580		

Note 12: A listed personal property loss expires after **7 tax years**.

Part 7 – Limited partnership losses

Current-year limited partnership losses

	1	2	3	4	5	6	7
	Partnership account number **600**	Tax year ending YYYY/MM/DD **602**	Corporation's share of limited partnership loss **604**	Corporation's at-risk amount **606**	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses **608**	Column 4 **minus** column 5 (if negative, enter "0")	Current -year limited partnership losses (column 3 **minus** column 6) **620**
1.	83867 3069 RZ0001	2021-12-31					

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

	1	2	3	4	5	6	7
	Partnership account number **630**	Tax year ending YYYY/MM/DD **632**	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary **634**	Corporation's at-risk amount **636**	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses **638**	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) **650**
1.	83867 3069 RZ0001	2021-12-31					

Continuity of limited partnership losses that can be carried forward to future tax years

	1	2	3	4	5	6
	Partnership account number **660**	Limited partnership losses at the end of the previous tax year **662**	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary **664**	Current-year limited partnership losses (from line 620) **670**	Limited partnership losses applied in the current year (must be equal to or less than line 650) **675**	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5) **680**
1.	83867 3069 RZ0001					

Total (enter this amount on line 335 of the T2 return)

Note
If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), tick the box . . . . **190** Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note
This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent.

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Tax Calculation Supplementary – Corporations

Schedule 5

Corporation's name	Business Number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- Use this schedule if, during the tax year, your corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B, and D in Part 1)
  - is claiming provincial or territorial tax credits or rebates (see Part 2), or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- All legislative references are to the Income Tax Regulations.
- For more information, see the T2 Corporation – Income Tax Guide.
- For the regulation number to be entered in field 100 of Part 1, see the chart below.

Part 1 – Allocation of taxable income

100 402 Corporations not specified — Enter the regulation that applies (402 to 413)

A Jurisdiction. Tick yes if your corporation had a permanent establishment in the jurisdiction during the tax year *		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue attributable to jurisdiction	E (D x taxable income) / H	F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 Yes ☐	104		144		
Prince Edward Island	005 Yes ☐	105		145		
Nova Scotia	007 Yes ☐	107		147		
Nova Scotia Offshore	008 Yes ☐	108		148		
New Brunswick	009 Yes ☐	109		149		
Quebec	011 Yes ☐	111		151		
Ontario	013 Yes X	113 447,677,066	51,534,561	153 4,935,857,000	51,614,084	51,574,322
Manitoba	015 Yes ☐	115		155		
Saskatchewan	017 Yes ☐	117		157		
Alberta	019 Yes X	119 690,814	79,523	159		39,762
British Columbia	021 Yes ☐	121		161		
Yukon	023 Yes ☐	123		163		
Northwest Territories	025 Yes ☐	125		165		
Nunavut	026 Yes ☐	126		166		
Outside Canada	027 Yes ☐	127		167		
Total		129 G 448,367,880	51,614,084	169 H 4,935,857,000	51,614,084	51,614,084

* **Permanent establishment** is defined in subsection 400(2)

** For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the T2 Corporation – Income Tax Guide.
2. If your corporation has provincial or territorial tax payable, complete Part 2.
3. If your corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
51,614,084		51,574,322	5,931,047

	Line	Amount		Amount	
Ontario basic income tax (from Schedule 500)	270	5,931,047			
Ontario small business deduction (from Schedule 500)	402				
Subtotal (line 270 **minus** line 402)		5,931,047	▶	5,931,047	5A
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal (line 276 **plus** line 277)			▶		5B
Gross Ontario tax (amount 5A **plus** amount 5B)				5,931,047	5C
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario political contributions tax credit (from Schedule 525)	415				
Ontario non-refundable tax credits (total of lines 404 to 415)			▶		5D
Subtotal (amount 5C **minus** amount 5D) (if negative, enter "0")				5,931,047	5E
Ontario research and development tax credit (from Schedule 508)	416			70,756	
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount 5E **minus** line 416) (if negative, enter "0")				5,860,291	5F
Ontario corporate minimum tax credit (from Schedule 510)	418				
Ontario community food program donation tax credit for farmers (from Schedule 2)	420				
Ontario corporate income tax payable (amount 5F **minus** the total of lines 418 and 420) (if negative, enter "0")				5,860,291	5G
Ontario corporate minimum tax (from Schedule 510)	278	5,522,623			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal (line 278 **plus** line 280)		5,522,623	▶	5,522,623	5H
Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H)				11,382,914	5I
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	125,400			
Ontario apprenticeship training tax credit (from Schedule 552)	454				
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Ontario regional opportunities investment tax credit (from Schedule 570)	472				
Ontario refundable tax credits (total of lines 450 to 472)		125,400	▶	125,400	5J
Net Ontario tax payable or refundable tax credit (amount 5I **minus** amount 5J) (if a credit, enter amount in brackets) Include this amount on line 255.	290			11,257,514	

Summary

Enter the total net tax payable or refundable tax credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable tax credits 255 11,257,514

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

For more information, see the section called "Capital Cost Allowance" in the T2 Corporation Income Tax Guide.

Is the corporation electing under Regulation 1101(5q)? **101** Yes [ ] No [X]

	1 Class number * See note 1 200	Description	2 Undepreciated capital cost (UCC) at the beginning of the year 201	3 Cost of acquisitions during the year (new property must be available for use) See note 2 203	4 Cost of acquisitions from column 3 that are accelerated investment incentive properties (AIIP) or zero-emission vehicle (ZEV) See note 3 225	5 Adjustments and transfers See note 4 205	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition See note 5 221	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition See note 6 222	8 Proceeds of dispositions See note 7 207	9 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See note 8
1.	1	NG Distribution pipelines--pre Mar 19/ 2(	2,298,694,525						0	2,298,694,525
2.	1b	Non-residential Building After March 19,	125,880,757	32,244,679	31,978,907				0	158,125,436
3.	2	NG DISTRIBUTION PIPELINES	162,237,059						0	162,237,059
4.	3	Buildings pre 1988	2,996,879						0	2,996,879
5.	6	Buildings	80,284						0	80,284
6.	7	Compressors	513,495,292	9,359,585	9,359,585				0	522,854,877
7.	8	Equipment, Furniture and Other	193,523,579	28,256,957	28,256,957				0	221,780,536
8.	10	TRANSPORTATION EQUIP, COMP HARD	29,543,755	13,591,100	13,591,100				86,191	43,048,664
9.	12	SOFTWARE		76,557,546	76,557,546				0	76,557,546
10.	13	Transferred Centra leases	12,987						0	12,987
11.	13	2300 Yonge & 777 Bay Streets, Toronto							0	
12.	13	Chatham Airport	29,198						0	29,198
13.	13	777 Bay Street	521,647						0	521,647
14.	13	745 Richmond St							0	
15.	17		502,630						0	502,630
16.	38	HEAVY WORK EQUIPMENT	11,055,613	5,457,277	5,457,277				0	16,512,890
17.	41	WELL EQUIPMENT-UNREGULATED STOI	81,151,325	66,587,245	65,066,239				0	147,738,570
18.	45	COMP HARDWARE-APR 04 to MAR 18/0	6,264						0	6,264
19.	49	NG Transmission Pipeline	752,159,922	75,856,774	75,856,774				0	828,016,696
20.	50	Computer Hardware/sys software post M	15,566,740	9,156,657	9,156,657				0	24,723,397
21.	51	NG Distribution pipelines-post Mar 18,07	5,233,199,825	824,236,213	812,822,867				0	6,057,436,038
22.	14.1		57,948,308	2,802,828	2,802,828				0	60,751,136
		Totals	9,478,606,589	1,144,106,861	1,130,906,737				86,191	10,622,627,259

	1 Class number * See note 1 200	Description	10 Proceeds of disposition available to reduce the UCC of AIIP and ZEV (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP and ZEV acquired during the year (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP and ZEV acquired during the year (column 11 **multiplied** by the relevant factor) See note 9	13 UCC adjustment for property acquired during the year other than AIIP and ZEV (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See note 10 224	14 CCA rate % See note 11 212	15 Recapture of CCA See note 12 213	16 Terminal loss See note 13 215	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See note 14 217	18 UCC at the end of the year (column 9 **minus** column 17) 220
1.	1	NG Distribution pipelines--pre					4	0	0	91,947,781	2,206,746,744
2.	1b	Non-residential Building After		31,978,907	15,989,454	132,886	6	0	0	10,438,920	147,686,516
3.	2	NG DISTRIBUTION PIPELINES					6	0	0	9,734,224	152,502,835
4.	3	Buildings pre 1988					5	0	0	149,844	2,847,035
5.	6	Buildings					10	0	0	8,028	72,256
6.	7	Compressors		9,359,585	4,679,793		15	0	0	79,130,201	443,724,676
7.	8	Equipment, Furniture and Oth		28,256,957	14,128,479		20	0	0	47,181,803	174,598,733
8.	10	TRANSPORTATION EQUIP, CC	86,191	13,504,909	6,752,455		30	0	0	14,940,336	28,108,328
9.	12	SOFTWARE		76,557,546			100	0	0	76,557,546	
10.	13	Transferred Centra leases					NA	0	0		12,987
11.	13	2300 Yonge & 777 Bay Streets					NA	0	0		
12.	13	Chatham Airport					NA	0	0	3,436	25,762
13.	13	777 Bay Street					NA	0	0	208,657	312,990
14.	13	745 Richmond St					NA	0	0		
15.	17						8	0	0	40,210	462,420
16.	38	HEAVY WORK EQUIPMENT		5,457,277	2,728,639		30	0	0	5,772,459	10,740,431
17.	41	WELL EQUIPMENT-UNREGUL/		65,066,239	32,533,120	760,503	25	0	0	44,877,797	102,860,773
18.	45	COMP HARDWARE-APR 04 to					45	0	0	2,819	3,445
19.	49	NG Transmission Pipeline		75,856,774	37,928,387		8	0	0	69,275,607	758,741,089
20.	50	Computer Hardware/sys softw		9,156,657	4,578,329		55	0	0	16,115,949	8,607,448
21.	51	NG Distribution pipelines-post		812,822,867	406,411,434	5,706,673	6	0	0	387,488,448	5,669,947,590
22.	14.1			2,802,828	1,401,414		5	0	0	4,055,211	56,695,925
		Totals	86,191	1,130,820,546	527,131,504	6,600,062				857,929,276	9,764,697,983

Enter the total of column 15 on line 107 of Schedule 1.
Enter the total of column 16 on line 404 of Schedule 1.
Enter the total of column 17 on line 403 of Schedule 1.

Note 1. If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101. Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

Note 2. Include any property acquired in previous years that has now become available for use, net of any government assistance received or entitled to be received in the year from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exceptions to the 50% rule.

Note 3. An AIIP is a property (other than ZEV) that you acquired after November 20, 2018 and became available for use before 2028. ZEV is, subject to certain exceptions, a motor vehicle included in Class 54 or 55 that you acquired after March 18, 2019 and became available for use before 2028. The Government proposes to create Class 56 for zero-emission automotive equipment and vehicles that currently do not benefit from the accelerated rate provided by Classes 54 and 55. Class 56 would apply to eligible zero-emission automotive equipment and vehicles that are acquired after March 1, 2020, and became available for use before 2028. Columns 4, 10, 11 and 12 also apply for additions of class 56 property. See the T2 Corporation Income Tax Guide for more information.

Note 4. Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the UCC (column 9). Items that increase the UCC include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the year for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See the T2 Corporation Income Tax Guide for other examples of adjustments and transfers to include in column 5.
Also include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor at least 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 5. Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Note 6. Include all amounts you have repaid during the year with respect to any legally required repayment, made after the disposition of a corresponding property, of:
- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Include the UCC of each property of a prescribed class acquired in the course of a corporate reorganization described under paragraph 55(3)(b) of the Act (also known as "butterfly reorganization") or include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor less than 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 7. For each property disposed of during the year, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).
The proceeds of disposition of a ZEV that has been included in Class 54 and that is subject to the $55,000 (plus sales taxes) capital cost limit will be adjusted based on a factor equal to the capital cost limit of $55,000 (plus sales taxes) as a proportion of the actual cost of the vehicle.

Note 8. If the amount in column 5 reduces the undepreciated capital cost (i.e. it is shown in brackets), you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purposes of the calculation.

Note 9. The relevant factors for property of a class in Schedule II, that is AIIP or included in Classes 54 to 56, available for use before 2024 are:
- 2 1/3 for property in Classes 43.1, 54 and 56
- 1 1/2 for property in Class 55
- 1 for property in Classes 43.2 and 53
- 0 for property in Classes 12, 13, 14, and 15, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 14 for additional information) and
- 0.5 for all other property that is AIIP

Note 10. The UCC adjustment for property acquired during the year other than AIIP and ZEV (formerly known as the half-year rule or 50% rule) does not apply to certain property (including AIIP). For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 11. Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 17.

Note 12. If the amount in column 9 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 9 in column 15 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1.

Note 13. If no property is left in the class at the end of the tax year and there is still a positive amount in the column 9, you have a terminal loss. If applicable, enter the positive amount from column 9 in column 16. The terminal loss rules do not apply to:
- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates or
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met

Note 14. If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the T2 Corporation Income Tax Guide for more information. For property in class 10.1 disposed of during the year, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the tax year. For AIIP listed below, the maximum first year allowance you can claim is determined as follows:
- Class 13: the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the tax year (before any CCA deduction)
- Class 14: the lesser of 150% of the allocation for the year of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the tax year (before any CCA deduction)
- Class 15: the lesser of 150% of an amount computed on the basis of a rate per cord, board foot or cubic metre cut in the tax year and the UCC at the end of the tax year (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% of the capital cost of the property and the UCC at the end of the tax year (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraph 1100(1)(y.2) (for single mine properties) and 1100(1)(ya.2) (for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP also apply to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the Income Tax Regulations for more detail.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	1329165 ALBERTA LTD.	CA	85359 6153 RC0001	3					
2.	8056587 CANADA INC	CA	83470 7887 RC0001	3					
3.	2099634 ONTARIO LIMITED	CA	85823 5120 RC0001	3					
4.	2193914 CANADA LIMITED	CA	10112 6530 RC0001	3					
5.	4296559 CANADA INC	CA	83059 8470 RC0001	3					
6.	626952 ALBERTA LTD.	CA	89641 4745 RC0001	3					
7.	627149 SASKATCHEWAN INC.	CA	87303 0555 RC0001	3					
8.	ENBRIDGE FINANCE HUNGARY KFT	HU	NR	3					
9.	912176 ONTARIO LIMITED	CA	89869 9541 RC0001	3					
10.	CCPS TRANSPORTATION, LLC	US	NR	3					
11.	2562961 ONTARIO LTD.	CA	72782 3692 RC0001	3					
12.	CRUICKSHANK WIND FARM LTD	CA	85249 6637 RC0001	3					
13.	ENBRIDGE (GATEWAY) HOLDINGS	CA	85955 3174 RC0001	3					
14.	ENBRIDGE (MARITIMES) INCORPO	CA	86667 9293 RC0001	3					
15.	ENBRIDGE (RABASKA) HOLDINGS I	CA	85878 5876 RC0001	3					
16.	ENBRIDGE (SASKATCHEWAN) OPE	CA	88344 2709 RC0001	3					
17.	ENBRIDGE (U.S.) INC.	US	NR	3					
18.	ENBRIDGE ATLANTIC (HOLDINGS)	CA	83625 3146 RC0001	3					
19.	ENBRIDGE HARDISTY STORAGE IN	CA	82481 3844 RC0001	3					
20.	ENBRIDGE AUX SABLE HOLDINGS I	CA	86640 9162 RC0001	3					
21.	ENBRIDGE AUX SABLE PRODUCTS	US	NR	3					
22.	ENBRIDGE FINANCE (BARBADOS) I	BB	NR	3					
23.	ENBRIDGE COMMERCIAL SERVICES	CA	86933 6180 RC0001	3					
24.	ENBRIDGE ÉOLIEN FRANCE S.À R.L	LU	NR	3					
25.	ENBRIDGE EMPLOYEE SERVICES, I	US	NR	3					
26.	ENBRIDGE ENERGY COMPANY, INC	US	NR	3					
27.	ENBRIDGE ENERGY DISTRIBUTION	CA	89641 6948 RC0001	3					
28.	ENBRIDGE RAMPION UK II LTD	GB	NR	3					
29.	ENBRIDGE HOLDINGS (MISSISSIPPI	US	NR	3					
30.	ENBRIDGE UK OFFSHORE WIND LT	GB	NR	3					
31.	ENBRIDGE BLACKSPRING RIDGE I	CA	82157 0330 RC0001	3					
32.	ENBRIDGE GAS STORAGE INC.	CA	85949 4288 RC0001	3					
33.	PACIFIC TRAIL PIPELINES MANAGE	CA	84836 1325 RC0001	3					
34.	ENBRIDGE HOLDINGS (FRONTIER)	US	NR	3					
35.	ENBRIDGE HOLDINGS (MUSTANG)	US	NR	3					
36.	ENBRIDGE HOLDINGS (OFFSHORE	US	NR	3					
37.	ENBRIDGE HOLDINGS (OLYMPIC) I	US	NR	3					
38.	ENBRIDGE HOLDINGS (U.S.) L.L.C.	US	NR	3					
39.	ENBRIDGE SERVICES (CMO) L.L.C.	US	NR	3					
40.	ENBRIDGE INC.	CA	11965 3384 RC0001	1					
41.	ENBRIDGE INSURANCE (BARBADO	BB	NR	3					
42.	ENBRIDGE INTERNATIONAL INC.	CA	13323 7578 RC0001	3					
43.	ENBRIDGE MANAGEMENT SERVICE	CA	86543 8352 RC0002	3					

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44.	ENBRIDGE MASSIF DU SUD WIND	CA	84352 6138 RC0001	3					
45.	ENBRIDGE OFFSHORE (DESTIN) L.	US	NR	3					
46.	ENBRIDGE OFFSHORE (GAS GATHI	US	NR	3					
47.	ENBRIDGE OFFSHORE (GAS TRANS	US	NR	3					
48.	ENBRIDGE OFFSHORE (NEPTUNE I	US	NR	3					
49.	ENBRIDGE OFFSHORE FACILITIES,	US	NR	3					
50.	ENBRIDGE OFFSHORE PIPELINES,	US	NR	3					
51.	ENBRIDGE OPERATIONAL SERVICE	CA	87061 0987 RC0001	3					
52.	ENBRIDGE PIPELINES (ATHABASCA	CA	88521 9592 RC0001	3					
53.	ENBRIDGE TRANSPORTATION (IL-	US	NR	3					
54.	ENBRIDGE PIPELINES (NW) INC.	CA	10251 6564 RC0001	3					
55.	ENBRIDGE PIPELINES (SOUTHERN	US	NR	3					
56.	ENBRIDGE PIPELINES (TOLEDO) II	US	NR	3					
57.	ENBRIDGE PIPELINES INC.	CA	10250 5641 RC0001	3					
58.	ENBRIDGE QUEBEC LNG INC.	CA	82952 0345 RC0001	3					
59.	ENBRIDGE RISK MANAGEMENT (U.	US	80411 2662 RC0001	3					
60.	ENBRIDGE RISK MANAGEMENT IN(	CA	85286 3349 RC0001	3					
61.	ENBRIDGE FINANCE COMPANY AG	CH	NR	3					
62.	ENBRIDGE SOUTHDOWN INC.	CA	85399 2378 RC0001	3					
63.	ENBRIDGE SOUTHERN LIGHTS G.P	CA	85044 3763 RC0001	3					
64.	ENBRIDGE STORAGE (PATOKA) L.L	US	NR	3					
65.	ENBRIDGE PIPELINES (L3R) L.L.C.	US	NR	3					
66.	ENBRIDGE TECHNOLOGY INC.	CA	13879 8814 RC0001	3					
67.	ENBRIDGE HOLDINGS (AUX SABLE	US	NR	3					
68.	ENBRIDGE WIND ENERGY INC.	CA	86124 8904 RC0001	3					
69.	ONTARIO EXCAVAC INC	CA	89002 6883 RC0003	3					
70.	GARDEN BANKS GAS PIPELINE, LL(	US	NR	3					
71.	GAZIFERE INC.	CA	10196 3916 RC0001	3					
72.	CEDAR POINT WIND, L.L.C.	US	NR	3					
73.	IPL AP HOLDINGS (U.S.A.) INC.	US	NR	3					
74.	IPL AP NGL HOLDINGS (U.S.A.) IN(	US	NR	3					
75.	IPL ENERGY (ATLANTIC) INCORPO	CA	87029 9732 RC0001	3					
76.	IPL ENERGY (COLOMBIA) LTD.	CA	89641 8340 RC0001	3					
77.	ENBRIDGE HOLDINGS (POWER) L.I	US	NR	3					
78.	ENBRIDGE HOLDINGS (AUX SABLE	US	NR	3					
79.	ENBRIDGE RENEWABLE INFRASTR	LU	NR	3					
80.	IPL INSURANCE (BARBADOS) LIMI	BB	NR	3					
81.	IPL SYSTEM INC.	CA	89641 7342 RC0001	3					
82.	IPL VECTOR (U.S.A.) INC.	US	NR	3					
83.	MANTA RAY OFFSHORE GATHERIN	US	NR	3					
84.	MIDCOAST CANADA OPERATING C	CA	87322 0222 RC0002	3					
85.	MISSISSIPPI CANYON GAS PIPELIN	US	NR	3					
86.	MJ ASPHALT HOLDINGS INC.	CA	89636 2548 RC0001	3					
87.	MJA OPERATIONS LTD.	CA	11945 5590 RC0001	3					
88.	NAUTILUS PIPELINE COMPANY L.L	US	NR	3					
89.	ENBRIDGE US HOLDINGS INC.	CA	83234 4600 RC0001	3					
90.	NIAGARA GAS TRANSMISSION LIM	CA	10387 6462 RC0001	3					
91.	NORTHERN GATEWAY PIPELINES I	CA	85963 9031 RC0001	3					
92.	ENBRIDGE WATER PIPELINE (PERI	US	NR	3					
93.	MI SOLAR, LLC	US	NR	3					
94.	SOUTH TEXAS TRAIL PIPELINE, LL	US	NR	3					
95.	SPECTRA ENERGY DEFS HOLDING,	US	NR	3					
96.	THE OTTAWA GAS COMPANY	CA	89870 0042 RC0001	3					

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97.	TIDAL ENERGY MARKETING (U.S.)	US	NR	3					
98.	TIDAL ENERGY MARKETING INC.	CA	87756 8279 RC0002	3					
99.	VECTOR PIPELINE HOLDINGS LTD.	CA	86981 3964 RC0001	3					
100.	VECTOR PIPELINE LIMITED	CA	87320 7641 RC0001	3					
101.	ENBRIDGE PIPELINES (WOODLANI	CA	84420 4255 RC0001	3					
102.	ALBERTA SALINE AQUIFER PROJEC	CA	82310 4856 RC0001	3					
103.	ENBRIDGE PIPELINES (ALBERTA CI	US	NR	3					
104.	ENBRIDGE HOLDINGS (NEW ENER	US	NR	3					
105.	ENBRIDGE HOLDINGS (LNG) L.L.C.	US	NR	3					
106.	ENBRIDGE GTM CANADA INC	CA	77710 2401 RC0001	3					
107.	ENBRIDGE HOLDINGS (PATRIOT) I	US	NR	3					
108.	EFL SERVICES (FRANCE) SAS	FR	NR	3					
109.	ENBRIDGE LAC ALFRED WIND PRC	CA	85311 6101 RC0001	3					
110.	ENBRIDGE EMERGING TECHNOLO(	CA	84468 5909 RC0001	3					
111.	ENBRIDGE TRANSMISSION HOLDII	CA	80612 5118 RC0001	3					
112.	ENBRIDGE RNG (SPROUT) LLC	US	NR	3					
113.	NEW CREEK WIND L.L.C.	US	NR	3					
114.	ENBRIDGE TRANSMISSION HOLDII	US	NR	3					
115.	CHAPMAN RANCH WIND I, LLC	US	NR	3					
116.	ENBRIDGE SOLAR (VESPER) LLC	US	NR	3					
117.	ENBRIDGE SOLAR (PORTAGE) LLC	US	NR	3					
118.	WRANGLER PIPELINE LLC	US	NR	3					
119.	ENBRIDGE HOLDINGS (SEAWAY) L	US	NR	3					
120.	ENBRIDGE PIPELINE (MAINLINE E)	US	NR	3					
121.	ENBRIDGE PIPELINE (EASTERN AC	US	NR	3					
122.	SILVER STATE SOLAR POWER NOF	US	NR	3					
123.	ENBRIDGE RAIL (PHILADELPHIA) L	US	NR	3					
124.	ENBRIDGE PIPLELINES (F.S.P.) LL(	US	NR	3					
125.	ENBRIDGE (COLOMBIA) S.A.S.	CO	NR	3					
126.	ENBRIDGE WESTERN ACCESS INC.	CA	81333 4687 RC0001	3					
127.	ENBRIDGE HYDROPOWER HOLDIN	CA	83462 5303 RC0001	3					
128.	MIDCOAST OLP GP, L.L.C.	US	NR	3					
129.	OLEODUCTO AL PACIFICO SAS	CO	NR	3					
130.	ENBRIDGE FINANCE LUXEMBOURG	LU	NR	3					
131.	ENBRIDGE (LUX) HOLDINGS INC.	CA	76508 3092 RC0001	3					
132.	KEECHI WIND, LLC	US	NR	3					
133.	ENBRIDGE HOLDINGS (TRUNKLINE	US	NR	3					
134.	LAKESIDE PERFORMANCE GAS SEF	CA	86596 9026 RC0002	3					
135.	ENBRIDGE SAINT ROBERT BELLAR	CA	82204 8138 RC0001	3					
136.	SUNWEST HEARTLAND TERMINAL!	CA	82257 1071 RC0001	3					
137.	WHITETAIL GAS-FIRED PEAKING P	CA	80895 8631 RC0001	3					
138.	WHITETAIL GAS-FIRED PEAKING P	CA	81743 4574 RC0001	3					
139.	ENBRIDGE WILD VALLEY HOLDING	US	NR	3					
140.	ENBRIDGE HOLDINGS (IDR) L.L.C.	US	NR	3					
141.	ENBRIDGE RAIL (FLANAGAN) L.L.C	US	NR	3					
142.	EIH S.A.R.L.	LU	NR	3					
143.	ENBRIDGE UK HOLDINGS LTD	GB	NR	3					
144.	ENBRIDGE RAMPION UK LTD	GB	NR	3					
145.	ENBRIDGE HOLDINGS (USGC) LLC	US	NR	3					
146.	ENBRIDGE THERMAL ENERGY HOL	CA	79971 7293 RC0001	3					
147.	ENBRIDGE EMPLOYEE SERVICES C	CA	80573 3391 RC0001	3					
148.	ENBRIDGE HOLDINGS (GREEN ENE	US	NR	3					
149.	ENBRIDGE INVESTMENT (NEW CRI	US	NR	3					

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
150.	ENBRIDGE INVESTMENT (PATRIOT	US	NR	3					
151.	ENBRIDGE INVESTMENT (CHAPMA	US	NR	3					
152.	ENBRIDGE INCOME PARTNERS HO	CA	89737 0508 RC0001	3					
153.	ENBRIDGE LUXEMBOURG S.A.R.L	LU	NR	3					
154.	SUPERIOR OIL LIMITED	CA	NR	3					
155.	ENBRIDGE FRONTIER INC.	CA	83765 4714 RC0001	3					
156.	ENBRIDGE BAKKEN PIPELINE COM	CA	82318 8859 RC0001	3					
157.	ENBRIDGE RENEWABLE ENERGY I	CA	82233 6673 RC0001	3					
158.	1682399 ONTARIO CORPORATION	CA	81558 9270 RC0002	3					
159.	TALBOT WINDFARM GP INC.	CA	80295 2291 RC0001	3					
160.	GREENWICH WINDFARM GP INC.	CA	80295 5898 RC0001	3					
161.	PROJECT AMBG2 INC.	CA	84850 7851 RC0001	3					
162.	7243341 CANADA INC.	CA	84726 1468 RC0001	3					
163.	HARDISTY CAVERNS LTD.	CA	85787 7641 RC0001	3					
164.	ENBRIDGE MIDSTREAM INC.	CA	84188 9272 RC0002	3					
165.	ENBRIDGE STORAGE (NORTH DAK	US	NR	3					
166.	ENBRIDGE STORAGE (CUSHING) L	US	NR	3					
167.	ONTARIO SUSTAINABLE FARMS IN	CA	83462 0296 RC0001	3					
168.	EIF US HOLDINGS INC.	US	NR	3					
169.	ENBRIDGE PIPELINES (OZARK) L.L	US	NR	3					
170.	ENBRIDGE MEXICO HOLDINGS INC	CA	77762 2895 RC0001	3					
171.	ENBRIDGE GME	MX	NR	3					
172.	BLAURACKE GMBH	DE	NR	3					
173.	ENBRIDGE INVESTMENT (GRANT F	US	NR	3					
174.	ENBRIDGE HOLDINGS (GRANT PLA	US	NR	3					
175.	MIDCOAST HOLDINGS L.L.C.	US	NR	3					
176.	ENBRIDGE RENEWABLE HOLDINGS	US	NR	3					
177.	ENBRIDGE EUROPEAN HOLDINGS	LU	NR	3					
178.	ENBRIDGE RENEWABLE INFRASTR	LU	NR	3					
179.	ENBRIDGE RENEWABLE INFRASTR	LU	NR	3					
180.	EI NORWAY HOLDINGS AS	NO	NR	3					
181.	ENBRIDGE SERVICES (GERMANY) (	DE	NR	3					
182.	BAKKEN PIPELINE COMPANY LLC	US	NR	3					
183.	GLB ENERGY MANAGEMENT INC.	CA	83363 5626 RC0001	3					
184.	WESTCOAST CONNECTOR GAS TR/	CA	85127 5248 RC0001	3					
185.	MARKET HUB PARTNERS MANAGE	CA	87160 8311 RC0001	3					
186.	ENBRIDGE PIPELINES (BEAVER LO	US	NR	3					
187.	SPECTRA ENERGY LIQUIDS PROJE	CA	81838 0594 RC0001	3					
188.	SEHLP MANAGEMENT INC.	CA	86448 2161 RC0001	3					
189.	ENBRIDGE OPERATING SERVICES,	US	NR	3					
190.	SPECTRA ENERGY CANADA CALL C	CA	87828 6319 RC0001	3					
191.	SPECTRA ENERGY CANADA EXCHA	CA	86604 9612 RC0001	3					
192.	SPECTRA ENERGY CANADA INVEST	CA	82927 0891 RC0001	3					
193.	SPECTRA ENERGY EMPRESS MANA	CA	77813 5921 RC0001	3					
194.	SPECTRA ENERGY EXPRESS (CANA	CA	83837 9931 RC0001	3					
195.	SPECTRA ENERGY HOLDINGS CO.	CA	85419 1962 RC0001	3					
196.	TRI-STATE HOLDINGS, LLC	US	NR	3					
197.	5679 CHERRY LANE, LLC	US	NR	3					
198.	SPECTRA ENERGY MIDSTREAM HO	CA	83075 6870 RC0001	3					
199.	ENBRIDGE PIPELINES (LAKEHEAD)	US	NR	3					
200.	SPECTRA ENERGY NOVA SCOTIA H	CA	86563 2616 RC0001	3					
201.	SPECTRA ENERGY U.S. - CANADA F	CA	82927 5296 RC0001	3					
202.	ST. CLAIR PIPELINES MANAGEMEN	CA	86565 3489 RC0001	3					

	Name	Country of residence (other than Canada)	Business number (see note 1)	Relationship code (see note 2)	Number of common shares you own	% of common shares you own	Number of preferred shares you own	% of preferred shares you own	Book value of capital stock
	100	200	300	400	500	550	600	650	700
203.	UEI HOLDINGS (NEW BRUNSWICK	CA	87160 3130 RC0001	3					
204.	ENBRIDGE ALLIANCE (U.S.) MANA(	US	NR	3					
205.	WESTCOAST ENERGY INC.	CA	10562 9372 RC0002	3					
206.	WESTCOAST ENERGY VENTURES I	CA	87296 2642 RC0001	3					
207.	ENBRIDGE AUX SABLE (U.S.) MAN/	US	NR	3					
208.	ENBRIDGE HOLDINGS (GRAY OAK)	US	NR	3					
209.	1090577 B.C. UNLIMITED LIABILIT	CA	74994 4328 RC0001	3					
210.	3268126 NOVA SCOTIA COMPANY	CA	86101 6947 RC0001	3					
211.	EXPRESS PIPELINE LTD.	CA	13671 3450 RC0002	3					
212.	SPECTRA ENERGY EXPRESS (US) R	CA	85674 0485 RC0002	3					
213.	ENBRIDGE SOLAR (DEER RIVER) L	US	NR	3					
214.	SPECTRA ENERGY FIELD SERVICES	US	NR	3					
215.	PORT BARRE INVESTMENTS, LLC D	US	NR	3					
216.	SPECTRA ENERGY PARTNERS CAN/	LU	NR	3					
217.	SPECTRA ALGONQUIN HOLDINGS,	US	NR	3					
218.	SPECTRA ALGONQUIN MANAGEME	US	NR	3					
219.	SPECTRA ENERGY CAPITAL, LLC	US	NR	3					
220.	M&N MANAGEMENT COMPANY, LL(	US	NR	3					
221.	M&N OPERATING COMPANY, L.L.C.	US	NR	3					
222.	TEXAS EASTERN COMMUNICATION	US	NR	3					
223.	SPECTRA ENERGY LNG SALES, LLC	US	NR	3					
224.	SPECTRA ENERGY OPERATING CO	US	NR	3					
225.	SPECTRA ENERGY ADMINISTRATI\	US	NR	3					
226.	SPECTRA ENERGY SOUTHEAST SEI	US	NR	3					
227.	SPECTRA ENERGY TRANSMISSION	US	NR	3					
228.	SPECTRA ENERGY TRANSMISSION	US	NR	3					
229.	BIG SANDY PIPELINE, LLC	US	NR	3					
230.	EXPRESS PIPELINE LLC	US	NR	3					
231.	PLATTE PIPELINE COMPANY, LLC	US	NR	3					
232.	EXPRESS HOLDINGS (USA), LLC	US	NR	3					
233.	EAST TENNESSEE NATURAL GAS, L	US	NR	3					
234.	SPECTRA ENERGY PARTNERS SAB/	US	NR	3					
235.	SPECTRA ENERGY TRANSPORT AN	US	NR	3					
236.	SABAL TRAIL MANAGEMENT, LLC	US	NR	3					
237.	SPECTRA ENERGY CROSS BORDER	US	NR	3					
238.	SPECTRA ENERGY TRANSMISSION	US	NR	3					
239.	MARKET HUB PARTNERS HOLDING	US	NR	3					
240.	COPIAH STORAGE, LLC	US	NR	3					
241.	MOSS BLUFF HUB, LLC	US	NR	3					
242.	EGAN HUB STORAGE, LLC	US	NR	3					
243.	POMELO CONNECTOR, LLC	US	NR	3					
244.	SPECTRA ENERGY TRANSMISSION	US	NR	3					
245.	SPECTRA ENERGY ISLANDER EAST	US	NR	3					
246.	WESTCOAST ENERGY (U.S.) LLC	US	NR	3					
247.	SPECTRA ENERGY WESTHEIMER, L	US	NR	3					
248.	SALTVILLE GAS STORAGE COMPAN	US	NR	3					
249.	SPECTRA ENERGY SOUTHEAST SU	US	NR	3					
250.	SPECTRA ENERGY CORP	US	NR	3					
251.	SPECTRA ENERGY SERVICES, LLC	US	NR	3					
252.	SPECTRA ENERGY AERIAL PATROL	US	NR	3					
253.	ENBRIDGE HOLDINGS TEXAS COLT	US	NR	3					
254.	SPECTRA ENERGY PARTNERS GP, I	US	NR	3					
255.	ENBRIDGE SOLAR (ADAMS) LLC	US	NR	3					

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
256.	ENBRIDGE SOLAR (CASS LAKE) LL(	US	NR	3					
257.	SPECTRA ENERGY FINANCE CORP(	US	NR	3					
258.	HIGHLAND PIPELINE LEASING, LL(	US	NR	3					
259.	SPECTRA ENERGY PARTNERS ATL/	US	NR	3					
260.	VALLEY CROSSING PIPELINE, LLC	US	NR	3					
261.	SPECTRA NEXUS GAS TRANSMISSI	US	NR	3					
262.	SPECTRA ENERGY NEXUS MANAGE	US	NR	3					
263.	BRAZORIA INTERCONNECTOR GAS	US	NR	3					
264.	SPECTRA ENERGY VCP HOLDINGS,	US	NR	3					
265.	SPECTRA ENERGY COUNTY LINE, L	US	NR	3					
266.	TEXAS EASTERN TERMINAL CO, LL	US	NR	3					
267.	SPECTRA ENERGY MIDWEST LIQUI	US	NR	3					
268.	SPECTRA ENERGY DEFS HOLDING	US	NR	3					
269.	SPECTRA ENERGY CAPITAL FUNDII	US	NR	3					
270.	TEXAS COLT LLC	US	NR	3					
271.	MARITIMES & NORTHEAST PIPELII	CA	89455 1191 RC0001	3					
272.	ENBRIDGE POWER OPERATIONS S	CA	75239 5111 RC0001	3					
273.	ENBRIDGE ALLIANCE (CANADA) M/	CA	75064 1516 RC0001	3					
274.	ENBRIDGE AUX SABLE (CANADA) N	CA	73747 3686 RC0001	3					
275.	ENBRIDGE CANADIAN RENEWABLE	CA	75832 2887 RC0001	3					
276.	ENBRIDGE ENERGY MANAGEMENT	US	NR	3					
277.	ENBRIDGE RENEWABLE GENERATI	CA	74046 7139 RC0001	3					
278.	ALBERTA SOLAR ONE, INC.	CA	76440 3895 RC0001	3					
279.	RIO BRAVO PIPELINE COMPANY, L	US	NR	3					
280.	ENBRIDGE (SPOT) LLC	US	NR	3					
281.	ENBRIDGE (HOUSTON OIL TERMIN	US	NR	3					
282.	NORTH DAKOTA PIPELINE COMPAI	US	NR	3					
283.	SPECTRA ENERGY GENERATION PI	US	NR	3					
284.	ENBRIDGE SOLAR (FLOODWOOD)	US	NR	3					
285.	ENBRIDGE SOLAR (FLANAGAN) LL(	US	NR	3					
286.	ENBRIDGE MIDSTREAM OPERATIN	US	NR	3					
287.	ENBRIDGE INGLESIDE TERMINAL !	US	NR	3					
288.	ENBRIDGE INGLESIDE HOLDINGS	US	NR	3					
289.	ENBRIDGE INGLESIDE ENERGY CE	US	NR	3					
290.	ENBRIDGE INGLESIDE LLC	US	NR	3					
291.	ENBRIDGE INGLESIDE LPG TERMII	US	NR	3					
292.	ENBRIDGE INGLESIDE OIL PIPELIN	US	NR	3					
293.	ENBRIDGE INGLESIDE CACTUS II H	US	NR	3					
294.	ENBRIDGE INGLESIDE LPG PIPELII	US	NR	3					
295.	ENBRIDGE INGLESIDE OPERATING	US	NR	3					
296.	ENBRIDGE INGLESIDE OIL TERMIN	US	NR	3					
297.	ENBRIDGE CACTUS II LLC	US	NR	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.

Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	CLAIMS AND DAMAGES	355,000			355,000	
2	SEVERANCE ACCRUAL	5,779,764			5,779,764	
3	PROV FOR MUNICIPAL TAXES N	195,260		162,851	195,260	162,851
4	Accrued - Sundries					
5	Self Insurance reserve	39,500		39,500	39,500	39,500
	Reserves from Part 2 of Schedule 13					
	Totals	6,369,524		202,351	6,369,524	202,351

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, PRPP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) (see note 3) 600
1	1	16,509,598	0263343			
2	1	999,134	0242016			
3	1	90,600	0242016			
4	1	142,600	0263343			
5	1	1,909,729	0242016			
6	1	6,136,524	0242016			
7	4	3,411,233		Spectra Energy Employee Savings Plan	Sun Life Financial Trust 227 King Street South PO Box Station Waterloo ON CA N2J 4C5	1
8	1	13,634,138	55084			

	Type of plan (see note 1)	Amount of contribution $ (see note 2)	Registration number (RPP, RSUBP, PRPP, and DPSP only)	Name of EPSP trust	Address of EPSP trust	T4PS slip(s) (see note 3)
	100	200	300	400	500	600
9	1	2,792,253	0378133			

Note 1

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

Note 2

You do not need to add to Schedule 1 any payments you made to deferred income plans.
To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule . . . . 45,625,809 A

Less:

Total of all amounts for deferred income plans deducted in your financial statements . . . . . ______ B

Deductible amount for contributions to deferred income plans
(amount A **minus** amount B) (if negative, enter "0") . . . . 45,625,809 C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer
(EPSP only)

T2 SCH 15 (13) Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 29

PAYMENTS TO NON-RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- A corporation that makes payments or credits amounts to non-residents under subsections 202(1) and 105(1) of the *Income Tax Regulations* has to file the applicable information return.
- The corporation has to complete the information below for all amounts paid or credited to non-residents that are listed in Note 1. If the total amount paid or credited is less than $100, you do not have to complete the information for that payee.

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
1	ALL PAYMENTS TO NON-RESIDENTS ARE REPOI	ON CALENDAR YEAR T4A-NR SUMM SEE T4A-NR SUMM SEE T4A-NR SUMM US	09	126,942
2	ALL PAYMENTS TO NON-RESIDENTS ARE REPOI	ON CALENDAR YEAR NR4 SUMM SEE NR4 SUMM SEE NR4 SUMM US	09	38,437

Note 1: Enter the applicable payment code in column 300:

1 – Royalties
2 – Rents
3 – Management fees/commissions
4 – Technical assistance fees
5 – Research and development fees
6 – Interest
7 – Dividends
8 – Film payments: – motion picture film, or – a film or video tape for use in connection with television
9 – Other services

T2 SCH 29 (99)

Canada

Canada Revenue Agency / Agence du revenu du Canada

Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year
  - to claim a deduction against Part I tax payable
  - to claim a refund of credit earned during the current tax year
  - to claim a carryforward of credit from previous tax years
  - to transfer a credit following an amalgamation or the wind-up of a subsidiary, as described under subsections 87(1) and 88(1)
  - to request a credit carryback to one or more previous years
  - if you are subject to a recapture of ITC
  - if you are claiming:
    - the **Ontario Research and Development Tax Credit**
    - the **Ontario Innovation Tax Credit**
- Unless otherwise stated, all legislative references are to the Income Tax Act and the Income Tax Regulations.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that currently earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule)
  - qualified scientific research and experimental development (SR&ED) expenditures (Parts 8 to 17). File Form T661, Scientific Research and Experimental Development (SR&ED) Expenditures Claim
  - pre-production mining expenditures (Part 18)
    - You can no longer claim the ITC for the pre-production mining expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you made the investment.
  - apprenticeship job creation expenditures (Parts 19 to 21)
  - child care spaces expenditures (Parts 22 to 26)
    - Expenditures related to child care spaces incurred after March 21, 2017 no longer qualify for the ITC. However, if you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 remain eligible for the credit.
- File this schedule with the T2 Corporation Income Tax Return. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, T2 Corporation – Income Tax Guide and read Information Circular IC78-4, Investment Tax Credit Rates, and its related Special Release.
- For more information on SR&ED, see guide T4088, Scientific Research and Experimental Development (SR&ED) Expenditures Claim – Guide to Form T661.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property at the time it files the income tax return for the year in which the property was acquired.
- An ITC deducted in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures.
- Expenditures for apprenticeship or child care space for an ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified members of a partnership and limited partners. For more information, see Guide T4068, Guide for the Partnership Information Return (T5013 Forms).
- For tax purposes**,** Canada includes the **exclusive economic zone of Canada** as defined in the Oceans Act (which generally consists of an area of the sea that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil of that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).

Detailed information (continued)

- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012, unless transitional measures were granted*. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.
- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %

Expenditures

If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %

Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 15% rate.

If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada	15 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred expenditures after March 18, 2007, and before March 22, 2017 (or before 2020 if you entered into a written agreement before March 22, 2017) for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

Corporation's name	Business number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if both of the following conditions are met:

- one corporation is associated with another corporation only because one or more persons own shares of the capital stock of both corporations
- one of the corporations has at least one shareholder who is not common to both corporations

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to one of the following:

a) one or more persons exempt from Part I tax under section 149
b) Her Majesty in right of a province, a Canadian municipality, or any other public authority
c) any combination of persons referred to in a) or b) above

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . **102** 1 Yes [ ] 2 No [X]

If **yes**, complete Schedule 125, Income Statement Information, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED* . . . . ________ x 80 % = **103** ________
Enter on line 350 of Part 8.

* Enter only contributions not already included on Form T661.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

Capital cost allowance class number **105**	Description of investment **110**	Date available for use **115**	Location used in Atlantic Canada (province) **120**	Amount of investment **125**
			Total of investments for qualified property and qualified resource property	A1

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year				B1
Credit deemed as a remittance of co-op corporations	210			
Credit expired	215			
Subtotal (line 210 **plus** line 215)			▶	C1
ITC at the beginning of the tax year (amount B1 **minus** amount C1)			220	
Credit transferred on an amalgamation or the wind-up of a subsidiary	230			
ITC from repayment of assistance	235			
Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part from amount A1 in Part 4) ______ x 10 % =	240			
Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part from amount A1 in Part 4) ______ x 5 % =	242			
Credit allocated from a partnership	250			
Subtotal (total of lines 230 to 250)			▶	D1
Total credit available (line 220 **plus** amount D1)				E1
Credit deducted from Part I tax	260			
Credit carried back to previous years (amount H1 in Part 6)			a	
Credit transferred to offset Part VII tax liability	280			
Subtotal (total of line 260, amount a, and line 280)			▶	F1
Credit balance before refund (amount E1 **minus** amount F1)				G1
Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7)			310	
ITC closing balance of investments from qualified property and qualified resource property (amount G1 **minus** line 310)			320	

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day			
1st previous tax year				Credit to be applied	901	
2nd previous tax year				Credit to be applied	902	
3rd previous tax year				Credit to be applied	903	
				Total of lines 901 to 903 Enter at amount a in Part 5.		H1

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 in Part 5)	I1
Credit balance before refund (from amount G1 in Part 5)	J1
Refund (40 % of amount I1 or J1, whichever is less)	K1

Enter amount K1 or a lesser amount on line 310 in Part 5 (also enter on line 780 of the T2 return if you do not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures (from line 559 on Form T661)		1,226,628		
Contributions to agricultural organizations for SR&ED				
Deduct:				
Government assistance, non-government assistance, or contract payment				
Subtotal				
x	80 %			
Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)*		+		
Qualified SR&ED expenditures (line 559 on Form T661 **plus** line 103 in Part 3)*		1,226,628	350	1,226,628
Repayments made in the year (from line 560 on Form T661)			370	
Total qualified SR&ED expenditures (line 350 **plus** line 370)			380	1,226,628

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if you are a CCPC.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if both of the following apply:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation
- one of the corporations has at least one shareholder who is not common to both corporations

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes ☐ 2 No ☐

If you answered **no** to the question on line 385 or if you are not associated with any other corporations, complete lines 390 and 398.
If you answered **yes**, complete Schedule 49, Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Expenditure Limit, to determine the amounts for associated corporations.

Enter your taxable income for the previous tax year* (prior to any loss carrybacks applied)	390	
Enter your taxable capital employed in Canada for the previous tax year **minus** $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million	398	

* If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone (not associated) corporation		$ 8,000,000	
Taxable income for the previous tax year (line 390 in Part 9) or $500,000, whichever is more	x 10 =		A2
Excess ($8,000,000 **minus** amount A2; if negative, enter "0")			B2
$ 40,000,000 **minus** line 398 in Part 9	b		
Amount b **divided** by $ 40,000,000			C2
For tax years ending before March 19, 2019 Amount B2 **multiplied** by amount C2			D2
For tax years ending after March 18, 2019 **multiplied** by amount C2			E2
Expenditure limit for the stand-alone corporation (amount D2 or amount E2, whichever applies)*			F2
For an associated corporation: If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49*	400		G2

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount F2 or G2 ______ x Number of days in the tax year / 365 ______ 365 = ______ H2

Your SR&ED expenditure limit for the year (enter amount F2, G2, or H2, whichever applies) 410 ______

* Amount F2 or G2 cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Qualified SR&ED expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less*	420		x	35 %	=		I2
Line 350 **minus** line 410 (if negative, enter "0")	430	1,226,628	x	15 %	=	183,994	J2

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8) . . . . . ______

Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayment of assistance that reduced a qualifying expenditure for a CCPC**	460		x	35 %	=		c
Repayment of assistance made after September 16, 2016 that reduced a qualifying expenditure incurred before 2015	480		x	20 %	=		d
Repayment of assistance made after September 16, 2016 that reduced a qualifying expenditure incurred after 2014	490		x	15 %	=		e
Subtotal (total of amounts c to e)						►	K2
Current-year SR&ED ITC (total of amounts I2 to K2; enter on line 540 in Part 12)						183,994	L2

* For corporations that are not CCPCs, enter "0" for amount I2.

** If you were a Canadian-controlled private corporation (CCPC), this percentage was applied to the portion that you claimed of the SR&ED qualified expenditure pool that did not exceed your expenditure limit at the time. This percentage includes the rate under subsection 127(10.1), **Additions to investment tax credit**. See subsection 127(10.1) for details about exceptions. For expenditures not eligible for this rate use line 480 or 490 as appropriate.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year					M2
Credit deemed as a remittance of co-op corporations	510				
Credit expired	515				
Subtotal (line 510 **plus** line 515)			►		N2
ITC at the beginning of the tax year (amount M2 **minus** amount N2)			520		
Credit transferred on an amalgamation or the wind-up of a subsidiary	530				
Total current-year credit (from amount L2 in Part 11)	540	183,994			
Credit allocated from a partnership	550				
Subtotal (total of lines 530 to 550)		183,994	►	183,994	O2
Total credit available (line 520 **plus** amount O2)				183,994	P2
Credit deducted from Part I tax	560	183,994			
Credit carried back to previous years (amount S2 in Part 13)			f		
Credit transferred to offset Part VII tax liability	580				
Subtotal (total of line 560, amount f, and line 580)		183,994	►	183,994	Q2
Credit balance before refund (amount P2 **minus** amount Q2)					R2
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)			610		
ITC closing balance on SR&ED (amount R2 **minus** line 610)			620		

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year Month Day				
1st previous tax year		Credit to be applied	911		
2nd previous tax year		Credit to be applied	912		
3rd previous tax year		Credit to be applied	913		
		Total of lines 911 to 913 Enter at amount f in Part 12.			S2

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined on line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? **650** 1 Yes [ ] 2 No [X]

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount K2 in Part 11) ______ g

Refundable credits (amount g or amount R2 in Part 12, whichever is less)* ______ T2

Amount T2 or amount I2 in Part 11, whichever is less ______ U2

Net amount (amount T2 **minus** amount U2; if negative, enter "0") ______ V2

Amount V2 **multiplied** by 40 % ______ W2

Amount U2 ______ X2

Refund of ITC (amount W2 **plus** amount X2 – enter this, or a lesser amount, on line 610 in Part 12) ______ Y2

Enter the total of line 310 in Part 5 and line 610 in Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation, as defined in subsection 127.1(2), this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y2.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this part only if you are a CCPC that is not a qualifying or excluded corporation as determined on line 101 in Part 2.

Credit balance before refund (amount R2 in Part 12) ______ Z2

Refund of ITC (amount Z2 or amount I2 in Part 11, whichever is less) ______ AA2

Enter amount AA2, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less

Subtotal Enter at amount C3 in Part 17. A3

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at amount B3.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (total of column F) Enter at amount D3 in Part 17. B3

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED (continued)

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC Enter at amount E3 in Part 17.	760		

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount A3 in Part 16		C3
Recaptured ITC from calculation 2, amount B3 in Part 16		D3
Recaptured ITC from calculation 3, line 760 in Part 16		E3
Total recapture of SR&ED investment tax credit (total of amounts C3 to E3) Enter at amount A8 in Part 27.		F3

Pre-Production Mining

Part 18 – Account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year					A4
Credit deemed as a remittance of co-op corporations	841				
Credit expired	845				
Subtotal (line 841 **plus** line 845)			►		B4
ITC at the beginning of the tax year (amount A4 **minus** amount B4)			850		
Credit transferred on an amalgamation or the wind-up of a subsidiary			860		
Total credit available (line 850 **plus** line 860)					C4
Amount of unused credit carried forward from previous years and applied to reduce Part I tax payable in the current year			885		
ITC closing balance from pre-production mining expenditures (amount C4 **minus** line 885)			890		

Apprenticeship Job Creation

Part 19 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) . . . . 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605

Total current-year credit (total of column E) Enter on line 640 in Part 20. ______ A5

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 20 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year . . . . ______ B5

Credit deemed as a remittance of co-op corporations . . . . 612 ______

Credit expired after 20 tax years . . . . 615 ______

Subtotal (line 612 **plus** line 615) ______ ► ______ C5

ITC at the beginning of the tax year (amount B5 **minus** amount C5) . . . . 625 ______

Credit transferred on an amalgamation or the wind-up of a subsidiary . . . . 630 ______

ITC from repayment of assistance . . . . 635 ______

Total current-year credit (amount A5 in Part 19) . . . . 640 ______

Credit allocated from a partnership . . . . 655 ______

Subtotal (total of lines 630 to 655) ______ ► ______ D5

Total credit available (line 625 **plus** amount D5) . . . . ______ E5

Credit deducted from Part I tax . . . . 660 ______

Credit carried back to previous years (amount G5 in Part 21) . . . . ______ h

Subtotal (line 660 **plus** amount h) ______ ► ______ F5

ITC closing balance from apprenticeship job creation expenditures (amount E5 **minus** amount F5) . . . . 690 ______

Part 21 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	

Total of lines 931 to 933 Enter at amount h in Part 20. ______ G5

Child Care Spaces

Part 22 – Eligible child care spaces expenditures

Enter the eligible expenditures that you incurred after March 18, 2007, and before March 22, 2017,* to create licensed child care spaces for the children of the employees and, potentially, for other children. You cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property)
- the specified child care start-up expenditures

Properties should be acquired and expenditures should be incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	Capital cost allowance class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year (total of column 695)	715		
Specified child care start-up expenditures from the current tax year	705		
Total gross eligible expenditures for child care spaces (line 715 **plus** line 705)			A6
Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to in amount A6	725		
Excess (amount A6 **minus** line 725) (if negative, enter "0")			B6
Repayments by the corporation of government and non-government assistance	735		
Total eligible expenditures for child care spaces (amount B6 **plus** line 735)	745		

* If you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 will remain eligible for the credit.

Part 23 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745 in Part 22)			x	25 % =		C6
Number of child care spaces	755		x	$ 10,000 =		D6
ITC from child care spaces expenditures (amount C6 or D6, whichever is less)						E6

Part 24 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				F6
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal (line 765 **plus** line 770)			▶	G6
ITC at the beginning of the tax year (amount F6 **minus** amount G6)			775	
Credit transferred on an amalgamation or the wind-up of a subsidiary	777			
Total current-year credit (amount E6 in Part 23)	780			
Credit allocated from a partnership	782			
Subtotal (total of lines 777 to 782)			▶	H6
Total credit available (line 775 **plus** amount H6)				I6
Credit deducted from Part I tax	785			
Credit carried back to previous years (amount K6 in Part 25)			i	
Subtotal (line 785 **plus** amount i)			▶	J6
ITC closing balance from child care spaces expenditures (amount I6 **minus** amount J6)			790	

Part 25 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2020-12-31	Credit to be applied	941	
2nd previous tax year	2019-12-31	Credit to be applied	942	
3rd previous tax year	2018-12-31	Credit to be applied	943	

Total of lines 941 to 943 K6
Enter at amount i in Part 24.

Recapture – Child Care Spaces

Part 26 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property, one of the following situations takes place:

- the new child care space is no longer available
- property that was an eligible expenditure for the child care space is
  - disposed of or leased to a lessee
  - converted to another use

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a))	792		
In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:			
The amount that can reasonably be considered to have been included in the original ITC	795		
25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property	797		
Amount from line 795 or line 797, whichever is less			A7

Partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 24. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC	799		
Total recapture of child care spaces investment tax credit (total of line 792, amount A7, and line 799) Enter at amount B8 in Part 27.			B7

Summary of Investment Tax Credits

Part 27 – Total recapture of investment tax credit

Recaptured SR&ED ITC (amount F3 in Part 17)		A8
Recaptured child care spaces ITC (amount B7 in Part 26)		B8
Total recapture of investment tax credit (amount A8 **plus** amount B8) Enter on line 602 of the T2 return.		C8

Part 28 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (line 260 in Part 5)		D8
ITC from SR&ED expenditures deducted from Part I tax (line 560 in Part 12)	183,994	E8
ITC from pre-production mining expenditures deducted from Part I tax (line 885 in Part 18)		F8
ITC from apprenticeship job creation expenditures deducted from Part I tax (line 660 in Part 20)		G8
ITC from child care space expenditures deducted from Part I tax (line 785 in Part 24)		H8
Total ITC deducted from Part I tax (total of amounts D8 to H8) Enter on line 652 of the T2 return.	183,994	I8

Alberta

ALBERTA CORPORATE INCOME TAX RETURN – AT1

The Alberta Corporate Tax Act

The AT1 and applicable schedules must be received by Tax and Revenue Administration (TRA) within 6 months of the corporation's taxation year end. Refer to form AT100 to determine if the corporation is exempt from filing. If the corporation is not exempt from filing and its gross revenue exceeds $1 million, the corporation must file electronically using net file unless it is an insurance corporation, a non-resident corporation, or reports in functional currency.

For Department Use
001 ■
004 ■
005 ■ **01RT**

010 ■ Legal Name of Corporation: ENBRIDGE GAS INC.

011 ■ Operating Name of Corporation:

012 ■ Mailing Address of Business: P.O.BOX 650

013 ■

014 ■ City/Town: SCARBOROUGH

015 ■ Prov./State: ON | 016 ■ Country Code (other than Canada): CA | 017 ■ Postal or Zip Code: M1K 5E3

If the assessment notice and assessment correspondence are to be sent to an address other than that above, provide that address:

018 ■ Name: MANAGER TAX REPORTING

019 ■ Address: P.O.BOX 650

020 ■

021 ■ City/Town: SCARBOROUGH

022 ■ Prov./State: ON | 023 ■ Country Code (other than Canada): | 024 ■ Postal or Zip Code: M1K 5E3

025 ■ Name of the person to contact to discuss this return: Andrew Wedel

Telephone number: 026 ■ Area Code (403) 231-5963

Fax number: 027 ■ Area Code (403) 231-4848

Nature of Business: Natural Gas Pipeline Transport Industry | 028 ■ SIC Code: 4611

Type of Corporation
029 ■
1 [ ] Canadian-controlled private corporation throughout the year (excluding Alberta professional)
2 [ ] Alberta Professional
3 [ ] Other private
4 [ ] Public
5 [X] Other, specify: CORPORATION CONTROLLED BY A PUBLIC CORPORATIO

Special Corporation Status (if applicable)
030 ■
1 [ ] Investment Corporation
2 [ ] Mutual Fund Corporation
3 [ ] Co-operative
4 [ ] Credit Union
5 [ ] Corporations exempt under the federal ITA section 149

Has there been a wind-up of a subsidiary under federal Income Tax Act (ITA) section 88 during the current taxation year? ■ 031 1 Yes [ ] 2 No [X]

Is this the first year of filing after an amalgamation? ■ 032 1 Yes [ ] 2 No [X]

Alberta Corporate Account Number (CAN) *(Enter the 9 or 10 digit account number)*
034 ■ 2121641795

Federal Business Number (BN)
035 ■ 10520 5140 RC0002

Taxation Year Beginning 036 ■ YYYY MM DD: 2021-01-01

Taxation Year Ending 037 ■ YYYY MM DD: 2021-12-31

Has the taxation year end changed since the last return was filed? 038 ■ 1 Yes [ ] 2 No [X]

If "Yes", specify the reason:
039 ■
1 [ ] Canada Revenue Agency (CRA) approved tax year end change
2 [ ] Change in control
3 [ ] Final return

State the functional currency used, if other than Canadian:
041 ■
1 [ ] United States of America
2 [ ] United Kingdom
3 [ ] European Monetary Union
4 [ ] Australia

If field 041 is checked, provide average exchange rate for calculation: (functional currency converting to Canadian currency) 043 ■

Gross Revenue (To nearest thousand) 047 ■ 4,935,857,000

Total Assets (Book value per balance sheet, to nearest thousand) 048 ■ 26,590,323,000

Is this a final return? 050 ■ 1 Yes [ ] 2 No [X]

If "Yes", specify the reason:
051 ■
1 [ ] Amalgamation, specify date of amalgamation: 052 ■ YYYY MM DD
2 [ ] Discontinuance of permanent establishment in Alberta
3 [ ] Bankruptcy
4 [ ] Wind-up into parent
5 [ ] Dissolution of corporation, specify date operations ceased: 053 ■ YYYY MM DD

Was there a transfer of property under federal ITA subsection 85(1), 85(2) or 97(2) that occurred after May 30, 2001, and during the taxation year being reported? 054 ■ 1 Yes [ ] 2 No [X]

Report all monetary amounts in dollars; DO NOT include cents. CAN: 2121641795 Taxation Year Ending: 2021-12-31

Taxable Income: The calculation of taxable income for federal purposes can differ from the calculation for Alberta purposes if the corporation chooses to use different discretionary deduction amounts (e.g., different application of losses, CCA, charitable donation, etc.).

	Line	Yes	No
Is the corporation reporting different taxable income for Alberta and federal purposes?	060		X
Has the corporation elected to use any different discretionary amounts for the current year claim or do opening balances differ for federal and Alberta purposes?	061		X

If line 060 and/or 061 is "Yes", then schedule 12 and supporting schedules MUST be completed to reconcile federal and Alberta taxable income.

	Line	Amount	Line	Amount
Alberta taxable income or (loss) **If both lines 060 and 061 are "No", then line 062 must equal federal T2, lines 360 - 370 OR, if reporting a loss, enter the amount from federal Schedule 4 lines 110 + 310 If either line 060 or 061 is "Yes", enter the amount from Schedule 12, lines 090 - 092**			062	51,614,084
(If line 062 is negative, complete Schedule 10 to request a loss carry-back, if applicable) Deduct: Royalty Tax Deduction (Schedule 5, line 021)			064	
Alberta Allocation Factor (Schedule 2, column I)			065	0.000770
Amount Taxable in Alberta (line 062 - line 064) X line 065 * (if negative, enter "0") (* if the corporation has permanent establishments only in Alberta, multiply by "1")			066	39,743
Basic Alberta Tax Payable: 8.000 % of amount on Line 066			068	3,179
Alberta Small Business Deduction Schedule 1, line 031	070			
Alberta Foreign Investment Income Tax Credit Schedule 4, line 020	072			
Alberta Other Tax Deductions and Credits Schedule 3, line 604	76a			
Other Deductions: (specify and attach the appropriate schedules)	76b			
Total (lines 76a + 76b)	076			
Total (lines 070 + 072 + 076)			079	
Alberta Tax Payable (lines 068 - line 079)			080	3,179
Alberta Scientific Research & Experimental Development Tax Credit, Schedule 9, line 120 (note : eliminated effective Jan. 1 2020)	081			
Innovation Employment Grant Schedule 29, line 134	129			
Instalments, other payments and ARTC instalments credited to income tax account for this taxation year	082	3,038		
Interactive Digital Media Tax Credit (IDMTC)	085			
Tax Certificate Number (issued at time of IDMTC approval) — 110				
Alberta Capital Gains Refund (available only to mutual fund corporations and public investment corporations)	086			
Other Credits: (specify and attach the appropriate schedule(s))	087			
Total (lines 081 + 129 + 082 + 085 + 086 + 087)			088	3,038
Balance Unpaid (Overpayment) (line 080 - line 088) (An assessed balance, including interest and penalty charges, of less than $20.00 will be neither charged nor refunded.)			090	141
If line 090 is a balance due (i.e. positive amount), indicate the amount enclosed with the return **Make cheque payable to Government of Alberta**			091	
If line 090 is an overpayment (i.e. negative amount), indicate the desired disposition: Refund = 1; Apply to payments for the next taxation year = 2			092	

Was this return prepared by a tax preparer for a fee? 095 1 Yes [ ] 2 No [X] 096 If yes, provide the preparer's name or firm name:

CERTIFICATION

I, 097 Wedel (Print Surname) 098 Andrew (Print First Name) 099 DIRECTOR TAX REPORTING (Position, office or rank),

am an authorized signing officer of the corporation. I certify that this return, including accompanying schedules and statements, has been examined by me and is a true, correct and complete return. I further certify that the method of computing income for this taxation year is consistent with that of the previous taxation year except as specifically disclosed in a statement to this return.

Signature of the authorized signing officer

2022-10-25
Date (YYYY MM DD)

Alberta

ALBERTA INCOME ALLOCATION FACTOR – AT1 SCHEDULE 2

The Alberta Corporate Tax Act

CAN: 2121641795 Taxation Year Ending: 2021-12-31

For corporations with taxable income that is in part allocable to permanent establishments outside Alberta.
Report all monetary values in dollars; DO NOT include cents.

Review the types of operations listed in AREA B.
Is the corporation in any of these special allocation categories? . . . . ■ 001 Yes [ ] No [X]

If "No", complete AREA A – General Allocation Formula to determine the corporation's Alberta Allocation Factor.
If "Yes", complete the applicable line in AREA B – Special Allocation Formula to determine the corporation's Alberta Allocation Factor.

Divided Businesses (ITA Reg 412): where more than one special allocation formula applies to a corporation, complete only the calculation for Divided Businesses at the bottom of page 2.

Non-resident Corporations (ITA Reg 413): Where a corporation is not resident in Canada, "salaries and wages paid in all jurisdictions" by the corporation does not include salaries and wages paid to employees of a permanent establishment outside of Canada. When calculating using the general allocation formula under ITA Reg. 402(3)(a), "gross revenue in all jurisdictions" does not include gross revenue reasonably attributable to a permanent establishment outside Canada.

Use the amounts from the federal Schedule 5 to complete the applicable formula.

References to Regulations below are to those of the Income Tax Act (Canada), as adopted by the Alberta Corporate Tax Act.

AREA A – General Allocation Formula (ITA Reg 402)

* If either amount B or D is nil, do not multiple by 1/2.

A	B	C	D	I — Alberta Allocation Factor (calculate to 6 decimal places) ***Carry this amount forward to AT1 line 065***
■ 002 Salaries and wages paid in Alberta	■ 004 Total salaries and wages paid in all jurisdictions	■ 006 Gross revenue in Alberta	■ 008 Gross revenue in all jurisdictions	(A/B + C/D) x 1/2 *
690,814	448,367,880		4,935,857,000	■ 0.000770

AREA B – Special Allocation Formulas

Type of operation	A	B	C	D	I — Alberta Allocation Factor (calculate to 6 decimal places) ***Carry this amount forward to AT1 line 065***
Bus and Truck Operators (ITA Reg 409)	■ 012 Salaries & wages paid in Alberta	■ 014 Total salaries & wages paid	■ 016 Kilometres traveled in Alberta	■ 018 Total kilometres traveled in jurisdictions where corporation has permanent establishment	(A/B + C/D) x 1/2 ■
Grain Elevator Operators (ITA Reg 408)	■ 022 Salaries & wages paid in Alberta	■ 024 Total salaries & wages paid	■ 026 Bushels of grain received at Alberta elevators	■ 028 Bushels of grain received at all elevators	(A/B + C/D) x 1/2 ■
Pipeline Operators (ITA Reg 411)	■ 032 Salaries & wages paid in Alberta	■ 034 Total salaries & wages paid	■ 036 Miles of pipeline in Alberta	■ 038 Total miles of pipeline in provinces where corporation has permanent establishment	(A/B + C/D) x 1/2 ■

AREA B is continued on page 2

CAN: 2121641795

Taxation Year Ending: 2021-12-31

AREA B – Special Allocation Formulas continued

Type of operation	A	B	C	D	I **Alberta Allocation Factor** (calculate to 6 decimal places) ***Carry this amount forward to AT1 line 065***
Insurance Corporations (ITA Reg 403)			▪ **046** Net premiums in Alberta	▪ **048** Total net premiums earned	C/D ▪
Chartered Banks (ITA Reg 404)	▪ **052** Salaries and wages paid in Alberta	▪ **054** Total salaries and wages paid	▪ **056** Loans & deposits in Alberta	▪ **058** Total loans & deposits	(A/B + 2C/D) x 1/3 ▪
Trust & Loan Corporations (ITA Reg 405)			▪ **066** Gross revenue earned in Alberta	▪ **068** Total gross revenue	C/D ▪
Airline Corporations (ITA Reg 407)	▪ **072** Fixed asset cost (other than aircraft) in Alberta	▪ **074** Fixed asset cost (other than aircraft) in Canada	▪ **076** Revenue plane miles flown in Alberta	▪ **078** Revenue plane miles flown in Canada where the corporation has permanent establishment	(A/B + 3C/D) x 1/4 ▪
Railway Corporations (ITA Reg 406)	▪ **082** Equated track miles in Alberta	▪ **084** Total equated track miles in Canada	▪ **086** Gross ton miles in Alberta	▪ **088** Total gross ton miles in Canada	(A/B + C/D) x 1/2 ▪
Ship Operators: (ITA Reg 410)	**A** ▪ **090** Salaries and wages paid in Alberta	**B** ▪ **092** Total salaries and wages paid in Canada*	**C** ▪ **094** Port-call-tonnage in Alberta	**D** ▪ **096** Total port-call-tonnage in all provinces with permanent establishments	$\frac{(G \times C/D) + H}{\text{AT1 lines 062 - 064}}$ ▪
	E ▪ **098** Total port-call-tonnage in Canada	**F** ▪ **100** Total port-call-tonnage in all countries	**G** ▪ **102** (E/F) x (AT1 lines 062 - 064)	**H** ▪ **104** (A/B) x [(AT1 lines 062 - 064) - G]	

* Salaries & wages paid by the corporation to employees of its permanent establishments (other than ships) in Canada.

	A	B	
Divided Businesses (ITA Reg 412)	▪ **106** Amount Taxable in Alberta (See Guide for details)	▪ **108** AT1 line 062 - AT1 line 064	A/B ▪

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- Use this schedule if your corporation had a **permanent establishment** (as defined in section 400 of the federal Income Tax Regulations) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- Legislative references are to the federal Income Tax Act and Income Tax Regulations.
- This schedule is a worksheet only and is not required to be filed with your T2 Corporation Income Tax Return.

Part 1 – Ontario basic income tax

Ontario taxable income Note 1	51,574,322	1A
Ontario basic rate of tax for the year	**11.5** %	1B
Ontario basic income tax (amount 1A **multiplied** by amount 1B) Note 2	5,931,047	1C

Note 1 If your corporation had a permanent establishment only in Ontario, enter the amount from line 360, from page 3 of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Note 2 If your corporation had a permanent establishment in more than one jurisdiction or is claiming an Ontario tax credit in addition to Ontario basic income tax, or Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount 1C on line 270 of Schedule 5, Tax Calculation Supplementary – Corporations. Otherwise, enter it on line 760 of the T2 return.

Part 2 – Ontario small business deduction (OSBD)

Complete this part if your corporation claimed the federal small business deduction under subsection 125(1).

Line 400 of the T2 return		2A
Line 405 of the T2 return		2B
Line 410 of the T2 return		2C
Line 415 of the T2 return		2D

Amount 2C x Amount 2D / 11,250 = ______ 2E

Line 515 of the T2 return		2F
Subtotal (amount 2C **minus** amount 2E **minus** amount 2F) ▶		2G
Amount 2A, 2B or 2G whichever is the least ▶		2H

Ontario domestic factor (ODF): Taxable income for Ontario Note 3 / Taxable income for all provinces Note 4 = 51,574,322.31 / 51,614,084 = 0.99923 2I

Amount 2H **multiplied** by amount 2I		2J
Ontario taxable income (amount 1A)	51,574,322	2K
Ontario small business income (amount 2J or 2K, whichever is less) ▶		2L

Ontario small business deduction for the year

Amount 2L ______ x (Number of days in the tax year before January 1, 2020 ______ / Number of days in the tax year 365) x 8 % = ______ 2M

Amount 2L ______ x (Number of days in the tax year after December 31, 2019 365 / Number of days in the tax year 365) x 8.3 % = ______ 2N

Ontario small business deduction for the year (amount 2M **plus** amount 2N) ▶ ______ 2O
Enter amount 2O on line 402 of Schedule 5.

Note 3 Enter amount 1A.

Note 4 Includes the territories and the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 3 – Ontario adjusted small business income

Complete this part if your corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (amount 1A or 2H, whichever is the least) 3A

Enter amount 3A at amount 4B in Part 4 of this schedule or at amount 2E in Part 2 of Schedule 502, Ontario Tax Credit for Manufacturing and Processing, whichever applies.

Part 4 – Credit union tax reduction

Complete this part and Schedule 17, Credit Union Deductions, if the corporation was a credit union throughout the tax year.

Amount 3C of Schedule 17 . . . . 4A

Ontario adjusted small business income (amount 3A) 4B

Subtotal (amount 4A **minus** amount 4B, if negative, enter "0") ▶ 4C

Amount 4C ______ x (Number of days in the tax year before January 1, 2020 ______ / Number of days in the tax year 365) x 8 % = ______ 4D

Amount 4C ______ x (Number of days in the tax year after December 31, 2019 365 / Number of days in the tax year 365) x 8.3 % = ______ 4E

Total (amount 4D **plus** amount 4E) ▶ 4F

Ontario domestic factor (amount 2I) 0.99923 4G

Ontario credit union tax reduction (amount 4F **multiplied** by amount 4G) 4H

Enter amount 4H on line 410 of Schedule 5.

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Schedule 508

Ontario Research and Development Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC earned in the tax year to reduce Ontario corporate income tax payable in any of the three previous tax years;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - add an ORDTC transferred after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year. The ORDTC rate is:
  - 4.5% for tax years that end before June 1, 2016;
  - 3.5% for tax years that start after May 31, 2016; and
  - prorated for a tax year that ends on or after June 1, 2016, and includes May 31, 2016.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Complete and attach this schedule to the *T2 Corporation Income Tax Return* for the tax year.
- To claim this credit, you must also send in completed copies of the Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*, and the Schedule 31, *Investment Tax Credit - Corporations*, within 18 months of the tax year end.

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	1,271,117 A			
Government assistance, non-government assistance, or a contract payment for eligible expenditures	105	B			
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		1,271,117 C			
Eligible expenditures transferred to the corporation by another corporation	110	D			
Subtotal (amount C **plus** amount D)		1,271,117	▶		1,271,117 E
Eligible expenditures the corporation transferred to another corporation				115	F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")				120	1,271,117 G

Part 2 – Eligible repayments

The repayment of the ORDTC is calculated using the ORDTC rate that you used to determine your tax credit at the time your eligible expenditures were reduced because of the government or non-government assistance, or contract payments. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayments for tax years that end before June 1, 2016 . . . . 210 ______ x 4.5 % = 215 ______ H

Repayment for a tax year that ends on or after June 1, 2016 and includes May 31, 2016. Complete the proration calculation below.

Number of days in the tax year before June 1, 2016	240	152	x	4.5 %	=	1.8689 %	1
Number of days in the tax year	241	366					
Number of days in the tax year after May 31, 2016	242	214	x	3.5 %	=	2.0464 %	2
Number of days in the tax year	243	366					

Subtotal (percentage 1 **plus** percentage 2) 3.9153 % 3

Repayments for a tax year that ends on or after June 1, 2016 and includes May 31, 2016 . . . . . . 211 ______ x percentage 3 3.9153 % = 216 ______ I

Part 2 – Eligible repayments (continued)

Repayments for tax years that start after May 31, 2016	**212**		x		3.5 % =	**217**	J
Repayments made in the tax year of government or non-government assistance or contract payments that reduced eligible expenditures for first term or second term shared-use equipment acquired before 2014	**220**		x 1 / 4 =		x 4.5 % =	**225**	K
Eligible repayments (total of amounts H to K)						**229**	L

Part 3 – Calculation of the current part of the ORDTC

For tax years that end before June 1, 2016

Ontario SR&ED expenditure pool (amount G in Part 1)	x 4.5 % =	**200**		M
ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *		**205**		N
Eligible repayments (amount L in Part 2)				O
Current part of the ORDTC for tax years that end before June 1, 2016 (total of amounts M to O)		**230**		P

For a tax year that ends on or after June 1, 2016, and includes May 31, 2016

Number of days in the tax year before June 1, 2016 / Number of days in the tax year		x	4.5 %	=	% 4
Number of days in the tax year after May 31, 2016 / Number of days in the tax year		x	3.5 %	=	% 5
Subtotal (percentage 4 **plus** percentage 5)					% 6

Ontario SR&ED expenditure pool (amount G in Part 1)		x percentage 6	% =	**201**	Q
ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *				**206**	R
Eligible repayments (amount L in Part 2)					S
Part of the ORDTC for a tax year that ends on or after June 1, 2016, and includes May 31, 2016 (total of amounts Q to S)				**231**	T

For tax years that start after May 31, 2016

Ontario SR&ED expenditure pool (amount G in Part 1)	1,271,117	x 3.5 % =	**202**	44,489	U
ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *			**207**		V
Eligible repayments (amount L in Part 2)					W
The ORDTC for tax years that start after May 31, 2016 (total of amounts U to W)			**232**	44,489	X

* If there is a disposal or change of use of eligible property, see Part 7 on page 4.

Part 4 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year			Y	
ORDTC expired after 20 tax years	**300**		Z	
ORDTC at the beginning of the tax year (amount Y **minus** amount Z)	**305**		AA	
ORDTC transferred to the corporation on amalgamation or windup	**310**	26,267	BB	
Current part of ORDTC (amount P, T or X in Part 3 whichever applies)	44,489 CC			

Are you waiving all or part of the current part of the ORDTC? **315** Yes 1 [ ] No 2 [X]

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Waiver of the current part of the ORDTC **320**	DD			
Subtotal (amount CC **minus** amount DD)	44,489 ▶	44,489	EE	
ORDTC available for deduction (total of amounts AA, BB and EE)		70,756 ▶		70,756 FF
ORDTC claimed ** (Enter amount GG on line 416 on page 5 of Schedule 5, *Tax Calculation Supplementary – Corporations*)		70,756	GG	
ORDTC carried back to previous tax years (from Part 5)			HH	
Subtotal (amount GG **plus** amount HH)		70,756 ▶		70,756 II
ORDTC balance at the end of the tax year (amount FF **minus** amount II) **325**				JJ

** This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount FF); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 on page 5 of Schedule 5).

Part 5 – Request for carryback of tax credit

	Year Month Day			
1st previous tax year	2020-12-31	Credit to be applied	**901**	
2nd previous tax year	2019-12-31	Credit to be applied	**902**	
3rd previous tax year	2018-12-31	Credit to be applied	**903**	

Total (total of amount 901 to 903)(enter at amount HH in Part 4)

Part 6 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from previous tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year / Month / Day	Credit available	Tax year of origin (earliest tax year first) Year / Month / Day	Credit available
2002-09-30		2011-12-31	
2003-09-30		2012-12-31	
2004-09-30		2013-12-31	
2005-09-30		2014-12-31	
2006-09-30		2015-12-31	
2006-12-31		2016-12-31	
2007-12-31		2017-12-31	
2008-12-31		2018-12-31	
2009-12-31		2019-12-31	
2010-12-31		2020-12-31	
		Current tax year 2021-12-31	

Total (equals line 325 in Part 4) ____________

The amount available from the 20th previous tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 7 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

  Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate ******* of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

Complete the columns for each disposition for which a recapture applies, using the calculation formats below.

*** Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – Complete this part If you meet all of the above conditions

	KK Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above 700	LL Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	MM Amount from column 700 or 710, whichever is less
1.			

Total of column MM (enter at amount WW in Part 8) ____________ NN

Part 7 – Calculation of a recapture of ORDTC (continued)

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line SS.

	OO Rate percentage that the transferee used to determine its federal ITC for qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	PP Proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	QQ Amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) 740
1.			

	RR Amount determined by the formula (OO x PP) - QQ (using the columns above)	SS Federal ITC earned by the transferee for the qualified expenditure that was transferred 750	TT Amount from column RR or SS, whichever is less
1.			

Total of column TT (enter at amount XX in Part 8) ______ UU

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205, 206, or 207 in Part 3, whichever applies. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line VV.

Corporate partner's share of the excess of ORDTC (enter at amount ZZ in Part 8) . . . . 760 ______ VV

Part 8 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount NN from Part 7) . . . . ______ WW

Recaptured federal ITC for Calculation 2 (amount UU from Part 7) . . . . ______ XX

Amount WW **plus** amount XX . . . . ______ x 23.56 % = ______ YY

Corporate partner's share of the excess of ORDTC for Calculation 3 (amount VV from Part 7) . . . . ______ ZZ

Recapture of ORDTC (amount YY **plus** amount ZZ) (enter amount AAA on line 277 on page 5 of Schedule 5) . . . . ______ AAA

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Total expenditures for SR&ED		1,400,674	
Add			
• payment of prior years' unpaid expenses (other than salary or wages)	+		
• prescribed proxy amount (Enter "0" if you use the traditional method)	+		
• other additions	+		
Subtotal	=	1,400,674	
Less			
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–		
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–		
• 20% of contract expenditures for SR&ED performed on your behalf	–	129,557	
• prescribed expenditures not allowed by regulations	–		
• other deductions	–		
• non-arm's length transactions			
– expenditures for non-arm's length SR&ED contracts	–		
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–		
Total	=	1,271,117	I

Enter amount I on line 100 of Schedule 508.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	26,590,323,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	
Total assets (total of lines 112 to 116)		26,590,323,000
Total revenue of the corporation for the tax year **	142	4,935,857,000
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	
Total revenue (total of lines 142 to 146)		4,935,857,000

The corporation is subject to CMT if:
– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
– Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
– The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
– The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

	Line	Amount		Line	Amount	
Net income/loss per financial statements *				210	550,814,000	
Add (to the extent reflected in income/loss):						
Provision for current income taxes/cost of current income taxes	220	77,525,000				
Provision for deferred income taxes (debits)/cost of future income taxes	222					
Equity losses from corporations	224					
Financial statement loss from partnerships and joint ventures	226					
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230					
Other additions (see note below):						
Share of adjusted net income of partnerships and joint ventures **	228					
Total patronage dividends received, not already included in net income/loss	232					
281	282					
283	284					
Subtotal		77,525,000	▶		77,525,000	A
Deduct (to the extent reflected in income/loss):						
Provision for recovery of current income taxes/benefit of current income taxes	320					
Provision for deferred income taxes (credits)/benefit of future income taxes	322	14,578,000				
Equity income from corporations	324					
Financial statement income from partnerships and joint ventures	326					
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330					
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332					
Gain on donation of listed security or ecological gift	340					
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342					
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344					
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346					
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348					
Other deductions (see note below):						
Share of adjusted net loss of partnerships and joint ventures **	328					
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334	191,846,709				
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336					
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338					
381	382					
383	384					
385	386					
387	388					
389	390					
Subtotal		206,424,709	▶		206,424,709	B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)				490	421,914,291	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515	421,914,291		
Deduct:					
CMT loss available (amount R from Part 7)					
Minus: Adjustment for an acquisition of control *	518				
Adjusted CMT loss available		▶		C	
Net income subject to CMT calculation (if negative, enter "0")		520	421,914,291		

Amount from line 520		Number of days in the tax year before July 1, 2010 / Number of days in the tax year			Rate		
421,914,291	x		/ 365	x	4 % =		1
421,914,291	x	365	/ 365	x	2.7 % =	11,391,686	2

(Second row: Number of days in the tax year after June 30, 2010 / Number of days in the tax year)

Subtotal (amount 1 **plus** amount 2) . . . 11,391,686 3

Gross CMT: amount on line 3 above x OAF **	540	11,382,914	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		11,382,914	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		5,860,291	
Net CMT payable (if negative, enter "0")		5,522,623	E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income ****	51,574,322.31	=	0.99923
Taxable income *****	51,614,084		

Ontario allocation factor . . . 0.99923 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		37,978,133	G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)		37,978,133	▶ 620	37,978,133	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)			650		
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				37,978,133	H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)				37,978,133	J
Add:					
Net CMT payable (amount E from Part 3)		5,522,623			
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal		5,522,623	▶	5,522,623	K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670	43,500,756	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					37,978,133	M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			5,860,291	1		
For a corporation that is not a life insurance corporation:						
CMT after foreign tax credit deduction (amount D from Part 3)	11,382,914	2				
For a life insurance corporation:						
Gross CMT (line 540 from Part 3)		3				
Gross SAT (line 460 from Part 6 of Schedule 512)		4				
The **greater** of amounts 3 and 4		5				
Deduct: line 2 or line 5, whichever applies:			11,382,914	6		
Subtotal (if negative, enter "0")				▶		N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			5,860,291			
Deduct:						
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)			125,400			
Subtotal (if negative, enter "0")			5,734,891	▶	5,734,891	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)						P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ▶ 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	1329165 ALBERTA LTD.	85359 6153 RC0001	0	0
2	8056587 CANADA INC	83470 7887 RC0001	0	0
3	2099634 ONTARIO LIMITED	85823 5120 RC0001	0	0
4	2193914 CANADA LIMITED	10112 6530 RC0001	0	0
5	4296559 CANADA INC	83059 8470 RC0001	0	0
6	626952 ALBERTA LTD.	89641 4745 RC0001	0	0
7	627149 SASKATCHEWAN INC.	87303 0555 RC0001	0	0
8	ENBRIDGE FINANCE HUNGARY KFT	NR	0	0
9	912176 ONTARIO LIMITED	89869 9541 RC0001	0	0
10	CCPS TRANSPORTATION, LLC	NR	0	0
11	2562961 ONTARIO LTD.	72782 3692 RC0001	0	0
12	CRUICKSHANK WIND FARM LTD	85249 6637 RC0001	0	0
13	ENBRIDGE (GATEWAY) HOLDINGS INC.	85955 3174 RC0001	0	0
14	ENBRIDGE (MARITIMES) INCORPORATED	86667 9293 RC0001	0	0
15	ENBRIDGE (RABASKA) HOLDINGS INC.	85878 5876 RC0001	0	0
16	ENBRIDGE (SASKATCHEWAN) OPERATING SERVI	88344 2709 RC0001	0	0
17	ENBRIDGE (U.S.) INC.	NR	0	0
18	ENBRIDGE ATLANTIC (HOLDINGS) INC.	83625 3146 RC0001	0	0
19	ENBRIDGE HARDISTY STORAGE INC	82481 3844 RC0001	0	0
20	ENBRIDGE AUX SABLE HOLDINGS INC.	86640 9162 RC0001	0	0
21	ENBRIDGE AUX SABLE PRODUCTS INC.	NR	0	0
22	ENBRIDGE FINANCE (BARBADOS) LIMITED	NR	0	0
23	ENBRIDGE COMMERCIAL SERVICES INC.	86933 6180 RC0001	0	0
24	ENBRIDGE ÉOLIEN FRANCE S.À R.L.	NR	0	0
25	ENBRIDGE EMPLOYEE SERVICES, INC.	NR	0	0
26	ENBRIDGE ENERGY COMPANY, INC.	NR	0	0
27	ENBRIDGE ENERGY DISTRIBUTION INC.	89641 6948 RC0001	0	0
28	ENBRIDGE RAMPION UK II LTD	NR	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
29	ENBRIDGE HOLDINGS (MISSISSIPPI) L.L.C.	NR	0	0
30	ENBRIDGE UK OFFSHORE WIND LTD	NR	0	0
31	ENBRIDGE BLACKSPRING RIDGE I WIND PROJECT GF	82157 0330 RC0001	0	0
32	ENBRIDGE GAS STORAGE INC.	85949 4288 RC0001	0	0
33	PACIFIC TRAIL PIPELINES MANAGEMENT INC	84836 1325 RC0001	0	0
34	ENBRIDGE HOLDINGS (FRONTIER) INC.	NR	0	0
35	ENBRIDGE HOLDINGS (MUSTANG) INC.	NR	0	0
36	ENBRIDGE HOLDINGS (OFFSHORE) L.L.C.	NR	0	0
37	ENBRIDGE HOLDINGS (OLYMPIC) L.L.C.	NR	0	0
38	ENBRIDGE HOLDINGS (U.S.) L.L.C.	NR	0	0
39	ENBRIDGE SERVICES (CMO) L.L.C.	NR	0	0
40	ENBRIDGE INC.	11965 3384 RC0001	0	0
41	ENBRIDGE INSURANCE (BARBADOS QIC) LIMIT	NR	0	0
42	ENBRIDGE INTERNATIONAL INC.	13323 7578 RC0001	0	0
43	ENBRIDGE MANAGEMENT SERVICES INC.	86543 8352 RC0002	0	0
44	ENBRIDGE MASSIF DU SUD WIND PROJECT GP INC.	84352 6138 RC0001	0	0
45	ENBRIDGE OFFSHORE (DESTIN) L.L.C.	NR	0	0
46	ENBRIDGE OFFSHORE (GAS GATHERING) L.L.C	NR	0	0
47	ENBRIDGE OFFSHORE (GAS TRANSMISSION) L.	NR	0	0
48	ENBRIDGE OFFSHORE (NEPTUNE HOLDINGS) INC.	NR	0	0
49	ENBRIDGE OFFSHORE FACILITIES, LLC	NR	0	0
50	ENBRIDGE OFFSHORE PIPELINES, L.L.C.	NR	0	0
51	ENBRIDGE OPERATIONAL SERVICES INC.	87061 0987 RC0001	0	0
52	ENBRIDGE PIPELINES (ATHABASCA) INC.	88521 9592 RC0001	0	0
53	ENBRIDGE TRANSPORTATION (IL-OK) L.L.C.	NR	0	0
54	ENBRIDGE PIPELINES (NW) INC.	10251 6564 RC0001	0	0
55	ENBRIDGE PIPELINES (SOUTHERN LIGHTS) LLC	NR	0	0
56	ENBRIDGE PIPELINES (TOLEDO) INC.	NR	0	0
57	ENBRIDGE PIPELINES INC.	10250 5641 RC0001	0	0
58	ENBRIDGE QUEBEC LNG INC.	82952 0345 RC0001	0	0
59	ENBRIDGE RISK MANAGEMENT (U.S.) L.L.C.	80411 2662 RC0001	0	0
60	ENBRIDGE RISK MANAGEMENT INC.	85286 3349 RC0001	0	0
61	ENBRIDGE FINANCE COMPANY AG	NR	0	0
62	ENBRIDGE SOUTHDOWN INC.	85399 2378 RC0001	0	0
63	ENBRIDGE SOUTHERN LIGHTS G.P. INC.	85044 3763 RC0001	0	0
64	ENBRIDGE STORAGE (PATOKA) L.L.C.	NR	0	0
65	ENBRIDGE PIPELINES (L3R) L.L.C.	NR	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
66	ENBRIDGE TECHNOLOGY INC.	13879 8814 RC0001	0	0
67	ENBRIDGE HOLDINGS (AUX SABLE MIDSTREAM) L.L.(	NR	0	0
68	ENBRIDGE WIND ENERGY INC.	86124 8904 RC0001	0	0
69	ONTARIO EXCAVAC INC	89002 6883 RC0003	0	0
70	GARDEN BANKS GAS PIPELINE, LLC	NR	0	0
71	GAZIFERE INC.	10196 3916 RC0001	0	0
72	CEDAR POINT WIND, L.L.C.	NR	0	0
73	IPL AP HOLDINGS (U.S.A.) INC.	NR	0	0
74	IPL AP NGL HOLDINGS (U.S.A.) INC.	NR	0	0
75	IPL ENERGY (ATLANTIC) INCORPORATED	87029 9732 RC0001	0	0
76	IPL ENERGY (COLOMBIA) LTD.	89641 8340 RC0001	0	0
77	ENBRIDGE HOLDINGS (POWER) L.L.C.	NR	0	0
78	ENBRIDGE HOLDINGS (AUX SABLE LIQUID PRODUCT!	NR	0	0
79	ENBRIDGE RENEWABLE INFRASTRUCTURE DEVELOPI	NR	0	0
80	IPL INSURANCE (BARBADOS) LIMITED	NR	0	0
81	IPL SYSTEM INC.	89641 7342 RC0001	0	0
82	IPL VECTOR (U.S.A.) INC.	NR	0	0
83	MANTA RAY OFFSHORE GATHERING COMPANY, L.L.C	NR	0	0
84	MIDCOAST CANADA OPERATING CORPORATION	87322 0222 RC0002	0	0
85	MISSISSIPPI CANYON GAS PIPELINE, LLC	NR	0	0
86	MJ ASPHALT HOLDINGS INC.	89636 2548 RC0001	0	0
87	MJA OPERATIONS LTD.	11945 5590 RC0001	0	0
88	NAUTILUS PIPELINE COMPANY L.L.C.	NR	0	0
89	ENBRIDGE US HOLDINGS INC.	83234 4600 RC0001	0	0
90	NIAGARA GAS TRANSMISSION LIMITED	10387 6462 RC0001	0	0
91	NORTHERN GATEWAY PIPELINES INC.	85963 9031 RC0001	0	0
92	ENBRIDGE WATER PIPELINE (PERMIAN) L.L.C.	NR	0	0
93	MI SOLAR, LLC	NR	0	0
94	SOUTH TEXAS TRAIL PIPELINE, LLC	NR	0	0
95	SPECTRA ENERGY DEFS HOLDING, LLC	NR	0	0
96	THE OTTAWA GAS COMPANY	89870 0042 RC0001	0	0
97	TIDAL ENERGY MARKETING (U.S.) L.L.C.	NR	0	0
98	TIDAL ENERGY MARKETING INC.	87756 8279 RC0002	0	0
99	VECTOR PIPELINE HOLDINGS LTD.	86981 3964 RC0001	0	0
100	VECTOR PIPELINE LIMITED	87320 7641 RC0001	0	0
101	ENBRIDGE PIPELINES (WOODLAND) INC.	84420 4255 RC0001	0	0
102	ALBERTA SALINE AQUIFER PROJECT INC.	82310 4856 RC0001	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
103	ENBRIDGE PIPELINES (ALBERTA CLIPPER) L.L.C.	NR	0	0
104	ENBRIDGE HOLDINGS (NEW ENERGY) LLC	NR	0	0
105	ENBRIDGE HOLDINGS (LNG) L.L.C.	NR	0	0
106	ENBRIDGE GTM CANADA INC	77710 2401 RC0001	0	0
107	ENBRIDGE HOLDINGS (PATRIOT) L.L.C.	NR	0	0
108	EFL SERVICES (FRANCE) SAS	NR	0	0
109	ENBRIDGE LAC ALFRED WIND PROJECT GP INC.	85311 6101 RC0001	0	0
110	ENBRIDGE EMERGING TECHNOLOGY INC	84468 5909 RC0001	0	0
111	ENBRIDGE TRANSMISSION HOLDINGS INC.	80612 5118 RC0001	0	0
112	ENBRIDGE RNG (SPROUT) LLC	NR	0	0
113	NEW CREEK WIND L.L.C.	NR	0	0
114	ENBRIDGE TRANSMISSION HOLDINGS (US) LLC	NR	0	0
115	CHAPMAN RANCH WIND I, LLC	NR	0	0
116	ENBRIDGE SOLAR (VESPER) LLC	NR	0	0
117	ENBRIDGE SOLAR (PORTAGE) LLC	NR	0	0
118	WRANGLER PIPELINE LLC	NR	0	0
119	ENBRIDGE HOLDINGS (SEAWAY) LLC	NR	0	0
120	ENBRIDGE PIPELINE (MAINLINE EXPANSION) L.L.C.	NR	0	0
121	ENBRIDGE PIPELINE (EASTERN ACCESS) L.L.C.	NR	0	0
122	SILVER STATE SOLAR POWER NORTH L.L.C.	NR	0	0
123	ENBRIDGE RAIL (PHILADELPHIA) L.L.C.	NR	0	0
124	ENBRIDGE PIPLELINES (F.S.P.) LLC	NR	0	0
125	ENBRIDGE (COLOMBIA) S.A.S.	NR	0	0
126	ENBRIDGE WESTERN ACCESS INC.	81333 4687 RC0001	0	0
127	ENBRIDGE HYDROPOWER HOLDINGS INC	83462 5303 RC0001	0	0
128	MIDCOAST OLP GP, L.L.C.	NR	0	0
129	OLEODUCTO AL PACIFICO SAS	NR	0	0
130	ENBRIDGE FINANCE LUXEMBOURG SA	NR	0	0
131	ENBRIDGE (LUX) HOLDINGS INC.	76508 3092 RC0001	0	0
132	KEECHI WIND, LLC	NR	0	0
133	ENBRIDGE HOLDINGS (TRUNKLINE) L.L.C.	NR	0	0
134	LAKESIDE PERFORMANCE GAS SERVICES LTD.	86596 9026 RC0002	0	0
135	ENBRIDGE SAINT ROBERT BELLARMIN WIND PROJEC	82204 8138 RC0001	0	0
136	SUNWEST HEARTLAND TERMINALS LTD.	82257 1071 RC0001	0	0
137	WHITETAIL GAS-FIRED PEAKING PROJECT LTD.	80895 8631 RC0001	0	0
138	WHITETAIL GAS-FIRED PEAKING PROJECT GP INC.	81743 4574 RC0001	0	0
139	ENBRIDGE WILD VALLEY HOLDINGS LLC	NR	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
140	ENBRIDGE HOLDINGS (IDR) L.L.C.	NR	0	0
141	ENBRIDGE RAIL (FLANAGAN) L.L.C.	NR	0	0
142	EIH S.A.R.L.	NR	0	0
143	ENBRIDGE UK HOLDINGS LTD	NR	0	0
144	ENBRIDGE RAMPION UK LTD	NR	0	0
145	ENBRIDGE HOLDINGS (USGC) LLC	NR	0	0
146	ENBRIDGE THERMAL ENERGY HOLDINGS INC.	79971 7293 RC0001	0	0
147	ENBRIDGE EMPLOYEE SERVICES CANADA INC.	80573 3391 RC0001	0	0
148	ENBRIDGE HOLDINGS (GREEN ENERGY) L.L.C.	NR	0	0
149	ENBRIDGE INVESTMENT (NEW CREEK) L.L.C.	NR	0	0
150	ENBRIDGE INVESTMENT (PATRIOT) L.L.C.	NR	0	0
151	ENBRIDGE INVESTMENT (CHAPMAN RANCH) L.L.C.	NR	0	0
152	ENBRIDGE INCOME PARTNERS HOLDINGS INC.	89737 0508 RC0001	0	0
153	ENBRIDGE LUXEMBOURG S.A.R.L	NR	0	0
154	SUPERIOR OIL LIMITED	NR	0	0
155	ENBRIDGE FRONTIER INC.	83765 4714 RC0001	0	0
156	ENBRIDGE BAKKEN PIPELINE COMPANY INC.	82318 8859 RC0001	0	0
157	ENBRIDGE RENEWABLE ENERGY INFRASTRUCTURE C	82233 6673 RC0001	0	0
158	1682399 ONTARIO CORPORATION	81558 9270 RC0002	0	0
159	TALBOT WINDFARM GP INC.	80295 2291 RC0001	0	0
160	GREENWICH WINDFARM GP INC.	80295 5898 RC0001	0	0
161	PROJECT AMBG2 INC.	84850 7851 RC0001	0	0
162	7243341 CANADA INC.	84726 1468 RC0001	0	0
163	HARDISTY CAVERNS LTD.	85787 7641 RC0001	0	0
164	ENBRIDGE MIDSTREAM INC.	84188 9272 RC0002	0	0
165	ENBRIDGE STORAGE (NORTH DAKOTA) L.L.C.	NR	0	0
166	ENBRIDGE STORAGE (CUSHING) L.L.C.	NR	0	0
167	ONTARIO SUSTAINABLE FARMS INC	83462 0296 RC0001	0	0
168	EIF US HOLDINGS INC.	NR	0	0
169	ENBRIDGE PIPELINES (OZARK) L.L.C.	NR	0	0
170	ENBRIDGE MEXICO HOLDINGS INC.	77762 2895 RC0001	0	0
171	ENBRIDGE GME	NR	0	0
172	BLAURACKE GMBH	NR	0	0
173	ENBRIDGE INVESTMENT (GRANT PLAINS) L.L.C.	NR	0	0
174	ENBRIDGE HOLDINGS (GRANT PLAINS) L.L.C.	NR	0	0
175	MIDCOAST HOLDINGS L.L.C.	NR	0	0
176	ENBRIDGE RENEWABLE HOLDINGS, L.L.C.	NR	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
177	ENBRIDGE EUROPEAN HOLDINGS S.A.R.L	NR	0	0
178	ENBRIDGE RENEWABLE INFRASTRUCTURE HOLDINGS	NR	0	0
179	ENBRIDGE RENEWABLE INFRASTRUCTURE INVESTME	NR	0	0
180	EI NORWAY HOLDINGS AS	NR	0	0
181	ENBRIDGE SERVICES (GERMANY) GMBH	NR	0	0
182	BAKKEN PIPELINE COMPANY LLC	NR	0	0
183	GLB ENERGY MANAGEMENT INC.	83363 5626 RC0001	0	0
184	WESTCOAST CONNECTOR GAS TRANSMISSION LTD.	85127 5248 RC0001	0	0
185	MARKET HUB PARTNERS MANAGEMENT INC.	87160 8311 RC0001	0	0
186	ENBRIDGE PIPELINES (BEAVER LODGE) L.L.C.	NR	0	0
187	SPECTRA ENERGY LIQUIDS PROJECTS GP INC.	81838 0594 RC0001	0	0
188	SEHLP MANAGEMENT INC.	86448 2161 RC0001	0	0
189	ENBRIDGE OPERATING SERVICES, L.L.C.	NR	0	0
190	SPECTRA ENERGY CANADA CALL CO.	87828 6319 RC0001	0	0
191	SPECTRA ENERGY CANADA EXCHANGECO INC.	86604 9612 RC0001	0	0
192	SPECTRA ENERGY CANADA INVESTMENTS GP, ULC	82927 0891 RC0001	0	0
193	SPECTRA ENERGY EMPRESS MANAGEMENT HOLDING	77813 5921 RC0001	0	0
194	SPECTRA ENERGY EXPRESS (CANADA) HOLDINGS UL	83837 9931 RC0001	0	0
195	SPECTRA ENERGY HOLDINGS CO.	85419 1962 RC0001	0	0
196	TRI-STATE HOLDINGS, LLC	NR	0	0
197	5679 CHERRY LANE, LLC	NR	0	0
198	SPECTRA ENERGY MIDSTREAM HOLDINGS LIMITED	83075 6870 RC0001	0	0
199	ENBRIDGE PIPELINES (LAKEHEAD) L.L.C.	NR	0	0
200	SPECTRA ENERGY NOVA SCOTIA HOLDINGS CO.	86563 2616 RC0001	0	0
201	SPECTRA ENERGY U.S. - CANADA FINANCE GP, ULC	82927 5296 RC0001	0	0
202	ST. CLAIR PIPELINES MANAGEMENT INC.	86565 3489 RC0001	0	0
203	UEI HOLDINGS (NEW BRUNSWICK) INC.	87160 3130 RC0001	0	0
204	ENBRIDGE ALLIANCE (U.S.) MANAGEMENT L.L.C.	NR	0	0
205	WESTCOAST ENERGY INC.	10562 9372 RC0002	0	0
206	WESTCOAST ENERGY VENTURES INC.	87296 2642 RC0001	0	0
207	ENBRIDGE AUX SABLE (U.S.) MANAGEMENT LLC	NR	0	0
208	ENBRIDGE HOLDINGS (GRAY OAK) LLC	NR	0	0
209	1090577 B.C. UNLIMITED LIABILITY COMPANY	74994 4328 RC0001	0	0
210	3268126 NOVA SCOTIA COMPANY	86101 6947 RC0001	0	0
211	EXPRESS PIPELINE LTD.	13671 3450 RC0002	0	0
212	SPECTRA ENERGY EXPRESS (US) RESTRUCTURE CO,	85674 0485 RC0002	0	0
213	ENBRIDGE SOLAR (DEER RIVER) LLC	NR	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
214	SPECTRA ENERGY FIELD SERVICES CANADA HOLDIN(	NR	0	0
215	PORT BARRE INVESTMENTS, LLC DBA BOBCAT OP	NR	0	0
216	SPECTRA ENERGY PARTNERS CANADA HOLDING SAR	NR	0	0
217	SPECTRA ALGONQUIN HOLDINGS, LLC	NR	0	0
218	SPECTRA ALGONQUIN MANAGEMENT, LLC	NR	0	0
219	SPECTRA ENERGY CAPITAL, LLC	NR	0	0
220	M&N MANAGEMENT COMPANY, LLC	NR	0	0
221	M&N OPERATING COMPANY, L.L.C.	NR	0	0
222	TEXAS EASTERN COMMUNICATIONS, LLC	NR	0	0
223	SPECTRA ENERGY LNG SALES, LLC	NR	0	0
224	SPECTRA ENERGY OPERATING COMPANY, LLC	NR	0	0
225	SPECTRA ENERGY ADMINISTRATIVE SERVICES, LLC	NR	0	0
226	SPECTRA ENERGY SOUTHEAST SERVICES, LLC	NR	0	0
227	SPECTRA ENERGY TRANSMISSION, LLC	NR	0	0
228	SPECTRA ENERGY TRANSMISSION II, LLC	NR	0	0
229	BIG SANDY PIPELINE, LLC	NR	0	0
230	EXPRESS PIPELINE LLC	NR	0	0
231	PLATTE PIPELINE COMPANY, LLC	NR	0	0
232	EXPRESS HOLDINGS (USA), LLC	NR	0	0
233	EAST TENNESSEE NATURAL GAS, LLC	NR	0	0
234	SPECTRA ENERGY PARTNERS SABAL TRAIL TRANSMI!	NR	0	0
235	SPECTRA ENERGY TRANSPORT AND TRADING COMPA	NR	0	0
236	SABAL TRAIL MANAGEMENT, LLC	NR	0	0
237	SPECTRA ENERGY CROSS BORDER, LLC (P/K/A SPECT	NR	0	0
238	SPECTRA ENERGY TRANSMISSION RESOURCES, LLC	NR	0	0
239	MARKET HUB PARTNERS HOLDING, LLC (P/K/A MARK	NR	0	0
240	COPIAH STORAGE, LLC	NR	0	0
241	MOSS BLUFF HUB, LLC	NR	0	0
242	EGAN HUB STORAGE, LLC	NR	0	0
243	POMELO CONNECTOR, LLC	NR	0	0
244	SPECTRA ENERGY TRANSMISSION SERVICES, LLC	NR	0	0
245	SPECTRA ENERGY ISLANDER EAST PIPELINE COMPAN	NR	0	0
246	WESTCOAST ENERGY (U.S.) LLC	NR	0	0
247	SPECTRA ENERGY WESTHEIMER, LLC	NR	0	0
248	SALTVILLE GAS STORAGE COMPANY L.L.C.	NR	0	0
249	SPECTRA ENERGY SOUTHEAST SUPPLY HEADER, LLC	NR	0	0
250	SPECTRA ENERGY CORP	NR	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
251	SPECTRA ENERGY SERVICES, LLC	NR	0	0
252	SPECTRA ENERGY AERIAL PATROL, LLC	NR	0	0
253	ENBRIDGE HOLDINGS TEXAS COLT LLC	NR	0	0
254	SPECTRA ENERGY PARTNERS GP, LLC	NR	0	0
255	ENBRIDGE SOLAR (ADAMS) LLC	NR	0	0
256	ENBRIDGE SOLAR (CASS LAKE) LLC	NR	0	0
257	SPECTRA ENERGY FINANCE CORPORATION	NR	0	0
258	HIGHLAND PIPELINE LEASING, LLC	NR	0	0
259	SPECTRA ENERGY PARTNERS ATLANTIC REGION NEV	NR	0	0
260	VALLEY CROSSING PIPELINE, LLC	NR	0	0
261	SPECTRA NEXUS GAS TRANSMISSION, LLC	NR	0	0
262	SPECTRA ENERGY NEXUS MANAGEMENT, LLC	NR	0	0
263	BRAZORIA INTERCONNECTOR GAS PIPELINE LLC	NR	0	0
264	SPECTRA ENERGY VCP HOLDINGS, LLC	NR	0	0
265	SPECTRA ENERGY COUNTY LINE, LLC	NR	0	0
266	TEXAS EASTERN TERMINAL CO, LLC	NR	0	0
267	SPECTRA ENERGY MIDWEST LIQUIDS PIPELINE, LLC	NR	0	0
268	SPECTRA ENERGY DEFS HOLDING II, LLC (P/K/A - SPI	NR	0	0
269	SPECTRA ENERGY CAPITAL FUNDING, INC.	NR	0	0
270	TEXAS COLT LLC	NR	0	0
271	MARITIMES & NORTHEAST PIPELINE MANAGEMENT L	89455 1191 RC0001	0	0
272	ENBRIDGE POWER OPERATIONS SERVICES INC.	75239 5111 RC0001	0	0
273	ENBRIDGE ALLIANCE (CANADA) MANAGEMENT INC.	75064 1516 RC0001	0	0
274	ENBRIDGE AUX SABLE (CANADA) MANAGEMENT INC.	73747 3686 RC0001	0	0
275	ENBRIDGE CANADIAN RENEWABLE GP INC.	75832 2887 RC0001	0	0
276	ENBRIDGE ENERGY MANAGEMENT, L.L.C.	NR	0	0
277	ENBRIDGE RENEWABLE GENERATION INC.	74046 7139 RC0001	0	0
278	ALBERTA SOLAR ONE, INC.	76440 3895 RC0001	0	0
279	RIO BRAVO PIPELINE COMPANY, LLC	NR	0	0
280	ENBRIDGE (SPOT) LLC	NR	0	0
281	ENBRIDGE (HOUSTON OIL TERMINAL) LLC	NR	0	0
282	NORTH DAKOTA PIPELINE COMPANY LLC	NR	0	0
283	SPECTRA ENERGY GENERATION PIPELINE MANAGEMI	NR	0	0
284	ENBRIDGE SOLAR (FLOODWOOD) LLC	NR	0	0
285	ENBRIDGE SOLAR (FLANAGAN) LLC	NR	0	0
286	ENBRIDGE MIDSTREAM OPERATING LLC	NR	0	0
287	ENBRIDGE INGLESIDE TERMINAL SERVICES LLC	NR	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
288	ENBRIDGE INGLESIDE HOLDINGS LLC	NR	0	0
289	ENBRIDGE INGLESIDE ENERGY CENTER LLC	NR	0	0
290	ENBRIDGE INGLESIDE LLC	NR	0	0
291	ENBRIDGE INGLESIDE LPG TERMINAL LLC	NR	0	0
292	ENBRIDGE INGLESIDE OIL PIPELINE LLC	NR	0	0
293	ENBRIDGE INGLESIDE CACTUS II HOLDINGS LLC	NR	0	0
294	ENBRIDGE INGLESIDE LPG PIPELINE LLC	NR	0	0
295	ENBRIDGE INGLESIDE OPERATING LLC	NR	0	0
296	ENBRIDGE INGLESIDE OIL TERMINAL LLC	NR	0	0
297	ENBRIDGE CACTUS II LLC	NR	0	0
		Total	450	550

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
ENBRIDGE GAS INC.	10520 5140 RC0002	2021-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	**120** Telephone number including area code
Andrew Wedel	(403) 231-5963

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ____________

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * 300 448,723,713

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \;\; \textbf{minus} \;\; \$ \;\; 400{,}000}{\$ \;\; 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . 310 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \;\; \textbf{minus} \;\; \$ \;\; 400{,}000}{\$ \;\; 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . 312 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
1.	Lakehead University	Enginerring
2.	Lakehead University	Enginerring
3.	Queens University	Applied Science
4.	Queens University	Applied Science
5.	Queens University	Applied Science
6.	Queens University	Applied Science
7.	Queens University	Applied Science
8.	Queens University	Applied Science
9.	Queens University	Applied Science
10.	Queens University	Applied Science
11.	Queens University	Applied Science
12.	Queens University	Applied Science
13.	Queens University	Applied Science
14.	Queens University	Applied Science
15.	Ryerson University	Chemical Engineering
16.	Ryerson University	Civil Enginerring
17.	Ryerson University	Civil Enginerring
18.	Ryerson University	Computer Science
19.	University of Calgary	Enginerring
20.	University of Calgary	Enginerring
21.	University of New Brunswick	Chemical Engineering
22.	University of New Brunswick	Chemical Engineering
23.	University of New Brunswick	Chemical Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
24.	University of New Brunswick	Chemical Engineering
25.	University of New Brunswick	Chemical Engineering
26.	University of New Brunswick	Chemical Engineering
27.	University of Toronto	Applied Science and Engineering
28.	University of Toronto	Applied Science and Engineering
29.	University of Toronto	Applied Science and Engineering
30.	University of Toronto	Applied Science and Engineering
31.	University of Toronto	Applied Science and Engineering
32.	University of Toronto	Applied Science and Engineering
33.	Queens University	Applied Science
34.	Queens University	Applied Science
35.	University of Toronto	Applied Science and Engineering
36.	University of Toronto	Applied Science and Engineering
37.	University of Waterloo	Chemical Engineering
38.	University of Waterloo	Chemical Engineering
39.	University of Windsor	Industrial Engineering
40.	University of Windsor	Industrial Engineering
41.	Western University	Mechanical Engineering
42.	Western University	Mechanical Engineering
43.		

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	Liam O'Sullivan	2021-01-02	2021-04-30
2.	Liam O'Sullivan	2021-05-01	2021-08-28
3.	Iain Moore	2021-01-02	2021-04-30
4.	Iain Moore	2021-05-01	2021-08-28
5.	Leah Capodagli	2021-01-02	2021-04-30
6.	Leah Capodagli	2021-05-01	2021-08-28
7.	Mustafa Fazal	2021-01-02	2021-04-30
8.	Mustafa Fazal	2021-05-01	2021-09-11
9.	Thomas Clayton	2021-01-02	2021-04-30
10.	Thomas Clayton	2021-05-01	2021-08-28
11.	Trevor Radder	2021-01-02	2021-04-30
12.	Trevor Radder	2021-05-01	2021-08-28
13.	Zixuan Sheng	2021-01-02	2021-04-30
14.	Zixuan Sheng	2021-05-01	2021-08-28
15.	Rabeen Raveendrakumar	2021-01-02	2021-04-24
16.	Sabrina Martins	2021-01-02	2021-04-30
17.	Sabrina Martins	2021-05-01	2021-08-28
18.	Siddharth Rawal	2021-07-03	2021-09-11
19.	Nafis Sadiq	2021-01-02	2021-04-30
20.	Nafis Sadiq	2021-05-01	2021-08-28
21.	Karyn Codjoe	2021-01-16	2021-04-30
22.	Karyn Codjoe	2021-05-01	2021-08-31
23.	Karyn Codjoe	2021-09-01	2021-12-18
24.	Sochima Nnama	2021-01-16	2021-04-30
25.	Sochima Nnama	2021-05-01	2021-08-31
26.	Sochima Nnama	2021-09-01	2021-12-18
27.	Alexander Sula	2021-01-02	2021-04-30
28.	Alexander Sula	2021-05-01	2021-08-28

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
29.	CARLY LI	2021-01-02	2021-04-30
30.	CARLY LI	2021-05-01	2021-08-28
31.	Marko Pejic	2021-01-02	2021-04-30
32.	Marko Pejic	2021-05-01	2021-08-28
33.	Nicholas Herdman	2021-01-02	2021-04-30
34.	Nicholas Herdman	2021-05-01	2021-08-28
35.	Patrick Ishimwe	2021-01-02	2021-04-30
36.	Patrick Ishimwe	2021-05-01	2021-08-28
37.	Munira Lakdawala	2021-01-16	2021-04-30
38.	Munira Lakdawala	2021-05-01	2021-07-17
39.	Aiden Banks	2021-01-02	2021-04-30
40.	Aiden Banks	2021-05-01	2021-08-28
41.	James Gielen	2021-01-02	2021-04-30
42.	James Gielen	2021-05-01	2021-08-28
43.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	20,904	25.000 %		17
2.		10.000 %	20,904	25.000 %		17
3.		10.000 %	19,555	25.000 %		17
4.		10.000 %	19,555	25.000 %		17
5.		10.000 %	24,760	25.000 %		17
6.		10.000 %	24,760	25.000 %		17
7.		10.000 %	20,524	25.000 %		17
8.		10.000 %	20,524	25.000 %		19
9.		10.000 %	19,440	25.000 %		17
10.		10.000 %	19,440	25.000 %		17
11.		10.000 %	20,845	25.000 %		17
12.		10.000 %	20,845	25.000 %		17
13.		10.000 %	19,594	25.000 %		17
14.		10.000 %	19,594	25.000 %		17
15.		10.000 %	19,505	25.000 %		16
16.		10.000 %	18,900	25.000 %		17
17.		10.000 %	18,900	25.000 %		17
18.		10.000 %	9,600	25.000 %		10
19.		10.000 %	19,963	25.000 %		17
20.		10.000 %	19,963	25.000 %		17
21.		10.000 %	16,407	25.000 %		15
22.		10.000 %	16,407	25.000 %		17
23.		10.000 %	16,407	25.000 %		15
24.		10.000 %	18,476	25.000 %		15
25.		10.000 %	18,476	25.000 %		17
26.		10.000 %	18,476	25.000 %		15
27.		10.000 %	18,485	25.000 %		17
28.		10.000 %	18,485	25.000 %		17
29.		10.000 %	19,963	25.000 %		17
30.		10.000 %	19,963	25.000 %		17
31.		10.000 %	19,633	25.000 %		17
32.		10.000 %	19,633	25.000 %		17
33.		10.000 %	19,402	25.000 %		17
34.		10.000 %	19,402	25.000 %		17
35.		10.000 %	19,352	25.000 %		17
36.		10.000 %	19,352	25.000 %		17
37.		10.000 %	18,206	25.000 %		15
38.		10.000 %	13,351	25.000 %		11
39.		10.000 %	19,320	25.000 %		17
40.		10.000 %	19,320	25.000 %		17
41.		10.000 %	19,466	25.000 %		17
42.		10.000 %	19,466	25.000 %		17
43.		10.000 %		25.000 %		

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	5,226	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
2.	5,226	3,000	3,000		3,000
3.	4,889	3,000	3,000		3,000
4.	4,889	3,000	3,000		3,000
5.	6,190	3,000	3,000		3,000
6.	6,190	3,000	3,000		3,000
7.	5,131	3,000	3,000		3,000
8.	5,131	3,000	3,000		3,000
9.	4,860	3,000	3,000		3,000
10.	4,860	3,000	3,000		3,000
11.	5,211	3,000	3,000		3,000
12.	5,211	3,000	3,000		3,000
13.	4,899	3,000	3,000		3,000
14.	4,899	3,000	3,000		3,000
15.	4,876	3,000	3,000		3,000
16.	4,725	3,000	3,000		3,000
17.	4,725	3,000	3,000		3,000
18.	2,400	3,000	2,400		2,400
19.	4,991	3,000	3,000		3,000
20.	4,991	3,000	3,000		3,000
21.	4,102	3,000	3,000		3,000
22.	4,102	3,000	3,000		3,000
23.	4,102	3,000	3,000		3,000
24.	4,619	3,000	3,000		3,000
25.	4,619	3,000	3,000		3,000
26.	4,619	3,000	3,000		3,000
27.	4,621	3,000	3,000		3,000
28.	4,621	3,000	3,000		3,000
29.	4,991	3,000	3,000		3,000
30.	4,991	3,000	3,000		3,000
31.	4,908	3,000	3,000		3,000
32.	4,908	3,000	3,000		3,000
33.	4,851	3,000	3,000		3,000
34.	4,851	3,000	3,000		3,000
35.	4,838	3,000	3,000		3,000
36.	4,838	3,000	3,000		3,000
37.	4,552	3,000	3,000		3,000
38.	3,338	3,000	3,000		3,000
39.	4,830	3,000	3,000		3,000
40.	4,830	3,000	3,000		3,000
41.	4,867	3,000	3,000		3,000
42.	4,867	3,000	3,000		3,000
43.					

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ____________ x percentage on line 170 in Part 1 ________ % = ... ____________ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009,
and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received.
Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

ACCOUNTING STANDARDS

JASON VINAGRE, MANAGER REGULATORY ACCOUNTING

1. This evidence is organized as follows:
    1. Accounting Standards
    2. Continued Use of US GAAP
    3. Changes to Accounting Policies

1. Accounting Standards

2. Enbridge Gas uses United States Generally Accepted Accounting Principles (US GAAP) as its basis of accounting and is permitted to do so for the purposes of meeting the continuous disclosure requirements for venture issuers within National Instrument 51-102 Continuous Disclosure Obligations. Securities regulators in Canada have granted Enbridge Gas exemptive relief to report under US GAAP instead of International Financial Reporting Standards (IFRS), as required by Section 3.2 of National Instrument 52-107 Acceptable Accounting Principles and Auditing Standards.

3. In 2008, the Accounting Standards Board (AcSB) of the Canadian Institute of Chartered Accountants (CICA) announced that publicly accountable enterprises were required to adopt IFRS in place of Canadian Generally Accepted Accounting Principles (CGAAP) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. Both EGD and Union operated under CGAAP in 2011 after electing to use an optional one-year deferral for adopting IFRS for qualifying entities with rate regulated activities. Such entities were permitted to continue to apply Part V – Pre-changeover accounting standards of the CICA Handbook during that period.

4. In 2011, Canadian securities regulators approved both EGD's and Union's exemptive relief to report under US GAAP instead of IFRS effective January 1, 2012. Both EGD and Union commenced reporting using US GAAP as its primary basis of accounting effective January 1, 2012. In 2012 the OEB issued its Decision(s) with Reasons granting both EGD's[1] and Union's[2] requests to use US GAAP for regulatory and rate making purposes commencing January 1, 2013.

5. In 2018, prior to the amalgamation of EGD and Union on January 1, 2019, the Alberta and Ontario Securities Commissions (the Commissions) approved the continued exemptive relief provided to each of EGD and Union and extended that relief to Enbridge Gas upon amalgamation. The parameters of the noted decision are as follows:

   [T]he Exemption Sought will terminate… on the earliest of the following:

   (i) January 1, 2024;
   (ii) if the Filer ceases to have activities subject to rate regulation, the first day of the Filer's financial year that commences after the Filer ceases to have activities subject to rate regulation; and
   (iii) the effective date prescribed by the IASB for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

6. Also in 2018, the OEB issued its Decision and Order[3] granting approval for Enbridge Gas to report under US GAAP for regulatory and rate making purposes effective January 1, 2019

[1] EB-2011-0354.
[2] EB-2011-0210.
[3] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.

2. Continued Use of US GAAP

7. In January 2023, the Commissions approved exemptive relief for Enbridge Gas to continue the use of US GAAP for financial reporting purposes until January 1, 2027. Attachment 1 sets out the Commissions' decision and parameters of that decision. /u

8. The International Accounting Standards Board (IASB) has proposed a new accounting standard that would require companies subject to rate regulation to give investors better information about their financial performance. In January 2021, the IASB published an exposure draft (ED/2021/1 on Regulatory Assets and Liabilities) with a comment period ending July 30, 2021. Since that time there has been no substantial update to the status of the exposure draft and the date of a final standard has not been announced. Based on the IASB's expectations, once a final standard is issued it would not be applicable for annual financial reporting purposes until 18 to 24 months subsequent to approval of the standard. Given the unknown timing, as well as the unknown substance of a final standard, Enbridge Gas believes it is appropriate to continue the use of US GAAP for rate making purposes in this Application and for the next IR term.

3. Changes to Accounting Policies

9. As part of the MAADs proceeding[4] it was noted that "(d)uring the deferred rebasing period, the applicants expect to change accounting policies and practices as part of the implementation of an integrated accounting system, including changes in the calculation of depreciation rates and its cost capitalization policy.

10. Since 2019, as part of the annual Utility Earnings and Disposition of Deferral & Variance Account Balances Application, Enbridge Gas has provided details of the

[4] EB-2017-0306/EB-2017-0307.

policies that have been harmonized and the resulting revenue requirement impacts. These impacts have been recorded and accumulated in the Accounting Policy Changes Deferral Account (APCDA). Please see Exhibit 9, Tab 2, Schedule 1 for further details of the accounting policy changes that resulted from amalgamation.

11. The following policies have been implemented during the deferred rebasing term and/or are proposed to be harmonized as of 2024:
    a) Unregulated storage allocation (please see Exhibit 1, Tab 13, Schedule 2)
    b) Capitalization (please see Exhibit 2, Tab 4, Schedule 1)
    c) Capitalization of overhead (please see Exhibit 2, Tab 4, Schedule 2)
    d) Depreciation (please see Exhibit 4, Tab 5, Schedule 1)

12. Beyond the policy changes implemented as part of amalgamation harmonization as noted above, EGD, Union and Enbridge Gas each have continuously monitored accounting standards updates from the Financial Accounting Standards Board for US GAAP standard changes required to be adopted and implemented. Since the 2012 OEB Decisions[5], there have been no material impacts to revenue requirement (i.e. greater than $1 million) from accounting policy changes due to the implementation of new accounting standards.

13. The items listed below are a summary of adopted accounting standard updates and the related impacts to Enbridge Gas. Table 1 shows the accounting standard updates (ASU) that had no impact, or an immaterial impact, on utility revenue requirement. Table 2 shows the accounting standard updates that impacted financial statement presentation and/or disclosure only.

[5] EB-2011-0354 and EB-2011-0210.

Table 1
Accounting Standard Updates That Had No Impact or An Immaterial Impact

Accounting Standard Update	Adoption date	Summary Description
Presentation of Unrecognized Tax Benefits ASU 2013-11	December 31, 2013 (EGD); January 1, 2014 (Union)	Requires presentation of unrecognized tax benefits as a reduction to a deferred tax asset for a net operating loss carryforward unless specific conditions exist.
Obligations Resulting from Joint and Several Liability Arrangements ASU 2013-04	January 1, 2014	Provides measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements.
Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements ASU 2015-15	January 1, 2016	Clarifies that debt issuance costs associated with line-of-credit arrangements may be deferred as an asset and subsequently amortized over the term of the arrangement.
Measurement Date of Defined Benefit Obligation and Plan Assets ASU 2015-04	January 1, 2016	Simplifies the fair value measurement of defined benefit plan assets and obligations.
Improving the Presentation of Net Periodic Benefit Cost related to Defined Benefit Plans ASU 2017-07	January 1, 2018	Improves the income statement presentation of the components of net periodic pension cost and net periodic postretirement benefit cost for an entity's sponsored defined benefit pension and other postretirement plans.
Simplifying Cash Flow Classification ASU 2016-15	January 1, 2018	Reduces diversity in practice of how certain cash receipts and cash payments are classified in the statement of cash flows.
Recognition and Measurement of Financial Assets and Liabilities ASU 2016-01	January 1, 2018	Addresses certain aspects of recognition, measurement, presentation and disclosure of financial assets and liabilities. Investments in equity securities, excluding equity method and consolidated

Accounting Standard Update	Adoption date	Summary Description
		investments, are no longer classified as trading or available-for-sale securities.
Cloud Computing Arrangements ASU 2018-15	January 1, 2019	Provide guidance on the accounting for implementation costs incurred in a cloud computing arrangement that is a service contract. The ASU specifies that an entity would apply Accounting Standards Codification 350-40, internal-use software, to determine which implementation costs related to a hosting arrangement that is a service contract should be capitalized and which should be expensed.
Recognition of Leases ASU 2016-02	January 1, 2019	Requires recognition of an arrangement as a lease when a customer in the arrangement has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset.
Accounting for Credit Losses ASU 2016-13	January 1, 2020	Adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes results in more timely recognition of such losses.
Accounting for Income Taxes ASU 2019-12	January 1, 2021	Removes certain exceptions to the general principles in ASC 740 Income Taxes as well as provides simplification by clarifying and amending existing guidance

Table 2
Accounting Standard Updates That Impacted Financial Statement Presentation and/or Disclosure Only

Accounting Standard Update	Adoption date	Summary Description
Balance Sheet Offsetting ASU 2011-11, ASU 2013-01	January 1, 2013	Requires enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position.
Accumulated Other Comprehensive Income ASU 2013-02	January 1, 2013	Requires enhanced disclosures on amounts reclassified out of Accumulated Other Comprehensive Income.
Classification of Deferred Taxes on the Statement of Financial Position ASU 2015-17	December 31, 2015 (Union): January 1, 2016 (EGD)	Requires that deferred tax liabilities and assets be classified as noncurrent in the statements of financial position.
Simplifying the Presentation of Debt Issuance Costs ASU 2015-03	December 31, 2015 (Union): January 1, 2016 (EGD)	Requires debt issuance costs related to a recognized debt liability to be presented in the statements of financial position as a direct deduction from the carrying amount of that debt liability, consistent with the presentation of debt discounts or premiums.
Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows ASU 2016-18	January 1, 2018	Clarifies guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the statement of cash flows.
Revenue from Contracts with Customers ASU 2014-09	January 1, 2018	Establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements.
Disclosure Effectiveness ASU 2018-13	January 1, 2020	Improves the disclosure requirements for fair value measurements by eliminating and modifying some disclosures, while also adding new disclosures.
Disclosures About Government Assistance ASU 2021-10	January 1, 2022	Adds new disclosure requirements for transactions with governments that are accounted for using a grant or contribution accounting model by analogy.

Citation: Re Enbridge Pipelines Inc., 2023 ABASC 3 **Date: 20230104**

In the Matter of
the Securities Legislation of
Alberta and Ontario (the **Jurisdictions**)

and

In the Matter of
the Process for Exemptive Relief Applications in Multiple Jurisdictions

and

In the Matter of
Enbridge Gas Inc., Enbridge Pipelines Inc. and Westcoast Energy Inc. (the **Filers**)

Decision

Background

The securities regulatory authority or regulator in each of the Jurisdictions (each a **Decision Maker**) has received an application (the **Application**) from the Filers for a decision under the securities legislation of the Jurisdictions (the **Legislation**) for an exemption (the **Exemption Sought**) from the requirements under section 3.2 of National Instrument 52-107 *Acceptable Accounting Principles and Auditing Standards* (**NI 52-107**) that the financial statements of the Filers (a) be prepared in accordance with Canadian GAAP applicable to publicly accountable enterprises (**Canadian GAAP**) and (b) disclose an unreserved statement of compliance with IFRS in the case of annual financial statements and an unreserved statement of compliance with IAS 34 in the case of an interim financial report.

The Exemption Sought is similar to the exemption granted to the Filers on May 25, 2018 in *Re Enbridge Gas Distribution Inc.*, 2018 ABASC 81 and on May 25, 2018 in *Re Westcoast Energy Inc.*, 2018 ABASC 82 (collectively, the **U.S. GAAP Relief**).

Under the Process for Exemptive Relief Applications in Multiple Jurisdictions (for a dual application):

(a) the Alberta Securities Commission is the principal regulator for this application;

(b) the Filers have provided notice that section 4.7(1) of Multilateral Instrument 11-102 *Passport System* (**MI 11-102**) is intended to be relied upon in British Columbia, Saskatchewan, Manitoba, Québec, New Brunswick, Prince Edward Island, Nova Scotia and Newfoundland and Labrador (the **Passport Jurisdictions**), and

(c) this decision is the decision of the Principal Regulator and evidences the decision of the securities regulatory authority or regulator in Ontario.

Interpretation
In this decision:

(a) unless otherwise defined herein, terms defined in National Instrument 14-101 *Definitions*, MI 11-102 or NI 52-107 have the same meaning; and

(b) rate-regulated activities has the meaning ascribed thereto in the Chartered Professional Accountants of Canada Handbook (**Handbook**).

Representations
This decision is based on the following facts represented by the Filers:

1. Enbridge Inc. (**EI**), Enbridge Pipelines Inc. and Westcoast Energy Inc. are continued under the *Canada Business Corporations Act* and each of their head offices is located in Calgary, Alberta.

2. Enbridge Gas Inc. is governed by the *Business Corporations Act* (Ontario) and its head office is located in North York, Ontario.

3. Each of the Filers is a reporting issuer or equivalent in the Jurisdictions and each of the Passport Jurisdictions and is not in default of securities legislation in any jurisdiction in Canada.

4. Each of the Filers currently prepares and files its financial statements for annual and interim periods in accordance with U.S. GAAP, relying on the U.S. GAAP Relief.

5. Each of the Filers has rate-regulated activities.

6. Each of the Filers are indirect wholly-owned subsidiaries of EI.

7. The financial statements of each of the Filers are consolidated into the financial statements of EI.

8. EI is an SEC issuer and relies on section 3.7 of NI 52-107 to file financial statements prepared in accordance with U.S. GAAP.

9. None of the Filers is currently an SEC issuer.

10. Were any of the Filers SEC issuers, they would be permitted by section 3.7 of NI 52-107 to file their financial statements prepared in accordance with U.S. GAAP.

11. The U.S. GAAP Relief provided that it would cease to apply to the Filers on the earliest of: (a) January 1, 2024; (b) if the Filer ceased to have activities subject to rate regulation, the first day of the Filer's financial year that commenced after the Filer ceased to have activities subject to rate regulation; and (c) the effective date prescribed by the International Accounting Standards Board (**IASB**) for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation. Accordingly, in the absence of further relief provided by Canadian securities regulators, the Filers would become subject to Canadian GAAP no later than January 1, 2024. Canadian GAAP includes IFRS as incorporated into the Handbook.

12. In January 2021, the IASB published the Exposure Draft - Regulatory Assets and Regulatory Liabilities, which introduces a proposed standard of accounting for regulatory assets and liabilities applicable to entities with rate-regulated activities. The issuance by the IASB of a standard within IFRS for entities with rate-regulated activities (a **Mandatory Rate-regulated Standard**) would have resulted in the expiry of the U.S. GAAP Relief, giving rise to the obligation of the Filers to commence financial statement preparation and reporting in accordance with IFRS pursuant to NI 52-107.

13. It is not yet known when the IASB will finalize and implement such a standard and the Filers will require sufficient time to: (a) interpret and implement such standard and transition from financial statement preparation and reporting in accordance with U.S. GAAP to IFRS; and (b) interpret and reconcile the implications on the customer rate setting process resulting from the implementation.

Decision

Each of the Decision Makers is satisfied that the decision meets the test set out in the Legislation for the Decision Maker to make the decision.

The decision of the Decision Makers under the Legislation is that:

(a) the U.S. GAAP Relief is revoked;

(b) the Exemption Sought is granted to each Filer in respect of such Filer's financial statements required to be filed on or after the date of this decision, provided that the Filer prepares those financial statements in accordance with U.S. GAAP; and

(c) the Exemption Sought will terminate in respect of each Filer on the earliest of the following:

(i) January 1, 2027;

(ii) if the Filer ceases to have rate-regulated activities, the first day of the Filer's financial year that commences after the Filer ceases to have rate-regulated activities; and

(iii) the first day of the Filer's financial year that commences on or following the later of:

A. the effective date prescribed by the IASB for a Mandatory Rate-regulated Standard; and

B. two years after the IASB publishes the final version of a Mandatory Rate-regulated Standard.

For the Commission:

"original signed by"	*"original signed by"*
Tom Cotter	Kari Horn
Vice-Chair	Vice-Chair

UTILITY CONSOLIDATION

TRINETTE LINDLEY, MANAGER UTILITY PORTFOLIO MANAGEMENT
DANIELLE DREVENY, MANAGER CAPITAL FINANCIAL PLANNING & ANALYSIS
TANYA FERGUSON, VICE PRESIDENT FINANCE & BUSINESS PARTNER

1. This evidence documents the integration activities and results of Enbridge Gas, the largest utility in Ontario to file a rebasing application with the OEB after operating under a deferred rebasing term. Notwithstanding the fact that the MAADs Decision[1] with a shortened 5-year term was followed by a period of significant global uncertainty, the utility aggressively delivered extensive integration benefits while continuing to deliver safe, reliable operations to 3.8 million customers. This evidence compiles both the quantitative and qualitative benefits achieved during the deferred rebasing term and the future cost treatment for the net book value of integration capital. Enbridge Gas vigorously sought out opportunities, over-achieving on the estimated savings in the MAADs Application[2]. Even with the 5-year term, Enbridge Gas invested in and delivered significant integration initiatives which result in sustainable savings to be passed on to customers at rebasing, with the net book value of these assets to be included in rate base. Integration benefits are broader than the quantitative savings achieved through aligned systems and programs that enable improvements for the same cost to customers, furthering the effectiveness as one utility. The fact that these complex, multi-faceted initiatives were delivered during the challenges of a global pandemic, further demonstrates Enbridge Gas's commitment to realizing the full benefits of integration. These ongoing benefits advance safe, reliable, and efficient business operations at

[1] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.
[2] EB-2017-0306/EB-2017-0307, Exhibit B, Tab 1, page 26, Table 4.

Enbridge Gas and strengthen its ability to respond to customer needs and market evolution in the future.

2. This evidence is organized as follows:
    1. Background: MAADs Application and OEB Decision
    2. Integration Achievements and Results (Benefits and Costs)
    3. Summary

<u>1. Background: MAADs Application and OEB Decision</u>

3. Prior to amalgamation, EGD and Union operated under successive Incentive Regulation (IR) frameworks for over 15 years. This paradigm left limited ability to continue to deliver incremental benefits as separate companies. Amalgamation provided an opportunity to deliver significant and sustainable benefits to current and future customers in Ontario and the synergies achieved and incorporated into rebasing demonstrate that customers are better off than they otherwise would have been had the utilities continued to operate as separate companies.

4. The MAADs Application[3] contemplated a 10-year term to enable the significant investments required to deliver estimated savings. Integration opportunities were anticipated in Customer Care, Distribution Work Management, Utility Shared Services, Storage and Transmission Operations, Management and Other functions. Table 1 notes the high-level ranges of savings and costs as filed in the MAADs Application, noting that there was no detailed planning, and planning would be completed upon receipt of the OEB's Decision.

[3] EB-2017-0306/EB-2017-0307.

Table 1
High Level Minimum and Maximum Cost and Savings Estimate
as filed in EB 2017-0306

Line No.	Particulars ($ millions)	Potential Capital Investment		Potential O&M Savings	
		Minimum	Maximum	Minimum	Maximum
1	Customer Service	25	110	120	250
2	Distribution Work Management	10	90	30	150
3	Shared Services	5	20	15	50
4	Storage & Transmission	5	10	15	50
5	Management Functions & Other	5	20	170	250
6	Total	50	250	350	750

Notes:
(1) Estimates as filed in EB-2017-0306.
(2) Filing contemplated 10 year deferred rebasing term.

5. As noted, the OEB Decision for the MAADs Application stipulated a 5-year term.[4] Enbridge Gas undertook significant investments during the rebasing term, in both O&M and capital, to deliver the anticipated savings. Enbridge Gas defined integration costs as one-time incremental costs required to deliver value for an opportunity or set of opportunities related to utility integration, and included items such as labour, consulting, and capital expenditures. Integration costs, both O&M and capital expenditures, were identified and managed separately throughout the deferred rebasing term. These investments were made to deliver the highest level of sustainable savings to customers, even as investments in the latter years of the term provide limited opportunity for Enbridge Gas to benefit from these investments as the sustained savings would be rebased at the end of the deferred rebasing term. At the time these savings are rebased to customers, so are the corresponding net book value of integration capital costs of those investments.

[4] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.

2. Integration Achievements and Results (Benefits and Costs)

6. Integration results were delivered through a portfolio of initiatives governed by senior leadership and enabled through a program office. The portfolio included initiatives for organizational restructuring, alignment of policies, processes, systems and procedures, integration of operating models, alignment for customers, and cost rationalization. Initiatives were prioritized based on strategic alignment, quantitative and qualitative benefits and costs, and customer impacts. While many initiatives delivered synergy savings, other initiatives were implemented to support safe, reliable, and effective operations, and were not driven by synergy savings. These initiatives leveraged the strong history of the utilities' experiences and delivered solutions to operate and manage risk, providing benefits to customers and stakeholders.

7. Enbridge Gas moved swiftly to deliver on integration activities upon receiving approval to amalgamate. Starting in 2019, Enbridge Gas tracked synergy savings and costs from integration initiatives in each area of accountability that were brought about under conditions made possible by amalgamation. Table 2 summarizes the savings by category to articulate the types of initiatives that delivered savings, and Table 3 by area of accountability to demonstrate where those corresponding savings were achieved.

Table 2
Integration Savings as Achieved by Category

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year
		(a)	(b)	(c)	(d)	(e)
1	Organizational Restructuring	25.1	41.8	54.8	54.8	54.8
2	Alignment for Customers	2.9	2.9	1.8	16.8	16.8
3	Policies, Programs, Processes & Procedures Alignment	1.7	3.4	4.0	4.1	4.3
4	Integration of Operating Models	-	0.1	5.7	5.2	5.2
5	Cost Rationalization	2.6	4.2	4.9	4.9	4.9
6	Total Annual Savings	32.3	52.4	71.2	85.8	86.0
7	Sustained Savings included in Rebasing					86.0

Table 3
Integration Savings as Achieved by Area

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year
		(a)	(b)	(c)	(d)	(e)
	O&M Savings					
1	Business Development & Regulatory	6.8	9.6	10.4	10.4	10.4
2	Customer Care	5.5	6.6	7.5	22.5	22.5
3	Distribution Operations	6.3	9.8	17.3	16.8	16.8
4	Energy Services	2.6	5.6	5.9	5.9	5.9
5	Engineering & STO	5.2	9.0	11.6	11.6	11.8
6	Central Functions	3.9	9.1	15.7	15.8	15.8
7	Other	2.0	2.7	2.8	2.8	2.8
8	Total Annual Savings	32.2	52.4	71.2	85.8	86.0

2.1. Organizational Restructuring

8. Organizational restructuring was the largest contributor to integration savings. The initial organizational restructuring was delivered by the end of first quarter in 2019

across all departmental areas to reduce duplication and align accountabilities. One of the first steps was to establish Enbridge Gas's new Executive Management Team and Senior Management Team to engage in planning for the complex initiatives anticipated. The layer-by-layer approach that followed to organizational restructuring reduced duplication and clarified accountabilities across the utility, setting in motion the significant efforts to deliver the integrated technology system solutions and process initiatives to move forward with amalgamation. In total, this rationalized structure delivered $25 million in savings in 2019 with the full year impact growing to over $34 million by 2020.

9. In addition to the initial restructuring in 2019 at the utility, Enbridge introduced a Voluntary Workforce Option (VWO) Program in 2020 which offered employees incentives for early retirement, part-time or job-sharing arrangements, leave of absence, or voluntary exits that contributed to compensation savings. While this was an Enbridge initiative in response to COVID-19, VWO served to facilitate synergy savings through changes in processes, and rationalization of programs with approximately 244 full-time equivalent (FTE) reductions at Enbridge Gas. VWO savings were realized in all departments and within Central Functions. Sustainable savings from VWO amounted to $7.4 million in 2020 and increased to $18.8 million annually starting 2021. These savings are reflected in the areas in which the savings were achieved. Please see Exhibit 4, Tab 4, Section 3 for more details on Enbridge Gas FTEs and employee compensation.

10. As a result of role rationalization in organizational restructuring efforts in 2019 and VWO in 2020, certain employees were re-deployed to work exclusively on integration projects with their corresponding costs captured in the projects. These

integration projects are expected to be complete by 2023, and as such, these project roles and related costs will no longer be required in 2024.

11. Integration benefits extended beyond quantitative synergy savings and delivered day to day benefits to further safety, reliability, and an aligned customer experience. Table 4 shares examples of these types of initiatives, with further descriptions in each area of accountability.

Table 4
Initiative Categories delivering Qualitative Benefits

Type of Initiative	Description of Benefits	Initiative Examples
Alignment of Policies, Programs, Processes and Procedures	Harmonized policies, programs, technical and business standards, processes and procedures, and technologies to conduct work and manage risks consistently supporting safe, reliable, and effective business operations for the utility.	Integrated Management System (IMS): with programs such as Emergency Response, Integrity, Damage Prevention Cost of Gas Automation Solution Quality Improvement Program EHS Training Program Integration
Alignment for our Customers	Alignment for customers for customer interactions and communications, with a focus on a consistent customer experience.	Website Integration Social Media, Brand Alignment General Service Rate and Service Harmonization Proposal Large Volume Operating Rules and Process Harmonization
Alignment of Asset Management Programs	Asset Management alignment for systems, programs, and processes with respect to managing the life cycle of capital assets.	Consolidated Asset Plans CopperLeaf C55 Implementation
Integration & Execution of Operating Models	Consistent delivery and operating models and how functional areas are structured to deliver services to stakeholders.	Distribution Operations Workflow Integration Storage & Transmission Work and Resource Strategy Distribution Operations Work Management Integration

2.2. Integration Benefits by Area of Accountability

12. The integration synergies listed in Table 2 and 3 and other qualitative benefits noted in Table 4 for each area of accountability are described in the following

paragraphs. As the utility established a new organizational structure, savings contemplated in the MAADs filing were delivered by the respective areas of accountability: Distribution Work Management integration efforts were delivered within Distribution Operations; Customer Care delivered foundational integration through a common Customer Information System; Storage and Transmission Operational synergies were delivered between Energy Services and Engineering and Storage and Transmission Operations. Utility Shared Services savings were delivered through Central Functions.

Business Development & Regulatory

13. In Business Development & Regulatory (BD&R), integration savings were realized in areas where services and processes were integrated. Savings were realized through restructuring alignment in 2019 which delivered $5.2 million in sustainable savings and VWO achieved $1.3 million in sustainable savings. BD&R also realized integration savings through a reduction of intervenor costs of $1.2 million as EGD and Union no longer require separate proceedings. The consolidation of membership and subscription services like the Canadian Gas Association and Ontario Energy Association also delivered $0.5 million in sustainable savings.

14. In addition to the financial savings, integration to a common website and social media accounts provided common platforms for customers and stakeholders to interact with Enbridge Gas in a consistent manner. The common media platforms enabled communications channels for emergency response, marketing campaigns, and awareness messages.

Customer Care

15. Customer Care restructuring alignment in 2019 delivered $2.7 million and VWO in 2020 delivered $2.9 million per year in sustainable savings. One of the most significant benefits of integration was achieved through the Customer Information System (CIS) consolidation which delivered $16.1 million in O&M savings starting in 2022. Implemented in July 2021, the creation of a common CIS served to align billing processes, deliver enhancements on a unified platform, and deliver savings through the decommissioning of Union's instance of the Banner CIS and the elimination of third-party contract costs. This integration initiative migrated 1.6 million customers to a single CIS on the SAP 4 HANA platform in use for EGD customers. This project also consolidated customers into one MyAccount system, one Interactive Voice Response (IVR) system, and a consolidated website. The project provided consistent processes and procedures for employees and customers, an enhanced user experience through efficient access to information, and a single integrated system to connect stakeholders across the organization. Stabilization for this complex system integration continued throughout 2022 with change management efforts including augmented staffing and enhanced training for staff and support teams, along with continued system enhancements in response to customer feedback.

16. In addition, the alignment of meter reading schedules across the utility from monthly readings to alternate-month readings delivered integration savings of $2.7 million in 2019 and 2020, subsequently reduced to $0.9 million in 2021 as a result of higher contract costs with a new vendor.

17. Within the contract rate market, harmonized rules for setting contract parameters and authorization of overrun, and common customer communication templates were established to create a more consistent customer experience across all rate

zones. These changes support future growth opportunities, while reducing the effort for contract renewals, and increasing the level of transparency for customers.

Distribution Operations

18. Distribution Operations restructuring alignment in 2019 delivered $6.4 million and VWO in 2020 delivered $1.7 million per year in sustainable savings. Savings were realized through a portfolio of integration initiatives undertaken to deliver consistent and efficient distribution work management practices across Enbridge Gas. Distribution work management includes the planning, scheduling, compliance, work management systems (WMS), WMS support, asset management, and support for overall work to maintain Enbridge Gas's assets across the utility. The Work Management initiative consolidated Work Management Centers from twelve centers to three. In addition to the consolidation, the strategy also aligned the organizational structure within the centers as well as harmonized processes and systems for Operations' front and back-end work functions that support planning, scheduling, execution, and analysis of field distribution maintenance work. The Work Management initiative resulted in approximately $1.9 million in savings starting in 2021.

19. To enable this harmonization and optimization of work management practices and supporting savings, Enbridge Gas undertook a multi-year, phased project to integrate the asset and work management system (AWS) onto a common platform, Maximo. Phase 1 was completed in July 2021 and delivered efficiencies through a common system and processes for planning work, and harmonized policies, processes, and procedures for distribution maintenance operations. The Phase 1 deployment created improved visibility of utility work orders across Enbridge Gas operations, streamlined reporting and decision-making opportunities, and

eliminated duplicate systems. In parallel with the harmonization of the Maximo asset and work management system, Distribution Operations field technicians and supporting staff were deployed with a consolidated technology solution, ClickSoftware Field Service Edge (FSE), for executing work in the field. The implementation of the field device impacted over 1,000 end users.

20. Distribution Operations also realized additional savings from lower FTEs due to the implementation of an integrated work and resource strategy. This comprehensive strategy established an aligned operating model for how internal and external field operations resources are managed to optimize Enbridge Gas's best-in-class safety, reliability, quality, customer, and cost performance. A significant component of this strategy was to align on the use of contractors for specific work activities. For regions in Union's previous franchise area, this meant shifting more day-to-day work to the Extended Alliance vendors. FTE, contractor, and burden savings were $2.7 million in 2021 and $2.2 million in annual sustainable savings thereafter.

21. Distribution Operations also achieved synergy savings through other initiatives including the fleet and garage strategy, and warehouse consolidation. Operations integrated the maintenance of fleet vehicles for EGD and Union through outsourcing. Implementing the fleet and garage strategy delivered $2.1 million of savings. Warehouse consolidation reduced the cost of maintaining multiple warehouses and a number of duplicate roles. Two locations were closed, and inventory was consolidated in the remaining five warehouses resulting in $0.3 million in sustained savings.

22. In addition, Distribution Operations delivered initiatives that produced $0.8 million in savings through integration that enabled further alignment, including adoption of a common emergency response process, and aligned emergency call handling

procedures. The expanded use of Alternate Locate Agreement (ALA) contracts improved locates efficiency and reduced locates costs by providing contractors more flexibility to manage locate requests within a larger time allotment.

23. As EGD and Union operated in distinct service areas, there was no fundamental overlap in the maintenance work orders generated, or volume of emergency calls, however the qualitative benefits of common processes, clear accountabilities, and consistent outreach delivers value to stakeholders and customers through common channels for delivery and response expectations. Through the implementation of a single Emergency Operations Centre and harmonized Incident Command protocols, the utility has common response structures supporting safety and reliability and predictability for stakeholders. Furthermore, by establishing a single Emergency Dispatch Centre aligning the receipt and dispatch of emergency calls, the Company continued to enhance the safety and reliability of operations.

24. Fundamental to safety and reliability, was establishing a common Damage Reduction Program building on the strong foundation of safety in each utility. This program represents the implementation of a collection of strategic, harmonized multi-year initiatives aimed at reducing third-party damages to GDS assets. Initiatives are centered on awareness, education, and partnerships, and advertising and marketing to ensure EGI effectively communicates and engages with contractors and homeowners. Additionally, technology and predictive analytics enable a more proactive approach to distribution protection measures and practices.

Energy Services

25. Energy Services restructuring alignment in 2019 delivered $4.7 million and 2020 VWO delivered $0.7 million in sustainable savings. Energy Services delivered early

synergies in 2019 through the centralization of the Gas Control and Nominations teams along with the Supervisory Control and Data Acquisition (SCADA) system. Prior to amalgamation, separate gas control centers were in operation, each using different scheduling systems and processes. This integration effort migrated EGD's control centre operations from Edmonton to a consolidated Enbridge Gas Control Centre in Chatham and the EGD assets into the SCADA system. The centralization of functions and consolidation of SCADA technology optimized operational costs by streamlining operational gas management across the system and aligning processes. Savings are included in the 2019 restructuring effort.

26. In early 2022, the Cost of Gas (COG) Project was implemented, delivering integrated processes into an automated utility gas purchase and financial reporting system in SAP for Energy Services and Finance. The integrated system and processes provide aligned automated functionality for gas inventory and financial reporting related to gas costs across Enbridge Gas, including contracting, purchasing, invoicing, and nominations. The benefits of this system are process consistency and accurate reporting and management of gas costs for Enbridge Gas.

Engineering and Storage and Transmission Operations (STO)

27. Engineering and STO restructuring efforts in 2019 delivered $6.6 million and VWO in 2020 contributed $2.9 million in sustainable savings. Within Engineering and STO, consolidation of separate meter shops and harmonization of accreditation audits contributed to $1.2 million savings starting in 2021 and provides a streamlined approach to effectively manage Enbridge Gas's metering asset life cycle. As well, harmonization of storage and transmission operations at the Dawn and Tecumseh locations identified opportunities to reduce duplication, and create optimal resourcing solutions leveraging internal employees, contractors, and

partner resources. An example of delivering consistency in processes and operating models was the transfer of corrosion survey accountabilities to the Distribution Protection team in Distribution Operations. The restructuring savings includes the harmonization of storage and transmission operations at Dawn and Tecumseh achieved through repurposing of roles to efficiently insource certain activities previously conducted by external service providers such as third-party observation for well drilling and inspection at Tecumseh.

28. Engineering also delivered a comprehensive Content Management Program (CMP), an initiative focused on harmonizing EGD and Union content, including standard operating practices and other technical and business-related processes and procedures. The CMP established standards for how content is stored, updated, and delivered throughout the Company. This consistency ensures documentation can be retrieved in a consistent format, resulting in consistency in accessing procedures, and updating and rolling out changes across the Company. These consistent standards were further used with the approximately 500 business process and procedures that were harmonized to support the safe and efficient delivery of work as part of the AWS and CIS implementations in 2021.

29. Harmonizing the Integrated Management System (IMS) for the Company was led by the Engineering department. This umbrella program harmonized the IMS governance and framework of the eight IMS management programs to meet requirements that support safe and reliable operations. Another initiative was delivered to align, integrate, and enhance the Quality Management Program, including implementing a single, consistent Operator Qualification Program, a Quality Assurance framework for the utility with aligned quality assurance checklists to support the evaluations of harmonized processes for Utilization, Operations (including Stations), Construction and Material Quality Assurance Programs for PE

Pipe, pressure reducing regulators, and Fusion Iron Heater Faces. In addition, a consistent Quality Material Equipment Report Program across Enbridge Gas was implemented.

30. Another integration milestone was a consolidated Asset Management Plan (AMP) for the Company, first filed with the OEB in October 2020. The AMP supports the financial planning and provides the basis for the long-range plan. Through this effort a consistent value-based decision-making framework was developed to standardize the approach to optimizing the investment portfolio based on cost, risk, and performance. The project required the establishment of a common AMP approach, processes, and procedures, including the corresponding tools that are used to support decision making.

Central Functions

31. Central Functions savings of $5.6 million were realized as a result of 2019 Restructuring and $9.1 million due to VWO. Throughout the deferred rebasing term, benefits were achieved in central functions by eliminating duplication of shared services and systems. This simplification further supports reliability through modernized, standardized systems and promotes customer and process alignment. Examples of simplified technology applications include the aligned Enbridge Gas website, CIS, Cost of Gas system, and AWS (Maximo). This technology rationalization also enabled common processes for customers and stakeholders in their experiences and interactions with Enbridge Gas.

32. Also, within Central Functions, an immediate opportunity was addressed to reduce leased real estate in Toronto where both utilities leased spaces for proximity to key stakeholders. Lease savings of $1 million were achieved starting in 2020 from locations that were no longer required following the consolidation of office spaces.

Summarized benefits of Utility Integration

33. Overall, the significant efforts undertaken by the Company throughout the deferred rebasing term are expected to deliver $86 million of annual sustained savings that will constitute savings to customers in the 2024 Test Year. In addition to the savings noted by area above, qualitative benefits were delivered as policies, programs, and systems were aligned furthering consistency and effectiveness across the utility benefiting customers, communities, and stakeholders.

2.3. Integration O&M Costs

34. To deliver the integration benefits and the savings to be passed on to customers at rebasing, O&M costs associated with integration were tracked separately over the deferred rebasing term. These costs will no longer be required beyond 2023 and were not reflected in rates during the deferred rebasing term, and as such were borne by the utility. Also included are severance costs associated with any FTE reductions brought about by restructuring. While many of the above initiatives achieved savings, some of the integration-related costs for business operations do not result in quantitative savings, however, they were fundamental to Enbridge Gas being able to deliver on integration while maintaining its safety and reliability commitments.

35. Integration initiatives have spanned all departments including Central Functions. The O&M costs largely represent dedicated FTEs and consultants working on aligning processes and procedures, harmonizing methodologies, and implementing common tools and systems. A number of these initiatives have contributed to the synergy savings referenced, with the savings sustained through the deferred rebasing term and beyond. As of the end of 2021, two-thirds of an expected $161 million of projected integration initiative costs over the 2019 to 2023 period has

been spent. Table 5 shows the integration costs by department, along with integration severance for the 2019 restructuring and 2020 VWO. By the end of 2023, significant progress on integration will be realized with benefits being passed on to customers and integration-related costs being eliminated.

Table 5
Integration O&M Costs Schedule by Area

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	Total
		(a)	(b)	(c)	(d)	(e)	(f)
	O&M Costs						
1	Business Development & Regulatory	-	0.3	0.9	0.4	0.5	2.1
2	Customer Care	2.0	14.0	13.8	0.4	0.5	30.8
3	Distribution Operations	2.6	18.0	21.9	22.7	10.9	76.2
4	Energy Services	0.7	1.0	0.5	0.6	0.6	3.3
5	Engineering & STO	1.6	8.3	6.9	8.9	6.2	31.9
6	Other Functions	3.2	4.8	5.8	2.2	0.9	16.9
7	Subtotal for O&M Integration Costs	10.2	46.4	49.8	35.2	19.5	161.1
8	Integration Severance	41.5	77.7				
9	Total Integration O&M Costs	51.7	124.1	49.8	35.2	19.5	280.3

36. Distribution Operations is expected to incur $76.2 million of integration costs over the deferred rebasing term. Consultant costs totaling $27.2 million and integration staff totaling $25.1 million comprise most of Distribution Operations' integration costs. Consultants have been tasked with providing subject matter expertise, industry best practices and project management for initiatives such as the Work & Resource Strategy, Work Management Initiative, and the Fleet Strategy, while integration staff have focused on policy, procedure, and system alignment. In addition, $16.1 million will have been spent by the end of 2023 on Asset and Work Management System (AWS) alignment initiatives, which bring together the management of frontline operational work, the scheduling and execution of field work, and customer interaction into an integrated, common set of platforms. Other

integration activities include $3.2 million to implement an outsourced model for meter work and $2.9 million to update EGD and Union pipeline markers to Enbridge Gas pipeline markers.

37. Engineering and STO is expected to incur $31.9 million of integration costs over the deferred rebasing term. The largest integration initiative led from this department incurred a cost of $16.5 million for the alignment of engineering policies and procedures through the Content Management Program. In the Storage and Transmission area, $4.7 million was spent to align storage training, documentation, and system policies and procedures. Other integration initiatives include $4.1 million for harmonizing the Integrated Management System (IMS) processes, and the alignment of Technical Training and Records policies and procedures, $2.7 million for system updates to include Union transmission pipelines into the Integrity Assessment Program, and $1.1 million for meter shop work and resource strategy which consolidated multiple meter shops and harmonized accreditation audits. The remaining costs incurred were primarily to consolidate programs including $.9 million for the integration of the asset plan and $.4 million consolidating the records management department.

38. Customer Care is expected to incur approximately $30.8 million in integration costs over the deferred rebasing term, primarily due to $27.5 million for CIS harmonization. These O&M costs included training, change management, stakeholder engagement, software, cloud, and data conversion costs required to enable the new system and processes. The project delivered a common system for Enbridge Gas, resulting in savings of approximately $15 million annually starting in 2022. Customer Care will also incur $2.1 million of integration staff costs supporting harmonization for customer care process and procedures over the deferred rebasing term which will not carry over into the 2024 Test Year.

39. Energy Services and BD&R are expected to incur $3.3 million and $2.1 million respectively, in integration costs over the deferred rebasing term. For Energy Services, integration staff in the Utility Portfolio Management (UPM) team have been providing oversight, tracking and support for all integration initiatives across the organization. For BD&R, integration initiatives are primarily Regulatory-related where $1.5 million will be spent on resources to develop harmonization proposals in preparation of the 2024 Rebasing Application. Costs in these areas support the coordination of multiple integration initiatives due to the inter-related changes across the portfolio.

40. Central Functions expect to incur $16.9 million in integration related costs with most spent as of 2021. These integration costs are primarily comprised of $10.3 million for Finance consultants leading process alignment initiatives such as the harmonized depreciation study, harmonized overhead capitalization methodology and unregulated storage allocation study; along with $4.4 million of Finance integration staff supporting integration activities such as alignment of financial data into a single source, alignment and consolidation of reporting and the development of harmonization proposals for rebasing application. Other integration costs include $2.1 million for supply chain harmonization, commercial contract renegotiations, and TIS alignment.

41. Severance costs related to integration were $41.5 million in 2019 and $77.7 million in 2020. In 2019, the severance costs are due to the initial Enbridge Gas organization restructuring and role rationalization. In 2020, the severance costs are due to the VWO program. No significant integration related severance costs were incurred in 2021, nor are any expected in 2022 and 2023. Please see Exhibit 4, Tab 4, Section 3 for more details on Enbridge Gas FTEs and employee compensation.

2.4. Integration Capital Expenditures and Inclusion in Rate Base

42. To deliver the benefits of integration, pillar system alignment was required to effectively manage business operations and customer interactions for over 3.8 million customers. Supporting multiple billing and work management systems with disparate processes and structures was not an effective way to deliver reliable, scalable, efficient service to customers, nor an effective way to maintain ongoing business operations. Investments throughout the deferred rebasing term brought the utility to common, modern, scalable platforms. These platforms provide foundations that deliver sustainable savings and ongoing benefits in common user experiences and practices across Enbridge Gas that will extend beyond the deferred rebasing term. Enbridge Gas expects to incur $189.0 million in capital /u
expenditures related to integration efforts over the deferred rebasing term as set out in Table 6. This represents a reduction of approximately $63.2 million relative to /u
Enbridge Gas's original forecast. The primary driver for the change in capital /u
expenditures is the deferral of the GTA East and GTA West facility integration /u
projects. Enbridge Gas is re-evaluating the costs and timing of the GTA East and /u
West projects due to delays to the construction schedules and a forecasted /u
increase in the construction costs for the facilities. /u

43. The revenue requirement to support these investments was not included in base rates, and as such was borne by the shareholder. The largest capital expenditures were in pillar technologies: one Customer Information System (CIS) and one Asset and Work Management (AWS) system. /u

44. By December 31, 2023, the residual net book value of the integration capital projects is forecasted to be $119 million. The associated impact reflected in the /u
2024 Test Year revenue requirement is $28 million, further details at paragraph 49. /u

A listing of the integration capital expenditures and descriptions is provided at Attachment 1. The CIS investments are included in Customer Care and the AWS investments are noted in Distribution Operations. /u

Table 6
Integration CapEx Investments Schedule

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	Total	
		(a)	(b)	(c)	(d)	(e)	(f)	
	CapEx							
1	Business Development & Regulatory		0.6	2.0			2.6	
2	Customer Care	6.7	27.7	32.0	0.8		67.3	/u
3	Distribution Operations	11.3	7.1	19.0	19.8	17.0	74.2	/u
4	Energy Services	3.6	3.7	8.0	5.6	3.0	23.9	/u
5	Engineering & STO		0.2	2.0	0.3		2.5	/u
6	Overheads	7.6	11.0				18.6	
7	Total Annual CapEx	29.1	50.4	63.0	26.5	20.0	189.0	/u
8	Net Book Value (included in rate base forecast)						119.0	/u

Notes:
(1) Distribution Ops: Work Mgmt. phases utility work, construction, meters, customer attachment /u
(2) CapEx is reflective of year spent /u
(3) Overheads are included at the project level starting in 2021 /u
(4) Associated impact of NBV reflected in the 2024 Test Year revenue requirement is $28 million /u

45. As noted, the largest investments in capital were driven by technology investments to align pillar applications, which started in 2019. Upon initiation, these projects assessed the current systems in place against business needs, the evolving technology landscape and security requirements, as well as evolving customer

expectations to determine the solutions to deliver on those requirements safely and reliably for Enbridge Gas. The decision to upgrade and migrate to existing systems provided significant benefits to customers, as implementing new systems would have been more expensive solutions.

46. As referenced in the savings section of this evidence, the CIS in Customer Care was a significant integration project for Enbridge Gas. The CIS in use prior to amalgamation were nearing end of life and migrating the UG Banner/ Enlogix CIS to the SAP S/4 HANA cloud application, mitigated sustainability issues and improved the reliability of the systems. The aligned CIS and complex interfaces to inter-related systems also enabled one common CIS platform and delivered a common brand and customer experience across Enbridge Gas. This foundational investment in the aligned billing system delivered synergy savings and served to modernize the system on which operational processes and customers continue to rely.

47. Another significant technology platform was delivered through the Asset and Work Management system implemented in Distribution Operations. The Asset and Work Management system enabled the efficient workload planning and execution in operations and set the stage for a scalable solution implemented through phases. This project initially migrated the service suite planning and dispatch application, along with related systems and processes in use at Union Gas pre-amalgamation into the Maximo system, creating alignment for utility maintenance work. This initiative expanded to a phased implementation leveraging system and processes for construction, meter shop, and planning for station operations. This integrated asset and work management system (Maximo) brought both companies onto a common platform with aligned policies, processes, and procedures for Distribution Operations, Customer Care, and Engineering while supporting Enbridge Gas's

goals in achieving safe, efficient, and reliable operations. These implementations included planning, execution, and reporting activities, as well as the implementation of a mobility solution for the field workforce. This aligned system is fundamental to work and asset management across the utility, enabling safe, reliable, and effective service to customers through work order management, asset reliability and emergency response.

48. In Energy Services, an investment in technology and an aligned, automated Cost of Gas Application delivered an integrated solution to purchase and contract, nominate, manage invoicing, manage credit requirements, and book gas costs and associated deferrals for financial and regulatory reporting, as well as inventory management across Enbridge Gas.

49. Enbridge Gas's expectation is that the net book value capital costs of the integration will be included in rate base in 2024 and be subject to recovery through rates going forward. These investments were made throughout the deferred rebasing term to deliver the highest level of sustainable savings and operational benefits. Much of the residual net book value of the PPE pertains to in-service additions in 2021, 2022, and 2023, which Enbridge Gas will not have had the opportunity to fully depreciate by the end of the approved 5-year deferred rebasing term.

50. Beginning in 2024, Enbridge Gas will reflect the impact of the efficiencies and cost savings resulting from the amalgamation in its going-forward rates. At the same time, it is appropriate that remaining costs from capital projects aimed at integration and delivering benefits should also be reflected in Enbridge Gas's rates. The expected annual synergy savings of $86 million resulting from all integration initiatives, net of $28 million in annual depreciation, based on proposed /u

depreciation rates pursuant to the depreciation study provided at Exhibit 4, Tab 5, Schedule 1, Attachment 1, taxes and carrying charges related to these projects will be passed on to customers during the next IR term and beyond, flowing through as a net reduction of $58 million to the revenue requirement in 2024. /u

51. This approach reflects the principle that benefits follow costs and is consistent with the fact that, under US GAAP, the costs of the amalgamation/ integration investments are expensed, as depreciation, over the period when they are providing value. These investments in complex systems have extended depreciation terms due to the life of the asset. These systems provide the foundation upon which business processes and customer experiences are built to deliver safe and reliable services to current and future customers. Considering that this value is credited to customers through rebasing, so too should the costs be charged to customers at that time. The capital investments made will continue to provide value and service to customers and establishing their continued rate base treatment and draw down through depreciation is consistent with how other utility assets are treated, and consistent with how GAAP requires assets to be treated. This treatment aligns the ongoing benefits for customers with the associated costs in rates.

3. Summary

52. At the end of 2023, with the end of the deferred rebasing term, Enbridge Gas will have completed the approved MAADs framework. Consistent with the commitments in the MAADs framework, the O&M costs incurred for integration activities are not included in proposed rates for 2024. The annual integration synergies of $86 million demonstrate the amalgamation of EGD and Union provides ongoing benefits to customers. As those savings are passed on to customers in 2024, it is appropriate

the corresponding net book value of integration costs of the assets used to provide continued safe and reliable services are included in rate base. This evidence compiled the view of the integration activities that were completed through the deferred rebasing term, which generated a net reduction of $58 million to the 2024 /u Test Year revenue requirement.

Capital Expenditures Integration Projects - Detailed Listing

Line No.	Particulars ($millions)	Project	In Service Date	2023 Total spend as at Dec 31 (a)	2023 Acc. Dep as at Dec 31 (b)	2023 NBV as at Dec 31 (c)	Project Description	
1	Customer Care	CIS Integration	July 2021	44.7	11.8	37.0	Integration to a common Customer Information Systems (CIS) resulting in the retirement of the UG Banner CIS, and required upgrade and migration to one SAP platform to ensure ongoing reliable operations.	
2	Operations	Asset & Work Management Systems (AWS)	July 2021 July 2022 Dec 2023	48.5	14.4	38.1	This project delivers the integrated Utility Asset & Work Management Systems (AWS) harmonizing work management systems for maintenance operations, construction, and customer attachment, and integrating to the Maximo system previously used by EGD. This project is executed in Phases: Phase 1: integration of work management systems to a common Maximo platform; Phase 2: integration of Construction, Attachment, and Meter Shop systems and processes for Maximo, GetConnected, and Customer Connections Work Suite; Phase 3: Align Station Operations for both EGD and Union to Maximo.	/u
3	Customer Care	CIS Integration - HANA	July 2020	15.5	6.1	11.7	This implementation is part of the CIS Integration Project, moving the EGD CIS information to the S4 HANA cloud application.	/u
4	Energy Services	RACOG	Nov 2023	2.3	0.0	2.3	Revenue and Gas Cost Financial Reporting Project (RACOG). Enable an integrated long-term solution for actual, budget, forecast and key regulatory reporting using consistent tools.	/u
5	Energy Services	Cost of Gas Replacement	Feb 2022	15.8	8.3	9.4	A single integrated Utility Gas Purchase and Financial Reporting automated solution is required to manage risks and ensure successful integration in Energy Services and Finance. The driver was to align processes and systems across Enbridge Gas to purchase and contract, nominate, manage credit requirements and track gas costs for financial reporting, inventory management, and deferrals for multiple rate zones.	/u

Capital Expenditures Integration Projects - Detailed Listing (Continued)

Line No.	Particulars ($millions)	Project	In Service Date	2023 Total spend as at Dec 31 (a)	2023 Acc. Dep as at Dec 31 (b)	2023 NBV as at Dec 31 (c)	Project Description	
6	Operations	Leak and Corrosion System Integration	Nov 2022	5.7	1.4	4.3	This project implements a unified solution to enable Leak and Corrosion Survey process integration between EGD and Union. The project delivers the technology solution that will support the integrated Corrosion and Leak survey processes by replacing the existing platforms (CSMS, LSMS, DNV-GL) and moving EGD and Union onto the same technology solution.	/u
7	Operations	Estimating & Forecasting Accuracy	Nov 2022	2.9	0.9	2.1	This project implements a harmonized capital project estimating tool (EcoSys) to provide consistent and reliable capital estimation, benchmarking, and resource planning through integrated processes and system. Future opportunities include adding capital forecasting and additional reporting functionality for GDS.	
8	Operations	ePackaging	Nov 2023	1.1	0.0	1.1	This project digitizes work packages and provide a single solution and process for accessing locates and permits information and other reference information (e.g. Site/Hazard assessment forms) to support efficient work management.	/u
9	Operations	Customer Attachment IVR	Nov 2022	0.8	0.3	0.5	This project is to harmonize IVR systems for both EGD and Union. This would include IVR for external customers/Builders/Heating contractors for customer attachment business function.	/u
10	Engineering	Meter Shop Consolidation	Dec 2021	1.9	0.1	1.8	This project consolidates the three existing Meter Shops (Chatham, North Bay and VPC) into two. Results in closure of the Meter Shop at VPC.	
11	Customer Care	IVR Enhancements and Consolidation	July 2021	2.9	2.0	1.3	This project is to enhance and consolidate the EGD and Union Interactive Voice Response (IVR) into a single Enbridge Gas IVR with the focus to increase the containment within the IVR and ultimately integrate call handling between the internal and external contact centers for Phase 2 go live of CIS - SAP S/4 HANA on cloud. Enables Enbridge Gas to deliver on a single consistent experience to customers and present Enbridge Gas as a single company.	

Capital Expenditures Integration Projects - Detailed Listing (Continued)

Line No.	Particulars ($millions)	Project	In Service Date	2023 Total spend as at Dec 31 (a)	2023 Acc. Dep as at Dec 31 (b)	2023 NBV as at Dec 31 (c)	Project Description	
12	Business Development	Website Integration	July 2021	2.8	1.8	1.2	This project integrates uniongas.com and enbridgegas.com to support the amalgamated utility. New website will use enbridgegas.com and implement enhancements to reflect combined utility business unit needs. This implementation includes content, functionality, infrastructure and processes.	
13	Operations	Emergency Solutions Harmonization	Nov 2022	2.1	0.6	1.5	The project delivers the technology solutions to support Enbridge Gas's integrated Emergency Response processes and amalgamation of dispatch centers by bringing both EGD and Union onto the same Interactive Voice Response and paging solutions.	/u
14	Operations	Locate Tracker Rollout to Union	Nov 2023	0.9	0.0	0.9	This project involves the roll-out a single application for the Locates Tracker functionality that EGD and Union will use to align their processes and procedures for ordering and tracking locates for internal dig work, supporting work management and damage prevention efforts.	/u
15	Customer Care	My Account Amalgamation	July 2021	2.2	1.5	1.0	This project will provide customers across Enbridge Gas with one My Account experience. This will be done in parallel with the CIS Integration project as UG customers migrate over to the Enbridge Gas My Account, maintaining a consistent and positive user experience.	
16	Operations	Harmonize Feasibility Tools	Nov 2023	1.0	0.0	1.0	This project supports the harmonized customer attachment process, and harmonizes the feasibility tool for EGD and Union. This will also provide automatic system archive capabilities for the feasibility analysis instead of needing to post on second SharePoint site. Results in the decommissioning of the Union and EGD models.	
17	Energy Services	PowerSpring LVB Integration	Jul 2023	2.0	0.2	1.8	The project supports the integration of business processes and applications to gather measurement data from field devices and ensures measurement integrity while facilitating large volume billing (LVB) accuracy.	/u
18	Operations	Dispatch Scheduling Harmonization	Nov 2022	0.4	0.1	0.3	This project integrates, harmonizes, and automates dispatch scheduling for both EGD and Union supporting work management.	/u
19	Operations	Locate Management Solution Harmonization	Nov 2023	0.7	0.0	0.7	This project is being executed to deliver the technology solution that will bring EGD and Union onto the same platform to support the integrated locate management processes. This solution will provide one source for all locate requests from Ontario One Call supporting damage prevention efforts at EGI.	

Capital Expenditures Integration Projects - Detailed Listing (Continued)

Line No.	Particulars ($millions)	Project	In Service Date	2023 Total spend as at Dec 31 (a)	2023 Acc. Dep as at Dec 31 (b)	2023 NBV as at Dec 31 (c)	Project Description	
20	Energy Services	Utility Weather & Demand Harmonization	Nov 2022	0.4	0.1	0.3	This project implements a reporting/statistical analysis solution for EGD data in support of the Utility Weather & Demand Harmonization Program. This new solution will mimic a current solution (Load vs Cold) in place for Union data.	/u
21	Operations	EGI Operations-Harmonized Field User Connectivity	Nov 2023	0.2	0.0	0.2	This project aligns the technology platform and technical support for remote connectivity for Enbridge Gas distribution operations field employees.	/u
22	Operations	Customer Connections	April 2020	0.5	0.3	0.2	This project supported the customer connections business processes with a unified solution and retirement of the duplicate systems while also delivering enhanced customer experience.	/u
23	Customer Care	Unionline Rebranding Project	May 2021	0.2	0.2	0.1	This project renames the existing Unionline application, including removing reference of Unionline and Union Gas from existing customer facing transactional system. This also includes contracts, invoices and reports accessed by customers through this platform.	
24	Operations	Alignment of Execution of Warning Tags	Nov 2022	0.2	0.0	0.2	This project implements an electronic warning tag solution integrating and automating processes to improve accuracy and efficiencies for the management of appliance warning tags..	/u
25	Operations	Customer Experience	Dec 2019	11.2	16.3	0.0	This project involved a full re-build of the MyEnbridge account management infrastructure, with the costs predominantly comprised of TIS hardware and software.	
26	Energy Services	SCADA and Gas Control Consolidation	Nov 2019	3.0	3.6	0.0	This project was to consolidate the utility control center operations in Chatham with migration to a single CygNet SCADA system.	
27	Business Development	Bill Print & Presentment	May 2020	0.1	0.0	0.0	This project moves the Union bill print processing and composition to Kubra resulting in a single bill image for Enbridge Gas customers.	
28	Overheads			18.6				/u
29	Total			189.0	70.0	119.0		/u

Note:
(1) Overheads shown at the project level effective 2021

ENERGY TRANSITION OVERVIEW

CARA-LYNNE WADE, DIRECTOR ENERGY TRANSITION PLANNING
JENNIFER MURPHY, MANAGER, CARBON AND ENERGY TRANSITION PLANNING

1. The purpose of this evidence is to provide an overview of the evidence set out in the series of exhibits presented in Exhibit 1, Tab 10 related to energy transition and how Enbridge Gas is incorporating energy transition into the business over the course of the rebasing term, and the AMP planning horizon of 2023 to 2032.

2. Broadly speaking, energy transition refers to a change in how energy is developed, used and benefits society. Although the term energy transition is often used interchangeably with climate change mitigation, it is important to recognize that access to reliable, resilient, secure, and affordable energy must also be addressed through energy transition.[1]

3. The evidence presented in Exhibit 1, Tab 10 is provided to detail how energy transition has been integrated within Enbridge Gas's business and planning processes, and to support the various proposals in this Application related to energy transition. Enbridge Gas is filing this energy transition evidence for the first time to reflect the changes rapidly occurring within the energy sector. Although a great deal of uncertainty exists with regards to how Ontario's energy transition will unfold, Enbridge Gas is excited and confident about the role the Company can play in supporting customers, the province, and municipalities in achieving their GHG emission reduction goals.

[1] As discussed at Exhibit 1, Tab 10, Schedule 2, Section 2, reliability refers to the system's ability to maintain energy deliveries under normal operating conditions. Resiliency is the ability to prevent, withstand, adapt to, and quickly recover from a high-impact, low-likelihood event, such as a severe weather event.

4. Large scale multi-decade transitions such as this need to be done in a way that is orderly and not disruptive. An orderly transition is one that allows energy consumers to adapt to energy transition such that Ontario's energy systems provide cost-effective choices that are reliable, resilient, and secure.

5. Details regarding energy transition can be found in Tab 10 as set out below:

Exhibit 1, Tab 10, Schedule 1	Energy Transition Overview
Exhibit 1, Tab 10, Schedule 2	Overview of Ontario's Energy System: Gas and Electric
Exhibit 1, Tab 10, Schedule 3	Enbridge Gas's GHG Emissions and Related Policies
Exhibit 1, Tab 10, Schedule 4	Integrating Energy Transition into the Business
Exhibit 1, Tab 10, Schedule 5	Pathways to Net-Zero and the Role of Gaseous Fuels
Exhibit 1, Tab 10, Schedule 6	Enbridge Gas's Energy Transition Plan and Safe Bet Actions
Exhibit 1, Tab 10, Schedule 7	Energy Transition Technology Fund
Exhibit 1, Tab 10, Schedule 8	Reducing Emissions from Operations

6. Exhibit 1, Tab 10, Schedule 2 provides an overview of the role of natural gas in meeting Ontario's energy demand on an annual and peak basis, relative to electricity and other fuels. This Exhibit also describes the reliability, resilience, energy security and affordability provided by Enbridge Gas's storage, transmission and distribution assets, the capabilities of Ontario's electricity sector during the regulatory term of this Application and the need to ensure that Ontario has an orderly energy transition that meets sustainability, reliability, and affordability goals of Ontario.

7. Exhibit 1, Tab 10, Schedule 3 provides a description of the greenhouse gas (GHG) emissions resulting from Enbridge Gas's activities and the current policies governing them.

8. Exhibit 1, Tab 10, Schedule 4 describes how energy transition assumptions and considerations have been integrated into the business and the rebasing application, with a focus on impacts on Enbridge Gas's Asset Management Plan (AMP), finance and regulatory approaches during the regulatory and asset management planning horizons.

9. Exhibit 1, Tab 10, Schedule 5 provides an overview of two energy transition studies conducted by two external consultants, commissioned by Enbridge Gas. These studies show that a diversified pathway that includes a role for low-carbon gases with non-emitting electricity achieves net-zero at a lower cost, with energy systems that are more reliable and resilient and that offer greater consumer choice than an electrification-heavy approach. This evidence also provides a summary of the stakeholder engagement Enbridge Gas has undertaken. Using the key findings from the studies and feedback from stakeholders, Enbridge Gas developed the Company's vision of energy transition in Ontario: a diversified pathway.

10. Exhibit 1, Tab 10, Schedule 6 describes emerging government climate change polices and the uncertainty around what energy transition pathway may unfold in Ontario. This evidence also presents Enbridge Gas's Energy Transition Plan (ETP) and the actions that the Company proposes to move forward with during the rebasing period, despite current policy uncertainty, to ensure continued progress towards Ontario's 2030 GHG emission reductions target. The ETP is focused on safe bet actions that will be critical to reducing emissions regardless of how energy transition evolves. This evidence also provides a summary of the GHG emission

reductions that can be enabled by the safe bet actions that Enbridge Gas is proposing to take in the ETP, which were modeled by an external consultant.

11. Exhibit 1, Tab 10, Schedule 7 provides Enbridge Gas's proposal for an Energy Transition Technology Fund (ETTF). Enbridge Gas proposes the ETTF to advance and accelerate research, development, and commercialization of low-carbon technologies.

12. Exhibit 1, Tab 10, Schedule 8 describes the efforts that Enbridge Gas is taking to reduce emissions from its operations to support achievement of the federal and provincial GHG emissions targets as well as the Enbridge GHG reduction targets.

OVERVIEW OF ONTARIO'S ENERGY SYSTEM: GAS AND ELECTRIC

CARA-LYNNE WADE, DIRECTOR ENERGY TRANSITION PLANNING
JENNIFER MURPHY, MANAGER CARBON AND ENERGY TRANSITION PLANNING

1. This evidence describes the role of the gas system in meeting Ontario's energy demand in a cost-effective, reliable, resilient, and affordable manner, and the capabilities of Ontario's electricity sector.

2. This evidence is organized as follows:
    1. Role of Natural Gas in meeting Ontario Energy Demand
    2. Reliable, Resilient, Secure and Affordable Energy Infrastructure
    3. Electricity Sector Overview

1. Role of Natural Gas in Meeting Ontario's Energy Demand

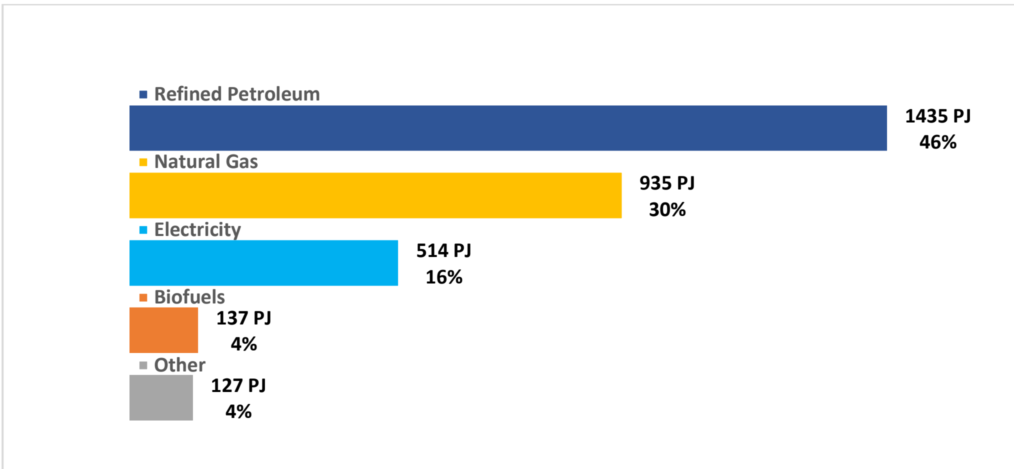
3. Enbridge Gas's system is comprised of distribution, transmission and storage assets, which are used to deliver energy to the Company's residential, commercial, and industrial buildings and processes, as well as gas-fired electric generation facilities, and transportation fuel providers. Enbridge Gas has over $14 billion in regulated assets and serves over 3.8 million customers in Ontario, including delivering energy to heat more than 75% of Ontario's homes.

4. Today, the gas system is mainly used to transport natural gas; however, an increasing amount of renewable natural gas (RNG) and hydrogen are also transported by the gas system.

5. Natural gas meets 30% of the province's energy needs on an annual basis, almost double that served by electricity at 16%. The balance of annual energy use in

Ontario is comprised of refined petroleum at 46%, biofuels at 4% and other at 4%.[1] Ontario's annual energy demand by fuel is shown in Figure 1.

Figure 1: Annual End-Use Demand by Fuel (2019)[2]



6. On a peak basis, the natural gas system provides three to five times as much energy as the electricity system. For example, the most recent winter peak (highest hourly flow measured during the winter) occurred at 9 am on January 22, 2022 and was 8,507 10^3m^3/hr or approximately 92 GW.[3] In comparison, the amount of electricity generated in Ontario at the same time was approximately 21 GW,[4] and of

[1] Government of Canada. (2022, July 28). Provincial and Territorial Energy Profiles – Ontario. Canada Energy Regulator. https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html
[2] Ibid.
[3] 8,507 10^3m^3/hr x 1 hr x 39.12MJ/m^3 / 3,600MJ/MWh = 92,433 MW or ~ 92 GW.
[4] Electricity generation was 20,975 MW on January 20, 2022, for the hour ending at 9 am, this is ~ 21GW, Source Generator Output by Fuel Type Hourly Report, 2022, http://reports.ieso.ca/public/GenOutputbyFuelHourly/.

this around 20 GW was to serve demand within the province.[5] The amount of electricity generated was close to 70% of the 30.2 GW effective winter capacity.[6,7]

7. Comparing the energy provided by the gas system to the electricity generation in this example, demand and effective capacity yields a delta ranging from 62-72 GW. Serving the delta of 62-72 GW via the electricity system would require incremental generation facilities, transmission and distribution infrastructure, significant enhancement of energy efficiency programs, and deployment of new space and water heating technologies at a massive scale.

2. Reliable, Resilient, Secure and Affordable Energy Infrastructure

2.1. Introduction

8. Enbridge Gas provides customers with the reliable, resilient, secure, and affordable energy that they need and want, which are key priorities for both the provincial government[8] and energy consumers[9] alike.

9. Enbridge Gas's system consistently fulfills these critical energy system needs because of its:

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[5] Electricity demand was 19,631 MW on January 20, 2022, for the hour ending at 9 am, this is ~ 20GW, Source: Hourly Demand Report, 2022, http://reports.ieso.ca/public/Demand/PUB_Demand_2022.csv.
[6] Effective capacity considers factors such as the availability of fuel, ambient conditions, and/or outages. Source: IESO. Annual Planning Outlook, December 2021, p. 28. https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook
[7] Ibid, p.29.
[8] In his letter to the Chair of the OEB dated November 15, 2021 (p.2), the Minister of Energy stated, "The government's priorities for the energy sector are about promoting reliability, affordability, sustainability and consumer choice". https://www.oeb.ca/sites/default/files/mandate-letter-from-the-Minister-of-Energy-20211115-en.pdf.
[9] The customer engagement process in support of this Application found that three of the top four priority outcomes for both residential and business customers included affordability, reliability and minimizing impacts on the environment. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, pp. 119-120, 174-177, 426.

a) Underground infrastructure, which is protected from most severe weather events;
b) Looped networks which can bring gas in at multiple points when disruptions do occur; and,
c) System storage capacity, via underground storage facilities and via 'linepack'[10] in the gas transmission system.

10. The following sections provide a discussion of energy system reliability, resiliency, and security, highlighting lessons learned from times when these three key system aspects were put to the test; illustrating why it is critical to evaluate how each approach to meeting energy transition targets contributes to or detracts from these three critical aspects of an energy system.

2.2. Gas System Reliability

11. Reliability refers to the system's ability to maintain energy deliveries under normal operating conditions.[11] Reliable energy delivery is especially critical on the hottest and coldest days of the year when Ontarians are most reliant on energy supply to cool and heat their homes and businesses.

12. Enbridge Gas's system is highly reliable, consistently meeting both seasonal and peak gas demands with few, if any, outages. For example, in 2021, more than 25

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[10] Linepack is the amount of natural gas stored within a pipeline and is the result of the compressible nature of natural gas. The larger the diameter and the higher the pressure of a pipeline the more linepack it can contain. Linepack is a key attribute of high-pressure large diameter pipelines typified by the transmission system. For more information about linepack and how it is used please see Exhibit 2, Tab 7, Schedule 1, pp.19-20.
[11] Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience, 2021, p.2, https://gasfoundation.org/wp-content/uploads/2021/01/Building-a-Resilient-Energy-Future-Full-Report_FINAL_1.13.21.pdf

billion m^3 [12] or approximately 272,000 GWh[13] of natural gas was delivered safely and reliably. Meeting seasonal and peak demands is a requirement of the system's design and is fundamental to delivering the energy Ontarians need and want.

13. In addition, the gas system also supports the reliability of the electricity system by providing fuel and storage services for gas-fired electricity generation.[14] The electricity system's ability to reliably meet the intra-day changes in electricity demand, especially during periods of peak electricity demand is made possible by the gas system. In Ontario, gas-fired generation makes up 10.7 GW, or 26%, of the installed electricity generation capacity and plays an important role in meeting peak electricity demands, as it can be brought online at short notice to provide electricity during peak periods of use.[15] For example, during the top 10 peak electricity demand periods of 2021,[16] 4.7 to 6.9 GW, or 22 to 31%, of electricity was supplied by gas-fired generation.[17]

14. The need for reliability is emphasized by Ontario's Independent Electricity System Operator (IESO) in their Resource Eligibility interim report.[18] The IESO indicates that up to 1,500 MW of incremental or new gas-fired capacity is required to "address short term energy needs and contribute to the province's longer term

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[12] 2021 Yearbook of Natural Gas Distributors, September 10, 2021, p.13, https://www.oeb.ca/oeb/_Documents/RRR/2021_Yearbook_of_Natural_Gas_Distributors.pdf.
[13] 25,053,000,000 m^3 x 39.12 MJ/m^3 x 1MWh/3600 MJ = 272,242,600 MWh or 272,243 GWh
[14] Gas-fired generation uses natural gas today; however, has the potential to transition to RNG or hydrogen in the future.
[15] IESO. Annual Planning Outlook, December 2021, p.29, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/2021-Annual-Planning-Outlook.ashx.
[16] Top Ten Ontario Demand Peaks, 2022, May 1, 2021, to April 30, 2022, https://www.ieso.ca/-/media/Files/IESO/settlements/Top-Ten-Ontario-Demand-Peaks-Archive.ashx.
[17] Generator Output by Fuel Type Hourly Report, 2021_v365, http://reports.ieso.ca/public/GenOutputbyFuelHourly/
[18] Resource Eligibility Interim Report, October 7, 2022, p.3, https://ieso.ca/en/Sector-Participants/Resource-Acquisition-and-Contracts/Resource-Eligibility

energy transition".[19] This demonstrates the value of gas-fired generation and emphasises the value of Enbridge Gas's system for Ontario as it moves through energy transition.

15. As Ontario moves toward a net-zero future, the reliability of its energy systems must be maintained. This means that the reliability provided by Enbridge Gas's system, for both gas and electric consumers, cannot be underestimated and must be considered by governments as they determine how to transition to low- and zero-carbon emission energy systems in Ontario.

2.3. Gas System Resiliency

16. Resiliency is the ability to prevent, withstand, adapt to, and quickly recover from a high-impact, low-likelihood event, such as extreme weather events or cybersecurity breaches.[20]

17. The increasing frequency and severity of extreme weather events underscores the need to maintain resiliency in Ontario's energy systems, and to incorporate resiliency in planning discussions regarding Ontario's energy future. For example, according to the Insurance Bureau of Canada, eight of the largest insurance payouts for natural disasters in Canadian history relate to extreme weather events that have occurred since 2011.[21] These events also demonstrate how different parts of the energy systems in Ontario are disproportionately impacted.

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[19] Ibid, p.11
[20] Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience, 2021, p.2, https://gasfoundation.org/wp-content/uploads/2021/01/Building-a-Resilient-Energy-Future-Full-Report_FINAL_1.13.21.pdf
[21] Insurance Bureau of Canada. (2022 June 15). Derecho Storm Ranks 6th Largest Insured Loss Event in Canadian History. http://www.ibc.ca/on/resources/media-centre/media-releases/derecho-storm-ranks-6th-largest-insured-loss-event-in-canadian-history.

18. Resiliency during these events is critical, as disruptions to energy delivery can cause widespread economic and societal impacts, including loss in productivity, as well as health and safety concerns for customers relying on energy for building space conditioning purposes.

19. Enbridge Gas's system not only supports energy system reliability, but it also supports resiliency in two key ways: (1) ensuring continued delivery of energy during extreme cold weather events and (2) supporting Ontario's electricity system during times of extreme heat weather events.

20. Enbridge Gas's system provides continued delivery of gas during extreme weather events, as the Company can purchase and store gas in times of low price and low demand, and then in times of extreme weather events use this stored energy to make up supply shortfalls. This shields Ontarians from shortages as well as large price fluctuations in the market caused by these events.

21. Enbridge Gas's system also supports a resilient electricity system by providing energy and storage services for gas-fired electricity generation.[22] Gas-fired electricity producers can quickly ramp up their electricity production during extreme weather events because of Enbridge Gas's system.

22. An example where the gas system provided back-up during an extreme weather event occurred in August 2020, when the western United States and in particular California experienced severe drought, wildfires, and a record heat wave[23], which

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[22] Gas-fired generation uses natural gas today; however, it has the potential to transition to RNG or hydrogen in the future.
[23] NOAA National Centers for Environmental Information. (2020 September). August 2020 National Climate Report. https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202008.

resulted in higher electricity demand and lower electricity supply.[24] More than 700,000 customers were impacted by rolling outages.[25]

23. The Governor of California declared a state of emergency on August 16, 2020,[26] and on August 17, 2020, suspended restrictions on power plants that prevented electricity generation during peak periods, such as restricted fuel usage and air quality requirements.[27] These measures enabled gas-fired power producers to ramp up and provide additional electricity to meet the peak demands, ending rolling outages. In this extreme weather event, it was SoCalGas's gas system, including their gas storage assets, that enabled energy system resiliency. Enbridge Gas's system provides the same role in supporting energy system resiliency in Ontario.

24. Another example of low likelihood high impact events is cyberattacks on energy systems, which have been increasing in frequency. Having multiple energy systems provides resiliency as there isn't a reliance on a single energy system for all energy needs, and some energy needs can continue to be met despite a cyberattack occurring on one system.

25. An example of a cyberattack on an energy system is the cyberattack on the Colonial Pipeline Company (CPC) in May 2021. CPC responded to the attack by shutting down all pipeline operations to isolate its pipeline systems. It took six days

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[24] Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm, 2020, p.33-39, http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf.
[25] Ibid, p.42.
[26] Executive Department State of California – Proclamation of a State of Emergency, August 16, 2020, https://www.gov.ca.gov/wp-content/uploads/2020/08/8.16.20-Extreme-Heat-Event-proclamation.pdf.
[27] Executive Department State of California – Proclamation of a State of Emergency, August 17, 2020, https://www.gov.ca.gov/wp-content/uploads/2020/08/8.17.20-EO-N-74-20.pdf.

to fully restore pipeline operations.[28] Although there were widespread shortages of gasoline and diesel fuels in the southeastern United States during the outage, the existence of multiple energy systems throughout the southeastern United States meant that the electricity and natural gas systems provided the energy needed for other aspects of the economy.

26. As demonstrated in the examples above, a resilient energy system is critical to the operation of every function of the economy, and it is best achieved through a diverse and interconnected energy system. Maintaining a resilient energy system must be at the forefront of energy system planning, particularly where the proposal may be to electrify all energy uses with sole or heavy reliance on a single energy system. Resiliency needs to be incorporated into net-zero energy system planning discussions. As concluded in the American Gas Foundation Report, Building a Resilient Energy Future:

> For energy system stakeholders at every level, resilience is not just a term that is currently in vogue, it is a characteristic that needs to be valued and engineered. Ensuring future energy system resilience will require careful assessments of all available solutions, maximizing the fundamental benefits of a diversity of assets. Utilities, system operators, regulators, and policymakers need new frameworks to consider resilience impacts as part of the energy system transformation, to ensure that resilience is not overlooked in the pursuit to achieve decarbonization goals. [29]

27. The role Enbridge Gas's system has in Ontario's energy system resiliency, for both gas and electric consumers, cannot be underestimated and it must be considered

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[28] US Department of Energy. Colonial Pipeline Cyber Incident. https://www.energy.gov/ceser/colonial-pipeline-cyber-incident
[29] Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience, 2021, p. 66, https://gasfoundation.org/2021/01/13/building-a-resilient-energy-future/.

by governments as they determine how to transition to low- and zero-carbon emission energy systems in Ontario.

2.4. Security of Energy Supply

28. Security is a key aspect of a reliable and resilient energy system, which involves having diversity and control of energy supply.

29. Security of energy supply enables energy system reliability and resiliency, and it provides greater price stability during weather events. Enbridge Gas's Dawn Hub storage assets and the province's low reliance on electricity imports provides Ontario with energy supply security today. Maintaining the security of energy supply is critical as the province moves through energy transition.

30. The need for energy security and how it is coupled with affordability is highlighted by the energy crisis in Europe. Energy prices have soared as Europe moves to wean itself off Russian energy imports in response to the war in Ukraine. For example, Germany has committed to replacing all imported energy from Russia by 2024. Notably, 55% of Germany's natural gas demand was imported from Russia in 2021, which has declined to 26% as of June 2022, with threat of a full cessation of imports to Germany by winter of 2022.[30] To replace the energy from imported natural gas and to fill natural gas storage in preparation for the upcoming winter heating season, Germany started importing liquified natural gas, passed laws to reinstate coal and oil-fired electricity generation as needed, considered extending the life of nuclear power plants, and asked consumers to cut natural gas usage by 20%.[31] This highlights the critical role gas storage assets play in providing energy

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[30] Reuters. (2022, August 19). Factbox: Germany's Efforts to Tackle Energy Crisis. https://www.reuters.com/business/energy/germanys-efforts-tackle-energy-crisis-2022-08-19/
[31] Ibid.

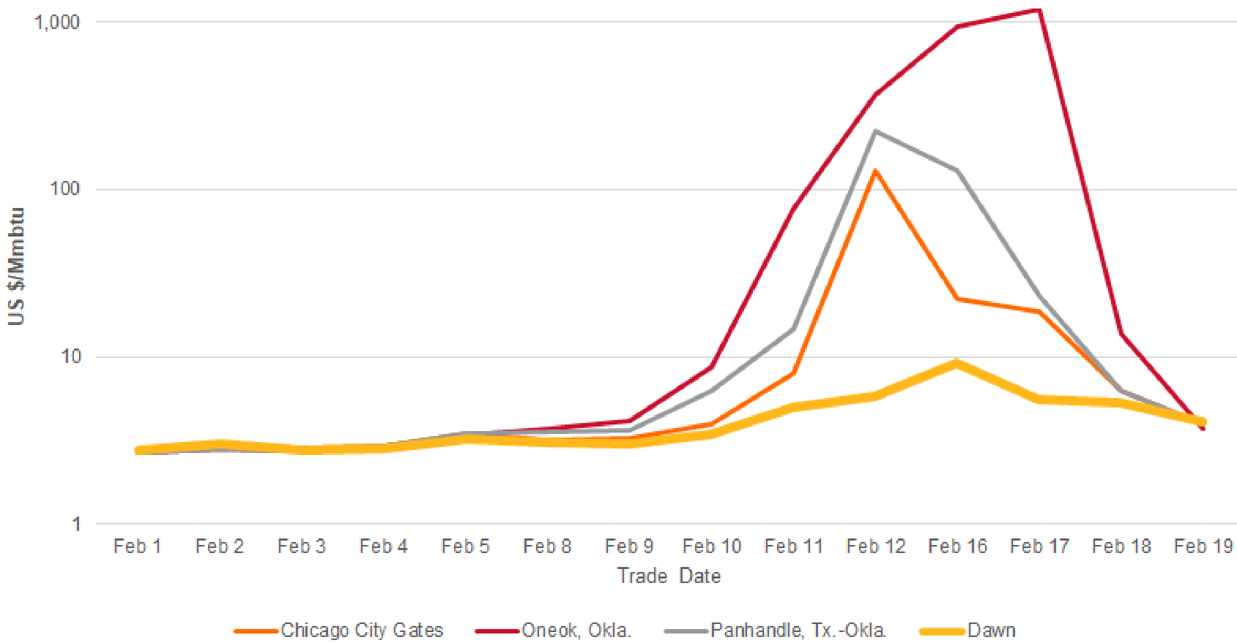
security, in addition to demonstrating the importance of having multiple sources of electricity generation.

31. To mitigate increasing energy costs due to the European energy crisis described above, governments of countries in and outside of the European Union are preparing funding packages in the multibillions to help ease the escalating prices resulting from the deepening energy crisis.[32,33] The example demonstrates how a lack of energy supply security can impact energy price stability and affordability.

32. Enbridge Gas's Dawn Hub storage assets provide security of energy supply and energy price stability for customers, particularly during extreme weather events. For example, during the February 2021 polar vortex, which brought record cold temperatures across North America, severe reductions in natural gas production and transmission volumes resulted in localized supply shortfalls during periods of peak demand causing severe price spikes at regional market hubs (Figure 2). The Dawn Hub provided security of energy supply to Ontario consumers by increasing storage withdrawals to offset upstream supply shortfalls. This avoided system outages and provided price stability during peak conditions.

[32] Bloomberg. (2022 September 6). Truss Plans £40 Billion Energy-Aid Package for UK Businesses. https://www.bloomberg.com/news/articles/2022-09-06/truss-plans-40-billion-energy-aid-package-for-uk-businesses?leadSource=uverify%20wall.
[33] BBC News. (2022 September 4). Germany announces €65bn package to curb soaring energy costs. https://www.bbc.com/news/world-europe-62788447.

Figure 2: 2021 Polar Vortex Natural Gas Price Impacts



33. As seen in Figure 2 the price of natural gas at the Dawn Hub rose to US$10/MMBtu, while prices in other regional markets rose to between US$100 to US$1,000/MMBtu. The price impacts at the Dawn Hub were 10 to 100 times lower due to the storage assets at Dawn Hub. Atmos Energy Corp., a natural gas distribution company that serves more than 3 million customers across 8 U.S. states – reported that it had accrued roughly $2.5 to $3.5 billion in natural gas purchases, mainly for its Colorado, Kansas, and Texas jurisdictions, due to this event.[34]

[34] S&P Global Market Intelligence. 2021 February 22. Gas utilities face multibillion-dollar financing needs after storm price surge. https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/gas-utilities-face-multibillion-dollar-financing-needs-after-storm-price-surge-62790289.

34. The examples above demonstrate the importance of energy supply security, and how Enbridge Gas's storage assets provide energy security and price stability by backstopping energy supply shortfalls, during extreme weather events.

2.5 Affordability of Natural Gas

Home energy costs for a typical Ontario household range from 1.2% to 4.6% of annual before tax income depending on household income.[35] Keeping energy prices low is a priority for the government of Ontario[36] and energy consumers[37] today and will continue to be a key consideration as the province goes through energy transition.

35. Ontario's natural gas system provides reliable, resilient, and secure energy in a cost-effective manner. According to the OEB's 2020 Yearbook of Natural Gas Distributors, Ontario's natural gas distributors received $5.1 billion in total revenue for services related to natural gas supply, transport and distribution in 2019.[38] During the same period, the 2020 Yearbook of Electricity Distributors lists power and distribution revenues of $21.7B for Ontario's electricity distributors.[39] Even if the differential between these revenues is adjusted for energy payments to other parties (natural gas marketers who provide natural gas supply to large users, for

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[35] Home Energy Spending in Ontario: Income and Regional Distribution, 2021, p.3, https://www.fao-on.org/web/default/files/publications/FA2004%20Home%20Energy/Home%20Energy%202021-EN.pdf.
[36] In his letter to the Chair of the OEB dated November 15, 2021 (p.2), the Minister of Energy stated, "The government's priorities for the energy sector are about promoting reliability, affordability, sustainability and consumer choice". https://www.oeb.ca/sites/default/files/mandate-letter-from-the-Minister-of-Energy-20211115-en.pdf.
[37] The customer engagement process in support of this Application found that three of the top four priority outcomes for both residential and business customers included affordability, reliability and minimizing impacts on the environment. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, pp.119-120, 174-177, 426.
[38] 2020/21 Yearbook of Natural Gas Distributors, September 10, 2021, p. 3, https://www.oeb.ca/oeb/_Documents/RRR/2020_Yearbook_of_Natural_Gas_Distributors.pdf.
[39] 2020/21 Yearbook of Electricity Distributors, September 10, 2021, p.3, https://www.oeb.ca/oeb/_Documents/RRR/2020_Yearbook_of_Electricity_Distributors.pdf.

example),[40] the conclusion that natural gas is very cost effective is inescapable, given that natural gas energy accounted for 30% of total energy demand of Ontario while electricity accounted for 16% of total energy demand in 2019, as shown in Figure 1.

36. Despite an increase in commodity prices and other costs to serve customers, Enbridge Gas's 2024 proposed test year revenues of $6.3 billion continue to be significantly less than electricity revenues including power and distribution revenues, net of certain taxpayer funded reductions to electricity bills.[41] Enbridge Gas's residential customers will pay approximately $45/month in distribution revenues based on Enbridge Gas's proposal, which reflects the value of resiliency, reliability and security provided by Enbridge Gas's rate base.

2.6 Conclusion: Resiliency, Reliability, Security and Affordability

37. Based on the information and examples above, it is clear that Enbridge Gas's system provides reliability, resiliency, security and affordability for Ontario's energy supply and energy system. Energy consumers in Ontario rely on the gas system's ability to meet peak and seasonal energy demands, withstand extreme weather events and to protect against energy supply and system interruptions, which help to minimize impacts on energy prices.

[40] Estimated as an approximate incremental $1.6 billion using the 2019 historical T-service consumption of 13,383,875 m^3 as provided at Exhibit 3, Tab 3, Schedule 1, Attachment 8, converted to 520,254,956 GJ with average heat value of 38.9 GJ/10^3m^3, times the Average Settlement Price Dawn 2019 - Flow Date: $3.02 CAD/GJ.
[41] The Financial Accountability Office of Ontario estimates that the Renewable Cost Shift, a subsidy to remove the cost of renewable energy contracts from ratepayer electricity bills, will provide $3.1 billion in support to all electricity ratepayers in 2022-2023. Ontario's Energy and Electricity Subsidy Programs, February 2022, p. 8, https://www.fao-on.org/web/default/files/publications/FA1907%20Electricity%20Sector%20Review/Ontario's%20Energy%20and%20Electricity%20Subsidy%20Programs-EN.pdf

38. The interdependence of the electricity and gas systems is a key characteristic of Ontario's energy system; leveraging both gas and electricity systems enables a diversified approach to managing the energy needs of the province through the energy transition. Diversity enhances energy system reliability, resiliency, security and affordability as compared to overleveraging a single system to achieve GHG emissions reduction goals.

39. It is critical to understand that the benefits of an integrated and optimized gas and electric system are not in conflict, or at odds, with reaching net-zero goals. When planning the energy system of the future, the beneficial characteristics of both the gas and electric systems can be recognized by leveraging the use of low- and zero-carbon fuels, including RNG and hydrogen, alongside renewable electricity. This has been considered and has informed Enbridge Gas's long-term energy vision for Ontario provided at Exhibit 1, Tab 10, Schedule 5, Section 3 and the Company's Energy Transition Plan provided at Exhibit 1, Tab 10, Schedule 6, Section 2.

3. Electricity Sector Overview

40. This section provides an overview of the electricity sector and what it is being planned for over the course of the next 10 years based on currently available public information. An overview of electricity demand and drivers, resulting capacity requirements, how capacity requirements are planned to be met, and the impacts on supply and transmission are presented.

41. The Independent Electricity System Operator (IESO) manages electricity grid operations and wholesale electricity markets for approximately 4.9 million customers in Ontario.[42] The IESO is responsible for assessing and maintaining the

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[42] IESO. Overview. https://www.ieso.ca/en/Corporate-IESO/Media/Overview

long-term adequacy of Ontario's electricity resources by carrying out long term forecasts, procuring supply resources and implementing government policy.

42. The Ontario electricity market includes power generators, transmission owners, electricity distributors, power marketers, and large consumers. The IESO operates a real-time wholesale electricity market into which generators offer into. These generators are subsequently called upon to produce electricity to meet demand on a five-minute basis. Within this market, many generating resources have long-term power purchase agreements or other forms of long-term supply agreements.

43. The electricity grid in Ontario has more than 30,000 kilometers of transmission lines, and 38 GW of transmission-connected generating capacity.[43,44] The current mix of transmission grid connected electricity generation is made up primarily of nuclear (34%), gas (28%) and hydro (23%) assets, with the remainder being wind, biofuel and solar.[45] In 2021, 142.5 TWh of electricity was produced in Ontario, 58% of which was produced with nuclear generation. Hydro, gas, and wind generation provided 24% 9%, and 8% respectively.[46]

44. The 2021 Annual Planning Outlook (APO)[47] presents a forecast of electricity demand and identifies capacity needs for Ontario over a 20-year time horizon, from

[43] IESO. Ontario's Electricity System. https://www.ieso.ca/localContent/ontarioenergymap/index.html
[44] IESO. 2021 Year in Review. https://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data#:~:text=Electricity%20use%20in%20Ontario%20is,22%2C986%20MW%20on%20August%2024.
[45] Ibid
[46] ibid
[47] IESO. Annual Planning Outlook, December 2021, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/2021-Annual-Planning-Outlook.ashx

2023 to 2042.[48] The 2022 Annual Acquisition Report (AAR)[49] outlines how capacity needs are planned to be met in over the first half of the APO outlook, from 2023 to 2032.

45. Electricity demand in Ontario is forecasted to increase from 147 TWh in 2023 to 168 TWh per year by 2032.[50] Industry is the largest contributor to the increase in electricity demand over this period with 5.7 TWh.[51] As noted in the APO, this is largely due to growth in mining in support of Ontario's Critical Mining Strategy and the electrification of steel making by Algoma Steel Inc.[52] Greenhouse expansion and the adoption of artificial lighting drive electricity demand growth in the agricultural sector. Electric vehicles (EVs) and the electrification of rail transit drive electricity demand in transportation. Electricity demand in the commercial sector is driven by the recovery from the pandemic, and a shift toward a digital economy provides moderate growth. Residential electricity demand is forecast to increase because of population growth due to supportive immigration polices and working from home. The electrification of space heating is not identified as a driver of forecasted demand. Figure 3 shows the sectoral contributions to the forecasted annual demand increase of 21 TWh by 2032.

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[48] The APO demand forecast represents the most current information, including known government policy and customer commitments; it doesn't reflect possible future government policy. The IESO's Pathways to Decarbonization study and demand scenario will be used to explore the implications of operating Ontario's electricity system under significantly higher demand with a non-emitting supply mix.

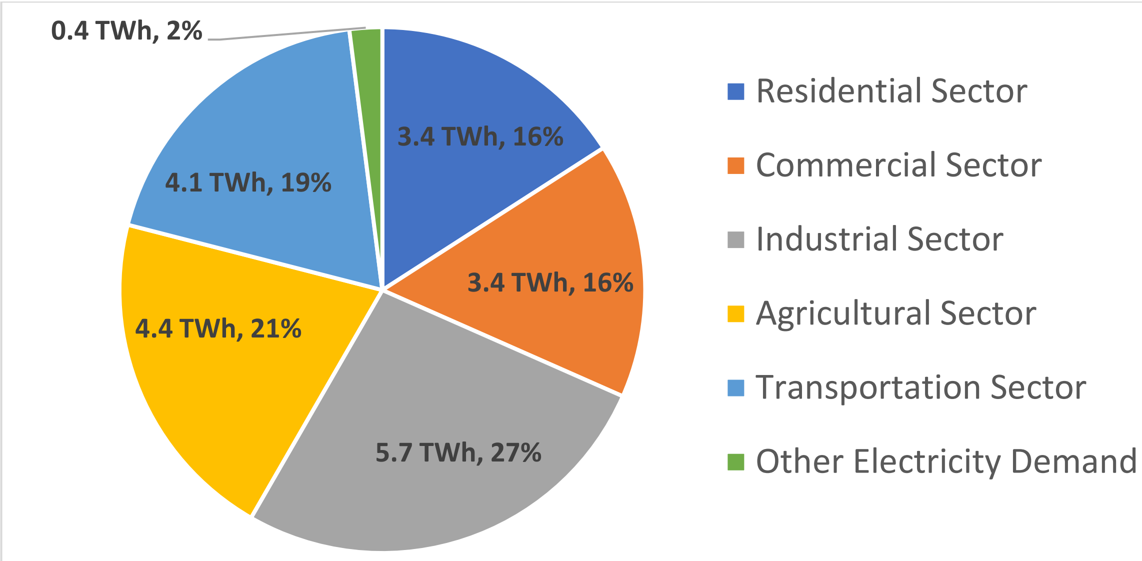
[49] Annual Acquisition Report, April 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/aar/Annual-Acquisition-Report-2022.ashx

[50] Annual Planning Outlook 2021 Data tables, December 2021, Figure 1, https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

[51] Ibid.

[52] IESO. Annual Planning Outlook, December 2021, pp. 22-23, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/2021-Annual-Planning-Outlook.ashx

Figure 3: Sectoral Share of 2023-2032 Increase in Electricity Demand[53]



46. With respect to energy conservation, the APO assumes that conservation will persist at levels consistent with those in the 2021 to 2024 Conservation and Demand Management (CDM) Framework resulting in 14 TWh of savings from 2023-2028, reducing to 10 TWh by 2042.[54] In addition to what was included in the APO, on September 30, 2022, the 2021 to 2024 CDM Framework budget was increased by $342 million, enabling additional programming that is expected to deliver an additional 1.1 TWh of electricity savings and a total peak demand savings of 725 MW.[55,56]

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[53] IESO. Annual Planning Outlook 2021 Data tables, December 2021 Figure 1, https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook
[54] IESO. Annual Planning Outlook, December 2021, page 24, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/2021-Annual-Planning-Outlook.ashx
[55] Order in Council O.C. 1314/2022, September 2022, https://www.ontario.ca/orders-in-council/oc-13142022
[56] IESO. Ministerial Directives. October 4, 2022, https://www.ieso.ca/en/Corporate-IESO/Ministerial-Directives

47. Summer and winter peak electricity demands are also forecasted to increase from 24.4 GW and 22.1 GW in 2023 to 27 GW and 25.3 GW by 2032 respectively.[57] The increase in peak and annual demands coupled with nuclear refurbishments and the retirement of Pickering nuclear generating station (PNGS) drives capacity requirements in the province out to 2032.[58]

48. The IESO forecasts incremental capacity needs of 1,796 MW with the continued availability of existing resources in 2025; by 2032 these incremental needs are expected to grow to 3,443 MW.[59] Without the continued availability of existing resources, the IESO forecasts capacity needs of 2,120 MW beginning in 2023, increasing to 12,270 MW in 2032.[60] The 2021 APO indicates that needs continue to be greater in the summer than winter throughout the outlook period. The AAR outlines planned actions that address capacity needs identified in the 2021 APO for the scenario without the re-acquisition of existing resources. [61] This ensures that resource acquisition (existing or new) and any new incremental capacity requirements are planned for across the province and within specific regions.

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[57] IESO. Annual Planning Outlook 2021 Data tables, December 2021, Figure 2, https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook
[58] OPG plans to extend the service life of PNGS to 2026, in addition to providing a refurbishment assessment for operating post 2026.Approval of the plan rests with the Canadian Nuclear Safety Commission (CNSC). Should the CNSC approve the plan, then PNGS could be available to provide capacity for an additional 30 years. Source: Government of Ontario, September 29, 2022. Ontario Supports Plan to Safely Continue Operating the Pickering Nuclear Generating Station. https://news.ontario.ca/en/release/1002338/ontario-supports-plan-to-safely-continue-operating-the-pickering-nuclear-generating-station?utm_source=newsroom&utm_medium=email&utm_campaign=%2Fen%2Frelease%2F1002373%2Fontario-building-more-electricity-generation-and-storage-to-meet-growing-demand&utm_term=public
[59] IESO. Annual Planning Outlook 2021 Data tables, December 2021 Figure 19, https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook
[60] Ibid.
[61] Annual Acquisition Report, April 2022, pp.49-51, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/aar/Annual-Acquisition-Report-2022.ashx

49. At a regional level, capacity needs can be driven by resource adequacy,[62] transmission system limitations for moving electricity between regions (transfer capability), and transmission security criteria. The IESO performs transmission security studies, which determine locational capacity needs through comparison of forecasted demand within a region to the total amount of resources and transmission transfer capability into the region.[63]

50. The IESO has identified regional capacity needs in four areas of the province:[64]
    a) West of London: 1,975 MW of capacity is required by 2035 in the region West of London due to rapid expansion of greenhouse growth. Local capacity is required along with increased transmission transfer capability into the region;
    b) East of Flow East Toward Toronto (FETT) interface: capacity needed due primarily to nuclear refurbishment and retirement of PNGS. Local capacity is required along with increased transmission transfer capability into the region;
    c) Northeast Ontario: capacity needed due to new industrial loads and expiring resource contracts. Local capacity is required, and the sufficiency of existing transmission capacity is being studied; and
    d) Ottawa Zone, east of the Flow into Ottawa (FIO) interface: a capacity gap exists during the summer peak due to demand growth. Local capacity and or increased transmission transfer capability into the region is required. The Gatineau Corridor end of life study is examining if transmission enhancements could reduce or eliminate this need.

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[62] Resource Adequacy is the electricity system's ability to serve peak loads (capacity adequacy) and loads in all hours (energy adequacy). Ibid, p. 13.
[63] Ibid, p.16.
[64] IESO. Annual Planning Outlook, December 2021, pages 57-64 https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/2021-Annual-Planning-Outlook.ashx

51. The IESO is implementing a diverse set of solutions as outlined in the 2022 AAR to meet the capacity needs identified in the 2021 APO. The planned actions in the 2022 AAR are in addition to those identified in the 2021 AAR. The capacity needs for 2023 and 2024 and part of the needs for 2025 and 2026 as identified in the 2021 APO are expected to be met by the actions from the 2021 AAR.[65] These actions are noted below.[66]

    a) Capacity Auctions achieving the forward guidance targets ranging from 1200 MW to 1800 MW for the five-year period of 2023 to 2027;
    b) Medium-Term 1 RFP with five-year terms and a common three-year commitment period of 2026 to 2029, targeting existing resources; the result of this RFP was the re-acquisition of more than 700 MW of nameplate existing capacity, most of which was gas-fired;[67,68]
    c) Bilateral re-contracting and negotiations with and for existing resources. Lennox generating station has been re-contracted until 2029 and contract renewal negotiations with Brighton Beach generating station are ongoing with an expected extension to 2029;
    d) Exercising the existing Hydro Quebec Capacity Sharing Agreement for 500 MW of firm import capacity in 2026;
    e) Entering into agreements with Calstock generating station (35 MW biofuel, five-year period) and Oneida Energy Storage Project (250 MW/1000 MWh battery storage, ten-year period) per Ministerial directives;[69,70] and

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[65] IESO. Annual Acquisition Report, April 2022, p. 25, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/aar/Annual-Acquisition-Report-2022.ashx
[66] Ibid, pp.50-51
[67] IESO. Resource Adequacy Update, August 23, 2022, p.2, https://www.ieso.ca/-/media/Files/IESO/Document-Library/resource-adequacy/ieso-resource-adequacy-update.ashx
[68] Selected Proponents - Medium-Term 1 RFP, August 23, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/medium-term-rfp/MT-I-RFP-results.ashx
[69] Order in Council O.C. 137/2022, January 27, 2022, https://www.ontario.ca/orders-in-council/oc-1372022
[70] Order in Council O.C. 990/2022, April 14, 2022, https://www.ontario.ca/orders-in-council/oc-9902022

f) The inclusion of OPG's 300 MW Small Modular Reactor project in service by 2029.

52. Planned actions from the 2022 AAR are intended to incent competition in the market as part of the Resource Adequacy Framework (RAF) and are noted below.[71]

a) Additional annual capacity auctions intended to be the primary means of acquisition for capacity needs prior to 2026. The auctions held from 2023 to 2026 would have 500 MW minimum capacity targets, and forward guidance of up to 1,800 MW;

b) The Medium-Term 2 RFP with core commitment years of 2029 to 2032 is planned as the primary re-acquisition mechanism for existing resources post contract expiry; and

c) The Long-Term 1 RFP, Expedited Long Term 1 RFP and the Same Technology Upgrade Solicitation, are long-term procurement actions intended to address the incremental capacity needs identified in the 2021 APO. Needs of 2,500 MW in 2027 growing to nearly 3,900 MW by 2030 have been identified. The target of this procurement action is 4,000 MW by 2027 or sooner, comprising a 2,500 MW target for battery and other storage and up to 1,500 MW of gas-fired generation.[72] The IESO has received a Ministerial directive to pursue the acquisition of the noted target capacity.[73]

[71] IESO. Annual Acquisition Report, April 2022, pp. 33-42 https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/aar/Annual-Acquisition-Report-2022.ashx

[72] IESO. Resource Eligibility Interim Report, October 7, 2022, p.3, https://www.ieso.ca/-/media/Files/IESO/Document-Library/resource-eligibility/resource-eligibility-interim-report.ashx

[73] Order in Council 1348/2022, October 7, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Directive-from-the-Minister-of-Energy-20221007-resource-eligibility.ashx

53. In addition to the actions outlined above, the IESO has identified transmission system upgrades in the 2021 APO to better meet the growing regional resource adequacy requirements and transmission constraints.

54. One example is the upgrades planned to support the region West of London including the Windsor Essex areas. These upgrades are intended to increase the transfer capability into the region by 550 MW and across the region by 1250 MW[74,75] to support the continued growth of greenhouses in the Leamington-Kingsville area of the region.

55. Another example, the FETT Capacity Upgrade, will increase the transfer capability into the region east of the FETT interface by 2000 MW by 2026. This reinforcement will enable some of the capacity that was lost east of the FETT interface due to nuclear refurbishment and retirement to be replaced with capacity from elsewhere in the province.[76]

56. These upgrades allow capacity needs that have been met through bilateral contract extensions up to 2029 to be sourced through competitive procurement actions post 2029. These timelines align with the proposed Medium-Term 2 RFP and the Long-Term procurement actions planned in the AAR through the RAF.

57. The future is uncertain, particularly beyond 2030. Current and emerging climate policies, as provided at Exhibit 1, Tab 10, Schedule 6, Section 1, could dramatically

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[74] IESO. Southwest Ontario Bulk Planning. https://www.ieso.ca/en/Get-Involved/Regional-Planning/Southwest-Ontario/Southwest-Ontario-Bulk-Planning-Initiatives
[75] Need for Bulk System Reinforcements West of London September 2021, p.48, https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/southwest-ontario/WOL_Bulk_Report_Final_20210923.ashx
[76] IESO. Annual Planning Outlook, December 2021, p.41, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/2021-Annual-Planning-Outlook.ashx

influence electrification trends and the capacity needs of the electricity system. Federal carbon pricing, Ontario's Emissions Performance Standard, and the proposed federal Clean Electricity Regulations,[77] which would require the electricity sector to have net-zero emissions by 2035, create uncertainties regarding the future of gas-fired generation.

58. These existing and proposed policies put pressure on the IESO to assess the potential for new types of non-emitting resources and pressure on gas-fired generators to reduce their carbon emissions.

59. To better understand the potential future electricity demand and capacity needs, the IESO is undertaking a Pathways to Decarbonization study and demand scenario. This study will be used to explore the implications of operating Ontario's electricity system under significantly higher demand with a non-emitting supply mix.[78] It is anticipated that the report will be available in November of 2022.

60. Regarding the uncertainty of the future of gas-fired resources, and to understand how different resources could provide the same characteristics,[79] the IESO has been investigating the potential role distributed energy resources (DER) can play in meeting the long-term electricity needs for Ontario.[80]

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[77] Proposed regulations for GHG emissions from fossil fuel supplied electricity generators, with a stringent near-zero emissions performance standard that would come into effect on January 1, 2035. Government of Canada. (2022 July 26). Proposed Frame for the Clean Electricity Regulations. https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/publications/proposed-frame-clean-electricity-regulations.html.
[78] IESO. Pathways to Decarbonization. 2022, https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Pathways-to-Decarbonization
[79] Gas generation is flexible and fast ramping, which allows for intra-day load balancing and for peak periods, and the ability to fill supply gaps when renewables like wind and solar are unavailable. In addition, gas-fired generation can provide steady continual supply of electricity.
[80] The recently released IESO commissioned DER study suggests that distributed energy resources (DERs), a significant portion of which is demand response, could also meet capacity deficits

61. It is anticipated that the results of these reports would be incorporated into future planning activities by the IESO.

62. Despite these uncertainties, the IESO's planned actions, such as the re-contracting of Brighton Beach and Lennox generating stations, suggest a larger reliance on gas-fired generation to meet localized short term capacity needs "that cannot be addressed in a practical and timely way through competitive processes".[81] Further credence is provided to the role gas-fired generation will play in Ontario from the results of the recent Medium-Term 1 RFP[82], the eligibility requirements for the Long-Term 1 RFP[83] and the Ministerial directive[84] for procurement of 4,000 MW of capacity with up to 1,500 MW of gas-fired generation contracted up to 2040. The IESO indicated that:[85]

> Without a limited amount of new natural gas in the near term, the IESO would be reliant on emergency actions such as conservation appeals and rotating blackouts to stabilize the grid. Failure to mitigate these risks, if combined with extreme weather, could create conditions similar to those seen in California where shortfalls resulted in rotating blackouts.

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identified out to 2032. Ontario's Distributed Energy Resources (DER) Potential Study, September 28, 2022, pp.2-5, https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/derps/derps-20220930-final-report-volume-1.ashx

[81] IESO. Annual Acquisition Report, April 2022, p. 10, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/aar/Annual-Acquisition-Report-2022.ashx

[82] Selected Proponents - Medium-Term 1 RFP, August 23, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/medium-term-rfp/MT-I-RFP-results.ashx

[83] IESO. Resource Eligibility Interim Report, October 7, 2022, p. 8, https://www.ieso.ca/-/media/Files/IESO/Document-Library/resource-eligibility/resource-eligibility-interim-report.ashx

[84] Order in Council 1348/2022, October 7, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Directive-from-the-Minister-of-Energy-20221007-resource-eligibility.ashx

[85] IESO. Resource Eligibility Interim Report, October 7, 2022, p.3, https://www.ieso.ca/-/media/Files/IESO/Document-Library/resource-eligibility/resource-eligibility-interim-report.ashx

63. The IESO has identified future capacity needs driven by increasing electricity demand, nuclear retirement and refurbishments, and contract expiry; however, as noted above, these needs do not currently plan for building heat electrification. The IESO's planning activities clearly demonstrate that the gas system, despite longer-term energy transition pathway uncertainty, is needed over the time period covered by this Application.

ENBRIDGE GAS'S GHG EMISSIONS AND RELATED POLICIES

CARA-LYNNE WADE, DIRECTOR, ENERGY TRANSITION PLANNING
JENNIFER MURPHY, MANAGER, CARBON AND ENERGY TRANSITION PLANNING

1. This evidence gives an overview of the greenhouse gas (GHG) emissions resulting both from Enbridge Gas's operations and from end-use customer combustion of natural gas, and a summary of current policies governing them.

2. This evidence is organized as follows:
    1. GHG Emissions Resulting from Enbridge Gas's Activities
    2. Current Climate Policies Impacting Enbridge Gas

1. GHG Emissions Resulting from Enbridge Gas's Activities

3. This section describes the GHG emissions resulting from Enbridge Gas's activities and Enbridge GHG reduction targets.

4. Enbridge Gas reports GHG emissions to the Ontario Ministry of Environment, Conservation and Parks (MECP) and federally to Environment and Climate Change Canada (ECCC) on an annual basis. Additionally, Enbridge Gas reports GHG emissions in the Enbridge corporate annual Sustainability Report and environmental, social and governance (ESG) Data Sheet.[1]

5. Enbridge Gas's GHG emissions, shown in tonnes of carbon dioxide equivalent (tCO_2e), as reported in the Enbridge ESG Data Sheet are shown on Table 1.

[1] Enbridge Inc. Sustainability. Our Values. https://www.enbridge.com/about-us/our-values/sustainability.

Table 1
Enbridge Gas GHG Emissions (1)

Line No.	Emissions Category (2)	Description	2021 Emissions (Million tCO_2e)
1	Scope 1	Emissions from Enbridge Gas's operations: combustion, flaring, venting and fugitives	0.9
2	Scope 2	Emissions from off-site generation of electricity, which Enbridge Gas buys and consumes	0.001
3	Scope 3	Emissions from combustion of natural gas by the Company's end-use customers.	48.3
4	Total		49.2

Notes:

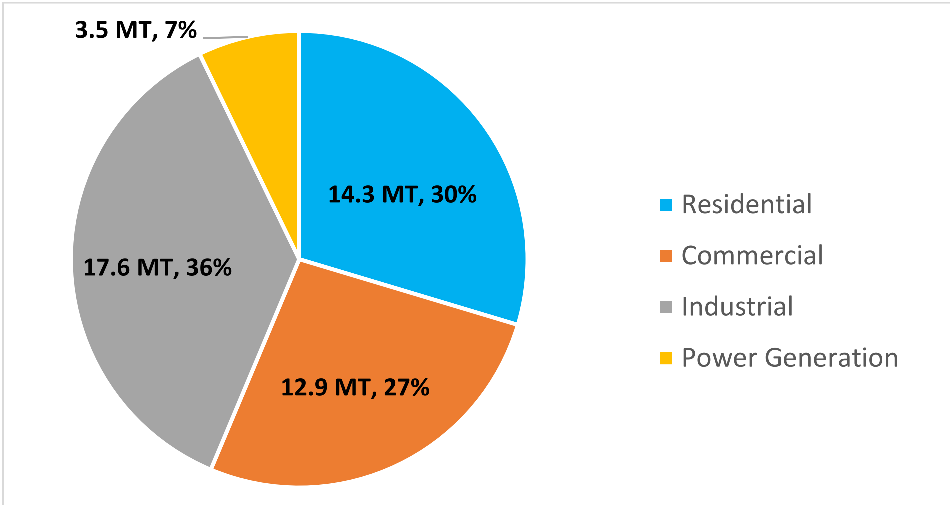
(1) Bridge to a cleaner energy future, Enbridge 2021 ESG Data Sheet, June 8, 2022, p.22, https://www.enbridge.com/~/media/Enb/Documents/Reports/Sustainability%20Report%202021/Enbridge-ESG%20Datasheet_2021

(2) Enbridge Gas follows the categories of GHG emissions outlined in The Greenhouse Gas Protocol. The Greenhouse Gas Protocol, A Corporate Accounting and Reporting Standard, March 2004, p.25, https://ghgprotocol.org/sites/default/files/standards/ghg-protocol-revised.pdf

6. Ontario's GHG emissions in 2020, the last year for which data are publicly available, were 150 million tCO_2e. Enbridge Gas's scope 1 and 2 emissions are less than 1% of Ontario's GHG emissions and the scope 3 GHG emissions from combustion of natural gas by Enbridge Gas's end-use customers are approximately 32% of Ontario's emissions.[2] Enbridge Gas's scope 3 GHG emissions by sector are provided in Figure 1.

[2] National Inventory Report 1990 – 2020: Greenhouse Gas Sources and Sinks in Canada, April 14, 2022, Part 3, p.27, https://unfccc.int/documents/461919

Figure 1: Scope 3 Emissions by Sector[3]



7. In line with the Government of Canada's target to reach net-zero emissions by 2050, in November 2020, Enbridge announced corporate ESG targets, which included targets related to reducing GHG emissions from operations. This includes achieving net-zero emissions by 2050 and an interim target of a 35% reduction in GHG emission intensity by 2030 relative to a 2018 base year.[4]

8. These targets are focused on GHG emissions generated by Enbridge operations arising from combustion and release of methane (scope 1 emissions) and from the generation of purchased electricity consumed by the Company (scope 2 emissions).

9. To date, Enbridge has not set any targets related to indirect emissions that occur in the Company's value chain, which includes end-use customer consumption of

[3] Based on 2021 volumes, as provided in EB-2022-0110, Exhibit B, Tab 2, Schedule 2, p.1.
[4] Enbridge Inc. (2020, November 6). Enbridge sets new environmental, social and governance goals for the future. https://www.enbridge.com/About-Us/Our-Values/Sustainability-Newsroom/Enbridge-sets-new-environmental-social-and-governance-goals-for-the-future.aspx

natural gas (scope 3 emissions). Enbridge has implemented two supplementary metrics for tracking the impact of the Company's investments related to avoidance of third-party GHG emissions. The two metrics are (1) Scope 3 GHG emissions reduced or avoided, which were enabled by Enbridge operated facilities, and (2) the carbon intensity of the energy delivered by Enbridge companies.

10. On an annual basis, Enbridge publicly reports on corporate GHG emissions data, including progress against its 2030 and 2050 targets, together with the supplementary metrics in its annual sustainability report.

11. Since the 2018 baseline year, Enbridge has reduced corporate GHG emissions intensity by 27%.[5]

12. Enbridge Gas's Energy Transition Plan (ETP), provided at Exhibit 1, Tab 10, Schedule 6, presents the Company's plans to assist customers in reducing their emissions from the use of natural gas and to reduce emissions from Company operations. Further details on Enbridge Gas's plan to reduce emissions from operations are provided at Exhibit 1, Tab 10, Schedule 8.

2. Current Climate Policies Impacting Enbridge Gas

13. In this section, Enbridge Gas provides a summary of the current climate policies that impact the Company. Enbridge Gas supports these policies and has taken the necessary actions to comply where required.

[5] Bridge to a cleaner future, Enbridge 2021 Sustainability Report, p.20, https://elink.enbridge.com/NewsEvents/Documents/Enbridge-SR-2021.pdf

2.1 Federal Climate Policies

14. There are three federal GHG reduction regulations that impact Enbridge Gas. A summary is provided in Table 2.

Table 2
Summary of Existing Federal Climate Regulations Impacting Enbridge Gas

#	Policy	Objective	Impact on Enbridge Gas
1	Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)	Reduce methane emissions by 40 to 45% below 2012 levels by 2025.	Enbridge Gas's storage and transmission facilities are required to reduce fugitive and vented methane emissions through prescribed actions.
2	Federal Carbon Pricing	Reduce GHG emissions by implementing a minimum national standard for carbon pricing across Canada. Includes both a charge on fuels distributed in Canada, and a program for large industrial emitters called the Output Based Pricing System (OBPS).	Enbridge Gas is required to remit payment to the Government of Canada monthly for the natural gas the Company distributes. From 2019 to 2021, Enbridge Gas was also covered under the OBPS and was required to calculate and report GHG emissions related to Company-owned storage and transmission compressor stations, and to remit payment for any emissions over the emissions limit determined by production limits stated in the OBPS.
3	Federal Clean Fuel Regulation (CFR)	Reduce the carbon intensity of liquid fuels produced and imported into Canada.	Enbridge Gas can voluntarily participate in the CFR by generating, trading, and selling credits from covered activities, including renewable natural gas (RNG), hydrogen and compressed natural gas vehicles (NGV).

Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)

15. In April 2018, the federal government published the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (Federal Methane Regulations).[6] The Federal Methane Regulations aim to reduce methane emissions from the Oil and Gas Sector by 40% to 45% below 2012 levels by 2025. Requirements under the Federal Methane Regulations came into force on January 1, 2020, with some requirements such as facility venting limits and equipment level emission limits for pneumatic devices coming into force January 1, 2023.

16. The Federal Methane Regulations impose facility venting limits, equipment level emission limits, and leak detection and repair requirements to upstream oil and gas facilities that extract, process and/or transport hydrocarbon gas, while providing the industry flexibility on how to meet the emissions reduction requirements. The key emissions sources covered are fugitives, production venting, and venting from pneumatic devices and compressors.

17. The Federal Methane Regulations apply to Enbridge Gas's storage and transmission facilities, covering emissions sources such as fugitive and vented emissions. Enbridge Gas's distribution-related facilities fall outside the scope of the Federal Methane Regulations. While generally the Federal Methane Regulations do not have regulatory reporting requirements, there are extensive record keeping requirements that Enbridge Gas must comply with, including but not limited to, measurement and calibration records, corrective action records, equipment inventories and vented gas volume records.

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[6] Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector), Sept 1, 2022, https://laws-lois.justice.gc.ca/PDF/SOR-2018-66.pdf

18. To facilitate compliance with the Federal Methane Regulations, funds have been allocated in the Asset Management Plan (AMP) provided at Exhibit 2, Tab 6, Schedule 2, Section 5.3.5.4.11, page 197 and Table 5.3.5-3, page 193, to complete the necessary work to meet the leak detection and repair requirements and to reduce venting from pneumatic devices and compressors.

19. In October 2021, the federal government announced Canada's commitment to develop a plan to further reduce methane emissions, setting a target of reducing methane emissions by at least 75% below 2012 levels by 2030. In March 2022, the government released a discussion paper and began consulting with the provinces, industry, and other stakeholders on how to achieve the increased ambition.[7] Enbridge Inc. submitted a response to the discussion paper. Draft regulations are anticipated in early 2023. Due to the current lack of information on the measures that will be included in the expanded Federal Methane Regulations, Enbridge Gas has not included any budget in the 2023 – 2032 AMP; however, the Company may seek recovery of additional costs in the future.

Greenhouse Gas Pollution Pricing Act

20. In June 2018, the Greenhouse Gas Pollution Pricing Act (GGPPA) was enacted, which set minimum national standards for carbon pricing across Canada, to meet the 2030 emission reduction targets.[8] The GGPPA is composed of two elements:
    a) Part 1 applies a charge on fossil fuels, including natural gas, imposed on distributors, importers, and producers effective April 1, 2019, and increasing annually on April 1; and

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[7] Reducing Methane Emissions from Canada's Oil and Gas Sector: Discussion Paper, 2022, https://www.canada.ca/content/dam/eccc/documents/pdf/cepa/20220325_OilGasMethaneDD-eng.pdf.
[8] Greenhouse Gas Pollution Pricing Act, 2018, https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf.

b) Part 2 imposes an Output-Based Pricing System (OBPS) program for prescribed industrial facilities that emit specified annual volumes of GHG emissions, effective January 1, 2019.

21. The federal government confirmed in October 2018 that the GGPPA would apply in Ontario. As a natural gas utility in Ontario, Enbridge Gas's operations fall under the GGPPA.[9]

22. Under Part 1, Enbridge Gas is required to remit the charge on a monthly basis to the Government of Canada, which is equivalent to \$50/tCO_2e or 9.79 cents per m^3 of natural gas as of April 1,2022 and will increase by \$15/tCO_2e annually starting in 2023, reaching \$170/tCO_2e in 2030.[10]

23. Enbridge Gas's transmission and storage operations were covered facilities under Part 2 of the GGPPA and the OBPS regulation from 2019 to 2021. As of January 1, 2022, the federal OBPS is no longer applicable to the Company as Ontario implemented its own carbon pricing program for large emitters which established similar compliance requirements for Enbridge Gas and is discussed further in Section 2.2.

24. To facilitate compliance with the GGPPA, Enbridge Gas, with approval from the OEB, established six deferral and variance accounts: a customer variance account, a facility variance account and a deferral variance account for each of the EGD rate zone and Union rate zones.[11] The customer and facility variance accounts are used to record the variances between actual carbon costs incurred and the amount

[9] EB-2022-0194.
[10] Government of Canada. (2021 December 03). Fuel Charge Rates for Listed Provinces and Territories for 2023 to 2030. Department of Finance Canada. https://www.canada.ca/en/department-finance/news/2021/12/fuel-charge-rates-for-listed-provinces-and-territories-for-2023-to-2030.html
[11] EB-2018-0205.

recovered through rates, while the deferral accounts record the actual administration costs associated with the impacts of federal and provincial regulations related to GHG emission requirements.

25. Enbridge Gas has applied to the OEB to increase the Federal Carbon Charge to 12.39 cents per m^3 of natural gas effective April 1, 2023.[12] The estimated cost of compliance with the GGPPA for the period of April 1, 2023, to March 31, 2024, is $2,154 million.[13]

Clean Fuel Regulations

26. The Clean Fuel Regulations were published in Canada Gazette Notice, Part II on July 6, 2022.[14] The Clean Fuel Regulations (CFR) apply to liquid fuel producers and importers, who, under CFR, are required to achieve a decrease of approximately 15% (below 2016 levels) in carbon intensity of gasoline and diesel produced or imported into Canada by 2030.

27. The CFR establishes a credit market for CO_2e. Credits can be generated through three main categories of credit-creating actions: 1. Actions that reduce the carbon intensity of the fossil fuel throughout its lifecycle, 2. Supplying low-carbon fuels and 3. Supplying fuel and energy in advanced vehicle technologies.

28. Gaseous fuel suppliers do not have a compliance obligation under the CFR; however, they can generate CFR credits from production of low-carbon gaseous fuels or through end-use fuel switching in vehicles.

[12] EB-2022-0194.
[13] Total compliance cost comprised of $2,151.82 million related to customer volumes and $2.47 million related to company use volumes, as provided in EB-2022-0194, Exhibit A, Tab 2, Schedule 1, pp.10-11.
[14] Canada Gazette II, Vol. 156, No. 14, July 6, 2022, pp.2645-2986, https://www.canadagazette.gc.ca/rp-pr/p2/2022/2022-07-06/pdf/g2-15614.pdf

29. The first compliance period begins on July 1, 2023; however, early action credits can be generated starting June 20, 2022. CFR credits can continue to be created for as long as the regulation is in effect.

30. Enbridge Gas is evaluating opportunities that can generate CFR credits which may include CNG vehicles, the voluntary RNG program and hydrogen blending. Enbridge Gas may register as a credit creator to generate, trade and sell credits under the program where participation in the CFR credit market can support the Company and its customers in adopting lower carbon solutions.

2.2 Provincial Climate Policies

31. There is only one current provincial regulation to enable GHG reductions that impacts Enbridge Gas, which is provided in Table 3.

Table 3
Summary of Existing Provincial Climate Regulations Impacting Enbridge Gas

#	Policy	Objective	Impact on Enbridge Gas
1	Greenhouse Gas Emissions Performance Standards (EPS), 2019	Reduce emissions from large industrial emitters through carbon pricing.	As of 2022, Enbridge Gas is required to calculate and report GHG emissions related to Company-owned storage and transmission compressor stations, and to remit payment for any emissions over the emissions limit determined based on production limits stated in the EPS.

Greenhouse Gas Emissions Performance Standards

32. The Greenhouse Gas Emissions Performance Standards (EPS) Regulation was released in July 2019 as one of Ontario’s commitments in the Made-in-Ontario

Environment Plan.[15] The EPS is targeted to achieve 15% of the emissions reductions (2.7 megatonnes) required to achieve the 2030 reduction target of 18 megatonnes stipulated in the Made-in-Ontario Environment Plan.

33. The EPS creates a pricing incentive to reduce GHG emissions from Emissions Intensive and Trade Exposed (EITE) industrial facilities while limiting the impacts of carbon pricing on their competitiveness. The EPS establishes GHG emissions performance standards, which become more stringent over time, that prescribed industrial facilities are required to meet annually. Participants in the EPS that exceed their annual emissions limit must pay the carbon price per excess tCO_2e (price per unit in $/$tCO_2e$ stipulated by the EPS Regulation) or submit emissions performance units issued by the provincial government.

34. The EPS came into effect in Ontario on January 1, 2022, replacing the Federal OBPS. Under the EPS, Enbridge Gas is required to register as a “covered facility” since its transmission and storage operations are covered by an industrial activity listed in Schedule 2 of the Regulations. As a covered facility, on an annual basis Enbridge Gas is required to calculate and report its GHG emissions to the Ontario Government and then provide compensation for any emissions over and above the stipulated emissions limit.[16]

35. Enbridge Gas’s estimated cost of compliance with the EPS for the period of January 1, 2023, to December 31, 2023, is $5.12 million.[17]

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[15] Government of Ontario. (2021 October 22). O. Reg. 241/19: Greenhouse Gas Emissions Performance Standards. https://www.ontario.ca/laws/regulation/190241.
[16] EB-2022-0194.
[17] Ibid, Exhibit A, Tab 2, Schedule 1, pg.12.

2.3 Summary

36. As provided at Exhibit 1, Tab 10, Schedule 6, Section 1, pages 1-13, climate change has led the federal, provincial, and municipal governments to develop targets, plans, and policies to reduce GHG emissions; however, to date, only the above noted policies are the ones that impact Enbridge Gas. This is a time of or rapid policy evolution at all three levels of government and, therefore, Enbridge Gas expects that new targets, plans, strategies and policies will be coming into place. Enbridge Gas will take all of the necessary actions to comply when required.

INTEGRATING ENERGY TRANSITION INTO THE BUSINESS

CARA-LYNNE WADE, DIRECTOR, ENERGY TRANSITION PLANNING
JENNIFER MURPHY, MANAGER, CARBON AND ENERGY TRANSITION PLANNING

1. This evidence describes the energy transition assumptions that Enbridge Gas has incorporated into the Company's forecasting and planning processes, and the impacts on the Company's Asset Management Plan (AMP), finance and regulatory approaches.

2. This evidence is organized as follows:
    1. Forecasting
    2. Planning
    3. Finance and Regulatory Approaches

1. Forecasting

1.1. Introduction

3. This section provides details on how Enbridge Gas has considered energy transition in the Company's forecasted number of customers, average use, design day and design hour demand, and distribution contract customer demand.

4. These forecasts are important inputs into the Company's planning activities, such as the Asset Management Plan (AMP) development, gas supply planning, and rate setting. To ensure Enbridge Gas's planning activities appropriately consider the impacts of climate policies and energy transition, the Company undertook a review of each forecast to determine what energy transition adjustments to make at this time.

5. Historically, these Enbridge Gas forecasts only considered climate policies that have been implemented. For example, Enbridge Gas's general service average use forecast includes the cost of carbon, based on existing carbon pricing policies in the model's price variable.

6. Enbridge Gas reviewed the following sources of data and insights to develop energy transition assumptions:
   a) The Energy Transition Scenario Analysis (ETSA) study, provided at Exhibit 1, Tab 10, Schedule 5, Section 1 (please also see the report provided at Exhibit 1, Tab 10, Schedule 5, Attachment 1);
   b) A review of current climate policies, provided at Exhibit 1, Tab 10, Schedule 3, Section 2; and
   c) Input from stakeholder engagement, provided at Exhibit 1, Tab 10, Schedule 5, Section 2 and a review of market trends

7. Using the insights gained, Enbridge Gas reviewed the aforementioned forecasts and their inputs to determine the appropriateness of including adjustments to reflect energy transition. This review contemplated both policy certainty and the risks of including or not including energy transition adjustments. As a result of this review, certain adjustment factors were developed and applied to the Company's forecasts and/or their input variables, where deemed appropriate. The adjustment factors included in each forecast are discussed below.

8. Enbridge Gas recognizes that incorporating energy transition assumptions into the Company's forecasting and planning process has had a relatively small impact during the rate rebasing period; however, this evidence demonstrates that Enbridge Gas is accounting for known energy transition factors, is incorporating changes as policy signals become more certain, and is building increased transparency into the

Company's forecasting and planning. Enbridge Gas will continue to monitor and evaluate any new climate policies being developed or implemented to determine the impact on Company forecasts. As Enbridge Gas gains certainty of the implementation date and impact of a policy, the Company will determine how that policy may impact the forecast and, where relevant, will incorporate these impacts into future forecasts. Please see Exhibit 1, Tab 10, Schedule 6, Section 4 for a discussion on the future evolution of Enbridge Gas's energy transition plan.

1.2. General Service Forecasts

9. Energy transition adjustments were considered for the general service average use forecast, as well as for the general service number of customers forecast. These two forecasts were then used to develop the forecasted total annual volume demand. In addition, the general service number of customers forecast was used in the design hour demand as provided at Section 1.4. The adjustments made to these forecasts are described below in more detail.

Energy Transition Assumptions for Average Use

10. The forecasting methodology and the factors affecting average use are provided at Exhibit 3, Tab 2, Schedule 5.

11. Enbridge Gas's average use forecast includes adjustments for carbon pricing. For clarity, the carbon price incorporated into the price variable of Enbridge Gas's proposed average use model assumes the Greenhouse Gas Pollution Pricing Act (GGPPA) will be updated with the Federal Carbon Charge increasing by $15 per tonne CO_2e per year starting in 2023, until it reaches $170 per tonne CO2e in 2030, where applicable, as provided at Exhibit 3, Tab 2, Schedule 5, Section 3.2, pg. 9, and Section 4.2, pg. 20. The average use forecast methodology is also designed to include impacts from energy efficiency measures, as provided at Exhibit 3, Tab 2,

Schedule 5, Section 3.1. At this time, adjustments related to future energy efficiency codes and standards (i.e., building and equipment performance) for both new build and retrofit have not been applied, as Enbridge Gas has insufficient information to estimate implementation timelines and methods, or potential performance outcomes within a reasonable level of certainty. Enbridge Gas will consider incorporating adjustments to the average use forecast to reflect new build and retrofit building codes once future code requirements are clear.

12. No further adjustments were made to the average use forecast related to blending of hydrogen[1], as based on the forecasted hydrogen blending volumes in the Low Carbon Energy Project (LCEP), the amount of hydrogen in the distribution system is forecasted to be minimal during the rate rebasing period. Based on the results of the Grid Study and once Enbridge Gas's plans regarding wider-spread injection of hydrogen into the gas distribution system are known, the Company will assess the appropriateness of an average use forecast adjustment factor to account for blending hydrogen.

13. Table 1 provides a summary of the energy transition assumptions that have been applied and may be applied in the future to the forecasted average annual use.

Table 1

Summary of Energy Transition Assumptions Affecting Average Use Per Customer

Line No.	Forecast Type	Energy Transition Assumption	Forecast Item Reference
1	Average Use: Federal Carbon Charge	April 1, 2023 - $65/ tCO2e April 1, 2024 - $80/ tCO2e	Exhibit 3, Tab 2, Schedule 5, Figures, 8 to 12

[1] Hydrogen has a lower energy density than natural gas and, therefore, blending of hydrogen in the gas distribution system can impact average use.

Energy Transition Assumptions in the Customer Forecast

14. The forecasting methodology for customer additions and average number of general service customers is provided at Exhibit 3, Tab 2, Schedule 6.

15. Enbridge Gas's existing customer additions forecast is based on an econometric model plus adjustments for market information gathered from builders, developers, and municipalities. This information is obtained via ongoing stakeholder engagement.

16. Based on market trends, Enbridge Gas assumed that on a voluntary basis a portion of new buildings would not be serviced by natural gas, and a portion of existing natural gas customers would choose to replace heating equipment reaching the end of its life with non-gas alternatives.

17. As an example, between the period of September 2015 and December 2020, 437 homes (or 0.1% of new housing starts[2]) in Ontario were built to a Net-zero Energy or Net-zero Energy Ready[3] (NZE/NZER) level of performance through participation in a pilot net-zero labelling program. Approximately 75 percent of these NZE/NZER homes were equipped with gas heating or dual fuel gas and electric heating systems.

18. Market research performed in 2020 indicated that of the surveyed homeowners that were very likely to replace their heating equipment within the next year (i.e., 2021),

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[2] 385,882 homes were built in Ontario between September 2015 and December 2020. Ontario Home Builders Association. (2022, March 1). Housing Starts. Ontario Home Builders Association. https://www.ohba.ca/housing-starts-ontario/

[3] CHBA Net-zero Home Labelling Program – Summary Report 2020 by Canadian Home Builders' Association, 2021, https://www.chba.ca/CHBA/HousingCanada/Net_Zero_Energy_Program/Program_Summary_Reports/CHBA/Housing_in_Canada/Net_Zero_Energy_Program/Program_Summary_Reports.aspx?hkey=b5c123aa-60b2-4411-9c76-8bda7f3d5043

94% and 82% were likely to replace their equipment with natural gas space and water heating equipment, respectively, which is similar to 2020 penetration rates (96% for space heating and 85% for water heating).[4]

19. Table 2 provides a summary of the energy transition assumptions that were used to adjust the general service forecast number of customer additions (new construction and replacements) and average number of customers (existing customers). Future customer forecasts will continue to consider government policy and market trends on an annual basis to develop adjustments specific to energy transition.

Table 2

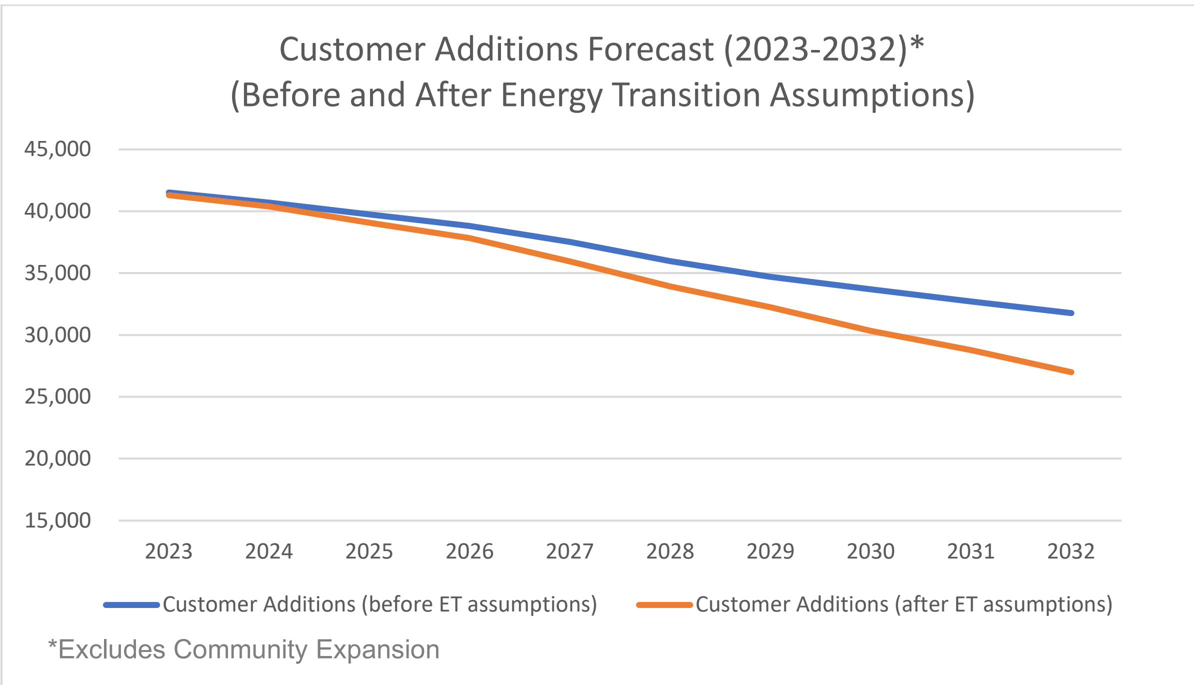
Summary of Energy Transition Assumptions Affecting Customer Forecast – General Service

Line No.	Forecast Type	Energy Transition Assumption	Forecast Item Reference
1	Customer Addition – New Construction	A small segment of builders (<1%) voluntarily do not connect to natural gas network starting in 2023, increasing to an estimated 12.5% by 2032.	- Exhibit 3, Tab 2, Schedule 6, Attachment 1, - Asset Management Plan 2023-2032, Figures 5.1.4-1, and 5.1.4-2
2	Customer Addition – Replacement Conversions	Starting in 2030, 10% fewer existing homes (not previously heated with natural gas) convert to natural gas	- Exhibit 3, Tab 2, Schedule 6, Attachment 1 - Asset Management Plan 2023-2032, Figures 5.1.4-1, and 5.1.4-2
3	Average Number of Customers – Existing Customers	Equipment lifespan is estimated at 20 years, resulting in a 5% annual turnover rate. 10% of customers have only one gas appliance.[5] Starting in 2026, it is assumed that 10% of general service customers voluntarily replace with non-gas equipment at the end of equipment life, those with one appliance are assumed to disconnect from the natural gas network.	- Exhibit 3, Tab 2, Schedule 6, Attachment 2

[4] 2020 Residential: Single Family Natural Gas End Use Study.
[5] Based on 2019 and 2020 Residential Natural Gas End Use Survey.

20. The impact of the energy transition assumptions included in Table 2 on the total number of customers for 2024 Test Year results in approximately 321 fewer general service customers than previously forecasted. Figure 1 shows the impact of the energy transition assumptions on the customer additions forecast.

Figure 1: Impact of Energy Transition Assumptions on the General Service Customer Additions Forecast



Energy Transition Assumptions in the Volume Forecast

21. The Annual Volume Forecast for general service customers is derived from the total number of general service customers and average use per customer forecasts, and is provided at Exhibit 3, Tab 2, Schedule 7.

22. In addition to the energy transition assumptions that have been applied to customer numbers and average use forecasts noted above, Enbridge Gas also includes an

adjustment to the general service volume forecast to account for the Demand Side Management (DSM) program. Forecasted annual volume reductions are detailed in Enbridge Gas's Multi-Year Demand Side Management Plan (2022 to 2027) Application[6] and provided at Exhibit 3, Tab 2, Schedule 7, Table 1.

23. As a result of the energy transition adjustment to the customer forecast, the 2024 Test Year general service annual volume forecast is approximately 2,899,408 cubic meters per year lower than would otherwise be the case. The forecasted general service volumes that have incorporated energy transition assumptions are provided at Exhibit 3, Tab 2, Schedule 7, Attachment 1, Page 1 (by rate class) and Page 2.

1.3. Distribution Contract Market

24. Enbridge Gas proposes to harmonize and simplify the distribution contract market customer and volume forecast which is provided at Exhibit 3, Tab 2, Schedule 8.

25. As the distribution contract market customer and volume forecasts are derived from customer and sector level intelligence, energy transition impacts are inherent and specific to customers in the proposed forecast methodology and do not require additional consideration or adjustment. Enbridge Gas, therefore, did not make any additional energy transition-related adjustments in the distribution contract market forecast.

1.4. Design Hour and Design Day Demand

26. The methodology used to calculate the design hour and design day demand is provided at Exhibit 4, Tab 2, Schedule 3, Section 4.3.

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[6] EB-2021-0002.

27. Factors that influence design hour and design day demand include the number and type of customers, historical weather data and historical customer consumption. Design hour is influenced by the energy performance of customers' buildings, heating and process equipment and what DSM initiatives customers participate in. Design hour and design day demand are reviewed and updated annually.

Energy Transition Assumptions used for Design Hour

28. Design hour demand is used to determine distribution system capacity and identify distribution system needs and is determined as provided at Exhibit 4, Tab 2, Schedule 3.

29. Enbridge Gas developed design hour demand adjustment factors based on peak hour trends observed in the ETSA Reference Case scenario, which include impacts from future DSM programing, carbon pricing and natural gas commodity pricing, building performance and appliance efficiency improvements for existing customers; impacts that had historically not been captured.

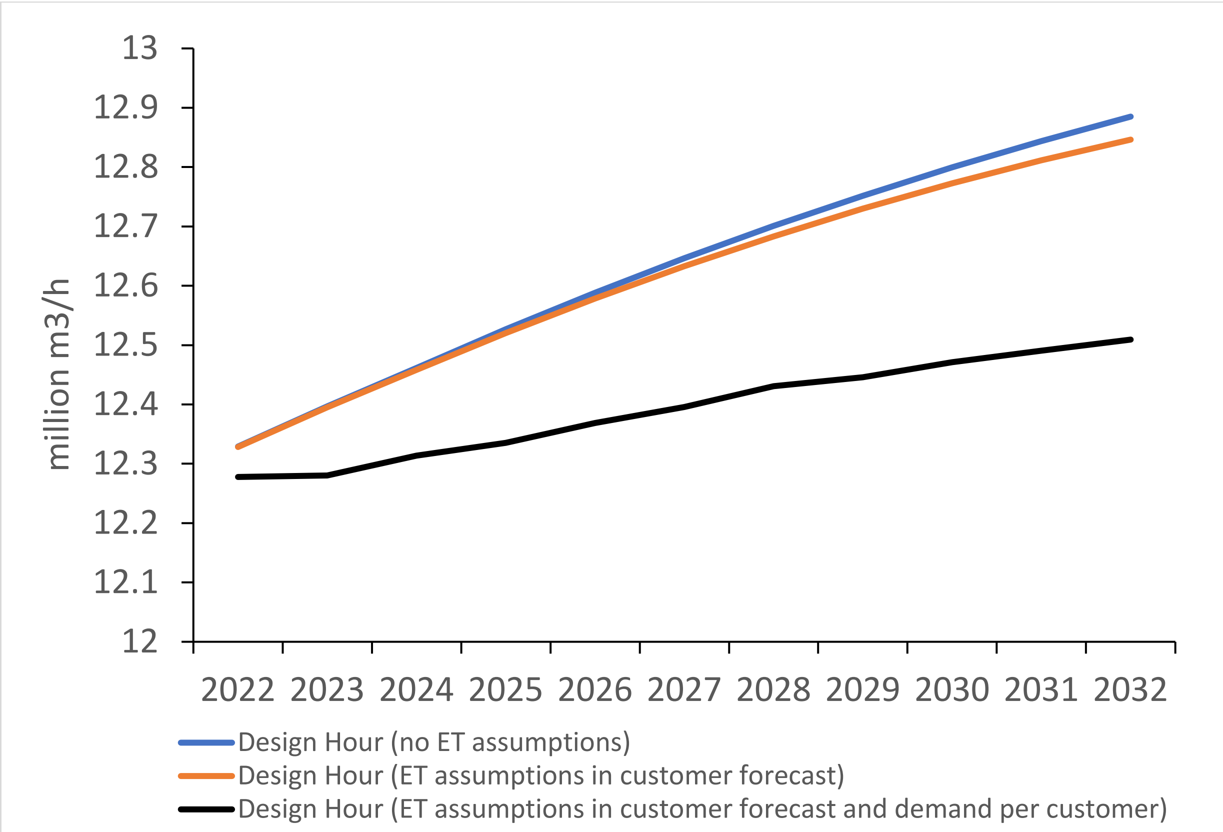
30. Table 3 provides a comparison of the historical design hour adjustment factors and the franchise average design hour adjustment factors that include energy transition assumptions.

Table 3
Comparison of Design Hour Demand Assumptions

Line No.			Existing Residential Customers	New Residential Customers	Existing Commercial and Apartment Customers	New Commercial and Apartment Customers	New Industrial Customers	Existing Industrial Customers
			Design hour Adjustment Factor					
1	Historical Assumption		1.0 multiplier for all future years					
2	Energy Transition Assumption	2021	1	1	1	1	1.0 multiplier for all future years	
3		2022	0.991	0.995	0.998	1		
4		2023	0.984	0.99	0.992	0.998		
5		2024	0.979	0.99	0.989	0.998		
6		2025	0.971	0.987	0.988	0.998		
7		2026	0.964	0.986	0.989	0.999		
8		2027	0.957	0.986	0.991	1		
9		2028	0.952	0.988	0.994	1.003		
10		2029	0.943	0.985	0.995	1.004		
11		2030	0.936	0.984	0.997	1.007		
12		2031	0.929	0.981	0.999	1.009		
13		2032	0.924	0.978	1.001	1.011		

31. The effect of including design hour adjustment factors is a reduction in design hour growth rate over time. Figure 3 shows the effects of including energy transition assumptions on design hour. The design hour demand without energy transition assumptions is shown in blue and labelled “Design Hour (no ET assumptions)”. The effect of including energy transition assumptions is shown by the black line labelled “Design Hour (ET assumptions in customer forecast and demand per customer)". The magnitude of the impact is a reduction in design hour demand of 375,786 m^3/h or 3% by 2032.

Figure 3: Effects of Energy Transition Assumptions on Design Hour Demand



32. The design hour demand, inclusive of energy transition assumptions provided in Table 3, has been used to develop the distribution system reinforcement projects and alternatives in the AMP as provided in Exhibit 2, Tab 6, Schedule 2. The impacts are provided in Section 2.2.

Energy Transition Assumptions used for Design Day

33. Design day demand is used for planning gas capacity for transmission system requirements. As provided at Exhibit 4, Tab 2, Schedule 3, the design day demand forecast incorporates historical trends for existing general service customers in Transmission Planning's use per customer, which have been observed to decline over time. Since the customer additions forecast and assumptions for design hour

demand are inputs for design day demand, the energy transition assumptions that have been applied to those inputs are also accounted for in the design day demand forecast.

34. While Enbridge Gas anticipates there may be changes to design day demand as energy transition in Ontario unfolds, additional energy transition adjustments were not made for the following reasons:
    a) The specific locations for wider-scale injection of hydrogen have yet to be identified, creating uncertainty regarding the impact on the design day demand forecast;
    b) The timing, volume, and geographic distribution of design day demand changes due to future building code changes and increased energy efficiency are not known with certainty; and
    c) Design day demand directly impacts the Gas Supply Plan. If design day demand is under-forecasted, there is risk that Enbridge Gas would not have sufficient assets in its Gas Supply Plan to meet the peak demands of its customers.

2. Planning

2.1. Introduction

35. In this section Enbridge Gas discusses how energy transition and the Integrated Resource Planning (IRP) Framework have been incorporated into Enbridge Gas's planning processes.

36. Since energy transition assumptions are incorporated into the customer forecast, average use forecast, design day and design hour forecasts, they are inherently included in downstream planning processes such as in the Company's AMP process including IRP, Gas Supply Plan, and rate setting processes.

2.2. Asset Management Planning

37. The asset management process provides Enbridge Gas with the ability to adjust the AMP should the pace of energy transition happen at a different rate than what was forecasted, or as government climate policy becomes more certain. Where changes to demand forecasts occur, system needs can be re-evaluated along with the associated projects or alternatives prior to their planning and execution.

38. The growth asset class of the AMP is provided at Exhibit 2, Tab 6, Schedule 2, Section 5.1. The Customer Connections, Distribution System Reinforcement and Transmission System Reinforcement subclasses use forecasts of customer additions, design day, and design hour as inputs. As provided in Section 1.2 and Section 1.4, these forecasts have been adjusted by incorporating energy transition assumptions where appropriate.

39. The customer additions forecast is used as an input into the 10-year capital expenditure forecast for the Customer Connections subclass of the Growth asset class. Figure 1 in Section 1.2 shows the impact of including energy transition assumptions in the customer additions forecast. By 2032, the annual additions are reduced by 4,774 customers per year. Although energy transition assumptions were included in the customer growth forecast as provided in the AMP Section 5.1.4.3, Figures 5.1-2 and 5.1-3 at Exhibit 2, Tab 6, Schedule 2, pages 65-66, due to the timing of best available information the connections capital budget forecast in the AMP is presented without the effects of the energy transition assumptions.

40. The customer forecast provided in Section 1.2, and the design hour adjustment factors provided in Section 1.4 are used as inputs for the design hour demands that are modelled and used to identify distribution system needs and reinforcements. The reduced design hour demand resulting from the changes to the design hour

process as provided at Exhibit 4, Tab 2, Schedule 3, and the inclusion of energy transition factors noted above, resulted in reduced system needs and fewer reinforcements. The combined impact to the AMP is a reduction of approximately $66 million excluding overheads, to the Distribution Reinforcement Capital forecast relative to the previously filed AMP.[7] The comparison is limited to overlapping years between plans: 2023, 2024, and 2025. The Distribution System Reinforcement capital forecast is provided at Exhibit 2, Tab 6, Schedule 2, Section 5.1.10, page 74.

41. The Transmission System Reinforcement subclass is provided at Exhibit 2, Tab 6, Schedule 2, Section 5.1.7.2, pages 69-70. There are no impacts to this subclass resulting from the inclusion of energy transition assumptions as provided in Section 2.2 and 2.4.

2.3. Integrated Resource Planning

42. Enbridge Gas has incorporated IRP into the asset management process in accordance with the OEB IRP Decision and Order and IRP Framework on July 22, 2021.[8] For details regarding types of IRP alternatives and the IRP Assessment Process, please see EB-2020-0091.[9,10][11] How the IRP Assessment Process was incorporated into the 2023 to 2032 AMP is provided at a high level at Exhibit 2, Tab 6, Schedule 2, Section 4.3.4.1, page 55, and in Section 2 "IRP Integration" in the 2021 IRP Annual Report[12].

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[7] EB-2020-0181, Exhibit C, Tab 2, Schedule 1, Section 5, October 15, 2020, p.89.
[8] EB-2020-0091.
[9] EB-2020-0091 Decision and Order, Section 7, Types of IRPA's pages 29-36 , July 22, 2021.
[10] EB-2020-0091 Decision and Order, Section 8, IRP Assessment, pages 37-58, July 22, 2021.
[11] EB-2020-0091, OEB Decision and Order, Section 8, July
[12] EB-2022-0110, Exhibit H, Tab 1, Section 2, June 10, 2022, pp.4-40.

43. Enbridge Gas considers the IRP Framework as a key component of the Company's Energy Transition Plan, as IRP alternatives could defer or avoid infrastructure, thus acting as a "bridging solution"[13] in the short term. The ability to defer or avoid infrastructure allows Enbridge Gas to manage the uncertainty that currently exists within the energy sector, and it ensures that Enbridge Gas will be better positioned when energy policy unfolds in a more concrete way, regardless of which pathway comes to fruition.

44. As part of the IRP regulatory proceeding[14], Enbridge Gas responded to Undertaking JT1.11 by providing a conceptual table that outlined the information that would appear in future versions of the AMP. Enbridge Gas has included Appendix B in the AMP to meet that commitment, as provided at Exhibit 2, Tab 6, Schedule 2, Appendix B. As discussed above, because energy transition assumptions were included within the forecasting process, the projects identified within Appendix B have these energy transition assumptions embedded; this supports a more accurate IRP alternative evaluation process.

45. At the time of this filing, Appendix B reflects the current state of Enbridge Gas's IRP Assessment process which includes identifying the projects that passed or failed the OEB's IRP Binary Screening criteria and a status update on the technical and economic evaluations of those projects that passed the binary screening. Enbridge Gas will continue to assess investments in the 10-year capital plan for IRP Alternative (IRPA) feasibility.

46. In response to the OEB IRP Decision, Enbridge Gas will be undertaking annual regional IRP stakeholder and Indigenous engagement activities. These IRP regional stakeholder activities will glean additional insights into region-specific

[13] EB-2020-0091, OEB Decision and Order, July 22, 2021, p.3.
[14] EB-2020-0091.

energy transition plans, policies, and targets. The gathering and consideration of these insights support continuous improvement of Enbridge Gas's demand forecast, AMP, and IRP processes.

2.4. Gas Supply Planning

47. The Gas Supply Plan is based on annual volume forecasts that include both general service and distribution contract customer demand. Energy transition assumptions are implicit in the 2024 Gas Supply Plan through their inclusion in the 2024 volume forecast as provided in Section 1.2, and through the design day forecast which includes energy transition indirectly through the customer forecast as provided in Section 1.4. For more information regarding the Gas Supply Plan please see Exhibit 4, Tab 2, Schedule 1.

3. Finance and Regulatory Approaches

3.1. Introduction

48. This section provides details on how Enbridge Gas has considered energy transition in other elements of this rebasing application, including in the development of the revenue requirement and rate design proposals.

49. Energy transition poses a significant increase in the risks faced by natural gas utilities. Enbridge Gas has considered alternatives to respond to these increasing risks, including changes to the Company's depreciation rates to mitigate stranded asset risk, and changes to the Company's deemed equity ratio to address increased business risk. These alternatives are further discussed below.

3.2. Depreciation

50. Enbridge Gas's proposed depreciation rates and depreciation expense forecast for the 2024 Test Year are provided at Exhibit 4, Tab 5, Schedule 1. The proposed

depreciation rates are supported by a depreciation study conducted by Concentric Energy Advisors, Inc. (Concentric), which is provided at Exhibit 4, Tab 5, Schedule 1, Attachment 1.

51. In developing the proposed depreciation rates, Enbridge Gas and Concentric considered the introduction of an 'Economic Planning Horizon' (EPH) or truncation date to reflect the potential impact that energy transition could have on the economic life of Enbridge Gas's system.

52. There is potential that climate change legislation, such as municipal or provincial plans to phase out the use of natural gas, could have a life-shortening effect on Enbridge Gas's system. However, there is also the possibility that service lives could be lengthened or maintained if low-carbon fuels, such as hydrogen and RNG, are determined to be viable sustainable alternatives to natural gas. Also, as demonstrated in the P2NZ Study provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, and Exhibit 1, Tab 10, Schedule 5, Section 3, Enbridge Gas's system will be a key contributor to achieving net-zero in the province.

53. Enbridge Gas and Concentric concluded that introducing an EPH is not appropriate at this time. There remains uncertainty around the impacts that energy transition could potentially have on Enbridge Gas's system as discussed above. However, future depreciation studies may warrant the introduction of regional or system wide EPHs, as the energy transition unfolds and more information on the future utilization of Enbridge Gas's assets becomes available.

54. If a diversified pathway to net-zero is not adopted in Ontario, Enbridge Gas would seek to introduce an EPH on its system to mitigate the risk of stranded assets. For illustrative purposes, if a system-wide 2050 EPH were to be implemented starting

2024, the 2024 Test Year depreciation expense would increase by $290 million[15], from $892 million to $1.2 billion. The depreciation study used to calculate this is provided at Exhibit 4, Tab 5, Schedule 1 Attachment 1. /u /u

3.3. Equity Thickness

55. The uncertainty around energy transition has significantly increased Enbridge Gas's business risk and is a major factor underpinning the Company's proposal to increase the equity thickness component of its deemed capital structure from 36% to 42%. The equity thickness proposal is provided at Exhibit 5, Tab 3, Schedule 1.

56. Enbridge Gas retained Concentric to perform an independent assessment of the reasonableness of the capital structure currently authorized by the OEB. The resulting report is provided at Exhibit 5, Tab 3, Schedule 1, Attachment 1, Enbridge Gas Inc. Common Equity Ratio Study (the Equity Ratio Study).

57. Enbridge Gas and Concentric concur that the Company's risk profile has increased significantly since 2012, the last time the OEB reviewed equity thickness for EGD[16] and Union[17]. In early 2013, the OEB concluded that new environmental policies at the time had not increased EGD's risks in comparison to 2007.

58. Since then, energy transition has become the most significant factor contributing to increased business risk for Enbridge Gas, as evidenced by findings in the Equity Ratio Study:

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[15] Calculated using the depreciation rates from Enbridge Gas Depreciation Study (Exhibit 4, Tab 5, Schedule 1, Attachment 1).
[16] EB-2011-0354.
[17] EB-2011-0210.

a) The future of natural gas distribution is uncertain and is dependent on the specific pathways that will be taken by various levels of government to achieve net-zero targets;
b) There is increased risk of stranded assets. This risk could be mitigated by accelerating depreciation rates (e.g. through an EPH), however this will increase rate pressure for customers and may result in natural gas becoming less competitive than alternative energy sources;
c) Energy transition exacerbates volumetric risk, as Enbridge Gas faces the risk of losing customers and sales volumes through challenges such as building code changes and potential net-zero mandates; and
d) Increasing opposition to natural gas has increased operational risk, as the Company is facing more challenges and delays in siting, permitting and constructing facilities.

These risks are provided in Equity Ratio Study provided at Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 34-43.

59. As stated in the Equity Ratio Study, the recommendation is to increase Enbridge Gas's equity ratio to 42% in order for the Company to "maintain financial strength to continue accessing the debt and equity capital it needs to manage the energy transition under a variety of economic and capital market conditions, while providing safe and reliable service to its customers." (Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 3)

3.4. Rate Setting

60. Enbridge Gas is proposing a straight fixed variable with demand (SFVD) rate design to be used for the proposed harmonized general service customer classes. SFVD rate design consists of a customer charge and a demand charge which

matches the cost to provide delivery service to each customer by reflecting the demand that each customer imposes on the network and the cost of being connected to the network.

61. Among other benefits, the SFVD rate design provides a number of advantages that are complementary to energy transition goals:
    a) SFVD rate design recognizes the uniqueness of individual customer size and consumption patterns and their energy related decisions;
    b) SFVD rate design most accurately reflects the cost to serve, adding to the transparency of utility bills;
    c) SFVD rate design renders the utility agnostic to third party conservation programs because utility fixed costs are protected, leading to a greater opportunity to partner, sponsor and/or support a broad range of third-party conservation programs; and
    d) SFVD rate design provides more accurate price signals to stimulate conservation behaviours and support IRP solutions focused on reducing peak demand in areas of network constraints.

62. Please see Exhibit 8, Tab 2, Schedule 3 for a full discussion on SFVD and its benefits.

PATHWAYS TO NET-ZERO AND THE ROLE OF GASEOUS FUELS

CARA-LYNNE WADE, DIRECTOR, ENERGY TRANSITION PLANNING
JENNIFER MURPHY, MANAGER, CARBON AND ENERGY TRANSITION PLANNING

1. This evidence describes the energy transition studies commissioned by Enbridge Gas to understand how net-zero goals could impact natural gas demand and what role the gas system can play in Ontario achieving its GHG reduction targets. This evidence also provides a summary of the stakeholder engagement Enbridge Gas has undertaken.

2. An overview of Enbridge Gas's vision of energy transition in Ontario and the role of gaseous fuels, which was informed by the studies and stakeholder engagement, is also provided.

3. This evidence is organized as follows:
    1. Energy Transition Studies
    2. Stakeholder Engagement
    3. Enbridge Gas's Vision of Energy Transition in Ontario: A Diversified Pathway

1. Energy Transition Studies

1.1. Introduction

4. In this section, Enbridge Gas describes two studies that the Company undertook to understand the impact of energy transition and associated climate policies on Ontario's natural gas demand and Enbridge Gas's transmission, distribution, and storage system. These studies have informed the Company's demand forecast, vision of Ontario's energy sector, and energy transition plan (ETP).

5. Enbridge Gas took a two-phased approach to this work. The first study, the Energy Transition Scenario Analysis (ETSA), was undertaken to understand the impacts of energy transition and the associated climate policies on natural gas demand in Enbridge Gas's distribution system. Four future scenarios were created as part of the ETSA work. Insights from ETSA were then used to support the development of energy transition adjustments to Enbridge Gas's forecasts, as provided at Exhibit 1, Tab 10, Schedule 4, Section 1. The climate policies considered in all four ETSA scenarios are provided at Exhibit 1, Tab 10, Schedule 6, Section 1, as well as potential future policies that could be implemented by federal, provincial, and municipal governments. Two of the ETSA scenarios were used as part of a second study, Pathways to Net-Zero for Ontario (P2NZ) and to inform Enbridge Gas's ETP, as provided at Exhibit 1, Tab 10, Schedule 6, Section 1.

6. The second study, P2NZ, was undertaken to understand how achieving net-zero via two different pathways impacts Ontario's energy system, including costs, reliability, and resilience. The P2NZ report built upon the two scenarios identified in the ETSA work as likely to achieve net-zero: the Diversified scenario and the Electrification scenario. The P2NZ study insights were used to support the development of Enbridge Gas's vision of Ontario's energy sector, as well as the ETP and related proposals, as provided at Exhibit 1, Tab 10, Schedule 6.

7. Both studies are based on scenario analyses intended to inform Enbridge Gas of the impact of various plausible and relevant scenarios; however, they are not intended to be a prediction of the future. The Company has focused on scenarios that would provide the best insight for planning purposes.

8. Due to the timing of the studies, to provide input to the planning processes for rebasing and the rapid pace of change in climate policies and energy transition, the

studies reflect climate policies that were known or anticipated at the time each study was initiated. Assumptions around future climate policies may not reflect recent climate policy announcements.

1.2. Energy Transition Scenario Analysis

9. In 2020, Enbridge Gas identified the need to undertake an analysis of the impact of climate policies on the gas distribution system under a range of possible scenarios. The ETSA Project was intended to inform the Company's energy transition strategies, forecasting and planning, and to assess potential scope 3 GHG reductions that the Company could support.[1] The ETSA Project looked only at gas demand and emissions for Enbridge Gas's distribution customers and does not reflect economy-wide emissions from other energy sources or activities in Ontario (i.e., gaseous fuel not delivered by Enbridge Gas, liquid or solid fossil fuel use).

10. In August 2020, Enbridge Gas retained Posterity Group to undertake the ETSA Project. The modeling approach and results are summarized in the report provided at Attachment 1.

11. The outputs of the ETSA Project include modeled annual volumetric gas demand, system peak hour and peak day demand according to customer and fuel types, and GHG emissions at an end-use level over a 20-year period (2019 to 2038) under four theoretical scenarios. The ETSA Project did not assign probabilities to the likelihood of each scenario occurring and did not include analysis of the cost implications of each scenario.

[1] As discussed in Exhibit 1, Tab 10, Schedule 3 scope 3 GHG emissions come from the combustion of natural gas by the Company's end-use customers.

12. The modeled results provided by the ETSA Project are for illustrative purposes only and are not intended to replace Enbridge Gas's OEB-approved forecasting methodologies; however, the results of the ETSA Project were used to inform Enbridge Gas's forecasting and planning inputs, where deemed appropriate, as provided at Exhibit 1, Tab 10, Schedule 4, Sections 1 and 2.

13. The four scenarios modeled in the ETSA Project were:
    a) Reference case (i.e., business as usual) scenario where there were no changes to the climate policies that were in place as of October 2020;
    b) Steady progress scenario that represented announced policies or proposed programs, as of April 2021, that had yet to be enshrined in law or approved, but had reasonable certainty of being implemented;
    c) Diversified portfolio scenario that assumed implementation of policies to support a wide-spread use of low-carbon gases, including renewable natural gas (RNG) and hydrogen, and carbon capture utilization and storage (CCUS), in addition to electrification to achieve net-zero emissions by 2050; and,
    d) Electricity centric scenario that assumed implementation of policies to support aggressive electrification, with a limited role for low-carbon gases and CCUS to achieve net-zero emissions by 2050.

14. Further information on each scenario, including the scenario narratives, key policies and exogenous conditions associated with each scenario, and the critical drivers that are most influential in each scenario are provided at Attachment 1, pages 40-41.

15. Each scenario considers key variables (critical drivers) that have the potential to affect gas demand and/or GHG emissions. The critical drivers included were carbon price, the price of natural gas, building and equipment codes and standards, equipment choice, population growth, and adoption of low-carbon fuels (e.g., RNG and hydrogen) and technologies (e.g., CCUS). The assumptions for critical drivers in each scenario are provided at Attachment 1, pages 41-45.

16. The scenario narratives, list of critical drivers and input assumptions for critical drivers in each scenario were developed by Posterity Group through consultation with internal subject matter experts and were presented to external stakeholders to solicit feedback. Where possible, publicly available third-party information was also used to inform the input assumptions. Data inputs and assumptions are provided at Attachment 1, pages 80-112.

17. Internal subject matter experts included members of the following departments at Enbridge Gas: Energy Transition Planning, Business Development, Marketing and Energy Conservation, Customer Care, Finance, Regulatory, Engineering, Energy Services, and Public Affairs.

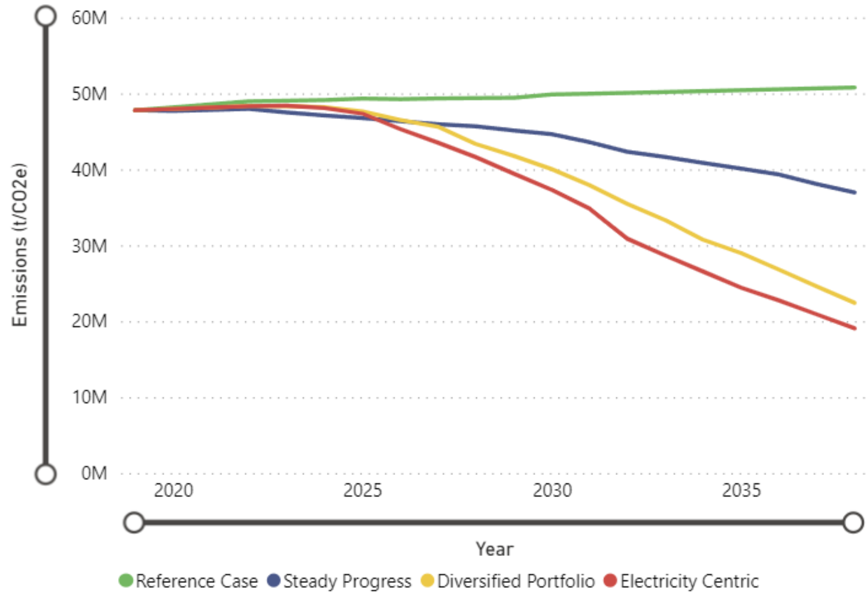
18. External input was sought from a second consultant, Building Knowledge Canada, on the impact of building codes on building energy usage. Additionally, an external stakeholder consultation was held with members of Toronto District 2030, which is a public-private initiative comprised of IESO, Toronto Hydro, Canadian Green Building Council, Enwave, housing developers, architects, and academics. Feedback received was generally supportive of the ETSA work and encouraged Enbridge Gas to continue with energy transition planning, and to work towards a goal of absolute zero GHG emissions by 2050.

19. The feedback received from internal subject matter experts and external stakeholders was considered in finalizing the scenario narratives and input assumptions. Once the scenario narratives and input assumptions were established, scenarios were modeled and compared to the reference case. The results of the modelling and analysis are provided at Attachment 1 at pages 47-79, with key results summarized below.

Key Findings

20. The results of the ETSA Project indicate that current and anticipated government policies reflected in the reference case and steady progress scenarios will not achieve net-zero emissions by 2050, as shown in Figure 1, which is also provided at Attachment 1, page 10, and further policies will be required to achieve the federal net-zero target. While the steady progress scenario assumes the adoption of higher carbon pricing ($170/tCO_2e$ by 2030) and the introduction of more stringent building codes and standards, modeled results indicate the emission reductions from these measures alone are not sufficient to meet net-zero emission goals by 2050.

Figure 1: Annual GHG Emissions by Scenario



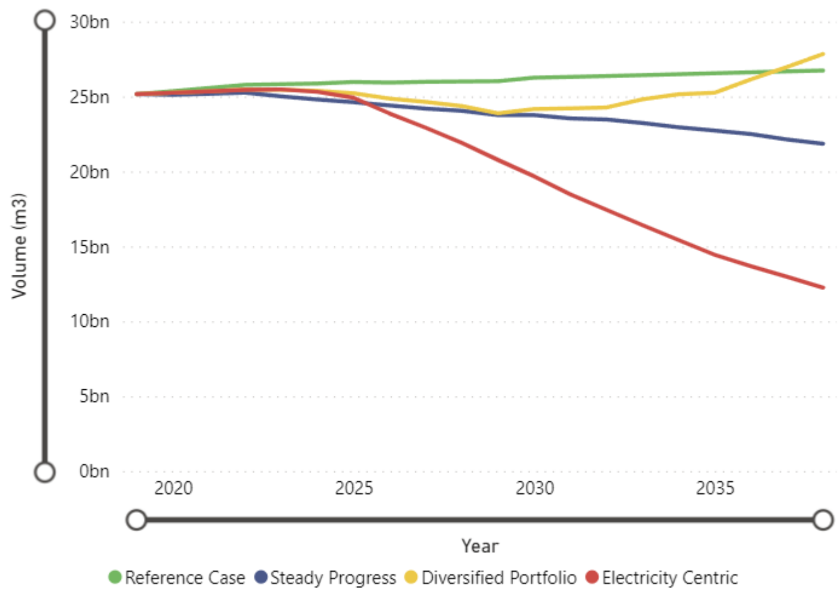
21. Figure 1 also demonstrates that although the Diversified Portfolio and the Electricity Centric scenarios assume distinctly different policies and energy types, both appear to be on a trajectory that could achieve net-zero emissions by 2050. These results are significant, as it demonstrates that a Diversified pathway to net-zero, one which leverages Enbridge Gas's distribution system, can effectively reduce GHG emissions in line with the federal GHG targets.

22. Although they share a similar trajectory for GHG emissions reductions, the annual gas volumes, peak hour and peak day demands in the Diversified Portfolio scenario and the Electricity Centric scenario differ greatly. In the Electricity Centric scenario there is a decline in annual gas volumes and peak hour and peak day demands between 2019 and 2038 due to less reliance on natural gas and low-carbon gasses.

23. In the Diversified Portfolio scenario, the opposite is true, with an ultimate increase in annual gas volumes and peak hour and peak day demands observed between 2019 and 2038. As shown in Figure 2, which is also provided at Attachment 1, page 9, the annual demand in the Diversified Portfolio scenario declines in the short term due to declining building energy demands from the introduction of progressively more stringent codes and standards for equipment and buildings being newly constructed or renovated and from fuel switching. In 2030, annual demand starts to increase due to the inclusion of larger amounts of hydrogen.[2] By the end of the study period in 2038, annual volumetric gas demand is higher than the reference case scenario. Similar trends were also observed for peak hour and peak day demands for the Diversified Portfolio scenario.

[2] Hydrogen has a lower energy content as compared to natural gas. The higher heating values used in the ETSA study were 12.7 megajoules per cubic meter of hydrogen and 38.5 megajoules per cubic meter of natural gas. Household and commercial building growth are provided at Attachment 2, pages 76 and 78.

Figure 2: Annual Volumetric Gas Demand by Scenario



24. This indicates that in the diversified portfolio scenario not only will Enbridge Gas's distribution system remain used or useful over the long-term, but additional distribution system capacity may also be needed to meet the growing hydrogen demand.

1.3. Pathways to Net-Zero for Ontario

25. In August 2021, Enbridge Gas retained Guidehouse Canada Ltd. (Guidehouse) to prepare a Pathways to Net-Zero Study (P2NZ Study) to inform the Company's internal planning. The purpose of the P2NZ Study is to present two different pathways that achieve net-zero emissions in Ontario by 2050 and to examine the associated costs and challenges with each scenario. To Enbridge Gas's knowledge, a similar study showing costs of achieving net-zero in Ontario has not yet been conducted. The full report is provided at Attachment 2.

26. The two scenarios modeled in the P2NZ project are:
    a) A Diversified scenario leveraging RNG, hydrogen, CCUS, and selective electrification in buildings and transportation and a diverse set of end-use technologies to achieve net-zero; and
    b) An Electrification scenario focused on using electricity in all sectors to achieve net-zero with a minimal role for RNG, hydrogen and CCUS.

27. These two scenarios were chosen based on the output from the ETSA Project, which demonstrated that both the Diversified Portfolio and the Electricity Centric scenarios appeared to be on trajectories towards net-zero GHG emissions by 2050.

28. The scope of the P2NZ Study was expanded beyond the ETSA Project to include energy demand and GHG emissions associated with refined petroleum product use in industry and transportation, and to model electric supply and demand. This is useful to understand the role the gas system plays in decarbonizing the economy in line with the 2030 and 2050 GHG emissions reduction targets provided at Exhibit 1, Tab 10, Schedule 3, Section 2. For more detail regarding the study method please see Attachment 2, page 23.

29. The P2NZ Study provides the costs for the investments in electricity, hydrogen, RNG, CCUS, and infrastructure that would be required in each of the scenarios. This is useful to understand the cost implications of achieving net-zero by 2050 with a Diversified scenario vs an Electrification scenario, and to demonstrate the value the gas system provides for achieving a net-zero future. The scope of costs included in the modeling is provided at Attachment 2, page 47.

30. The P2NZ Study compares the pathway of each scenario and the associated impact in Ontario in terms of GHG emission reductions, energy system capacity, costs and overall system feasibility and reliability, as the province transitions toward a low-carbon economy. These scenarios describe two potential futures, and their associated pathways are meant to be plausible approaches, not prescriptive, to reaching net-zero. Enbridge Gas recognizes that there are many different permutations of solutions that can be implemented to achieve net-zero.

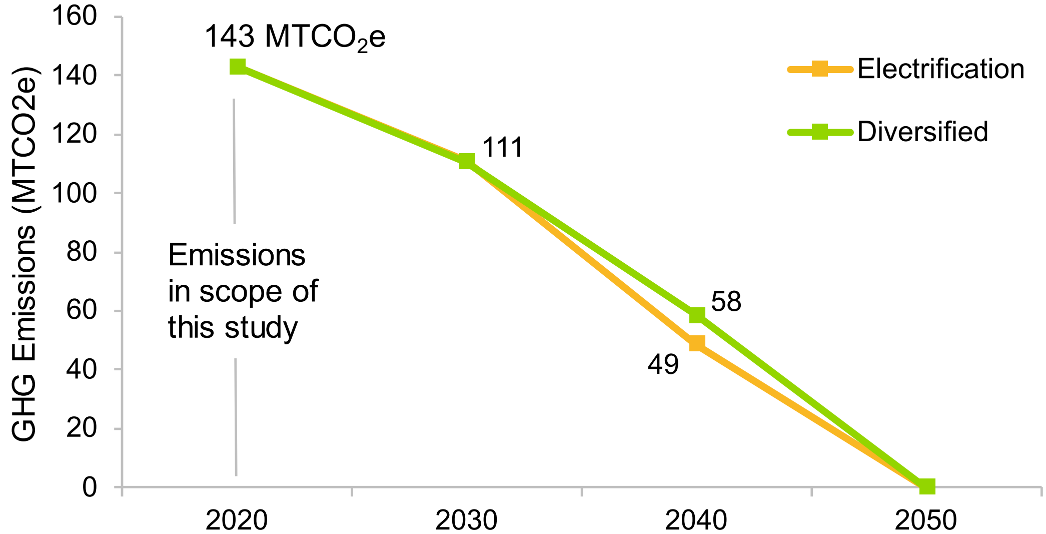
31. Guidehouse also evaluated four sensitivities to understand how the study findings and costs would be affected by altering specific assumptions in each scenario. The sensitives investigated are:
    a) Distributed energy resources with behind the meter battery storage and solar electricity generation coupled with reduced costs for renewables,
    b) Reduced investment in gas supply and infrastructure,
    c) Reduced costs for green hydrogen production, including electrolyser and storage costs, and
    d) Wide-scale adoption of hybrid heating systems.

32. The results of the modelling and sensitivity analysis are provided at Attachment 2, pages 36-56 and key findings are discussed below.

Key Findings

33. The P2NZ Study found that both the Electrification and Diversified scenarios achieve net-zero GHG emissions by 2050, as provided in Figure 3, which is also provided at Attachment 2, page 48. This is a significant finding because it demonstrates that a diversified approach to achieving GHG emission reduction targets is just as plausible as electrification.

<u>Figure 3: Ontario Emissions Pathways</u> /u



34. The results demonstrate that achieving net-zero in Ontario by 2050 will be costly, regardless of the pathway chosen. The Diversified scenario, however, which leverages Enbridge Gas's extensive pipeline and storage network, was found to achieve net-zero at a cost savings of $41 billion compared to the Electrification /u scenario, as provided at Attachment 2, page 45.

35. The sensitivity analysis demonstrates that the costs for the scenarios can vary depending on input assumptions; however, in all cases the Diversified scenario remained the lowest cost pathway, as provided at Attachment 2, page 6. The lowest /u cost Diversified scenario included reduced costs for renewables and distributed energy resources, which provided an additional cost savings of $11 billion. A Diversified scenario that included adoption of a large amount of hybrid heating was among the lowest cost scenarios and provided an additional cost reduction of $9 /u billion

36. Furthermore, the sensitivity analysis found that decreasing investments in the gas system will result in the inability to achieve net-zero by 2050, with significant residual GHG emissions remaining. These findings emphasize that maintaining the gas system into the future is less costly than sole reliance on electrification, even if low-carbon gases are more expensive than natural gas in the shorter term.

37. In addition to achieving net-zero at a lower cost, the study finds that the Diversified scenario has several other key benefits, which are greater reliability, resiliency, consumer choice and industrial competitiveness.

38. The Diversified scenario provides significant reliability and resiliency benefits for Ontarians. As discussed throughout the P2NZ Study, and provided at Attachment

2, pages 60 to 61, the Diversified scenario uses the gas system to provide /u
significant storage flexibility and, thereby, reliability to meet the seasonal fluctuation in energy demand due to variable heating needs in Ontario. Continued use of gas-fired generation with low-carbon gases provides reliability for the electricity system through redundancy for renewable generation when renewable supply is adversely impacted by weather, for example when there is little wind.

39. The Diversified scenario maintains a higher level of reliability and resiliency than the Electrification scenario and it does so while minimizing disruption to end-users and being more cost-effective. The P2NZ Study concludes that "…for Ontario, the Diversified scenario presents a more cost-optimal and feasible pathway for reducing GHG emissions through 2050" as provided at Attachment 2, page 49.

40. The Diversified scenario provides greater consumer choice because it allows for a larger range of end-use options, providing flexibility for consumers to make choices on the path to net-zero. For industrial energy users, the Diversified scenario provides lower cost options for achieving net-zero, increasing their competitiveness.

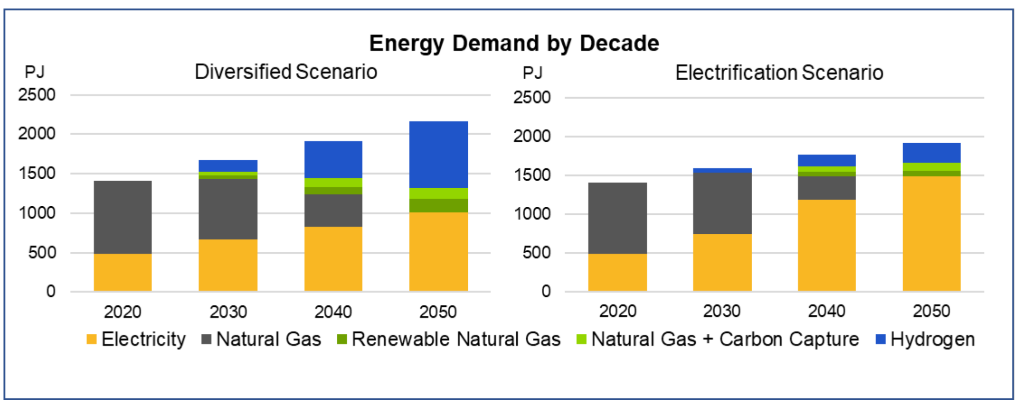
41. Regardless of the pathway chosen to achieve net-zero, the study found that energy efficiency, RNG, hydrogen and natural gas with CCUS are required, and net-zero cannot be achieved without these actions.

42. Energy efficiency is a key aspect of both scenarios. Both the economy and population of Ontario are anticipated to grow over the study period. [3] Despite this growth, peak gas demand decreases on an energy basis by 2050, as provided at
Attachment 2, page 31. /u

Household and commercial building growth are provided at Attachment 2, pages 76 and 78.

43. By 2050, gaseous energy in both scenarios is provided by RNG, hydrogen and natural gas with CCUS, as shown in Figure 4, which is also provided at Attachment 2, page 5. RNG can replace natural gas in pipelines today, achieving emissions reductions across all sectors in the near-term. Hydrogen can also reduce emissions across all sectors and provides a critical pathway for the decarbonization of hard to electrify sectors like industry and heavy transportation in both scenarios. CCUS is needed to produce blue hydrogen, and for high temperature processes in industry that may not have another means to reach net-zero. This demonstrates that investments in RNG, hydrogen and CCUS must begin today to meet the demand seen in 2030 onwards.

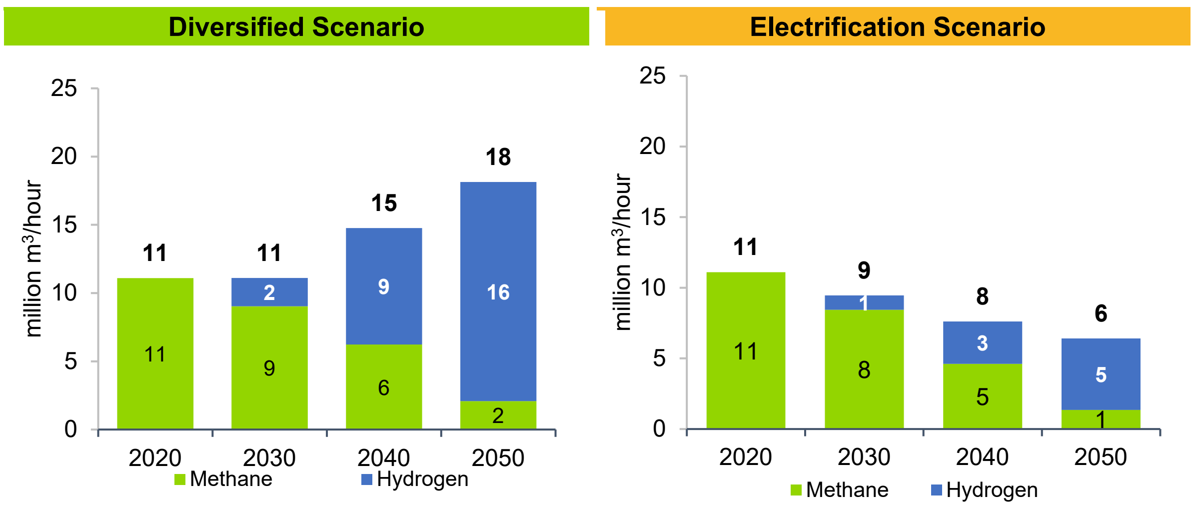
Figure 4: Energy Demand by Decade /u



44. In the Diversified scenario, hydrogen plays a large role in building heat. Since hydrogen is less energy dense on a volumetric basis than natural gas, the volumetric peak demand in the Diversified scenario increases, as shown in Figure 5, which is also provided at Attachment 2, page 31. In the Electrification scenario, the volumetric peak demand decreases to approximately 58% of 2020 levels. /u
Enbridge Gas's pipeline network can be repurposed for the distribution of hydrogen and will play an important role in achieving net-zero in either scenario, as provided

at Attachment 2, page 60. /u

Figure 5: Volumetric Gas System Peak Demand /u



45. The study demonstrates that the electricity and gas systems become more interconnected on the path to net-zero. Electricity supply is critical to scale up production of green hydrogen to meet hydrogen demand. Hydrogen plays a role for electricity storage and for peak electricity supply through hydrogen-fired generation. Combining the electricity and gas systems through hybrid heating to provide space heating in buildings reduces peak electricity system demand and increases resilience. Additionally, the scale at which both scenarios envision building electrification will require the rapid build-out of new electricity generation, and more closely aligned planning between electricity and gas system planners.

2. Stakeholder Engagement

2.1. Introduction

46. In this section, Enbridge Gas describes the feedback the Company has received from customers during the customer engagement process in support of this Application. Additionally, Enbridge Gas's engagement in community energy planning is also discussed.

47. Enbridge Gas is working to further integrate stakeholder feedback and community and municipal plans into the Company's energy transition planning, which is provided at Exhibit 1, Tab 10, Schedule 6, Section 4.

2.2. Rebasing Customer Engagement

48. As provided at Exhibit 1, Tab 6, Schedule 1, Enbridge Gas conducted a customer engagement process throughout 2021 and early 2022 in support of this Application. Detailed customer engagement reports are provided at Exhibit 1, Tab 6, Schedule 1, Attachments 1 and 2.

49. Energy transition was included in all three phases of the customer engagement process covering topics such as the future of natural gas and investments in new technologies or solutions. Questions evolved over the phases to include more detail as the Company's plans became more refined in response to customer feedback.

50. Customers, both residential and business alike, indicated they believe Enbridge Gas should minimize any impacts on the environment as one of the priority outcomes that matter to them. Among outcomes ranked by customers, reducing impacts on the environment was listed just behind providing affordable pricing and safely and reliably delivering natural gas among residential customers. Among

small business and contract customers, it followed affordability, safety, and reliability as well as predictable pricing for medium and large business customers. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 119-120, 174-177, 426.

51. Most general service customers believe that compared to today they will be using the same amount of natural gas 10 years from now, while about 2-in-5 customers believe that they will be using less natural gas 30 years from now, citing various reasons for why this may be the case. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 143-145, 204-206.

52. Most customers indicate that Enbridge Gas should actively invest in low-carbon options and solutions that would help reduce impacts on the environment, as well as to help customers reduce their natural gas usage. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 146-147, 207-209.

53. In phase three of the customer engagement, customers were asked about Enbridge Gas's business plan objectives which included the Company's future plans, along with its climate change goals and efforts to reduce GHG emissions from natural gas. These objectives were all met with support from most customers, across all segments. Among individual investment choices, which included increased hydrogen blending, creating an Innovation and Technology Fund, as well as options to increase the proportion of RNG in the gas supply, all were met with support from customers across all segments. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 245-246, 256-261, 293-295, 327-329, 342-349, 382-385, 428-431, 442-447.

54. Transportation customers and Ontario producers also rated their key outcome priorities. Ontario producers were more likely to rank minimizing impacts on the environment near the top (4/6 placing it in the top 3, compared to 4/15 transportation customers). These customers were also asked to provide feedback on how Enbridge Gas could help them reach their organization's goals as well as broader climate targets. Most offered detailed feedback that included a discussion of RNG, hydrogen, and new technologies. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 2, pages 9, 20, 21, 32, 42, 43.

<u>2.3. Community Energy Planning Engagement</u>

55. As provided in Exhibit 1, Tab 10, Schedule 6, Section 1.5, Municipal Energy Plans (MEPs), Community Energy Plans (CEPs), and Climate Change Action Plans (CCAPs) aim to mitigate the impacts of climate change and 95 Ontario municipalities have completed (or near-completed) plans.

56. These plans are subject to many dependencies ranging from public buy-in to the will of local council. A particular dependency that drives uncertainty is funding and the associated source; for example, funding decisions of municipal councils or funding from other levels of government, to execute upon the plans. Enbridge Gas supports climate plans and the reduction of GHG emissions and as of 2020 Enbridge Gas has dedicated resources to support municipalities as they develop and enact their MEPs, CEPs and/or CCAPs.

57. To support the development of MEPs, CEPs and/or CCAPs, when requested, Enbridge Gas provides gas consumption data and historical energy efficiency program participation data to municipalities so they may understand their baseline gas usage and participation rates across sectors (residential, commercial, and

industrial). This information is used by municipalities in the development of their GHG reduction targets, creation of MEPs, and the identification of programs and activities that aide in the execution of those plans.

58. Enbridge Gas is actively engaged with and has provided information to 79 municipalities and participates on many municipal task forces, advisory bodies, working groups and committees alongside other municipal stakeholders in the development of MEPs, CEPs, CCAPs and/or enabling initiatives. Through this ongoing engagement with municipalities Enbridge Gas regularly collects and shares information about municipal climate change action and energy planning with municipal staff.

59. Enbridge Gas has assisted some municipalities in the creation of new entities and municipal service corporations that will be responsible for actioning municipal plans. The City of Brampton’s Centre for Community Energy Transformation (CCET) is one such entity that Enbridge Gas has helped to establish.[4] As a member of the CCET advisory task force, Enbridge Gas participated in monthly meetings “to provide strategic guidance to help transition the CCET from a conceptual framework to an established not-for-profit corporation”.[5]

60. Please see Exhibit 1, Tab 10, Schedule 6, Section 4 for how Enbridge Gas intends to evolve engagement with municipalities over time.

[4] Staff Report: Centre for Community Energy Transformation (CCET), 2022/02/02, page 4, https://pub-brampton.escribemeetings.com/filestream.ashx?DocumentId=42060
[5] Ibid

3. Enbridge Gas's Vision of Energy Transition in Ontario; a Diversified Pathway

61. As the largest natural gas distributor in Ontario, Enbridge Gas has over $14 billion in regulated assets and serves over 3.8 million customers. Enbridge Gas distributes the energy to heat more than 75% of Ontario's residential homes, as well as delivering energy to most of Ontario's commercial and industrial businesses, and to critical infrastructure such as hospitals and schools.

62. Enbridge Gas supports the GHG emission reduction targets that have been implemented by all levels of government. Given the immense level of critical energy that Enbridge Gas delivers within the province, the Company must support all levels of government in their development of net-zero pathways if the most cost-effective, reliable, resilient, and secure transition is to be understood and seamlessly implemented.

63. To enable this support, Enbridge Gas has developed a vision for Ontario's energy system, and the role that gaseous fuels can play. The vision is based on the Company's extensive industry experience and deep understanding of its operating environment, as well as the following data and insights:
    a) A review of the current and evolving climate polices in Canada, Ontario, and the municipalities where Enbridge Gas operates, are provided at Exhibit 1, Tab 10, Schedule 3, Section 2 and Exhibit 1, Tab 10, Schedule 6, Section 1;
    b) Gathering insights from the two-energy transition studies Enbridge Gas commissioned from external consultants, ETSA and P2NZ, as provided in Section 1 above;
    c) A review of actions being taken in the electricity sector to prepare for energy transition, as provided at Exhibit 1, Tab 10, Schedule 2, Section 3; and

d) Collecting insights from stakeholder engagement activities, as provided in Section 2.2 above.

64. Enbridge Gas's vision for Ontario's energy system is a diversified pathway to net-zero. A diversified pathway recognizes that there are many solutions to reduce GHG emissions and achieve net-zero, some of which include leveraging the existing natural gas systems in the province.

65. While some assume that the only pathway to achieve net-zero is the complete electrification of the energy demand that is currently served by natural gas, it is critical to understand that this would eliminate the resiliency and reliability that is provided by the gas distribution, storage, and transmission system in the province, as provided at Exhibit 1, Tab 10, Schedule 2, Section 2. In addition, an electrification pathway to net-zero will require massive investment in new electrical generation, transmission, storage and distribution systems, and end user equipment. This investment is so large because the value of the natural gas system is not leveraged.

66. Conversely, a diversified pathway, which uses both gas and electric systems working together, will be the most cost-effective, reliable, resilient, and seamless pathway for Ontario's energy system to achieve net-zero, while providing consumer choice and ensuring Ontario's businesses remain competitive.

67. A diversified pathway includes using energy more efficiently in the short term, as well as beginning to invest in a longer-term shift to an increasing amount of renewable or low-carbon energy sources, including solutions such as wind and solar electricity generation, RNG and hydrogen, as well as use of technologies to capture carbon emissions from remaining natural gas use.

68. Within the buildings sector, energy demand reductions would be driven via continued energy efficiency and increased building code stringency. Most of the remaining building heat load would decarbonize via the transition from natural gas to hydrogen and renewable natural gas (RNG) and the balance of heating load would electrify. The transportation sector would see light and medium duty vehicles electrify, and hydrogen and RNG would fuel most heavy transport. Finally, the industrial sector would see low-temperature processes electrify and both medium and high-temperature processes utilize either hydrogen or methane with carbon capture, utilization, and storage (CCUS).

69. For Ontario's gas system, a diversified pathway to net-zero means transitioning over time to a system that delivers RNG and hydrogen, and any other low-carbon and zero-carbon gas solutions that may become available, and only a small amount of natural gas combined with carbon capture to serve those customers that cannot practically use an alternative energy. This transition of the gas system is much how the electricity system has already transitioned from coal to renewables and natural gas. This would mean that the gas system continues to be used and useful and continues to provide the reliability and resiliency that it provides today. In addition, it enables an orderly transition by providing consumer choice on energy types and end use technologies.

70. Enbridge Gas based its diversified pathway vision on a significant scope of insights and data and therefore believes that this vision can meet federal, provincial, and municipal GHG emissions reduction targets in the most cost-effective, reliable, resilient, and secure manner.

71. It is also important to note that Enbridge Gas believes that the diversified pathway outlined in the P2NZ Study is just one version of what a diversified pathway could look like; there are many different permutations of how it could unfold in Ontario. Enbridge Gas believes that to develop the most optimal diversified pathway, that it must work closely with the electricity sector to undertake an integrated approach to energy transition modeling and planning.

72. Regardless of the pathway and the associated targets that the province sets beyond 2030, energy transition will require fundamental transformation in virtually all aspects of Ontario's economy, and coordination between all levels of government (federal, provincial and municipal), Indigenous nations and groups, gas and electric utilities and energy consumers.

73. This transformation must be undertaken in an orderly manner. An orderly transition means that businesses and residential energy consumers have choices on how to transition and that they have adequate time to plan for, and adapt to, future changes. It also means that energy remains affordable, reliable, resilient, secure, and safe, while environmental goals are met. An orderly transition will provide greater economic stability by allowing time to make the necessary investments to phase out carbon intensive activities, retrain or redeploy workers, and develop new technologies to power the low-carbon economy.

74. While planning for and implementing an orderly energy transition to reduce GHG emissions, it is important to ensure that future energy systems are reliable, resilient, and affordable; considerations which are key priorities for both government[6] and

[6] In his letter to the Chair of the OEB dated November 15, 2021, the Minister of Energy stated, "The government's priorities for the energy sector are about promoting reliability, affordability,

energy consumers[7]. A pathway to net-zero must also ensure factors unique to Ontario are considered, such as the energy infrastructure that currently exists in the province and the cold weather climate present for a large portion of the year.

sustainability and consumer choice". https://www.oeb.ca/sites/default/files/mandate-letter-from-the-Minister-of-Energy-20211115-en.pdf.

[7] The customer engagement process in support of this Application found that three of the top four priority outcomes for both residential and business customers included affordability, reliability and minimizing impacts on the environment. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, pp.119-120, 174-177, 426.

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Project Report

Energy Transition Scenario Analysis

June 23, 2022

Enbridge Gas Inc.

Posterity Group Consulting 6S3

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Contents

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Acronyms

APS	Achievable Potential Study
C&S	Codes (buildings) and Standards (equipment)
CCS	Carbon capture and storage
CD	Critical Driver
CFR	Clean Fuel Regulation
DSM	Demand side management
EGI	Enbridge Gas Inc.
ETSA	Energy Transition Scenario Analysis
GGPPA	Greenhouse Gas Pollution Pricing Act
GHG	Greenhouse gas
H2	Hydrogen
IPCC	Intergovernmental Panel on Climate Change
LCEP	Low carbon energy project
NBC	National Building Code
NC	New Construction
NECB	National Energy Code for Buildings
NGT	Natural gas transportation
OBPS	Output based pricing system
OEB	Ontario Energy Board
PG	Posterity Group
RNG	Renewable Natural Gas

Executive Summary

About the Project

Enbridge Gas Inc (Enbridge Gas) retained Posterity Group Consulting (PG) to work on an Energy Transition Scenario Analysis (ETSA) project. The ETSA project provides Enbridge Gas with theoretical scenarios of the future to help assess the potential impacts from climate policies and economic conditions that Enbridge Gas' system could experience over the next 20 years. Four scenarios were modelled of future gas demand and greenhouse gas emissions over a twenty-year time horizon. Probabilities are not assigned to the scenarios and Enbridge Gas does not endorse or oppose any of the scenarios presented in this report.

Scenario analysis can help an organization such as Enbridge Gas to:

- Develop more robust strategies
- Improve decision making
- Reduce decision making response times
- Improve individual and organizational learning
- Improve organizational communication and shared mental models

Enbridge Gas and PG worked closely together throughout the project which consisted of six main phases:

- *Develop a Reference Case Forecast* – 2019 is the base year and 2020 to 2038 is the forecast period. The reference case scenario is based on Enbridge Gas' 2020-2030 customer and volume forecasts and calibrated to PG's end-use model. The scenario reflects regulations and approved Ontario Energy Board (OEB) applications as of October 2020.
- *Identify Critical Drivers* – The project team worked collaboratively to identify the key variables ("Critical Drivers") that are expected to impact gas demand, peak load, and GHG emissions over the next 20 years. Input data was developed for each Critical Driver across of a range of possible values (e.g., various carbon price possibilities, possible incoming building codes and equipment standards, etc.)
- *Conduct Parametric Analysis & Establish the Boundaries for the Scenarios* – The impact on Enbridge Gas' annual volume, peak load, and GHG emissions from each Critical Driver independently was evaluated to see how sensitive the model is to the variables. This analysis is done by setting each Critical Driver to its highest and lowest possible value and seeing the change on the model of Enbridge Gas' system.
- *Develop Scenario Narratives & Input Assumptions* – Qualitative narratives of the scenarios Enbridge Gas wanted to explore were developed. Input assumptions were set for each Critical Driver to model the scenarios.
- *Scenario Modelling & Analysis of Results* – The scenarios are modelled based on the different Critical Driver settings to create distinct outputs.

The ETSA Scenarios

In addition to the Reference Case scenario, the three scenarios developed under the ETSA project are:

Steady Progress: Represents the gradual implementation of anticipated policies announced by January of 2021 including the 2020 Federal Climate Action Plan, the Clean Fuel Regulation, and more stringent building codes including for new construction and retrofits.

Diversified Portfolio: Reflects a scenario where the majority of GHG reductions are achieved by decarbonizing the gas grid, while recognizing that some electrification may occur. The Diversified Portfolio scenario is intended to represent one possible pathway to achieve net zero by 2050. The policies assumed to achieve this pathway include the 2020 Federal Climate Action Plan, the Clean Fuel Regulation, more stringent building codes including for new construction and retrofits, low carbon gas mandates, and enhanced support for deployment of hydrogen and carbon capture and storage technology. This scenario assumes innovation in electrical storage, hydrogen equipment, CCS, and low-carbon fuels.

Electricity Centric: Illustrates a pathway where GHG reductions are sought primarily from the electrification of heating equipment in buildings. The Electricity Centric scenario is intended to represent one possible pathway to achieve net zero by 2050. The policies assumed to achieve this pathway include the 2020 Federal Climate Action Plan, the Clean Fuel Regulation, more stringent building codes including for new construction and retrofits, as well as mandated use of electric space and water heating equipment. This scenario assumes innovation in electrical storage, non-emitting generation of electricity, and CCS.

All scenarios also include energy savings potential from DSM programming based on various assumed DSM budgets.

Key Findings: Sensitivity Analysis to Critical Drivers

The ETSA project assessed the impact of each Critical Driver independently on Enbridge Gas' system in terms of annual volume, peak and GHG emissions. Each Critical Driver was moved to the maximum and minimum on the range of possible values ("parametric analysis"). The results are summarized below and detailed in section 5.1. Before reading the results below, please note that these results reflect the values developed for this project so the results would be different if other values were used. Also, some Critical Drivers were not set to their maximum or minimum setting in the scenarios. With this context in mind, the following Critical Drivers had the most significant impact on Enbridge Gas' system based on the values used in the analysis:

- Non-price driven fuel switching: This Critical Driver reflects customers using less gas due to policies and preferences for electric heating equipment and had a significant impact on lowering annual volume, hourly and daily peak, and GHG emissions.
- Natural Gas Price: when gas prices increase, annual volumes are expected to decrease as customers use less gas in the long run.
- Hydrogen: blending hydrogen into the gas grid can increase annual volume and peak while reducing GHG emissions, as this study assumed hydrogen had zero combustion emissions.

Other interesting findings from the parametric analysis include:

- GHG emissions can decline while annual volume can increase when there is sufficient uptake of renewable natural gas, hydrogen and carbon capture and storage. Hydrogen in particular increases annual volume while contributing to GHG reductions.
- Peak load is most significantly impacted by hydrogen, DSM programming, more stringent equipment standards and building codes for retrofits and new construction, and the

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electrification of space and water heating loads. Peak load is also impacted by Enbridge Gas' expected growth in some Industrial customers that have a higher portion of their load used for HVAC, as HVAC accounts for approximately 60% of industrial peak but only 16% of annual volume.

Key Findings: Scenario Analysis

By 2038, the Diversified Portfolio scenario has the highest gas volume as this scenario has the most hydrogen volumes[1], which are driven by low carbon gas mandates and enhanced support for deployment of hydrogen. The Electricity Centric scenario has the lowest volumes starting in 2025 as space and water heating end-uses switch to electricity. The Reference Case has steadily increasing gas volumes, while the Steady Progress scenario has a slow decline in volume since it reflects the continuation of today's trends and implementation of announced policies.

GHG emission[2] (from the end-user) trends differ from the annual volume results when hydrogen and renewable natural gas displace conventional natural gas, and carbon capture and storage is deployed. While the Diversified Portfolio scenario has the highest annual volume by 2038, emissions decline due to relatively high volumes of hydrogen. The Electricity Centric scenario has a similar decline in GHG emissions as end-uses and customers switch from gaseous fuels to electricity. These two scenarios take different pathways to achieve these GHG emissions reductions: one by predominantly decarbonizing the gas system and the other through electrification. The Reference Case has the highest GHG emissions because nearly all the annual volume is conventional natural gas.

Exhibit 1 presents forecasted annual volume for all scenarios and Exhibit 2 illustrates the GHG emissions for all scenarios.

[1] The volumetric energy density of hydrogen was captured in the model: blending hydrogen increases annual volume (m^3) even if energy demand (PJ) remains the same.

[2] All greenhouse gas emissions reported in the ETSA project represent end-use combustion - not lifecycle emissions - that occur at Enbridge Gas customers, which exclude upstream emissions or avoided emissions associated with fuel production.

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Exhibit 1 – Annual Volume, All Scenarios

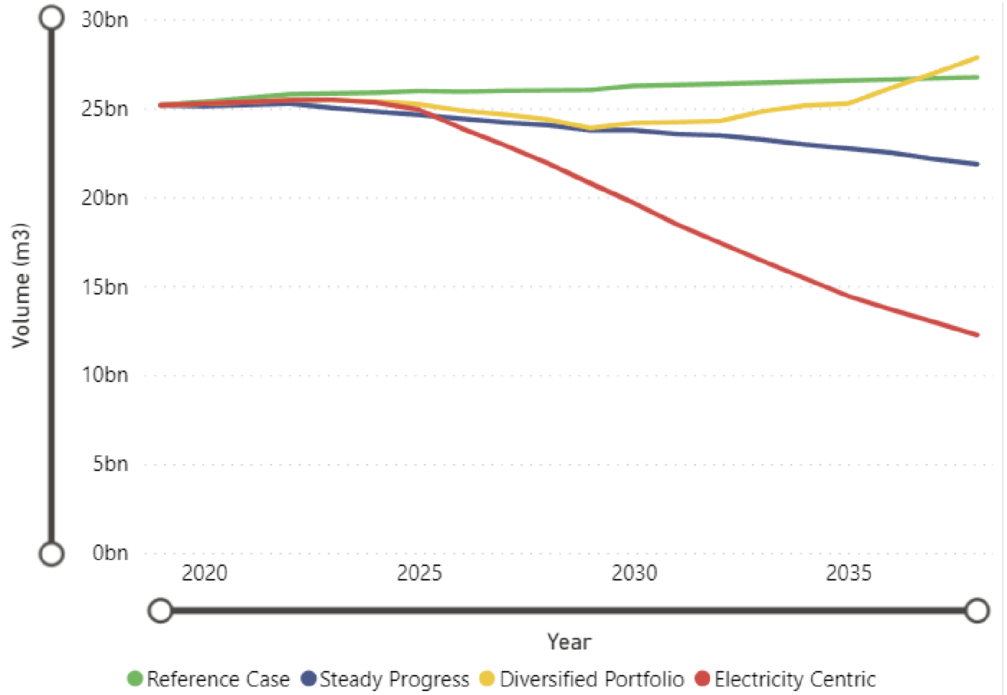
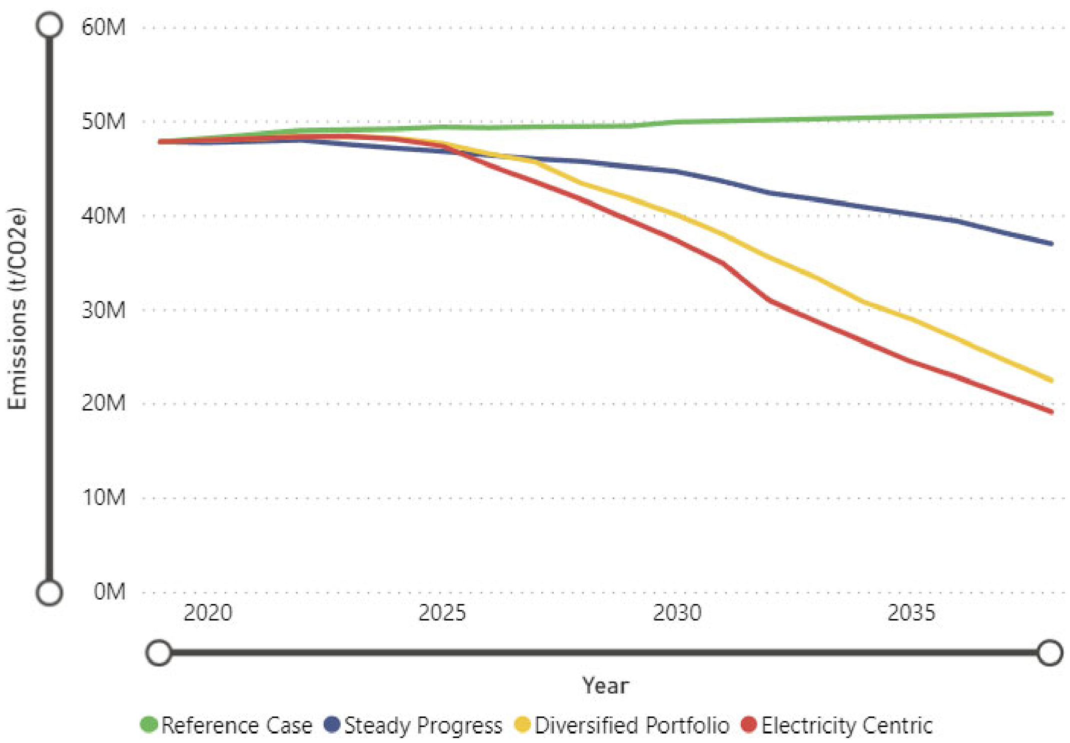


Exhibit 2 – GHG Emissions, All Scenarios



The Reference Case has the highest hourly peak because it is the scenario with the lowest DSM spending, the least stringent policy mechanisms to increase energy efficiency or encourage fuel switching; and negligible amounts low-carbon gases. The Electricity Centric scenario has the lowest hourly peak by 2038 as equipment and buildings electrify and reduce peak load. The hourly peak also decreases in the Steady Progress scenario mainly due to more stringent building codes and equipment standards which lower heating loads and improve heating equipment efficiencies. For all scenarios, DSM programming impacts peak when measures reduce peak loads. Exhibit 3 below presents hourly peaks for all scenarios.

Results for daily peak across the scenarios mirror the results for hourly peak discussed above. Exhibit 4 presents daily peaks for all scenarios.

Exhibit 3 - Hourly Peak, All Scenarios

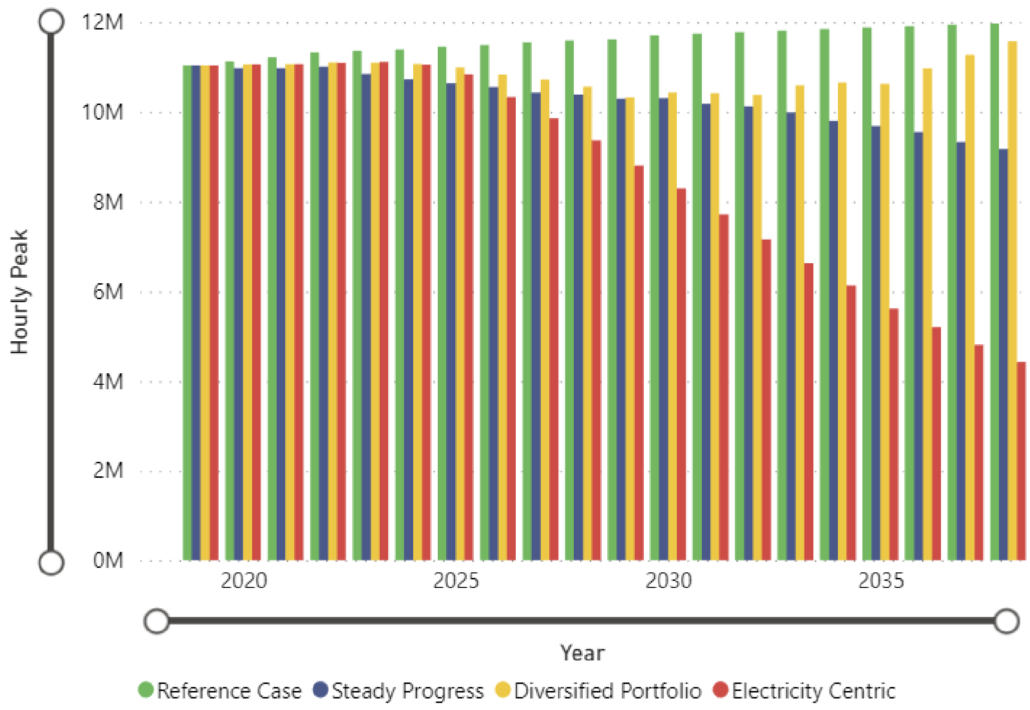
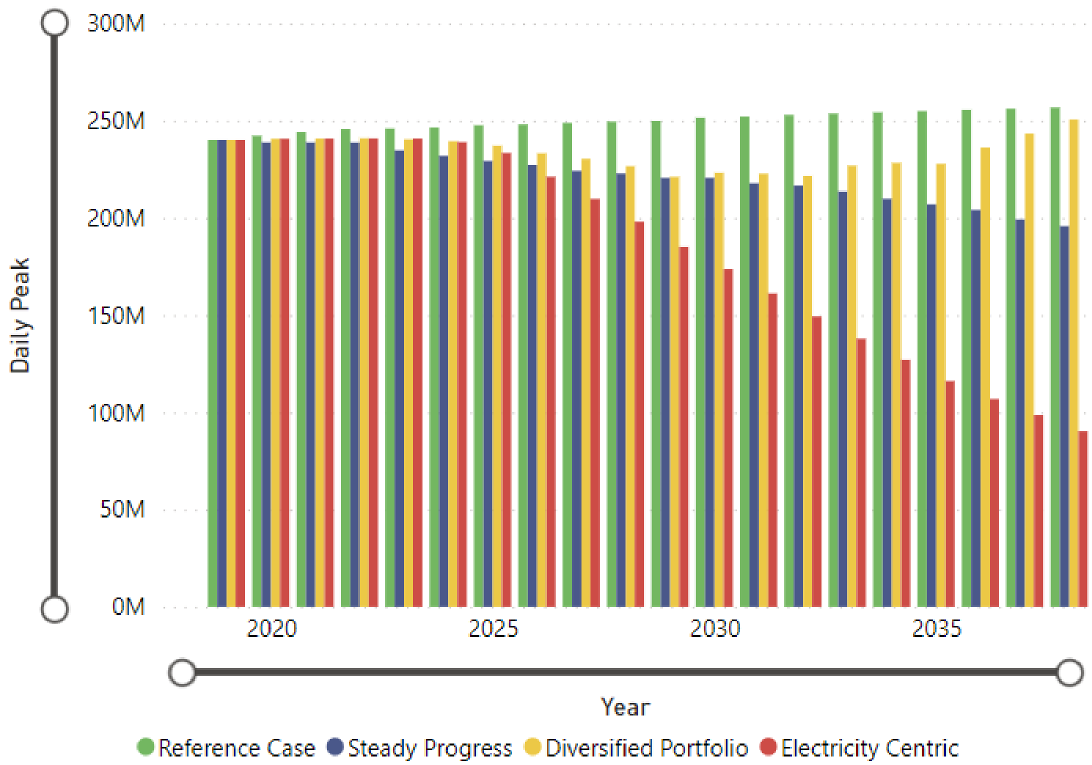


Exhibit 4 - Daily Peak, All Scenarios



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1 About the Energy Transition Scenario Analysis Project

1.1 Introduction

Enbridge Gas Inc. (EGI) retained Posterity Group Consulting (PG) to work on an Energy Transition Scenario Analysis (ETSA) project. The ETSA project provides Enbridge Gas with theoretical scenarios of the future to help assess the impacts from climate policies and economic conditions that Enbridge Gas' system could experience over the next 20 years. Four scenarios were modelled of future gas demand and greenhouse gas emissions over a twenty-year time horizon. Probabilities are not assigned to the scenarios and Enbridge Gas does not endorse or oppose any of the scenarios presented in this report.

1.2 Objectives and Outcomes

The purpose of this project was for PG to support Enbridge Gas decision making by modeling future load and associated customer emissions at the granular level of energy end-uses, different building types, rate classes, and regions. System load and customer emissions are forecasted under several scenarios to explore various possible economic and policy conditions under which Enbridge Gas may operate. The outputs of the scenario modeling help to inform and evolve Enbridge Gas' future business strategies and planning processes where the potential impacts of various government policies and customer preferences are better understood. The ETSA is not a substitute for the analysis done to support specific supply or expansion projects, programs, or rate design in the future, but rather helps to inform the process of other initiatives. This report presents the results of the study and documents the project process, modelling inputs and assumptions. The ETSA project and the underlying model are not intended to replace Enbridge Gas' current forecasting methods or models and are to be used for illustrative purposes only.

1.3 Project Phases

The ETSA project involved six major phases, which are summarized in Exhibit 5 below. This report details the process and outcomes of each phase.

Exhibit 5 - Project Phases

Phase	Main Activities & Purpose	Outcomes
Develop a Reference Case forecast	Develop a Reference Case scenario based on Enbridge Gas' latest customer and volume forecasts by calibrating PG's end-use model to match Enbridge Gas annual forecast numbers.	20-year forecast which serves as the comparison for developing alternative scenarios.
Identify Critical Drivers	Identify the variables to model that are thought to impact Enbridge Gas' system and GHG emission over the next 20 years. Once defined, various forecasts were developed for each Critical Driver.	Defined Critical Drivers and input assumptions.

Phase	Main Activities & Purpose	Outcomes
Conduct Parametric Analysis & Establish the Boundaries for the Scenarios	Estimate the impact of each Critical Driver on annual volume, peak and GHG emissions by setting a Driver at each bound of the input assumptions. The purpose of this analysis is to identify which Drivers have the biggest impact on Enbridge Gas' system and customer GHG emissions to help inform Drivers of focus for the scenarios. By setting the Drivers to their maximum and minimum, the highest and lowest theoretical annual volumes are established which provide the upper and lower bounds under which any scenario should fall.	Identification of which Critical Drivers are most impactful on Enbridge Gas' system and GHG emissions; upper & lower bounds to support scenario planning; an online data visualization dashboard.
Develop Scenario Narratives & Input Assumptions	Develop concepts for three scenarios that deviate from the Reference Case by imagining possible futures under which Enbridge Gas may operate. Once a scenario concept is developed, a narrative is drafted to qualitatively explain the scenario. Settings for each Critical Driver are then established to provide the input assumptions for how the scenario is modelled.	Scenario narratives and input assumptions for how the Critical Drivers will be set to model the scenarios.
Scenario Modelling & Analysis of Results	Scenarios are modelled by setting the Critical Drivers to align with the scenario narrative. The model output for each scenario is assembled and analyzed to see how the scenarios compare to the Reference Case, and each other.	Model output files, analysis of results; an online data visualization dashboard.

This report explains the project process and summarizes results of each phase of the ETSA project. Appendices provide detailed information about certain elements of this report.

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2 ETSA Model Description and Development

The model used for the ETSA project was developed using PG's Navigator Energy and Emissions Simulation Suite. This section provides an overview of the model structure and development, and how it was used for the ETSA project.

2.1 About the end-use model used for the ETSA Project

PG's Navigator Energy and Emissions Simulation Suite ("Navigator") is a model designed to provide decision makers the flexibility to undertake scenario planning at the end-use level. This model uses an "end-use" method which forecasts future end-use demand using a "bottom-up" approach by estimating energy consumption at the end-use level, using information on the prevalence of equipment and how energy is used in specific applications. An end-use model, rather than an econometric model, is necessary to accurately forecast energy demand when energy is being used in different ways and amounts than historic trends. Benefits of using an end-use model include:

- Provides a more detailed understanding of how much energy customers use for different purposes (relative to a "top-down" econometric model);
- Permits estimation of the rate of natural change in energy use from buildings upgrading their envelope or their equipment in response to policies or incentives;
- Provides a better comparison of the energy consumption of new buildings versus existing stock to capture changes in the building stock over time;
- Allows for the calculation of overall load shapes based on researched load shapes for different end-uses and analysis of how the overall load shape may change with time or with other end-use changes, thereby providing more accurate estimates of daily and hourly peak; and,
- Enables energy efficiency potential to be layered into the analysis to incorporate energy savings induced by demand-side management programming.

The Navigator end-use model is structured based on Enbridge Gas' system (regions, fuels, etc.) as explained in Section 2.5 and populated with data (provided in Section 2.4). The data and input assumptions are run through the Navigator model to produce output files that include estimates of volumes, peak load and GHG emissions for every combination of sector, region, rate class, segment, end-use and fuel type.

The following content provides more details about how the model is developed, the model structure, key data sources, and the scope of the ESTA project which was used to custom tailor the Navigator model for this project.

2.2 Sequence of Model Development

The model is developed in the following sequence for each sector:

1. *Base Year (2019):* The first year of a forecast period and is based on historical data. Base year data for consumption and number of accounts by rate class and postal code from Enbridge Gas was disaggregated into regions and end-uses (provided in Exhibit 8).

2. *Reference Case (2020-2038):* The forecast of gas consumption from 2020 to 2038 based on exogenous conditions that follow a "business-as-usual" scenario. Account totals and energy intensities in the base year are adjusted to match the forecasted account and consumption growth provided by EGI. Please see Exhibit 7 in Section 2.4 for a detail description of the data sources and modelling method used to develop the base year and Reference Case forecast.
3. *Scenario Analysis (2020-2038):* Multiple forecasts that illustrate possible futures based on assumptions of what might occur (e.g., economic conditions or policy interventions) by varying model parameters. Energy savings potential from DSM programming is also included in the scenario analysis.

2.3 Model Parameters

Exhibit 6 defines the five parameters that provides the structure used for the model.

Exhibit 6 – ETSA Model Parameters

Parameter	Definition
Accounts	The number of Enbridge Gas customer accounts.
Units	The basis for how energy consumption is expressed. Note that the unit of analysis is unique to each sector: dwellings in the residential sector, square feet of floor area in the commercial sector and the relative size of different rate class accounts in the industrial sector.
Saturation	The extent to which an end-use is present in a region and segment (for most end-uses).
Fuel Share	The percentage of the energy end-use that is supplied by each fuel
Unit Energy Consumption (UEC)	The amount of energy used by each end-use per unit.

The model is populated with inputs for each parameter, as explained in the following sections for each sector. Once each parameter of the model is populated with the applicable data, annual volume and GHG emissions is calculated for a specific end-use for each region, segment, and vintage.

2.4 Key Data Sources

Exhibit 7 provides the key data used to build the base year, Reference Case, and scenario models. Some of this data was also used for the associated Critical Drivers found in Section 4.2 (provides the input assumptions for the Critical Drivers, including data sources which are not captured here).

Exhibit 7 – ETSA Model Key Data Sources

Data (Source)	Contents & Purpose
2019 "actuals" provided (EGI)	Enbridge Gas provided PG with weather-normalized 2019 gas demand in cubic meters and number of customers at each postal code. The datasets from Enbridge Gas data systems provided the basis for the base year (2019) of the forecast. PG mapped these actuals into the model parameters (outlined above) and adjusted

Data (Source)	Contents & Purpose
	the base year data to achieve Enbridge Gas' forecasted account and consumption growth. As the base year is common across all scenarios, this is a key data input to the project.
2019 Ontario Achievable Potential Study (OEB via EGI)	The 2019 APS Reference Forecast was used to disaggregate gas consumption by end-use and estimate fuel shares in the commercial and industrial sector.
10-year Customer Account Forecast (EGI)	Enbridge Gas provided PG with a 10-year forecast of the number of accounts by sector for the rates 1, 6, 01, M1, M2, and 10. This was used to calibrate the Reference Case accounts and volumes, and to create changes in the growth rates of customers by sector to use as a Critical Driver.
10-year consumption forecast (EGI)	Enbridge Gas provided PG with a 10-year forecast for consumption and expected DSM volumes for effectively all rates, with certain sectors disaggregated from the rest of the rate class. Details on the assumptions use in this forecast is provided in Appendix A. The Reference Case forecast volume was calibrated to this consumption forecast.
Residential End-Use Survey (EGI)	The 2019 residential end-use survey provides estimates for the penetration of gas appliances in Enbridge Gas customers' residences for space heating, water heating, cooking, and clothes drying, separated into legacy Enbridge Gas and Union territories. This was used as fuel shares for all residential segments. Note that because consumption is calibrated to the Enbridge Gas forecast, fuel share only provides an upper limit for fuel switching but does not affect Reference Case consumption.
Expected RNG and Hydrogen Volumes under Enbridge Gas' Planned Programs (EGI)	Enbridge Gas provided a workbook of upper and lower possible volumes of RNG and Hydrogen in their system. Enbridge Gas and PG agreed to include the lower possibility (representing Ontario Energy Board (OEB) approved programs including the Voluntary RNG Program and the Low Carbon Energy Project) in the Reference Case. This volume, about 0.01% of total demand in 2030, was divided between the three sectors, with fuel shares for natural gas reduced accordingly so that overall energy demand remains the same. These volumes also helped inform the input assumptions for the RNG and H2 Critical Drivers.

2.5 ETSA Study Coverage

This subsection outlines coverage of the ETSA project in terms of regions, sectors, segments, end-uses, and vintages.

Regions

The ETSA model disaggregates gas customers into the following legacy service regions:

- Union-North
- Union-South
- EGD-GTA
- EGD-Niagara

- EGD-Ottawa

Segments, End-Uses & Vintages by Sector

The model was built for three sectors: Residential, Commercial, and Industrial. Each sector is unique and has important differences which are reflected in how inputs and outputs are organized. PG used the key data sources described in Section 2.4 to populate the model parameters to generate a model of each sector. Exhibit 8 presents the specific way each sector is organized in the PG model, and how inputs and outputs for each sector are disaggregated.

Exhibit 8 - ETSA Segments, End-Uses & Vintages by Sector

	Residential	Commercial	Industrial
Segments	• Attached or Row House • Detached House • Multi-Res High Rise • Multi-Res Low Rise • Low-Income Multi-Family • Low-Income Single-Family	• Food Retail • Hospital • Large Hotel • Large Non-Food Retail • Large Office • Long Term Care • Other Commercial • Other Hotel/Motel • Other Non-Food Retail • Other Office • Restaurant • School • University/College • Warehouse	• Agriculture • Chemicals Manufacturing (“Mfg”) • Fabricated Metals Mfg • Food and Beverage Mfg • Mining; Quarrying and Oil & Gas Extraction • Non-metallic Minerals Product Mfg • Other Industrial • Petroleum Mfg • Plastic and Rubber Mfg • Primary Metals Mfg • Pulp; Paper; and Wood Products Mfg • Transportation and Machinery Mfg • Water & Wastewater Treatment • Power and Other Utility • Transportation
End-Uses	• Cooking • Lighting • Misc Residential • Space Cooling • Space Heating • Washing/Drying Appliances • Water Heating	• Cooking • Lighting • Space Heating • Water Heating • Misc Commercial • Refrigeration	• HVAC • Other Process • Process Cooling • Process Heating (Direct) • Process Heating (Water and Steam) • Power and Utility • Other Electricity • Transportation
Vintages	• Existing (Pre-2019) • New (Post-2019)	• Existing (Pre-2019) • New (Post-2019)	• N/A

2.5.1 Alignment with 2019 Achievable Potential Study

PG built an end-use model of Enbridge Gas' system which mirrored the end-use breakdown used by the APS.

PG made the following changes to the model to be able to conduct the analysis required for the ETSA Project and reflect more recent information provided by Enbridge Gas:

- *Rate Classes:* Included all legacy Union and Enbridge Gas rate classes, allowing Enbridge Gas to filter scenario results for rate, contract type, or large volume customers.
- *Adjusted Geographic Account Mapping:* Used granular postal code data to map industrial, commercial, and residential customers into the legacy utilities' planning regions. This enabled Enbridge Gas to access an end-use level disaggregation of sales volumes by region and rate class.
- *Adjusted Industrial and Commercial Account Classification:* Used Enbridge Gas' 2019 account data to appropriately classify accounts into their segments.
- *Calibrated to a 2019 Base Year:* Calibrated to weather adjusted 2019 consumption, providing an up-to-date representation of Enbridge Gas' system. The APS forecast used a 2017 base year.
- *Calibrated to Enbridge Gas' 2020 Forecasts for Sales Volumes and Account Growth:* Used Enbridge Gas' 2020 forecasts of sales volumes and customer accounts by rate class and segment to project account growth and energy intensity in the ETSA Reference Case.

Combined, these changes to the model will provide more accurate outputs at an additional level of detail.

3 Modelling Method

This section provides the key assumptions and modelling method used for the ETSA project.

3.1 Key Modelling Assumptions for Fuel Switching

The following assumptions are used to model fuel switching caused by policies and prices.

3.1.1 End-Use Lifetimes and Fuel Switching

The following assumptions were used for typical lifetimes of equipment associated with each end-use, and if an end-use can fuel switch, what is the next likely substitute fuel. The assumptions are provided for each sector.

The PG Navigator model calculates annual changes to fuel shares of end-uses in response to price changes or prescriptive fuel-switching. In all cases, the change in fuel share towards or away from natural gas is limited by the estimated lifetime of appliance. For example, if the average water heater lasts 15 years, no one year should see a change in fuel share in existing buildings of more than 1/15th for water heating. There are additional assumptions about which segments in the industrial sector can be electrified and receive hydrogen, which are provided in Appendix F.

Exhibit 9 - Assumed Residential Equipment Lifetimes

End-Use	Lifetime
Washing/Drying Appliances	12
Cooking	N/A[3]
Water Heating	15
Space Heating	18
Misc Residential	7

Exhibit 10 - Assumed Commercial Equipment Lifetimes

End-Use	Lifetime
Space Heating	18
Water Heating	15

[3] Due to the very low variable cost component of cooking with a gas range, this end-use was assumed to be completely price inelastic (i.e., demand would be driven by factors such as the cost of a gas range and consumer preference)

End-Use	Lifetime
Cooking	20
Misc Commercial	20

Exhibit 11 - Assumed Industrial Equipment Lifetimes

End-Use	Lifetime
HVAC	18
Other Process	N/A[4]
Process Cooling	20
Process Heating (Direct)	20
Process Heating (Water and Steam)	20
Power and Utility	20[5]

3.1.2 Price Elasticity of Demand

The price elasticity of demand reflects how demand for a good changes in response to a change in the price of that good, all else being equal. Price elasticity is represented numerically and calculated as the percent change in quantity demand divided by the percent change in price.

Price elasticities were used to estimate the change in demand for natural gas in response to changes in commodity price of natural gas and carbon price. Changes to these prices to do not effect volumes of RNG, hydrogen or CCS.

The following simplifying assumptions were made regarding price elasticity:

- Price elasticities will not vary by year; the same value will be used throughout the study period.
- Price elasticities vary by sector, but not by region, segment, rate class, end-use, etc.
- 'Own price' elasticity is used (how demand for a good responds to a price change for that good); while cross price elasticity was out of scope (how demand for a good responds to a

[4] "Other Process" is the end-use which captures end-uses in which natural gas is used in processes instead of combusted. It is assumed that this end-uses cannot fuel switch to electricity.

[5] The 'power and utility' end use cannot fuel switch. However, this end use can result in no consumption if there is an end to gas-fired power generation, like in the Electricity Centric scenario which assumed there is no gas-fired electricity generation as of 2035.

change in price for a substitute good (i.e., impact on demand for natural gas in response to a change in price of electricity or other fuels is not considered[6]).

- The same price elasticity value is used to changes in commodity price and carbon price.

Exhibit 12 provides the price elasticity values used for each sector.

Exhibit 12 – Price Elasticity of Demand by Sectors[7]

	Residential	Commercial	Industrial
Long Run Price Elasticity Value	-0.380	-0.350	-0.700

To calculate the change in demand, we assume a constant mid-point arc elasticity of demand for each year and sector with an elasticity equal to the values presented above. Applying the formula for mid-point arc elasticity, the change in quantity demanded (Q_2) can be calculated from the change in price:

$$elasticity = \frac{\frac{Q_2 - Q_1}{0.5 * (Q_2 + Q_1)}}{\frac{P_2 - P_1}{0.5 * (P_2 + P_1)}}$$

Where:

- Q_1 is the initial quantity
- Q_2 is the final quantity
- P_1 is the initial price
- P_2 is the final price

For small changes to price, this is equivalent to applying a percentage change in demand equal to the elasticity times the percentage change in price. For larger changes in price, the above formula is more appropriate to maintain a constant elasticity assumption.

3.1.3 Treatment of Prices of RNG, Hydrogen and Natural Gas with Carbon Capture

Price elasticity is only used to adjust consumption of natural gas in response to price changes of natural gas and carbon price, but did not influence demand for RNG, hydrogen or CCS.

Prices of RNG, hydrogen and natural gas with carbon capture were not used as factors that change consumption of these fuels. Rather, the possible prices for these fuels were one factor used to build the volume and uptake assumptions in the Steady Progress and Electricity Centric scenarios. The possible

[6] The changes in price of natural gas and carbon were Critical Drivers that were coupled with price elasticity values to estimate change in demand for natural gas. Electricity price was not a Critical Driver therefore it was not used to drive change in gas demand.

[7] Washington State Department of Commerce, "CTAM Price Elasticity 2015," 2015. [Online]. Available: https://www.commerce.wa.gov/growing-the-economy/energy/washington-state-energy-office/carbon-tax/.

implications on fuel prices (i.e., RNG, hydrogen and carbon capture becoming cost competitive with natural gas with a carbon charge) from the Clean Fuel Regulation were also used in the supply forecasts used in the Steady Progress and Electricity Centric scenarios. Gas blending mandates and government driven strategies influenced the timing and volumes of RNG, hydrogen and carbon capture deployment in the Diversified scenario.

3.2 Greenhouse Gas Emissions Accounting Method

All greenhouse gas emissions reported in the ETSA project represent end-use combustion (not lifecycle emissions). This presents the most accurate depiction of known, quantifiable emissions that occur at Enbridge Gas customers, but does exclude any potential upstream emissions or avoided emissions associated with fuel production.

For example, hydrogen is assumed to have an emission factor of zero, meaning there are no emissions from Enbridge Gas' customers when hydrogen is consumed for energy. For the purposes of this study, Enbridge Gas assumes that this hydrogen would be produced independent of its gas system and purchased as a commodity by EGI.

See Exhibit 13 for the emissions factors of the fuels examined in this study.

Exhibit 13 – Emission Factors

Fuel	Emission Factor (gramsCO2e/m3)	Notes/Assumptions
Natural Gas	1,899	• Calculated using a 100-year AR4 GWP values of 25 and 298 for CH4 and NO2 respectively.[8]
Natural Gas with Carbon Capture	389	• PG Analysis, using the 2020 NIR emission factors for CH4 and NO2 and assuming an 80% capture rate of CO2.
Renewable Natural Gas	11	• Enbridge Gas analysis, using the 2020 NIR emissions factors for CH4 and NO2 and assuming 100% of CO2 is biogenic.
Hydrogen	0	• Hydrogen does not produce combustion emissions.

[8] Government of Canada, "National Inventory Report (1990-2018)", 2020, Table A6.1-1, and A6.1-2.

4 Critical Drivers

4.1 Defining Critical Drivers

Critical Drivers (CDs) are the key variables identified by Enbridge Gas and PG as most likely to impact Enbridge Gas' system over the next 20 years. PG and Enbridge Gas worked together to develop an initial list of CDs. Although there are countless variables that can or could impact Enbridge Gas' system, the project needed a finite list of variables to analyze.

The criteria for a variable to be included as a CD for the project were:

A) It was thought the variable would have a material impact on Enbridge Gas annual volume, peak hour and day, and/or GHG emissions in the next 20 years.
B) There was sufficient data available to predict what the variable could be in the next 20 years.

Enbridge Gas provided feedback on the long list of CDs and then a series of virtual meetings, called "Discovery Sessions", were hosted to discuss potential CDs with Enbridge Gas subject-matter expects and PG. The long list was adjusted based on the feedback and Discovery Sessions until a short-list of CDs was created for analysis in the ETSA project.

4.2 Input Assumptions for Critical Uncertainties

Once the list of CDs was established, PG and Enbridge Gas worked together to develop input assumptions for each CD. The input assumptions are meant to reflect the range of possible trajectories each CD are thought to plausibly take over the next 20 years. For each CD, a theoretical but plausible maximum and minimum bound were established to form the range of uncertainty for how each CD may evolve under various policy and economic conditions. For some CDs, the maximum setting would cause natural gas demand to decrease (e.g., higher carbon price, lower natural gas demand) and for some CDs, the maximum setting would cause natural gas demand to increase (e.g., customer accounts increase, gas demand increases). Exhibit 14 provides a description of each CD, how the CD impacts the model outputs, the maximum and minimum setting which reflects the range of input assumptions, and the data source used to develop the input assumptions.

Exhibit 14 – Critical Driver Input Assumptions

Critical Driver	Description	Impact on the model output	Maximum Setting	Minimum Setting	Data Source(s)
Carbon price	• The federal carbon charge applied to natural gas in Ontario (30% of the federal backstop carbon price was applied to Industrial customers to	• Gas demand: price increases, demand decreases and vice-versa	• The maximum value, \$282/tonne by 2030, is the price that the Parliamentary Budget Officer estimated would be required to meet Canada's	• The minimum value, \$50/tonne, is the price currently legislated for 2022 in the Greenhouse Gas	• GGPPA, and the Parliamentary Budget Office

Critical Driver	Description	Impact on the model output	Maximum Setting	Minimum Setting	Data Source(s)
	reflect the Output Based Pricing System[9])		2030 climate targets[10]	Pollution Pricing Act (GGPPA) • Post-2022, the carbon price is escalated by inflation	
Natural Gas Price	• Cost of natural gas including commodity price, and transportation, customer & distribution charges. Only the commodity price varied, while other bill charges were held constant[11]	• Price increases, gas demand decreases and vice-versa	• 400% higher than current natural gas commodity prices	• 50% of current natural gas commodity prices	• EGI
Climate Change	• Proxy for climate change is average temperature	• Gas demand for space heating: Warmer winters due to climate change are expected to reduce space heating demand;	• Average annual temperature increases by 3.3-5.9C in 2100 according to IPCC RCP 8.5 (Intergovernmental Panel on Climate Change worst-case climate scenario)[12] [13]	• No change (cooler average annual temperature not expected)	• IPCC & PG analysis

[9] Direction on the application of carbon price to Industrial customers was provided by Enbridge Gas to PG in an email titled "OBPS & EPS Stringency Factors" on November 10, 2020.
[10] Office of the Parliamentary Budget Officer, "Carbon pricing for the Paris target: Closing the gap with output-based pricing", 2020. [Online]. Available: https://www.pbo-dpb.gc.ca/en/blog/news/RP-2021-019-S--carbon-pricing-paris-target-closing-gap-with-output-based-pricing--tarification-carbone-accord-paris-combler-ecart-avec-tarification-fondee-rendement
[11] More details on cost of natural gas Critical Driver are provided in Appendix E.
[12] Intergovernmental Panel on Climate Change, "AR5 Synthesis Report: Climate Change", 2014.
[13] York University – Laboratory of Mathematical Parallel Systems, "Ontario Climate Data Portal", 2018. [Online]. Available: https://lamps.math.yorku.ca/OntarioClimate/index_v18.htm

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Critical Driver	Description	Impact on the model output	Maximum Setting	Minimum Setting	Data Source(s)
		estimated using Enbridge Gas' weather-elasticities of demand			
Codes and standards: Retrofit	• Energy-related building codes and equipment standards for existing buildings that would apply to retrofits	• Gas demand for space and water heating declines as more stringent codes for equipment and building envelope take effect	• Mandatory retrofitting of the worst-performing 5% of buildings ever year post-2030 • Implementation of the Toronto Green Standard and similar codes in other municipalities, beginning in 2022[14]	• No change from current code	• Building Knowledge Canada, and research & analysis conducted by PG (details in Appendix C)
Codes and standards: New Construction	• Energy-related building codes and equipment standards applicable to new construction	• Gas demand for space and water heating declines as more stringent codes for equipment and building envelope take effect	• Energy performance targets from the National Energy Code of Canada for Buildings tiers 3, 4, and 5 are implemented for new buildings in 2025, 2030, and 2035 respectively[15] [16] • Implementation of the Toronto Green Standard and similar codes in other municipalities, beginning in 2022	• No change from current code	• Building Knowledge Canada, and research & analysis conducted by PG (details in Appendix C)
Enbridge Gas Customer	• Variation in Enbridge Gas'	• Gas demand increases or	• Annual account growth of about	• Annual account	• EGI

[14] Toronto Green Standard, "TGS Version 3", 2019. [Online]. Available: https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/toronto-green-standard/
[15] NECB 2020 Tiered Code (Part 3)
[16] NBC 2020 Tiered Code (Part 9)

Critical Driver	Description	Impact on the model output	Maximum Setting	Minimum Setting	Data Source(s)
Account Growth Due to Population and Economic Growth	account forecast to account for uncertainty in population growth and economic conditions	decreases with the number of new buildings that do or do not connect to the gas grid	0.5% above Enbridge Gas' forecast growth of 0-1% growth from industrial, commercial, and residential accounts	growth of about 0.5% below Enbridge Gas' forecast growth of 0-1% growth from industrial, commercial, and residential accounts	
Non-Price Driven fuel-switching (gas to electricity)	• Regulatory requirements or customer policies that restrict the use of gas-fired space and water heating equipment	• Gas demand decreases and customers switch to electric equipment	• Beginning in 2025, no new gas connections, and space and water heating equipment at existing accounts is replaced with electric alternatives at the equipment's natural end of life	• No fuel-switching away from natural gas	• Enbridge Gas & PG analysis (details in Appendix C)
DSM Program Spending	• Annual Enbridge Gas DSM spending, as a percentage of the proposed 2022-2026 annual spending	• Higher spending decrease gas demand, and vise versa • Energy savings are estimated using PG's library of DSM measures, prepared for Enbridge Gas' DSM group	• Starting in 2022, a 3% year-over-year real increase in DSM spending. Starting in 2028, a 10% annual increase	• Starting in 2022, a 3% year-over-year real increase in DSM spending	• EGI
Natural Gas Transportation	• Transportation sector demand for natural gas	• Increased demand from transportation increases gas demand	• The Canada Energy Regulator's	• No change from 2019 levels	• Enbridge Gas & Canada's Energy Regulator

Critical Driver	Description	Impact on the model output	Maximum Setting	Minimum Setting	Data Source(s)
			forecast of Ontario NGT demand[17]		
Renewable Natural Gas (RNG)	• The amount of RNG blended into Enbridge Gas' gas supply	• GHG Emissions: Increased supply of RNG decreases GHG emissions	• Mandated use of RNG requires about three billion cubic meters per year by 2038, which is 11% of reference case demand in 2038	• 0.005% of total sales volumes by 2030, the amount currently forecasted due to Enbridge Gas' existing voluntary RNG program	• EGI
Hydrogen (H2)	• The amount of low-carbon hydrogen blended into the Ontario gas supply	• GHG Emissions and volume: increase supply of H2 results in lower GHG emissions & increased volume of gas delivered because of hydrogen's energy density	• Hydrogen blending begins in the late 2025, consumption reaches 12 billion cubic meters per year in 2038, or about 14% of reference case demand in 2038, based on mandated hydrogen targets	• 0.003% of total sales volumes by 2030, the amount currently forecasted due to Enbridge Gas' approved Low Carbon Energy Project	• EGI
Carbon Capture and Storage (CCS) adoption	• The fraction of applicable industrial accounts that adopt CCS technology	• GHG emissions: CCS adoption increases, GHG emissions decrease	• Carbon capture is used for all process heating and power generation in refineries, chemicals, non-metallic minerals, primary metals, and utilities in the Union-South region, phased-in between 2028 and 2037	• No carbon capture and storage	• EGI

[17] Canada Energy Regulator, "Canada's Energy Future", 2019.

Treatment of Costs for RNG, Hydrogen and CCS

The costs of RNG, hydrogen, and CCS were not treated as CDs. Rather, these costs we used as an assumption to develop supply forecasts for RNG, hydrogen and CCS.

Critical Drivers Discussed but Excluded

The following items were discussed as possible CDs but ultimately were not selected as drivers because it was too difficult to obtain data to support modelling and/or the topic was included in another CD captured in the list above. The rationale for excluding these items as CDs is provided briefly below.

- DSM savings potential: This was not a CD, but a DSM budget was specified in the scenarios and the associated energy savings potential was included in the scenario results.
- Changing customer behaviours: Non-price driven fuel switching is a CD and designed to capture non-price reasons why customers may switch away from gas. Also, account defection was modelled in the Diversified Scenario to reflect customers leaving the gas system.
- Delivery charges: It was too difficult to forecast delivery charges and develop ranges of a forecast.
- Gas quality: It was too difficult to integrate gas quality considerations into the analysis.
- Clean Fuel Regulation: The CFR was not an explicit CD; however, the impacts of the CFR were included in terms of how it may influence the supply forecast for RNG, H2 and CCS from impacts on costs for these fuels.

5 Parametric Analysis & Boundary Establishment

This section provides an overview of the parametric analysis process and how the results of the parametric analysis define the boundaries (upper and lower limits) for the scenario analysis.

Parametric analysis is the process of determining the effect of varying one independent variable along a range of values on the dependent variable. For the ETSA project, the parametric analysis was conducted in the following steps:

- Establish the maximum and minimum bounds for the input assumptions for each CD.
- Estimate the impact from each CD over their range of input assumptions on system volume, peak consumption and GHG emissions while holding all other CDs constant.
- Establish the boundaries – the upper and lower bounds – for energy demand based on the combination of max/min settings for the CDs. This provides the boundaries of the scenario analysis.

The parametric analysis is a precursor to the scenario analysis which varies all the Critical Uncertainties to establish a combination of settings that vary from the Reference Case to estimate load under the combined effect of the Critical Uncertainties with specific settings.

5.1 Parametric Analysis Results

The parametric analysis provides insight into what CDs cause the largest impact on annual volumes, peak, and GHG emissions. It also provides the upper and lower bounds for the scenario analysis by setting all the CDs to their maximum and minimum settings to cause the largest increase and decrease in annual volumes. This section presents these results.

5.1.1 Sensitivity to Critical Drivers

How much change is caused to annual volumes of gaseous fuels, system peak, and GHG emissions for gaseous fuels relative to the Reference Case is established by setting each CD to the maximum or minimum setting, whichever is further from the Reference Case setting. The results below reflect the extreme of the values possible developed for this project so the results would vary if different bounds were developed. Note that the scenarios used settings for each Critical Driver that were not the maximum or minimum setting (input settings for each Critical Driver used to generate the scenarios is provided in 6.4.)

Using this approach, the input assumptions for the CDs (provided in Exhibit 14), and the key assumptions used for the modelling method (provided in Section 3), the CDs that had the largest estimated impacts are:

- *Non-price driven fuel switching:* Set to its maximum setting, there is an estimated 42% decline in annual volume by 2038, a 50% decline in hourly peak, a 55% decline in daily peak, and a 42% decline in GHG emissions, relative to the Reference Case caused by the non-price driven fuel switching CD.
- *Natural Gas Price:* Set to its maximum setting, there is an estimated 30% decline in annual volume by 2038, a 6% decline in hourly and daily peak, and a 30% decline in GHG emissions, relative to the Reference Case caused by increase in natural gas price.

- *Hydrogen:* Set to its maximum setting, there is an estimated 30% increase in annual volume and daily/hourly peak by 2038, and a 14% decline in GHG emissions, relative to the Reference Case caused by blending hydrogen into the gas system.

The CDs that had the smallest estimated impact are:

- *Natural gas transportation:* at the maximum setting, there is about a 1% increase in annual volume, daily/hourly peak and GHG emissions from natural gas demand compared to 2019 levels.
- *RNG and CCS:* RNG and CCS do not impact annual volume or peak, however both CDs do impact GHG emissions. At their maximum settings, RNG and CCS each cause an estimated 10% decline in GHG emissions.

Exhibit 15 provides a summary of the sensitivity for each CD in terms of the difference in annual volumes, peak and GHG emissions relative to the Reference Case forecast. Impacts have been rounded in this table. For further details, including changes in terms of m^3 and tonnes of CO2e, and to visualize these impacts, please see the "ESTA Critical Drivers Sensitivity Visualizer" dashboard in PowerBI.

Exhibit 15 – Sensitivity of Annual Volumes, Peak and GHG Emissions by Critical Driver

Critical Driver	Setting that deviates the most from the Reference Case assumption	Impact on Annual Volume by 2038	Impact on Peak	Impact on GHG Emissions by 2038
Carbon price	Max: $282/tonne.	22% decline	22% decline in hourly and daily peak	22% decline
Natural Gas Price	Max: 400% higher than current natural gas prices.	30% decline	~27% decline in hourly and daily peak	30% decline
Climate Change	Max: 3.4 degrees Celsius increase in average annual temperature by 2050.	4% decline	~6% decline in hourly and daily peak	4% decline
Codes and standards: Retrofit	Max: Mandatory retrofitting of the worst-performing 5% of buildings every year post-2030.	5% decline	~7% decline in hourly and daily peak	5% decline
Codes and standards: New Construction	Max: Energy performance targets from the National Energy Code of Canada for Buildings tiers 3, 4, and 5 are implemented for new buildings in 2025, 2030, and 2035 respectively; Implementation of the Toronto Green Standard and similar codes in other	9% decline	12% decline in hourly peak; 13% decline in daily peak	9% decline

Critical Driver	Setting that deviates the most from the Reference Case assumption	Impact on Annual Volume by 2038	Impact on Peak	Impact on GHG Emissions by 2038
	municipalities with community energy plans, beginning in 2022.			
Enbridge Gas Customer Account Growth Due to Population and Economic Growth	The Reference Case account growth is based on Enbridge Gas' 10-year customer account forecast. The maximum and minimum setting deviate equally from this forecast. Max: Annual account growth of .5% *above* Enbridge Gas' forecast growth of 0-1% growth from industrial, commercial, and residential accounts. Min: Annual account growth of 0.5% *below* Enbridge Gas' forecast growth of 0-1% growth from industrial, commercial, and residential accounts.	Max setting (increase in accounts): 8% increase Min setting (decrease in accounts): 8% decrease	Max setting (increase in accounts): 10% increase in hourly and daily peak Min setting (decrease in accounts): ~7% decrease in daily and hourly peak	Max setting (increase in accounts): 8% increase Min setting (decrease in accounts): 8% decrease
Non-Price Driven fuel-switching (gas to electricity)	Max: Beginning in 2025, no new gas connections, and space and water heating equipment at existing accounts must be replaced with electric alternatives at the equipment's natural end of life.	42% decline	Hourly peak: 50% decline Daily peak: 55% decline	42% decline
DSM Program Spending	Max: Starting in 2022, a 3% year-over-year real increase in DSM spending. Starting in 2028, a 10% annual increase.	12% decline	~14% decline in hourly and daily peak	12% decline
Natural Gas Transportation	Min: no change from 2019 volume. Max: Canada Energy Regulator's forecast of Ontario NGT demand.	1% increase	~1% increase in hourly and daily peak	1% increase
Renewable Natural Gas (RNG)	Max: Mandated use of RNG requires about three billion cubic meters per year by 2038, which is 11% of Reference Case demand in 2038.	No impact	No impact	10% decline
Hydrogen (H2)	Max: Hydrogen blending begins in 2025, consumption reaches 12 billion cubic meters per year in 2038, or about 14% of Reference Case demand in 2038, based on mandated hydrogen targets.	30% increase	30% increase in hourly and daily peak	14% decline

Critical Driver	Setting that deviates the most from the Reference Case assumption	Impact on Annual Volume by 2038	Impact on Peak	Impact on GHG Emissions by 2038
Carbon Capture and Storage (CCS) adoption	Max: Carbon capture is used for all process heating and power generation in refineries, chemicals, non-metallic minerals, primary metals, and utilities in the Union-South region, phased-in between 2028 and 2037.	No impact	No impact	10% decline

5.1.2 Upper and Lower Bounds

Setting all the CDs to their maximum/minimum setting such that the largest increase/decrease in annual volumes is created provides the upper and lower bounds. These bounds provide the "jaws" for which the scenarios should fall between. The bounds help set the most extreme expected change in annual volume based on the CDs.

Upper Bound

To create the upper bound (highest theoretical annual volume), all CDs are set to their minimum setting except for natural gas transportation, hydrogen, RNG, and customer account CDs, which are set to their maximum setting to increase annual volume as much as possible. Using these settings, the Upper Bound represents a 31% increase in total volume by 2038 relative to the Reference Case, as illustrated in Exhibit 16 (the 'hypothetical scenario' is the upper bound).

Exhibit 16 – Upper Bound Annual Volume (m3)

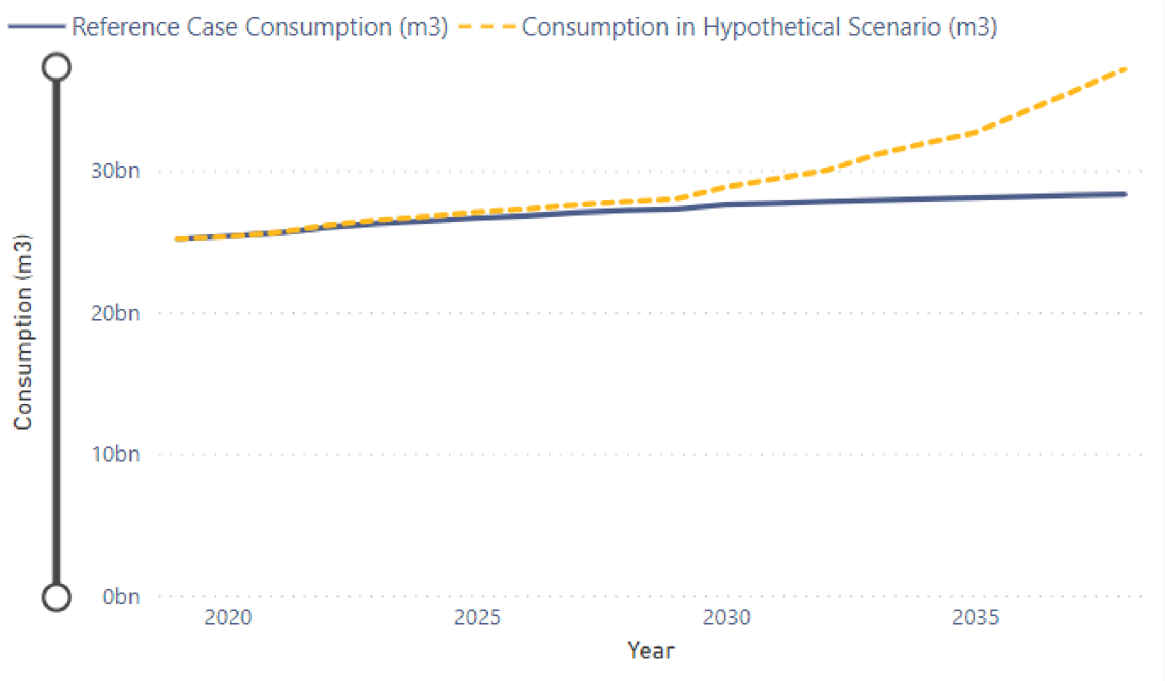
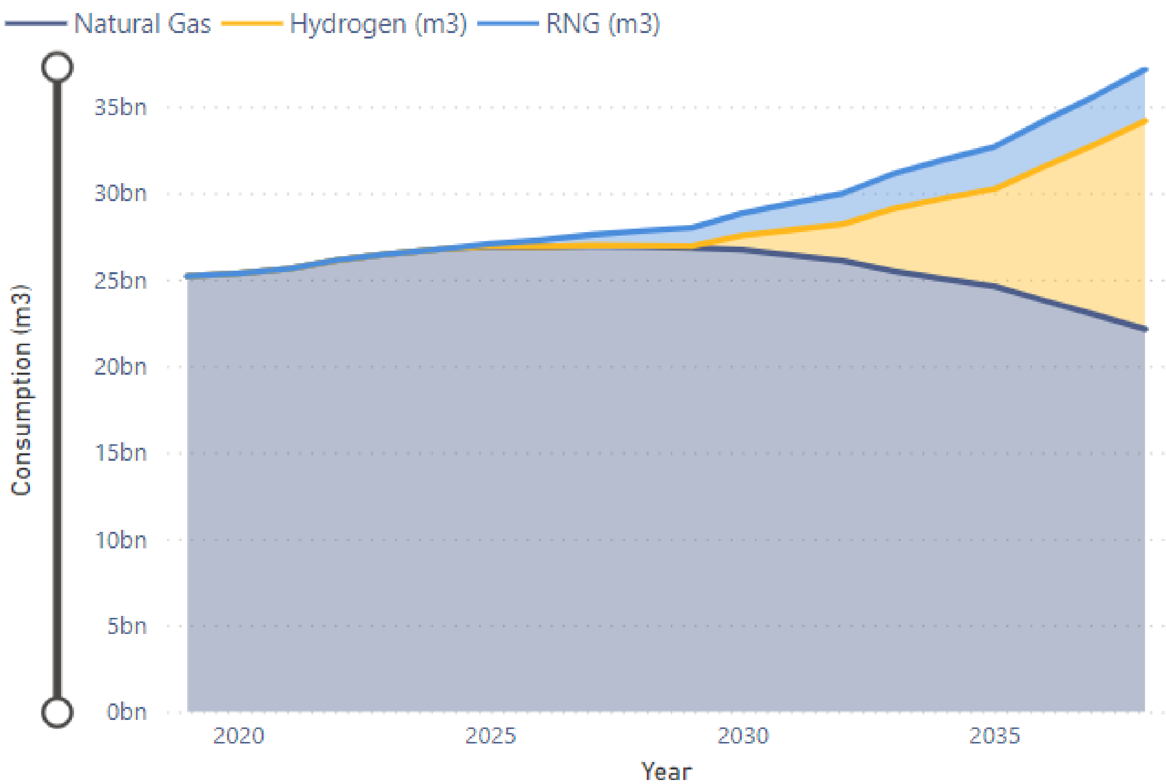


Exhibit 17 presents the fuel breakdown in the Upper Bound which illustrates the impact of increase hydrogen on annual volume.

Exhibit 17 – Upper Bound Volume by Fuel



The following exhibits present the Upper Bound hourly peak, daily peak, and GHG emissions relative to the Reference Case. Details of the differences are available in the "ESTA Critical Drivers Sensitivity Visualizer" dashboard online via PowerBI.

Exhibit 18 – Upper Bound Hourly Peak (m3/hour)

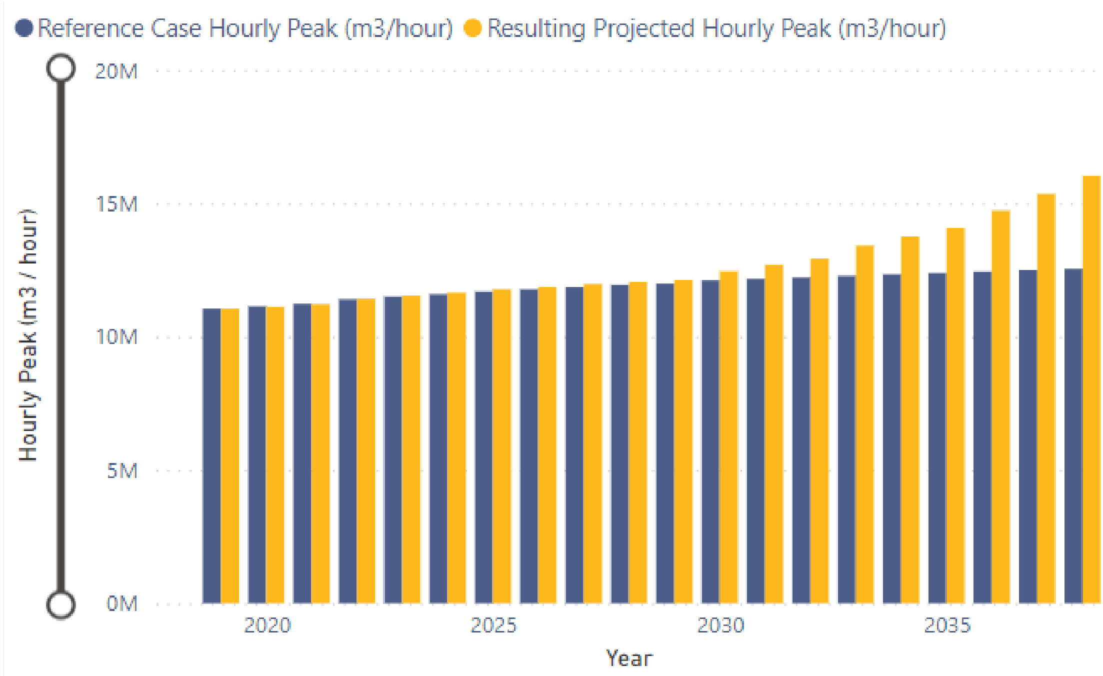


Exhibit 19 – Upper Bound Daily Peak (m3/day)

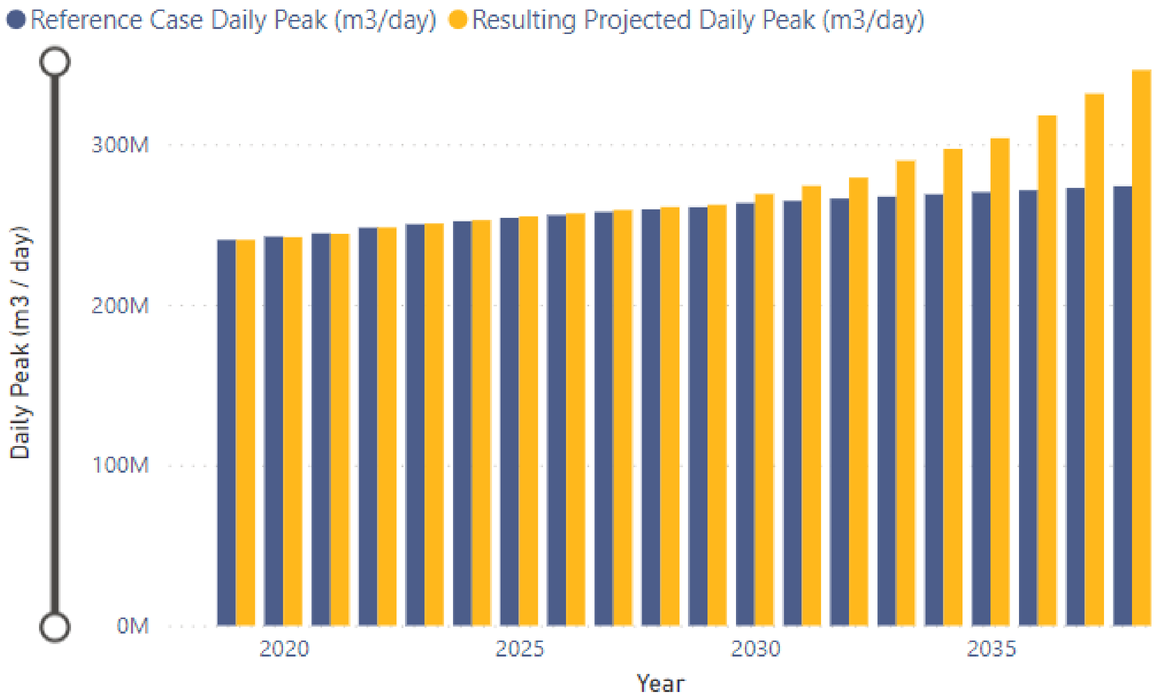
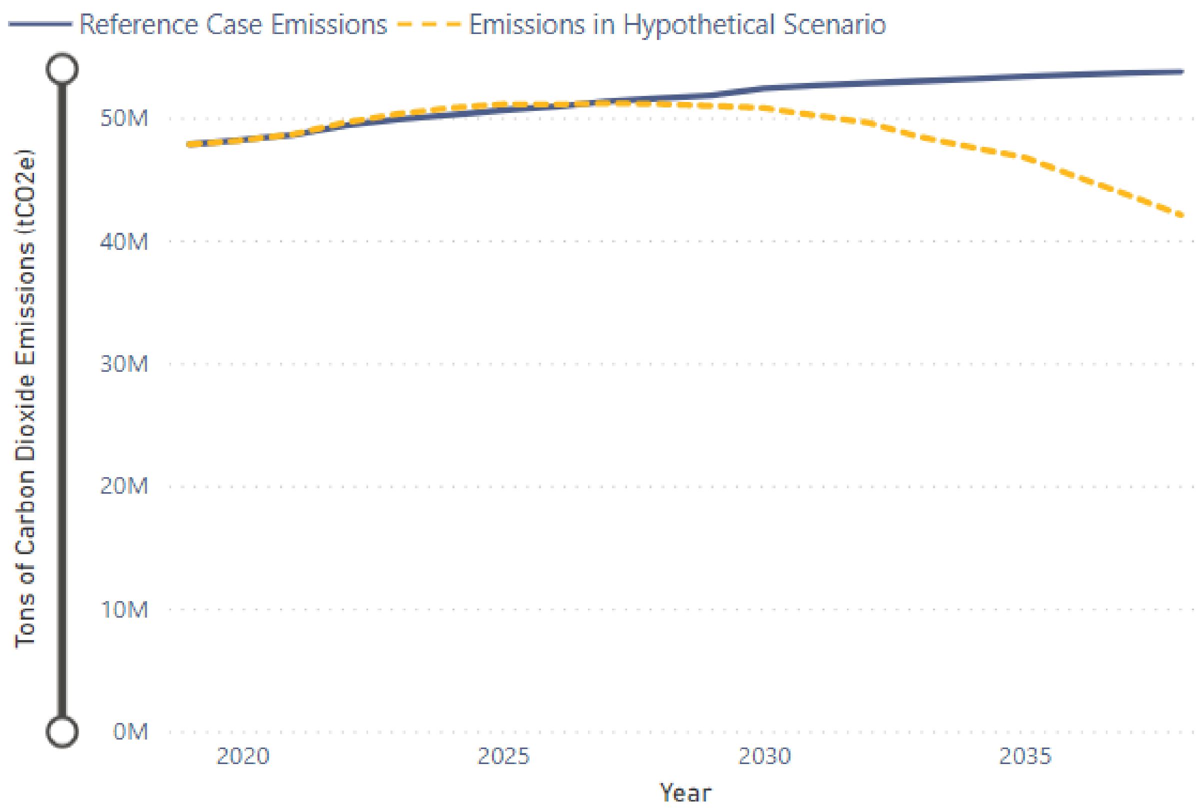


Exhibit 20 illustrates the change in GHG emissions from the Reference Case in the Upper Bound (the 'hypothetical scenario' line). While total volume has increased, GHG emissions have decreased by 2038. This is due to the increase in hydrogen in the gas system beginning in the late 2020's.

Exhibit 20 – Upper Bound GHG Emissions (t/CO2e)



Lower Bound

To create the lower bound (lowest annual volume), all CDs are set to their maximum setting except for natural gas transportation, climate change, hydrogen, and customer account CDs, which are set to their minimum setting to decrease annual volume as much as possible. Using these settings, the Lower Bound (the 'hypothetical scenario' line) represents a 73% decline in total volume by 2038 relative to the Reference Case, as illustrated in Exhibit 21.

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Exhibit 21 – Lower Bound Annual Volume (m3)

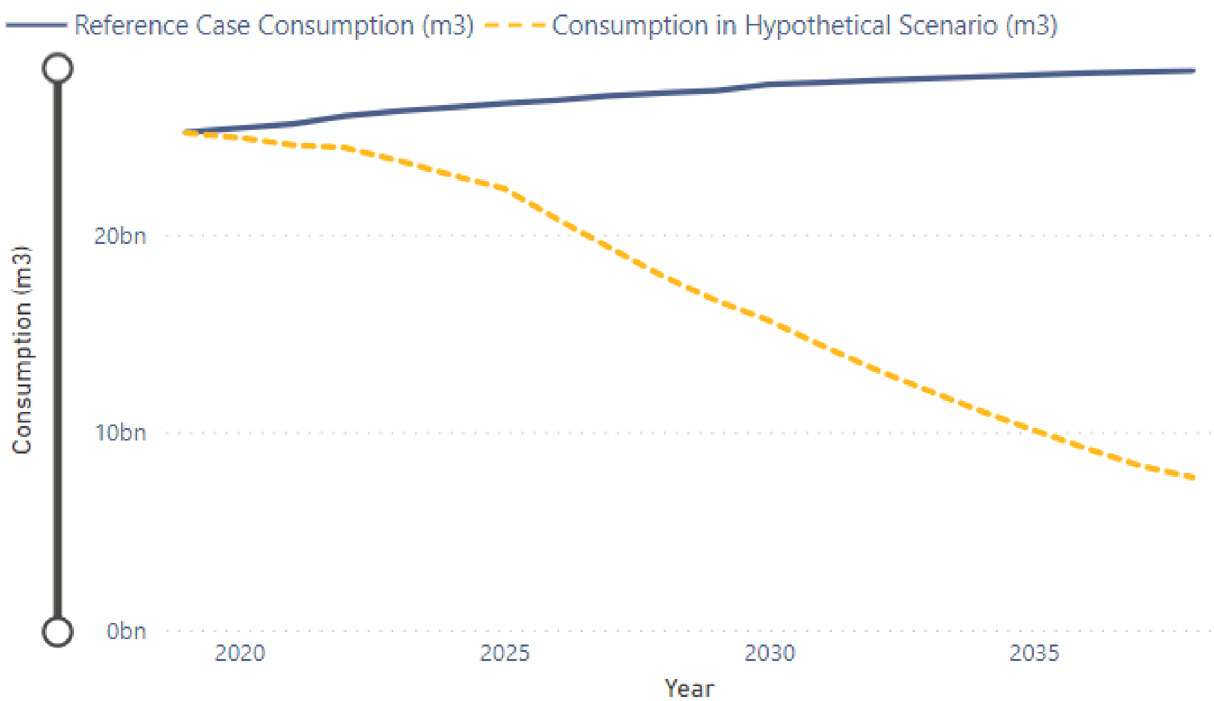

Exhibit 22 presents the fuel breakdown in the Lower Bound. Hydrogen is set to the minimum setting to decrease annual volumes based on the volumetric energy density of hydrogen.

Exhibit 22 – Lower Bound Volume by Fuel

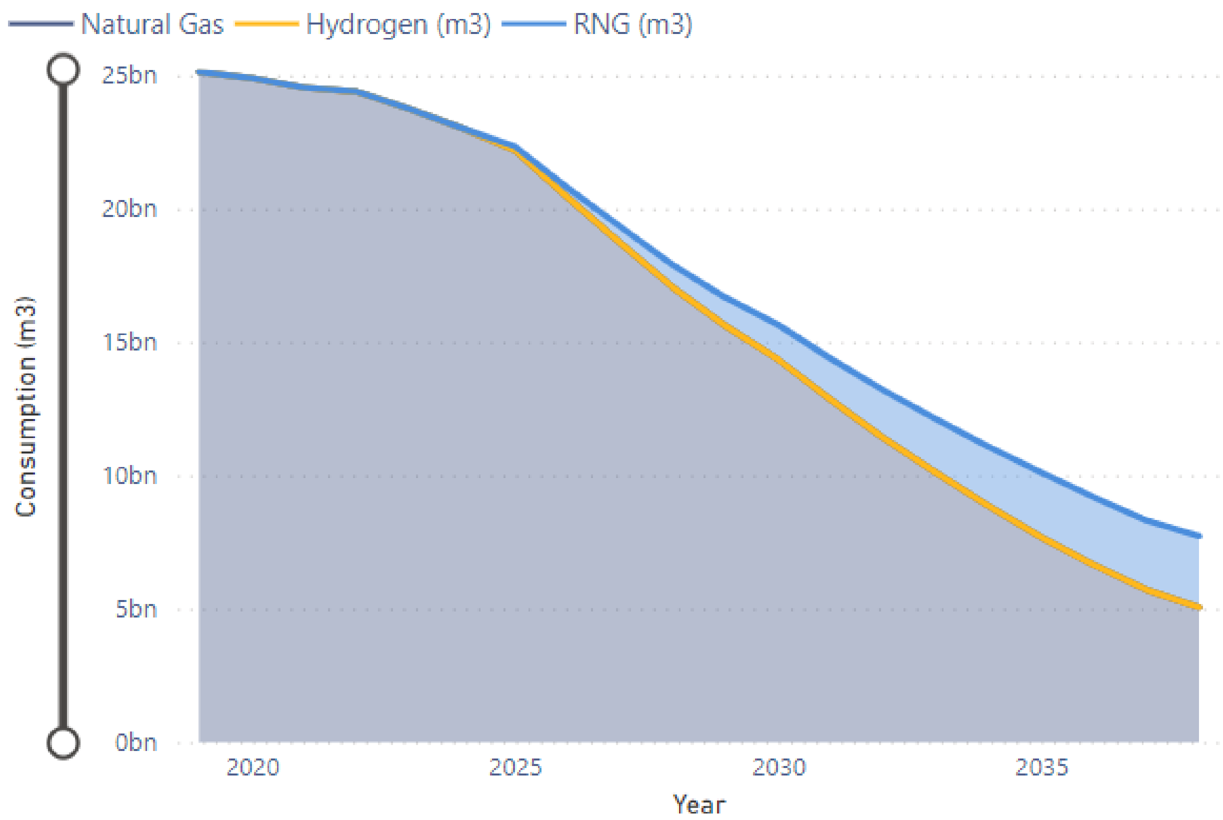

Exhibit 23, Exhibit 24, and Exhibit 25 present the Lower Bound hourly peak, daily peak, and GHG emissions relative to the Reference Case which all decline, following the decrease in annual volume. Details of the differences are available in the "ESTA Critical Drivers Sensitivity Visualizer" dashboard online via PowerBI.

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Exhibit 23 – Lower Bound Hourly Peak (m^3/hour)

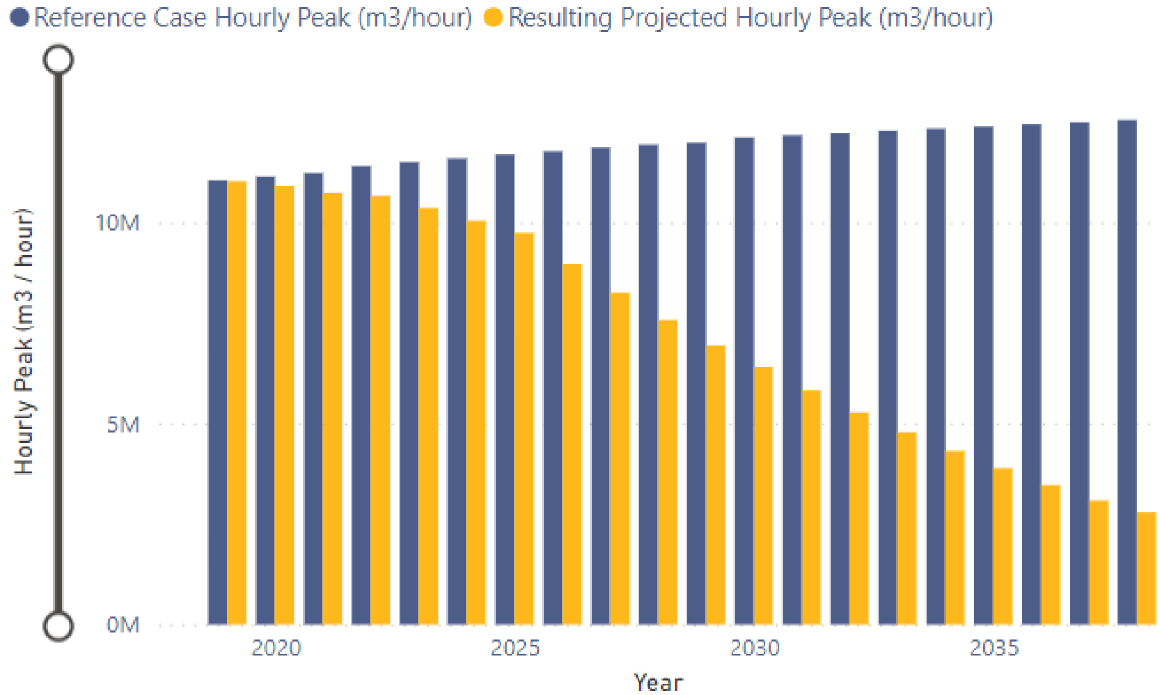


Exhibit 24 – Lower Bound Daily Peak (m^3/day)

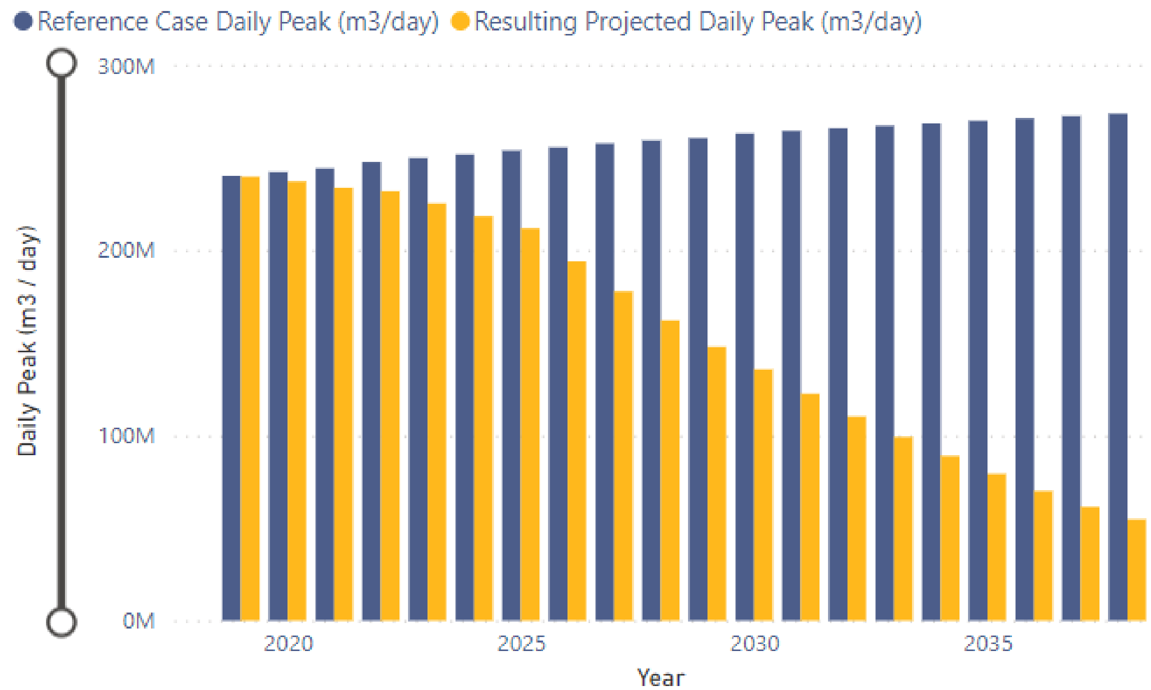
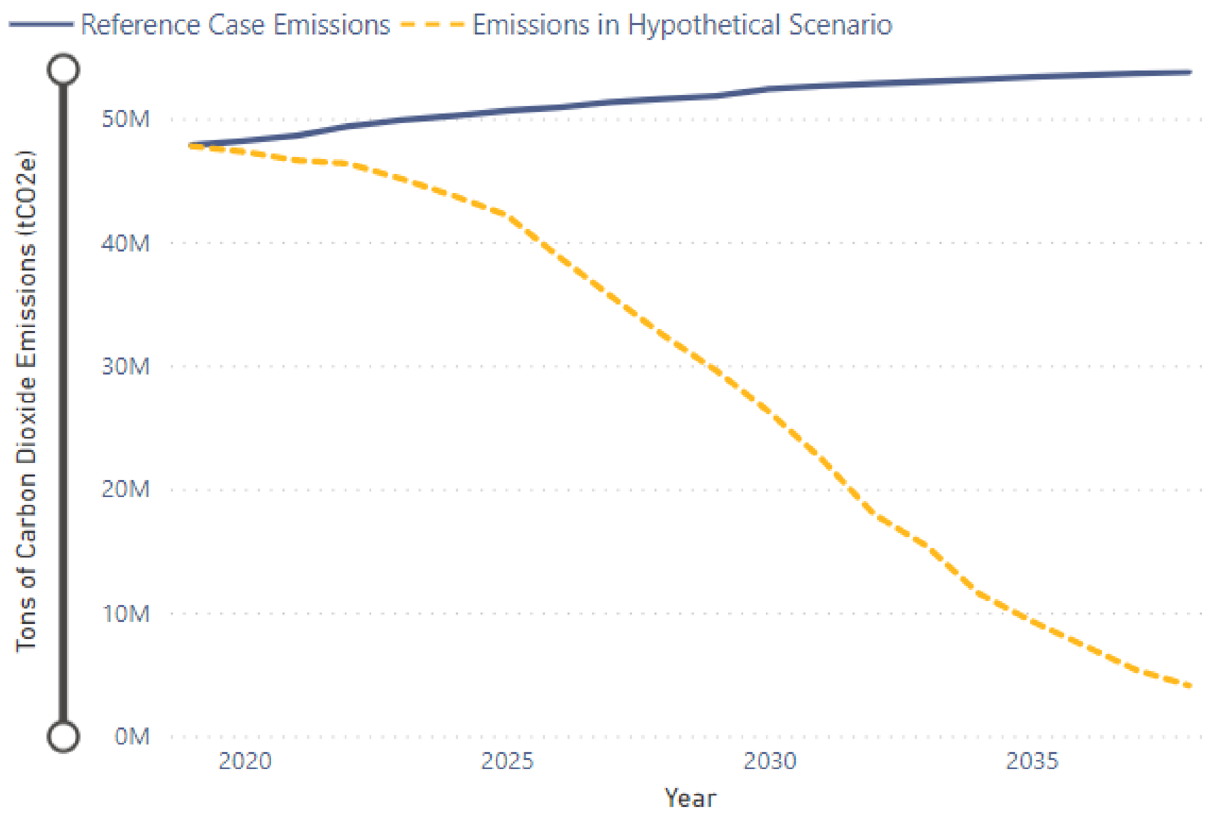


Exhibit 25 – Lower Bound GHG Emissions (t/CO2e)



6 Scenario Narratives

Before modelling the scenarios, scenario narratives were drafted to provide a qualitative description of each scenario. This section provides the process used to develop the scenario narratives and the input assumptions for each scenario.

6.1 Introduction to Scenario Planning

This section provides a brief overview on scenario planning. Key references include:

- Swartz, Peter, 1991. The Art of the Long View – Planning for the Future in an Uncertain World
- Chermack, Thomas, J., 2011. Scenario Planning in Organizations – How to Create, Use, and Assess Scenarios
- Advanced Energy Centre – MaRS Cleantech. Future Scenarios: Canada's Energy Landscape in 2033
- Canadian Institute for Climate Choices, 2021. Canada's Net Zero Future – Finding our Way in the Global Transition

Scenarios are not about predicting the future, rather they are about perceiving futures in the present. A good scenario asks people to suspend disbelief in its stories long enough to appreciate their impact. The end result is not an accurate picture of tomorrow, but better decisions about the future.

Scenario analysis can help an organization such as Enbridge Gas to:

- Develop more robust strategies
- Identify signals
- Improve decision making
- Reduce decision making response times
- Improve individual and organizational learning
- Improve organizational communication and shared mental models

Good practices for scenario planning include:

- Create scenario logics which are plausible, challenging, and relevant
- Avoid having low, middle, high scenarios, where middle mistakenly gets cast as the most 'likely'
- Do not assign probabilities to scenarios
- Develop distinct and memorable scenarios which present a story line supported by the CDs and data to support their action in the scenarios
- Consider how would the world get from here to there, and what events might be necessary to make the end point of the scenario plausible.
- Consider timelines
    - e.g., define major events occurring at define milestones over the planning period

6.2 Scenario Planning Process

The ETSA project team built off the scenario narratives envisioned by Enbridge Gas prior to beginning the project to draft scenario narratives. Draft narratives were presented to stakeholders internal and external to Enbridge Gas to solicit feedback[18]. A survey was also administered to collect feedback on input assumptions drafted to provide modelling instructions to reflect the scenario narratives. The ETSA project team used the feedback to finalize the scenario narratives and input assumptions.

6.3 Scenario Narratives

Exhibit 26 presents the scenario plot, narrative, the key policies/exogenous conditions associated with each scenario, and the CDs that are most influential in the scenario.

Exhibit 26 – Scenario Narratives

Scenario Title:	Reference Case	Steady Progress	Diversified Portfolio	Electricity Centric
Scenario Narrative	• Continuation of current "business as usual" trends • Reflects Enbridge Gas' 2020-2030 volume and account forecast, with trends extended to 2038 • Incorporates OEB-approved applications as of Oct 2020	• Policies that have been announced (but perhaps not yet legislated) are implemented • Expected to fall short of Net Zero by 2050	• Additional policies implemented to reach Net Zero Emissions by 2050 • Leverages existing natural gas delivery and storage assets • Maximizes energy system flexibility, inter-operability, reliability • Partial electrification of new and existing buildings from more stringent codes and standards	• Additional policies implemented to reach Net Zero Emissions by 2050 • High dependence on single energy system (electricity) • Major electrical grid infrastructure investments (new supply, distribution, storage)
Policy Focus, Conditions Present:	Carbon charge and rebate: • GGPPA – including federal carbon charge and	Energy conservation for built environment, transportation sector: • Clean Fuel Regulation (CFR) incents CNG, RNG, H2	Decarbonize gas system, CCS: • Renewable content policy • Federal strategy to evolve gas system to H2 and deploy CCS	Electrification of space and water heating: • Policy driven electrification of new and existing buildings

[18] Please see Appendix H for details on the stakeholder engagement conducted for this project.

Scenario Title:	Reference Case	Steady Progress	Diversified Portfolio	Electricity Centric
	Output Based Pricing system (OBPS) • Voluntary RNG Program • Low Carbon Energy Project (LCEP)	• Codes & Std promote energy efficiency • Moderate carbon price, high CFR credit price	• Some voluntary/incentive driven fuel switching • Moderate carbon price, high CFR credit price • Accelerated Codes & Stds	• Fuel switching space and water heating in res/com sector • CFR incents CNG, RNG, H2 • Accelerated Codes & Stds • High carbon price, low CFR credit price

6.4 Scenario Input Assumptions

Once scenario narratives are established, the setting of each CD is determined. The collection of settings for all the CDs are the input assumptions, which are the set of instructions to model the scenario. Exhibit 27 describes the CD settings for the scenarios. The appendices provide details on the CDs that involve more in-depth research and detailed modelling assumptions (Appendix C, Appendix D), details on the input data and assumptions used to develop the Reference Case (Appendix A), and details on input assumptions for hydrogen, RNG and electrification in the industrial sector (Appendix E).

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Exhibit 27 – Scenario Input Assumptions by Critical Driver

Critical Driver	Reference Case	"Steady Progress"	"Diversified Portfolio"	"Electricity Centric"
Carbon Price	Greenhouse Gas Pollution Pricing Act schedule to 2022: • \$20/tonne CO2e in 2019 rising to \$58.58/tonne C02e in 2023	Moderate • \$15/tonne CO2e annual increase beyond 2022 • \$170/tonne CO2e by 2030 • \$200/tonne CO2e in 2038	Moderate • Same as "Steady Progress"	High • \$290/t by 2030 • \$338/t by 2038
Natural Gas Commodity Price	• 11.75¢/m3 in 2019 rising to 15.90 ¢/m3 by 2038	• Reference Case assumptions used for all sectors	• Reference Case assumptions used for all sectors	Low: • 50% lower than the Reference Case (going to \$7.95 ¢/m3 by 2038) due to decreased demand
Customer Accounts (growth due to population/ economic growth)	The Reference Case is calibrated to Enbridge Gas' account forecast[19] which provides growth rates by rate class which are mapped to the sectors in the model: • Residential: ~1% annual growth • Commercial: 0.1-0.4% annual growth • Industrial: decline by 0.7% from 2019-2021; hold constant from 2022-2038	• Reference Case assumptions used for all sectors	• Reference Case assumptions used for all sectors	• Reference Case assumptions used for all sectors

[19] Enbridge Gas provided PG with the following files: Reference Case account forecast in the "Enbridge Gas General Service Actual and Forecast Customers.xlsx" workbook and the historic count of contract market customers in the "EGD Contract Market Customer Count actual from 2008 to 2019.xlsx" workbook.

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<table>
<tr><th>Critical Driver</th><th>Reference Case</th><th>“Steady Progress”</th><th>“Diversified Portfolio”</th><th>“Electricity Centric”</th></tr>
<tr><td>Non-price driven fuel switching</td><td>The Reference Case represents a ‘status quo’ where there is no fuel switching beyond what is captured in Enbridge Gas volume and account forecast</td><td>None
No policy or incentive driven fuel switching of heating equipment</td><td>New Construction (Res, Com sectors)
Starting in 2030, 10% of new Res and Com buildings across the province won't connect to the gas grid in select communities (due to policy or incentives); by 2038, 20% of new construction won't connect
Existing Buildings (Res, Com sectors)
Starting in 2026, province wide, 10% of gas-fired space & water heating equipment that is being replaced annually (due to equipment reaching end-of-life) will be replaced with electric equipment (due to policy or incentives)
10% of the customers installing new electric space heating equipment will disconnect from the gas system (the assumption is these customers only have 1 gas appliance)</td><td>Accelerated, all sectors:
Policy driven fuel switching for Res/Com sectors: New Res and Com won’t connect to the gas grid starting in 2026, and water/space heating in existing buildings replaced at equipment turnover rate
Space and water heating being served by ASHP without gas back-up
Non-mandated electrification of some industrial end-uses in some sectors as equipment is replaced</td></tr>
<tr><td>Codes & Standards</td><td>Reference case follows the volume and account forecast provided by Enbridge Gas which reflects current (2019) enforced codes and standards</td><td>Medium Stringency:
Increased stringency of codes and stds lowers overall gaseous demand. Specifically:
TGS for NC in Toronto: Tier 2/3 starts in 2025</td><td>High Stringency
High stringency codes and stds lowers overall gaseous demand
NECB code: Tier 2 (2030), Tier 3 (2035), Tier 4 (2040)
NBC code: Tier 3 (2030), Tier 4 (2035), Tier 5 (2040)
Retrofit code implemented</td><td>High Stringency
High stringency codes and stds lowers overall
NECB code: Tier 2 (2030), Tier 3 (2035), Tier 4 (2040)
NBC code: Tier 3 (2030), Tier 4 (2035), Tier 5 (2040)
Retrofit code implemented</td></tr>
</table>

Critical Driver	Reference Case	"Steady Progress"	"Diversified Portfolio"	"Electricity Centric"
		○ Non-Toronto CEPs on NC (impacting 50% of non-Toronto customers): Tier 2/3 starts in 2027 ○ NBC code for NC in the rest of the province: Tier 2/3 starts in 2028 • Retrofit code implemented only in specific regions toward end of study period • Upper Tiers of building code met with high efficiency gas options (e.g., gas heat pump)		
RNG, H2 and CCS	Very Low: • OEB-approved Voluntary RNG Program volume, and Enbridge Low Carbon Energy Project represents about 0.01% of total demand in 2030, divided between the sectors • No CCS	Low: • CFR directs RNG and H2 to transportation • CFR provides modest incentive for CCS, RNG & H2 • H2 cost competitive with natural gas in 2035, RNG is cost competitive in 2030	High: • Renewable content policies build demand for RNG and H2 • H2 strategy overcomes equipment H2 barriers • CCS deployed for industrial end-uses/sectors not using H2	Low: • CFR remains, like Steady Progress scenario • H2 cost competitive with natural gas in 2035, RNG is cost competitive in 2030
Climate change	• Reference case follows the volume and account forecast provided by Enbridge Gas which reflects historic average climate trends	• IPCC Average annual temperature increases by 2.3-3.9C in 2100 (IPCC RCP 6.0)	• Average annual temperature increases by 1-2.5C in 2100 (IPCC RCP 2.6)	• Average annual temperature increases by 1-2.5C by 2100 (IPCC RCP 2.6) •

Critical Driver	Reference Case	"Steady Progress"	"Diversified Portfolio"	"Electricity Centric"
Natural gas transportation	• Reference case follows volume forecast for Enbridge Gas accounts currently providing natural gas to CNG suppliers	Moderate: • CNG replaces diesel used in heavy duty transportation at two-thirds the rate of Canada Energy Regulator's Canada's Energy Future 2019 forecast	High: • CNG replaces diesel used in heavy duty transportation per Canada Energy Regulator's Canada's Energy Future 2019 forecast	Low: • CNG replaces diesel used in heavy duty transportation at one-thirds the rate of Canada Energy Regulator's Canada's Energy Future 2019 forecast
DSM Budget[20]	• The 2021 DSM budget of $132 million held constant	• Starting with $132 million in 2019 and increasing by 3% year over year after 2021	• Starting with $132 million in 2019, increasing by 3% from 2021-2027 and then increasing by 10% in 2028-2038	• Starting with $132 million in 2019, increasing by 3% from 2021-2027 and then increasing by 10% in 2028-2038

[20] All dollars are in 2019 CAD and model output is in real values.

6.5 Scenario Modelling Steps

For all scenarios, the same procedure for producing modelling outputs was followed:

1. Begin with the accounts, units, fuel shares, and unit energy consumption values from the ETSA Reference Case (described in detail in Appendix A).
2. Adjust account growth due to prescriptive fuel switching away from natural gas. For the Electricity Centric Scenario, electrical heating equipment is assumed to become mandatory beginning in 2026. For the Diversified Portfolio Scenario, 10% of new residential and commercial buildings that would have connected to the gas grid do not due to electrical incentives or policy implementation, increasing to 20% in 2038.
3. Adjust heating demand for natural gas due to warmer winter weather due to climate change. This involves reducing heating UECs for all segments.
4. Adjust space and water heating UECs due to changes to equipment and envelope efficiency required by codes and standards.
5. Reduce/increase natural gas fuel shares in response to price signals or prescriptive fuel switching. Non-price driven fuel switching, such as the 10% reduction in new gas equipment beginning 2030 in the Diversified Portfolio Scenario, was taken to be additional to changes to the gas fuel shares caused by the carbon price.
6. Blend the appropriate amount of RNG and hydrogen into the gas supply for each sector, segment and year. Apply carbon capture to the applicable end-uses in industry.
7. Apply energy savings potential based on specified DSM budget for the scenario. Energy savings are estimated at the end-use level using PG's library of DSM measures. Further explanation of the DSM modelling method is provided in Appendix G. The amount of potential depends on:
    a. DSM budget
    b. Which measures pass the Total Resource Cost (TRC) Test based on the gas and carbon price in each scenario
    c. Estimated uptake of the measures based on the customer payback in each scenario

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7 Summary of Scenario Results

This section summarizes the key results for the Reference Case, Steady Progress, Diversified Portfolio, and Electricity Centric scenarios. Results are discussed in terms of annual volume, hourly and daily peak, and greenhouse gas (GHG) emissions. Results in 2030 and 2038 are compared to 2019 (the base year) as 2030 is a milestone year for many GHG targets and 2038 is the end of the forecast period. Results are presented for gaseous fuels only, which include fossil-based natural gas ('natural gas' for short), renewable natural gas (RNG), hydrogen, and natural gas with carbon capture and storage (CCS). The section concludes with a brief comparison between the four scenarios. Further details of the results are available in an online data visualization dashboard.[21]

7.1 Reference Case Scenario

This section summarizes results for the Reference Case scenario for annual volume, hourly and daily peaks, and GHG emissions from gaseous fuels. Recall that the Reference Case represents 'business as usual' trends continuing based on what was in-market and enshrined in law as of 2019. The Reference Case was calibrated to Enbridge Gas' latest 10-year (2020 to 2030) customer account and annual volume forecast and PG extrapolated the trends from 2030 to 2038. (Please see Appendix A for details on how the reference case scenario was developed.) These forecasts have embedded assumptions about economic and population growth. Energy savings potential from demand side management (DSM) programming is included based on the 2021 DSM budget which is held constant over the forecast period.

7.1.1 Annual Volume

In the Reference Case scenario, annual volume increases by 4% by 2030 and by 6% by 2038, relative to 2019. The increase in volume is mainly driven by account growth (due to an increasing population and economic growth).

In the Reference Case, the DSM program budget is fixed at $132 million. At this spending level, there is an estimated 6% of energy savings by 2038 compared to the Reference Case absent DSM. The commercial sector saves about 4%, and the industrial and residential sectors save about 6% each by 2038 relative to the Reference Case without DSM.

In 2038, natural gas comprises nearly 100% of annual volume. Volumes of RNG and hydrogen are almost nil (0.01%) as the Reference Case reflects expected RNG and hydrogen volumes under Enbridge Gas' currently planned programs (Voluntary RNG Program and Low Carbon Energy Project). The Reference Case does not include natural gas with carbon capture and storage (CCS). The increase in total volume by 2038 is about the same as the increase in natural gas volume, both overall (6%) and across the sectors (9%, 4%, and 6% in the residential, industrial, and commercial sectors, respectively) because total volume is nearly all natural gas. The forecasted increase in volume is greater than the energy savings from the DSM programming.

Exhibit 28 illustrates total volume by fuel. RNG and hydrogen do not appear on the graph as they account for 0.01% of total volume by 2030.

[21] Please contact the Enbridge Gas Energy Transition Planning Department for login information to the data visualization dashboard in PowerBI.

Exhibit 28 - Reference Case Scenario: Annual volume by fuel

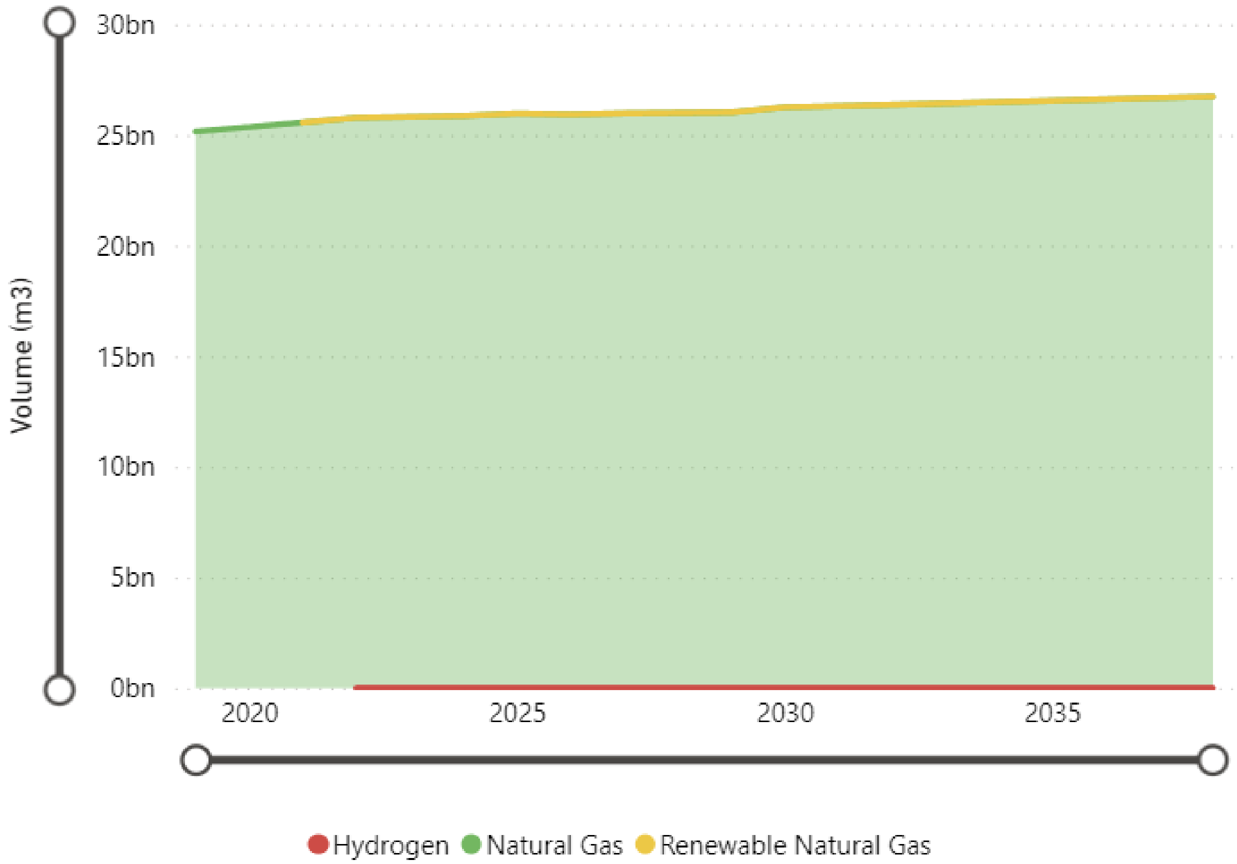

Exhibit 29 and Exhibit 30 provide annual volume composition by fuel in 2019, 2030, and 2038.

Exhibit 29 - Reference Case Scenario: Annual Volume Composition by Fuel (m^3) in 2019, 2030, and 2038

Year	Hydrogen	Natural Gas	Renewable Natural Gas	**Total**
2019		25,162,554K		**25,162,554K**
2030	746K	26,248,404K	1,347K	**26,250,497K**
2038	1,007K	26,737,703K	1,861K	**26,740,570K**

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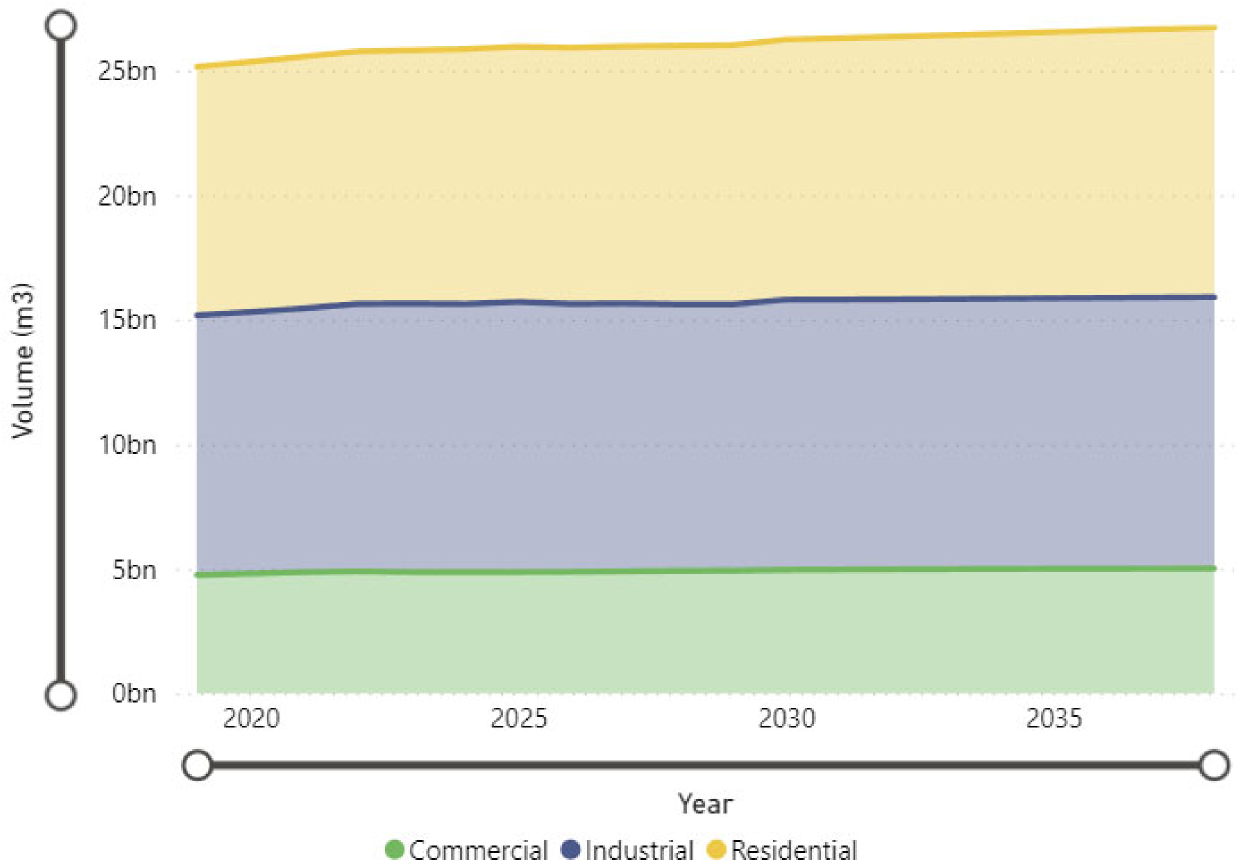
Exhibit 30 - Reference Case Scenario: Annual Volume Composition by Fuel (%) in 2019, 2030, and 2038

Year	% H2 Volume	% Natural Gas Volume	% RNG Volume	% CCS Volume
2019	0%	100%	0%	0%
2030	<0.01%	99.99%	0.01%	0%
2038	<0.01%	99.99%	0.01%	0%

Exhibit 31 illustrates annual volume by sector. The industrial and residential sectors each account for about 40% of volume, while the commercial sector accounts for the remaining 20%.

Exhibit 31 - Reference Case: Annual volume by sector

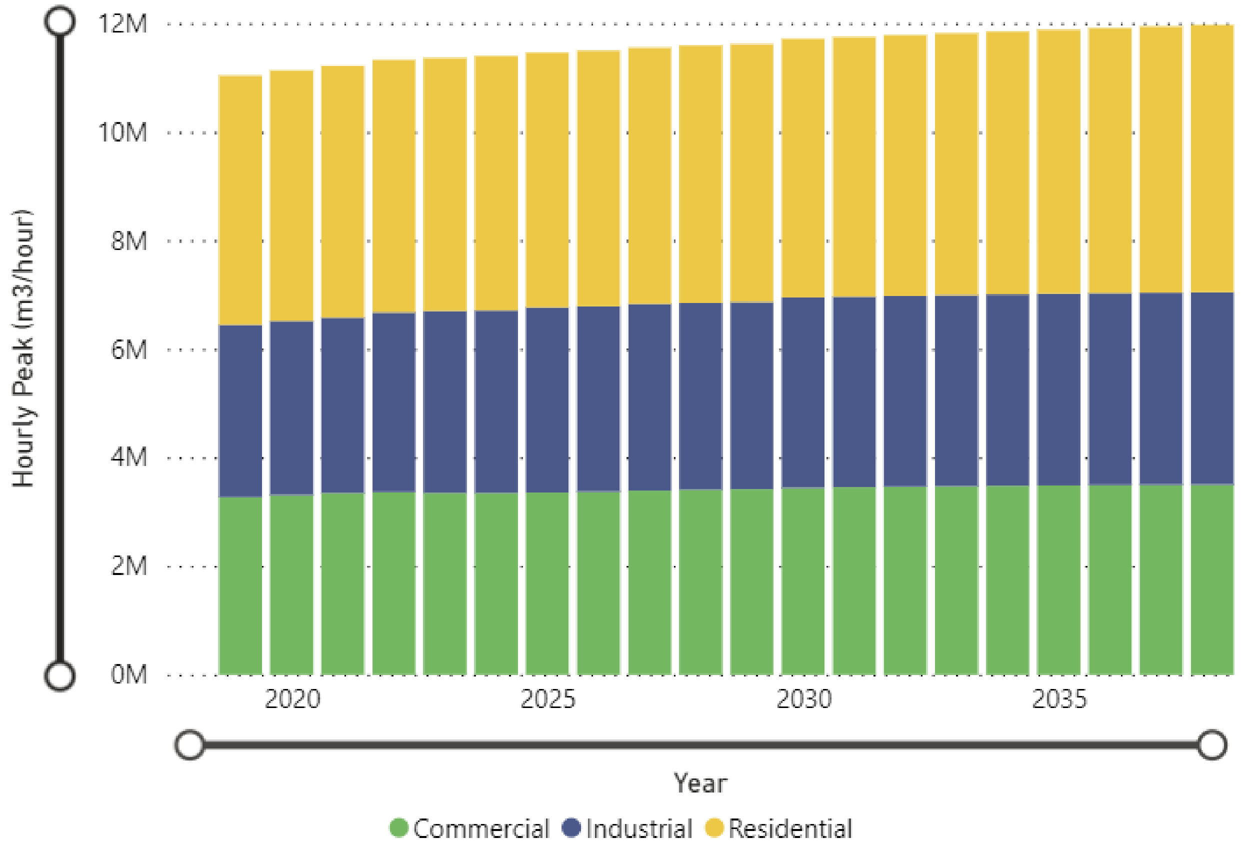


7.1.2 Peak

In the Reference Case scenario, hourly peak increases by 6% by 2030 and 8% by 2038, relative to 2019. Daily peak increases by 5% by 2030 and by 7% by 2038, relative to 2019. These increases are mainly driven by the same factors that increase annual volume.

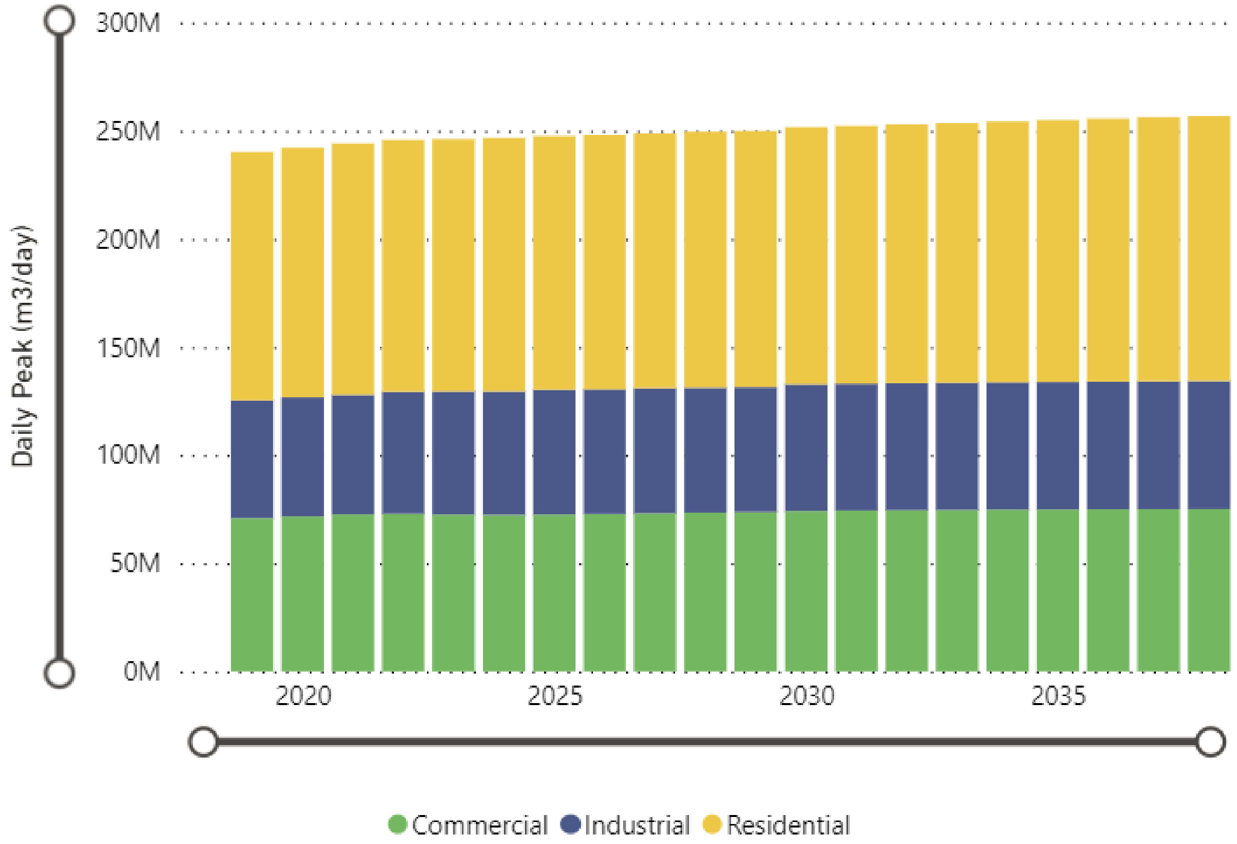
Peak hour increases by 7%, 8%, and 11% in residential, commercial, and industrial sectors, respectively. Industrial segments with higher HVAC end-use shares (e.g., Agriculture) are projected to grow faster than segments with relatively smaller HVAC end-use shares. The result is that Industrial peak increases more than annual volume because HVAC accounts for about 60% of industrial peak but only 16% of annual volume. Exhibit 32 presents the hourly peak in total fuel by sector.

Exhibit 32 - Reference Case: Hourly peak by sector



Daily peak increases by about 7% by 2038 in the Reference Case scenario. Sector breakdown for this growth is 7% from residential, 6% for commercial, and 8% for industrial. Exhibit 33 shows the daily peak by sector.

Exhibit 33 - Reference Case: Daily peak by sector



Compared to the Reference Case without DSM, the Reference Case hourly peak is 4% smaller and the daily peak is 5% smaller. The industrial hourly peak with DSM is 2% smaller than without DSM, and the industrial daily peak is 4% smaller with DSM. The commercial hourly peak with DSM is 3% smaller than without DSM, and the commercial daily peak is 4% smaller with DSM. The residential hourly peak with DSM is 6% smaller than without DSM, and the residential daily peak is 7% smaller with DSM. DSM has a greater impact on the residential and commercial sector peak because many measures focus on reducing space heating load.

7.1.3 End-User GHG Emissions

In the Reference Case scenario, annual end-user GHG emissions from gaseous fuels increases by 4% by 2030 and by 6% by 2038, relative to 2019. This increase in GHG emissions is caused by the increase in consumption of natural gas; lower carbon gaseous fuels only represent a small fraction of total volume on Enbridge Gas' system in this scenario. Exhibit 34 and Exhibit 35 provide GHG emissions by fuel in 2019, 2030, and 2038.

Exhibit 34 – Reference Case Scenario: GHG Emissions by fuel (t/CO2e) in 2019, 2030, and 2038

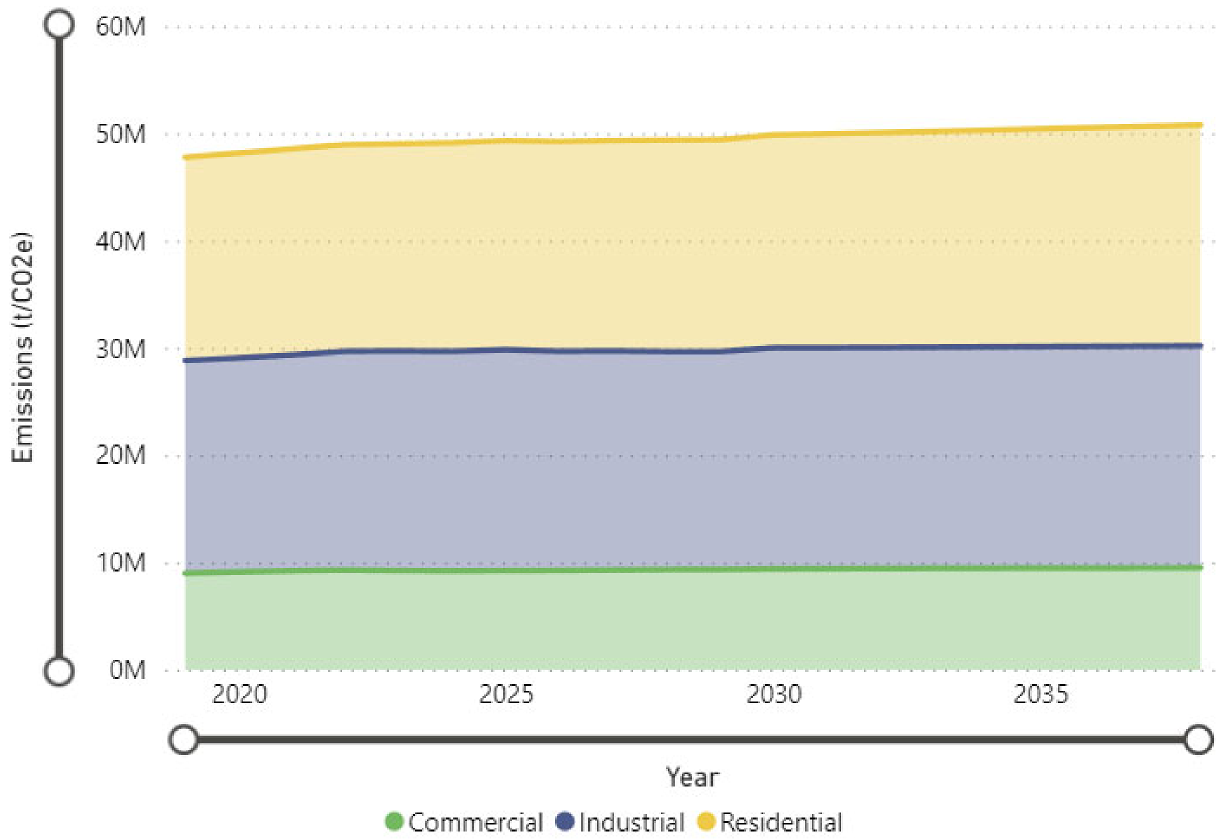
Year	Hydrogen	Natural Gas	Renewable Natural Gas	**Total**
2019		47,792,623		**47,792,623**
2030	0	49,855,037	15	**49,855,052**
2038	0	50,784,389	21	**50,784,410**

Exhibit 35 – Reference Case Scenario: GHG Emissions by fuel (%) in 2019, 2030, and 2038

Year	% H2 Emissions	% Natural Gas Emissions	% RNG Emissions
2019	0.%	100%	0.00%
2030	0%	~100%	<0.01%
2038	0%	~100%	<0.01%

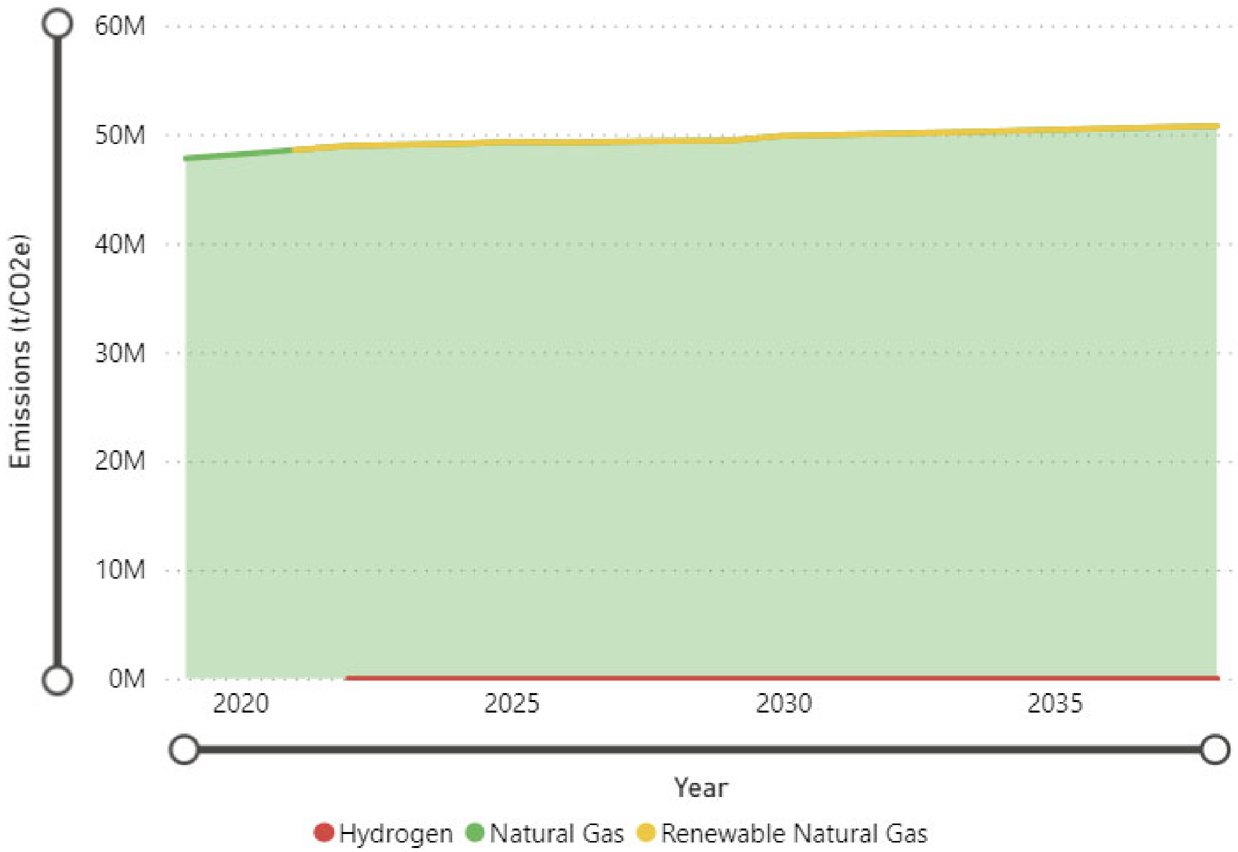
Exhibit 36 presents GHG emissions by sector.

Exhibit 36 - Reference Case: Annual GHG emissions by sector



Emissions in the residential, commercial, and industrial sectors increase by 9%, 6%, and 4% respectively. Exhibit 37 presents GHG emissions by fuel.

Exhibit 37 - Reference Case: Annual GHG emissions by fuel



7.2 Steady Progress Scenario

This section summarizes results for the Steady Progress scenario for annual volume, hourly and daily peaks, and GHG emissions. The Steady Progress scenario represents the gradual implementation of policies announced by January of 2021 including the 2020 Federal Climate Action Plan, the Clean Fuel Regulation, and more stringent building codes including for new construction and retrofits. The energy savings potential achieved through DSM programming is based on Enbridge Gas' 2021 DSM budget increasing by 3% annually after 2021.

7.2.1 Annual Volume

In the Steady Progress scenario, annual volume decreases by 6% by 2030 and by 13% by 2038, relative to 2019. This moderate decrease in volume is driven by more stringent building codes, moderate carbon prices, and moderate DSM spending which cause reductions that are countered by account growth (due to an increasing population and economic growth), and climate change impacts.

By 2038, natural gas comprises 88% of annual volume in the Steady Progress scenario, a 24% decrease in natural gas from 2019. RNG and natural gas with carbon capture comprise 6% and 5% of annual volume respectively, and hydrogen comprises the remaining 1%. The reduction in natural gas is caused by increased stringency of new construction code, retrofit codes, and equipment standards; carbon price increases also lower natural gas volumes. Increases in RNG, hydrogen, and CCS technology are driven by incentives from the Clean Fuel Regulations. Exhibit 38 presents annual volume by fuel.

Exhibit 38 - Steady Progress Scenario: Annual volume by fuel

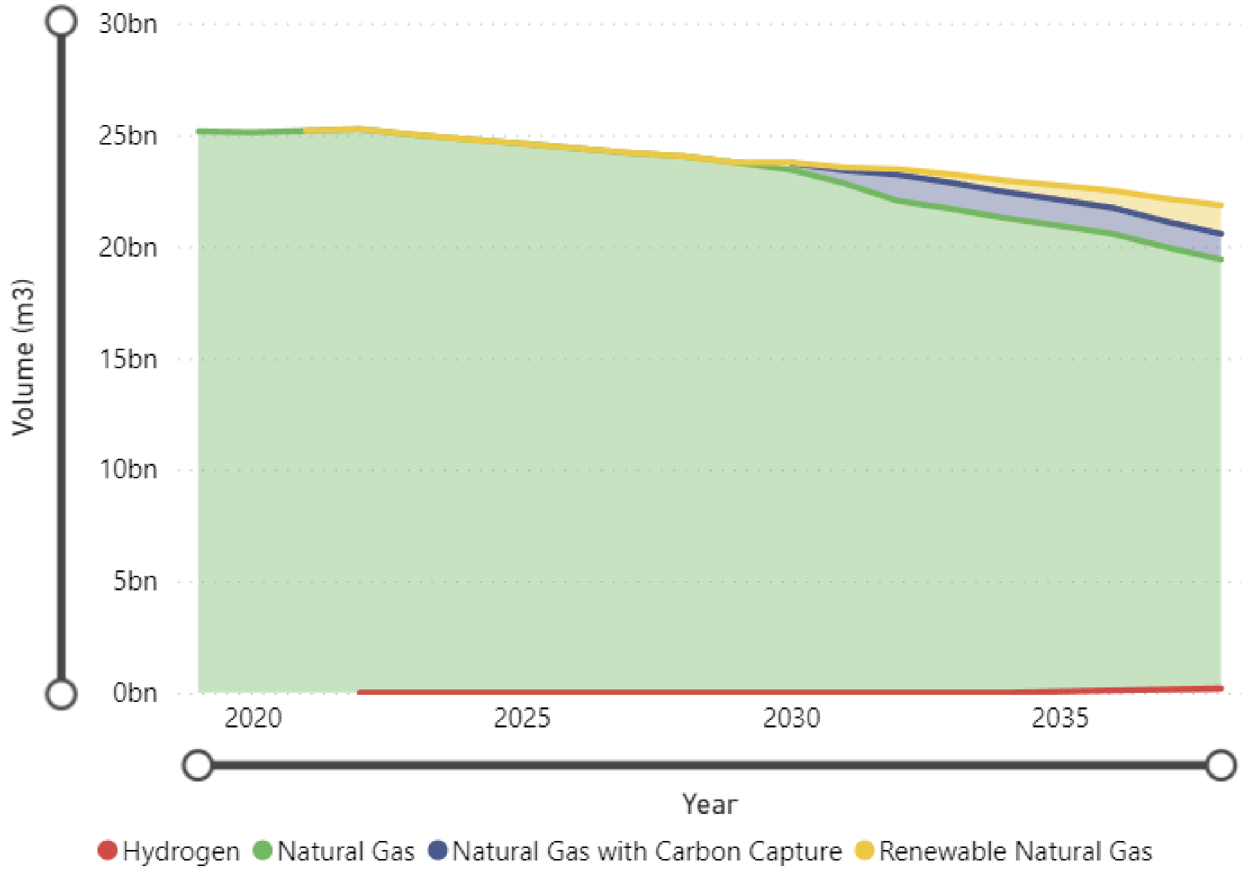


Exhibit 39 and Exhibit 40 provide annual volume composition by fuel in 2019, 2030, and 2038.

Exhibit 39 - Steady Progress Scenario: Annual Volume Composition by fuel (m3) in 2019, 2030, and 2038

Year	Hydrogen	Natural Gas	Natural Gas with Carbon Capture	Renewable Natural Gas	**Total**
2019		25,162,555K			**25,162,555K**
2030	735K	23,444,244K	293,097K	25,782K	**23,763,858K**
2038	197,108K	19,216,347K	1,151,951K	1,283,405K	**21,848,811K**

Exhibit 40 - Steady Progress Scenario: Annual Volume Composition by fuel (%) in 2019, 2030, and 2038

Year	% H2 Volume	% Natural Gas Volume	% RNG Volume	% CCS Volume
2019	0%	100%	0%	0%
2030	<0.01%	~99%	0.1%	1%
2038	1%	88%	6%	5%

Annual volume declines by 22%, by 7%, and by 16% in the commercial, industrial, and residential sectors, respectively. The growth of customer accounts (due to community expansion) in the Steady Progress scenario counteracts reduction in consumption from other drivers (e.g., codes and standards, carbon price, hydrogen/RNG supply, natural gas with CCS, and DSM) particularly in the industrial sector. In the residential and commercial sectors, the consumption is significantly impacted by the drivers mentioned above. There is uptake of natural gas with CCS in the Industrial sector in this scenario. Exhibit 41 presents annual volume by sector.

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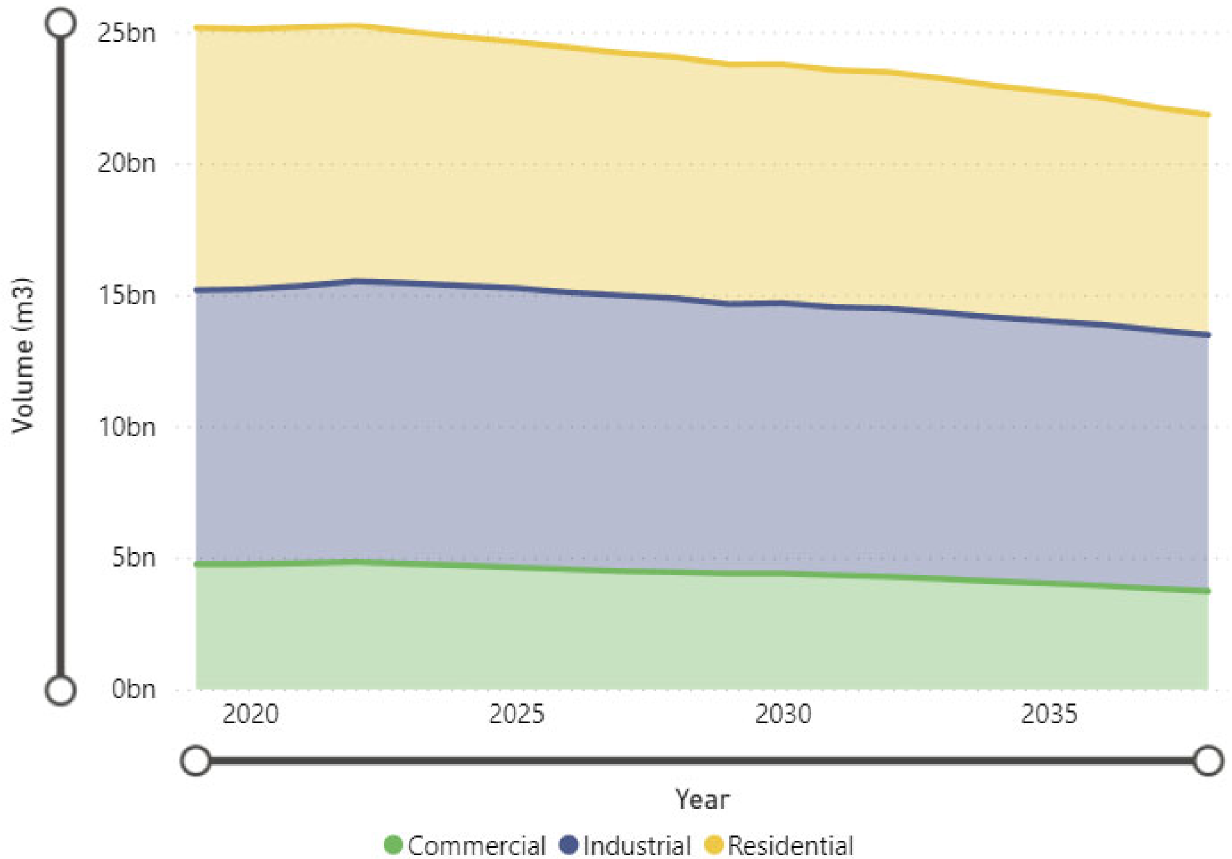
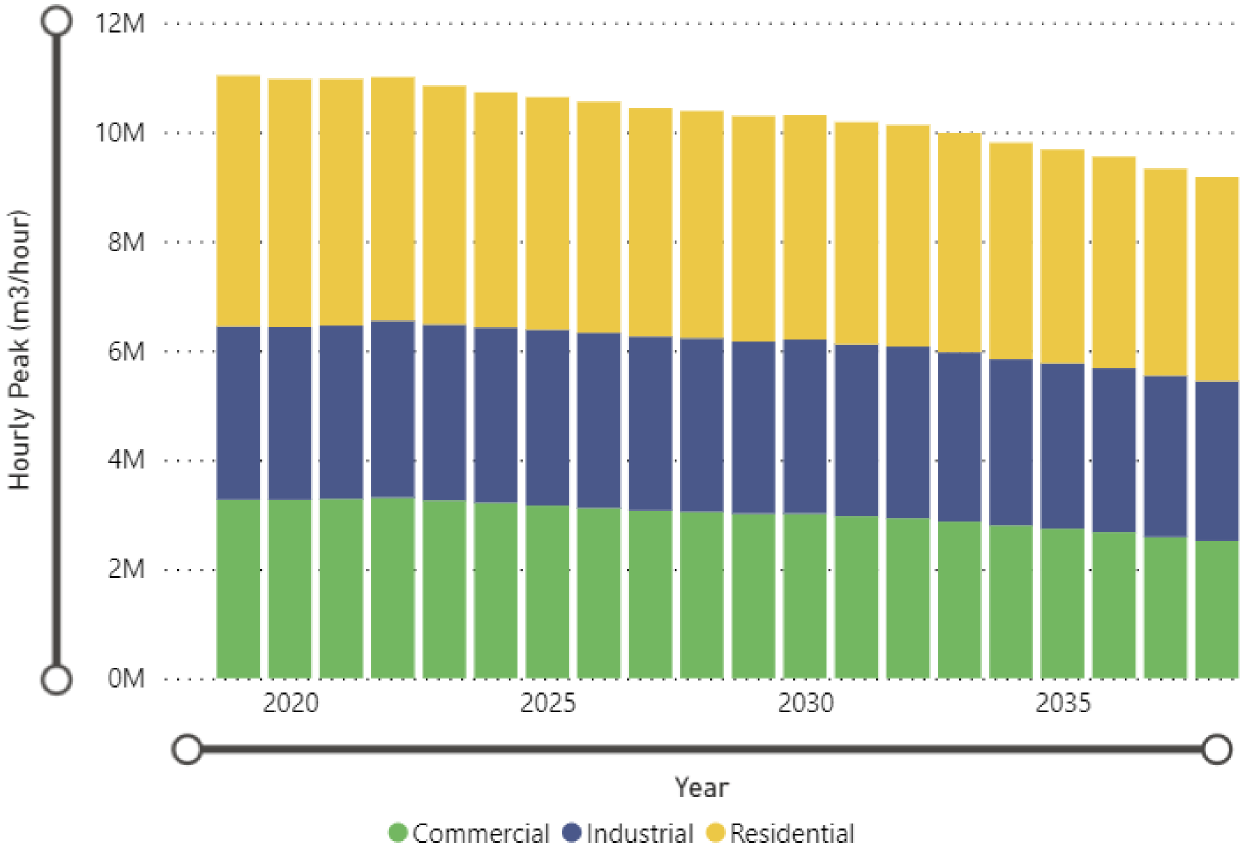
Exhibit 41 – Steady Progress Scenario: Annual volume by sector



7.2.2 Peak

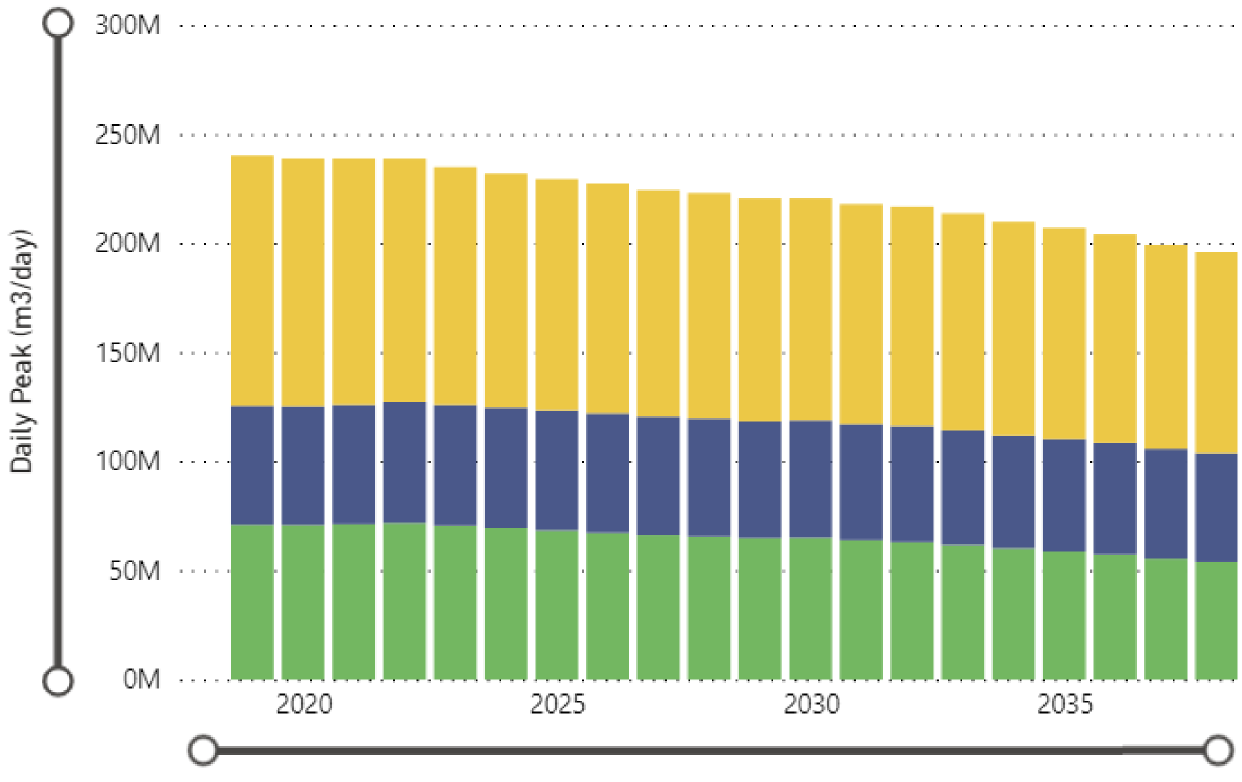
Peak hour decreases by 7% by 2030 and by 17% by 2038, relative to 2019 in the Steady Progress scenario. Peak day decreases by 8% by 2030 and by 18% by 2038, relative to 2019. Reductions in peaks are caused by CDs that reduce space and water heating loads, such as codes and standards, and DSM measures that focus on reducing those loads. Carbon pricing also reduces loads as price signals cause a decrease in gas consumption when space and water heating equipment are replaced with electrical alternatives, thereby also reducing peak load (no account defection was assumed in the Steady Progress scenario). The residential, industrial, and commercial hourly peaks decrease by about 19%, 8%, and 23%, respectively. Exhibit 42 presents hourly peak by sector.

Exhibit 42 - Steady Progress Scenario: Hourly peak by sector



The daily peak decreases by about 20%, 9%, and 24% for the residential, industrial, and commercial sectors, respectively. Exhibit 43 presents daily peak by sector.

Exhibit 43 - Steady Progress Scenario: Daily peak by sector



7.2.3 End-User GHG Emissions

End-user GHG emissions in the Steady Progress scenario decrease 7% by 2030 and 23% by 2038, relative to 2019. The decrease in natural gas consumption resulting from stricter codes and standards, DSM spending, and carbon price driving fuel switching to electricity represents the bulk of the GHG emissions reductions. The introduction of natural gas with carbon capture to the industrial sector in 2030, and to a lesser extent the additional RNG and hydrogen on Enbridge Gas' system, also contribute to the emission reductions between 2030 and 2038. Exhibit 44 and Exhibit 45 provide GHG emissions by fuel in 2019, 2030, and 2038.

Exhibit 44 - Steady Progress Scenario: GHG emissions by fuel (t/CO2e) in 2019, 2030, and 2038

Year	Hydrogen	Natural Gas	Natural Gas with Carbon Capture	Renewable Natural Gas	**Total**
2019		47,792,623			**47,792,623**
2030	0	44,528,942	114,002	293	**44,643,236**
2038	0	36,498,663	448,057	14,573	**36,961,293**

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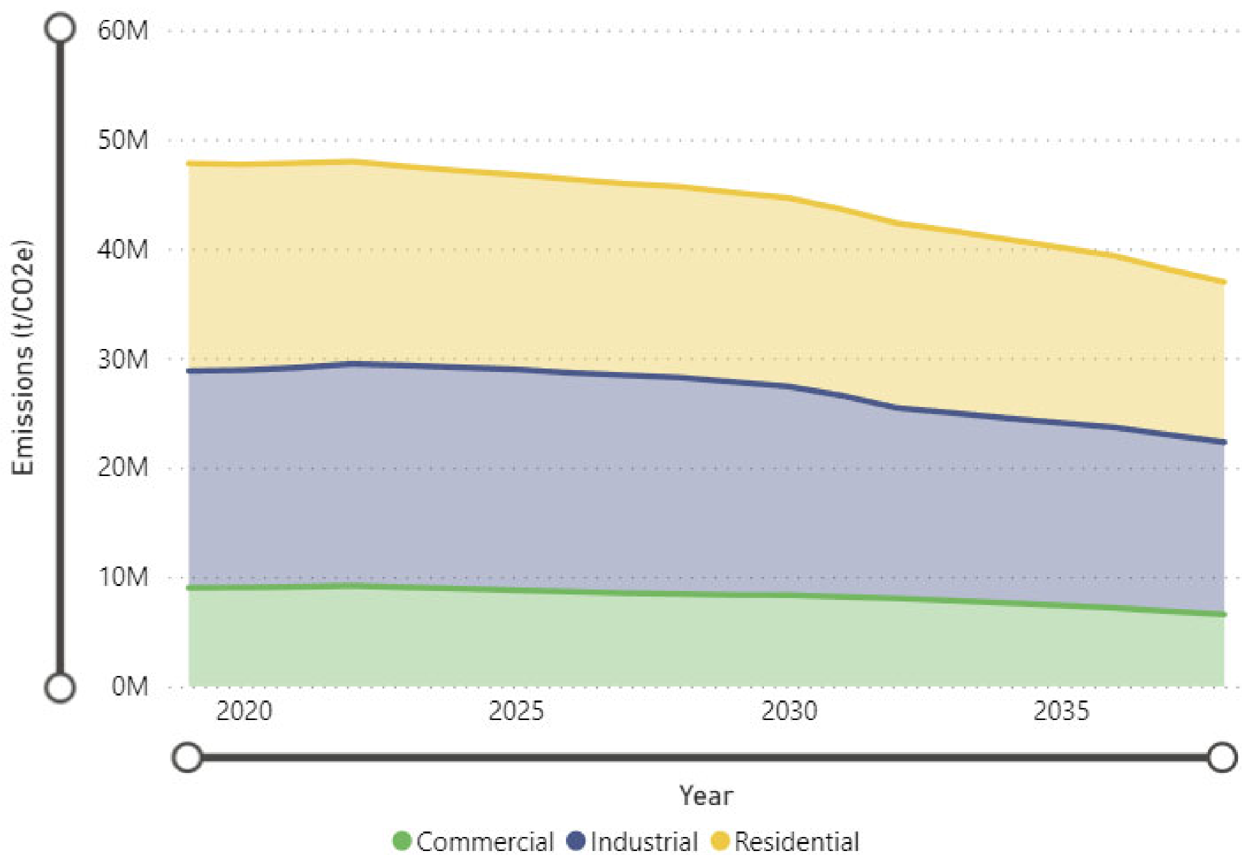
Exhibit 45 - Steady Progress Scenario: GHG emissions by fuel (%) in 2019, 2030, and 2038

Year	% H2 Emissions	% Natural Gas Emissions	% RNG Emissions	% CCS Emissions
2019	0.00%	100.00%	0.00%	0.00%
2030	0.00%	99.74%	<0.01%	0.26%
2038	0.00%	98.75%	0.04%	1.21%

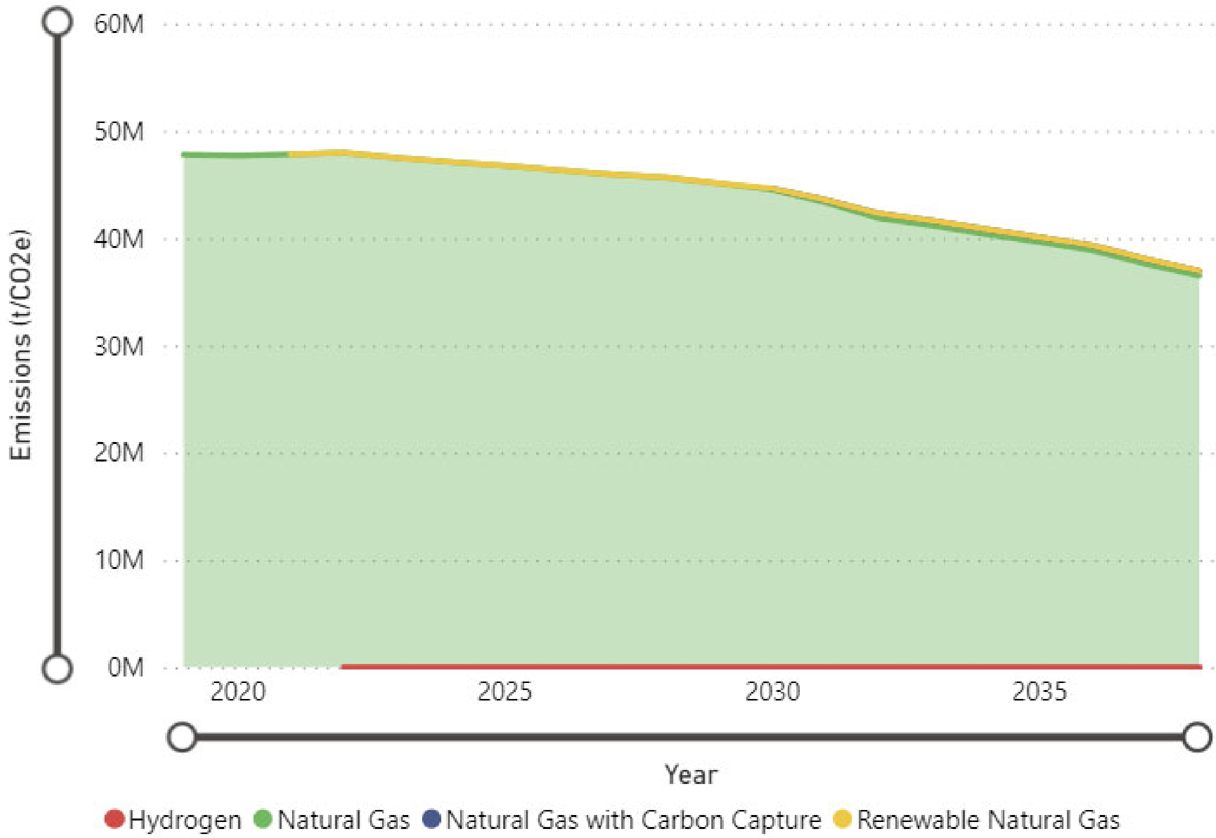
By sector, emissions decrease by 23% in residential, 27% in commercial, and 21% in the industrial sector. These trends follow the decreases in natural gas volume (the main source of GHG emissions) by 2038 across the sectors. Exhibit 46 shows GHG emissions by sector.

Exhibit 46 - Steady Progress Scenario: Annual GHG emissions by sector



By fuel, natural gas accounts for 99% of GHG emissions in 2038. Natural gas with carbon capture is the remaining 1%. The emissions from RNG are negligible and hydrogen has no end-user GHG emissions. Exhibit 47 shows GHG emissions by fuel.

Exhibit 47 - Steady Progress Scenario: Annual GHG emissions by fuel



7.3 Diversified Portfolio Scenario

This section summarizes results for the Diversified Portfolio scenario for annual volume, hourly and daily peaks, and GHG emissions. The Diversified Portfolio scenario reflects a future where GHG reductions are mainly achieved by decarbonizing the gas grid with some electrification in specific segments and end-uses. This scenario builds on the Steady Progress scenario with additional low carbon gas mandates, greater hydrogen and carbon capture development, earlier adoption of, and more stringent, codes and standards, and some electrification.

7.3.1 Annual Volume

In the Diversified Portfolio scenario, annual volume decreases 4% by 2030 and then increases 11% by 2038 relative to 2019. The increase in volume by 2038 is from hydrogen replacing natural gas in pursuit of lowering emissions from the gas system. There is also uptake of RNG and CCS, as these fuels lower GHG emissions without changing energy demand. Exhibit 48 and Exhibit 49 provide annual volume composition by fuel in 2019, 2030, and 2038.

Exhibit 48 - Diversified Portfolio Scenario: Annual Volume Composition by Fuel (m3) in 2019, 2030, and 2038

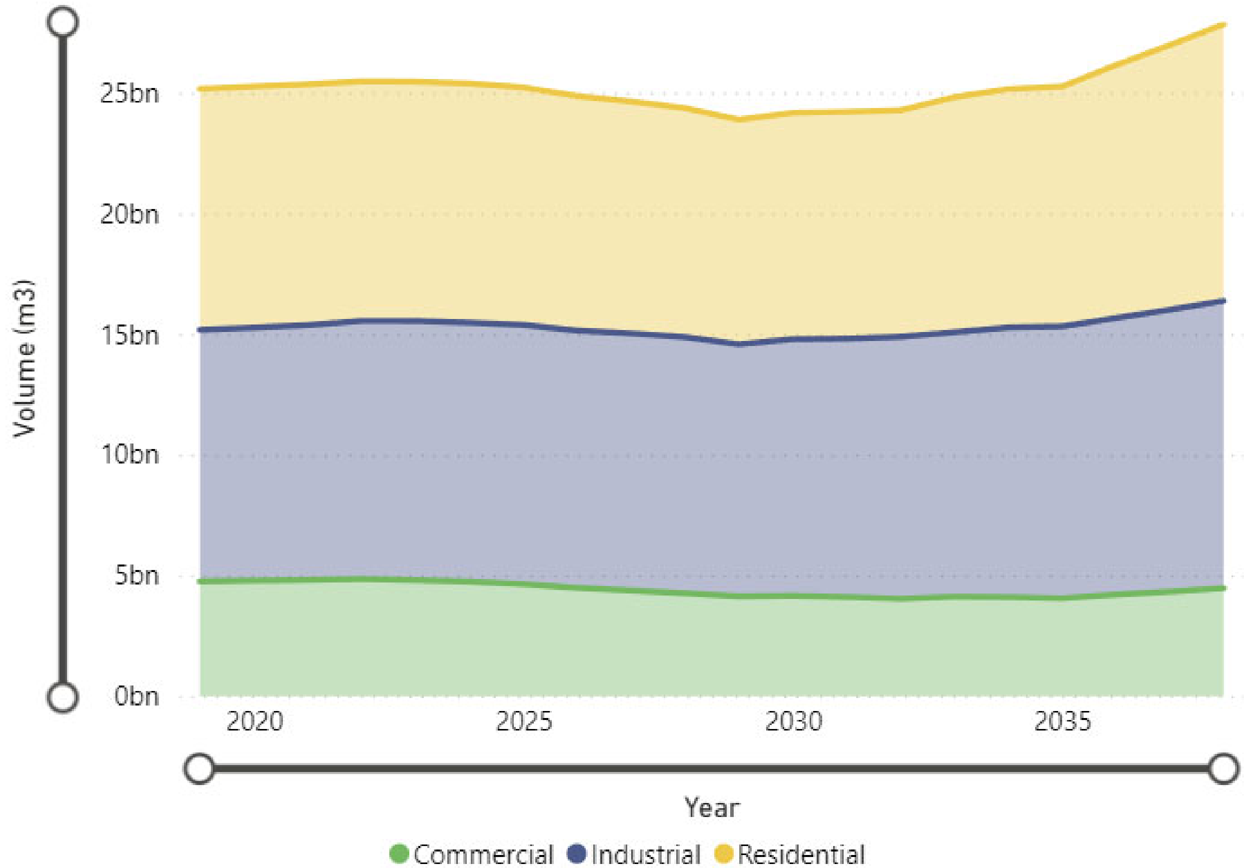
Year	Hydrogen	Natural Gas	Natural Gas with Carbon Capture	Renewable Natural Gas	**Total**
2019		25,162,555K			**25,162,555K**
2030	766,464K	20,800,872K	1,351,849K	1,248,453K	**24,167,638K**
2038	10,762,947K	11,128,731K	3,228,904K	2,722,126K	**27,842,708K**

Exhibit 49 - Diversified Portfolio Scenario: Annual Volume Composition by Fuel (%) in 2019, 2030, and 2038

Year	% H2 Volume	% Natural Gas Volume	% RNG Volume	% CCS Volume
2019	0%	100%	0%	0%
2030	3%	86%	5%	6%
2038	39%	40%	10%	11 %

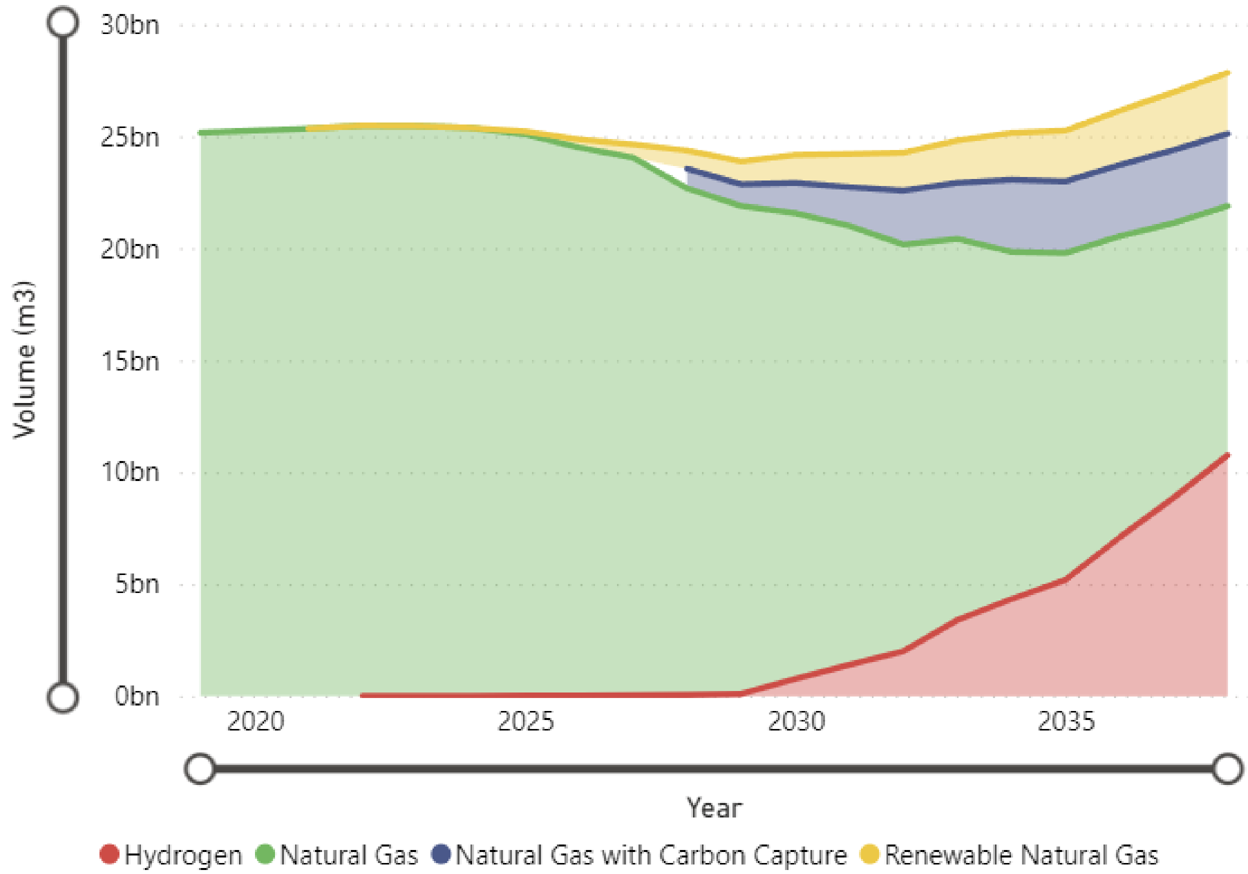
By sector, industrial and residential volume increase by about 15% by 2038, while the commercial sector decreases by 6%. Hydrogen supply is contributing to volume increases in the residential and industrial sector. Commercial sector customers are also receiving hydrogen, but there is a small overall decrease in volume resulting from codes and standards driver assumptions. While the commercial and residential sectors follow similar timeline trajectories for codes and standards changes, the impact of these changes are different. The National Energy Code for Buildings ('NECB', applicable to the commercial sector) and National Building Code ('NBC', application to the residential sector) have different savings assumptions, where improvements to commercial facilities are expected to be higher (as a percentage compared to current code) than residential improvements over the forecast period. For example, under the high stringency performance targets, the first round of upgrades for building codes occurs in 2025, where the required savings over code are 14% higher for commercial buildings compared to residential buildings. The next round of code changes in 2030 are even more significant. (Please see Appendix C for details on the assumptions for the codes and standards Critical Driver.) Exhibit 50 presents annual volume by sector.

Exhibit 50 - Diversified Portfolio Scenario: Annual volume by sector



Natural gas volume decreases by 56% by 2038 due to a combination of CDs which lower gas demand: higher carbon price and policy-driven fuel switching, high stringency codes and standards, and DSM programming. In 2038, annual volume is 40% natural gas, 39% hydrogen, 10% RNG, and 12% natural gas with carbon capture. The Diversified Portfolio scenario emphasizes "sharing the load" between fuels and working with the existing gas system to reach net zero emissions by 2050. Hydrogen, RNG, and natural gas with carbon capture all help replace natural gas in the system, largely driven by low carbon mandates. Exhibit 51 presents annual volume by fuel.

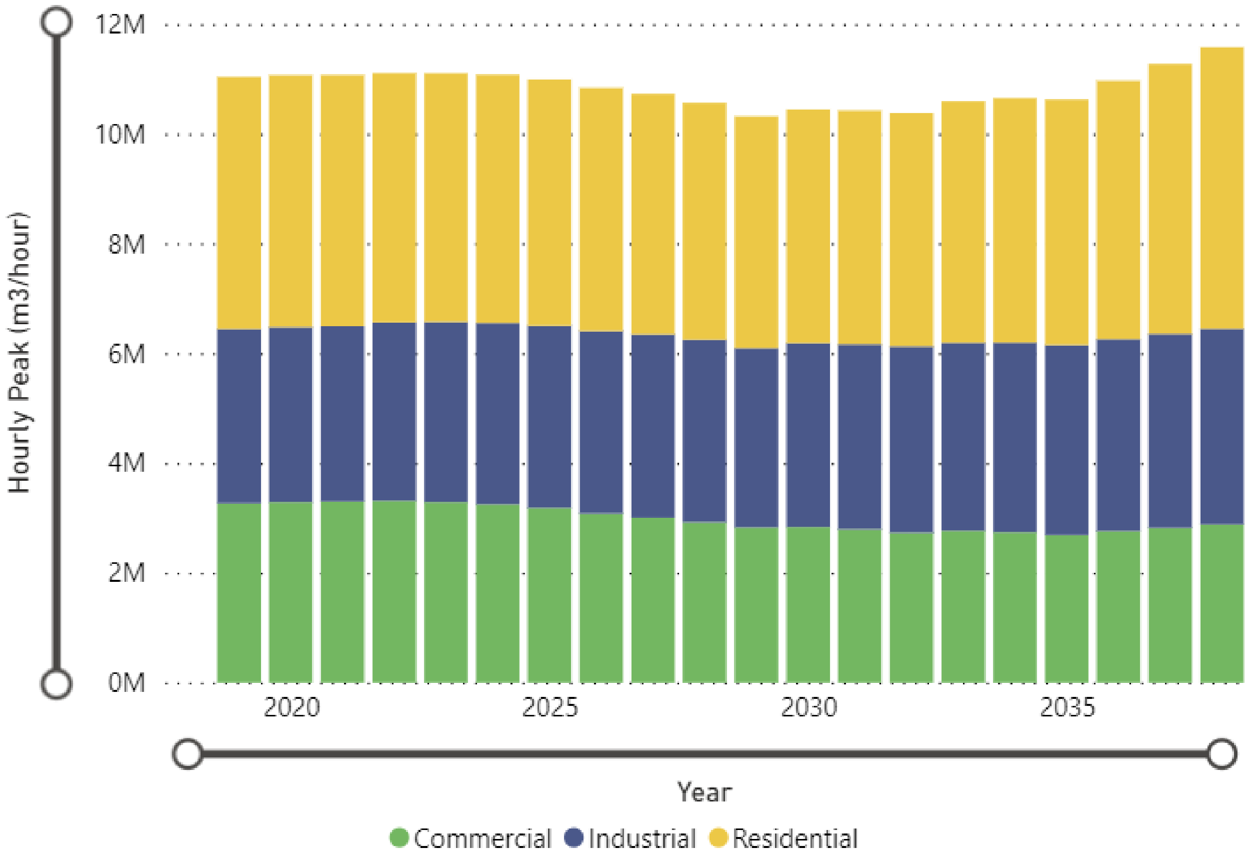
Exhibit 51 - Diversified Portfolio Scenario: Annual volume by fuel



7.3.2 Peak

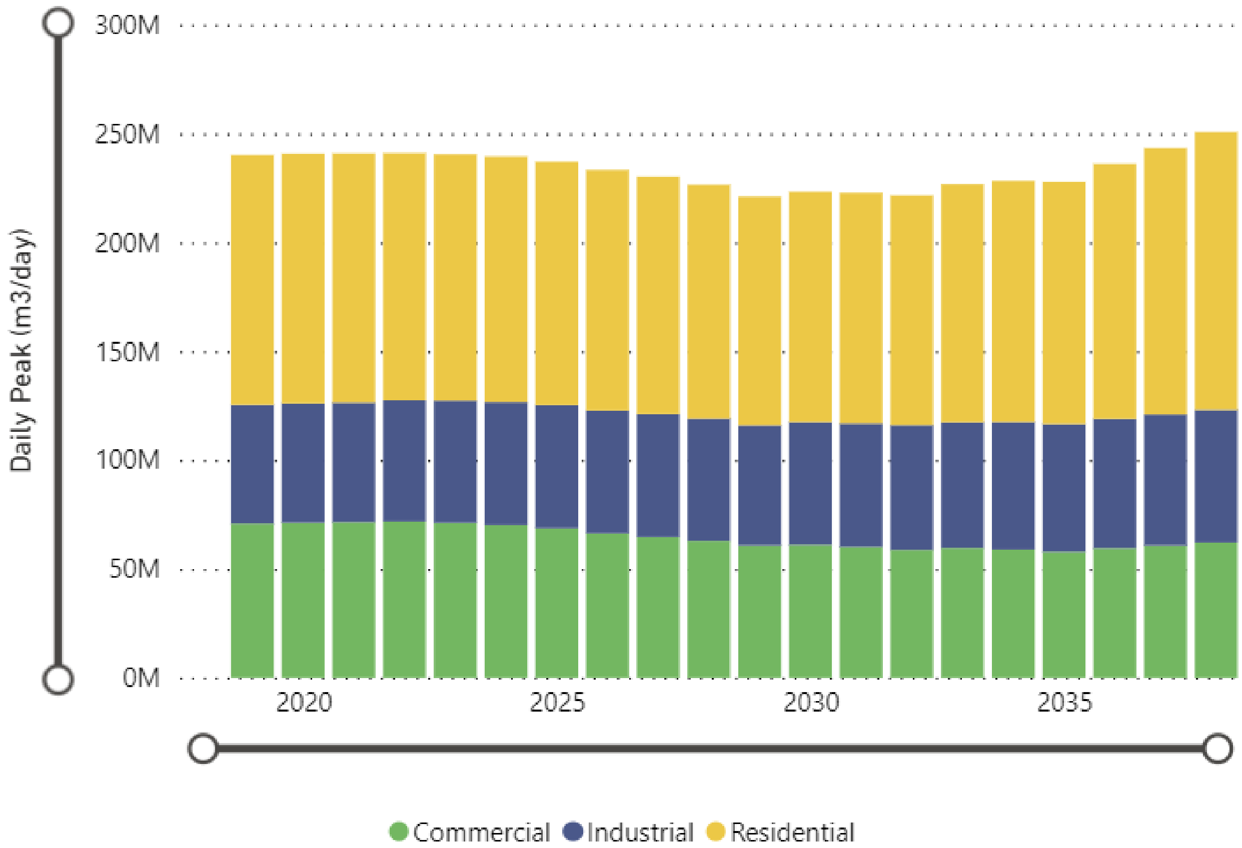
In the Diversified Portfolio Scenario, the peak hour increases by about 5% by 2038 relative to 2019, mainly caused by the uptake in hydrogen after 2030. The hourly peak increases by 12% in the industrial and residential sectors, while it decreases by 12% in the commercial sector. This is due to the increasingly stringent building codes which caused volume in the commercial sector to decrease by 2038. Exhibit 52 presents hourly peak by sector.

Exhibit 52 - Diversified Portfolio Scenario: Peak Hour by sector



The daily peak decreases by 12% in the commercial sector and increases by 12% and 11% in the industrial and residential sectors, respectively. Exhibit 53 presents peak day by sector.

Exhibit 53 - Diversified Portfolio Scenario: Peak Day by sector



7.3.3 End-User GHG Emissions

In the Diversified Portfolio scenario, end-user GHG emissions decrease by 16% by 2030 and by 53% by 2038, relative to 2019. Emissions decline as natural gas is displaced by lower-carbon gaseous fuels and carbon capture technology is deployed, and as natural gas demand lowers due to stricter codes and standards, DSM spending, and fuel switching to electricity from a higher carbon price and policies. By 2038, 94% of GHG emissions are from natural gas, and the remaining 6% are from natural gas with carbon capture. RNG emissions are small due to RNG's low end-user emission factor, and end-user emissions from hydrogen are zero. Exhibit 54 presents GHG emissions by fuel.

Exhibit 54 - Diversified Portfolio Scenario: Annual GHG emissions by fuel

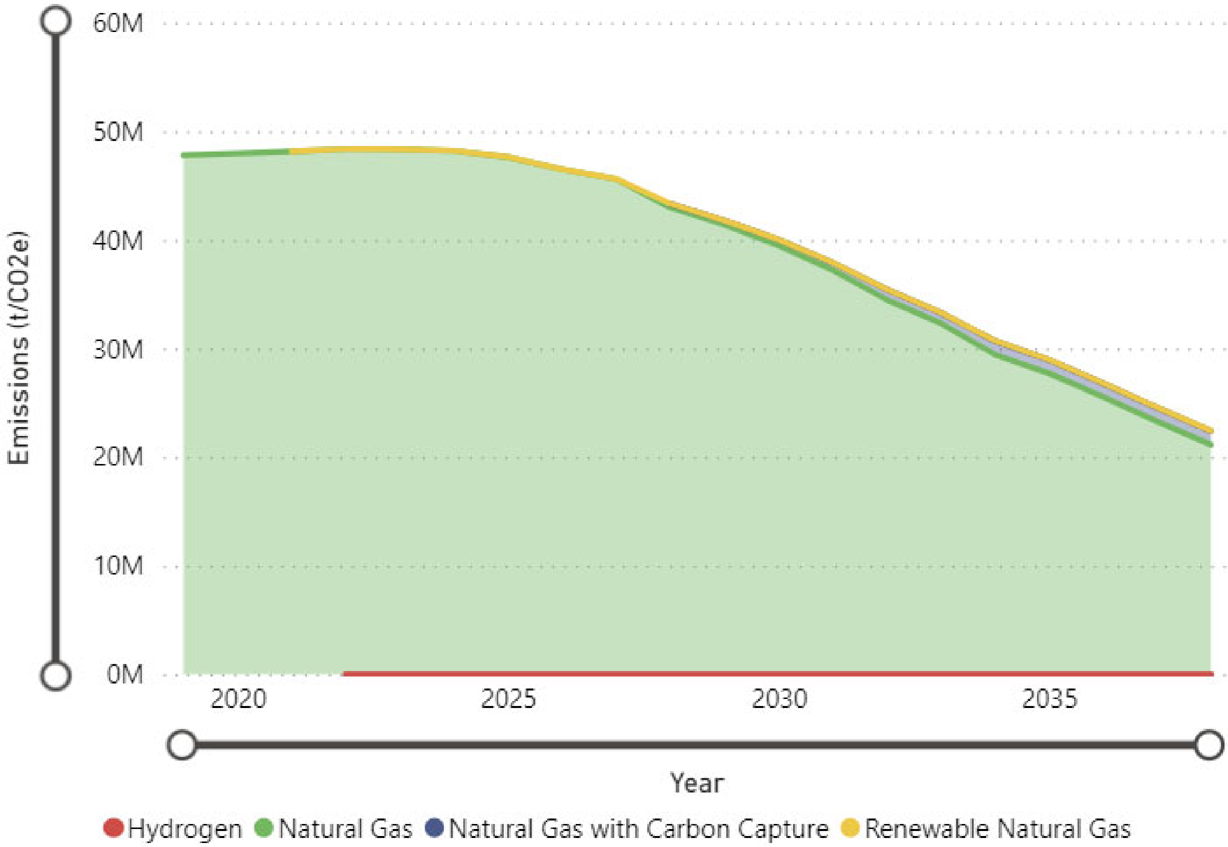


Exhibit 55 and Exhibit 56 provide GHG emissions by fuel in 2019, 2030, and 2038.

Exhibit 55 - Diversified Portfolio Scenario: GHG emissions by fuel (t/CO2e) in 2019, 2030, and 2038

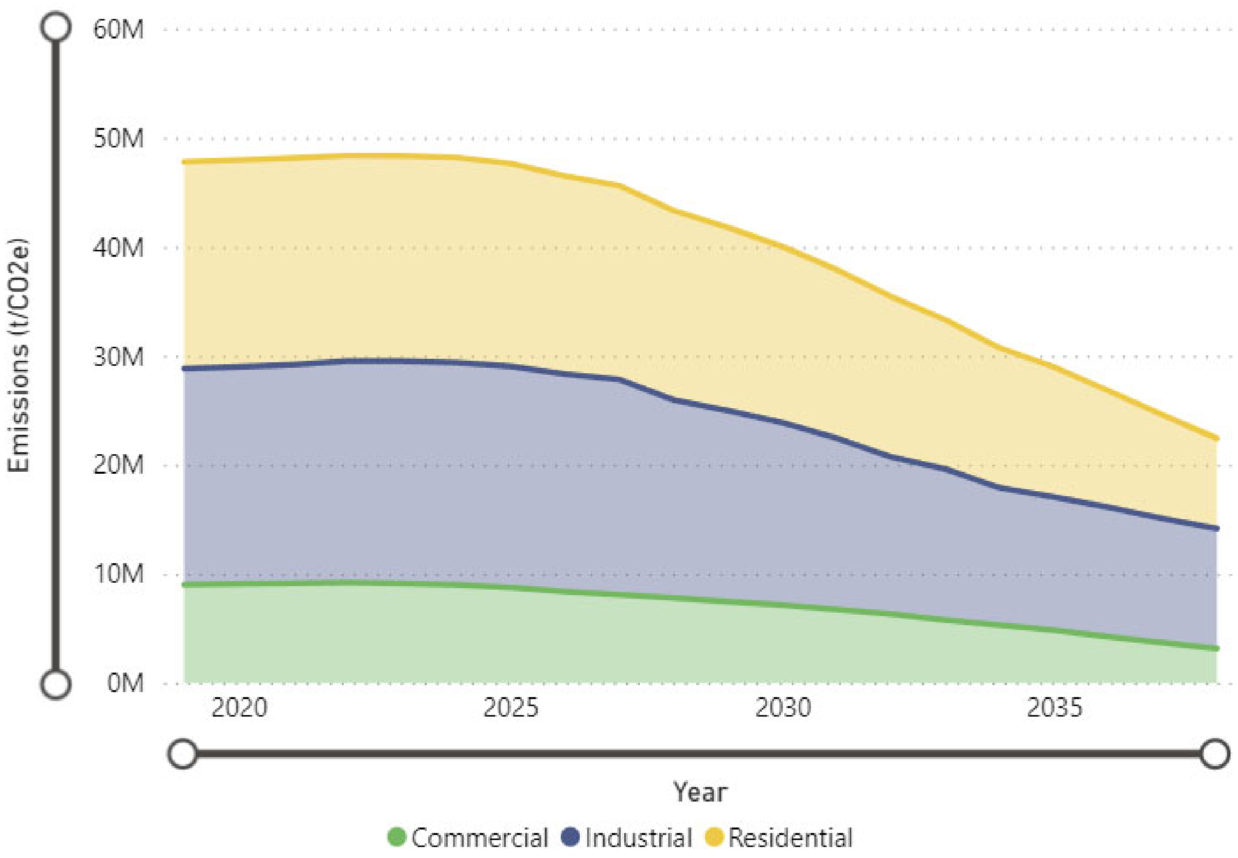
Year	Hydrogen	Natural Gas	Natural Gas with Carbon Capture	Renewable Natural Gas	**Total**
2019		47,792,623			**47,792,623**
2030	0	39,508,239	525,809	14,176	**40,048,224**
2038	0	21,137,410	1,255,898	30,910	**22,424,218**

Exhibit 56 - Diversified Portfolio Scenario: GHG emissions by fuel (%) in 2019, 2030, and 2038

Year	% H2 Emissions	% Natural Gas Emissions	% RNG Emissions	% CCS Emissions
2019	0%	100%	0%	0%
2030	0%	98.6%	0.04%	1%
2038	0%	94.3%	0.1%	5.6%

Each sector sees GHG emission decline by 2038. The commercial sector has a 65% emissions reduction, the industrial sector a 44% reduction, and the residential sector has 56% reduction. Exhibit 57 presents GHG emissions by sector.

Exhibit 57 – Diversified Portfolio Scenario: Annual GHG emissions by sector



7.4 Electricity Centric Scenario

This section summarizes results for the Electricity Centric scenario for annual volume, hourly and daily peak, and GHG emissions. The Electricity Centric scenario illustrates a pathway where GHG reductions are sought primarily from electrification. The policies assumed to achieve this pathway include the 2020

Federal Climate Action Plan, the Clean Fuel Regulation, more stringent building codes including for new construction and retrofits, as well as mandated electrification of space and water heating for new construction and existing buildings. The energy savings potential achieved through DSM programming is based on Enbridge Gas' 2021 DSM budget increasing by 3% annually from 2021 to 2027 and then by 10% annually from 2028 to 2038.

7.4.1 Annual Volume

In the Electricity Centric scenario, annual volume decreases by 22% by 2030 and by 52% by 2038 relative to 2019. Increased electrification of space and water heating, high stringency codes and standards, high carbon pricing, and high DSM spending all lower volumes of gaseous fuels.

In 2038, the annual volume is 80% natural gas, 11% RNG, and 9% natural gas with carbon capture. The amount of hydrogen is negligible. This scenario focuses on decarbonizing by investing in the electric grid rather than leveraging existing gas infrastructure. Consequently, development of hydrogen, RNG, and natural gas with carbon capture is minimal, and the annual volume is still mostly natural gas by 2038. However, the natural gas volume decreases by 62% by 2038 because of electrification. Exhibit 58 presents annual volume by fuel.

Exhibit 58 – Electricity Centric Scenario: Annual volume by fuel

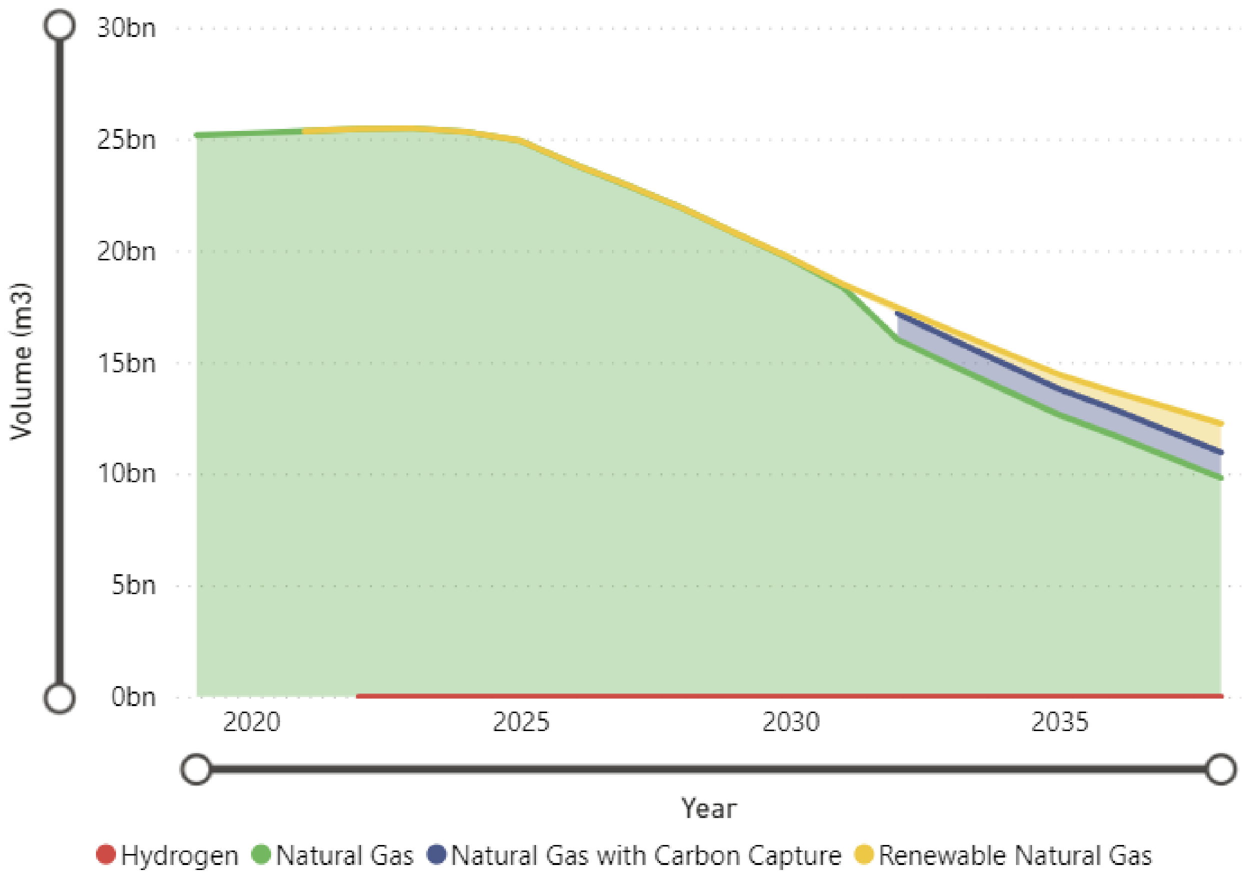


Exhibit 59 and Exhibit 60 show annual volume composition by fuel in 2019, 2030, and 2038.

Exhibit 59 - Electricity Centric Scenario: Annual Volume Composition (m^3) in 2019, 2030, and 2038

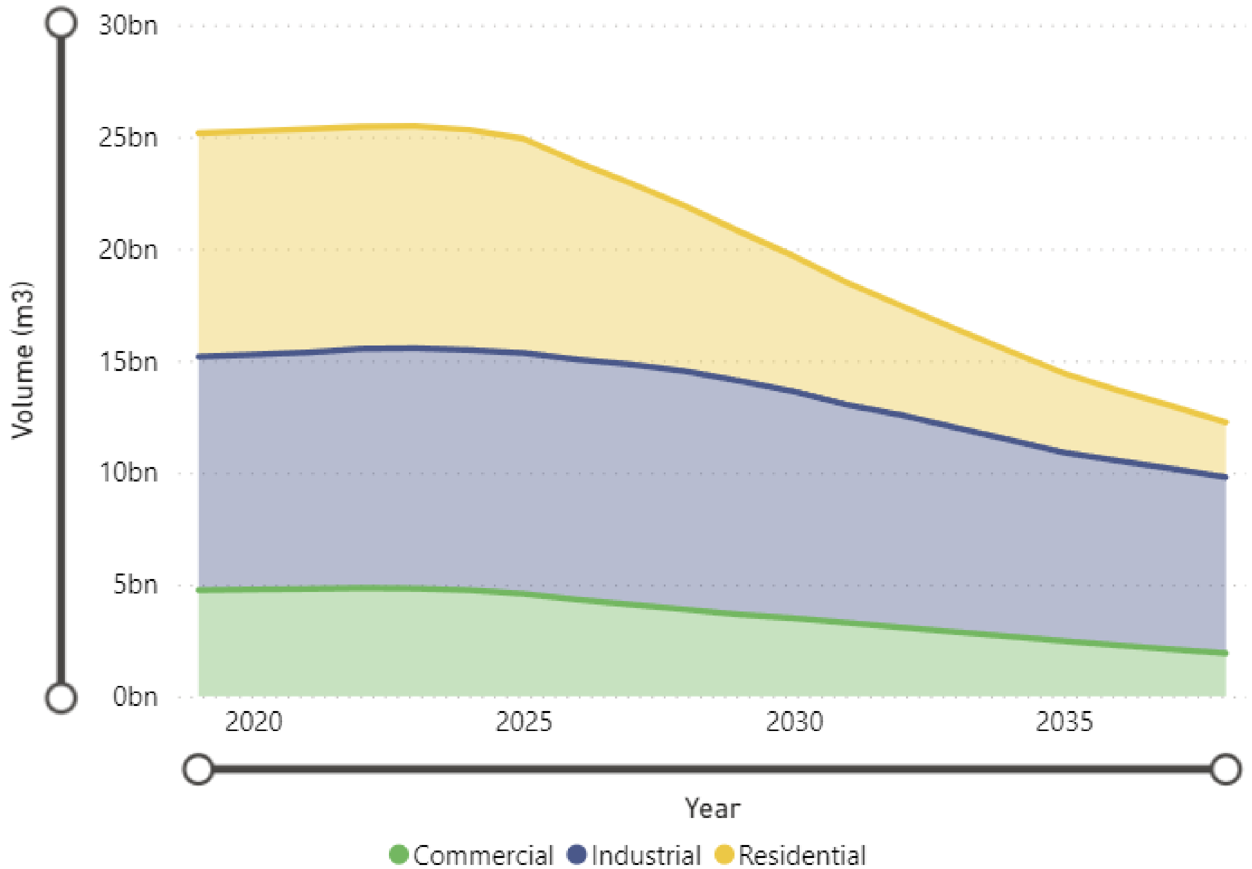
Year	Hydrogen	Natural Gas	Natural Gas with Carbon Capture	Renewable Natural Gas	**Total**
2019		25,162,554K			**25,162,554K**
2030	750K	19,564,013K		25,842K	**19,590,606K**
2038	5,362K	9,674,265K	1,146,483K	1,280,873K	**12,106,983K**

Exhibit 60 - Electricity Centric Scenario: Annual Volume Composition (%) in 2019, 2030, and 2038

Year	% H2 Volume	% Natural Gas Volume	% RNG Volume	% CCS Volume
2019	0.00%	100.00%	0.00%	0.00%
2030	<0.01%	99.86%	0.13%	0.00%
2038	0.04%	80.00%	10.59%	9.36%

By 2038, the residential sector annual volume decreases by 75% relative to 2019. The commercial and industrial sectors decrease 60% and 26%, respectively. In this scenario, new residential and commercial construction do not connect to the gas grid and existing space and water heating end-uses in these sectors are mandated to electrify as end-of-life equipment is replaced. In the Industrial sector, some end-uses switch to electricity when replaced. Exhibit 61 presents annual volume by sector.

Exhibit 61 - Electricity Centric Scenario: Annual volume by sector

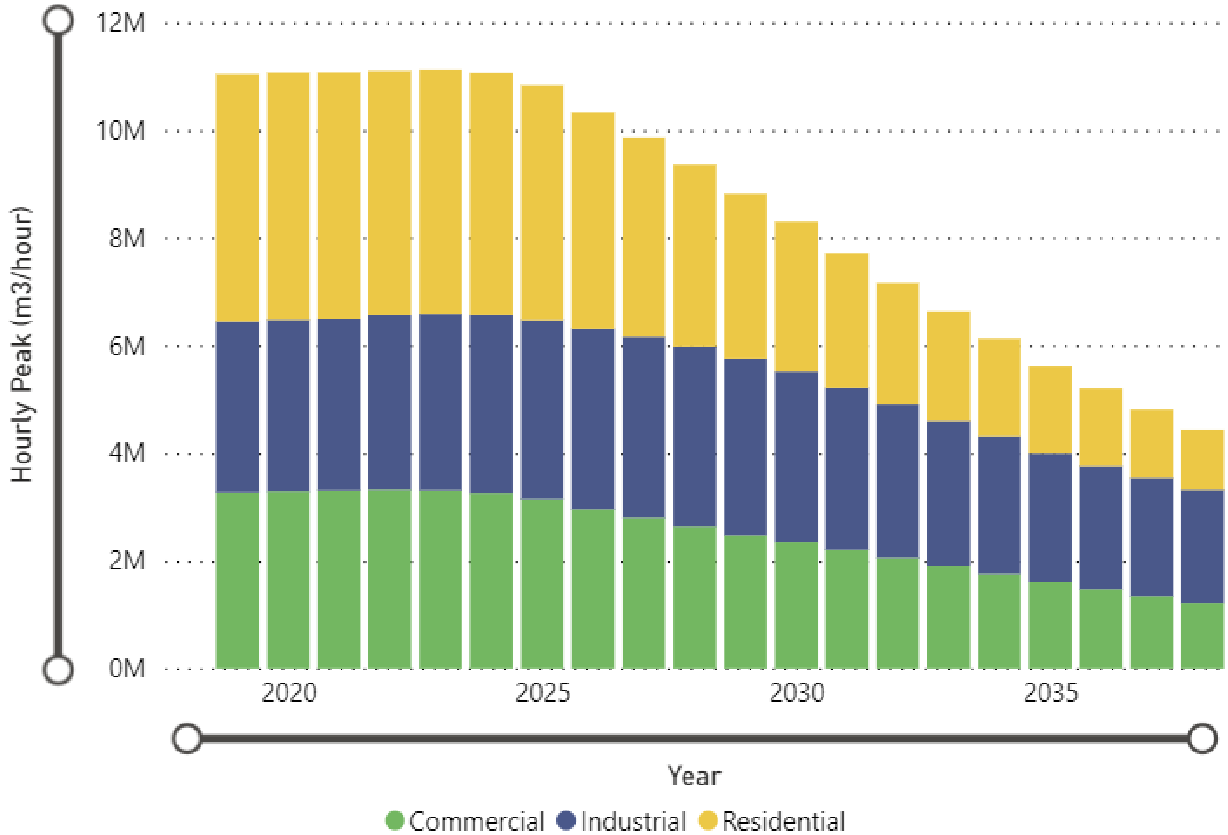


7.4.2 Peak

In the Electricity Centric scenario, hourly peak decreases by 25% by 2030 and by 60% by 2038 relative to 2019. The daily peak decreases by 28% by 2030 and by 62% by 2038 relative to 2019. Widespread electrification and a reduction of new customers connecting to the gas grid decreases peak across the sectors like the annual volume decrease.

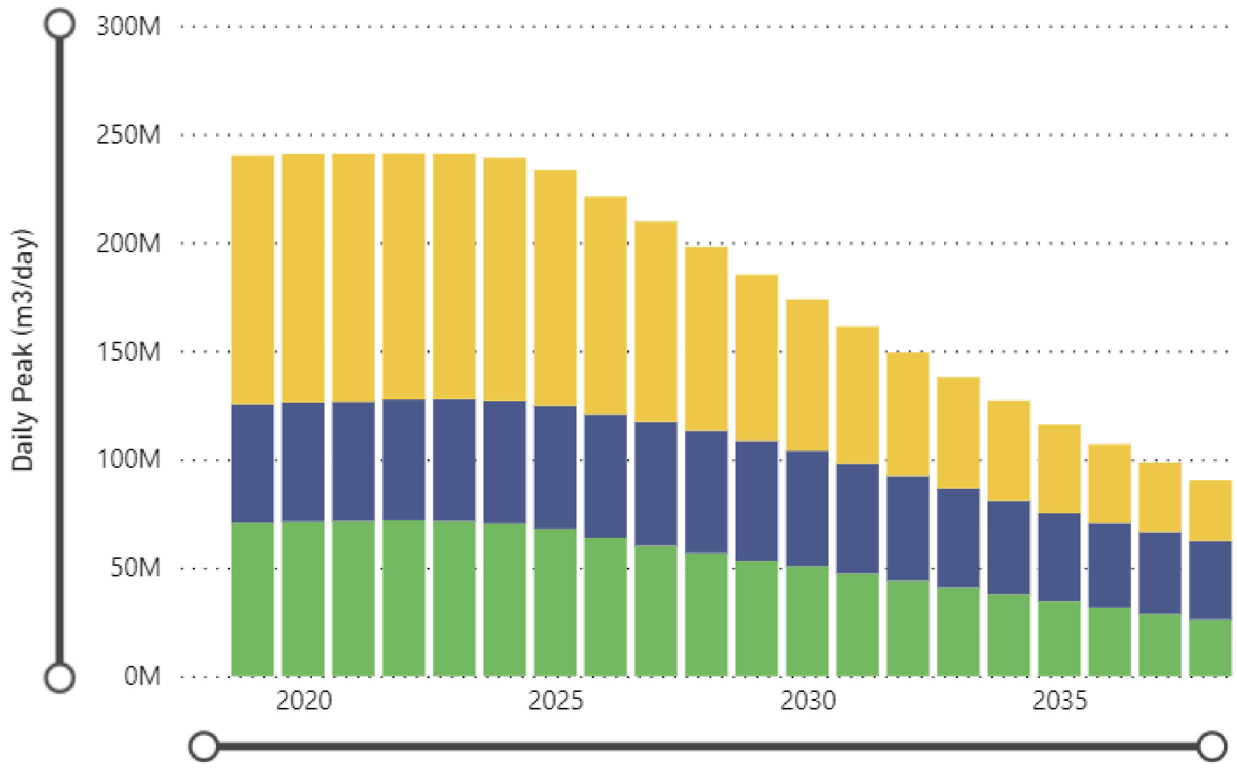
The industrial hourly peak decreases by 35% by 2038. The commercial and residential hourly peaks decrease by 62% and 76%, respectively, by 2038. Exhibit 62 presents hourly peak by sector.

Exhibit 62 - Electricity Centric Scenario: Peak Hour by sector



The industrial daily peak decreases by 34% by 2038. The commercial and residential daily peaks decrease by 63% and 76%, respectively, by 2038. Mandated electrification of space and water heating reduces the commercial and residential daily peaks. Exhibit 63 presents daily peak by sector.

Exhibit 63 - Electricity Centric Scenario: Peak Day by sector



7.4.3 End-User GHG Emissions

In the Electricity Centric scenario, GHG emissions decrease by 22% by 2030 and by 61% by 2038, relative to 2019. Carbon price and policy driven electrification has a meaningful impact on these reductions, while code driven energy efficiency and DSM incentives also reduce emissions from gaseous fuels. Exhibit 64 and Exhibit 65 present GHG emissions by fuel in 2019, 2030, and 2038.

Exhibit 64 - Electricity Centric Scenario: GHG emissions by fuel (tCO2e) in 2019, 2030, and 2038

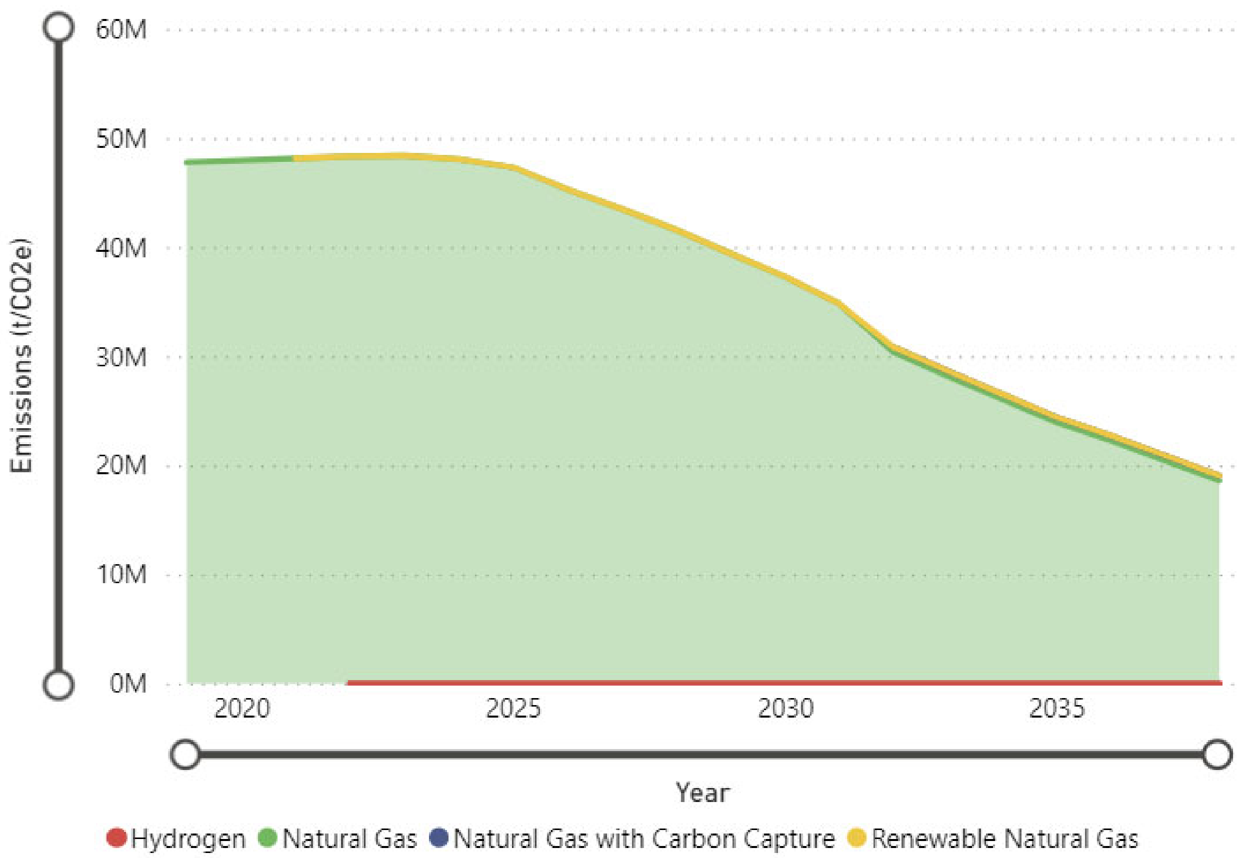
Year	Hydrogen	Natural Gas	Natural Gas with Carbon Capture	Renewable Natural Gas	**Total**
2019		47,792,622			**47,792,622**
2030	0	37,271,048		294	**37,271,342**
2038	0	18,573,790	445,930	14,698	**19,034,418**

Exhibit 65 - Electricity Centric Scenario: GHG emissions by fuel (%) in 2019, 2030, and 2038

Year	% H2 Emissions	% Natural Gas Emissions	% RNG Emissions	% CCS Emissions
2019	0.00%	100.00%	0.00%	0.00%
2030	0.00%	100.00%	<0.01%	0.00%
2038	0.00%	97.58%	0.08%	2.34%

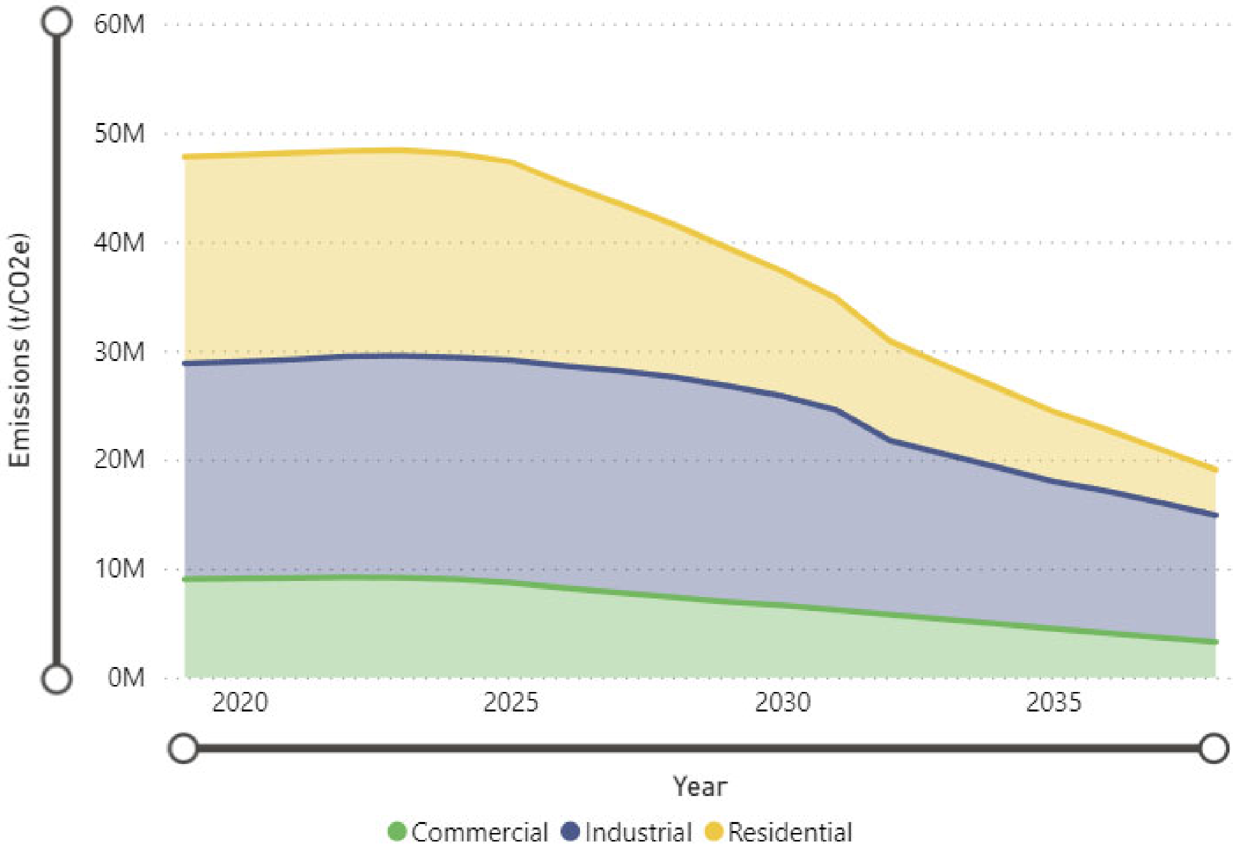
In 2038, 98% of GHG emissions are from natural gas while the remaining 2% are from natural gas with carbon capture. RNG, hydrogen and natural gas with carbon capture have minimal impact on GHG emissions due to low uptake in this scenario and low emission factors. GHG emissions reduce sharply largely because of reduction in gaseous fuel volume. Exhibit 66 presents annual GHG emissions by fuel.

Exhibit 66 - Electricity Centric Scenario: Annual GHG emissions by fuel



By 2038, industrial sector GHG emissions decrease by 43%. Commercial and residential sector GHG emissions decrease by 64% and 78%, respectively. The focus on commercial and residential electrification reduces GHG emissions substantially in these two sectors. Electrification of HVAC end-uses and an end to gas-fired power generation by 2035 in the industrial sector cause reductions in the industrial reductions. Exhibit 67 presents GHG emissions by sector.

Exhibit 67 – Electricity Centric Scenario: Annual GHG emissions by sector



7.5 Comparison of All Scenarios

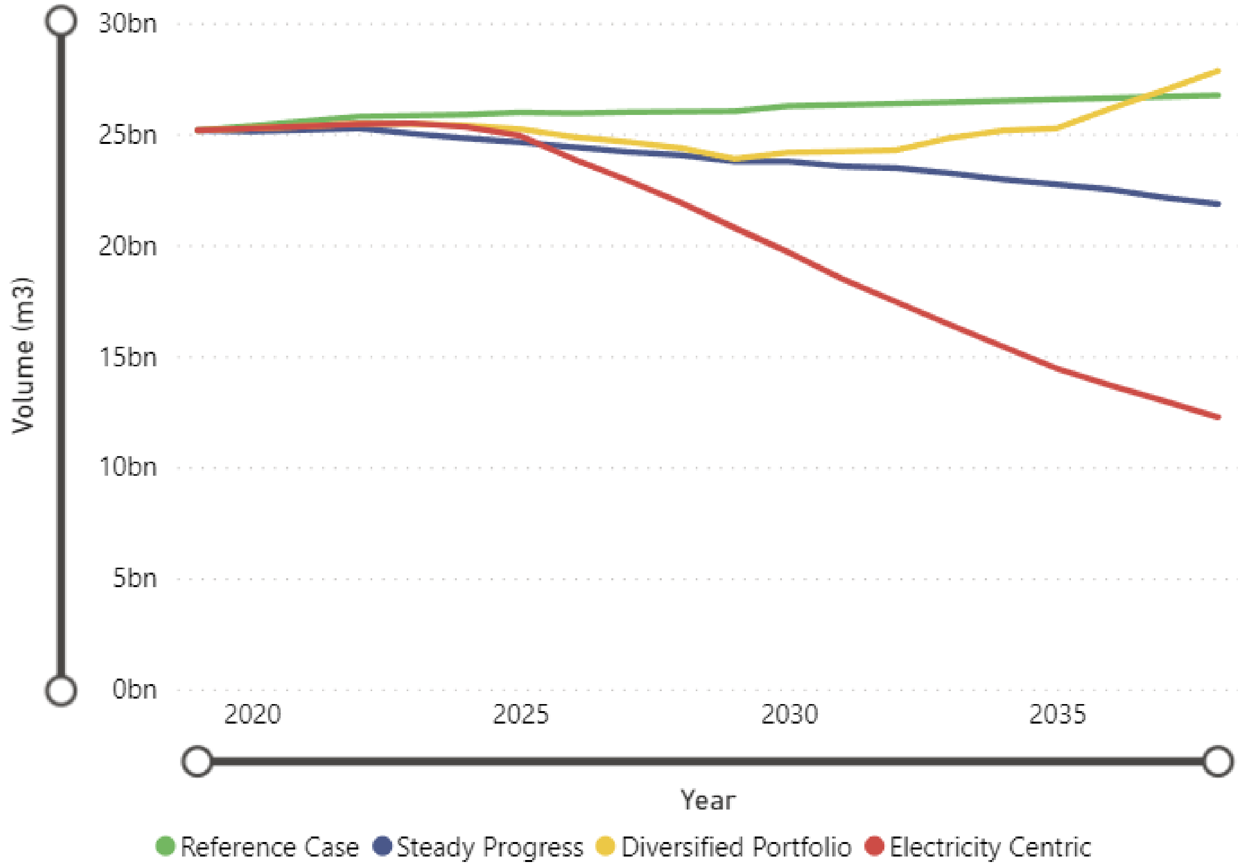
This section provides a high-level comparison of the scenarios in terms of annual volume, peak load and GHG emissions.

7.5.1 Annual Volume

By 2038, the Diversified Portfolio scenario has the greatest volume because it has the most hydrogen, which is driven by low carbon gas mandates and enhanced support for deployment of hydrogen[22]. The Electricity Centric scenario has the lowest volumes starting in 2025 as space and water heating end-uses switch to electricity. The Reference Case has steadily increasing volumes, while the Steady Progress scenario shows a slow decline in volume due to a higher carbon price, the implementation of more stringent building codes and equipment standards, and a higher DSM budget relative to the Reference Case. Exhibit 68 presents annual volume for all scenarios.

[22] The volumetric energy density of hydrogen was captured in the model: blending hydrogen increases annual volume (m^3) even if energy demand (PJ) remains the same.

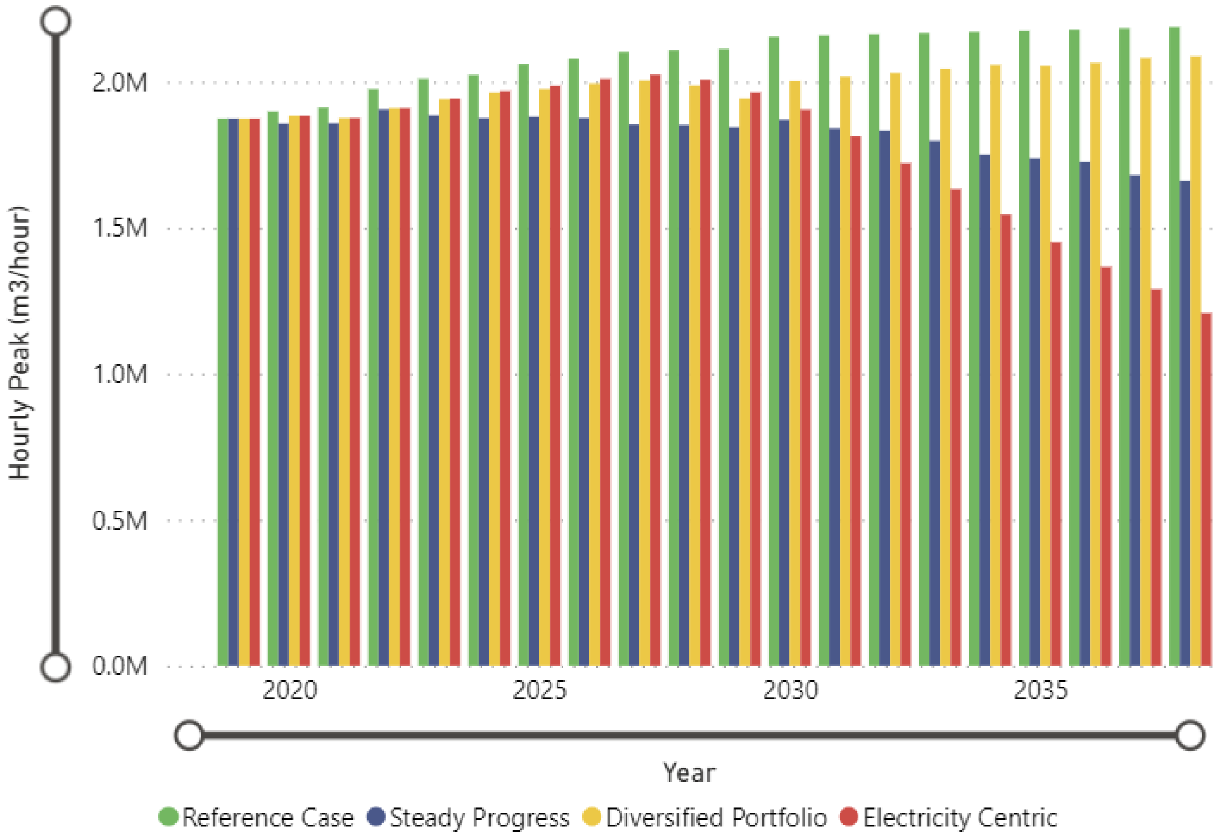
Exhibit 68 – Scenarios Comparison: Annual Volume



7.5.2 Peak

The Reference Case has the highest hourly peak as it is the scenario with the lowest DSM spending and the least stringent policy mechanisms to increase energy efficiency or encourage fuel switching. The Electricity Centric scenario has the lowest hourly peak by 2031 as equipment and buildings electrify. The hourly peak also decreases in the Steady Progress scenario due to more stringent building codes and equipment standards which lower heating loads. For all scenarios, DSM programming impacts peak when measures are applied that reduce peaks. Exhibit 69 presents hourly peaks for all scenarios.

Exhibit 69 - All Scenario Comparison: Hourly Peak



Trends in daily peak across the scenarios match trends in hourly peak discussed above. The Diversified Portfolio scenario daily peak is significantly higher than the Electricity Centric scenario daily peak. Exhibit 70 presents daily peaks for all scenarios.

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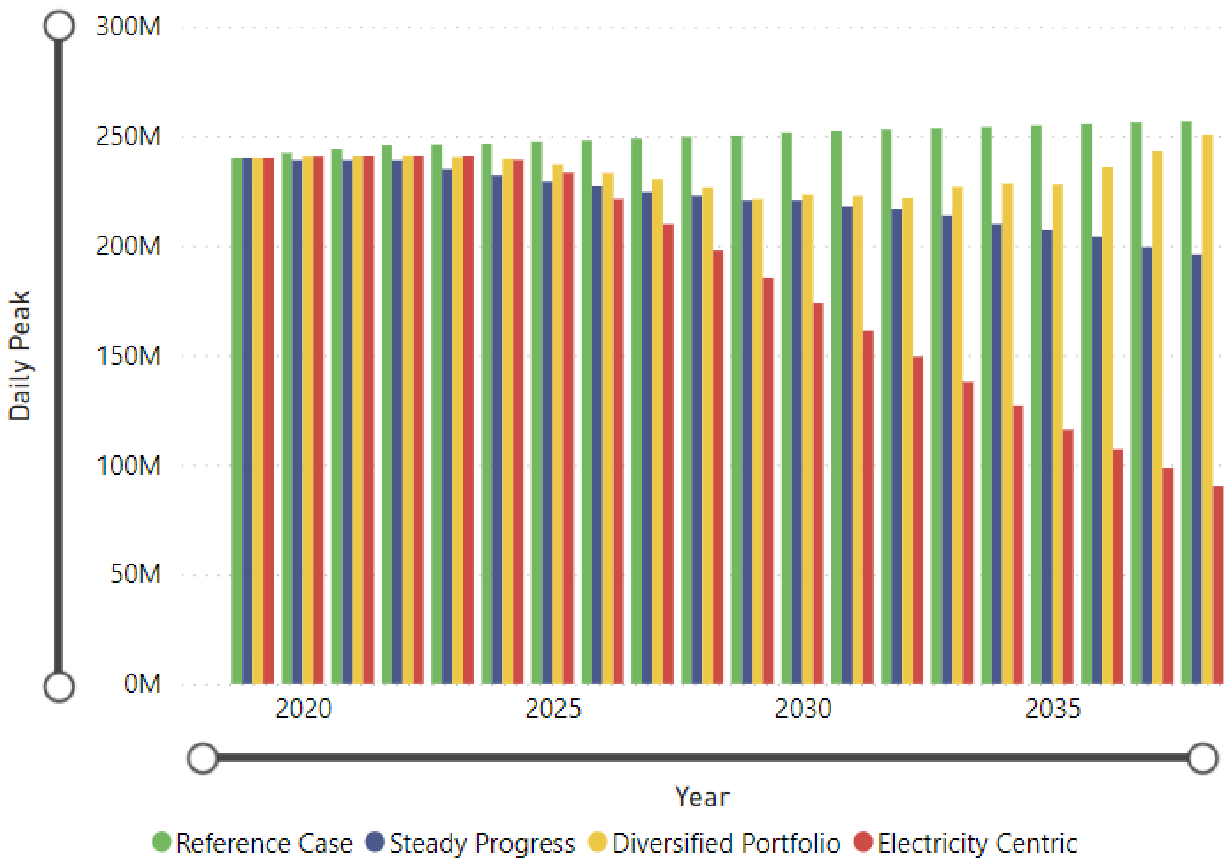
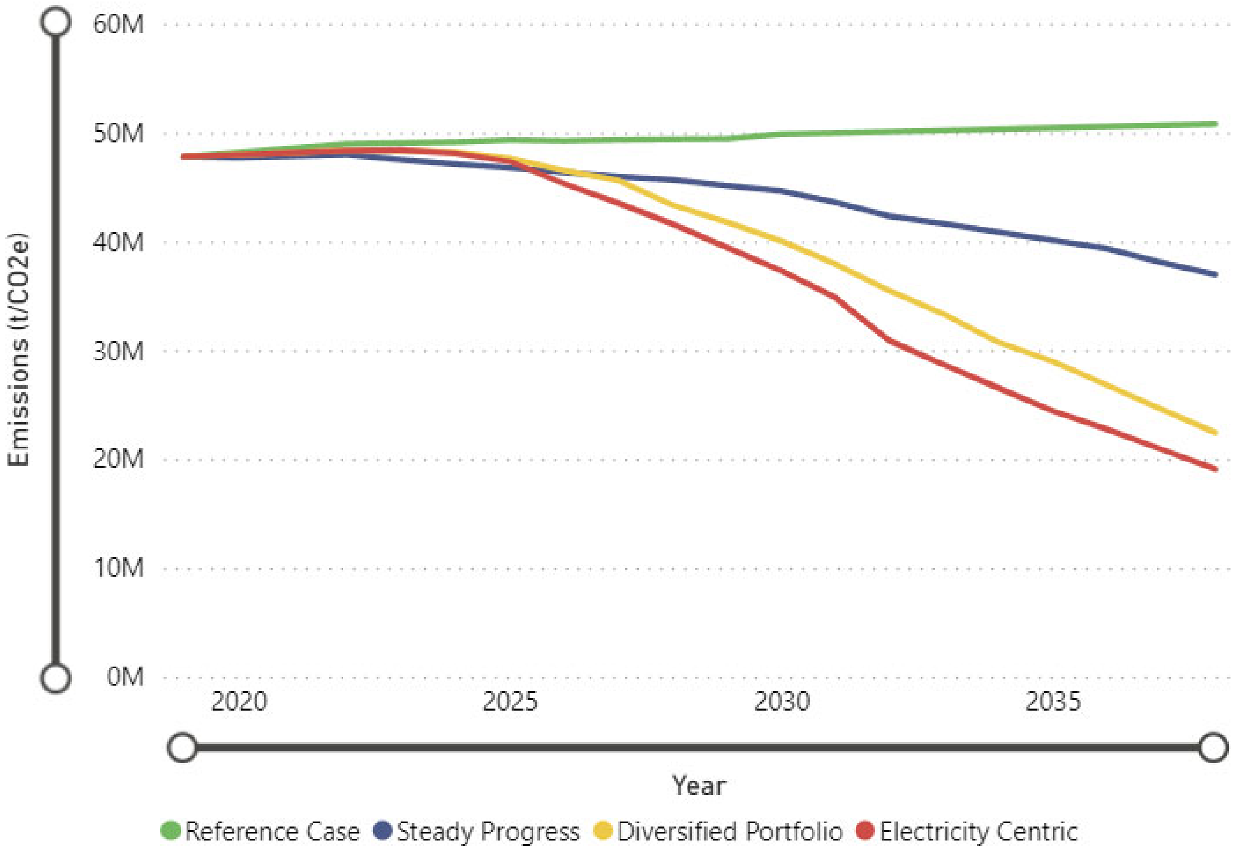
Exhibit 70 - All Scenario Comparison: Daily Peak



7.5.3 End-User GHG Emissions

Emissions trend differently than annual volumes in the scenarios due to the varying uptake of RNG, hydrogen, and natural gas with carbon capture. The Electricity Centric scenario has the lowest GHG emissions, followed by the Diversified Portfolio scenario. The high levels of hydrogen in the Diversified Portfolio scenario cause GHG emissions to decline (hydrogen has zero end-user GHG emissions for Enbridge Gas' system) while GHG reductions in the Electricity Centric scenario are from lower gas demand as the province electrifies. The Reference Case has the highest GHG emissions because almost all the annual volume is met with natural gas, and volume is not curtailed from codes and standards, a higher carbon price or policies to encourage fuel switching. Exhibit 71 displays the GHG emissions for each scenario.

Exhibit 71 – Scenarios Comparison: GHG Emissions



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Appendix A ETSA Reference Case Data Inputs and Modelling Method

The objectives of this appendix are to identify the data sources used to develop the model of energy demand for the ETSA project and explain how the data was used to create the ETSA Reference Case. This document is organized by sector and complements the model output files that contain the data from the load forecast.

Introduction

Context on the forecasts developed under the Energy Transition Scenario Analysis project

Posterity Group (PG) worked with Enbridge Gas Inc. (EGI) to create two forecasts that draw on elements of the 2019 Ontario Achievable Potential Study (APS) Reference Case:

1. **Adjusted APS Forecast:** First, we disaggregated Enbridge Gas' 2019 actual consumption ("actuals") values into the APS segments and end-uses. Then, we applied the region- and segment-based growth rates used in the APS to the 2019 base year data. The purpose of this exercise was to "ground" the 2019 data in the APS with the most recent actuals from EGI, while maintaining the APS segments and trends in consumption growth. This forecast was developed for Enbridge Gas to compare the APS trends in consumption growth to their more up-to-date internal forecasts and was not used for subsequent analysis for the Energy Transition Scenario Analysis (ETSA) project.
2. **ETSA Reference Case:** Starting with the 2019 base year described above, we created another forecast using Enbridge Gas' 2020 (the most recent) forecasts of customer accounts and gas consumption. PG took the Enbridge Gas volume and account forecasts and disaggregated them into the segments and end-uses in the APS. The reason for creating this forecast was to make reviewing the impacts of CDs on the Reference Case and the alternate scenarios more reflective of Enbridge Gas' current corporate forecasts. This is the Reference Case dataset that was used for the parametric analysis and scenario modelling for the ETSA project, hence why it is called the "ETSA Reference Case".

As the ETSA Reference Case is used for subsequent analysis in the project, this document focuses on how this forecast was developed.

Visibility into Input Assumptions

PG has limited visibility into the underlying assumptions of the APS Reference Case, as it was developed by another contractor and the inputs were provided by the IESO and Legacy Union and Enbridge Gas utilities. We can make some estimates as to what assumptions are used for some inputs based on when the APS Reference Case was developed (~2017-2018) and based on the dataset we received. Publicly available information on the data sources used to develop the APS Reference Case is provided in Appendix B..

PG took Enbridge Gas' 2020 account and consumption forecast and provided some information about the assumptions used to develop these forecasts, which are supplied at the end of this appendix.

Model Validation Relative to Enbridge Gas' Volume Forecast

Enbridge Gas provided a forecast of consumption by rate class and sector from 2021-2030, which was used to calibrate PG's model. Due to misalignment of customer categorization in Enbridge Gas' forecasting system compared to the base year data, there is some minor variance in total consumption. A comparison of all-sector consumption from 2021-2030 is presented in the Exhibit 82 below, with the right column presenting the difference between the two.

Exhibit 72 - Consumption Forecast Differences between PG and Enbridge Gas Models

	PG Model (billion m3)	Enbridge Gas Volume Forecast (billion m3)	Deviation
2021	25.6	25.5	0.1%
2022	26.0	25.9	0.2%
2023	26.2	26.2	0.2%
2024	26.4	26.4	0.2%
2025	26.6	26.6	0.3%
2026	26.8	26.7	0.3%
2027	27.0	26.9	0.4%
2028	27.2	27.0	0.4%
2029	27.3	27.1	0.5%
2030	27.6	27.4	0.6%

At the segment and rate class level, there exist some smaller deviations from the Enbridge Gas volumes forecast for two reasons:

1. Enbridge Gas' forecasting system uses a different disaggregation of apartment, commercial, and industrial accounts than is used in the base year data. One example of this is the forecast for Enbridge Gas' rate 6, where the volumes forecast has a different percent share of apartments, commercial accounts, and industrial accounts than exists in the base year data. To resolve this, the PG model was calibrated to the year-over-year growth rate, rather than absolute volumes within each subcategory.
2. PG's model changes the energy intensity of accounts within a given segment of accounts in each region. When two rate classes with different per-account consumption forecasts exist in the same segment, such as LEG rates 6 and 110 in the multi-family residential sector, the segment is grown by the weighted average of the rates classes that compose it. This does not affect overall volumes but results in minor deviations from one rate class to another.

Residential Sector

Residential Base Year

The first year of the study period, the "base year" for the ETSA project is 2019.

The residential sector model relies on three key sources: Enbridge Gas account data, data from the 2019 APS, and Enbridge Gas' Residential End-Use Study. Given that multi-family residential is in the residential, rather than commercial sector, the LEG and LUG commercial accounts labelled "Multiresidential" and "Multiresidential Units" were added to the single-family residential accounts.

Accounts

- Enbridge Gas' account data has fields titled "House Type" and "Sector" which contain information about the building type. They were mapped to the segments of the APS which removed some granularity about building type but was necessary to ensure that the detailed measure specification files used for DSM planning continue to function. See Exhibit 73 for details.

Exhibit 73 - Residential Segment Matching between Enbridge Gas and the ETSA Model

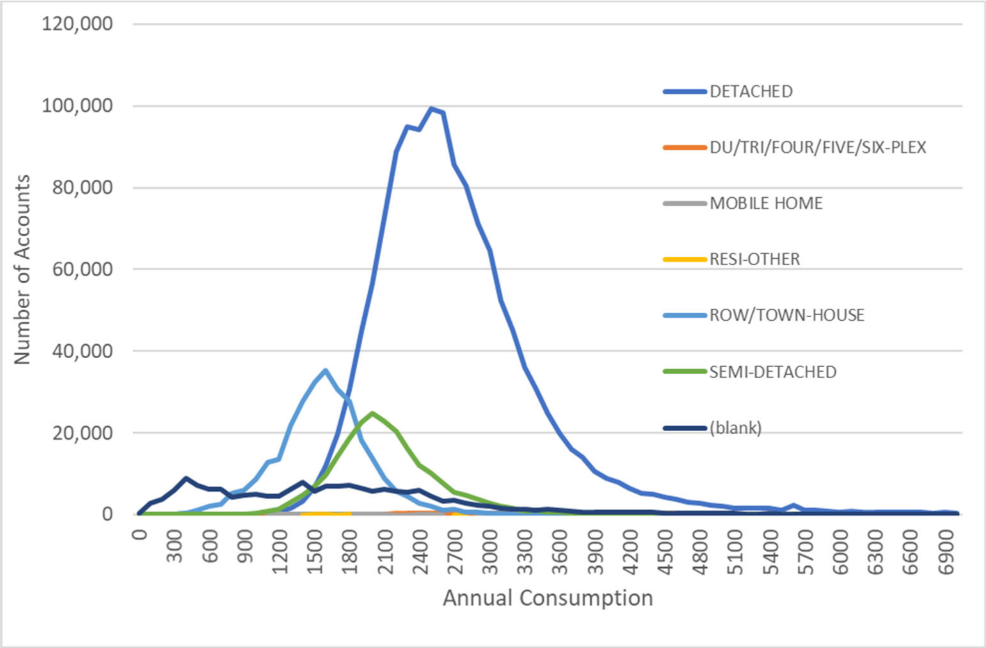
Enbridge Gas Segment	ETSA Model Segment
DETACHED	Detached House and Low-Income SF
DU/TRI/FOUR/FIVE/SIX-PLEX	Attached or Row House and Low-Income SF
DUPLEX RESIDENCE	Attached or Row House and Low-Income SF
MOBILE HOME	Detached House and Low-Income SF
MULTIRESIDENTIAL	Multi-Res, High Rise, Low Rise, and Low-Income
MULTIRESIDENTIAL UNITS	Multi-Res, High Rise, Low Rise, and Low-Income
QUAD/FOUR-PLEX RESIDENCE	Attached or Row House and Low-Income SF
RESIDENTIAL POOL[23]	Detached House and Low-Income SF
RESI-OTHER	Detached House and Low-Income SF
ROW/TOWN-HOUSE	Attached or Row House and Low-Income SF
ROW/TOWNHOUSE COMPLEX	Attached or Row House and Low-Income SF
ROW/TOWNHOUSE UNIT	Attached or Row House and Low-Income SF
SEMI-DETACHED	Attached or Row House and Low-Income SF
SINGLE DETACHED RESIDENCE	Detached House and Low-Income SF
TRI-PLEX RESIDENCE	Attached or Row House and Low-Income SF
(blank)	Attached or Row House, Detached, and Low-Income SF

- The number of accounts in 2019 was provided by postal code by EGI. Postal codes were used to assign accounts into gas and IESO planning regions.

[23] Residential pool and resi-other were added to the detached house category. These categories represent 150 out of 3.46 million accounts; their mapping to an APS segment is not consequential.

- There were about 8,000 accounts in the Niagara IESO zone whose postal codes were in the lookup table twice, once for EGD-GTA and once for EGD-NIAGARA. A significant majority of these were in the vicinity of Niagara-On-The-Lake, thus it was assumed that EGD-NIAGARA is the correct gas zone, not EGD-GTA.
- Missing segment information: there were 177,000 LEG residential account with no information in the "house type" field. These accounts were relatively small; in 2019 they had an average consumption of 1,900 m3. This consumption corresponds to a size somewhere between that of detached and attached house. Therefore they were assigned to these categories in proportion. For example, if the average rate 1 annual consumption in a certain region for detached, attached, and unlabeled was 3,000, 2,000, and 2,300, the unlabeled houses were assumed to be 70% attached and 30% attached. The distribution of account sizes is presented in the Exhibit 74 below.

Exhibit 74 - Distribution of Residential Enbridge Gas Account Sizes



- Missing rate information: there were about 4,000 accounts in the LUG Res dataset with missing rate class information, labelled as "TotRes". These were distributed to rates 01 and M1 based on each rate's share of detached and attached houses in that region. For example, if there were 100 detached houses labelled "TotRes", and 90% of the other detached houses in that region were in rate class 01 and 10% in M1, 90% of the "TotRes" houses were assigned to 01 and 10% to M1.
- Disaggregating Low-Income: the share of dwellings and consumption that are low-income in the APS were calculated for each gas region. The fractions were then removed from the SF and MF segments of each rate. For example, if low-income houses are 30% of the single-family dwellings in Union-North, and there are 100 detached and 10 attached houses in rate 01, this is changed to be 70 detached, 7 attached, and 33 low-income houses in rate 01 for

this region. The low-income segment is a lower fraction of consumption than dwellings, thus the resulting estimate for consumption per account is lower.

- Disaggregating Multi-Res Low-rise and High-rise: these two segments were split apart on a case-by-case basis for each region. Larger rate classes were assigned to high-rise, smaller-rate classes were assigned to low-rise, and rate classes in the middle were split apart so that the ratio of high- and low-rise consumption is roughly equal to that in the APS. In rate classes that were split into both segments, the accounts were divided so that the high-rise accounts are roughly twice as large as the low-rise accounts.

Units

- Units in the residential model are dwellings.
- For attached, detached, and low-income SF, each account is assumed to have one dwelling.
- For multi-residential high-rise, low-rise, and low-income, the number of gas-connected dwellings (as opposed to accounts) is taken from the APS base year data. Units were split into rate classes based on consumption within those rate classes. For example, if the APS said there are 10,000 high-rise dwellings in a region, and 70% of the estimated high-rise consumption in that region was rate 6, this rate would receive 7,000 units.
- For new construction, the number of units per account was set to equal that of existing accounts.

Unit Energy Consumption and Fuel Share

- UECs were estimated by using the natural gas end-use shares from the 2019 APS and the appliance penetrations from Enbridge Gas' 2019 residential end-use survey.
- The average end-use shares for each segment are presented below in Exhibit 85. These were calibrated by region in the 2019 APS, so they vary slightly by gas region. The consumption of natural gas for each end-use was estimated by multiplying the total consumption within that segment by the end-use share.

Exhibit 75 - Residential End-Use Shares by Segment

Segments	Cooking	Misc Residential	Space Heating	Washing/Drying Appliances	Water Heating
Attached / Row House	1%	7%	77%	1%	14%
Detached House	1%	9%	75%	1%	13%
Low Income, MF	2%	2%	55%	4%	37%
Low Income, SF	1%	5%	78%	2%	14%
Multi-Res, High Rise	1%	1%	71%	2%	24%
Multi-Res, Low Rise	1%	1%	71%	2%	24%

- Unit energy consumption for gas appliances was then estimated by dividing the estimate for end-use consumption by the number of dwellings in that segment and region and the rate of natural gas penetration for that end-use among Enbridge Gas' customers. The results of the single-family residential end-use survey were used as a proxy for the entire residential sector; the penetration rates are presented below in Exhibit 76. Note that the choice of fuel shares does not affect end-use consumption in the model (determined solely by the consumption forecast and end-use shares) but does place a limit on the amount of fuel switching to/from natural gas that can take place.

Exhibit 76 - Penetration Rates of Residential Gas Appliances

	Legacy Enbridge	Legacy Union
Washing/Drying Appliances	13%	20%
Cooking	30%	29%
Water Heating	83%	80%
Space Heating	97%	95%
Misc Residential	50%	50%

- Base year UECs for each segment in each region were then set using the following equation:

$$UEC = \frac{Gas\ Consumption\ x\ end\ use\ share}{Number\ of\ dwellings\ x\ natural\ gas\ appliance\ penetration}$$

- Electric UECs for space heating, water heating, cooking, and washing/drying appliances were determined by multiplying the gas UECs by assumed efficiencies of 85%, 65%, 55%, and 85% respectively. Electric UECs for space cooling, lighting, and other residential were calculated from the APS by dividing consumption for each end-use in each segment and region by the number of dwellings.

Residential Reference Case Forecast

This section outlines the method used to develop the ETSA Reference Case for the Residential sector.

- A separate Reference Case was calibrated to Enbridge Gas' internal forecasts of accounts and consumption, which were provided by rate class.
- Enbridge Gas account and consumption forecasts end in 2030. To extend them throughout the study period, the annual growth rate for each rate class was calculated during Enbridge Gas forecast period of 2021-2030. The trend of annual changes in year-over-year growth was then extended to calculate year-over-year growths in 2030-2038.
- Forecasted total single-family and multi-family accounts were developed by applying the growth rates of each rate class to the number of accounts in each region and segment. The number of post-2019 buildings was calculated as the difference between the forecasted number of buildings and the previous year's number of buildings, plus a demolition rate of existing buildings of 2%.
- CMHC data on housing starts was used to estimate the share attached and detached houses in new construction. The 2020 housing starts for the census metropolitan areas in Exhibit 77

below were taken to be representative of single-family houses in their gas regions. Note that this does not affect forecasted consumption, which was still calibrated to Enbridge Gas' forecasts, but does affect the applicability of DSM measures and codes and standards. For example, some DSM measures differ if they are applicable to attached or detached houses.

Exhibit 77 - Residential Housing Starts in 2020

	Attached/Row House Share of SF Accounts	Representative Region in CMHC Data	Attached/Row House Share of 2020 Housing Starts
EGD-GTA	33%	Toronto CMA	45%
EGD-Niagara	22%	St. Catherines-Niagara CMA	38%
EGD-Ottawa	41%	Ottawa CMA (Excluding Gatineau)	54%
Union - North	5%	Sudbury and Thunder Bay CMAs	31%
Union - South	16%	London and Windsor CMAs	33%
Total	26%	Ontario	44%

- Annual changes to UECs were calculated based on Enbridge Gas' forecasted consumption and account growth in that segment and region. For multi-family and low-income segments, the annual change in UEC was the growth rate of consumption divided by the growth rate of accounts. For the single-family segment, this was further adjusted so that the ratio of annual consumption in attached and detached houses remains constant in order to ensure the sum of the two segments equals Enbridge Gas' forecast.
- Added RNG and hydrogen based on expected volumes under Enbridge Gas' planned programs. Enbridge Gas provided RNG and hydrogen volume scenarios for the study. The lower bound of that forecast (planned programs only) was included in the Reference Case. This volume, about 0.01% of total demand in 2030, was added to the Reference Case, with fuel shares for conventional natural gas reduced accordingly so that overall energy demand remain the same.

Commercial Sector

The first year of the study period, the "base year" for the ETSA project is 2019.

The commercial sector was extracted from the "Com Ind" base year data files provided by EGI. The multi-family residential sector was removed (included in residential), and a subset of the "Com Ind" sectors were used to match with the APS segments in the commercial sector.

Commercial Base Year

Accounts

- Enbridge Gas' account data has a "Sector" field which was used to sort accounts into the APS segments. The mapping is presented in Exhibit 83 below.

Exhibit 78 - Enbridge Gas and APS Commercial Sector Mapping

Enbridge Gas Sector	APS Segment
ACCOMODATION	Large Hotel, Other Hotel/Motel
COLLEGE	University/College
COLLEGE/UNIVERSITY	University/College
EDUCATION COLLEGE/UNIVERSITY	University/College
ENTERTAINMENT	Other Commercial
FOOD SERVICES	Restaurant
HOSPITAL	Hospital
HOSPITAL FACILITY	Hospital
LONG TERM CARE	Long Term Care
OFFICE	Large Office, Other Office
OTHER COMMERCIAL	Other Commercial
PLACE OF WORSHIP	Other Commercial
RETAIL	Large Retail, Food Retail, Other Non-Food Retail
SCHOOL	School
TRANSPORTATION AND WAREHOUSE	Warehouse
UNIVERSITY	University/College

- For Enbridge Gas sectors spanning multiple APS segments (such as retail, which includes large retail, food retail, and other non-food retail), these accounts were separated based on their relative share of consumption in the APS base year. For example, in Union-North and the IESO Northeast Zone, 25% of office consumption was “Large Office” and 75% was “Other Office”. The 7011 rate 01 accounts labelled as “Office” were split with these percentages. The same process was applied for accounts in Enbridge Gas’ data labelled “Hotel” and “Office”.
- Two entries were missing data for rate class: one hospital and one office. These two accounts were assigned to the most common rate class for hospitals and offices in that region.

Units

- Units in the commercial sector model are square meters of floor area.
- Base year units were calculated with the commercial energy use intensity (EUI[24]) for each segment and gas region in the 2019 APS.

[24] The APS does not include discussion of fuel shares, which is why we use EUI here rather than UEC (EUI=UEC*Fuel Share).

Unit Energy Consumption and Fuel Share

- We do not have any survey data on penetration of natural gas appliances among Enbridge Gas accounts in the commercial sector. As a next-best data source, natural gas fuel shares were estimated from the APS base year data for gas and electricity consumption, along with estimated consumption of other fuels obtained from NRCan's Comprehensive Energy Use Database. Note that the selection of fuel share does not affect consumption in the segment (this is calibrated to the consumption forecast) but does provide an upper limit for fuel switching towards or away from gas.
- To estimate fuel shares among gas-connected customers from the APS, we compared the relative consumption of electricity and gas for a given end-use to the gas-connected floor area for a segment to develop an estimate of what fraction of the gas-connected floor area must use gas to supply that end-use. The average fuel shares for each segment are presented in Exhibit 79 below.

Exhibit 79 - Commercial Fuel Shares Per Segment

Segment	Space Heating	Water Heating	Cooking
Food Retail	98%	93%	61%
Hospital	99%	82%	78%
Large Hotel	88%	96%	70%
Large Non-Food Retail	99%	92%	79%
Large Office	89%	86%	10%
Long Term Care	94%	96%	75%
Other Commercial	100%	100%	100%
Other Hotel_Motel	80%	81%	46%
Other Non-Food Retail	96%	69%	37%
Other Office	91%	72%	0%
Restaurant	94%	93%	96%
School	98%	88%	63%
University_College	93%	92%	87%
Warehouse	90%	50%	0%

- UECs were then determined by dividing gas EUIs from the APS by these estimated fuel shares.

Commercial Reference Case Forecast

This section outlines the method used to develop the ETSA Reference Case for the Commercial sector.

- Enbridge Gas provided a forecast of accounts and consumption by rate class to 2030. Accounts and UECs were calibrated to Enbridge Gas' internal forecasts.

- To extend forecasts throughout the study period, the annual growth rate for each rate class was calculated during Enbridge Gas forecast period of 2021-2030. The trend in year-over-year growth was then extended to calculate year-over-year growths in 2030-2038.
- No account forecast was provided for commercial rates 100, 110, 115, 135, 145, 170, 9, M4, M5A, M7, R20, T1, or T2. These rate classes are all forecasted to have relatively constant consumption 2021-2030, thus the number of accounts in these rate classes was maintained at the number of the base year for the entire forecast period.
- The same fuel shares as the APS Reference Case were used, which remain constant throughout the forecast period. Note that because consumption is calibrated to Enbridge Gas' forecast, the selection of fuel share does not affect consumption, but only places an upper or lower limit on the amount of fuel switching that is possible.
- UECs were adjusted on a yearly basis for each segment and region based on Enbridge Gas' relative forecasts of consumption and accounts within that segment:

$$UEC_{2020} = End\ Use\ Share * \frac{\sum Consumption_{2019,rate\ i} * GrowthRate_{Consumption,rate\ i,2019-2020}}{\sum Accounts_{2019,rate\ i} * GrowthRate_{Accounts,rate\ i,2019-2020}} * \frac{1}{Fuel\ Share_{gas}}$$

- Added RNG and hydrogen based on expected volumes under Enbridge Gas' planned programs. Enbridge Gas provided RNG and hydrogen volume scenarios for the study. The lower bound of that forecast (planned programs only) was included in the Reference Case. This volume, about 0.01% of total demand in 2030, was added to the Reference Case, with fuel shares for conventional natural gas reduced accordingly so that overall energy demand remain the same.

Industrial Sector

Similar to the commercial sector, the Industrial and Large-Volume (referred to as "Industrial") sector base year data was taken from the "Com Ind" base year data files provided by EGI. Within the files, the data points with the sector names in the table below were included in the industrial sector.

Industrial Base Year

Accounts

- Except for the Plastic and Rubber Manufacturing sector, all "Sector" options in Enbridge Gas' account data corresponded to only one of the APS sectors. This mapping is presented in Exhibit 80 below.

Exhibit 80 - Enbridge Gas and APS Industrial Sector Mapping

Enbridge Gas Sector	APS Sector
AGGREGATE PROCESSING/MFG	Non-metallic Minerals Product Mfg
AGRICULTURE AND GREENHOUSE	Agriculture
ASPHALT	Non-metallic Minerals Product Mfg
ASPHALT PAVING AND ROOFING MATERIALS	Non-metallic Minerals Product Mfg
AUTO	Transportation and Machinery Mfg
BRICK	Non-metallic Minerals Product Mfg
BUILDING PRODUCTS	Non-metallic Minerals Product Mfg
CEMENT	Non-metallic Minerals Product Mfg
CEMENT/ASPHALT	Non-metallic Minerals Product Mfg
CHEMICAL	Chemicals Mfg
CHEMICAL/PETRO PROCESSING	Chemicals Mfg
COMPANY OWNED	Utility
CONCRETE GYPSUM AND PLASTER CATEGORIES - CEMENT	Non-metallic Minerals Product Mfg
CONSUMERS GOODS AND NON-METALLIC MANUFACTURING	Other Industrial
FABRICATED METALS	Fabricated Metals Mfg
FOOD AND BEVERAGE	Food and Beverage Mfg
FOOD AND BEVERAGE PROCESSING	Food and Beverage Mfg
FOOD, BEVERAGES AND KINDRED PRODUCTS	Food and Beverage Mfg
GLASS	Non-metallic Minerals Product Mfg
HEAVY MFG/ASSEMBLY	Other Industrial
INDUSTRIAL BUILDING/OTHER	Other Industrial
INDUSTRIAL MINES	Mining; Quarrying and Oil & Gas Extraction
LIGHT MFG/ASSEMBLY	Other Industrial
LIME	Non-metallic Minerals Product Mfg
MARKETERS/PRODUCERS	Mining; Quarrying and Oil & Gas Extraction
METAL FABRICATING	Fabricated Metals Mfg
MINING	Mining; Quarrying and Oil & Gas Extraction
MINING, QUARRYING, OIL AND GAS EXTRACTION	Mining; Quarrying and Oil & Gas Extraction
MISCELLANEOUS	Other Industrial
NON-FERROUS SMELT	Primary Metals Mfg
OTHER	Other Industrial
OTHER	Other Industrial
PETROLEUM REFINING	Petroleum Mfg
PHARMACEUTICAL	Other Industrial

Enbridge Gas Sector	APS Sector
PRIMARY METALS	Primary Metals Mfg
PUBLIC/PRIV NG REFUELING	Utility
PULP AND PAPER	Pulp; Paper; and Wood Products Mfg
RECYCLING	Other Industrial
REFINERY	Petroleum Mfg
SERVICE LINE ONLY	Utility
SMELTING/CASTING/REFINING	Primary Metals Mfg
SPECIAL LARGE VOLUME	Other Industrial
STEEL	Primary Metals Mfg
STEEL / CHEMICAL	Primary Metals Mfg
STONE, CLAY, GLASS, AND CONCRETE PRODUCTS	Non-metallic Minerals Product Mfg
TEXTILE AND APPAREL MFG	Other Industrial
TEXTILES	Other Industrial
TRANSPORTATION EQUIPMENT AND MACHINERY	Transportation and Machinery Mfg
UTILITIES - NON-COMPANY	Utility
UTILITY	Utility
WATER TREATMENT AND SEWAGE PLANTS	Water & Wastewater Treatment
WOOD AND PAPER MFG	Pulp; Paper; and Wood Products Mfg

- For the Plastic and Rubber Manufacturing sector (about ~150 million m3 of annual consumption), the specific accounts (only about a dozen) in this sector were identified by account name and SIC code in files provided for Enbridge Gas' DSM planning. These accounts were manually labelled as Plastic and Rubber, regardless of there classification in Enbridge Gas' internal account system.

Units

- Units for a given rate class, segment, and region are equal to the consumption in that rate class, segment, and region, divided by the average size of an account (of all rate classes) in that segment and region. This is necessary because UECs are set by segment, but account sizes vary significantly between rate classes.

Unit Energy Consumption and Fuel Share

- Gas consumption was disaggregated into end-use using the end-use shares from the 2019 APS, presented below in Exhibit 81 below. These figures indicate the share of natural gas in a given industry used for each end-use.

Exhibit 81 - Industrial Fuel Shares Per Segment

	HVAC	Other Process	Process Cooling	Process Heating (Direct)	Process Heating (Water and Steam)
Agriculture	50.0%	0.0%	0.0%	0.0%	50.0%
Chemicals Mfg	4.1%	6.3%	1.3%	60.0%	28.3%
Fabricated Metals Mfg	27.8%	1.3%	0.0%	68.4%	2.5%
Food and Beverage Mfg	9.2%	6.9%	0.8%	41.7%	41.5%
Mining; Quarrying and Oil & Gas Extraction	8.3%	58.2%	0.0%	27.9%	5.7%
Non-metallic Minerals Product Mfg	6.8%	1.5%	0.8%	90.2%	0.8%
Other Industrial	49.8%	0.0%	0.0%	20.5%	29.7%
Petroleum Mfg	0.7%	4.2%	0.1%	79.4%	15.6%
Plastic and Rubber Mfg	31.7%	1.6%	0.0%	34.9%	31.7%
Primary Metals Mfg	7.0%	7.7%	0.9%	80.4%	4.0%
Pulp; Paper; and Wood Products Mfg	10.0%	3.2%	0.0%	67.1%	19.6%
Transportation and Machinery Mfg	37.3%	5.6%	0.0%	43.7%	13.5%
Water & Wastewater Treatment	94.1%	0.0%	0.0%	5.9%	0.0%

- The resulting estimate for end-use consumption in a given segment and region was combined the APS estimate for electricity consumption in this segment and region, adjusted for efficiency, to produce the UEC. Conceptually, these numbers represent the amount of natural gas (or electricity) that would be required to supply all of a certain end-use at an average sized account in this segment.
- The UECs are calculated as follows:

$$UEC_{gas} = gas\ consumed\ for\ this\ end\ use + \frac{electricity\ consumed\ for\ this\ end\ use * efficiency_{elec}}{efficiency_{gas}}$$

$$UEC_{elec} = electricity\ consumed\ for\ this\ end\ use + \frac{gas\ consumed\ for\ this\ end\ use * efficiency_{gas}}{efficiency_{elec}}$$

- Fuel share is then determined by dividing the estimated gas that was actually consumed for this end-use in 2019 by the UEC:

$$Fuel\ Share_{gas} = \frac{gas\ consumed\ for\ this\ end\ use}{UEC_{gas}}$$

$$Fuel\ Share_{Elec} = \frac{electricity\ consumed\ for\ this\ end\ use}{UEC_{electricity}}$$

Industrial Reference Case Forecast

This section outlines how the method used to develop the ETSA Reference Case for the Industrial sector.

- Enbridge Gas provided a forecast of accounts and consumption by rate class to 2030, with certain industrial segments disaggregated from general consumption within that rate class. Account growth and UECs were calibrated to these forecasts.
- The Enbridge Gas forecasts were extended to 2038 by continuing the trend in the final years of the of Enbridge Gas' consumption or account forecast. For most industrial rate classes, consumption was forecasted to be constant over the study period.
- No account forecast was provided for rates 100, 110, 115, 135, 145, 170, 9, M4, M5A, M7, R20, T1, or T2. These rate classes are all forecasted to have relatively constant consumption 2021-2030, thus the number of accounts in these rate classes was maintained at the number of the base year for the entire forecast period.
- UECs were adjusted on a yearly basis for each segment and region based on Enbridge Gas' relative forecasts of consumption and accounts within that segment:

$$UEC_{2020} = End\ Use\ Share * \frac{\sum Consumption_{2019,rate\ i} * GrowthRate_{Consumption,rate\ i,2019-2020}}{\sum Accounts_{2019,rate\ i} * GrowthRate_{Accounts,rate\ i,2019-2020}} * \frac{1}{Fuel\ Share_{gas}}$$

- Added RNG and hydrogen based on expected volumes under Enbridge Gas' planned programs. Enbridge Gas provided RNG and hydrogen volume scenarios for the study. The lower bound of that forecast (planned programs only) was included in the Reference Case. This volume, about 0.01% of total demand in 2030, was added to the Reference Case, with fuel shares for conventional natural gas reduced accordingly so that overall energy demand remain the same.

Method for Setting Commercial and Industrial Fuel Shares

For the residential sector, Enbridge Gas was able to provide PG with the results of its 2019 Residential End-Use Survey, which provided regional estimates of natural gas penetration for each end-use, among households with Enbridge Gas account. Because this data was only available for the residential sector, segment electricity and gas consumption in the APS were used to estimate fuel shares for the commercial and industrial models.

At a high level, the challenge in using the APS electricity data to estimate fuel shares for our Navigator model is that we lack data on energy consumption *per instance of an end-use with a given fuel*; we only have data on total energy consumed for a given end-use and the number of gas-connected and gas-free houses, but we do not know how many gas and electric versions there are of a given end-use. The easiest way to insert the data we had into our model would have been to give every dwelling an electric and a gas version of each end-use (e.g., two dryers, one gas and one electric, per house), with relative unit consumptions set to match the provincial total. Given the importance of fuel-switching in the ETSA project, this was not a workable solution. We needed to use the data that we had to create reasonable estimates for fuel shares and unit energy consumptions (UECs) for each end-use and fuel. Different approaches were used for different end-uses, presented in Exhibit 82.

Exhibit 82 - Method for Setting UECs and Fuel Shares

Category	Method	End-uses in this category
End-uses with only one fuel	UEC equal to (energy consumption for that end-use) / (units). Fuel share set to 1 for the applicable fuel.	• Space cooling • Lighting • Misc Commercial25 • Refrigeration • Other Electricity (industrial)
End-uses with only gas and electricity as the fuels	Gas UEC assumed to be (gas energy + electric energy/efficiency) / (all stock), assuming every account has the end-use, and the total energy for the gas and electric versions are the same. Accounts without gas accounts were assumed to only have the electric end-use (i.e. houses without a gas account all have electric dryers). In the gas-connected region, the estimated electricity consumed by the gas-free houses is subtracted from the total electricity from this end-use for the region, and the remaining energy is assumed to be gas-connected houses with an electric end-use of this type. The remaining share of gas-connected houses use gas.	• Washing/Drying Appliances • Cooking • All remaining industrial end-uses
End-uses with many fuels and no easy assumptions for UEC	The province-wide share of energy for this end-use supplied by other fuels (propane, heating oil, wood) was taken from NRCan's Comprehensive Energy End-Use Database (5% and 14% for	• Water Heating • Space Heating

[25] "Misc Residential" and "Misc Commercial" does appear as an end-use for both gas and electricity. However, we assumed the miscellaneous electricity is the same at all houses/businesses (gas connected or not) and the miscellaneous gas is energy consumption that only happens at gas-connected house (the only APS measures affecting this category were regarding gas pool heaters). For the gas-connected regions, the misc commercial UEC for both electricity and gas was doubled and the fuel share was set at 50%.

	residential water and space heating, 7% for commercial for both water and space heating). All the consumption of other fuels was assumed to take place a non-gas connected houses. The steps above for end-uses with only gas and electricity for fuels were applied.	

Assumptions in Enbridge Gas' Volume Forecast

Enbridge Gas provided PG with its most recent volume forecast for 2021 to 2030. The sales volumes were produced with Enbridge Gas' internal demand forecasting model, using the assumptions in the exhibits below. [26]

The average price and bill figures were calculated prior to the federal government's December 2020 announcement that the federal carbon charge would increase by $15 per year in the post 2022-period. The price forecast used in Enbridge Gas' volume forecast assume the carbon price grows at the rate of inflation for the post-2022 period.

Exhibit 83 - Input Assumptions for Enbridge Gas' Volume Forecast (1/5)

	ON	ON	EGD Central	EGD Eastern	EGD Niagara	ON
	Housing Starts	**Employment**	**Employment**	**Employment**	**Employment**	**GDP**
2019 (actual)	68,991	7,451.2	4,566.8	741.3	199.0	790,974.3
2020	62,963	7,189.1	4,402.5	726.2	192.1	751,538.6
2021	75,135	7,465.9	4,603.2	748.6	197.8	789,759.7
2022	71,616	7,604.0	4,711.5	761.3	200.2	807,134.4
2023	69,858	7,737.1	4,817.2	773.7	202.5	819,241.4
2024	68,077	7,880.2	4,930.6	786.8	205.0	832,349.3
2025	65,802	8,026.0	5,046.7	800.2	207.5	845,666.9
2026	65,383	8,174.5	5,165.5	813.8	210.1	859,197.5
2027	63,924	8,325.7	5,287.1	827.6	212.7	872,944.7
2028	62,465	8,479.8	5,411.5	841.6	215.3	886,911.8
2029	61,006	8,636.6	5,538.9	855.9	217.9	901,102.4
2030	59,547	8,796.4	5,669.3	870.5	220.6	915,520.0

[26] Units were not provided for the input assumptions.

Exhibit 84 - Input Assumptions for Enbridge Gas' Volume Forecast (2/5)

	EGD Central Commercial	EGD Central Industrial	ON	Central	Eastern	EGD Central
	Vacancy Rate	Vacancy Rate	CPI	CPI	CPI	HDD
2019 (actual)	5.600	1.375	137.5	139.9	135.9	3,066.4
2020	5.600	1.375	139.2	141.6	137.6	2,780.8
2021	5.600	1.375	142.0	144.7	140.5	2,780.8
2022	5.600	1.375	144.9	147.7	143.3	2,780.8
2023	5.600	1.375	147.8	150.7	146.3	2,780.8
2024	5.600	1.375	150.7	153.8	149.2	2,780.8
2025	5.600	1.375	150.7	157.0	152.2	2,780.8
2026	5.600	1.375	150.7	160.2	155.3	2,780.8
2027	5.600	1.375	150.7	163.5	158.5	2,780.8
2028	5.600	1.375	150.7	166.8	161.7	2,780.8
2029	5.600	1.375	150.7	170.3	165.0	2,780.8
2030	5.600	1.375	150.7	173.8	168.3	2,780.8

Exhibit 85 - Input Assumptions for Enbridge Gas' Volume Forecast (3/5)

	EGD Eastern	EGD Niagara	UG South	UG North	ON (UG Res only)	ON (UG Res only)
	HDD	HDD	HDD	HDD	Furnace Efficiency Index	Persons Per Household Index
2019 (actual)	3,789.0	2,976.7	3,929.1	5,230.6	0.875	2.482
2020	3,410.4	2,696.3	3,794.6	4,991.6	0.878	2.476
2021	3,410.4	2,696.3	3,772.2	4,963.6	0.880	2.470
2022	3,410.4	2,696.3	3,772.2	4,963.6	0.882	2.465
2023	3,410.4	2,696.3	3,772.2	4,963.6	0.884	2.461
2024	3,410.4	2,696.3	3,794.6	4,991.6	0.886	2.458
2025	3,410.4	2,696.3	3,772.2	4,963.6	0.888	2.455
2026	3,410.4	2,696.3	3,772.2	4,963.6	0.890	2.452
2027	3,410.4	2,696.3	3,772.2	4,963.6	0.892	2.450
2028	3,410.4	2,696.3	3,794.6	4,991.6	0.894	2.449
2029	3,410.4	2,696.3	3,772.2	4,963.6	0.896	2.447

	EGD Eastern	EGD Niagara	UG South	UG North	ON (UG Res only)	ON (UG Res only)
	HDD	HDD	HDD	HDD	Furnace Efficiency Index	Persons Per Household Index
2030	3,410.4	2,696.3	3,772.2	4,963.6	0.898	2.446

Exhibit 86 - Input Assumptions for Enbridge Gas' Volume Forecast (4/5)

	Res R01	Res M1/M2	Res R01	Res M1/M2	UG NonRes North	UG NonRes North
	Total Bill	**Total Bill**	**Avg. Price**	**Avg. Price**	**Total Bill**	**Avg. Price**
2019 (actual)	1,234.98	927.34	33.18	47.98	9,218.95	30.07
2020	1,116.62	903.87	29.98	48.45	8,350.87	27.81
2021	1,159.14	996.86	32.87	53.19	8,860.59	30.96
2022	1,240.95	1,075.68	35.79	56.78	9,605.31	33.87
2023	1,288.13	1,120.08	37.00	58.44	9,999.58	35.06
2024	1,313.50	1,143.06	37.76	59.61	10,191.50	35.80
2025	1,339.26	1,166.41	38.54	60.79	10,385.88	36.54
2026	1,363.24	1,188.00	39.24	61.90	10,562.77	37.22
2027	1,387.11	1,209.46	39.94	63.00	10,737.26	37.88
2028	1,411.89	1,231.78	40.66	64.15	10,919.32	38.57
2029	1,436.58	1,253.99	41.38	65.30	11,099.08	39.26
2030	1,462.05	1,276.92	42.12	66.47	11,286.39	39.97

Exhibit 87 - Input Assumptions for Enbridge Gas' Volume Forecast (5/5)

	UG NonRes South	UG NonRes South	EGD Central	EGD Eastern	EGD Niagara	ON
	Total Bill	Avg. Price	Vintage	Vintage	Vintage	FX_US
2019 (actual)	6,343.86	22.58	0.72	0.74	0.69	1.33
2020	6,097.47	22.44	0.72	0.73	0.68	1.40
2021	6,971.79	26.30	0.72	0.73	0.67	1.36
2022	7,701.51	29.12	0.72	0.73	0.66	1.34
2023	8,088.38	30.24	0.71	0.73	0.65	1.34
2024	8,270.20	30.91	0.71	0.72	0.65	1.34
2025	8,454.27	31.59	0.71	0.72	0.64	1.33

	UG NonRes South	UG NonRes South	EGD Central	EGD Eastern	EGD Niagara	ON
	Total Bill	Avg. Price	Vintage	Vintage	Vintage	FX_US
2026	8,621.34	32.20	0.71	0.72	0.63	1.33
2027	8,785.80	32.80	0.71	0.72	0.62	1.33
2028	8,958.01	33.43	0.71	0.72	0.61	1.33
2029	9,127.96	34.05	0.71	0.71	0.61	1.33
2030	9,305.13	34.69	0.71	0.71	0.60	1.33

Appendix B APS Reference Case Data Sources

The APS Reference Case begins with a 2017 base year and provides a 20-year forecast (2018-2038) of electricity and natural gas consumption by sector, segment and end-use. Data inputs to this original Reference Case were provided by the IESO, Enbridge Gas and Union Gas. Exhibit 88 presents the data sources used to develop the APS Reference Case as provided in the APS report.[27]

Exhibit 88 – Data Sources Used to Develop the APS Reference Case

Data Type	Data Source	Workbook(s) Destination	Description of Data
Forecast Electricity Consumption	IESO	**Electricity:** Residential, Commercial, Industrial	kWh consumption for all 10 IESO zones, disaggregated by IESO segment and end use, from 2018 to 2040
Forecast Natural Gas Consumption	Natural Gas Utilities	**Gas**: Residential, Commercial, Industrial	m^3 consumption for all utility natural gas regions, at sector-level, from 2018 to 2028
Housing Forecast[95]	IESO	**Electricity**: Residential **Gas**: Residential	Residential households, by IESO segment and IESO zone, from 2018 to 2040
Commercial Floor Space Forecast[96]	IESO	**Electricity**: Commercial **Gas**: Commercial	Commercial square footage, by IESO segment and IESO zone, from 2018 to 2040
Forecast Greenhouse Natural Gas Consumption	Union Gas	**Gas**: Industrial	Forecast of greenhouse-specific consumption in West IESO zone from 2018 to 2028
Forecast Greenhouse Electricity Consumption	IESO	**Electricity:** Industrial	Forecast of greenhouse-specific consumption (extrapolated from Agriculture segment) in West IESO zone from 2018 to 2028
Forecast Residential Water Heating Consumption	IESO	**Gas**: Residential	Forecast of water heating load, by segment and IESO zone, from 2018 to 2040, caused by fuel switching from electricity to natural gas

For more details on the methodology used to build the Reference Case forecast, please see Appendix B of the 2019 APS Report (available online).

[27] Navigant Consulting, 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study, Page B-1.

Appendix C Critical Driver Data Inputs and Assumptions: Codes & Standards

This appendix focuses on building codes and equipment standards.

Approach to selecting and modelling codes and standards

For the codes and standards (C&S) CD, the goal was to capture C&S's that influenced the Reference Case (the Enbridge Gas calibrated model in Navigator). We determined the most reasonable of the extreme potential code changes, known as the "high stringency" case. We also established an intermediate case, referred to as the "medium stringency" case.

The difference between the Reference Case and other scenarios was applied to the Navigator model as a percentage energy reduction. The Reference Case was calibrated to Enbridge Gas's latest volume and account forecast.

We focused on C&S's that were implemented, planned, or drafted. The goal was to capture the impacts of defined codes, and to avoid speculating on possible future codes that were not yet determined, with the exception of the potential retrofit codes for which the timing and impact were also estimated. The details surrounding Amendment 17 of the federal energy efficiency requirements were not released at the time, but we made assumptions about its potential impact.

Note that although higher code levels could cause increases in fuel switching, fuel switching was not included in this analysis but was included in the non-price fuel switching analysis.

The consideration criteria for C&S were as follows:

- Came into effect from 2017 onwards
- Could affect Enbridge Gas' service territory during the study period
- Expected to affect the market, either because they are legally enforced and/or there are incentives for the market to adopt the C&S
- Analyzed public information about what the C&S would mean in practice

List of codes included in the Codes and Standards Critical Driver analysis

- NECB 2020 Tiered Code (Part 3) and NBC 2020 Tiered Code (Part 9)
  Ontario has taken steps to harmonize the Ontario Building Code with the National Construction Codes. Therefore, Ontario is likely to adopt these codes for Part 3 and Part 9 buildings. These codes have tiers, allowing higher efficiency levels to be selected by different jurisdictions more easily. The NECB has four Tiers with Tiers 2, 3 and 4, specifying that the buildings should be 25%, 50% and 60% better than Tier 1, respectively. The NBC for homes is similar, except that it has 5 tiers with Tiers 2, 3, 4, and 5 saving 10%, 20%, 45% and 70% of the energy of Tier 1, respectively. These codes are planned to be released at the end of 2021. After adopting the codes (estimated to be around 2023-2025) the Ontario government then will likely use them to ratchet up the energy requirements.
- Select Community Energy Plans
  Community Energy Plans (CEPs) created by municipalities allow them to make and enforce their own energy efficiency standards. These standards are enforced via the permitting process of the municipality and developers generally comply with these requirements. There

are many large cities in Ontario that have adopted or are in the process of adopting CEPs; however, the objectives and targets laid out in these plans are not always directly linked to standards (or other behaviour changing policies) that will lead to achievable outcomes. The Toronto Green Standard (TGS) is an example of a municipal energy efficiency standard resulting from a community plan that has a quantifiable impact on unit energy consumption forecasts for the built environment in Toronto. Outside of Toronto, we sampled CEPs from other municipalities to generalize about the impact of CEPs more broadly across the province.

- Energy Efficiency Regulations and their Amendments
  Canada's Energy Efficiency Regulations, under the Energy Efficiency Act, include prohibitions on the importation (internationally) of products that do not meet certain energy efficiency requirements. They also include Minimum Energy Performance Standards (MEPS), that prohibit the sales of products interprovincially that do not meet energy efficiency requirements. The amendments to the energy efficiency regulations include more products and efficiency improvements to products already covered. We included Amendment 15, 16, and 17 in our analysis, since these amendments have improvements that occur during the study period. Amendment 17 is in its consultation phase, so we estimated its impact. Since the building energy codes are generally better than the MEPS, these Amendments primarily impact retrofit energy consumption. In general, the federal energy efficiency regulations are more stringent or are implemented sooner than Ontario's energy efficiency regulations (O. Reg. 509/18). The exception is window performance, which the federal requirements have not yet included.
- Potential Retrofit Codes (Part 3 and Part 9)
  Although there is no specific code that has been drafted or proposed, there has been significant speculation and discussion about retrofit codes. Therefore, it is important to include an estimate about the potential impact and timeline of such codes since the effects on energy demand could be significant. The federal government plans to have a model retrofit code completed by 2022, for implementation by the provinces by 2025. Since it will take time for the industry to adjust, the expected time when the code would come into force (within the high stringency case) is 2030.

Codes Excluded

We did not include the Ontario Building Code SB-10 or SB-12 energy codes. In the past the Ontario government has ratcheted up its building energy codes and has generally stayed ahead of the NECB and NBC (in the previous, non-tiered versions). However, it is not likely that Ontario will maintain separate energy codes since they have committed to harmonizing their codes nationally and with the provinces. While they will reserve the right to make changes to the implementation of the code in the province, we envisioned that these changes will be small.

Other policies that were considered but deemed not applicable to this driver are the Pan Canadian Framework (PCF), the Canadian Infrastructure Bank (CIB), and the Clean Fuel Standard (CFS). The PCF may drive improvements to codes and standards, but for this critical driver we were only focusing on the C&S themselves. Additionally, incentives that are a result of the PCF or the CIB are not codes and were therefore also excluded from the analysis. It was assumed that as C&S improve, voluntary standards and incentives would improve proportionally. The CFS was not included since it was covered under the renewable fuel switching component of this project.

Expected impact for each code for the high and medium stringency settings

NECB 2020 Tiered Code (Part 3) and NBC 2020 Tiered Code (Part 9)

To calculate the impact of these code changes, first the energy consumption savings at each efficiency level was calculated, then the timing of these code changes was estimated. The part 3 buildings energy savings values were calculated using archetype buildings modelled at various energy savings levels. The part 9 home energy savings were obtained from archetype homes modelled by Building Knowledge Canada. See the Exhibit 89 to Exhibit 94 below for the energy savings break down by end-use. These are separated by tier and building type.

Estimated impact of NECB Tiers by end-use for commercial buildings

For the NECB models, four buildings (high school, large retail, MURB, Office) were modelled in Ottawa at different efficiency levels, with a variety of measures. The measures were applied to the buildings based on the TAF zero emissions buildings framework[28], which contains optimized pathways for high efficiency buildings. The other building types in Navigator (healthcare, warehouse, hospitality, and other) were assigned energy savings values from the most similar building type. In preliminary modelling it was found that the percentage savings differed minimally by region. Therefore, the detailed modelling was only performed for the Ottawa region. For NECB Tier 4, gas heat pumps with an average annual COP of 1.15 were assumed for heating and hot water systems. Once the modelling was completed, the results were interpolated so that the energy savings values of each major end-use (heating, water heating, cooling and non-cooling electric) exactly matched the performance targets of the Tiers.

While cooling energy consumption in high performance buildings can be substantially reduced with careful design, cooling energy was expected to increase due to improvements in the envelope. The combination of a tight, highly insulated envelope and high gain windows causes increases in cooling demand, which explains the significantly increased cooling energy consumption in the higher tiers. Builders are expected to select high gain windows since they are less expensive than low gain windows.

Exhibit 89 - NECB Tier 2 Savings (overall 25% savings - from current code ~= NECB Tier 1)

	End-use			
Building type	Heating	Water Heating	Cooling	All Other Non-Cooling Electricity
Education	31%	22%	1%	10%
Health Care	31%	22%	1%	10%
Retail	28%	10%	8%	22%
Warehouse	28%	10%	8%	22%
Hospitality	34%	25%	-2%	5%
MURB	34%	25%	-2%	5%
Office	21%	33%	33%	25%
Other	21%	33%	33%	25%

[28] https://www.toronto.ca/wp-content/uploads/2017/11/9875-Zero-Emissions-Buildings-Framework-Report.pdf

Exhibit 90 - NECB Tier 3 Savings (overall 50% savings - from current code ~= NECB Tier 1)

	End-use			
Building type	Heating	Water Heating	Cooling	All Other Non-Cooling Electricity
Education	59%	33%	-65%	32%
Health Care	59%	33%	-65%	32%
Retail	64%	18%	-25%	39%
Warehouse	64%	18%	-25%	39%
Hospitality	65%	51%	-139%	16%
MURB	65%	51%	-139%	16%
Office	61%	43%	19%	45%
Other	61%	43%	19%	45%

Exhibit 91 - NECB Tier 4 Savings (overall 60% savings - from current code ~= NECB Tier 1)

	End-use			
Building type	Heating	Water Heating	Cooling	All Other Non-Cooling Electricity
Education	70%	37%	-105%	44%
Health Care	70%	37%	-105%	44%
Retail	77%	30%	-32%	46%
Warehouse	77%	30%	-32%	46%
Hospitality	77%	62%	-166%	19%
MURB	77%	62%	-166%	19%
Office	81%	60%	-59%	48%
Other	81%	60%	-59%	48%

Estimated impact of NBC Tiers by end-use for homes

For the NBC models, archetype homes (single detached, attached) were modelled at different efficiency levels by Building Knowledge Canada. The savings at each major end-use was interpolated to exactly meet the overall energy savings at each Tier. NBC code assumes constant equipment energy consumption for all tiers, however it is likely that there will be some equipment and lighting savings in better performing homes, so we estimated some improvement for the "All Other Non-Cooling Electricity" end-use.

Specific modifications were made to the Tier 5 homes. Since fuel switching is not covered in this analysis, the Tier 5's space heating and hot water was switched from electric ASHP or ASHP dual fuel systems to gas heat pumps with an average annual COP of 1.15.

Since cooling is a more substantial component of energy consumption for homes than for buildings, the cooling energy was reduced in Tier 5 homes to meet the energy targets. In practice, that meant careful design of the window and shading components to reduce cooling consumption.

Exhibit 92 - NBC Tier 3 Savings (overall 11% savings - from current code ~= NBC Tier 2)

	End-use			
Building type	**Heating**	**Water Heating**	**Cooling**	**All Other Non-Cooling Electricity**
Single Detached	14%	0%	-2%	5%
Attached	20%	0%	-2%	5%

Exhibit 93 - NBC Tier 4 Savings (overall 33% savings - from current code ~= NBC Tier 2)

	End-use			
Building type	**Heating**	**Water Heating**	**Cooling**	**All Other Non-Cooling Electricity**
Single Detached	42%	22%	-60%	16%
Attached	51%	29%	-52%	16%

Exhibit 94 - NBC Tier 5 Savings (overall 67% savings - from current code ~= NBC Tier 2)

	End-use			
Building type	**Heating**	**Water Heating**	**Cooling**	**All Other Non-Cooling Electricity**
Single Detached	70%	61%	39%	19%
Attached	71%	64%	54%	19%

Timing of Code Implementation

Although the codes were likely to be released in 2021, builders need time to adapt to the code so adoption of these codes was estimated to occur between 2023 and 2025. For simplicity, we assumed that one tier higher than current code would be chosen (for both NECB and NBC). In the past, the Ontario Government has improved the code approximately every 5 years, thus, for both scenarios the efficiency targets are expected to increase by 1 tier every 5 years. The timing of the scenarios is shown in Exhibit 95 below.

Exhibit 95 - Estimated Timing for the NECB and NBC Code for New Construction

Equivalent Energy Performance Target	NECB	Tier 1 NECB ~= OBC 2017	Tier 2	Tier 3	Tier 4
	NBC	Tier 2 NBC ~= OBC 2017	Tier 3	Tier 4	Tier 5
Year implemented	High Stringency		2025	2030	2035
	Medium Stringency		2028	2033	2037

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Select Community Energy Plans

For community energy plans, the most developed example of an actionable policy driver is the Toronto Green Standard (TGS), which outlines energy efficiency requirements for buildings, as well as targets for the city. Some of the municipalities that have community energy plans or are developing plans are Kingston, London, Burlington, Guelph, Halton Hills, Hamilton, Oxford County, Sudbury, Waterloo, and Windsor. The TGS seems to be leading the way for the other municipalities, since many of these municipalities lay out goals and timing that are similar to the TGS, like becoming carbon neutral by 2050.

We mapped the building energy efficiency targets in the TGS to the tiers for the NECB and NBC as a proxy for the energy savings targets. See Exhibit 89 to Exhibit 94 above for the energy savings breakdowns by building type and end-use. The timing that was selected for the high stringency case for Toronto matches the TGS official plan. We assumed that the other municipalities with community energy plans were on average a couple years behind Toronto, but a few years ahead of the province. See the Exhibit 96 and Exhibit 97 below for the expected timing of the implementation of these efficiency levels. It was estimated that approximately 50% of non-Toronto customers would fall under a CEP, since many of the large cities had already adopted CEPs, and that more cites were in the process of drafting and adopting CEPs. It was assumed that the CEPs would only affect new construction.

The Toronto Green Standard requires all new construction heating and hot water systems be electric only (i.e., heat pumps) starting in 2030, but this requirement was not included in this analysis since it was included in the non-price fuel switching analysis.

Exhibit 96 - Estimated Timing for Toronto

Equivalent Energy Performance Target	NECB	Tier 1 NECB ~= OBC 2017	Tier 2	Tier 3	Tier 4
	NBC	Tier 2 NBC ~= OBC 2017	Tier 3	Tier 4	Tier 5
Year implemented	High Stringency		2022	2026	2030
	Medium Stringency		2025	2029	2033

Exhibit 97 - Estimated Timing for Non-Toronto CEPs, Assuming Impact to 50% of Non-Toronto Customers

Equivalent Energy Performance Target	NECB	Tier 1 NECB ~= OBC 2017	Tier 2	Tier 3	Tier 4
	NBC	Tier 2 NBC ~= OBC 2017	Tier 3	Tier 4	Tier 5
Year implemented	High Stringency		2024	2028	2032
	Medium Stringency		2027	2031	2035

Energy Efficiency Regulations and their Amendments

Preliminary investigations of the Amendments 15, 16 and 17, and O. Reg. 509/18 MEPS, showed that they would have a limited impact on efficiency levels. Therefore, the analysis was simplified and generalized.

Since the code was always better than MEPS, these efficiency improvements were applicable only to existing buildings. The expected efficiency improvements are listed below. These are included in both the medium and high stringency cases.

The following assumptions were made:

- Major retrofits occur at 4% per year
- Equipment/appliance replacements (minor retrofits) occur at 1/15th (6.7%) per year
- Retrofits reduce energy consumption by 4%
- Equipment MEPs improve at 2% per year, affecting minor retrofits

Potential Retrofit Codes (Part 3 and Part 9)

Since there is very little information about what a retrofit code may look like, the estimated energy targets and timing are based on two things: engineering and policy experience, and the Pan Canadian Framework goal of reaching 80% carbon emissions savings by 2050. For that goal to be achieved, emissions would have to be significantly reduced from existing buildings and homes, since they make up a large component of emissions. To achieve this, mandatory building retrofits would be necessary. With 20 years (2030-2050) to achieve the retrofits, then 1/20th of the existing building and home stock would have to be retrofitted each year, starting with the worst performing buildings and homes. The high stringency case relates to the possibilities of such a retrofit program.

An alternative approach would be to perform electrification retrofits, however, rapid expansion of electrical grid capabilities may not be feasible. Therefore, comprehensive building retrofits will likely still be pursued. To achieve large scale retrofits, economical means of mass-produced retrofits could be pursued, similar to the Energiesprong[29] program. A program like this would need to be heavily subsidized and would be an expensive federal program.

Note that voluntary major retrofits are already covered under code, and voluntary minor retrofits are covered under MEPS.

- High Stringency: Mandatory retrofitting of buildings with the assumption that the bottom 1/20th of existing buildings will be retrofitted to one tier lower than the new construction code in each year, starting in 2030. We chose one tier lower than new construction code since even this would be a very aggressive program. Age ranges of buildings were selected to approximately match the retrofit timeline. See Exhibit 98 below for the expected timing of a retrofit code and the applicable building and home ages that would be retrofitted during each 5-year period.
- Medium Stringency: The timing is delayed by 5 years compared to the high stringency case and only affects Toronto and 50% of non-Toronto customers (i.e., the locations with CEPs). Other locations are unaffected.

[29] https://energiesprong.org/

Exhibit 98 - Estimated Performance Levels and Timing of a Retrofit Code

Equivalent Energy Performance Target	NECB	Tier 1 NECB ~= OBC 2017	Tier 2	Tier 3	Tier 4	Tier 4
	NBC	Tier 2 NBC ~= OBC 2017	Tier 3	Tier 4	Tier 5	Tier 5
Year implemented	High Stringency		2030	2035	2040	2045
	Medium Stringency		2035	2040	2045	2050
Applicable building or home year of construction			Pre-1955	1955-1979	1980-2004	2005-2029

Appendix D Critical Driver Data Inputs and Assumptions: Non-Price Driven Fuel Switching

The appendix provides more details on the data inputs and assumptions used for the CDs that required more extensive research and analysis. This appendix focuses on non-price driven fuel switching.

Scope of the Non-Price Driven Fuel Switching Critical Driver

This CD was meant to reflect Enbridge Gas customers switching from gas to electricity for reasons other than price. Reasons such as altruism, consumer preference, and regulations that require or incentivize switching from gas to electricity were within the scope of this CD. Changes in energy use intensity from building codes and equipment standards were captured in the C&S CD, and changes to the number of Enbridge Gas customers from fuel switching were captured in the customer growth/accounts CD. Price-driven fuel switching were caused by changes in carbon and gas prices.

The space and water heating end-uses were of focus for this CD, because they were the end-uses which switch away from natural gas most often. The focus was on the residential and commercial sectors where fuel switching from gas to electricity is common. Also, the policies and incentives for decarbonization of energy use in buildings tend to focus on the residential and commercial sectors. The Industrial sector was excluded as space and water heating represent a lower portion of energy use there. Decarbonization was expected in the Industrial sector, but the biggest levers for industrial decarbonization were captured in other CDs.

Electric to natural gas fuel switching from non-price signals was not explored because it is unlikely there will be incentives/regulations supporting such a switch.

Possible Causes of Gas to Electric Fuel Switching

Switching from gas to electricity for reasons other than fuel price may be caused by the following:

- *Individual preference* for low-carbon fuels for altruistic reasons or interest in emerging low-emission technologies, like heat pumps, may cause individuals to switch from gas to electric equipment.[30]
- *Policies that limit the use of natural gas* like setting carbon intensity limits for buildings, requiring zero emissions from space and water heating technologies, and/or banning the uses of natural gas for some applications/building segments. Examples of such policies include:
    - The City of Vancouver Zero Emissions Building Plan aims to have all new buildings achieve zero emissions by 2030. The plan sets GHG and energy intensity targets for new construction MURBs, offices and detached homes.[31] The Vancouver Building Bylaw, amended in the spring of 2020, requires all new and replacement heating and hot water systems by zero emissions by 2025.[32]

[30] Environics. "Exploratory Assessment of Energy Needs." December 2019.
[31] https://vancouver.ca/green-vancouver/zero-emissions-buildings.aspx#zero-emissions-building-plan
[32] https://council.vancouver.ca/20200331/documents/9.pdf

- Many cities in the U.S have banned natural gas equipment in new buildings including several in California (San Francisco, Berkley, San Joe, Mountain View, Santa Rosa, Brisbane), as well as Brookline, Massachusetts. Several other cities are reportedly considering implementing similar policies.[33] New York City aims to end the use of fossil fuels in large building systems by 2040, with mandatory carbon intensity limits for existing buildings beginning in 2024[34]
- Some U.S states, including New York and California, are actively pursuing the electrification of heating and hot water equipment in both the residential and commercial building sectors. According to the report, "Toward a Clean Energy Future: A Strategic Outlook 2020-2023" from the New York State Energy Research and Development Authority (NYSERDA), NYSERDA has included the electrification of buildings as one of the focuses of its strategy for becoming a carbon-free electricity system by 2040 and eventually a carbon-neutral economy.[35]

- *Stringent building codes* that may cause builders to pick whether the home has a gas or an electricity connection, as it would be too expensive to pick both.
- *Incentives for low carbon/electric technologies* the IESO/electric LDCs and the green stimulus fund may shift the market away from gas and towards electricity. There may also be incentives for net zero homes from the Canadian Infrastructure Bank. Incentives from the federal government may be available soon, as the federal plan includes provisions for providing grants for home energy improvements starting in 2021 and mentions working to increase the uptake of low emission space and water heating equipment. Financial incentives may not be sufficient to significantly affect consumer choice but could be effective if combined with consumer and HVAC contractor education campaigns and other efforts to address non-price barriers to adopt electric technologies.

[33] https://rmi.org/fossil-gas-has-no-future-in-low-carbon-buildings/, https://sfgov.legistar.com/LegislationDetail.aspx?ID=4584221&GUID=1DA24E52-38A0-4249-9396-270D0E9353BB , https://durkan.seattle.gov/2020/12/mayor-durkan-announces-ban-on-fossil-fuels-for-heating-in-new-construction-to-further-electrify-buildings-using-clean-energy/ , https://www.smartcitiesdive.com/news/san-jose-oakland-join-growing-list-of-california-cities-to-ban-natural-gas/591507/

[34] https://www1.nyc.gov/office-of-the-mayor/news/064-20/state-the-city-2020-mayor-de-blasio-blueprint-save-our-city#/0

[35] https://www.nyserda.ny.gov/About/Publications/Program%20Planning%20Status%20and%20Evaluation%20Reports/Strategic%20Outlook

Modelling Approach

A two-pronged approach was used to model the non-price driven fuel switching CD. The two levers used to reflect a decrease in gas use were:

- *Accounts:* It would not be economical for new buildings to connect to the gas system if space and water heating loads were not met by gas.
- *Fuel Share:* For existing homes that had multiple end-uses supplied by natural gas, we assumed that they remained connected to the gas system even if water heating and/or space heating end-uses were switched off gas because they may still use gas for cooking, fireplaces or BBQs. While some customers may have decided to disconnect from the gas system if they switched to a heat pump, we assumed that it was valuable for Enbridge Gas to explore the impacts to annual volumes and peaks due to reductions in gas use rather than changes in accounts. Hence, we proposed to use fuel shares as the mechanism to model changes in gas demand in existing accounts when switching away from gas. To explore potential disconnections of existing totals in response to electrification of specific end-uses, we would require much more granular survey data regarding end-use saturation by building type and the presence of other end-uses.

Method for Developing Modelling Assumptions

To establish the modelling assumptions for fuel share changes, we applied a turnover rate based on average equipment lifetimes for space and water heating[36] to the average 2019 gas fuel share for the space and water heating end-uses in residential and commercial models. We applied the turnover rate starting in 2026 with the assumption that equipment was replaced with non-gas fueled appliances. Details of this analysis are in an Excel workbook called "ETSA – non-price fuel switch assumptions estimation."

The baseline residential fuel shares for space and water heating were from Enbridge Gas' 2019 residential end-use study. The commercial figures were estimates back-calculated from the 2019 APS by comparing electricity and gas consumption for a given end-use.

[36] Assumed lifetimes for gas equipment are 18 years for space heating equipment and 12 years for water heating equipment.

Appendix E Critical Driver Data Inputs and Assumptions: Cost of Natural Gas

To estimate how customer demand for gas changes in response to prices, the following prices were used to reflect a customer's bill, by sector:

- Commodity price of natural gas
- Transportation, distribution, and customer charges ("other bill charges")

The commodity price component of a customer's bill was varied in the scenarios, while other bill charges were held constant in all scenarios. Carbon price was treated separately as its own CD as it was varied independently from commodity price.

Commodity Price of Natural Gas

The following price settings were used for commodity price of natural gas. Data on 2019 prices came from Enbridge Gas and were increased over the forecast period based on the Dawn Hub consensus forecast. The high and low cases were 400% and 50% of the Reference Case, respectively, as per direction from EGI.

Exhibit 99 - Gas Commodity Price Settings (c/ m^3)

	Gas Commodity Price Settings (c/m^3)		
	Low	**Reference**	**High**
2019	11.75	11.75	11.75
2020	8.55	8.55	8.55
2021	5.28	10.56	42.23
2022	5.60	11.21	44.83
2023	5.77	11.55	46.18
2024	5.93	11.87	47.48
2025	6.10	12.19	48.78
2026	6.23	12.46	49.84
2027	6.36	12.71	50.85
2028	6.49	12.98	51.93
2029	6.62	13.24	52.95
2030	6.76	13.51	54.05
2031	6.90	13.80	55.22
2032	7.04	14.08	56.33
2033	7.18	14.36	57.45
2034	7.33	14.66	58.64
2035	7.48	14.96	59.85
2036	7.63	15.27	61.08

	Gas Commodity Price Settings (c/m^3)		
	Low	**Reference**	**High**
2037	7.79	15.58	62.33
2038	7.95	15.90	63.61

Other Bill Charges

Other components of a customer's bill include transportation costs, distribution, and customer charges. Enbridge Gas provided price information for Rate 1 and Rate 6 which were used for Residential and Commercial customers. The Canada Energy Regulator's "Canada's Energy Future 2019 Ontario Industrial Gas End-Use Price Forecast" was used for Industrial customers.

Distribution charges were increased using the Consumer Price Index (using the OEB approved formula). Transportation charges and customer chargers were held constant in each year of the forecast period.

These costs did not vary in the scenarios therefore the 'reference' setting was used in the all the scenarios (while commodity price and carbon price varied).

Exhibit 100 - Other Bill Charges by Sector (c/m^3)

	Residential	Commercial	Industrial
2019	25.16	16.32	14.66
2020	25.16	16.32	14.66
2021	25.33	16.45	14.78
2022	25.50	16.59	14.91
2023	25.68	16.73	15.03
2024	25.86	16.88	15.16
2025	26.04	17.02	15.29
2026	26.22	17.17	15.43
2027	26.41	17.32	15.56
2028	26.60	17.47	15.70
2029	26.79	17.63	15.84
2030	26.99	17.79	15.98
2031	27.19	17.95	16.13
2032	27.40	18.11	16.27
2033	27.60	18.28	16.42
2034	27.81	18.45	16.58
2035	28.03	18.62	16.73
2036	28.25	18.80	16.89
2037	28.46	18.97	17.04
2038	28.68	19.15	17.20

Appendix F *Assumptions for Hydrogen, RNG and Industrial Electrification*

Several assumptions were made for hydrogen, RNG and Industrial Electrification:

- *Steady Progress Scenario:* Enbridge Gas begins to deliver 10% hydrogen to residential and commercial customers in 2035.
- *Electricity Centric Scenario:* The fuel shares for residential and commercial space heating is 27% and 24% respectively by 2038 (approximately 800,000 customers). As the natural gas system is contracting, investment into adding new hydrogen loops (additional customers) is not made. Blend percent is increased from 2% to 10% in 2035 for customers on existing hydrogen loop (21,000 customers).

Exhibit 101 – Hydrogen Blend in the Steady Progress and All Electric Scenarios

	Steady Progress Scenario (# customers receiving 10% H2)	All Electric Scenario (#customers receiving 10% H2)
2035	200,000 customers	18,760 customers
2038	800,000 customers	20,770 customers

The following fuel blends were used in the Diversified Portfolio scenario. R&C is short for the "residential and commercial sectors".

Exhibit 102 – RNG and Hydrogen Blends in the Diversified Portfolio Scenario

	2025	2030	2035	2038
RNG (% of total energy)	0.5% (starts)	5%	10%	13%
% of R&C system converted to 100% H2		1%	10%	25%
% of R&C receiving 10% H2 blended gas	1%	10%	30%	60%
Percent of Identified Industries converting to H2 (see table below)		Begin conversion to H2 at 5% per year	30%	45%

The following Exhibit 103 provides the assumptions for the electrification potential and hydrogen conversation potential for the Industrial sector by segment.

Exhibit 103 – Industrial Sector Electrification Potential and Hydrogen Conversion Potential by Segment

Segment	Electrification Potential	Diversified (H2 conversion)
Agriculture	HVAC, water and steam	H2, all end-uses (except direct feedstock)
Chemicals Mfg	No	No, CCS
Fabricated Metals Mfg	HVAC, water and steam	H2, all end-uses (except direct feedstock)
Food and Beverage Mfg	HVAC, water and steam	H2, all end-uses (except direct feedstock)
Mining; Quarrying and Oil & Gas Extraction	No	No
Non-metallic Minerals Product Mfg	HVAC, water and steam	No, CCS
Other Industrial	No	No
Petroleum Mfg	No	No, CCS
Plastic and Rubber Mfg	No	H2, all end-uses (except direct feedstock)
Power and Other Utility	No more gas fired power generation as of 2035 for electricity,	No, CCS
Primary Metals Mfg	HVAC, water and steam	No, CCS
Pulp; Paper; and Wood Products Mfg	HVAC, water and steam	H2, all end-uses (except direct feedstock)
Transportation and Machinery Mfg	HVAC, water and steam	H2, all end-uses (except direct feedstock)
Water & Wastewater Treatment	HVAC, water and steam	H2, all end-uses (except direct feedstock)
Equipment Turnover Assumptions	Starting in 2030, 'HVAC' and 'Process (water and steam)' end-uses electrify at the rate of equipment turnover for the relevant segments	Industrial segments start converting in 2030: convert at rate of equipment turnover.

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Appendix G DSM Modelling Method

The following steps were taken to apply DSM to the ETSA scenarios based on the DSM budget amounts specific in each scenario:

- Determine the avoided cost based on the gas price and carbon price in each scenario.
    - Apply the Total Resource Cost (TRC) effectiveness test to determine which measures are cost-effective.
    - Update the payback acceptance curves based on the avoided costs and the resulting measures that pass the economic screen.
- Define the DSM budget in each year, and then solve for the combination of measures and incentive levels that provide the most savings in each year within that year's budget.
- Apply the energy savings potential to each of the scenarios.

Measure input assumptions were primarily from the APS conducted for the IESO and OEB. PG and Enbridge Gas conducted an extensive review of the measure input assumptions used in the APS and adjusted them based on the best Ontario-specific information available. The objective was to produce the best estimate of potential savings that can be obtained by programs, which was distinct from the achievable potential estimated by the APS. At the time of the ETSA modeling, EGI's 2022-2027 DSM application had yet to be filed, approved, and finalized. While annual DSM budget amounts for 2022 to 2027 in the scenarios may align with proposed DSM Plan spending targets, the modeled DSM savings in the ETSA scenarios may differ from forecasted or actual DSM Plan savings, as the specific measures and adoption assumptions in the proposed and approved DSM program may vary from those used in the ETSA DSM model.

Appendix H Stakeholder Engagement

Enbridge Gas engaged with internal and external stakeholders for this ETSA project in the following ways:

- The scenario narratives, list of critical drivers and input assumptions for critical drivers in each scenario were developed by PG through consultation with internal subject experts and were presented to external stakeholders to solicit feedback. Where possible, publicly available third-party information was used to inform the input assumptions.
- Enbridge Gas collected input from internal subject matter experts through a series of meetings and electronically via emails and surveys. Internal subject matter experts were from the following departments: Energy Transition Planning, Business Development, Marketing and Energy Conservation, Customer Care, Finance, Regulatory, Engineering, Energy Services, and Public Affairs.
- External input was sought from Building Knowledge Canada on the impact of building codes on building energy usage. Additionally, an external stakeholder consultation was held with members of Toronto District 2030, which is a public-private initiative comprised of IESO, Toronto Hydro, Canadian Green Building Council, Enwave, housing developers, architects, and academics. Feedback from Toronto District 2030 members was collected during the consultation and through a follow up survey. Comments received were generally supportive of the ETSA work and encouraged Enbridge Gas to complete decarbonization planning, with a goal of absolute zero GHG emissions by 2050.
- The feedback received from internal subject matter experts and external stakeholders was considered in finalizing the scenario narratives and input assumptions.

PATHWAYS TO NET ZERO EMISSIONS FOR ONTARIO

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June 2022, Revised April 2023

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Disclaimer

This deliverable was prepared by Guidehouse Inc. for the sole use and benefit of, and pursuant to a client relationship exclusively with Enbridge Gas Inc. (“Client” or “Enbridge Gas”), and for purposes of filing in a regulatory proceeding before the Ontario Energy Board. The work presented in this deliverable represents Guidehouse’s professional judgement based on the information available at the time this report was prepared (June 2022). Guidehouse is not responsible for a third party’s use of, or reliance upon, the deliverable, nor any decisions based on the report. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings, and opinions contained in the report. /u

While this study aims to adequately simulate an increasingly integrated electricity and gas system in Ontario, the results of this analysis are not intended to dictate when and where infrastructure investments will take place. The results presented in this report are purely reflective of a cost optimization modelling exercise and may not reflect specific technical, operational, and locational (spatial) constraints of the Ontario electricity and gas systems. The pathway results presented in this report are contingent on developments in provincial and federal energy policy, regulation, and other related areas. All analysis is based on credible assumptions, but these are subject to the uncertainty typical in long-term forecasting exercises. Findings from this study should be read in this context and should take into consideration limitations of the analysis.

Executive Summary

In July 2021, the Government of Canada committed to reducing its greenhouse gas (GHG) emissions by 40%- 45% below 2005 levels by 2030, and to achieve net zero emissions by 2050.[1] Achieving net zero emissions means the Canadian economy either emits no GHG emissions or emits a small amount of emissions that are offset through actions such as reforestation or capturing carbon before it is released into the air.[2] Policymakers at all levels of government are developing new climate policies to support the achievement of these targets. In November 2020, Enbridge Inc. (Enbridge) was among the first North American midstream energy companies to announce a target of net zero emissions by 2050.[3] Enbridge Gas Inc. (Enbridge Gas), which serves over 98% of the natural gas demand in Ontario, has an interest in both understanding the role of the company's existing gas distribution system under ambitious federal and provincial emission reduction policies and in helping its customers and the province to achieve their emission reduction goals.

Enbridge Gas commissioned Guidehouse to evaluate two different scenarios that achieve net zero emissions for Ontario by 2050, to chart GHG reduction pathways that can achieve these net zero emissions scenarios, and to examine each pathway in terms of overall feasibility, energy system capacity, system reliability and resiliency, GHG emissions reductions, and cost. The objective of this analysis was not to determine the best or most likely pathway to net zero for the entire energy system. Rather, this analysis was meant to examine how Ontario's energy systems can support the achievement of net zero emissions in Ontario by 2050, including identifying what investments in electricity, hydrogen, and methane supply capacity, storage, and infrastructure would be required. This report does not contemplate how future technology innovations could change the identified investment requirements. Note that this analysis represents data available and market conditions in June 2022 when the report was first published. /u

This report presents the findings from that analysis, which concluded that a diversified approach that includes a targeted approach to electrification tied with deployment of low- or zero-carbon gases, including renewable natural gas (RNG), hydrogen, and natural gas with carbon capture, is the most cost-effective and resilient method to achieve net zero emissions in Ontario. The analysis found that a diversified approach that leverages existing gas delivery infrastructure to deliver low-carbon fuels and offers cost savings compared to an electrification focused approach that would underutilize existing infrastructure. The analysis also demonstrates the role gas delivery infrastructure has in both approaches, delivering low-carbon fuels across sectors in the diversified approach and for hard-to-abate sectors like industry and heavy transport in an electrification approach. This is consistent with the findings of similar analyses Guidehouse has conducted regarding utilities' roles in energy transition across Europe and North America[4]. Similarly, these studies consistently found that net zero pathways that focus on a diversified approach can achieve GHG reductions at a lower cost and achieve greater energy system resiliency. This report is intended to provide quantitative and

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[1] Government of Canada (2021). Canada's Climate Actions for a Healthy Environment and a Healthy Economy. Available: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/actions-healthy-environment-economy.html

[2] Government of Canada (2021). Net-Zero Emissions by 2050. https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/net-zero-emissions-2050.html

[3] This net-zero target includes scope 1 (direct emissions from operations such as stationary fuel combustion, mobile combustion, and fugitive, flaring, and vented emissions) and scope 2 (indirect emissions from purchased and imported electricity consumption) emissions. It does not include scope 3 (selected indirect emissions related to operations: utility customers' natural gas use, business travel, and transmission and distribution (T&D) losses from electricity usage) emissions.

[4] For example, Guidehouse (2020). Pathways for British Columbia to achieve its GHG reductions goals. Available: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf; Navigant (2019). Gas for Climate 2050: The optimal role for gas in a net zero emissions energy system (Europe). Available: https://gasforclimate2050.eu/wp-content/uploads/2020/03/Navigant-Gas-for-Climate-The-optimal-role-for-gas-in-a-net-zero-emissions-energy-system-March-2019.pdf; Navigant (2019). Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain. Available: https://www.energynetworks.org/industry-hub/resource-library/pathways-to-net-zero-decarbonising-the-gas-networks-in-great-britain.pdf; McKinsey (2020). How the European Union could achieve net zero emissions at net-zero costs. Available: https://www.mckinsey.com/business-functions/sustainability/our-insights/how-the-european-union-could-achieve-net-zero-emissions-at-net-zero-cost; UK Climate Change Committee (2020). The Sixth Carbon Budget - The UK's path to Net Zero. Available: https://www.theccc.org.uk/wp-content/uploads/2020/12/The-Sixth-Carbon-Budget-The-UKs-path-to-Net-Zero.pdf

qualitative information about the total costs, benefits, and risks of the two net zero pathways, that are required to generate dialogue and solutions-focused thinking about approaches for GHG reduction.

Scenario Analysis Methodology

Guidehouse developed two scenarios for Ontario's energy system to achieve net zero by 2050:

- A **Diversified Scenario** in which low and zero carbon gases and the gas delivery infrastructure are used in combination with end-use electrification to reduce GHG emissions in all sectors.
- An **Electrification Scenario** that focuses on electrification of all sectors, with low and zero carbon gas use limited to cases where no reasonable alternative energy source exists.

Both scenarios share similarities that reflect accepted and well-understood approaches to GHG emissions reduction for several subsectors (e.g., energy efficiency and building codes reduce heating energy demand, light duty road transport is electrified, the steel industry uses hydrogen to reduce GHG emissions). Nevertheless, there are some key differences between the scenarios, illustrated in Figure ES-1.

To model cost-optimal net zero pathways to 2050 for these two scenarios, this study uses an integrated energy system model: Guidehouse's Low Carbon Pathways (LCP) model. This model was adapted to the characteristics of Ontario's gas and electricity networks, including evolving energy supply-demand conditions, and interties with neighbouring regions. This study includes technologies that are commercialized or are near commercialization today, and it does not include future technologies that may evolve to reduce GHG emissions.

Figure ES-1. Description of Demand Scenario Hypotheses

Diversified Scenario		Electrification Scenario	
BUILDINGS	Gas heating continues to play a key role in building heating, complemented by electric heat pumps. Gas-equipped buildings shift to gas-powered heat pumps, fueled by low- or zero-carbon gas. Energy efficiency and building codes reduce heating energy demand.	BUILDINGS	Electric heat pumps replace most natural gas heating in buildings. The small share of buildings that remain on gas adopt gas-powered heat pumps, fueled by low- or zero-carbon gas. Energy efficiency and building codes reduce heating energy demand.
TRANSPORT	Hydrogen plays a major role in all heavy transport. Light road transport is largely electrified using battery electric vehicles. RNG (as bio-CNG) plays a role in heavy road transport.	TRANSPORT	Electrification and biofuels play major roles in all transport methods. Hydrogen's role is limited to aviation (via synthetic kerosene).
INDUSTRY	Low temperature processes are electrified; medium and high temperature processes are served by hydrogen or methane gas with carbon capture.	INDUSTRY	Low and medium temperature processes are electrified. High temperature processes are served by hydrogen or methane gas with carbon capture.

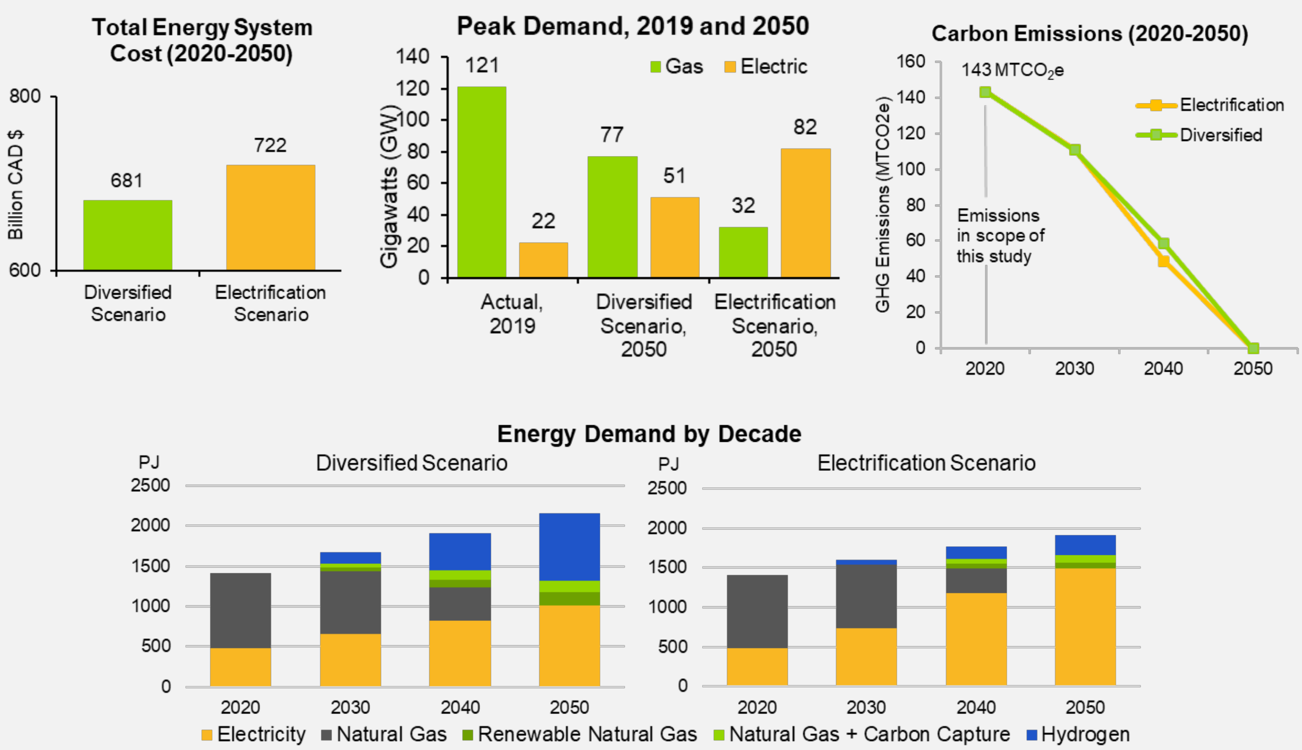
Summary of Results

The study's key findings are as follows:

- The Diversified and the Electrification Scenarios both achieve interim 2030 targets and net zero GHG emissions by 2050.
- The pathway to a Diversified scenario saves $41 billion by 2050 compared to the Electrification pathway because the Diversification scenario requires less new electric infrastructure to meet peak demand.
- Both pathways will require a significant scale up of electrical infrastructure.
    - Electric peak demand will increase twofold in the Diversified scenario or nearly fourfold in the Electrification scenario.
    - This will require changes to electricity capacity and infrastructure planning and to the speed of new development.
- The development of carbon storage in Ontario will be critical in both scenarios.
- The electricity and gas systems will become increasingly integrated in the future.
    - Gas-powered generation will play a critical role in Ontario's electricity system, and electricity generation will shift from natural gas to hydrogen sources.
    - Residential hybrid heating systems can reduce peak electric load and save Ontario an additional $9 billion by 2050 /u compared to alternative heating systems in the base Diversified scenario. /u
- In both Pathways, gas infrastructure must evolve to deliver RNG and hydrogen.
    - Ontario will need a dedicated network of hydrogen pipelines and some gas infrastructure in the province will be repurposed to deliver hydrogen.
    - Domestic sources of low- and zero-carbon gas will be developed in Ontario /u and will reduce Ontario's reliance on gas imports in both scenarios.
- Energy system resilience will be a key consideration as peak electric demand grows in both scenarios.
    - The Diversified Pathway provides resilience and reliability benefits and provides solutions for hard-to-electrify sectors, such as industrial customers and heavy transport vehicles.

The Diversified Pathway achieves interim 2030 emissions targets and net zero emissions by 2050 at a lower total cost, with a lower electric system peak demand compared to the Electrification scenario. These summary results are illustrated in Figure ES-2.

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



Sensitivity Analysis

As with any analysis attempting to model a future integrated energy system, the results of this analysis are uncertain, and real-world outcomes may vary greatly if growth trends and price conditions vary from assumptions. To understand how the findings of this study may be influenced by different assumptions, Guidehouse analyzed four sensitivity cases.

Sensitivity 1. Increased Decentralized Electricity: Assumes that solar energy, wind energy, and battery storage decline in cost, leading to rapid deployment of distributed energy resources (DER), with 50% of new capacity located behind the meter.
Outcome: In both scenarios, the reduced cost for renewables and electric storage resulted in an increased deployment of decentralized renewable capacity. This yields cost savings of $12 billion for the Electrification scenario and $11 billion for the Diversified scenario. /u

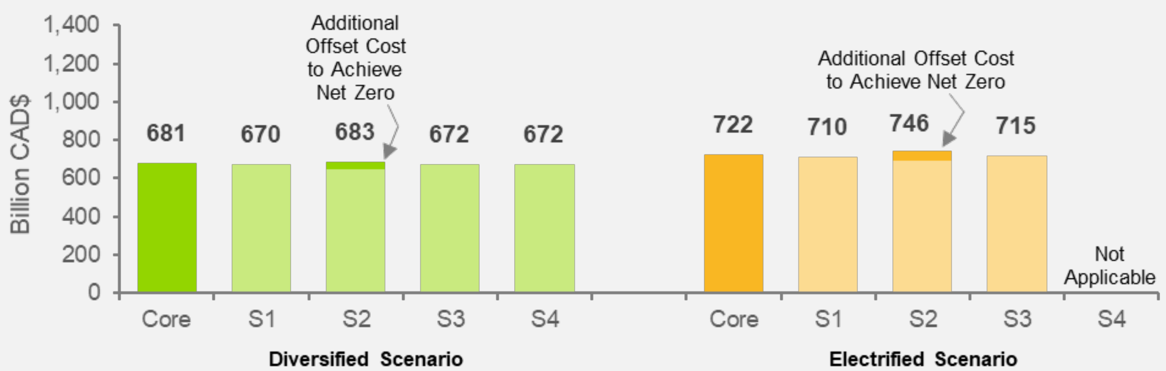
Sensitivity 2. Limited Investment in Gas Supply and Infrastructure: Explores how a decrease in the gas infrastructure investment included within both scenarios would impact Ontario's ability to meet net zero emissions by 2050.
Outcome: Decreasing future investments in the gas system through 2050 is projected to cause /u
unabated emissions of more than 13 $MTCO_2$ in 2050 for either scenario. From the Diversified or /u
Electrified pathways, significant reductions in gas system spending will result in even greater spending towards emissions offsets to achieve net zero emissions by 2050.

Sensitivity 3. Lower Electrolyzer and Hydrogen Storage Costs: Assumes that electrolyzer and wind costs are reduced by over 50% and hydrogen storage costs are reduced by 25% /u
compared to the scenario assumptions.
Outcome: Lower electrolyzer costs lead to an increase in the buildout of electrolyzer capacity and an increase in hydrogen production from renewable energy sources. Lower wind costs lead to savings of $7 billion for the Electrification scenario and $9 billion for the Diversification scenario. /u

Sensitivity 4. Adoption of Hybrid Heating Technologies: Assumes that a significant portion of residential buildings adopt hybrid heating systems that combine electric heat pumps with high efficiency gas-fired furnaces fueled by low- or zero-carbon gas.
Outcome: The deployment of hybrid heating systems reduces electrical peak loads in the Diversified scenario and has the potential to save $9 billion in total energy system costs /u
compared to the core Diversified Scenario.

These sensitivity cases had several commonalities. Like the Diversified and Electrified pathways, all the sensitivity cases required a large buildout of renewable generation capacity and hydrogen supply. Figure ES-3 summarizes the impact that these sensitivity cases have on total energy system costs from 2020-2050 and demonstrates that the findings of this analysis are not highly sensitive to reductions in the cost of hydrogen production or distributed generation. Figure ES-3 also illustrates that for sensitivity 2, the additional costs of emissions offsets required to achieve net zero make sensitivity 2 more costly than the central Diversified and Electrified scenarios. The figure shows that changes to these assumptions do not alter the key finding of this analysis, that net zero emissions is less costly to achieve in a Diversified scenario than in an Electrified scenario.

Figure ES-3. Sensitivity Analysis Results, Total Energy System Costs (2020-2050) /u



Policy Implications

This report identifies a set of strategic actions and initiatives for Ontario's energy stakeholders to implement within the next few years, described in Figure ES-4.

Figure ES-4. Strategic Actions and Initiatives for Ontario's Energy Stakeholders

	Electricity	Hydrogen	RNG	CCS
Government Ministries	• **Streamline the permitting and approval process for generation and transmission infrastructure** and make the process more predictable. • **Analyze the potential economic value and societal impacts of wind power in the province,** to bolster support for wind energy, and **initiate citing studies** to provide clear direction to plan transmission needs. • The Ministry should **develop an electricity system pathway** that supports the reduction of GHG emissions of Ontario's economy by 2050.	• **Define medium-term (2030) and long-term (2045) planning targets** for hydrogen supply.[5] • **Investigate market measures and incentives that support hydrogen adoption** such as low carbon fuel incentives, carbon pricing, targets for fuel cell electric vehicle (FCEV) and hydrogen-fueled appliance deployment, and renewable gas mandates. • **Expand the regulatory oversight of the Ontario Energy Board (OEB) to include hydrogen,** hydrogen-derivatives and the associated supply, transport, and storage infrastructure. • **Enable carbon capture and storage** for blue hydrogen production.	• **Define binding medium-term (2030) and long-term (2045) RNG production targets** to provide a long-term investment horizon for RNG market players. • **Investigate supply and demand market measures that can bolster RNG adoption** in Ontario (e.g., guarantees of origin, RNG registers, low-carbon fuel incentives, waste reduction policies), and renewable gas mandates.	• **Amend prohibitions on the injection of carbon dioxide for storage** to allow potential carbon storage for the purpose of GHG emission abatement. • **Develop a streamlined permitting regime for approving CCS projects** that encourages commercial-scale CCS projects.
Ontario Energy Board	• **Lead the development of an integrated energy planning working group** involving major electricity and gas utilities. • **Develop regulatory structures that measure and value energy system resilience** and require consideration of resilience as a part of all utility planning efforts.	• **Gather stakeholder views and investigate best practices** for a hydrogen regulatory framework. • **Allow utilities to recover the cost of hydrogen at a different cost than natural gas** and in line with the market price of hydrogen.	• **Work with the Ministry of the Environment** to ensure existing and future environmental regulations are supportive of RNG production. • **Allow utilities to recover the cost of RNG at a different cost than natural gas** and in line with the market price of RNG.	• **Develop regulatory structures that facilitate the adoption of CCS** from fuel-fired electric generation.

[5] A planning target is not intended to be legally binding; rather, it is a strategic objective that can provide clarity for electricity and gas system planning and regulatory planning.

	Electricity	Hydrogen	RNG	CCS
Gas and Electric Utilities and System Operators	• **Develop a GHG emissions reduction pathway for the electricity and gas systems** to achieve Ontario's economy-wide net zero target by 2050 while controlling costs and maximizing GHG reductions.[6]	• **Conduct pilots** to assess the hydrogen readiness of the existing gas system (Enbridge Gas has pilot projects underway). • **Develop a made-in-Ontario hydrogen infrastructure plan** akin to National Grid's Project Union in the UK, Gasunie's HyWay 27 in the Netherlands, and SoCal Gas's Angeles Link Project.[7,8,9] • **Conduct an electricity transmission impact assessment** to identify future network impacts of green hydrogen production.	• **Develop tariffs specific to RNG.** Having separate rates for RNG and conventional natural gas may incentivize project development by RNG suppliers, as utilities would be able to recover the higher cost associated with RNG.	• **Develop pilot CCS projects** to demonstrate feasibility of CO_2 collection, transport, and sequestration.

[6] This recommendation covers a larger scope than the Ministry's October 2021 directive, which only covers the decarbonization of the electricity system, not the entire economy.
Ministry of Energy (October 2021). Available: https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-Minister-Gas-Phase-Out-Impact-Assessment.ashx

[7] National Grid. Project Union. Available: https://www.nationalgrid.com/stories/journey-to-net-zero-stories/making-plans-hydrogen-backbone-across-britain

[8] Gasunie. HyWay 27. Available: https://www.gasunie.nl/en/expertise/hydrogen/hyway-27

[9] SoCal Gas (2022). Application of Southern California Gas Company (U904g) for Authority to Establish a Memorandum Account for the Angeles Link Project. Available: https://www.socalgas.com/sites/default/files/A22-02-SOCALGAS-Angeles_Link_Memorandum_Account_Application.pdf

Table of Contents

/u

/u

List of Tables

List of Figures

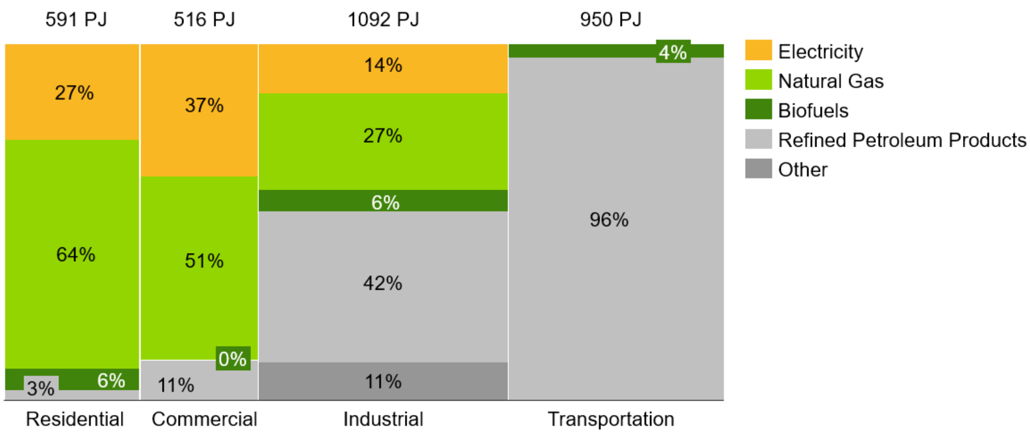
/u

1. Introduction

Canada has set ambitious greenhouse gas (GHG) emissions reduction targets, including the achievement of net zero GHG emissions by 2050. An interim emissions reduction target has also been established, targeting a 40%-45% reduction by 2030 compared to 2005 levels (equal to a 20% reduction from today). Ontario's current climate targets, which were set before the new federal targets were established, commit the province to a 30% reduction below 2005 levels by 2030 (a 10% reduction from today).

Ontario has made significant progress in reducing the GHG emissions of its energy system. Following the decommissioning of the coal-fired electricity generation fleet, Ontario's electricity mix is largely made up of low carbon and renewable electricity. Ontario's electricity system, however, only accounts for a small fraction of the province's total energy demand. In 2019, electricity represented only 16% of /u
total energy demand across all sectors – residential, commercial, industrial and transportation – while natural gas and petroleum accounted for 30% and 46% of demand, respectively.[10] The use of natural /u
gas in Ontario is largely associated with heating residential and commercial buildings, and industry, as shown below in Figure 1, whereas the use of petroleum is largely associated with industry and transport.

Figure 1: Ontario Energy Demand by Sector and Fuel (2019)[11] /u



[10] Canada Energy Regulator (2021). Canada's Energy Future 2021: Energy Supply and Demand Projections to 2050. Available: https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA
[11] Ibid.

Figure 2: Ontario's Historical GHG Emissions by Sector (1990-2020)[12]

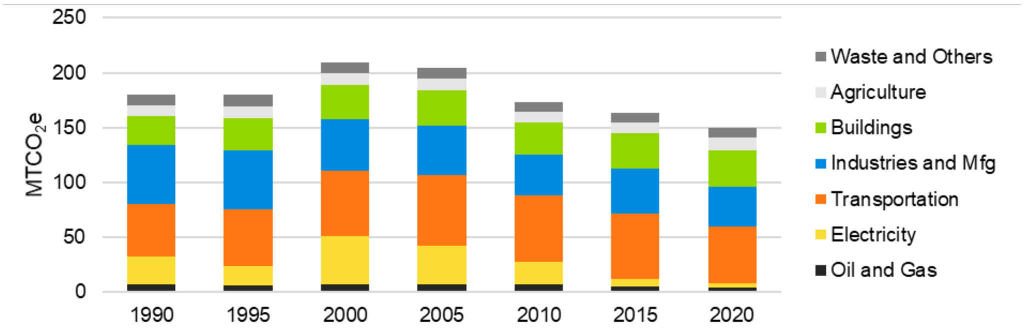


Figure 2 presents Ontario's historical GHG emissions by sector. The challenge of reducing GHG emissions is not unique to Ontario. Most of Canada's provinces and territories, along with most other world economies, are facing the need to reduce GHG emissions from high-emissions sectors, including building heating, transport, and industry. How best to reduce GHG emissions from these sectors and how to do it cost-effectively are some of the key questions policymakers and regulators are faced with today. This study focuses on the challenge of reducing GHG emissions from these sectors and provides insight and guidance to policymakers.

This report explores two potential pathways for Ontario to achieve a net zero future by 2050, focusing primarily on the roles of the gas and electric systems in reducing GHG emissions in the province. The report takes an Ontario-specific view that considers the province's unique electricity and gas systems, its energy infrastructure and resources, and how those can be leveraged to reduce GHG emissions in the building heating, transport, and industry sectors.

The objective of this report is to compare the two potential scenarios and, within the constraints of the scenarios, identify the most cost-effective pathway to net zero emissions based on the information available at the time the report was prepared. Additionally, this report addresses the following questions:

- **What role can electricity and low- and zero-carbon gas play** in achieving a net zero future in Ontario by 2050?
- **What pathways** could achieve the net zero scenarios defined for 2050? **What will it cost** to pursue these pathways and **how feasible are they**?
- **What are the major implications and opportunities** of Ontario's transition to net zero?

The remainder of the report is divided into the following sections:

- **Ontario's Energy Systems:** describes the current state of Ontario's electricity and gas systems. This section also provides background information on some of the future sources of low- and zero-carbon gases, like hydrogen and RNG.
- **Study Methodology:** describes the study approach and modelling methodology to assess different energy transition pathways for Ontario.
- **Developing Net Zero Scenarios for Ontario:** describes the two net zero scenarios developed for this study: a Diversified Scenario and an Electrification Scenario.
- **Comparing Pathways to a Net Zero Future** compares the results of the Diversified and Electrification Scenarios, identifies the least-cost pathways (given the constraints of each scenario) for Ontario to achieve net zero emissions, describes the impact of each sensitivity analysis, and describes challenges and opportunities.
- **Implications on Ontario's Energy System** describes key implications for Ontario associated with achieving interim GHG emissions targets and setting the province on a net zero pathway.

[12] Government of Canada (2022). Canada's Official Greenhouse Gas Inventory. Available: https://data.ec.gc.ca/data/substances/monitor/canada-s-official-greenhouse-gas-inventory/A-IPCC-Sector/?lang=en

2. Ontario's Energy System

Ontario has an extensive energy system with electricity and gas infrastructure spanning most of the province and serving as mainstays for economic activity in the province.

The **electricity transmission system**—primarily operated by Hydro One—is made up of over 30,000 km of high voltage power lines connecting electricity supply resources across Ontario with major demand centres.[13]

The **natural gas transmission system**—primarily operated by TC Energy and Enbridge Gas—is made up of roughly 5,500 km of high-pressure pipelines connected to upstream pipelines and supply basins across North America.[14] The natural gas distribution system, which is the distribution backbone of gaseous energy in the province, includes about 148,000 km of main and service lines.[15]

As illustrated in Figure 1, a large portion of Ontario's energy demand is presently served by refined petroleum products such as gasoline. In particular, consumption of petroleum products in Ontario's transportation sector represented 29% of the total energy demand from buildings, industry, and transport. Though not discussed in detail here, this analysis modeled the transportation sector's shift from a reliance on refined petroleum products to electricity and low- and zero-carbon gases. /u

2.1 Ontario's Electricity System

Ontario's electricity system has an installed generation capacity of approximately 40 GW, producing approximately 150 TWh of electricity every year. Ontario's annual electricity consumption is roughly 135 TWh, and in 2020 the province's net exports of electricity to neighbouring regions were 15.2 TWh.[16] Ontario's revenues from exported electricity are often less than the cost of production.[17] Over the last 5 years, 93% of the electricity produced in Ontario was low emissions or emissions-free, with 61% of electricity supply being generated from nuclear power, 25% from hydro, and 7% from renewables. Only 7% of Ontario's electricity supply is generated from natural gas despite natural gas turbines making up approximately 28% of installed generation capacity.[18]

While electricity supply from natural gas is limited, natural gas-fired peaking plants play a critical role in supporting Ontario's electricity system to meet system peaks cost-effectively while maintaining system reliability. The importance of the natural gas fleet to the electricity system was highlighted by a recent IESO study[19], which estimated the costs of decommissioning the natural gas fleet to eliminate

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[13] Hydro One (2021). Our Subsidiaries. Available: https://www.hydroone.com/about/corporate-information/subsidiaries

[14] Enbridge Gas (2020). 2019 Annual Report. Available: https://www.enbridge.com/investment-center/reports-and-sec-filings/~/media/Enb/Documents/Investor%20Relations/2020/ENB_2019_Annual_Report.pdf

[15] Enbridge Gas (2021). Infrastructure Map. Available: https://www.enbridge.com/Map.aspx#map:infrastructure

[16] IESO (2021). 2021 Annual Planning Outlook, December 2021. https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook /u

[17] OSPE (2017). Empower Ontario's Engineers to Obtain Opportunity. Available: https://ospe.on.ca/public/documents/advocacy/submissions/OSPE_Electricity_Export_Analysis.pdf

[18] IESO (2021). Generator Output by Fuel Type. Available: http://reports.ieso.ca/public/GenOutputbyFuelMonthly/

[19] IESO (2021). Decarbonization and Ontario's Electricity System. Available: https://www.ieso.ca/en/Learn/Ontario-Supply-Mix/Natural-Gas-Phase-Out-Study

GHG emissions from the electricity system by 2030. The report found that, even in an optimistic scenario, eliminating natural gas generation in Ontario by 2030 would require over $27 billion of investment and result in a 60% increase to ratepayers' electricity bills. Phasing out Ontario's 11 GW gas fleet would require adding at least 17 GW of non-emitting generation capacity (e.g., wind, solar, battery storage, demand response, and imports, among others), 1.6 GW of energy efficiency improvements, and significant investment in transmission infrastructure. The IESO study concluded by recognizing the potential that alternative technologies could have in enabling more cost-effective pathways to reducing emissions from the natural gas fleet; among these, the use of hydrogen-fired peaking plants was discussed. Another pillar of Ontario's electricity supply mix is its 13 GW nuclear fleet. Ontario's nuclear fleet has provided most of its baseload electricity for decades—roughly 60% of total supply in recent years. However, there are plans to retire the Ontario Power Generation Pickering nuclear plant beginning in 2024/2025,[20] leaving a meaningful firm capacity supply gap. Replacing this gap with fossil fuels would lead to an increase in GHG emissions in the province, so renewables and energy efficiency will need to be leveraged to minimize the GHG impact of nuclear retirements.[21] It should be noted that Ontario Power Generation has planned to install 0.3 GW of /u Small Modular Reactors (nuclear SMR) to be completed as early as 2028, but this is not nearly enough to mitigate the effects of the Pickering nuclear plant retirements.[22] The importance of Ontario's nuclear fleet may, in the future, extend beyond the electricity system. On April 7, 2022, the Government of Ontario published its first Low-Carbon Hydrogen Strategy and, as one of eight immediate actions to enable production and expand the low-carbon hydrogen economy, the strategy calls for Bruce Power to explore opportunities to leverage excess energy from the Bruce station for hydrogen production.[23] Bruce Power intends to use electrolysis to produce hydrogen from nuclear and renewable power when electricity demand is low instead of curtailing power.[24]

Ontario's electricity grid does not operate in isolation; it is part of a highly interconnected transmission network with neighbouring provinces and states. Ontario's electricity grid has interties with Quebec, Manitoba, New York, Michigan, and Minnesota. New York and Michigan are largely importers of Ontario's electricity, importing net 7-8 TWh/year and 9-10 TWh/year on average, respectively. Ontario also exports 1-3 TWh/year to Quebec; however, imports from Quebec are greater, with overall net imports of 2-5 TWh/year. Electricity trade with Manitoba and Minnesota is minimal.[25] Figure 3 shows electricity imports and exports in 2020 between Ontario and its neighbouring regions.

A 1 GW intertie called the Lake Erie Connector between southern Ontario and Pennsylvania has been proposed to connect the IESO to PJM, the largest electricity market in the world. Construction is expected to begin in 2022, with operation by the mid-to-late 2020s. This intertie will provide each with enhanced optionality to manage their energy needs and respond to shifting supply/demand conditions, outages, and system planning requirements.[26]

[20] Ontario Power Generation (2021). The Future of Pickering Generating Station. Available: https://www.opg.com/powering-ontario/our-generation/nuclear/pickering-nuclear-generation-station/future-of-pickering/

[21] Pollution Probe (2020). Replacing Pickering: The Next Step in the GTA's Clean Energy Transition. Available: https://www.pollutionprobe.org/energy/replacing-pickering/

[22] Ontario Power Generation Media Release (2021). Available: https://www.opg.com/media_releases/opg-advances-clean-energy-generation-project/ /u

[23] Government of Ontario (2022). Ontario's Low-Carbon Hydrogen Strategy. p.41. Available: https://www.ontario.ca/files/2022-04/energy-ontarios-low-carbon-hydrogen-strategy-en-2022-04-11.pdf

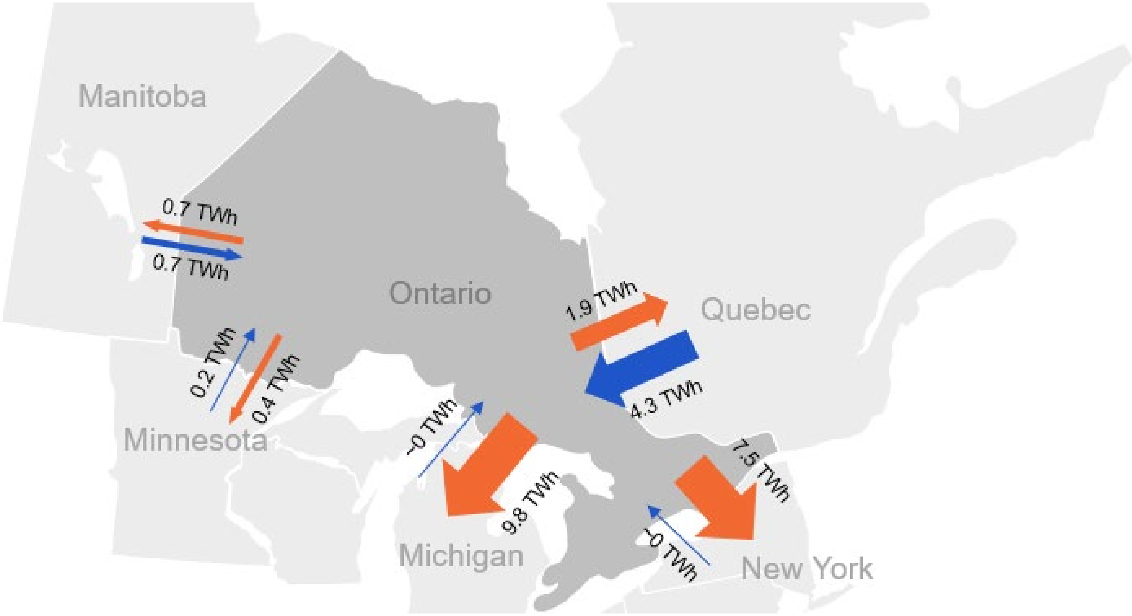
[24] Bruce County (2020). Foundational Hydrogen Infrastructure Project. Available: https://brucecounty.on.ca/sites/default/files/file-upload/bruce_innovates_-_foundational_hydrogen_infrastructure_project_-_overview_-_2020.pdf

[25] IESO (2021). Imports and Exports. Available: https://www.ieso.ca/en/Power-Data/Supply-Overview/Imports-and-Exports

[26] ITC Investment Holdings (2022). Lake Erie Connector Project. Available: https://www.itclakeerieconnector.com/

Figure 3. Electricity Imports and Exports with Neighboring Regions (2020)

/u



2.2 Ontario's Natural Gas System

In 2019, Ontario consumed approximately 940 PJ of natural gas.[27] Converted to electricity units, this is roughly 261 TWh, which is almost twice the province's annual electricity consumption (~135 TWh/year). Figure 4 shows this comparison of annual electricity and gas demand.

Natural gas demand is primarily driven by building heating (63% of demand) and industry (37% of demand), with very limited use in transport. Most of the natural gas consumed by buildings is used for heating during the winter months, and more than 80% of building heating in Ontario is fueled by natural gas.[28] Natural gas is also used in industrial processes such as the manufacturing of metals, chemicals, and fertilizers, and pulp and paper processes.[29]

[27] According to the Canada Energy Regulator's (CER's) Energy Futures 2021 report, natural gas demand in Ontario was 940 PJ in 2019, while it fluctuated between 800 PJ and 950 PJ over the 2010-2019 period. Enbridge Gas accounts for the vast majority of gas demand in the province, with limited additional gas demand from other gas distributors (some regulated and some not). For example, while the CER estimated Ontario-wide natural gas demand in 2019 at 941 PJ, the OEB reported natural gas demand from Ontario's regulated distributors (Enbridge Gas and EPCOR) at 939 PJ, or 26.7 billion cubic meters. Of this, Enbridge Gas accounted for 936 PJ, equivalent to 99.5% of demand reported by CER. Enbridge Gas's share of Ontario's total gas demand, however, has varied year-over-year. On average, from 2015 to 2019, Enbridge Gas accounted for 98.3% of gas demand.

Canada Energy Regulator (2021). Canada's Energy Futures 2021. Available: https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

Ontario Energy Board (OEB, 2019). 2019 Yearbook of Gas Distributors. Available: https://www.oeb.ca/utility-performance-and-monitoring/natural-gas-and-electricity-utility-yearbooks

[28] Natural Resources Canada (2021). Space Heating Secondary Energy Use. Available:
Residential Sector, Ontario:
https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/data_e/downloads/comprehensive/Excel/2018/res_on_e_8.xls
Commercial / Institutional Sector, Ontario:
https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/data_e/downloads/comprehensive/Excel/2018/com_on_e_24.xls

/u

[29] Statistics Canada (2021). Supply and demand of primary and secondary energy in natural units. Available: https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=2510003001

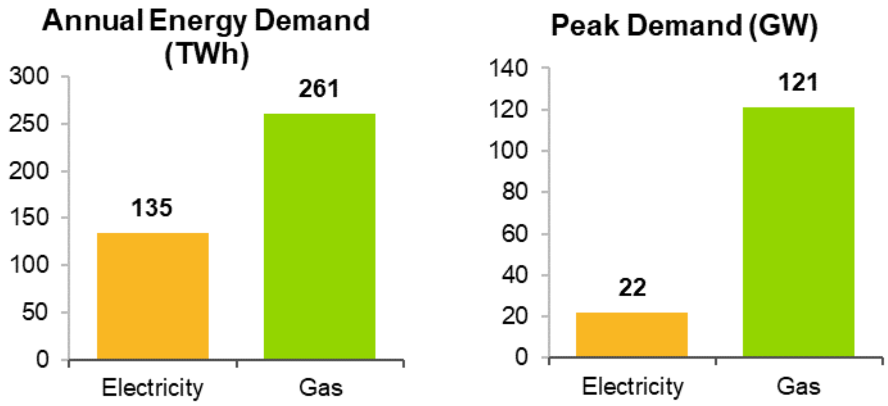
Natural gas plays a critical role in meeting peak energy demand. Ontario's peak-hour natural gas demand is approximately 435 TJ/hour,[30] which translates to approximately 121 GW. This is more than 5 times the magnitude of the electricity peak demand of 22 GW.[31]

Scope of Natural Gas Demand in this Study

This study models reductions in GHG emissions of the Ontario-wide energy system, aiming to capture all gas demand in the province. The baseline forecast of gas demand used in this analysis is based exclusively on Enbridge Gas demand, accounting for 98%-99% of gas demand in Ontario (see footnote 27). This also captures a small share of natural gas demand from industry for use as feedstock in non-energy purposes – roughly 1.5% or 15 PJ.[32]

The remaining 1%-2% of gas demand (not served by Enbridge Gas) is not explicitly captured. Nevertheless, future demand for low- and zero-carbon gases from new sectors such as transport and industry are captured.

Figure 4. Comparison of Ontario's Electricity and Natural Gas Demand (2019)



Ontario represents 24% of total natural gas consumption in Canada. However, with limited natural gas production in Ontario—representing less than 0.1% of total Canadian gas supply—Ontario is almost completely reliant on natural gas imports.[33] Ontario has historically relied on natural gas supply from Western Canada, also acting as a transit hub for natural gas export to the US. However, the Appalachian Basin, specifically the Marcellus and Utica shale gas formations, has experienced the most prolific natural gas production growth in North America. This abundant natural gas supply is located within the Great Lakes region near Ontario, the Dawn Parkway System, and other eastern North American-consuming markets.

This supply is delivered to Ontario through Michigan (via the Great Lakes Canada Pipeline Ltd./Great Lakes Gas Transmission; Vector Pipeline L.P.; DTE Energy/St. Clair Pipelines [St. Clair Pipelines L.P.]; Bluewater Gas Storage, LLC/Bluewater Pipeline [St. Clair Pipelines L.P.], Panhandle Eastern Pipeline, and Niagara Gas Transmission Limited LINK Pipeline) interconnecting to the Dawn Hub. Ontario is also interconnected with New York (via pipelines at Niagara and Chippawa), interconnecting with the Dawn Parkway System Kirkwall. As shale gas production from the US has scaled over the last decade, supply from Western Canada has declined, resulting in an increasing share of gas supply into Ontario coming from New York.

Balancing gas supply and demand in Ontario is largely supported by the province's gas storage resources. The Enbridge Gas-owned Dawn Hub is a natural gas storage facility in southwestern

30 Enbridge Gas internal analysis. Gas peak demand is 11 million m^3/hour, equivalent to ~435 TJ/hour.

31 IESO (2021). Hourly Demand Report. *PUB_Demand_2019*. Available: http://reports.ieso.ca/public/Demand/

32 The Ontario Fuels Technical Report (2016), prepared by Navigant (now Guidehouse) for the Ministry of Energy estimated non-energy natural gas demand by industry at 15 PJ in 2015.

33 Canada Energy Regulator (2021). Provincial and Territorial Energy Profiles. Available: https://www.rec-cer.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html?=undefined&wbdisable=true#s2

Ontario, with storage capacity of 281 Bcf (about 296 PJs or 82 TWh), equivalent to 30% of Ontario's annual natural gas demand.

Natural gas storage allows suppliers to minimize price volatility for customers because they can purchase and store gas when prices or demand are low and withdraw it when prices or demand are high. The Dawn Hub also provides Ontario security of natural gas supply during peak periods in case of shortages, emergencies, or extended cold waves. Beyond Ontario, the Dawn Hub plays a major role in the operation of the natural gas system across North America. The Dawn Hub is one of the most important natural gas trading hubs and pricing benchmarks, with access to supply routes from Western Canada, mid-continental US, the Rockies, the Gulf of Mexico, and markets in the Midwest, Eastern Canada, and the US Northeast.[34] The Dawn Hub is also connected through various upstream natural gas transmission pipelines to all major natural gas supply basins across Canada and the continental US including Western Canadian Sedimentary Basin in Alberta and the Marcellus shale production region in the US Northeast.

Natural gas is one of the most flexible forms of energy because, unlike electricity, it can be stored relatively inexpensively for long periods of time. This flexibility allows the gas system to deal with large fluctuations in demand and volume, which are common in Ontario due to the seasonal nature of space heating and process heating loads in the province. Serving Ontario's energy needs with a purely electric system would require building sufficient generation, transmission, and distribution capacity to meet those extreme energy needs in real time, for example, on low-wind and low-sun days, or when above-ground infrastructure is impacted by severe weather events like ice or high winds. Ontario's gas distribution infrastructure is largely underground, where it is protected from most weather events.

2.3 Low- and Zero-Carbon Gases

One approach to reducing GHG emissions in natural gas systems is to displace natural gas with low- or zero-carbon gases, such as RNG and hydrogen. This analysis considered the development of RNG and hydrogen resources in Ontario, as well as the importation of these gases from neighbouring provinces. This subsection provides a brief introduction to these technologies and summarizes the current status of these fuels in Ontario. Table 1 summarizes the primary technologies used to produce these fuels, followed by discussion of the technologies in scope for this analysis.

[34] Enbridge Gas (2021). The Dawn Hub. Available: https://www.enbridgegas.com/storage-transportation/doing-business-with-us/our-dawn-facility

Table 1. Renewable Natural Gas and Hydrogen Production Technologies

Renewable Natural Gas (RNG)			Hydrogen[35]	
Anaerobic Digestion	**Biomass Gasification**	**Landfill Gas**	**Grey and Blue Hydrogen**	**Green and Pink Hydrogen**
Anaerobic digestion is a well-known and widely used biological process for converting biomass or natural feedstock into biogas in the absence of oxygen. Typical feedstocks for anaerobic digestion are wet organic waste materials such as manures, sewage sludge, and food wastes as well as crops such as maize. Landfills and anaerobic digestors receive these feedstocks and then produce biogas, which is then upgraded to RNG.	Biomass gasification uses solid feedstock such as wood residues from manufacturers or discarded wood products. This feedstock is heated in the presence of a reduced concentration atmosphere (comprising air, oxygen, or steam) to produce a synthetic gas (syngas). This syngas must then go through a methanation process to be cleaned and converted into bio-syngas (bioSNG).	Landfill gas is a natural by-product of the decomposition of organic material in landfills. Landfill gas is composed of roughly 50% methane, 50% CO_2, and a small amount of non-methane organic compounds. Landfill gas can be upgraded to RNG through treatment processes by increasing its methane content and, conversely, reducing its CO_2, nitrogen, and oxygen contents.	Hydrogen can be produced via SMR, which is based on a thermochemical conversion of natural gas. Hydrogen production via SMR produces carbon emissions **Grey hydrogen** refers to hydrogen produced via SMR without carbon capture. **Blue hydrogen** refers to hydrogen produced via SMR and paired with carbon capture and storage (CCS) to significantly reduce carbon emissions. Hydrogen produced in this manner is also termed low carbon hydrogen.	Hydrogen can be produced via electrolysis, a process that uses electricity to split water into hydrogen and oxygen.[36] Hydrogen production via electrolysis can be free of carbon emissions depending on the source of electricity. **Green hydrogen** is produced using electricity from renewable energy (wind, solar, or hydro power) and is completely emissions-free. **Pink hydrogen** is produced from nuclear power and is also free of GHG emissions.

Renewable natural gas is produced primarily via anaerobic digestion of organic waste (from landfills, wastewater, and agricultural waste) and biomass gasification. RNG is considered a carbon-neutral fuel because it comes from organic sources that once absorbed carbon dioxide from the atmosphere during photosynthesis. RNG has even greater benefits when it's produced from organic waste that would otherwise decay and create methane emissions.

Another RNG production technology is power-to-gas RNG, where hydrogen can be used as feedstock to produce synthetic methane. Synthetic methane is produced via the hydrogenation of CO_2, using captured CO_2 from anaerobic digestion plants or other biogenic sources and hydrogen from excess electricity. Our analysis did not include power-to-gas RNG because it is more costly and, given the feedstock and inputs needed, more limited in availability.

Hydrogen is produced primarily via steam methane reforming (SMR) and electrolysis. Because hydrogen is a carbon-free molecule, the combustion of hydrogen does not directly produce GHG emissions at the burner tip. However, hydrogen use may lead indirectly to GHG emissions if the process used to produce hydrogen creates GHG emissions; the quantity of these indirect emissions depends on the method and energy source used to produce hydrogen. With its low rate of GHG emissions, Ontario's electricity grid offers a significant advantage to produce low-carbon hydrogen. As mentioned in Section 2, 93% of electricity generated in Ontario is low emissions or emissions-free. As such, hydrogen produced using surplus electricity from Ontario's grid can be considered green hydrogen. /u

Two alternative hydrogen production methods are described in the following bullets. Our analysis focused exclusively on hydrogen production via SMR and electrolysis and did not include these

[35] The industry and government, including Canada's federal government, are moving to simplify the terminology to either renewable hydrogen or low-carbon hydrogen.

[36] There are different types of electrolyzers; alkaline electrolyzers, proton exchange membrane, and solid oxide electrolysis cells. Alkaline electrolyzers are the most mature and cost-effective technology, although other technologies are rapidly approaching cost parity.

technologies because they are at a less mature stage of technology development and are more costly than current alternatives.

- **Auto-thermal reforming (ATR)**: An alternative to hydrogen production via SMR is ATR. SMR is more dominant than ATR. Unlike SMR, the ATR process requires an additional oxygen supply, which can lead to additional emissions and costs if the oxygen is not supplied as a by-product from a separate process.
- **Bio-hydrogen:** Another production method is biomass gasification, which involves the thermochemical (or biochemical) conversion of biomass resources or biomass waste to produce hydrogen. Hydrogen produced via biomass gasification is also referred to as bio-hydrogen. Due to relatively high biomass feedstock costs, bio-hydrogen is unlikely to play a role in hydrogen supply in the long term.

Hydrogen is traditionally transported and delivered in two ways: via pipelines and road transport.

- **Pipeline:** Pipeline transport is an economical and efficient method of transporting hydrogen. However, large volumes are required before building a pipeline can be justified. Most hydrogen is produced onsite at refineries in Southwestern Ontario where it is also used. This means hydrogen transport via pipeline is currently limited in Ontario, likely only used for relatively short distances within facilities.
- **Road transport:** Road transport is a more costly transportation method because of constraints on the amount of volume that can be transported by trucks and the additional compression infrastructure required. Hydrogen can also be liquified for storage or delivery. This increases the energy density significantly but requires extreme cooling and compression, which are expensive.

Ontario's Experience with Low- and Zero-Carbon Gases

While Ontario's RNG and hydrogen supplies remain largely undeveloped today, the scale-up of RNG and hydrogen is becoming an increasingly relevant topic for policymakers and gas utilities at the provincial and federal levels. At a federal level, in December 2020, Natural Resources Canada (NRCan) published Canada's Hydrogen Strategy outlining a vision for the development of hydrogen supply and infrastructure across Canada.[37] In April 2022, the Ontario government released its Low-Carbon Hydrogen Strategy, which describes near-term actions to launch a hydrogen production pilot, identify strategic locations for hydrogen hubs, support hydrogen storage and grid integration pilots, transition industry to hydrogen-ready equipment, and support ongoing hydrogen research, among other actions.[38] Operational experience with RNG and hydrogen supply remains relatively limited across Canada, but as described below, several high-profile projects in Ontario are changing this.

RNG production in Ontario: There are several RNG production facilities in Ontario including the City of Toronto's Dufferin Solid Waste Management Facility, which produces RNG from the city's Green Bin program; Hamilton's Woodward Avenue Water Treatment plant, which produces RNG from captured raw biogas; and London's StormFisher facility, which produces RNG from organic waste. As of April 2021, Enbridge Gas customers can voluntarily pay $2/month via the OptUp program[39] to fund RNG to be added to Enbridge Gas' gas supply.[40]

Enbridge Gas is also collaborating with Walker Industries and Comcor Environmental to build Ontario's largest RNG production facility, to be located in Niagara Falls, Ontario. The plant is expected to be operational in 2023 and is expected to generate enough energy to heat 8,750

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[37] NRCan (2020). Hydrogen Strategy for Canada. Available: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

[38] Government of Ontario (2022). Ontario's Low-Carbon Hydrogen Strategy. Available: https://www.ontario.ca/page/ontarios-low-carbon-hydrogen-strategy

[39] Enbridge Gas (2020). OptUp. Available: https://www.enbridgegas.com/sustainability/optup

[40] Enbridge Gas (2021). Ontario Customers Can OptUp to Greener Choices. Available: https://www.enbridge.com/stories/2021/april/enbridge-gas-optup-voluntary-renewable-natural-gas-initiative

homes.[41] Demand for RNG has also begun materializing in heavy road transport applications with cities like Hamilton introducing a blend of RNG in some of their compressed natural gas (CNG) buses.[42] The City of Hamilton operates 137 buses on CNG, representing approximately 2% of Ontario's fleet of transit buses. A portion of the natural gas supplied to these buses is RNG from organic waste. Over the next five years, Hamilton's bus fleet is anticipated to add 177 more CNG-powered buses.

Ontario's RNG Potential

While the supply of RNG in Ontario is currently small and more costly that importing natural gas, the province has significant RNG production potential. Torchlight Bioresources estimated Ontario's RNG potential via conventional RNG production technologies like anaerobic digestion and landfill gas.[43] Torchlight's report estimated that Ontario has the technical potential to produce around 40 PJ per year of RNG supply from wet organic wastes and up to around 224 PJ per year if agricultural residues are included. These agricultural residues reflect waste products such as corn stover and corn silage, and not new crop production that would need to be redirected to RNG production. This RNG potential represents roughly 4%-26% of Ontario's annual natural gas demand.[44] /u /u

Most of Ontario's RNG is exported and, with other provinces setting ambitious RNG goals, this trend may continue. This may limit Ontario's ability to access local RNG supplies in the near term. The province of Quebec has announced in its Green Economy Plan that it aims to increase its renewable gas (including RNG and hydrogen) supply to 10% of its total gas supply by 2030.[45] The British Columbia government has a 2030 goal for 15% of gas consumption to come from renewable gas, which may include RNG and hydrogen.[46]

Hydrogen production in Ontario: Enbridge Gas and Cummins collaborated to develop a hydrogen and natural gas blending project in the southern Ontario city of Markham. The project leverages their Markham 2.5 MW power-to-gas facility, which uses proton exchange membrane electrolyzer technology to produce hydrogen and store it while providing regulation services to the IESO. In January 2022, Enbridge Gas announced that the first-of-a-kind hydrogen blending initiative is fully operational, successfully serving 3,600 customers in Markham.[47]

Limited hydrogen infrastructure is in operation in Ontario. As a result, there is also limited technical and operational experience in the operation of hydrogen transmission and distribution (T&D) networks. Most experience in hydrogen is limited to the handling of hydrogen in an industrial setting, with the main users in Ontario being refineries and fertilizer production industries. Safety procedures and standards in the production, transport, storage, and handling of hydrogen are known within industry; however, outside industry, safety procedures and standards are less known and established.

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[41] Enbridge Gas (2020). Enbridge and Partners Break Ground on Ontario's Largest RNG Plant. Available: https://www.enbridge.com/stories/2020/october/enbridge-and-partners-break-ground-ontarios-largest-rng-plant

[42] City of Hamilton (2021). Enbridge Gas Partners with City of Hamilton to Fuel Ontario's First Carbon-Negative Bus. Available: https://www.hamilton.ca/government-information/news-centre/news-releases/enbridge-gas-partners-city-hamilton-fuel-ontarios

[43] Torchlight Bioresources (2020). Renewable Natural Gas (Biomethane) Feedstock Potential in Canada. Available: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf?la=en

[44] Torchlight's 224 PJ estimate is based on anaerobic digestion and landfill potential and does not reflect more advanced RNG production technologies like biomass gasification or power-to-gas, which are not yet commercially available. Of the 224 PJ estimate, landfill gas accounts for approximately 21 PJ, equivalent to 9%. /u

[45] Government of Quebec (2022). 2030 Plan for a Green Economy. Available: https://cdn-contenu.quebec.ca/cdn-contenu/adm/min/environnement/publications-adm/plan-economie-verte/plan-economie-verte-2030-en.pdf?1635262991

[46] Government of British Columbia (2021). CleanBC Roadmap to 2030. p.60. Available: https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_roadmap_2030.pdf

[47] Enbridge Gas (2020). Groundbreaking $5.2M Hydrogen Blending Project Aims to Green Ontario's Natural Gas Grid. Available: https://www.enbridge.com/Stories/2020/November/Enbridge-Gas-and-Hydrogenics-groundbreaking-hydrogen-blending-project-Ontario.aspx

2.4 Carbon Capture and Storage

Carbon capture and storage (CCS) involves the capture of carbon dioxide emissions from industrial processes or from the burning of fossil fuels. This carbon is then transported from where it was produced and stored deep underground in geological formations. There are no active CCS projects in Ontario since Ontario laws currently prohibit the geologic storage of carbon dioxide. However, in January 2022, the Ministry of Northern Development, Mines, Natural Resources and Forestry issued a discussion paper exploring possible legislative changes to remove barriers to the storage of carbon dioxide, which would enable the creation of a regulatory framework to govern CCS and other new technologies.[48]

Prior studies have assessed CCS options in Ontario and have determined that the only sequestration option is geological sequestration in saline aquifers. Carbon dioxide is expected to be stored in these aquifers for long periods, from one hundred years to several thousand years depending on the size, properties, and location of the reservoir. Prior studies identified two different major reservoirs appropriate for CCS in southwestern Ontario: one located in the southern part of Lake Huron and the other located inside Lake Erie. These sites have approximate storage capacities of 289 million and 442 million tonnes of CO_2 emissions.[49]

The analysis presented in this report assumes that the use of CCS would begin around 2030 and would be used for two purposes: (1) to store CO_2 by-products from hydrogen production via steam methane reformation of natural gas feedstocks, and (2) to store CO_2 emissions produced from the combustion of natural gas.

[48] Canada Ministry of Northern Development, Mines, Natural Resources and Forestry (2022). Discussion Paper: Geologic Carbon Storage in Ontario. Available: https://prod-environmental-registry.s3.amazonaws.com/2022-01/Geologic%20Carbon%20Storage%20Discussion%20Paper%20-%20FinalENG%20-%202022-01-04_0.pdf

[49] Shafeen, Ahmed & Croiset, Eric & Douglas, Peter & Chatzis, Ioannis. (2004). CO_2 sequestration in Ontario, Canada. Part I: Storage evaluation of potential reservoirs. Energy Conversion and Management. 45. 2645-2659. Available: http://dx.doi.org/10.1016/j.enconman.2003.12.003

3. Study Methodology

This study developed two main scenarios that accomplish net zero GHG emissions in the Ontario energy system by 2050: a **Diversified Scenario** in which low- and zero-carbon gases are used for targeted applications in combination with electricity, and an **Electrification Scenario** in which electrification is the main approach, with a limited role for low- and zero-carbon gases. These scenarios, detailed in section 4, define constraints for the future energy system.

To model pathways for these two scenarios from today to 2050, this study used an integrated energy system model, Guidehouse's Low Carbon Pathways (LCP) model. This model was adapted to the characteristics of Ontario's gas and electricity networks, its energy supply-demand conditions, and its interties with neighbouring regions. For each net zero scenario, our analysis produced a cost-optimal pathway of how the electricity and gas systems could reduce GHG emissions by 2050, including identifying what investments will be required for electricity, hydrogen, and methane. The pathways describe investments in generation and supply capacity, storage, and infrastructure, as well as when those investments will be needed. The study approach was divided into three phases (see Figure 5).

Figure 5. Overview of Study Methodology

Phase 1: Data Collection and Input Development	Phase 2: Development of Net Zero Scenarios	Phase 3: Low-Carbon Pathway Modelling
Techno-economic parameters: Development and collection of techno-economic parameters for all supply capacity technologies (wind, solar, hydrogen production technologies, etc.) and transmission infrastructure (power lines, gas pipelines, etc.).[50] **Ontario energy system data:** Characterization of the current state of the electricity and gas system (electricity supply mix, transmission interties between Ontario and neighbouring regions, etc.). **Technology scope:** Including all electricity generation and gas production technologies, conversion technologies, storage, and transmission infrastructure. **Appendix A** presents the inputs and assumptions used in this study.	**Net zero scenarios:** Development of 2020-2050 forecasts for electricity, hydrogen, and methane demand in Ontario. **Geographies:** Including electricity demand forecasts through 2050 for all neighbouring regions. Hydrogen and methane demand is not defined in neighbouring regions. **Appendix B** describes the approaches and assumptions used for each sector.	**Energy supply and infrastructure:** Configuration of the LCP model to the Ontario energy system and neighbouring regions to optimize the buildout of supply capacity and transmission infrastructure. **Alternative scenarios and sensitivities:** Exploration of the impact of alternative demand scenarios and sensitivities on the role of gas supply and infrastructure. **Appendix C** describes the modelling approach.

[50] These inputs were sourced from Ontario and Canadian energy stakeholders, including the IESO, the CER, and Enbridge Gas. Technology costs were sourced from a collection of international organizations, including the International Energy Agency (IEA) and the European Network of Transmission System Operators for Electricity (ENTSO-E), among others.

4. Developing Net Zero Scenarios for Ontario

This study developed two net zero scenarios of energy demand to 2050: a Diversified scenario and an Electrification scenario. These scenarios represent two different but plausible futures of energy demand in Ontario. Neither scenario is intended to represent the optimal or most likely pathway. Rather, the scenarios are potential future outcomes that use different pathways to achieve net zero emissions in the energy sector. This section defines the scenarios and their constraints in depth, and Section 5 describes how energy systems and the power sector would evolve differently to meet each scenario's constraints. The objective of this scenario analysis was to assess the costs associated with two different pathways to net zero and to explore the role played by electricity and low- and zero-carbon gases. This study's consideration of cost-optimal pathways does not attempt to pick technology winners or losers. There are different options for reducing GHG emissions and many solutions will be needed to achieve net zero.

The analysis focused on energy demand from three sectors: buildings, transport, and industry.[51] Figure 6 describes the scope of each sector and the ways in which they may reduce GHG emissions.

[51] The analysis does not capture emissions from agriculture, land use, waste, or embedded emissions from products or materials. These external sectors are assumed to reduce GHG emissions in step with the rest of the economy.

Figure 6. Description of Energy Demand by Sector

BUILDINGS	**Building heating** includes heating demand from residential and commercial buildings	With more than 80% of Ontario's buildings heated by natural gas, building heating, and approximately 24% of Ontario's emissions coming from buildings[52], it is the second largest contributor of emissions. GHG emissions from building heat demand can be reduced through low-carbon heating alternatives such as electric heat pumps (air-source and geothermal), and transitioning over time to utilizing hydrogen or RNG in hybrid dual fuel (gas and electric) systems, hydrogen- or RNG-based furnaces, and gas heat pumps, among other alternatives. Additionally, more efficient heating equipment will be available in the future, while newer and renovated buildings will have better insulation due to changes in building codes and standards, which will reduce heating demand.
TRANSPORT	**Transport** includes energy demand from light and heavy road transport, marine transport, rail, and aviation	Transport is the highest emitting sector in Ontario, accounting for 45% of emissions. Today, energy demand in the transport sector heavily relies on fossil fuels. Road transport relies largely on diesel and gasoline, aviation relies on jet fuel, rail transport relies on diesel, and marine transport relies on medium and heavy fuel oil. Energy transition options include electrification, hydrogen and hydrogen-derivatives, and bio-CNG (also called compressed renewable natural gas, or CRNG), among others. Ontario's transport sector will reduce GHG emissions in line with global trends. This is because Ontario's fueling and charging infrastructure will need to be largely consistent with the rest of North America and the world to enable international transport.
INDUSTRY	**Industry** includes energy demand from all major energy-intensive industries	Industry is the third largest emitting sector in Ontario, accounting for 23% of Ontario's GHG emissions. With the main industries being ferrous and non-ferrous metal production, oil and petroleum refining, and fertilizer and chemical manufacturing. For low temperature industrial processes (e.g., below 150°C) the transition to net zero will most likely rely on electrification. Medium temperature processes (e.g., 150°C to 400°C) may use electrification or low carbon gas. Industrial processes requiring high temperature heat will be more challenging and may require research and development into new low carbon and carbon capture technologies.

The two scenarios modelled differ in the approaches used to reduce GHG emissions in each sector. Table 2 shows those differences.

[52] Canada Energy Regulator (2022). Provincial and Territorial Energy Profiles – Ontario. Available: https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html

Table 2. Scenario Assumptions by Demand Sector

	Diversified Scenario	Electrification Scenario
	Low- and zero-carbon gases serve targeted uses in combination with electricity to reduce GHG emissions.	**Electricity is the main means of reducing GHG emissions. Low- and zero-carbon gases are limited to sectors that cannot feasibly be electrified.**
BUILDINGS	**Gas heating continues to play a key role in building heating.** • Gas heat pumps (fuelled by low carbon gas) play a dominant role in heating, complemented by electric heat pumps, including both air-source and geothermal. • Energy efficiency and building codes reduce heating energy demand.	**Electric heating displaces natural gas in most building heating.** • Electric heat pumps, including both air -source and geothermal, replace most gas heating in buildings. Low- and zero-carbon gas serves remaining gas heated buildings. • Energy efficiency and building codes reduce heating energy demand.
TRANSPORT	**Hydrogen plays a major role in all heavy transport.** • Light road transport is largely electrified using battery electric vehicles (BEVs) with a limited role for hydrogen fuel cell electric vehicles (FCEVs). • RNG (as bio-CNG) plays a limited role in heavy road transport. • Hydrogen plays a major role in road, marine (via ammonia), and aviation (via synthetic kerosene). • GHG emissions from rail are reduced using hydrogen and electrification.	**Electrification and biofuels play major roles in all transport methods.** • Light road transport is fully electrified via BEVs. • GHG emissions from heavy road and marine transport are reduced using electrification and biofuels. • The role of hydrogen is limited to aviation (via synthetic kerosene). • GHG emissions from rail are reduced using electrification.
INDUSTRY	**Hydrogen and natural gas + CCS play a key role in industry.** • Most industrial segments adopt hydrogen or natural gas + CCS for medium and high temperature processes. • Low temperature heat processes are electrified.	**Hydrogen and natural gas + CCS play a key role in industry.** • Hydrogen and natural gas + CCS play a role in high temperature heat processes and certain industries. • Most medium and low temperature heat processes are electrified.

In the **Diversified scenario**, **building heating** is mainly supplied by gas. Natural gas furnaces are the predominant heating method through 2030, but gas-equipped buildings are assumed to shift to gas-powered heat pumps in later years to meet the government's long-term goal that by 2035, all space heating technologies for sale in Canada meet an energy performance of more than 100%.[53] The emissions of gas heating appliances will decrease over time, as the gas supply is projected to shift from fossil natural gas to low- and zero-carbon gases. Fully electric heating plays a complementary role to gas heating through the deployment of electric air-source heat pumps and geothermal heat pumps. In **transport**, light road transportation is largely electrified, with hydrogen limited to a minor role. In heavy road transport, biodiesel, hydrogen, and electrification all play major roles supported by a small share of bio-CNG. Marine transport relies on ammonia (a hydrogen derivative) and, to a lesser degree, on electrification for short-distance transport. Rail transport is assumed to move from diesel to an equal share of hydrogen and electricity by 2050. In **industry**, hydrogen becomes the prominent option to displace natural gas in medium and high temperature industrial processes.

[53] Energy and Mines Ministers' Conference (2017). Market transformation strategies for energy-using equipment in the building sector. p.16. Available: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/Market-Transformation-Strategies_en.pdf

Natural gas + CCS also plays a significant role. For low temperature heat processes, electrification is the main option.

In the **Electrification scenario**, electricity plays a greater role in buildings, transport, and industry. With an increased role for electrification, low- and zero-carbon gas plays a limited role in all sectors. **Building heating** is mostly electrified as gas furnaces are replaced by electric heat pumps (including geothermal and air-source heat pumps), with gas heat pumps serving a small share of all buildings. In **transport**, light duty transport is fully electrified. Heavy duty transport relies mostly on electrification and biodiesel, with hydrogen only playing a limited role. Marine transport is less reliant on ammonia than in the Diversified scenario, with electrification and biodiesel also playing critical roles. In **industry**, electrification becomes the prominent option for low and medium temperature industrial processes, while natural gas + CCS plays a role for high temperature processes. Hydrogen is limited to steelmaking and other industries, where it is the only available pathway for achieving net zero.

While the Diversified and Electrification scenarios are intended to represent different views of a net zero future for Ontario, some sub-sectors are assumed to follow the same net zero pathway in both scenarios. These similarities reflect the confidence and certainty shared by stakeholders on how some sub-sectors are expected to reduce GHG emissions. For example:

- In the **buildings sector**, total energy demand for space heating decreases due to energy efficiency improvements in the new building stock and renovation of existing buildings.
- In the **iron ore and steel industry**, the views of most major stakeholders, globally and in Ontario, have consolidated behind the adoption of hydrogen-based direct reduction of iron ore (HDRI) as the only plausible option to eliminate GHG emissions. ArcelorMittal Dofasco and the Government of Canada have announced that they will be investing $1.8 billion into reducing the GHG emissions from ArcelorMittal Dofasco's Hamilton steel plant by pursuing natural gas-fired DRI and electric arc furnace production.[54] ArcelorMittal has successfully tested the use of green hydrogen in the production of direct reduced iron and, in the longer term, the Hamilton plant may be able to replace some of its natural gas use with hydrogen.[55] Hence, the rollout of the HDRI technology is incorporated in both scenarios.
- Similarly, in the **aviation sector**, the reduction of GHG emissions is expected to be driven by global aviation trends rather than by unique market drivers in Ontario. Because of this dependence on global trends, the approach for the aviation sector is the same in both scenarios, with roles for synthetic kerosene (produced with hydrogen) and biojet fuel.
- In the **light duty road transport sector**, the adoption of BEVs is expected to be the most common way of reducing GHG emissions from passenger vehicles. As a result, both scenarios are based on a large adoption of BEVs: 100% BEV penetration in the Electrification scenario and 95% BEV / 5% hydrogen FCEVs penetration in the Diversified scenario.

4.1 Comparison of Demand Scenarios

The following charts describe how the demand for different energy carriers evolves over time for the buildings, industry, and transportation sectors. Three energy carriers are considered in detail:

- **Electricity:** Annual electricity demand increases significantly in both scenarios. In the Diversified scenario, electricity increases two-fold from 135 TWh today to 281 TWh by 2050, while in the Electrification scenario, demand increases over three-fold to 413 TWh. /u
- **Methane:** In 2050, methane demand is met by a combination of RNG and natural gas paired with CCS. In the Diversified scenario, annual methane demand decreases from 922 PJ today

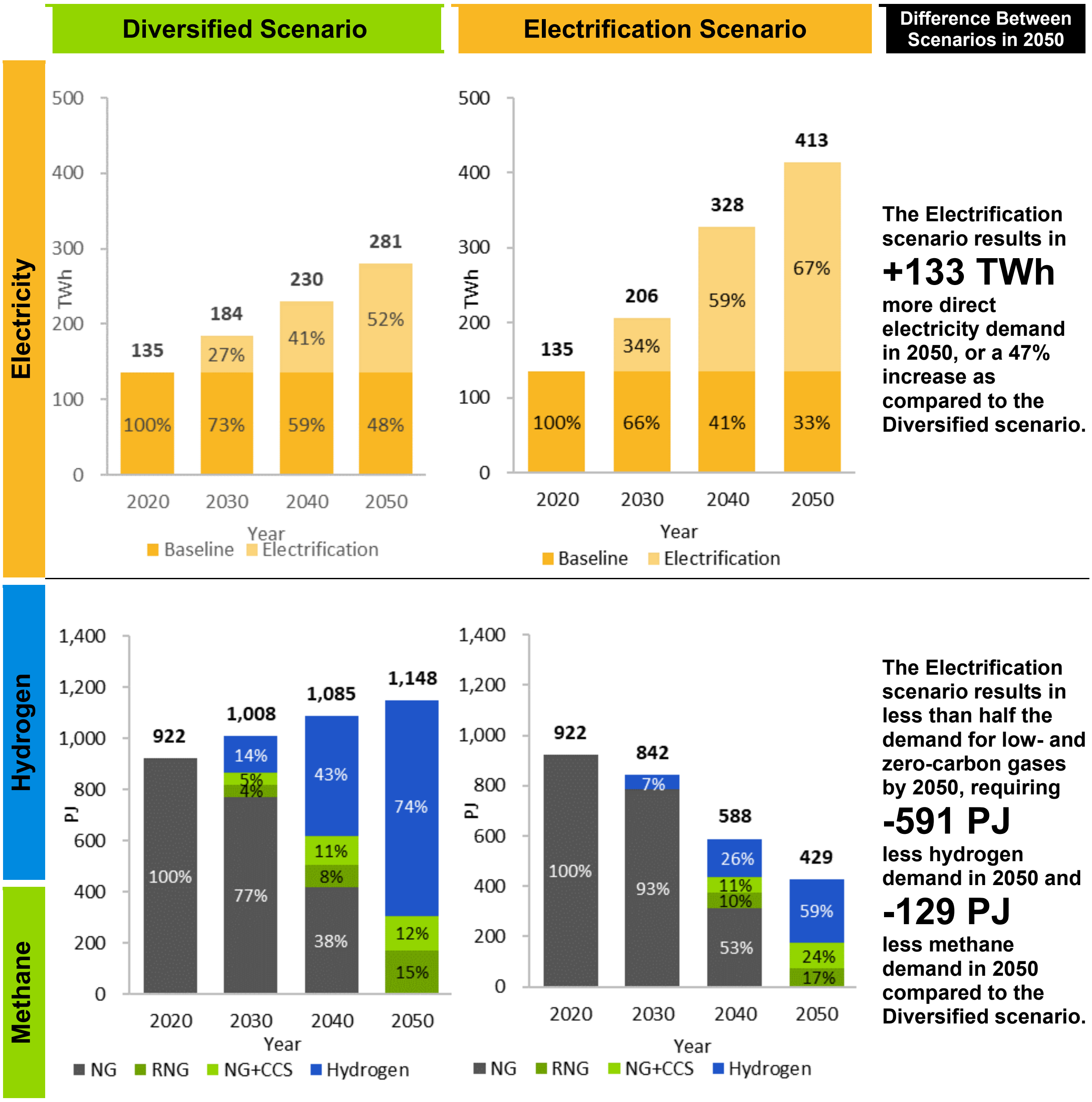
[54] ArcelorMittal (2021). ArcelorMittal and the Government of Canada announce investment of CAD$1.765 billion in decarbonisation technologies in Canada. Available: https://corporate.arcelormittal.com/media/press-releases/arcelormittal-and-the-government-of-canada-announce-investment-of-cad-1-765-billion-in-decarbonization-technologies-in-canada

[55] The Bay Observer (2022). Arcelormittal Experimenting with Clean Hydrogen in Steelmaking. Available: https://bayobserver.ca/2022/05/04/arcelormittal-experimenting-with-clean-hydrogen-in-steelmaking/

to 304 PJ by 2050, while in the Electrification scenario, demand decreases to 175 PJ by 2050. Natural gas is predominantly displaced by hydrogen, as described below. /u

- **Hydrogen:** In the Diversified scenario, annual hydrogen demand increases from 0 PJ today to 844 PJ, while in the Electrification scenario, hydrogen demand increases to 253 PJ by 2050. /u

Figure 7. Comparison of Annual Demand Scenario Forecasts by Energy Type[56] /u



[56] Note that the percentages in this graphic have been rounded for ease of visual inspection. Any calculations based on them are subject to rounding errors. /u

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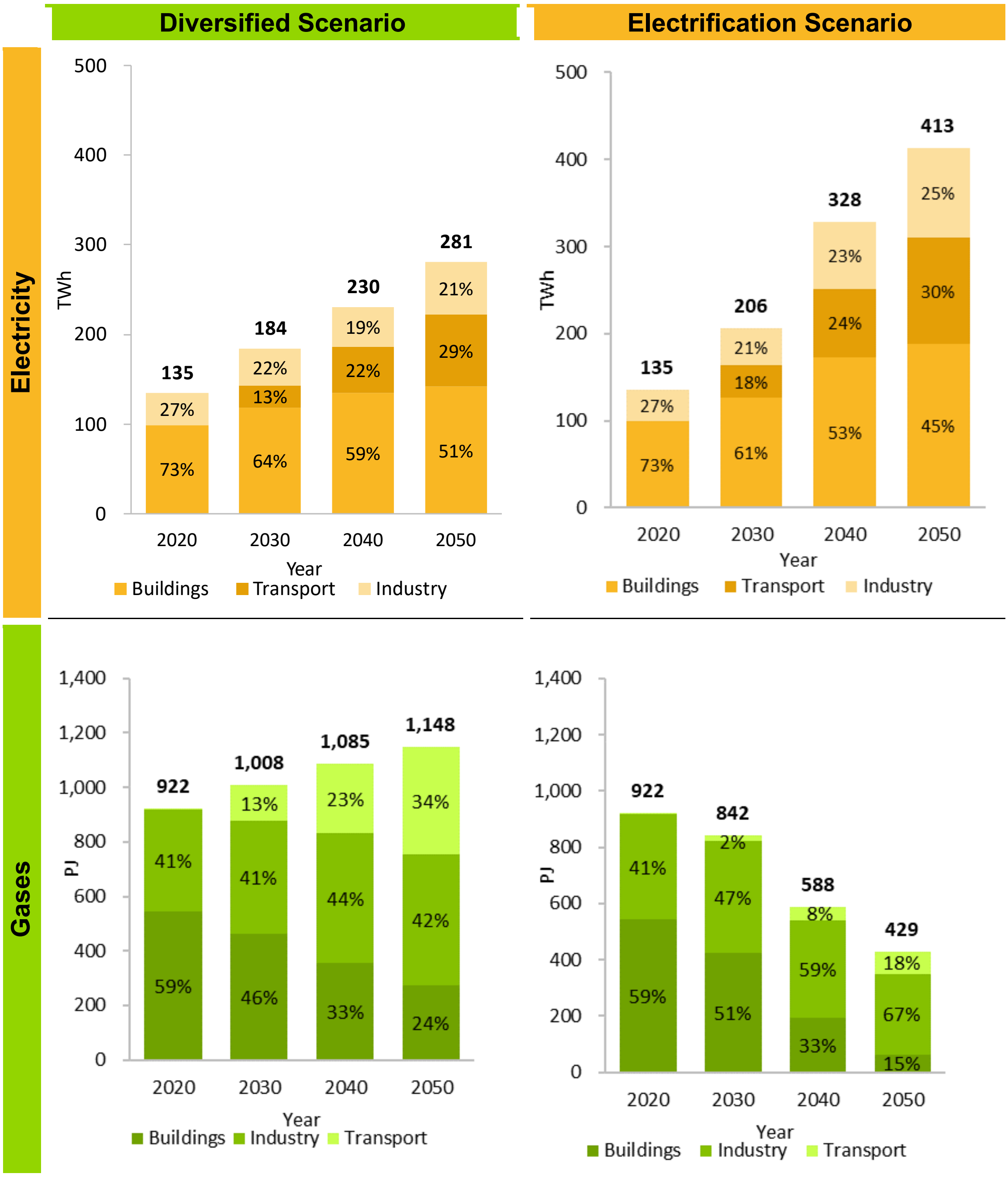
Figure 8. Comparison of Annual Demand Scenario Forecasts by Sector

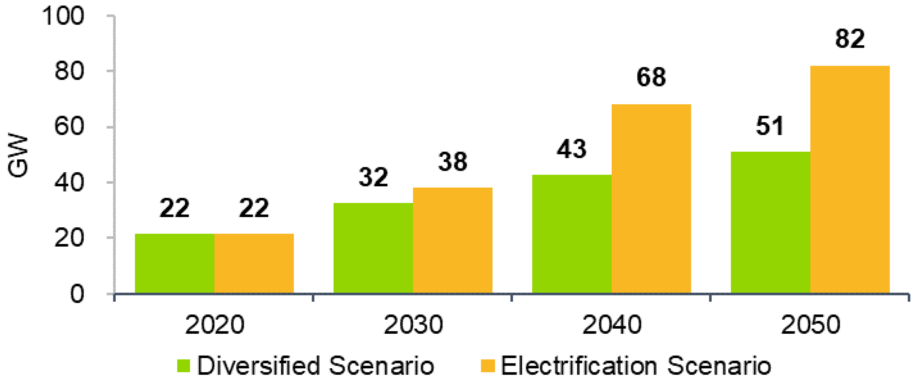


In addition to annual energy demand, the degree of fuel switching in each scenario has a large impact on energy system peak demand over time. Historically, Ontario has a winter peaking energy system for natural gas and a summer peaking system for electricity. In 2019, the electricity system experienced peak demand on July 29th at a magnitude of 22 GW.[57] Looking towards a net zero future, decisions around electrifying building heating will have the largest impacts of any sector on the electric system peak. For electric heating technology, this study focused on the adoption of cold climate air-source heat pumps and geothermal heat pumps to comply with the Pan Canadian

[57] IESO (2021). Hourly Demand Report. *PUB_Demand_2019*. Available: http://reports.ieso.ca/public/Demand/

Framework. Currently, 7% of homes in the province rely on electric heat pumps for space heating.[58] While the upfront installation and equipment cost for air-source heat pumps is considerably less than geothermal heat pumps, the efficiency of the air-source heat pump system decreases with colder outside air temperatures. To provide adequate heating in winter conditions, electrically heated homes need to be well-insulated and weatherized to minimize heat leakage. This analysis assumes that homes with electric heat pumps undergo deep energy efficiency retrofits. The Electrification scenario assumes that, by 2050, 85% of all buildings will convert to electric heating systems and most will adopt cold climate air-source heat pumps over geothermal heat pumps due to the up-front cost of geothermal systems. This results in a nearly four-fold increase in system peak compared to 2020. In contrast, the Diversified scenario assumes that 55% of buildings will be heated by gas heat pumps, and that the penetration of electric heat pumps only climbs to 40% by 2050. This results in an increase in electricity system peak to more than double what it is today. The change in electricity system peak over the study period for both scenarios can be seen in Figure 9 below. /u

Figure 9. Electricity System Peak Demand /u



Gas system peak demand in the province today is 11 million m^3/hr which is equivalent to 121 GW. In both net zero scenarios, the peak energy demand rapidly decreases as imported conventional natural gas from fossil reserves is replaced by electricity, hydrogen, and RNG. In some industry sector cases, conventional natural gas is outfitted with CCS technology to reduce emissions. The Diversified scenario assumes that methane in the form of RNG and NG + CCS will play a larger role in the energy system in 2050 compared to the Electrification scenario.

Hydrogen peak demand starts at zero in 2020 in both scenarios. In the Diversified scenario, hydrogen, as a proportion of peak demand scales up considerably to power industry, transportation, and buildings. In the Electrification scenario, hydrogen is mostly used in the industrial sector for processes that are difficult to electrify, such as high temperature heating. The methane and hydrogen peak demands over the study period can be seen in Figure 10 below.

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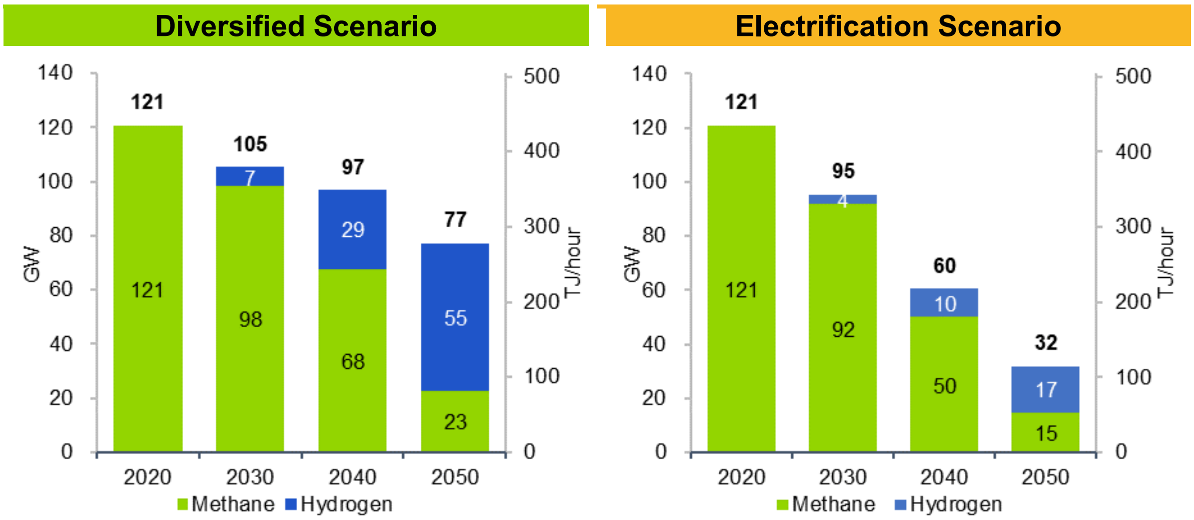
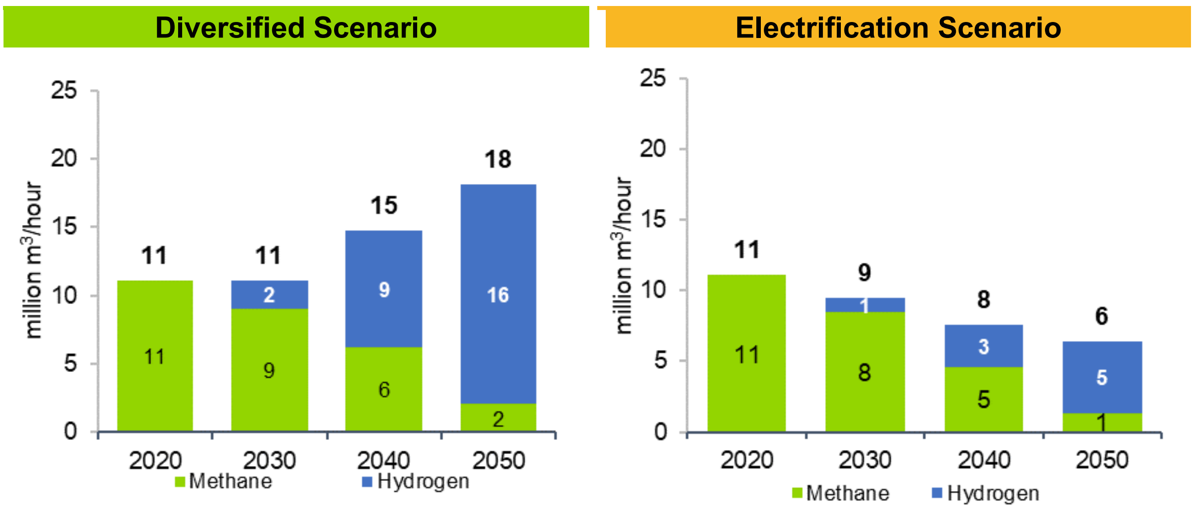
[58] NRCan (2018). Residential Sector Heating System Stock. Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=on&rn=21&page=0
Note: This source states that 67% of residential buildings have a natural gas-fired appliance for primary heat. Consistent with this statistic, section 2 and section 4 of this report note that 80% of total energy consumed for space heating in residential and commercial buildings is provided by natural gas.

Figure 10. Gas System Peak Demand[59] /u



While the gas system peak declines for both scenarios in energy terms, the volumetric gas system peak rises significantly in the Diversified scenario. This is because hydrogen has a lower energy density than methane, so more volume is needed to provide the same amount of energy. This trend, along with the volumetric gas system peak for the Electrification scenario can be seen below in Figure 11.

Figure 11. Volumetric Gas System Peak Demand[59] /u



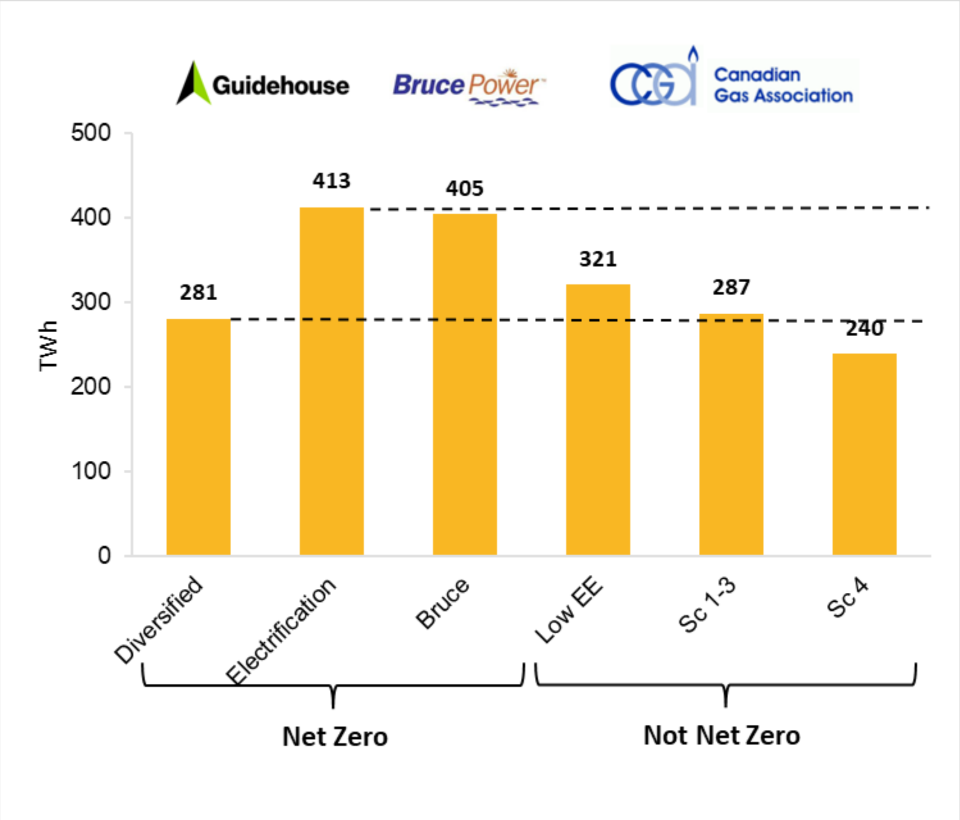
4.2 Benchmark to Other Demand Forecasts

Electricity demand projections from the Diversified scenario in 2050 are broadly aligned with other net zero electricity demand estimates, which range from 240 TWh to 405 TWh, as Figure 12 shows. In the Electrification scenario, electricity demand slightly exceeds the range of these studies at 413 TWh, which is expected given the Electrification scenario represents a future with aggressive electrification across all sectors. The reports used for comparison are as follows: /u

[59] The methane peak demand presented in this chart is adjusted from the peak demand used in the model to reflect ETSA inputs. As a result, peak methane demand is slightly understated in the model. This calibration does not affect the model's optimization or the cost results that it produces because the model calculates costs associated with the existing methane system based on energy content, not capacity, and because no new methane infrastructure capacity is built in any scenario considered in this analysis. /u

- **Bruce Power, The Next 50 Years Report:**[60] This 2050 electricity forecast for Ontario incorporates electricity demand used in the production of green hydrogen. In comparison, the Guidehouse demand scenarios do not. In the current study, electricity used to produce hydrogen is modelled separately, as a supply option, and is presented in Section 5.2.1 of this report.
- **Canadian Gas Association (CGA), Implications of Policy-Driven Electrification in Canada:**[61] The CGA study is a Canada-wide analysis. The 2050 electricity demand forecasts reported in Figure 12 have been estimated for Ontario by applying the growth rates in Canadian electricity demand from 2020 to 2050 to Ontario's 2020 electricity demand. The CGA study was completed prior to the federal government's announcement of a net zero target for 2050, and therefore the scope of the emission reductions contemplated in the study do not achieve net zero. In comparison, both Guidehouse demand scenarios do achieve net zero.

Figure 12. Comparison of Electric Demand Projections, 2050 /u



Source: Guidehouse analysis and reports listed in text above

The electric demand projections do not align with the IESO's 2021 Annual Planning Outlook (APO)[62] since the APO does not aim to meet any carbon emissions reduction targets. While the APO does account for moderate transportation electrification, it does not assume the same amount of economy-wide electrification as the Diversified or the Electrification scenarios. Thus, the APO's total forecasted annual electricity demand of 196 TWh in 2040 is lower than the forecasted 230 TWh in 2040 for the /u

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[60] BrucePower (2021). The Next 50 Years. Available: https://www.brucepower.com/wp-content/uploads/2021/07/210219D_Next50YearsReport_R000.pdf

[61] Canadian Gas Association (2019). Implications of Policy-Driven Electrification in Canada. Available: https://www.cga.ca/wp-content/uploads/2019/10/Implications-of-Policy-Driven-Electrification-in-Canada-Final-Report-October-2019.pdf

[62] IESO (2021). Annual Planning Outlook. Available: https://ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

Diversified scenario and is significantly lower than the forecasted 328 TWh in 2040 for the Electrification scenario. /u

The mix of 2050 total energy demand met by hydrogen in the Diversified scenario (39%) is consistent with the higher end of results from other Canadian and European estimates, ranging from 19% to 36%. The Electrification scenario (with 13% of 2050 total energy demand met by hydrogen) is not comparable to the other estimates because of its aggressive electrification assumptions.[63] Of these comparisons, there are two Canadian reference studies. All other studies reported focus exclusively on Europe. These studies include the following: /u /u

- **NRCan, Hydrogen Strategy for Canada:**[64] This Canada-wide study estimates 20 Mt of hydrogen demand across Canada in 2050, corresponding to 30% of Canada's end-use energy.
- **University of Calgary, Towards Net Zero Energy Systems in Canada:** This Canada-wide study estimates 3,300 PJ of hydrogen demand across Canada, corresponding to 36% or 27% of energy demand depending on the baseline estimate of 2050 energy demand.[65]
- **McKinsey, Net Zero Europe:** This Europe-wide study estimates 1,510 TWh of hydrogen demand, equivalent to 19% of total energy demand.[66]
- **Guidehouse, European Hydrogen Backbone:** The 2021 European Hydrogen Backbone study estimated 1,995 TWh of demand for the European Union and the United Kingdom, equivalent to 24% of total energy demand.[67]
- **European Commission, Impact Assessment:** The European Commission's impact assessment staff working document #176 estimated 2,162 TWh of hydrogen demand, equivalent to 30% of energy demand.[68]
- **Fuel Cells and Hydrogen, Hydrogen Roadmap Europe:** This study estimated 2,251 TWh of hydrogen demand, equivalent to 28% of total energy demand.[69]
- **International Energy Agency (IEA), World Energy Outlook 2021:** In the IEA Announced Pledges Scenario (APS), total global hydrogen production increases to 5,560 TWh in 2050 (equivalent to 4% of global energy demand) and plays a key role in displacing oil in transport and coal and natural gas in power generation and industry. In the more aggressive Net Zero Emissions Scenario (NZE), global hydrogen production increases to 16,680 TWh in 2050 (equivalent to 17% of global energy demand), around one-quarter of which is converted into hydrogen-based fuels.[70]

Figure 13 summarizes our review of hydrogen demand projections.

[63] Figures reported here show hydrogen demand as a percentage of total energy demand, referencing the total provincial energy demand as reported by the CER, which includes energy demand from sectors such as agriculture that are outside the scope of this study.

[64] NRCan (2020). Hydrogen Strategy for Canada. Available: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

[65] The Transition Accelerator (2021). Towards Net-Zero Energy Systems in Canada: A Key Role for Hydrogen. Available: https://transitionaccelerator.ca/wp-content/uploads/2020/09/Net-zero-energy-systems_role-for-hydrogen_200909-Final-print-1.pdf

[66] McKinsey & Company (2020). Net-Zero Europe: Decarbonization pathways and socioeconomic implications. Available: https://www.mckinsey.com/~/media/mckinsey/business%20functions/sustainability/our%20insights/how%20the%20european%20union%20could%20achieve%20net%20zero%20emissions%20at%20net%20zero%20cost/net-zero-europe-vf.pdf

[67] Gas for Climate (2021). European Hydrogen Backbone: Analysing future demand, supply, and transport of hydrogen. Available: https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021_v3.pdf

[68] European Commission (2020). Stepping up Europe's 2030 Climate Ambition. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020SC0176

[69] Fuel Cells and Hydrogen 2 Joint Undertaking (2019). Hydrogen Roadmap Europe. Available: https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf

[70] International Energy Agency (2021). World Energy Outlook 2021. pp. 236-237, 300, 310. Available: https://iea.blob.core.windows.net/assets/4ed140c1-c3f3-4fd9-acae-789a4e14a23c/WorldEnergyOutlook2021.pdf

Figure 13. Comparison of Hydrogen Demand Projections, 2050

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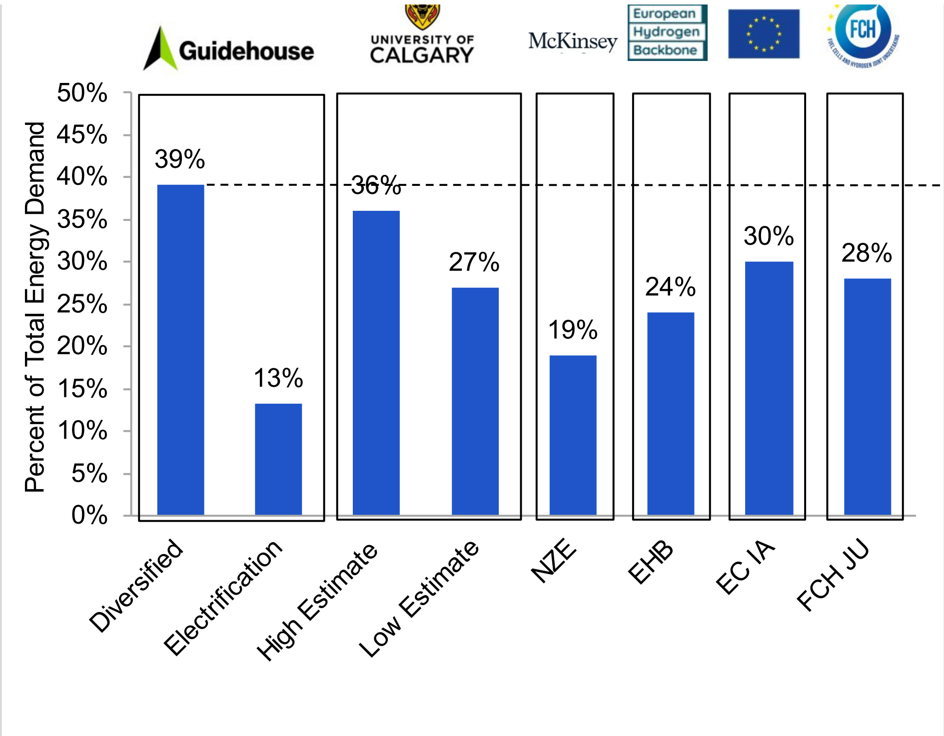


Source: Guidehouse analysis and reports listed in text above

Case Studies: Sweden and Denmark

To demonstrate stakeholders' roles in defining and actualizing GHG reductions, this section presents case studies of two countries that are advanced in their development of low carbon fuels.

With the EU aiming to reach net zero GHG emissions by 2050, the deployment of low carbon gases is set to play a foundational role in strategies for achieving a low carbon energy system. Low carbon gases offer a unique advantage by leveraging existing gas infrastructure to support the transition to an energy system with net zero emissions at the lowest societal cost. As a result of ambitious climate targets set by the Green New Deal as well as limited domestic fossil energy sources, Europe's RNG sector has been experiencing rapid growth and development compared to the global context. In 2021 alone, the EU saw a 13% increase in RNG production capacity. With varying national-level approaches across the EU, Denmark and Sweden stand as two case studies of successful strategies that have realized the deployment potential of RNG. In 2020, Denmark produced 4 TWh of power from RNG and Sweden produced 1.8 TWh, enough production to meet 12% or more of both countries' total gas demand.[71]

Non-binding national-level strategies informed by partnerships between government and domestic energy companies have been the driving force behind Denmark and Sweden's success. In Denmark, the government and private sector worked together to develop a strategic RNG roadmap to increase domestic biogas production to 4 TWh today and 13.3 TWh by 2030. Stakeholders envision RNG primarily being used in domestic industry and for heat and power production.[72] These future and current RNG deployments are underpinned by innovative infrastructure integrations such as biogas pooling systems where small- to medium-sized biogas plants are connected via biogas pipelines to one large RNG upgrading facility. This makes RNG production more economical as grid connection costs are reduced. Reverse flow facilities are also being tested, allowing for flexible physical flows between the T&D grid. If too much RNG is injected into the low-pressure distribution grid, the RNG is compressed and injected into the high-pressure transmission grid.[73] This ensures more flexibility for the gas system and expands the possibility for decentralized RNG injection.

Further north in Sweden, a similar non-binding national strategy named the National Biogas Strategy 2.0 launched by Energigas sets a biogas growth target of 15 TWh by 2030, with the majority of RNG deployment to be used in the hard-to-electrify segments in the transport and industrial sectors. Sweden is the European leader for transport sector RNG deployment with 68 onsite bio-CNG production plants. Bio-CNG is often produced in areas without a gas grid or with a limited gas grid where RNG must be transported—for example, via fuelling trucks. Bio-liquified natural gas (bio-LNG) and bio-CNG have a similar composition to fossil LNG and CNG, so the same infrastructure can be used. Furthermore, bio-LNG and bio-CNG can be blended into the gas supply at any percentage, which allows a fast upscaling of its use in these sectors. RNG is also becoming more attractive due to EU carbon prices, which treat RNG as a non-GHG-emitting fuel.

In Denmark, subsidies support the large-scale build out of RNG deployment. In 2018, the base subsidy for grid injection of RNG was €39/MWh (CAD 58.65/MWh), with an additional price adder adjusted based on the natural gas price. The adder allows biogas production to remain competitive, even at low gas prices. However, a new subsidy system consisting of an annual pool of €32 million (CAD 48.1 million) will be assigned in tenders due to the original subsidy not being capped. As for Sweden, the current support scheme primarily works through avoided carbon taxes and fiscal incentives for certified low carbon gas, which the Swedish Energy Agency approves in a national biogas registry. Compared to gasoline, the tax reduction for RNG equates to €74/MWh (CAD 111/MWh). There is also production support for biogas from manure (€20/MWh, CAD 30/MWh) and RNG upgrading (€26/MWh, CAD 39/MWh), except for sewage sludge, landfill, food, or feed crops.[74]

[71] European Biogas Association (EBA), EBA Statistical Report 2021. https://www.europeanbiogas.eu/eba-statistical-report-2021/

[72] Marc-Antoine Eyl-Mazzega and Carole Mathieu (eds.), Biogas and Biomethane in Europe: Lessons from Denmark, Germany and Italy, Ifri, April 2019. https://www.ifri.org/sites/default/files/atoms/files/mathieu_eyl-mazzega_biomethane_2019.pdf

[73] Guidehouse, Market state and trends in renewable and low-carbon gases in Europe, prepared for Gas for Climate, December 2021. https://gasforclimate2050.eu/wp-content/uploads/2021/12/Gas-for-Climate-Market-State-and-Trends-report-2021.pdf

[74] Klackenberg, L., National Biogas Strategy 2.0, The Swedish Gas Association, April 2018, https://www.energigas.se/media/boujhdr1/biomethane-in-sweden-210316-slutlig.pdf

5. Comparing Pathways to a Net Zero Future

This section presents the results of our pathways analysis for the Diversified and Electrification scenarios. The Diversified and Electrification scenarios represent two different but plausible visions of how Ontario could achieve net zero emissions. This section focuses on the development of electricity, hydrogen, and RNG supply in both scenarios and compares the total energy system costs associated with each. This section also presents the results of four sensitivity scenarios, each exploring how different drivers impact results.

- **Section 5.1** compares how the electricity supply mix evolves from 2020 to 2050 in each of the two scenarios.
- **Section 5.2** compares the evolution of the gas supply mix, with a focus on the development of hydrogen and RNG supply.
- **Section 5.3** compares the total energy system costs in each of the two scenarios, identifying the key cost drivers.
- **Section 5.4** compares the emissions reduction pathways for the two scenarios.
- **Section 5.5** discusses the challenges associated with implementing the emissions reduction pathways
- **Section 5.6** summarizes key results for the four sensitivity cases.

5.1 Electricity Supply Development

Both scenarios lead to a significant increase in generation capacity, but the Electrification scenario leads to a more aggressive buildout of capacity. In both scenarios, installed generation capacity is forecast to increase significantly: around 3 times in the Diversified scenario, from 40 GW in 2020 to 129 GW in 2050; and nearly 4 times in the Electrification scenario, from 40 GW to 148 GW. This increase in capacity is driven by the growth in electricity demand—more than doubling in the Diversified scenario and tripling in the Electrification scenario. In the Electrification scenario, the greater increase in peak demand is driven by higher penetration of electric heat pumps and the electrification of transport, triggering significant investment in hydrogen gas turbine capacity and T&D infrastructure. A large portion of the growth in supply capacity occurs post-2030, in line with the timeline of growth resulting from the electrification of buildings, transport, and industry and the need for hydrogen production. These trends can be observed in greater detail in Figure 14.

Both scenarios require a large scale-up in wind capacity and hydrogen-fired gas turbines.[75] Most of the increase in generation capacity results from an increase in installed wind. In the Diversified scenario, wind capacity increases in the near term to 21 GW in 2030 and 43 GW in 2040, rising to 75 GW in 2050. In the Electrification scenario, it increases at a similar rate, to 21 GW in /u
2030, 43 GW in 2040 and 72 GW in 2050. To meet peak demand and to enable this large scale-up in /u
variable generation capacity, there is a significant need for dispatchable generation such as hydrogen-fired gas turbines and battery storage, particularly in the Electrification scenario. By 2040, 20 GW of hydrogen gas turbine capacity is installed in the Electrification scenario, and this number /u
rises to 35 GW by 2050. In the Diversified scenario, only 13 GW of hydrogen gas turbine capacity is installed by 2050 due to the lower electricity-system peak. In both scenarios, new battery storage capacity complements the build out of hydrogen gas turbine capacity to provide the electricity system with flexibility and resiliency.

Electricity peak demand increases substantially in both scenarios. In the Diversified scenario, peak demand more than doubles, from 22 GW in 2020 to 51 GW by 2050. In the Electrification /u
scenario, peak demand increases almost 4 times, to 82 GW by 2050. The Electrification scenario sees a drastic increase in peak demand for the 2030-2040 period (Figure 14) as a result of the high degree of electrification in buildings, driven by the government's goal that by 2035, all space heating technologies for sale in Canada meet an energy performance of more than 100%.[76] The Diversified scenario shows a slower growth in peak demand post-2030 because it assumes a higher portion of homes switch to gas heat pumps, which have a small impact on peak electric demand. The Electrification scenario is primarily dependent on a single energy system (electricity) and the implications on energy system resilience should be studied in more depth. Consideration of energy system resilience is important given the increased risks of extreme weather events and potential cyberattacks.

Annual electricity generation is comparable in both scenarios. While electricity demand is significantly higher in the Electrification scenario compared to the Diversified scenario, the Diversified scenario also requires significant electricity supply to produce hydrogen. By 2050, roughly 181 TWh of /u
electricity supply is used in the Diversified scenario for hydrogen production, whereas 37 TWh of /u
electricity supply is needed in the Electrification scenario.

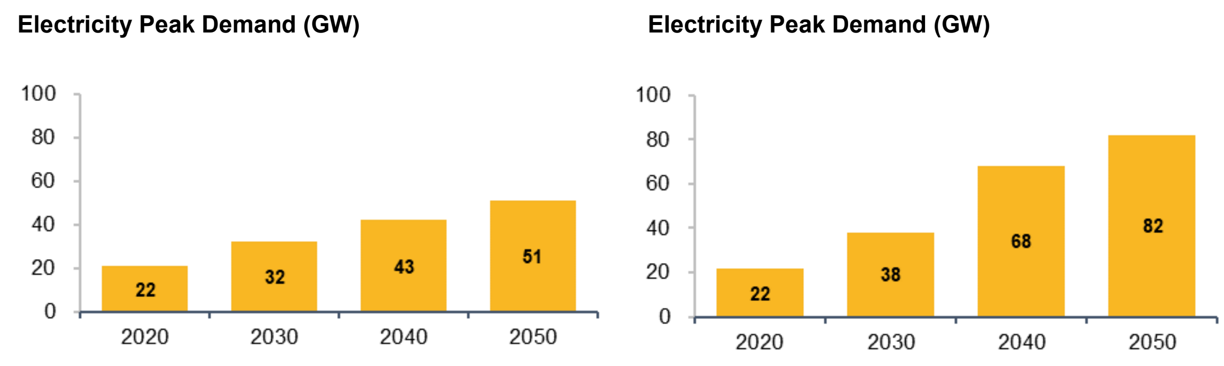
[75] Guidehouse's analysis focuses on the use of hydrogen gas turbines in both scenarios rather than natural gas-fired gas turbines. Hydrogen gas turbines are intended to reflect natural gas-fired gas turbines retrofitted to hydrogen or new hydrogen gas turbines. Our analysis does not make any explicit assumptions on whether existing gas turbines are retrofitted, nor when. For simplicity, we assume all hydrogen gas turbines are costed out as new gas turbines.

[76] Energy and Mines Ministers' Conference (2017). Market transformation strategies for energy-using equipment in the building sector. p.16. Available: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/Market-Transformation-Strategies_en.pdf /u

/u

Figure 14. Electricity Supply for the Diversified and Electrification Scenarios[77,78]

***Note**: Total electricity supply (domestic supply +/- imports and exports) is greater than demand due to losses in T&D. Storage denotes battery storage and pumped hydro storage; however, pumped hydro storage makes up less than 3% of total storage.*

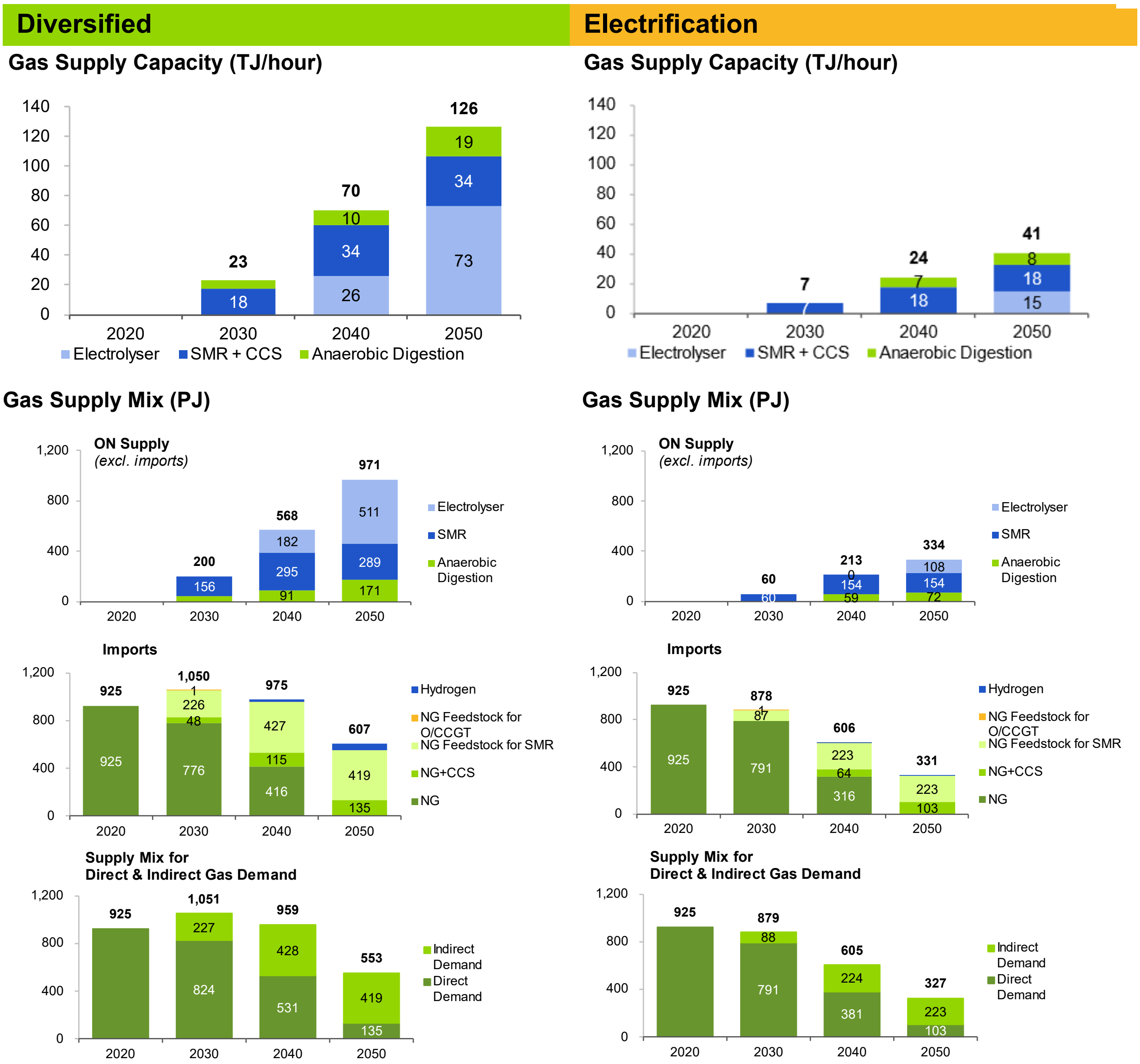


[77] The electricity supply capacity and supply mix graphs reflect the capacity and supply needed to produce green hydrogen.
[78] Direct demand is the electricity needed to meet end user demand without any conversion across energy carriers (i.e., converting electricity into hydrogen). Indirect demand is the electricity needed to produce hydrogen via electrolyzers.

5.2 Gas Supply Development

Today, Ontario imports all natural gas used in the province. As the province moves toward a net zero future, conventional natural gas will be replaced by hydrogen, RNG or the end use will be outfitted with CCS to abate emissions. This provides Ontario with the opportunity to develop domestic gas supply. The Diversified scenario presents a future in which this supply is sharply scaled up to 126 /u
TJ/hour in 2050 to meet demand (107 TJ/hour of hydrogen and 19 TJ/hour of methane). In contrast, /u
the Electrification scenario uses these fuels only for end uses that are difficult to electrify, such as high temperature. Therefore, domestic gas supply scales to reach a total capacity of 41 TJ/hour in 2050 (33 TJ/hour of hydrogen and 8 TJ/hour of methane). These supply capacities, as well as /u
imports, can be seen in Figure 15 below. While the gas system peak declines for both scenarios in energy terms, the volumetric gas system peak rises significantly in the Diversified scenario. This is because hydrogen has a lower energy density than methane, so more volume is needed to provide the same amount of energy.

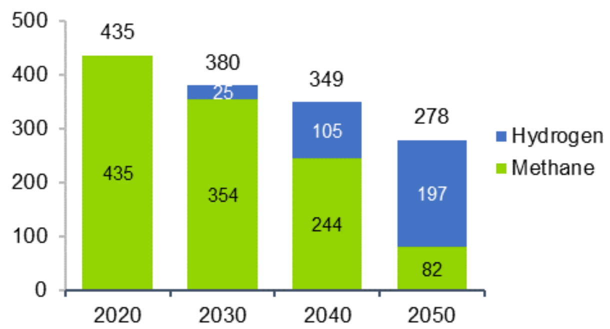
Figure 15. Gas Supply for the Diversified and Electrification Scenarios /u



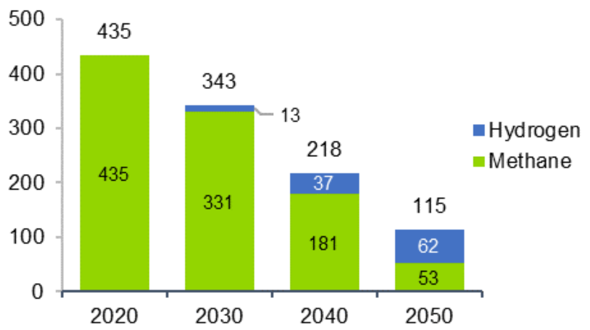
Note: *Total gas supply (domestic supply plus imports) is greater than demand due to losses in T&D.*

Diversified	**Electrification**

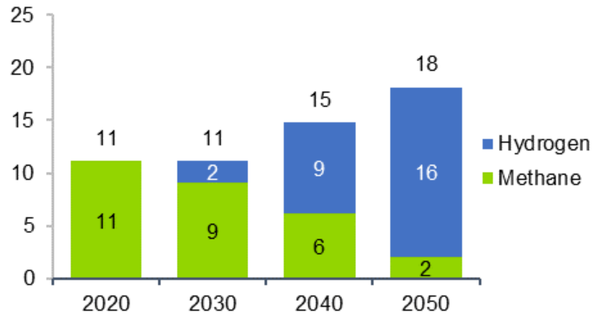
Gas Energy Peak Demand (TJ/hour)



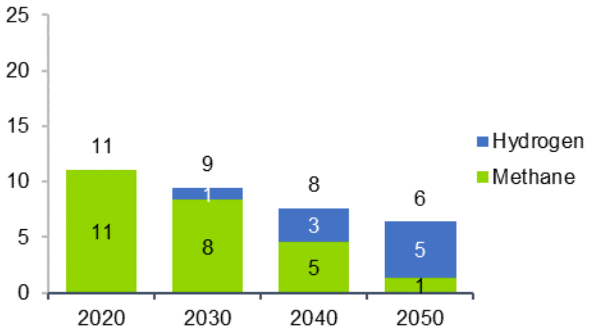
Gas Energy Peak Demand (TJ/hour)



Gas Volume Peak Demand (million m³/hour)



Gas Volume Peak Demand (million m³/hour)



5.2.1 Hydrogen Supply Mix

Compared to the Electrification scenario, the Diversified scenario leads to a significantly larger scale-up of domestic hydrogen supply and a greater need for hydrogen imports transported via pipeline from neighbouring regions. In the Diversified scenario, domestic hydrogen supply[79] is forecast to
increase to 800 PJ by 2050: 511 PJ of green hydrogen (via electrolyzers) and 289 PJ of blue /u
hydrogen (via SMR + CCS). The increase of hydrogen supply in the Electrification scenario is more
limited. The domestic hydrogen supply is forecast to increase to 262 PJ by 2050: 108 PJ of green /u
hydrogen (via electrolyzers) and 154 PJ of blue hydrogen (via SMR + CCS). /u

Blue hydrogen plays a major role in meeting hydrogen demand in the near term. In both scenarios, the scale-up of blue hydrogen (SMR + CCS) leads the scale-up of green hydrogen (electrolyzers). Up to 2030, blue hydrogen production is more cost-effective than green, making it the preferred production method. From 2030 to 2040, while decreasing costs of green hydrogen lead to a buildup in green hydrogen supply, blue hydrogen supply continues to scale. By 2050, no new additional blue hydrogen supply comes online. Nevertheless, existing supply—installed by 2030 and 2040—continues operating and meets a significant share of hydrogen demand.

Hydrogen demand is met mostly via domestic supply rather than imports. In both scenarios, most hydrogen demand is met via domestic supply as a combination of blue and green hydrogen. By
2050, in the Diversified scenario, domestic hydrogen accounts for 94% of total supply, equivalent to /u

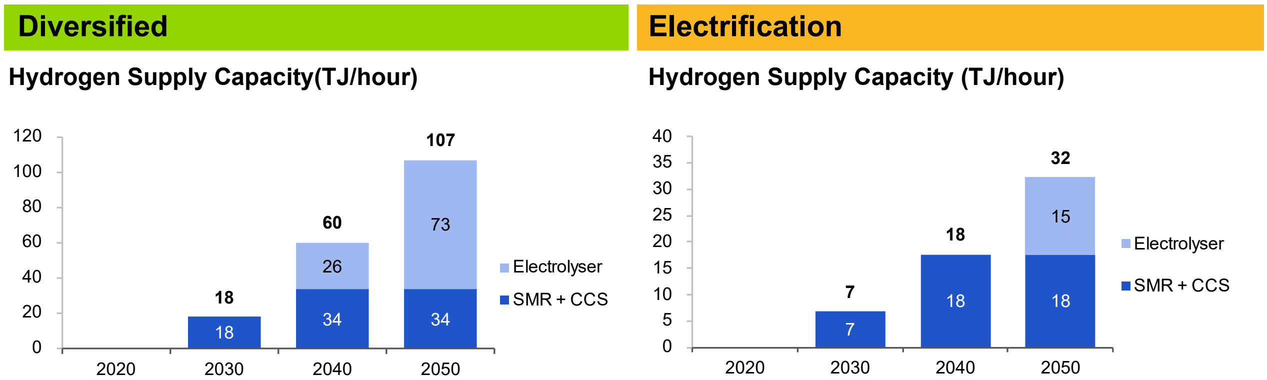
[79] Domestic hydrogen supply refers to hydrogen produced in Ontario, whether via SMR + CCS (blue hydrogen) or electrolyzers (green hydrogen). /u

800 PJ, while imports from Western Canada and Quebec account for 6%, or 54 PJ. Similarly, in the Electrification scenario, imports play a small role contributing 5 PJ, or 2%, by 2050.[80] [81]

Increased demand for hydrogen boosts the scale-up of green hydrogen supply. High demand for hydrogen in the Diversified scenario results in significant scale-up of green hydrogen supply capacity. Much of this increase in demand occurs from 2040 to 2050, when the levelized cost of green hydrogen becomes more competitive than blue hydrogen. This results in all new hydrogen supply capacity installed after 2040 to be green. Overall, while blue hydrogen plays a major role in the near term, by 2050, the mix of domestic hydrogen supply is dominated by green hydrogen. In comparison, in the Electrification scenario, low demand for hydrogen results in a hydrogen supply build out of 32 TJ/hour of capacity by 2050. Compared to the Diversified scenario, blue hydrogen plays a larger role in the hydrogen market. By 2050, a slight majority of the capacity is blue hydrogen.

Green hydrogen supply leads to significant, additional demand for electricity supply.[82] The scale-up of green hydrogen supply in the Diversified scenario has major implications for the electricity system in 2040 and 2050. By 2040, green hydrogen scales to 182 PJ of supply, requiring roughly 66 TWh of electricity supply. This is equivalent to a 46% increase in Ontario's electricity demand today. By 2050, the impact on the electricity system is even greater, increasing by more than two times. Green hydrogen supply scales to 511 PJ, requiring roughly 181 TWh of electricity supply, roughly equivalent to 126% of the province's total electricity demand today. In comparison, since the demand for hydrogen is much lower in the Electrification scenario, the electricity required to power the electrolyzers is much less. In 2050, green hydrogen supply reaches 108 PJ, which would require approximately 37 TWh of electricity, or the equivalent of over one quarter of the electricity used in the province today.

Figure 16. Hydrogen Supply for the Diversified and Electrification Scenarios

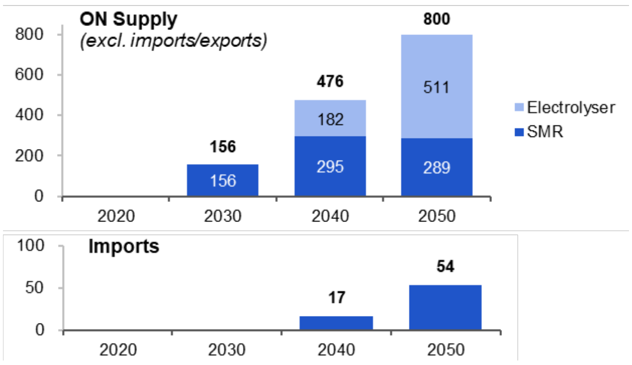


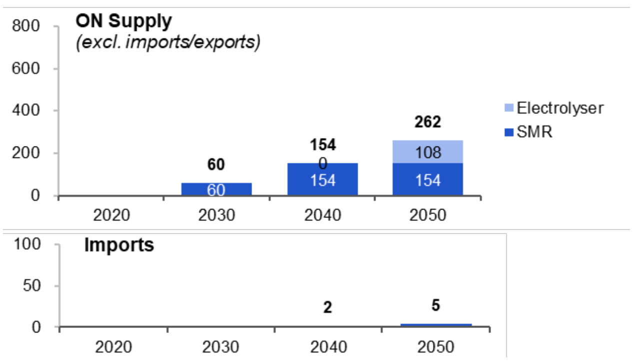
[80] Guidehouse's analysis assumes inter-provincial transmission pipelines are not repurposed for hydrogen until 2040. This means hydrogen imports are not available in 2030. By 2040, we assume some of the existing natural gas pipeline capacity from Western Canada is repurposed for hydrogen, allowing for hydrogen imports in Ontario. Our analysis assumes the mix of hydrogen imports to be a 50/50 split between blue and green hydrogen. Finally, by 2050, we assume existing gas pipelines between Ontario and Quebec are also repurposed, enabling hydrogen imports from Quebec to Ontario. Hydrogen imports from Quebec are assumed to be 100% based on green hydrogen.

[81] The share of green versus blue imports into Ontario varies across scenarios. The Diversified scenario leads to a greater reliance on imports from Quebec versus Western Canada and green hydrogen dominates imports accounting for nearly 87% of import volumes. By comparison, green hydrogen accounts for 56% of imports in the Electrification scenario, with most hydrogen imports coming from Western Canada.

[82] Guidehouse's analysis does not forecast a major role for surplus baseload generation (SBG) in the production of green hydrogen. While SBG conditions are not uncommon today, increased electricity demand over the coming decade is expected to significantly reduce the frequency and magnitude of SBG. This is consistent with findings from the IESO's 2021 APO, which forecasts the magnitude and frequency of SBG to decline significantly from 2023/2024 onward. Because the scale-up of green hydrogen supply begins in 2040 in our analysis, SBG does not play a role in hydrogen production.

Diversified	**Electrification**
Hydrogen Supply Mix (PJ)	**Hydrogen Supply Mix (PJ)**





Note: *Total hydrogen supply (domestic supply plus imports) is greater than demand due to losses in T&D.*

5.2.2 Methane Supply Mix

Both scenarios require a significant scale-up in RNG supply capacity over time. The increase in supply capacity for RNG production will be primarily via anaerobic digestion, reaching 171 PJ by 2050 in the Diversified scenario and 72 PJ in the Electrification scenario. These figures represent a /u significant share of Ontario's RNG potential, estimated to be 224 PJ.[83] Other RNG production technologies such as biomass gasification do not play major roles in RNG supply today; however, local conditions and the availability of low-cost biomass feedstock (such as in Northern Ontario) may encourage the development of gasification plants in the future.

While RNG achieves significant scale, natural gas imports continue to play a major role in meeting gas demand. The scale-up in domestically produced RNG leads to a significant share of Ontario's overall methane demand being met by RNG. By 2050, domestic RNG scales to amount to 56% of overall direct methane demand in the Diversified scenario, and 41% in the Electrification /u scenario.[84] This increase in RNG, along with decreased demand for natural gas, leads to a reduction in the volume of natural gas imports from Western Canada and New York. Despite this, natural gas imports continue to play a key role in meeting overall methane demand because of the need for natural gas in the production of blue hydrogen (via SMR + CCS) and the adoption of CCS in natural gas use. The Electrification scenario assumes less production of blue hydrogen, and natural gas imports are expected to decline more in the Electrification scenario.

CCS is fundamental in reducing GHG emissions from natural gas. By 2050, 100% of natural gas consumption incorporates CCS, whether for blue hydrogen production or directly in natural gas use. Therefore, share of natural gas with CCS installed at the end user and natural gas used to create blue hydrogen increases significantly over time in both scenarios. In the Diversified scenario, natural gas used for both technologies accounts for 26% by 2030, equivalent to 274 PJ, increasing to 553 PJ by /u 2050. In the Electrification scenario, this share accounts for 10% by 2030, equivalent to 87 PJ, /u increasing to 327 PJ by 2050. The scale-up of CCS for blue hydrogen and natural gas use is required to reach net zero emissions in both scenarios.

The development of carbon storage in Ontario will be critical in all net zero pathways. To achieve the emissions reduction targets, the development of carbon storage in Ontario will be required to store captured carbon emissions from blue hydrogen production and the use of natural gas in industry applications that are difficult to electrify. The Diversified scenario will require more than double the storage capacity than the Electrification scenario. In the Diversified scenario, the total storage required up to 2050 is for 415 megatonnes of CO_2 ($MTCO_2$), reaching 26 $MTCO_2$ of new /u

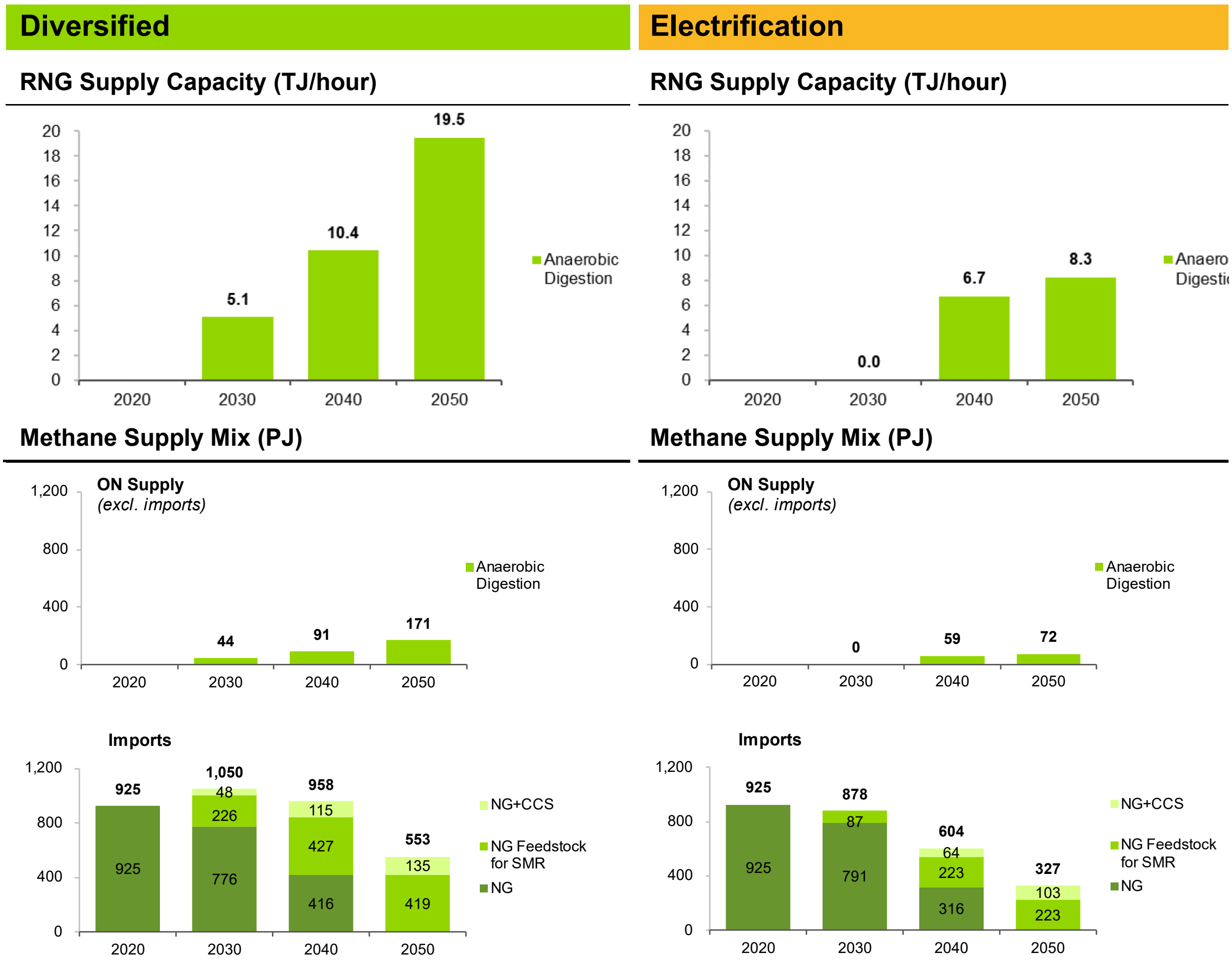
[83] Torchlight Bioresources (2020). Renewable Natural Gas (Biomethane) Feedstock Potential in Canada. Available: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf?la=en

[84] The larger share of RNG in the Electrification scenario reflects a much lower forecast of total methane demand.

storage needs per year in 2050. In the Electrification scenario, the storage required up to 2050 is 194 $MTCO_2$, with 16 $MTCO_2$ of new storage needs each year from 2050 onward. /u

An Ontario study estimated the amount of CO_2 storage of two major reservoirs in Ontario totalling approximately 730 $MTCO_2$.[85] The CO_2 storage requirements for the Diversified and Electrification scenarios up to 2050 would be satisfied with these two reservoirs. In the Diversified scenario, these two major reservoirs would provide sufficient storage volumes up to 2062, while in the Electrification scenario, they would be sufficient up to 2084[86] /u

Figure 17. Methane Supply for the Diversified and Electrification Scenarios /u



Note: *Total methane supply (domestic supply plus imports) is greater than demand due to losses in T&D.*

[85] Shafeen, Ahmed & Croiset, Eric & Douglas, Peter & Chatzis, Ioannis. (2004). CO_2 sequestration in Ontario, Canada. Part I: Storage evaluation of potential reservoirs. Energy Conversion and Management. 45. 2645-2659. Available: http://dx.doi.org/10.1016/j.enconman.2003.12.003

[86] Ontario may not be constrained by the volume of domestic CO_2 storage reservoirs. CO_2 storage in neighboring jurisdictions may also be tapped. For example, the Midwest Regional Carbon Sequestration Partnership in nearby US states may have up to 245 billion metric tonnes of CO_2 storage potential in deep rock salt formations.

US Department of Energy (2011). Midwest Has Potential to Store Hundreds of Years of CO2 Emissions https://www.energy.gov/fecm/articles/midwest-has-potential-store-hundreds-years-co2-emissions

Residual CO_2 Emissions

The production of hydrogen from SMR + CCS and the use of natural gas + CCS are assumed to have a 95% carbon capture rate.[87] The remaining emissions need to be eliminated or offset in the 2050 timeframe to achieve a carbon-neutral energy system. Hydrogen production via SMR + CCS or the use of natural gas + CCS has the potential to become a source of negative emissions if the methane comes from RNG instead of natural gas. See Section 2.3 for further information.

[87] The IEA's Assumptions Annex to its Future of Hydrogen Report reports captures rates for CCS technologies (e.g., SMR + CCS, natural gas + CCS) ranging between 90% and 95% capture rates. Guidehouse's analysis assumes a 95% capture rate is required to achieve the 2050 emissions reductions targets.

IEA (2019). The Future of Hydrogen, Assumptions Annex. Available: https://www.iea.org/reports/the-future-of-hydrogen/data-and-assumptions

5.3 Comparison of Pathway Energy System Costs

The estimated cost for the Diversified scenario is $41 billion less as compared to the Electrification /u scenario, cumulative from 2022-2050, or 6% lower. The reduced costs are due to less spending on electricity generation capacity and infrastructure, end user heating systems, and building energy efficiency retrofits.[88]

The Diversified scenario costs sum to $681 billion through 2050. Of these costs, gas system /u costs amount to approximately 29%. Gas system costs increase over time driven by the costs of deploying and operating new hydrogen and RNG production facilities. Costs increase over time as gas infrastructure is repurposed to hydrogen and as more hydrogen and RNG volumes are injected into the transmission and distribution network. Electricity system costs amount to 45% of costs, /u increasing steadily and are driven primarily by investments in wind and solar capacity and transmission infrastructure. Emissions costs amount to 18% of costs. End-user costs account for the /u remaining 8% of costs. End-user costs ramp up initially as adoption of heat pumps (gas and electric) increase, accompanied by investments in building retrofits and insulation. However, they are much /u lower from 2040 to 2050. Note that these costs are lower due to the construction of the analysis that does not include the salvage value of assets past 2050. Therefore, things such as heat pumps installed in the final decade have lower cost as their total lifetime would extend beyond the end of the study period.

In comparison, **the Electrification scenario costs amount to $722 billion through 2050**. Figure 18 /u illustrates that, in each decade of the study period, the gas system infrastructure and operating costs in the Electrified scenario are lower than in the Diversified scenario, which is consistent with lower /u projected demand for low- or zero-carbon gases from end-users and less investment in the associated gas supply and infrastructure. In the middle decade, from 2030 to 2040, emissions costs are $43 billion higher in the Electrification scenario than in the Diversified scenario. This is because in /u that decade, carbon emissions will still be significant, and the price of carbon will have risen significantly. The Electrification scenario uses a higher projected price of carbon compared to the Diversified scenario, resulting in higher emissions costs in that decade. The carbon price projections for each scenario can be seen in Appendix A.1. Electricity system costs are $32 billion higher than in /u the Diversified scenario, which is driven by a much larger electricity peak demand in the Electrification scenario (82 GW) compared to the Diversified scenario (51 GW). This increase in peak is driven by /u higher penetration of electric heat pumps and the electrification of transport, leading to significant investment in hydrogen gas turbine capacity and T&D infrastructure. Finally, end-user costs are $17 /u billion higher compared to the Diversified scenario. End-user costs are higher because of the high penetration of electric heat pumps which require significant upfront investment in equipment for; geothermal heat pumps and costly building retrofits to maintain the same level of comfort for air-source heat pumps.[89] The higher end user costs and higher system wide costs in the Electrification scenario may require more social policy actions to protect low income and small business customers and ensure their access to energy.

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[88] This cost differential is consistent in magnitude and direction with previous studies, where a cost difference of ~10%-25% is /u common in a comparison of economy-wide GHG emissions reduction pathways between scenarios that lean in opposing directions in terms of the role played by electricity and gas. While results are impacted by electricity and gas supply-demand conditions unique to each jurisdiction, there is a strong degree of consistency across most studies. The results of our scenario analysis for Ontario are directionally consistent with most literature.

For example, in a Canadian context, FortisBC (2020) estimated savings of 16% between a Diversified scenario and an Electrification scenario in its pathways assessment for achieving 80% emissions reductions in British Columbia. From a European perspective, Gas for Climate (2019) estimated savings of 11% between an Optimised Gas scenario and a Minimal Gas scenario in its 2050 net-zero assessment covering the EU27 countries and the UK. ENA (2019) estimated savings of 12% between a Balanced and an Electrified scenario in its 2050 net-zero pathways assessment for Great Britain (England, Scotland, and Wales).

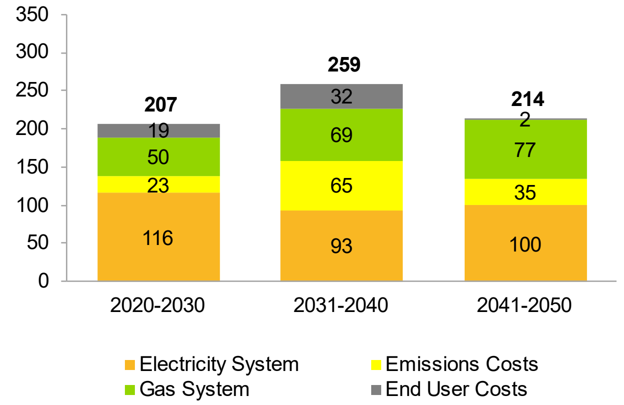
[89] To provide adequate heating in winter conditions, electrically heated homes need to be well-insulated and weatherized to minimize heat leakage. Reduction of heat loss is important for electrically heated homes because the heating capacity of air-source heat pump systems is less than gas furnaces, especially at low outdoor temperatures. A regular-sized gas furnace usually provides 20 to 35 kW of heat output, while a whole-home heat pump may only provide 5 to 15 kW of heat output at colder outdoor temperatures.

In the discussion of sensitivity analyses in section 5.6, emissions costs are allocated to the gas system. Figure 18 reports emissions costs separate from gas system costs to better demonstrate the costs associated with investment in the gas system.

Figure 18. Energy System Costs for Diversified and Electrification Scenarios[90] /u

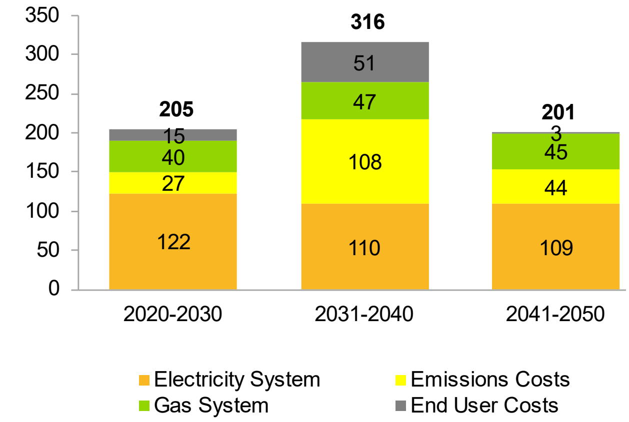
Diversified

Energy System Costs (billion CAD, real 2020$)



Electrification

Energy System Costs (billion CAD, real 2020$)



Billion CAD, real 2020$

	2020-30	2031-40	2041-50	Total
Gas System	50	69	77	**197**
Elec. System	116	93	100	**309**
Emissions	23	65	35	**122**
End Users	19	32	2	**53**
Total	**207**	**259**	**214**	**681**

Billion CAD, real 2020$

	2020-30	2031-40	2041-50	Total
Gas System	40	47	45	**132**
Elec. System	122	110	109	**341**
Emissions	27	108	44	**179**
End Users	15	51	3	**70**
Total	**205**	**316**	**201**	**722**

[90] This analysis also calculated the average annual energy system costs of scenarios on a per capita basis and found: Diversified scenario: costs of $1,300/year per person in 2025, rising to $1,470/year in 2035, and falling to $1,090/year in 2045. Electrified scenario: costs of $1,290/year per person in 2025, rising to $1,790/year in 2035, and falling to $1,020/year in 2045. This calculation of per capita costs assumes that Ontario's population rises to 15.9 million people in 2025, to 17.6 million people in 2035, and to 19.7 million people in 2045, as projected by Ontario's Ministry of Finance, at: https://www.ontario.ca/document/ontarios-long-term-report-economy/chapter-1-demographic-trends-and-projections /u

Scope of Energy System Costs

The energy system costs included in this study are broken down into three categories: gas system costs, electricity system costs, and end-user costs. The cost allocation approach for each of these categories is described as follows:

The allocation of costs across these categories is not intended to identify who is responsible for accruing these costs (e.g., gas system vs. end users) since all costs are ultimately recovered from consumers. Rather, this cost allocation is intended to represent where costs originate. For example, costs associated with RNG supply could be reflected under gas system costs or end-user costs. Our analysis reports RNG costs are under gas system costs because gas infrastructure companies are responsible for developing and initially paying for RNG supply infrastructure, not end users.

In some cases, costs have been allocated to either the gas or electricity systems based on reporting simplicity. For example, all costs associated with the generation of electricity—whether for hydrogen production or direct electricity demand—are allocated to the electricity system. How these costs are ultimately distributed across the energy supply chain would depend on factors such as tariff formulation and regulatory policy.

- **Gas system costs:** Gas system costs include CAPEX and OPEX of new gas supply capacity (e.g., RNG, hydrogen production, CCS), and gas transmission pipeline costs (including hydrogen and RNG integration and injection costs). These costs include the cost of intra-province pipelines necessary to connect new resources to the gas network. The ongoing costs of natural gas imports and operating existing pipeline infrastructure are included and are roughly equal in both scenarios. /u
- **Electricity system costs:** Electricity system costs include CAPEX and OPEX of new electricity supply capacity (e.g., wind, solar, battery storage, hydrogen gas turbines) and new transmission infrastructure. These costs include the cost of incremental transmission wires necessary to connect new generation assets to the electric grid. As noted above, the costs of electricity generation capacity used for hydrogen production are reported under electricity system costs. The costs of continuing to operate existing electricity supply capacity (e.g., nuclear, hydro) and T&D infrastructure are included and are roughly equal in both scenarios. /u
- **End-user costs:** End-user costs include CAPEX of all residential building heating equipment upgrades including gas heat pumps (hydrogen- or methane-fired), and electric heat pumps.[91] Costs associated with insulation retrofit requirements (for new and existing homes) are also included. Insulation costs vary based on the type of heating system used. For example, there are different insulation requirements for a home heated with a gas furnace versus an electric heat pump. The analysis focuses purely on the end-user costs associated with building heating and not any other end-user sectors. /u
- **Out of Scope costs:** In the Electrification scenario, with large amounts of customers switching away from gas-fired heating, it is possible that portions of the gas network may be retired and/or decommissioned before the end of their useful life. There are large uncertainties regarding the timing, extent, and geographic scope of decommissioning. Thus, the results of this study *exclude* the potential costs for decommissioning portions of the gas network. These costs warrant further study, though, as cost estimates from UK-based utilities suggest that Ontario's decommissioning costs could exceed $1.0 billion per year.[92]

  Costs for expanding and upgrading gas and electricity distribution systems (last-mile delivery) are out of scope.

  End user costs associated with the transport sector (e.g., electric vehicles, charging infrastructure) and end user costs in the industrial sector (e.g., electric arc furnaces, kilns) are not captured in the analysis. Based on a similar study performed for British Columbia, Guidehouse would not expect these costs to have a material impact on results.[93]

  Costs associated with improving the resiliency of either the electric or the gas system are not captured in this analysis. The future may see more investments in system resiliency, given the increased risks of extreme weather events and potential cyberattacks. And, at least in the Electrification scenario, the increased reliance on a single energy system may prompt customers to invest in backup generators as insurance against adverse events.

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[91] This does not include wood or biomass heating or district heating, nor the cost of existing heating system.

[92] Decommissioning costs are based on a high level estimate developed for four gas distribution companies in the UK: Cadent Gas, Northern Gas Networks, Scotia Gas Networks, and Wales & West Utilities. These four UK gas distributors estimated decommissioning costs of GBP1.24 billion per year (incurred annually over 20 years) based on several gas network characteristics including kilometres of distribution pipelines, compression stations, gas storage capacity, and gas connections, among other gas system characteristics. If these UK-based cost estimates are scaled linearly to represent Ontario based on the extent of the gas distribution network (e.g., reduced to 148,000 km in Ontario vs. 280,000 pipeline-km of distribution network in the UK), Ontario decommissioning costs are roughly estimated at CAD1.10 billion per year (or GBP0.66 billion/year).

UK Energy Networks Association (2019). Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain. Available: https://www.energynetworks.org/industry-hub/resource-library/pathways-to-net-zero-decarbonising-the-gas-networks-in-great-britain.pdf

[93] FortisBC (2020). Pathways for British Columbia to Achieve its GHG Reduction Goals. Available: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf?sfvrsn=dbb70958_4

5.4 Comparison of Emissions Pathways

In both the Diversified and Electrification scenarios, Ontario emissions decrease significantly toward 2030 and 2040, reaching the net zero emissions target by 2050. The emissions pathways of both scenarios are largely consistent. This is driven by two factors:

- First, both scenarios take a consistent approach to reducing GHG emissions in large portions of the transportation and industrial sectors. For example, light road transport will reduce GHG emissions via electrification, while the steel and iron ore industries will reduce GHG emissions via hydrogen.
- Second, both scenarios are based on emissions reduction trajectories with the same magnitude—e.g., GHG emissions from trucks and buses are reduced at roughly the same rate, whether by electrification (in the Electrification scenario) or by hydrogen (in the Diversified scenario).

Because total energy system costs are lower in the Diversified scenario as compared to the Electrification scenario, the costs of reducing emissions are also proportionally lower. The cost of emissions reductions in the Diversified scenario are estimated at approximately \$269MTCO$_2$e compared to \$275/MTCO$_2$e in the Electrification scenario. /u

Scope of GHG Emissions

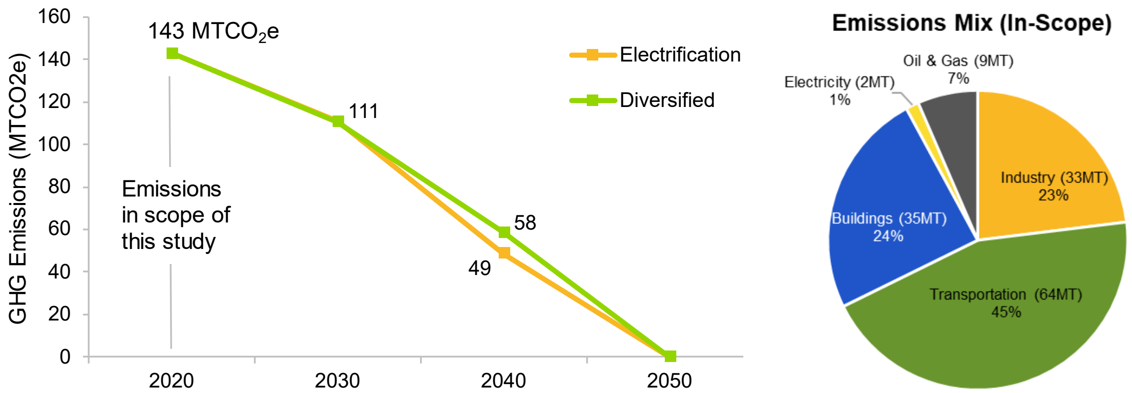
The scope of this study does not capture all Ontario-wide emissions, estimated to be 159 MTCO$_2$e in 2018. This study captures approximately 90% of provincial emissions, or roughly 143 MTCO$_2$e. [94]

The breakdown of Ontario emissions in the scope of this study are presented in the pie chart shown in Figure 19 and include transportation (45%), buildings (24%), industry (23%), oil and gas (7%), and electricity (1%).

The remaining 10% of provincial emissions (not included in the pie chart) are associated with agriculture, waste, and other sources—all of which are not captured in this study. Our analysis assumes these out-of-scope sectors reduce GHG emissions in step with society.

/u

Figure 19. Ontario Emissions Pathways[95]



One of the differences between the Diversified and Electrification scenarios is the magnitude of residual emissions from gas supply. In the Diversified scenario, blue hydrogen (SMR + CCS) and

[94] Ontario emissions reported by NRCan for 2018 are adopted as an estimate for 2020 and are used as the baseline for this study.

Natural Resources Canada (2020). Comprehensive End Use Database. Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

[95] The scope of this study does not capture 100% of Ontario-wide emissions. The scope of this study is approximately 90% of provincial emissions, or roughly 143 out of 159 MMTCO$_2$e.

These in-scope emissions are associated with buildings, transport, industry, and power. The remaining 10% of emissions are associated with agriculture, waste, and other sources, all of which are not part of the analysis. We assume these out-of-scope sectors reduce GHG emissions in step with society.

natural gas + CCS scale up significantly, whereas in the Electrification scenario, they play a limited role because GHG emissions from most demand sectors are reduced via electrification. Because CCS does not capture 100% of emissions, some residual emissions remain in both scenarios. In both scenarios, residual emissions in 2050 are minimal: 2.4 $MTCO_2e$ in the Diversified scenario and 1.5 $MTCO_2e$ in the Electrification scenario. In both scenarios, residual emissions are offset via the use of bioenergy with CCS in power generation. /u

5.5 Pathway Feasibility

For both the Diversified and Electrification scenarios, there will be challenges in implementing the pathways to net zero emissions. Both pathways rely on the development of new low- and zero-carbon gas sources. The Diversified pathway requires rapid adoption of electrolyzer and CCS technologies, and industrial customers' conversion to hydrogen-consuming equipment. The Diversified pathway also assumes that within a decade, building owners will begin converting their heating systems to gas heat pumps – a technology that is not widely available today. The deployment of these new technologies results in a more gradual increase in peak electric demand.

In contrast, the Electrification pathway largely relies on electric heat pump technologies that are readily available today. The main challenge for the Electrification pathway is in the scale of deployment of new electric infrastructure that will be needed to power these solutions. As shown in Figure 14, the Electrification pathway will see a 73% increase in electric peak demand in the 2020-2030 decade, followed by a further doubling of electric peak demand in the 2030-2040 decade. This will require rapid growth in electric generation capacity and in T&D infrastructure to avoid electric system failures, especially during extreme events such as low-wind and low-sun days, or when above-ground infrastructure is impacted by severe weather like ice or high winds. This growth will be especially challenging given the anticipated 4,000 to 6,000 MW capacity shortfalls driven by the retirement of the Pickering Nuclear Generating Station.[96] /u

Beyond the cost impacts detailed in section 5.3, stakeholders must consider the feasibility of pursuing the rapid but diffuse adoption of new technology compared with the equally rapid deployment of new electric infrastructure.

5.6 Sensitivity Scenario Results

Previous sections compared the results of the Diversified and Electrification scenarios. These sections concluded that, for Ontario, the Diversified scenario presents a more cost-optimal and feasible pathway for reducing GHG emissions through 2050. In this section, we stress-test the results of the Diversified and Electrification scenarios by exploring how these two central scenarios would evolve in other potential net zero visions for Ontario. These alternative net zero visions capture relevant trends in the energy system which may lead to other possible futures for Ontario's energy system. For example, if current trends on the adoption of distributed electricity resources – like rooftop solar and battery storage – were to accelerate aggressively, how would this impact the results of the Diversified and Electrification scenarios? Alternatively, if the adoption of hybrid heating systems were to take off and became the most common heating equipment by 2050, how would this impact the electricity and gas peak?

The objective of this section is to explore the impact of these trends, and others, on the Diversified and Electrification scenarios. This includes four sensitivity scenarios:

- **Sensitivity 1: Increased Decentralized Electricity** explores the impact of an increase in the degree of decentralized electricity supply on total energy system costs.
- **Sensitivity 2: Limited Investment in Gas Supply and Infrastructure** explores the impact of decreased investment in gas infrastructure on Ontario's ability to meet net zero emissions by 2050.

[96] See IESO (2022). Annual Acquisition Report: April 2022. pp. 1, 14, and Figure 13. Available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/aar/Annual-Acquisition-Report-2022.ashx

- **Sensitivity 3: Lower Electrolyzer and Hydrogen Storage Costs** explores the impact of lower hydrogen production costs and hydrogen storage costs on the development of hydrogen supply infrastructure.
- **Sensitivity 4: Adoption of Hybrid Heating Technologies** explores the impact if a significant portion of homes adopt hybrid heating systems that combine gas-fired furnaces with electric heat pumps.

5.6.1 Sensitivity 1: Increased Decentralized Electricity

This sensitivity explores a future where distributed and renewable energy resources play a more central role in the evolution of the electricity system. This sensitivity assumes this scenario is accompanied by aggressive capital cost reductions for solar, wind, and battery storage. These cost reductions lead to high adoption of small-scale, behind-the-meter solar and battery storage resources, which have an impact on the need for T&D power lines. The shift in electricity supply from centralized locations (e.g., large-scale solar) to end users (e.g., behind-the-meter solar) results in avoided T&D investments that would otherwise be required to transport power from centralized locations to end users.

The premise for this sensitivity is based on the development of microgrid projects and large-scale, residential solar-and-storage projects across Ontario. Some high-profile examples include Elexicon's Pickering microgrid and Alectra's PowerHouse project in Vaughan.[97] [98]

The core assumptions underlying this sensitivity are:

- Higher uptake in customer-sited solar and battery storage with 50% of all new capacity assumed to be behind-the-meter and not centralized.
- Capital costs of solar, wind, and battery storage decrease 25% compared to the base Diversified and Electrification scenarios.

Impact on Total Energy System Costs

The impact of this sensitivity on energy system costs is a slight decrease in total energy system costs for both scenarios. The assumed cost reductions in solar, battery storage, and wind lead to an increase in the amount of installed renewable capacity compared to both base scenarios. Additional battery storage capacity in the Electrification scenario provides some balancing of the increase in /u
renewables.[99]

In the Diversified scenario, the assumptions adjusted in this sensitivity decrease the overall energy system costs by $11 billion from $681 to $670 billion due to abundant renewables making green /u
hydrogen more attractive than in the base scenario. Cheaper renewables decrease the electricity system costs by $8 billion over the study period. A greater share of hydrogen produced by electrolysis /u
reduces the need for blue hydrogen, thus reducing overall gas system costs. For the Electrification scenario, this sensitivity results in $12 billion in total energy system savings, largely concentrated in the electricity system and mainly due to reduced capital cost of renewables and reduced investments /u
in transmission and distribution.

Impact on Diversified Scenario:

- **Slightly reduced electricity system costs:** The decrease in solar costs results in a /u
significant increase in solar capacity to approximately 27 GW in 2050, which replaces

[97] Global News (2021). Pickering community can go off-grid with nested microgrid technology. Available: https://globalnews.ca/news/8370542/off-grid-pickering-nested-microgrid-community/

[98] Alectra (2020). POWER.HOUSE virtual power plant delivers peace of mind. Available: https://www.alectra.com/sites/default/files/assets/pdf/Alectra_GREATCentre_PowerHouse_2020-07-15.pdf

[99] It should be noted that outside of this modelling exercise, depending on scenario, it is assumed that 95-100% of light duty vehicles in Ontario are electric by 2050. While out of scope for this study, these vehicles represent significant storage capabilities for the province when not in use, and this storage capacity should be analyzed further.

baseload nuclear SMR capacity that is built in the base scenario. Slightly more hydrogen fired /u
gas turbines are required to balance the added solar capacity. The reduced cost of solar
capacity as well as the reduced build out of nuclear SMR offset the increase in cost due to
increased solar and hydrogen fired capacity, which results in an overall reduction of $8 billion
in electricity system costs.

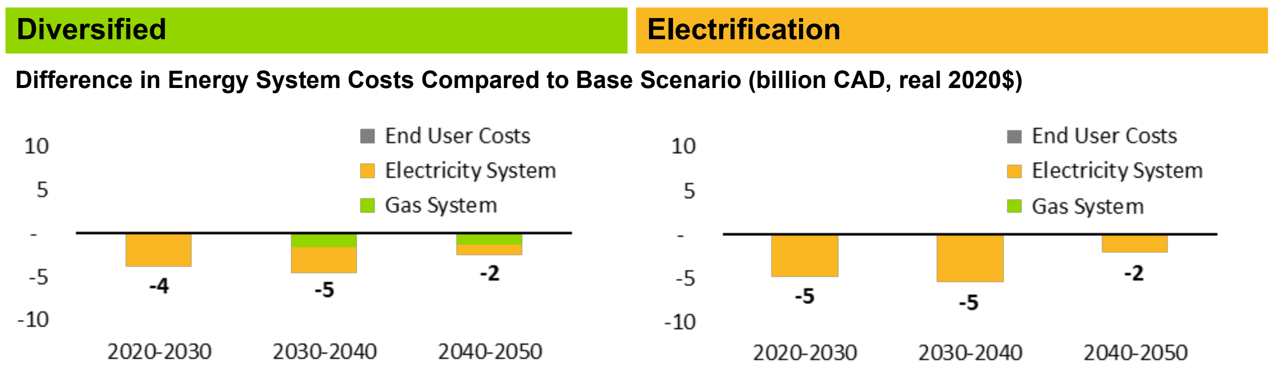
- **Gradual cost savings over time.** With a more moderate approach to electrification, the investments in solar, wind, and battery storage are distributed over the study period.
- **Lower gas system costs:** With the lower cost of renewables, the cost of green hydrogen is
reduced and becomes competitive with blue hydrogen earlier in the study period. In this
sensitivity, green hydrogen accounts for 51% of 2040 hydrogen capacity and 72% of 2050 /u
hydrogen capacity, compared to 44% and 69% in the central Diversified scenario. Gas
system costs are reduced because with a reduced build out of SMR + CCS, there is less /u
natural gas feedstock for SMR required.

Impact on Electrification Scenario:

- **Lower electricity system costs:** The decrease in solar costs results in an increase in solar /u
capacity by 5 GW, to 13 GW by 2050, which replaces additional hydroelectric capacity in the
base Electrification scenario. Since hydroelectricity is a more costly resource, the reduction in /u
capital costs results in $12 billion in electricity system savings.
- **Significant upfront cost savings.** Over half of the cost savings of this sensitivity occur in in the first decade of the study period. This is because in the base Electrification scenario, significant investments in battery storage, solar, and wind occur before the mid 2030's due to the immediate and aggressive electrification efforts needed to meet demand that was previously met by the gas system.

Slight decrease in gas system costs: While electricity system costs are the main impact
area of this sensitivity, gas system costs decrease as well by $30 million. Similar to the /u
Diversified scenario, the reduction in gas system costs is due to lower capital costs for
renewable which make green hydrogen more cost-effective than in the base scenario. This
results in an increase in green hydrogen in 2050. Increased electric capacity also reduces the /u
need for more costly methane imports from 2030 to 2040.

Figure 20. Sensitivity 1 – Comparison of Energy System Costs /u



Note: In this comparison chart, changes in emissions costs are included in the "Gas System" series.

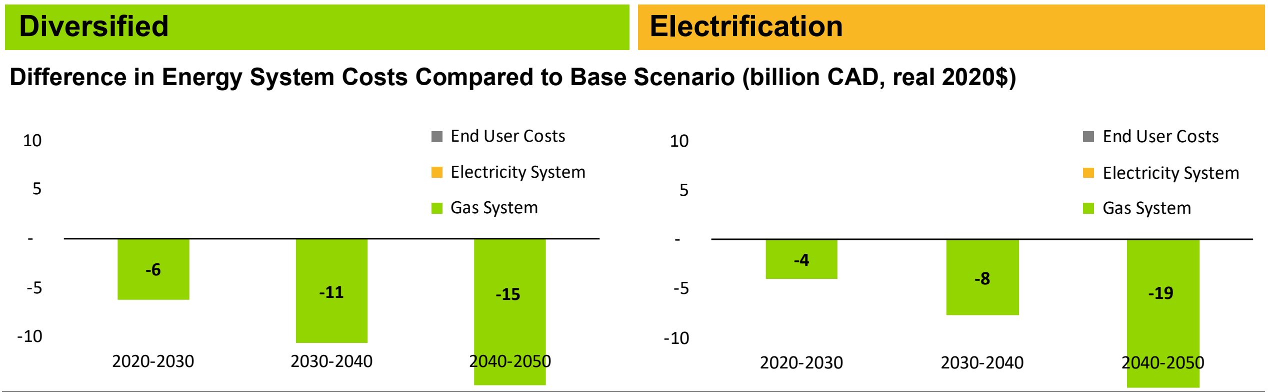
5.6.2 Sensitivity 2: Limited Investment in Gas Supply and Infrastructure

This sensitivity explores the impact of reduced investment in the gas system compared to the base
Diversified and Electrification scenarios. This sensitivity analyzes how constrained spending on
reducing GHG emissions of the gas supply and infrastructure could impact Ontario's ability to reach
net zero by 2050. This reduction in investment is assumed to impact the buildout of blue hydrogen
supply capacity (SMR + CCS) and the development of RNG supply. As a result, gas demand /u
previously met by blue hydrogen and RNG is now met by unabated natural gas. The callout box at the

end of this section explores the cost of offsetting the increased emissions that arise from this sensitivity, if such a magnitude of offsets were available.

Guidehouse's analysis assumes a **reduction in gas system investment compared to the base Diversified and Electrification scenarios**, leading to a reduction in spend of approximately $31-32 billion, cumulative through 2050. This reduction in achieved through a reduction of the capacity buildout of SMR + CCS, anaerobic digestion, and natural gas + CCS compared to the base scenarios. /u

Figure 21. Sensitivity 2 – Comparison of Energy System Costs /u

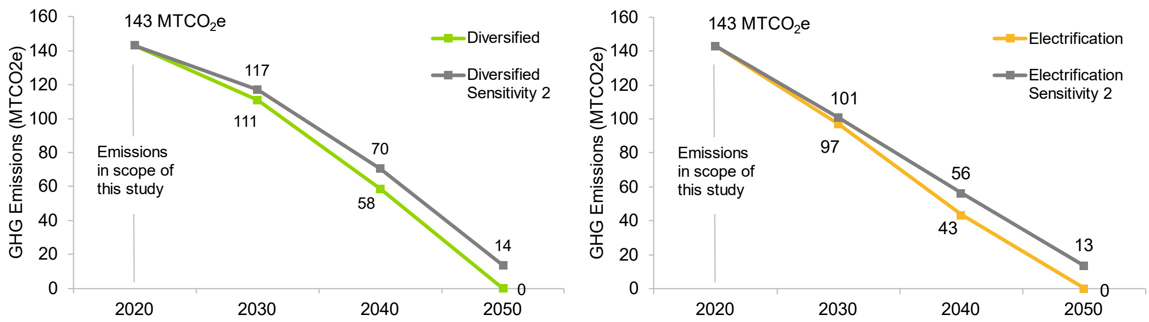


Note: In this comparison chart, increases in emissions costs are not included..

Impact on Emissions Pathway

For the Diversified scenario, the impact of this sensitivity is unabated emissions of 14 $MTCO_2$ in 2050 compared to the base Diversified scenario. This is equivalent to roughly 10% of Ontario's natural gas emissions today. For the Electrification scenario, however, the impact on blue hydrogen and RNG production is much greater in magnitude since this scenario assumes the minimum investment in the gas system needed to achieve net zero emissions. Thus, these investment dollars are targeted towards end uses that are difficult to electrify such as high-temperature industry and heavy transport. It is important to note that these sectors also contribute significantly to present day emissions. Reducing this investment results in unabated emissions of 13 $MTCO_2$ in 2050, which is equivalent to roughly 9% of Ontario's natural gas emissions today. It is important to note that **under the conditions of this sensitivity, Ontario does not achieve net zero emissions by 2050 in either scenario**. This sensitivity results in Ontario only reducing emissions by approximately 90% of current emission levels by 2050. The carbon emissions trajectories traced by this sensitivity analysis can be seen in Figure 22 below for both scenarios. /u /u /u /u

Figure 22. Comparison of Emissions Pathways of Sensitivity 2 for Both Scenarios /u



Cost of Residual Emissions

This sensitivity analysis determined that in the Diversified scenario, reducing spending on the gas system by /u
\$32 billion will result in 14 $MTCO_2$ of residual emissions in 2050, or the equivalent of an additional 257 $MTCO_2$
in cumulative emissions released into the atmosphere from 2020 to 2050. For the Electrification scenario,
reducing gas system spending by approximately \$31 billion would result in 13 $MTCO_2$ of residual emissions in /u
2050, or the equivalent of 239 $MTCO_2$ in cumulative emissions over the study period. For these magnitudes of
residual emissions*, it cannot be assumed that sufficient offsets will be available to reach net zero* if Ontario
addressed these residual emissions using carbon offsets.

Using the projected carbon tax values in Table A-2 as a proxy for the price of carbon emissions, it would cost
Ontario \$34 billion (2020\$) to offset these residual emissions if the gas system spending is reduced by /u
\$32 billion in the Diversified scenario. Similarly, it would cost Ontario \$55 billion for the emissions created if the
gas system spending is reduced by \$31 billion in the Electrification scenario. Because the cost of emissions /u
offsets outweighs the cost of GHG mitigation through gas system investments, we conclude that targeted gas
system investments are more cost-effective than carbon offsets to reduce GHG emissions.

5.6.3 Sensitivity 3: Lower Electrolyzer and Hydrogen Storage Costs

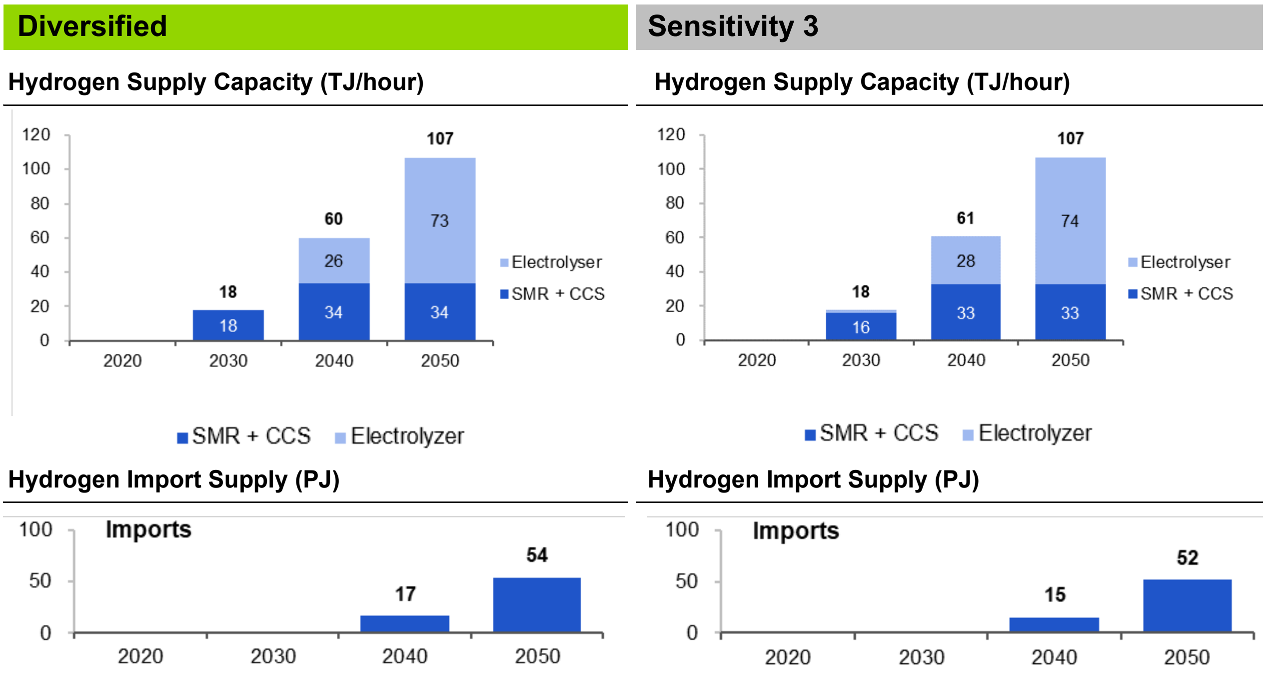
This sensitivity explores the impact of a future with decreased green hydrogen costs compared to today's price forecasts. The core assumptions underlying this sensitivity are:

- Capital costs for electrolyzer and wind follow a lower price forecast than assumed in the Diversified scenario. These cost reductions lower the cost of green hydrogen production in Ontario and neighbouring jurisdictions, which leads to a decrease in the cost of hydrogen imports from Western Canada and Quebec.
- Costs of hydrogen storage decrease 25% compared to hydrogen storage costs in the Diversified scenario.

The impact of this sensitivity in the Diversified scenario is a decrease in total energy system costs by
just over \$9 billion from \$681 billion to \$672 billion. In the Electrification scenario, this reduction is /u
smaller at \$7 billion from \$722 billion to \$715 billion. While this sensitivity affects the costs of both the
electricity and gas systems, the majority of savings come from reduced electricity system costs in the
Electrification scenario, and relatively evenly from both gas and electricity system savings in the /u
Diversified scenario.

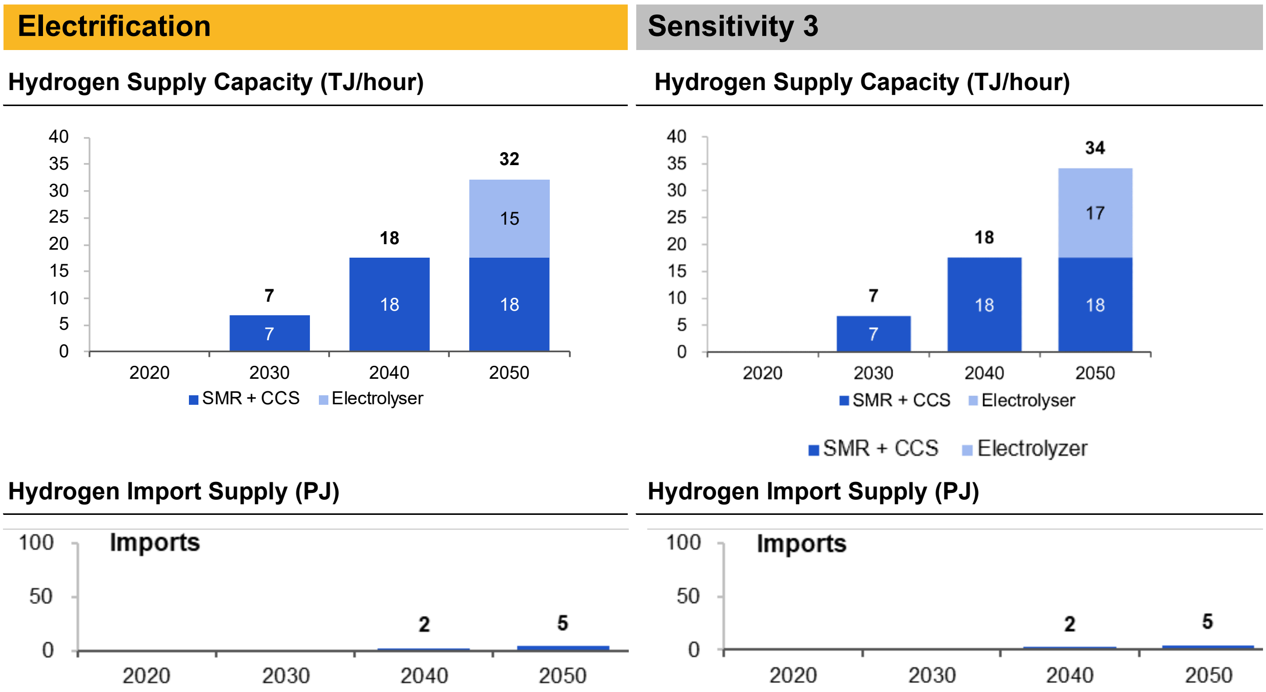
For the Diversified scenario, the result of this sensitivity is that green hydrogen meets a larger share /u
of the overall hydrogen demand due to decreased costs. SMR + CCS operates at a higher utilization
than electrolyzers because it does not depend on renewables, so to meet the same demand with
electrolyzers powered by renewables, slightly more capacity needs to be installed (e.g. in 2030 and
2040). The electricity system cost savings are due to the reduction in wind costs compared to the /u
base Diversified scenario.

Figure 23. Sensitivity 3 – Comparison of Hydrogen Supply Capacity and Imports /u



Similarly for the Electrification scenario, reduced electrolyzer and hydrogen storage costs increase the share of green hydrogen in the production of hydrogen overall (see Figure 24). Due to this, overall hydrogen capacity increases due to the capacity factors of the renewable electricity generation that the electrolyzers rely upon.

Figure 24. Sensitivity 3 – Comparison of Hydrogen Supply Capacity and Imports /u

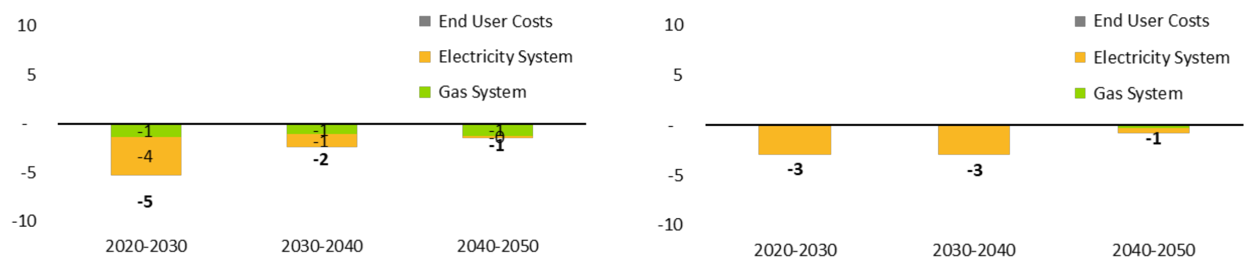


Compared to the base Diversified scenario, gas system costs fall by $4 billion and electricity system costs fall by $5 billion, due to reduced wind energy costs. Similarly, compared to the base Electrification scenario, electricity system costs decrease by $7 billion due to decreased wind energy costs. Gas system costs decrease by close to half a billion due to decreased hydrogen import costs, decreased electrolyzer costs, and decreased hydrogen storage costs. /u /u

Figure 25. Sensitivity 3 – Comparison of Energy System Costs /u

Diversified **Electrification**

Difference in Energy System Costs Compared to Base Scenario (billion CAD, real 2020$)



Note: In this comparison chart, changes in emissions costs are included in the “Gas System” series.

5.6.4 Sensitivity 4: Hybrid Heating System Adoption

This sensitivity explores the peak load reduction potential of hybrid heating systems, which combine gas-fired furnaces with electric heat pumps, installed in residential homes across the province in comparison to the base Diversified scenario. The core assumption underlying this sensitivity is the aggressive adoption of hybrid heating systems for residential space heating outlined in Table 3 below.

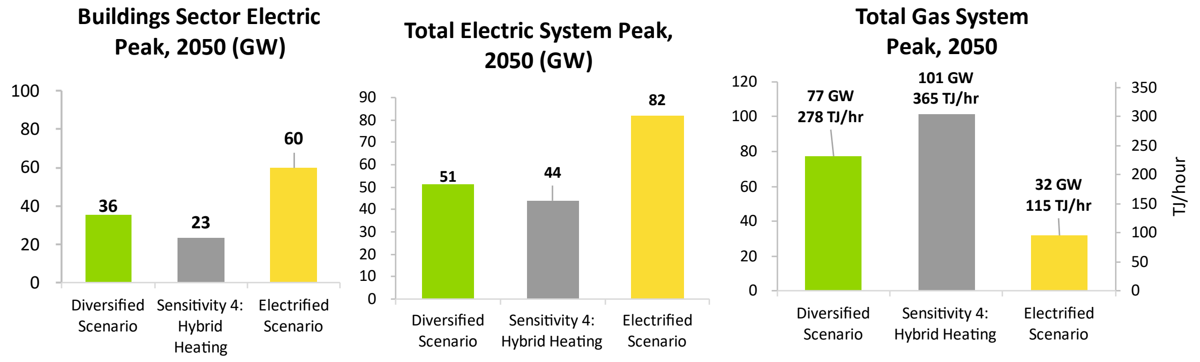
Table 3. Sensitivity 4 – Residential Heating Equipment Shares

Space Heating	2020	2030	2040	2050
Gas heat pump	0%	1%	15%	20%
Air-source heat pump	7%	7%	8%	10%
Geothermal heat pump	0%	4%	7%	10%
Hybrid heating system	0%	14%	35%	55%
Natural gas furnace	82%	65%	28%	0%
Other	11%	9%	7%	5%

The impact of this sensitivity is the optimization of peak demand through integration of the electricity and gas systems at the end-use level. This optimization results in reduced electric system peak demand in 2050 and reduced annual gas demand through the study period compared to the base Diversified scenario due to homes moving away from natural gas as their sole heating source. Hybrid heating technology mitigates the effects of cold temperature on electric heat pump performance, so the electric peak is significantly lower than the base Electrification scenario and somewhat lower than /u the base Diversified scenario. Relative to the Diversified scenario, this reduction in peak leads to a 5 GW decrease in electricity supply build out and cumulative savings of $670 million in electricity /u system spending. Reducing winter peak demand should also improve system resilience in cold climate regions. While the cost of the gas system increases by $4 billion due to increased gas system /u peak compared to the base Diversified scenario, this is more than offset by the significant decrease in end user costs. Figure 26 summarizes the peak load impacts of this sensitivity. /u

The buildings sector electric peak values in Figure 26 the peak of just the buildings sector, which may /u coincide with the electric system peak, depending on the scenario. For the Diversified scenario in 2050, the buildings sector electric demand shown in Figure 26 occurs at a separate time from the coincident electric system peak load. For the Electrification scenario in 2050, the buildings sector peak occurs at the same time as total system peak.

Figure 26. Sensitivity 4 – Comparison of Peak Load in 2050 /u



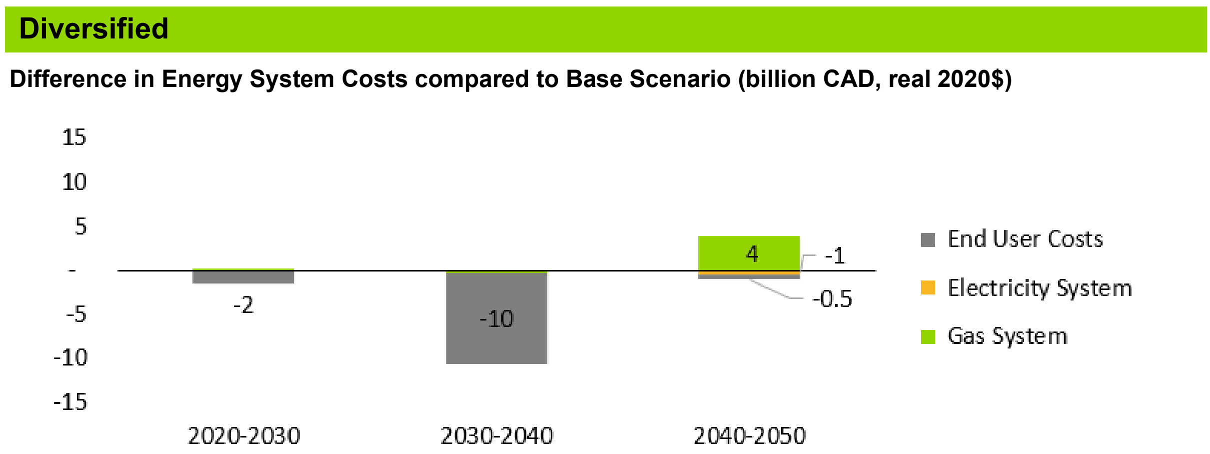
A large share of cost savings, $12 billion, come from decreased end-user costs. In the base Diversified scenario, gas-fired heat pumps overtake natural gas furnaces as the most prevalent space heating technology in the province. Sensitivity 4 results in cost savings because hybrid heating systems are less costly to install than gas heat pumps and do not require the deep energy efficiency retrofits that are accompany cold-climate air-source heat pump installations. The costs of each technology can be seen in Table 4 below. /u

Table 4. Sensitivity 4 – Residential Space Heating Technology Costs[100]

Space Heating Technology	Cost (2020$)
Gas heat pump with low-capacity A/C unit	$12,200
Electric cold climate heat pump with electric resistance backup	$11,100
Hybrid heating system	$11,350

Gas system costs increase by $4 billion dollars because of an increase in gas system peak when compared to the base Diversified scenario. Although there are associated savings with slightly reduced hydrogen gas supply built in Ontario over the entire study period, the increase in reliance on gas import volumes negates these savings. Since hybrid heating systems only switch to gas heating below a certain design temperature, less gas is needed on an annual basis compared with using a gas furnace or a gas fired heat pump. These cost differences can be seen in Figure 27 below. /u /u

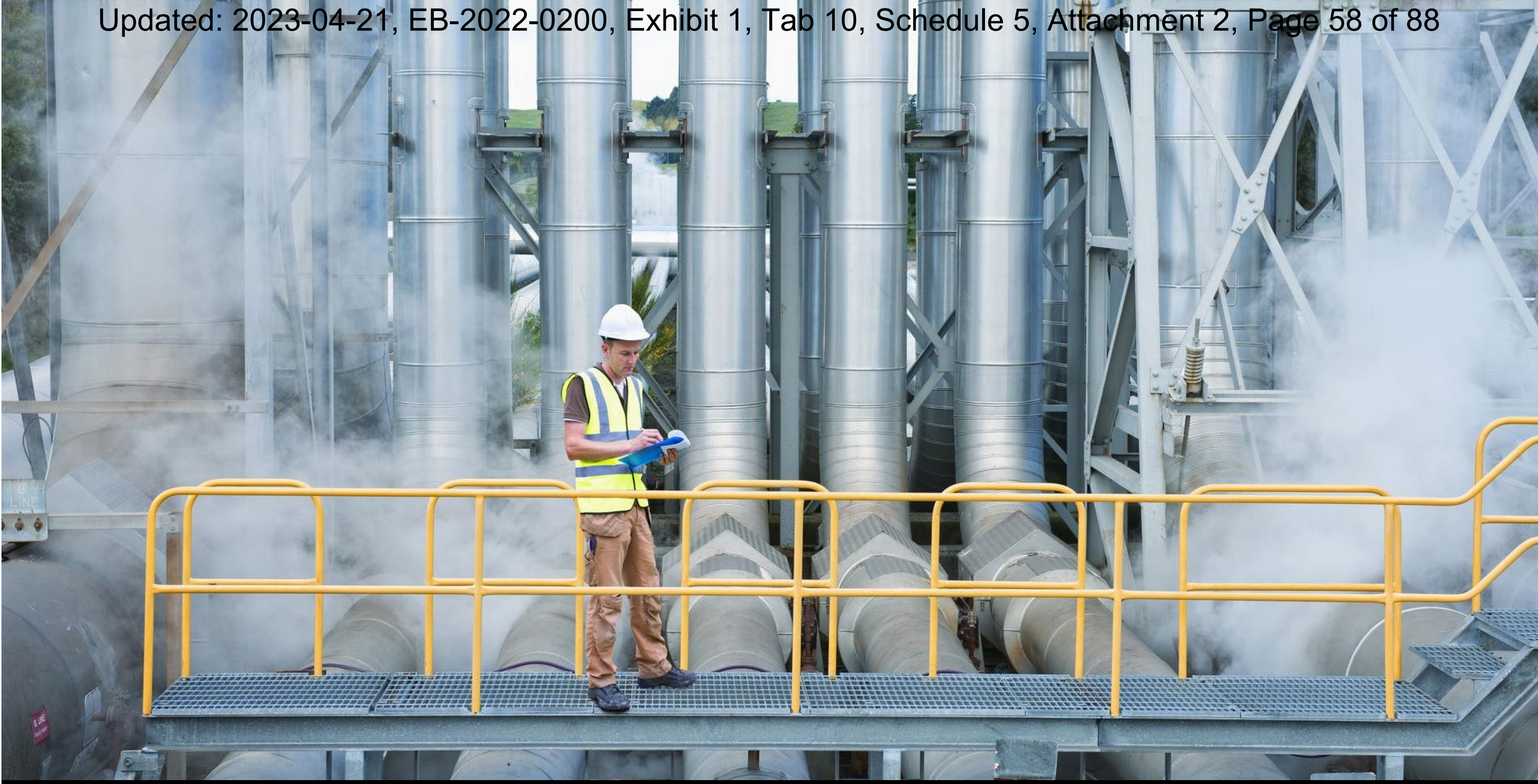
Figure 27. Sensitivity 4 – Comparison of Energy System Costs /u



Note: In this comparison chart, changes in emissions costs are included in the "Gas System" series.

[100] Residential space heating equipment costs were sourced from Enbridge Gas Inc. (2021). Answer to Interrogatory from Ontario Energy Board, pp.343-356. Available: https://www.rds.oeb.ca/CMWebDrawer/Record/732115/File/document

This sensitivity analysis shows that through peak demand management via adoption of hybrid heating systems in residential homes, Ontario has the potential to save $9 billion compared to the base Diversified scenario. The addition of hybrid heating to the core Diversified scenario improves the scenario's feasibility in two ways: (1) Fewer homes will require deep energy retrofits with the inclusion of hybrid heating systems, since hybrid heating systems rely on gas-fired backup heating systems during cold weather periods and the heating capacity of gas-fired systems does not diminish in cold outdoor temperatures. (2) Since hybrid heating systems rely on gas-backup during peak cooling periods, the deployment of hybrid heating systems reduces the amount of electric capacity growth needed to supply heat during winter peak conditions (see Figure 26). /u



6. Implications for Ontario’s Energy System

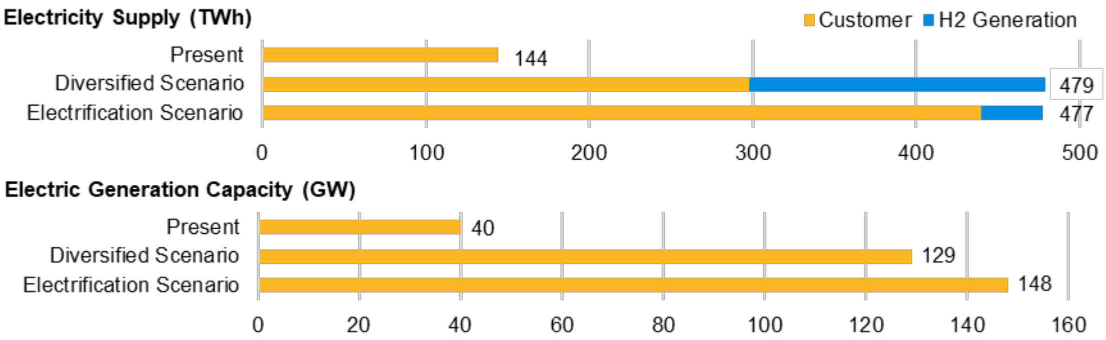
Guidehouse’s analysis determined the Diversified scenario is more cost-effective than the Electrification scenario when modelling how Ontario could reach net zero emissions by 2050. To stress-test our findings, we also evaluated the impact of four scenario sensitivities relative to the base Diversified and Electrification scenarios. The sensitivities explored, including increased decentralized electricity, lower electrolyzer and hydrogen storage costs, and adoption of hybrid heating technologies illustrated pathways that could further reduce energy system costs relative to the Diversified scenario. None of the sensitivities altered the directionality of the Diversified scenario having lower estimated energy system costs than the Electrified scenario. /u

In all scenarios and sensitivities, the analysis shows that Ontario’s energy system will require energy infrastructure to increase significantly in scale and will require drastic changes in the way the electricity and gas systems operate. Across all these scenarios, several common themes emerged. This section summarizes these common themes and explores some of the major implications on the future of Ontario’s electricity and gas grids.

1. **Low- and zero-carbon gas will be indispensable to get to net zero.**
   While electrification is a powerful tool for reducing GHG emissions, electrification is not practical for all sectors. Some sectors such as heavy transport or industries with high temperature processes like steel and chemicals have considerable carbon footprints and are challenging or next-to-impossible to decarbonize through electrification. Reaching net zero emissions in Ontario by 2050 cannot be achieved through electrification only. Low- and zero-carbon gases like RNG and hydrogen will play a role in the GHG emissions reductions of most sectors, particularly in hard-to-abate sectors like heavy transport and industry.

2. **All pathways to net zero will require a significant scale-up in electricity infrastructure.** Guidehouse's scenarios forecast a significant increase in direct electricity supply to end users: a two-fold increase in the Diversified scenario to 281 TWh and a three-fold increase in the Electrification scenario to 413 TWh. Additionally, in the Diversified scenario, electricity generation capacity will also have to scale up to meet indirect electricity demand for green hydrogen production.[101] Our analysis estimated 511 PJ of green hydrogen production in 2050, leading to an additional approximately 181 TWh of electricity demand in the Diversified scenario. In all scenarios and sensitivities, the magnitude of the increase in electricity demand will require a significant buildout of generation capacity, T&D infrastructure, and storage capacity. Our analysis forecasts generation capacity increasing from 40 GW today to 129 GW in the Diversified scenario and to 148 GW in the Electrification scenario. An increase in scale of this magnitude will require changes in the way electricity generation capacity and transmission infrastructure is planned and evaluated, and the speed at which it is developed. /u /u /u

Figure 28. Comparison of Present and Future Electricity Supply and Generation Capacity /u



3. **The electricity and gas systems will become increasingly integrated.** These two energy delivery systems will grow more interconnected on the journey to net zero. Our analysis has shown how important energy conversion between electricity and hydrogen will be in the future. Electricity supply will be critical to scale up green hydrogen supply and meet hydrogen demand. Hydrogen supply will also be critical in meeting peak electricity demand through hydrogen-fired gas turbines. Hydrogen will become an important long-term electricity storage option. Hydrogen will be produced during periods of electricity oversupply, and it will be used in periods of peak demand. This integration can also happen behind the meter, with dual fuel technologies like hybrid heating systems operating intelligently to optimize the use of electricity and gas for space heating. Hybrid heating systems can reduce electricity system costs by reducing peak electric load. Our analysis shows that significant adoption of residential hybrid heating systems can save Ontario $9 billion compared to the base Diversified scenario. /u

4. **Reducing GHG emissions from the gas system will be a less disruptive and more cost-effective option than full electrification.** The analysis shows that the Diversified scenario can save Ontario $41 billion by 2050 relative to the Electrification scenario. The benefits from this scenario are not only limited to costs savings, but also largely to ease of implementation. The Diversified scenario avoids highly disruptive building retrofits and heating equipment upgrades, both of which are required in the Electrification scenario. With more than 65% of residential buildings in Ontario already equipped with either gas furnaces or boilers,[102] replacing them with electric heat pumps will require extensive and disruptive renovation to ensure buildings are adequately heated and insulated. Despite these energy efficiency improvements, electricity peak demand will increase significantly. This will lead to major investments in new generation, transmission, and distribution infrastructure. /u

[101] Direct energy supply to end users and indirect energy supply for green hydrogen production are treated separately in our model and are impacted by various factors including the availability of surplus electricity, gas/electricity storage and energy imports.

[102] NRCan (2018). Residential Sector Heating System Stock. Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=on&rn=21&page=0

The Diversified scenario offers an opportunity to avoid some of this disruption. Heating with low- and zero-carbon gas requires limited building renovation. In the near term, blending RNG and hydrogen into the gas grid does not require new heating systems. Only in the longer term, with a 100% hydrogen gas grid, would hydrogen-ready heating systems be needed.

5. **The transition to low- and zero-carbon gas will reduce Ontario's reliance on energy imports**.
Our analysis shows that domestic sources of low- and zero-carbon gas will be developed right here in Ontario in the future. In the Diversified scenario, domestic RNG supply is expected to scale up to deliver roughly 15% of gas supply, while domestic green hydrogen will grow to meet roughly 44% of gas supply. Overall, more than half of Ontario's gas supply can be met /u
with domestic resources. RNG and hydrogen present an excellent opportunity to minimize Ontario's reliance on energy imports and promote energy independence.

6. **Ontario's gas infrastructure can be cost-effectively repurposed to hydrogen to avoid costly investments in new electricity infrastructure.**
Ontario has an extensive natural gas pipeline network, delivering nearly twice as much energy per year as the province's electricity system and an even greater contribution to peak energy demand. Ontario's pipeline network is ideally suited to be repurposed to a hydrogen network, as the province's newer pipelines, typically made of polyethylene, are already largely hydrogen-ready. Metal pipes will require integrity assessments and internal coatings before they can be used to transport hydrogen. Nevertheless, this can be done for less than a quarter of the cost to build new hydrogen pipelines.[103] Repurposing existing natural gas infrastructure for hydrogen, as in the Diversified scenario, would be a more efficient use of existing infrastructure than the Electrification scenario, in which much of the gas network would be decommissioned. Utilizing the existing pipeline infrastructure will also allow stakeholders to continue benefitting from the reliability that gas utility systems provide. Additionally, the inherent characteristics of pipeline infrastructure (which is mostly underground) support a resilient energy system.

   Additionally, the Electrification scenario would likely face major societal acceptance challenges associated with the development of new electricity transmission infrastructure and associated land area requirements. For example, to transport the equivalent volume of energy as a traditional 48-inch gas pipeline would require the equivalent of 5-6 overhead high voltage alternating current transmission lines. These land area considerations are particularly important in high density regions like the metro areas of Toronto, Ottawa, and Hamilton, and crossing Indigenous territories.

7. **Gas generation will continue to play a critical role in Ontario's electricity system.**
Today, electricity system resiliency is achieved with dispatchable natural gas turbines. In a net zero future, the Diversified and Electrification scenarios project a major role for hydrogen-fired turbines in meeting peak demand and ensuring system resiliency and reliability. Hydrogen plays an even more pivotal role in the face of over 70 GW of wind capacity /u
forecasted by both scenarios, with hour-to-hour fluctuations in generation and the potential for week-long periods with little or no electricity generation from wind (commonly known as a *dunkelflaute* event). Without hydrogen-fired generation, a net zero electricity system would require overbuilding generation capacity and interties with neighbouring regions to ensure adequate peak supply. This approach would be more expensive, and it would be less resilient in cases of emergency with limited availability of imports and limited renewable generation. According to the IESO, phasing out natural gas generation by 2030 would require more than $27 billion of investment in supply and transmission infrastructure, translating to a 60% increase in electricity bills, and it would still result in blackouts.[104]

   Repurposing gas infrastructure for hydrogen would also bring an enormous storage benefit. Electricity storage technologies like batteries are expensive and only capable of storing electricity for several hours. Hydrogen is a promising solution to this problem because it can

[103] Guidehouse (2021). European Hydrogen Backbone: Analysing the future demand, supply and transport of hydrogen. Available: https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021.pdf

[104] IESO (2021). Decarbonization and Ontario's Electricity System: Assessing the impacts of phasing out natural gas generation by 2030. Available: https://www.ieso.ca/en/Learn/Ontario-Supply-Mix/Natural-Gas-Phase-Out-Study

be created from electricity with electrolyzers and converted back to electricity via fuel cells, internal combustion engines, and turbines. Electricity can be stored as hydrogen indefinitely, and Ontario has enormous gas storage potential in the Dawn Hub, which may be used for hydrogen pending further analysis to determine geological compatibility. A hydrogen system could be used to address daily, weekly, monthly, and seasonal variation in electricity and gas demand instead of overbuilding electricity generation, transmission, and storage capacity.

8. **A dedicated hydrogen pipeline network will be required.**
This analysis shows that by 2050 between 59 and 74% of gas demand will be hydrogen. To /u supply hydrogen to end users from production sites across Ontario and from neighbouring regions, T&D infrastructure will be repurposed for hydrogen. Planning to develop this network and repurpose the existing natural gas network needs to begin now to ensure Ontario is ready to transition.

Our analysis indicates that by 2030, hydrogen demand—primarily from industry and heavy transport—will be met exclusively via blue hydrogen because green/renewable hydrogen costs will remain high in the near term. By 2040, blue hydrogen imports from Western Canada are expected to materialize in the Diversified scenario. As hydrogen demand scales across all /u demand sectors, regional hydrogen networks will develop to connect green hydrogen supply points to end users across the province. This will require some pipeline capacity from the TC Canadian Mainline to be repurposed for hydrogen. By 2050, a full hydrogen transmission backbone will develop across Ontario. Green hydrogen supply potential from Quebec may also lead to imports into Ontario, which is reflected in modeling results of the Diversified /u scenario showing most of hydrogen imports being from Quebec.

As peak electric demand grows, energy system reliability and resilience will be key considerations.
Significant growth in energy production from intermittent renewable resources, such as wind and solar, requires energy storage and dispatchable electricity generation capabilities to ensure that energy system reliability can be maintained. An American Gas Foundation study published in January 2021 demonstrates that "Utilities, system operators, regulators, and policymakers need to recognize that resilience will be achieved through a diverse set of integrated assets … policies need to focus on optimizing the characteristics of both the gas and electric systems." [105] The IESO examined the possibility of phasing-out natural gas generation by 2030 and concluded that, "Diversity in energy supply strengthens the reliability and resilience of Ontario's power system, as different types serve different functions in order to meet needs…. Maintaining a diverse supply mix, where the different forms of supply complement each other, is an effective way to balance supply and demand to maintain the reliability of Ontario's power system."[106]

6.1 Recommended Actions by Stakeholders

To achieve net zero emissions by 2050, actions are required by all Ontario stakeholders. Policymakers, regulators, and utilities must consider the outlook to 2050 when evaluating different GHG emissions reduction pathways because some options that achieve 2030 goals may not enable cost-effectively achieving net zero emissions by 2050.

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[105] American Gas Foundation (2021). "Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience" Available at: https://gasfoundation.org/2021/01/13/building-a-resilient-energy-future/

[106] IESO (2021). Decarbonization and Ontario's Electricity System: Assessing the impacts of phasing out natural gas generation by 2030. p.7. Available: https://www.ieso.ca/en/Learn/Ontario-Supply-Mix/Natural-Gas-Phase-Out-Study

Table 5. Recommended Actions to Scale Electricity Supply and Infrastructure

Electricity	
Ministry of Energy	• **Investigate streamlined and predictable permitting and approval process.** Large-scale generation and transmission projects often face years of delay during the permitting process. The Ministry should investigate ways to streamline the permitting and approval process for generation and transmission infrastructure and make the process more predictable. • **Develop a provincial wind development strategy.** Wind capacity is projected to increase by more than 10-fold by 2050 and will be critical in meeting electricity and hydrogen demand. The Ministry should develop a provincial wind strategy to ensure coordination at all levels of government to provide clear direction to plan transmission needs, identify bottlenecks, and develop a grid connection strategy. • **Develop an electricity system pathway to a net-zero Ontario.** The Ministry should develop an electricity system pathway that supports the reduction of GHG emissions of Ontario's economy by 2050. This recommendation covers a larger scope than the Ministry's October 2021 directive,[107] which only covers GHG emissions reduction for the electricity system, not the entire economy.
Ontario Energy Board (OEB)	• **Develop integrated electricity and gas system planning.** Electricity system planning must take a holistic view of the evolving energy system and be closely aligned with gas system planning. The OEB should lead the development of an integrated energy planning working group involving major electricity and gas utilities. • **Develop regulatory structures that value energy system resilience.** The increased reliance on intermittent renewable sources establishes the need for a new consideration of the resilience of the energy system. Policies that foster complementary operations of electric and pipeline systems for resilience will reduce risks to local economies and communities.
Gas and Electric Utilities and System Operators	• **Develop a GHG emissions reduction pathway for the electricity and gas systems** to achieve Ontario's economy-wide net zero target by 2050 while controlling costs and maximizing GHG reductions. Utilities should support the Ministry with capacity expansion planning that supports the reduction of GHG emissions of Ontario's economy by 2050.

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[107] Ministry of Energy (October 2021). Available: https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-Minister-Gas-Phase-Out-Impact-Assessment.ashx

Table 6. Recommended Actions to Scale Hydrogen Supply and Infrastructure

Hydrogen	
Ministry of Energy	• **Establish hydrogen supply planning targets.** The Ministry should define medium-term (2030) and long-term (2045) planning targets for hydrogen supply[108] much like the strategic ambitions set by other countries such as the UK (5 GW), France (6.5 GW), and Spain (4 GW) and by the European Commission (40 GW). • **Support GHG emissions reductions of end users.** The Ministry should investigate market measures and incentives that support hydrogen adoption such as low carbon fuel incentives, carbon pricing, targets for FCEV and hydrogen-fueled appliance deployment, and renewable gas mandates. • **Expand the regulatory oversight of the Ontario Energy Board (OEB) to include hydrogen**, hydrogen-derivatives and the associated supply, transport, and storage infrastructure. • **Enable carbon capture and storage** for blue hydrogen production.
Ontario Energy Board	• **Develop regulatory framework for hydrogen and infrastructure.** Without clarity on how hydrogen supply and infrastructure investments will be regulated, utilities and end users can only rely on the existing natural gas framework as an example. The OEB should gather stakeholder views and investigate how other jurisdictions are approaching the development of a hydrogen regulatory framework. • **Allow utilities to recover the cost of hydrogen at a different cost than natural gas** and in line with the market price of hydrogen.
Gas and Electric Utilities and System Operators	• **Assess future hydrogen network needs.** Enbridge Gas should conduct pilots to assess the hydrogen-readiness of the existing gas system and to determine the next steps required to realize a hydrogen network. This is underway—Enbridge Gas is in the process of planning a hydrogen-readiness assessment and is piloting a hydrogen blending initiative that is serving customers in the city of Markham. • **Develop hydrogen infrastructure plan.** Enbridge Gas should plan how and when natural gas infrastructure can be repurposed for hydrogen and where new infrastructure will be required. This is akin to National Grid's Project Union in the UK, Gasunie's HyWay 27 in the Netherlands, and SoCal Gas's Angeles Link Project.[109,110,111] • **Perform electricity transmission impact assessment.** The IESO and HydroOne should perform a transmission grid impact assessment to identify future network impacts of green hydrogen production on transmission capacity requirements and regional energy flows.

[108] A planning target is not intended to be legally binding; rather, it is a strategic objective that can provide clarity for electricity and gas system planning and regulatory planning.

[109] National Grid (2021). Making plans for a hydrogen 'backbone' across Britain. Available: https://www.nationalgrid.com/national-grid-explores-plans-uk-hydrogen-backbone

/u

[110] Gasunie (2021). HyWay 27. Available: https://www.gasunie.nl/en/expertise/hydrogen/hyway-27

[111] SoCal Gas (2022). Application of Southern California Gas Company (U904g) for Authority to Establish a Memorandum Account for the Angeles Link Project. Available: https://www.socalgas.com/sites/default/files/A22-02-SOCALGAS-Angeles_Link_Memorandum_Account_Application.pdf

Table 7. Recommended Actions to Scale RNG Supply and Infrastructure

RNG	
Ministry of Energy	• **Establish an RNG production binding target**. The Ministry should define binding medium-term (2030) and long-term (2045) RNG production targets. Adopting binding RNG targets will provide a clear long-term planning horizon and investment certainty for RNG market players, investors, and for regulatory planning. • **Strengthen market support for RNG**. The Ministry should investigate supply and demand market measures that can bolster RNG adoption in Ontario (e.g., guarantees of origin, RNG registers and certificates, low carbon fuel incentives, waste reduction policies), and renewable gas mandates.
Ontario Energy Board	• **Work with the Ministry of the Environment** to ensure existing and future environmental regulations are supportive of RNG production. • **Allow utilities to recover the cost of RNG at a different cost** than natural gas and in line with the market price of RNG.
Gas and Electric Utilities and System Operators	• **Develop tariffs specific to RNG.** Having separate rates for RNG and conventional natural gas may incentivize project development by RNG suppliers, as utilities would be able to recover the higher cost associated with RNG

Table 8. Recommended Actions to Advance Carbon Capture and Storage

CCS	
Ministry of Northern Development, Mines, Natural Resources and Forestry	• **Amend prohibitions on the injection of carbon dioxide for storage**. The *Oil, Gas and Salt Resources Act* prohibits the injection of CO_2 associated with different regulated activities, and the *Mining Act* prohibits the permanent storage of any substance under storage leases covered by the Act. These prohibitions should be narrowed to allow potential carbon storage for the purpose of GHG emission abatement. • **Develop a streamlined permitting regime for approving CCS projects.** The Ministry should develop a permitting process that encourages commercial-scale CCS projects.
Ontario Energy Board	• **Develop regulatory structures that facilitate the adoption of CCS from fuel-fired electric generation.**
Gas and Electric Utilities and System Operators	• **Develop pilot CCS projects** to demonstrate the feasibility of CO_2 collection, transport, and sequestration.

List of Acronyms

This section defines key terms and acronyms used throughout this report.

APO	Annual Planning Outlook, a report from IESO
ASHP	Air-source heat pump
ATR	Auto-thermal reforming
bcm	Billion cubic metres, a unit of volume
BEV	Battery electric vehicles
Bio-CNG	Biologically derived compressed natural gas
BioSNG	Bio-syngas
CAD	Canadian dollar
CAPEX	Capital expenditures
CCS	Carbon capture and storage
CGA	Canadian Gas Association
CH4	Methane
CNG	Compressed natural gas
CO_2	Carbon dioxide, a greenhouse gas
CONE	Cost of new entry
CRNG	Compressed renewable natural gas
DSM	Demand side management
ETSA	Energy transition scenario analysis, conducted by Enbridge Gas
EU	European Union
EV	Electric vehicle
FCEV	Fuel cell electric vehicle
FOM	Fixed operating and maintenance costs
GHG	Greenhouse gas
GJ	Gigajoule, a unit of energy
GSHP	Ground-source heat pump
GT	Gas turbine
GW	Gigawatts, a unit of power
H2	Hydrogen
HDRI	Hydrogen-based direct reduction of iron ore
IEA	International Energy Agency
IESO	Independent Electricity System Operator
km	Kilometre, a unit of distance
kW	Kilowatt, a unit of power
LCP	Low Carbon Pathways model
LNG	Liquified natural gas
m^3	Cubic metres, a measurement of volume
Mt	Megatonnes

$MTCO_2$	Megatonnes of carbon dioxide
MW	Megawatt, a unit of power
MWh	Megawatt-hour, a unit of energy
NRCan	Natural Resources Canada
OEB	Ontario Energy Board
OPEX	Operating expenses
PJ	Petajoules, a unit of energy
PJM	A regional transmission organization in the United States
PV	Photovoltaic
RNG	Renewable natural gas
SMR	Steam methane reforming
T&D	Transmission and distribution
tCO_2e	Tonnes of carbon dioxide equivalent
TJ	Terajoules, a unit of energy
TWh	Terawatt-hour, a unit of energy
US	United States
VOM	Variable operation and maintenance costs

Appendix A. Model Inputs and Assumptions

A.1 General Economic Parameters

Natural Gas Price Forecast

The forecasts of natural gas prices from 2020 to 2050 are based on 2019 prices from Enbridge Gas escalated until 2038 based on the Dawn Hub consensus forecast. This analysis extrapolates the 2020-2038 trends out to 2040 and 2050 by escalating gas prices annually at inflation (2%). /u

Table A-1. Natural Gas (cents/m^3) (nominal CAD$) /u

Year	Natural Gas Price
2020	8.55
2030	13.51
2040	16.54
2050	20.17

Carbon Price Forecast

The forecasts of carbon prices from 2020 to 2050 are based on a forecast done in a previous Enbridge Gas analysis that forecasted the carbon prices to 2038 using the Greenhouse Gas Pollution Pricing Act[112] scheduled to 2022 and the recently announced update to the Pan-Canadian approach to carbon pollution pricing from 2023 through 2030.[113] For the Diversified scenario, the carbon price increases with inflation after 2030. For the Electrification scenario, the Parliamentary Budget Officer estimates[114] required to meet Canada's 2030 climate targets are used. The prices were adjusted for the calendar year, from the ECCC calendar year. Carbon prices from 2038 to 2050 are extrapolated by escalating prices annually at inflation (2%). This is done for both scenarios. Below the prices are presented for both scenarios in nominal 2020 dollars.

Table A-2. Carbon Price Forecast (nominal CAD$/tCO2e) /u

Year	Diversified	Electrification
2020	$28	$28
2030	$166	$282
2040	$206	$351
2050	$251	$427

Discount Rate

The analysis assumes a 4% real discount rate consistent with the OEB's guidance to gas and electric utilities on the evaluation of demand-side management programs, as per the Conservation First Framework.[115]

A.2 Electricity and Gas Supply Inputs

Existing Electricity Supply Capacity

[112] Government of Canada (2022). Greenhouse Gas Pollution Pricing Act. Available: https://laws-lois.justice.gc.ca/eng/acts/G-11.55/

[113] Government of Canada (2021). Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html

[114] Parliamentary Budget Office (2021). Carbon Pricing for the Paris Target: Closing the Gap with Output-Based Pricing. Available: https://www.pbo-dpb.gc.ca/web/default/files/Documents/Reports/RP-2021-019-S/RP-2021-019-S_en.pdf

[115] Ontario Energy Board (2014). Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020). https://www.oeb.ca/oeb/_Documents/EB-2014-0134/Filing_Guidelines_to_the_DSM_Framework_20141222.pdf

Existing electricity supply capacity for all six regions was obtained primarily from public independent system operator (ISO), utility reports, or Guidehouse internal forecasts. Installed capacities for Ontario (ON), Manitoba (MB), Quebec (QC) and New York (NY) are modelled for the entire electricity interconnection regions, while for the Midcontinent Independent System Operator (MISO) and the Pennsylvania, New Jersey, Maryland Interconnection (PJM), only the sub-regions contiguous to ON are modelled. For simplicity, only Ontario electricity supply capacities are reported in Table A-3. /u

Table A-3. 2020/2021 Installed Electricity Generation Capacity in Ontario (GW)[116] /u

Resource	Capacity (GW)
Wind	5.5
Solar PV	0.5
Hydroelectric	9.3
Nuclear	13.1
Gas/oil	10.8
Bioenergy	0.6
Battery Storage	0
Total	**40**

Planned New Electricity Supply Capacity

Planned new electricity supply capacity was obtained for all six regions from a variety of sources, including public ISO or utility reports (where available), press releases, and S&P Capital IQ. Installed capacities for ON, MB, QC and NY are incorporated in the model for the entire electricity interconnection regions, while for MISO and PJM, only the sub-regions contiguous to ON are modelled.

For ON, our modelling incorporates the option to build additional capacity in addition to planned capacities to determine the cost-optimal installed supply capacity mix in each modelled year. The planned capacities for ON are obtained from the IESO 2020 APO as well as Guidehouse internal forecasts.[117] For non-ON regions, the model will not optimize the installed electricity supply capacity above and beyond planned investments. /u

Planned Electricity Supply Retirements

Planned supply capacity retirements are also incorporated into Guidehouse's analysis. This incorporates Ontario's planned decommissioning schedule for various nuclear power stations in the province. The IESO 2020 APO shows that the nuclear reactors at the Bruce, Darlington, and Pickering Nuclear Generation Stations are expected to be refurbished in the next 10-12 years. In addition, it is assumed that existing gas turbines will be linearly phased out from 2030 to 2050, and planned new gas turbines in 2030 will be decommissioned by 2050. This leads to no natural gas-fired gas turbines in the electricity supply mix by 2050. The only gas-fired turbines in 2050 are hydrogen-powered turbines. /u

Renewable Energy Capacity Factors

Solar and wind generation resources in ON and each neighbouring region are characterized with different capacity factors. Capacity factors for Canadian provinces are available from the NRCan database (2020).[118] We use wind and solar capacity factors specific to ON and QC, whereas Western Canada (WC) is characterized as an average of capacity factors for MB, SK, and AB. Solar and wind capacity factors for MB, SK and AB only vary slightly.

[116] IESO (2020). Transmission-Connected Generation. https://www.ieso.ca/en/Power-Data/Supply-Overview/Transmission-Connected-Generation
[117] IESO (2020). Annual Planning Outlook. https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook /u
[118] Government of Canada (2020). Renewables. https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/renewable-energy/7293

For US regions, we use wind capacity factors from Berkeley Lab.[119] Because wind capacity factors are available for each US state, we use state-level capacity factors for the New York Independent System Operator (NYISO), MISO (using an average of Michigan and Wisconsin), and PJM (using Ohio). Solar capacity factors were obtained from the Berkeley Lab.[120] These capacity factors were available for individual electricity market regions. As a result, no state-level aggregation of capacity factors was required. We used capacity factors defined for NYISO, MISO and PJM.

The wind and solar capacity factors obtained from the sources above are based on the performance of the existing wind and solar fleets in each region. To reflect improvements in technologies and increased capacity factors, we assumed a fleet-wide 0.75%/year annual improvement factor across all regions. The resulting capacity factors are presented in Table A-4. /u

Table A-4. Renewable Capacity Factors (%) /u

Region	Wind	Solar
ON	47%	16%
QC	33%	16%
WC	46%	17%
NY	44%	22%
PJM	39%	23%
MI	47%	23%

Green Hydrogen Supply Costs

Green hydrogen production costs are determined assuming that hydrogen is produced from renewable sources: solar PV, wind, and hydro. The wind and solar capacity factors shown previously produce hydrogen supply costs specific to each region. In general, hydrogen produced from wind and hydro (if hydro is available, e.g., QC and WC) are the most price-competitive hydrogen supply resources. We assume hydrogen supply costs in each region are defined by the most price-competitive resource. For example, in QC and WC, hydrogen supply costs are based on hydroelectric power, whereas in NY, PJM, and MI, hydrogen supply costs are based on wind power.

The calculation of hydrogen supply costs for neighbouring regions is performed to identify potential supply routes for hydrogen imports into ON. Based on the hydrogen costs calculated, hydrogen supply from QC and WC are the most competitive. As a result, our analysis gives ON the option to meet hydrogen demand with imports from QC and WC. The costs of hydrogen production from NY, PJM, and MI are less attractive and are not modelled as supply routes for ON.

Our analysis assumes the costs of hydrogen imports from QC and WC to be static. This means hydrogen import costs do not change hour-to-hour. In comparison, the cost of hydrogen production in ON is not static, but rather changes hour-to-hour based on several factors, including hour-to-hour changes in hydrogen demand, the electricity supply mix, periods of surplus electricity generation, among other factors. The impacts of all these factors are modelled endogenously via our energy systems model.

To allow for a simple comparison of hydrogen supply costs between ON and neighbouring regions, Table A-5 shows static hydrogen costs in all regions. While hydrogen imports appear more cost-effective than domestic hydrogen production in ON, imports may be not available until, or if, gas interconnections are not repurposed to hydrogen.

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[119] Berkeley Lab (2021). Lab-based Wind Market Report. https://emp.lbl.gov/wind-technologies-market-report/
[120] Berkeley Lab (2021). Utility-scale Solar. https://emp.lbl.gov/utility-scale-solar/

Table A-5. Green Hydrogen Costs (CAD$/kg)[121]

Region	2030	2040	2050
ON	2.5	1.8	1.6
QC	2.0	1.6	1.5
WC	2.3	1.7	1.6
NY	2.7	1.9	1.7
PJM	3.0	2.2	1.9
MI	2.5	1.8	1.6

Blue Hydrogen Supply Costs

Table A-6 below shows the techno-economic parameters and the cost of SMR+CCS capacity. /u

Table A-66. Techno-Economic Parameters of Blue Hydrogen /u

	Value
CAPEX (CAD/MW)	3,150,000
Efficiency (%)	69%
Capture Rate (%)	95%
CO_2 Transport & Storage Costs (CAD/tCO_2)	30
Utilization Factor (%)	90%
Lifetime (years)	25
Discount Rate (%)	5%

Hydrogen Import Costs

The costs of hydrogen imports are presented in Table A-7. Hydrogen imports from Quebec are assumed to be 100% green hydrogen. Hydrogen imports from western Canada are assumed to be 50% green hydrogen in 2030 through 2040 and 75% green hydrogen in 2050. The remaining 50% and 25%, respectively, is assumed to be blue hydrogen. The source of hydrogen import costs is the European Hydrogen Backbone.[122] /u

Table A-77. Hydrogen Import Costs (CAD$/kg) /u

	Imports from Quebec	Imports from Western Canada
2030	2.0	2.4
2040	1.6	2.1
2050	1.5	1.8

RNG Supply Potential

RNG potential in ON is in the range of 1.2 to 6.4 bcm per year depending on whether agricultural residues are included. Previous work conducted by Enbridge Gas forecasted RNG demand by 2038 in two different scenarios: 2.7 bcm in the Diversified scenario and 1.3 bcm in the Electrification scenario. In both scenarios, RNG demand is greater than the non-crop RNG potential of 1.2 bcm per year. This suggests RNG demand in 2038-2050 will exceed non-crop feedstock and will require some

[121] A discount rate of 5% is used for levelized cost of hydrogen (LCOH) calculations. Capacity factors used to calculate the green hydrogen costs are different in 2030, 2040, and 2050 based on 0.75%/year improvement – described in the "Renewable Energy Capacity Factors" section of Appendix A.2.

[122] European Hydrogen Backbone (2020). Extending the European Hydrogen Backbone. https://gasforclimate2050.eu/wp-content/uploads/2021/06/European-Hydrogen-Backbone_April-2021_V3.pdf /u

share of crop feedstock. Crop feedstock would not only reflect purpose-grown crops (e.g., dedicated for RNG supply) but also a notable contribution from crop wastes.

Table A-8 and Table A-9 show RNG demand in each of the Enbridge Gas scenarios and maximum RNG supply potential (with and without crop feedstock).

Table A-8. RNG Demand by Enbridge Gas Scenario (bcm/year)[123] /u

Unit	bcm		PJ	
Year	**2030**	**2038**	**2030**	**2038**
Diversified	1.3	3.0	46	105
Electrification	0	1.3	0	46

Table A-9. RNG Supply Potential (bcm/year and PJ)[124]

	bcm	PJ
Supply (excl. crops)	1.2	41
Supply (incl. crops)	6.4	224

The costs of RNG crop feedstock shown in Table A-10 are estimated based on the techno-economic parameters presented.

Table A-10. RNG Crop Feedstock Cost /u

	2020	2030	2040	2050
Cost of crop feedstock for RNG in (real 2020$/MWh)	42	39	38	36

Costs of Electricity and Gas Supply Technologies

The economic parameters for each supply technology are characterized as shown in Table A-11. The cost parameters are broken down into fixed operating and maintenance costs (FOM), variable operation and maintenance costs (VOM), and cost of new entry (CONE). CONE figures are analogous to CAPEX costs. In addition, the efficiency of electrolyzers is included in the table and is forecasted to increase from 2030 to 2050. The FOM and CONE for natural gas fired turbines, solar, /u
and wind, as well as the VOM for gas turbines are based ENTSO-E's TYNDP 2020 report.[125]
Hydrogen fired gas turbines are assumed to cost 15% more than natural gas fired turbines.[126] The /u
cost assumptions are based on IEA (2019)[127] for batteries, Guidehouse (2019)[128] for anerobic digestion, biomass and biomass + CCS, and Guidehouse (2021)[129] for SMR + CCS and electrolyzers. Guidehouse (2021)[129] reports the price of hydrogen storage to cost between 5 and 20 €/MWh H_2 (~7 and 29 CAD$/MWh H_2). Based on this range of costs, for this analysis, a levelized cost of 11

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[123] Enbridge Gas scenarios.

[124] Torchlight Bioresources (2020). Renewable Natural Gas (Biomethane) Feedstock Potential in Canada. Figure 19. Available: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf?la=en /u

[125] ENTSO-E (2020), TYNPD 2020. https://www.entsos-tyndp2020-scenarios.eu/wp-content/uploads/2020/07/TYNDP_2020_Scenario_Building-Guidelines_03_Annex_2_Cost_Assumptions_final_report.pdf

[126] Oberg et al. 2022. Available: https://doi.org/10.1016/j.ijhydene.2021.10.035 /u

[127] IEA (2019). Capital cost of utility-scale battery storage systems in the New Policies Scenario, 2017-2040. https://www.iea.org/data-and-statistics/charts/capital-cost-of-utility-scale-battery-storage-systems-in-the-new-policies-scenario-2017-2040

[128] Guidehouse (2019). Pathways to Net-Zero: Decarbonizing the Gas Networks in Great Britain. https://www.energynetworks.org/assets/images/Resource%20library/ENA%20Gas%20decarbonisation%20Pathways%202050%20FINAL.pdf

[129] Guidehouse (2021). Analysing future demand, supply, and transport of hydrogen. Available: https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021_v3.pdf

CAD$/MWh H_2 is assumed for hydrogen storage. As it is a levelized cost, it is defined as the VOM in the model.

The cost of nuclear is the Ontario Power Generation's prescribed generation payment amounts for 2021.[130] Since these are levelized costs, they are defined as VOM. The CONE cost of small modular nuclear reactors (nuclear SMR) is from the CER's Canada's Energy Future 2021 report.[131] The FOM is assumed to be 2.5% of the CAPEX, or CONE. The VOM is the cost of uranium.[132] The costs for hydro were sourced from a report commissioned by the Ontario Water Association.[133] /u

The cost of combined cycle gas turbines assumed in our analysis is comparable to recent Ontario projects. For example, Ontario Power Generation recently acquired 3 combined cycle gas turbines with a combined 2.15 GW for CAD$2.8 billion, roughly equivalent to $1.3 million/MW.[134] This deal includes the Halton Hills combined cycle gas turbines, with capacity of 683 MW, for CAD$700 million, roughly equivalent to $1.0 million/MW.[135] /u

Table A-11. Supply Techno-Economic Parameters /u

Supply Technology	Cost Type	Unit	2030	2040	2050
Wind Onshore	FOM	CAD$/MW-year	25,000	25,000	25,000
	VOM	CAD$/MWh	0	0	0
	CONE	CAD$/MW	1,412,875	1,212,875	1,112,875
Wind Offshore	FOM	CAD$/MW-year	40,000	30,000	30,000
	VOM	CAD$/MWh	0	0	0
	CONE	CAD$/MW	2,662,875	2,112,875	2,112,875
Solar PV	FOM	CAD$/MW-year	22,000	18,000	18,000
	VOM	CAD$/MWh	0	0	0
	CONE	CAD$/MW	1,062,875	812,875	712,875
Nuclear	VOM	CAD$/MWh	96	96	96
Nuclear SMR	FOM	CAD$/MW-year	175,000	150,000	125,000
	VOM	CAD$/MWh	7	7	7
	CONE	CAD$/MW	7,000,000	6,000,000	5,000,000
Hydro	FOM	CAD$/MW-year	60,306	60,306	60,306
	CONE	CAD$/MWh	6,892,114	6,892,114	6,892,114
Gas Turbine – CH4	FOM	CAD$/MW-year	20,000	20,000	20,000
	VOM	CAD$/MWh	2.4	2.4	2.4
	CONE	CAD$/MW	660,000	660,000	660,000
Gas Turbine – H2	FOM	CAD$/MW-year	23,000	23,000	23,000
	VOM	CAD$/MWh	3	3	3
	CONE	CAD$/MW	759,000	759,000	759,000
Battery Storage	FOM	CAD$/MW-year	30,000	28,000	24,000
	VOM	CAD$/MWh	-	-	-

130 Ontario Energy Board (2021). Regulated Price Plan: Price Report. Available: https://www.oeb.ca/sites/default/files/rpp-price-report-20210422.pdf

131 CER (2021). Canada's Energy Future 2021. Available: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2021/canada-energy-futures-2021.pdf /u

132 Canadian Energy Research Institute (2004). Levelised Unit Electricity Cost Comparison of Alternate Technologies for Baseload Generation in Ontario. Available: https://inis.iaea.org/collection/NCLCollectionStore/_Public/43/123/43123919.pdf /u

133 Hatch (2013), commissioned by the Ontario Water Association. Northern Hydro Assessment Waterpower Potential in the Far North of Ontario. Available: https://www.owa.ca/wp-content/uploads/2017/01/NorthernHydroFinal-Executive-Summary.pdf /u

134 EnerData (2020). OPG's Atura Power acquires 3 CCGT power plants for US$2bn. Available: https://www.enerdata.net/publications/daily-energy-news/opgs-atura-power-acquires-3-ccgt-power-plants-us2bn.html

135 Power Technology (2020). Halton Hills Combined Cycle Plant. Available: https://www.power-technology.com/projects/halton-hills-combined-cycle-plant/

Supply Technology	Cost Type	Unit	2030	2040	2050
	CONE	CAD$/MW	1,200,000	1,100,000	950,000
Electrolyzer	FOM	CAD$/MW-year	20,000	14,000	8,000
	VOM	CAD$/MWh	0	0	0
	CONE	CAD$/MW	570,000	390,000	240,000
	Efficiency	%	71%	76%	80%
SMR + CCS	FOM	CAD$/MW-year	94,500	94,500	94,500
	VOM	CAD$/MWh	6	6	6
	CONE	CAD$/MW	3,150,000	3,150,000	3,150,000
Biomass + CCS	FOM	CAD$/MW-year	287,300	287,300	287,300
	VOM	CAD$/MWh	1	1	1
	CONE	CAD$/MW	5,780,000	5,780,000	5,780,000
Anaerobic Digestion	FOM	CAD$/MW-year	89,640	89,640	89,640
	VOM	CAD$/MWh	70	69	67
	CONE	CAD$/MW	446,820	446,820	446,820
Biomass	FOM	CAD$/MW-year	19,338	19,338	19,338
	VOM	CAD$/MWh	2	2	2
	CONE	CAD$/MW	654,500	654,500	654,500
Hydrogen Storage	VOM	CAD$/MW	11	11	11

Lifetime of Electricity and Gas Supply Technologies

The assumed lifetime of each supply technology is presented in the table below.

Table A-12. Assumed Lifetimes of Electricity and Gas Supply Technologies /u

Supply Technology	Assumed Lifetime
Wind Onshore	25
Wind Offshore	25
Solar PV	25
Nuclear	50
Nuclear SMR	50
Hydro	50
Hydro Pumped Storage	50
Gas Turbine – CH4/H2	25
Battery Storage	15
Electrolyzer	25
SMR + CCS	25
Biomass + CCS	25
Anaerobic Digestion	25
Biomass	25
Hydrogen Storage	50

Existing Electricity and Gas Interconnections

The capacity of existing electricity and gas interconnections across regions is characterized as per Table A-13. No existing hydrogen interconnections exist; however, the analysis allows for existing gas interconnections to be repurposed to hydrogen, as well as new hydrogen interconnections to be built.

The existing electricity capacities are based on the IESO Fall 2021 Reliability Report, and the gas interconnection capacities values are based on the Canadian Energy Regulator (2021).[136, 137, 138]

Table A-13. Existing Electricity and Gas Interconnections between ON and Neighboring Regions /u

	Region 1	Region 2	Import Capacity	Export Capacity	Notes
Electricity	ON	WV	300 MW	300 MW	Interconnection with Manitoba
	ON	QC	2,165 MW	2,350 MW	Combined interconnection capability via Northeast, Ottawa, and East zones
	ON	NY	2,100 MW	1,950 MW	Combined interconnection capability via St. Lawrence and Niagara
	ON	MI	1,650 MW	1,700 MW	via Michigan
	ON	PJM	-	-	No existing electricity interconnections.
Gas	ON	NY	0.65 bcf/day + 0.2 bcf/day		Via Niagara and Chippawa
	ON	QC	1.21 bcf/day		Via Iroquois
	ON	WC	5.30 bcf/day		Via Northern Ontario Line (NOL) and the Vector Pipeline

General Interconnection Parameters

Lifetime and Line Losses: The economic decision of building new interconnections is also affected by line losses and the lifetime of infrastructure. All transmission line and pipelines are assumed to have a 70-year life. Intra-regional electricity line losses are assumed to be 6%. Inter-regional electricity line losses are estimated at 1.1% per 100-km while gas losses from inter-region pipelines (methane and hydrogen) are estimated at 0.5% per 100-km. For gas intra-regional pipelines, line losses are estimated at 0.4%.[139] /u /u

Costs of Gas Infrastructure

Gas infrastructure costs include the cost of repurposing gas infrastructure to hydrogen (e.g., pipeline, compression costs), operation costs associated with transporting hydrogen and RNG, and integration (injection) costs. The cost of repurposing existing gas infrastructure to transport hydrogen vary by pipeline size. For inter-jurisdiction transmission pipelines to Ontario, we assume 48-inch pipelines. The gas transmission repurposing from natural gas to hydrogen and new hydrogen pipeline CAPEX values shown in Table A-14 and Table A-15 and are based on the European Hydrogen Backbone.[140] Natural gas and RNG T&D OPEX costs are low because these reflect the existing natural gas infrastructure being reused for RNG transport, while higher hydrogen costs reflect repurposing of gas infrastructure, as shown in Table A-16.

Table A-14. New Gas Transmission CAPEX (CAD $M/km)

Diameter	Pipeline CAPEX	Compression CAPEX	Total CAPEX
48-inch	4.2	0.9	5.1
36-inch	3.3	0.5	3.8
20-inch	2.3	0.1	2.4

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136 IESO (2021) Fall 2021 Reliability Report. https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook

137 Canadian Energy Regulator (2021). Natural Gas Pipeline Transportation System. https://www.cer-rec.gc.ca/en/data-analysis/facilities-we-regulate/canadas-pipeline-system/2021/natural-gas-pipeline-transportation-system.html

138 Canadian Energy Regulator (2021). Pipeline Profiles: TC Canadian Mainline. https://www.cer-rec.gc.ca/en/data-analysis/facilities-we-regulate/pipeline-profiles/natural-gas/transcanadas-canadian-mainline.html

139 Enbridge Gas internal source

140 European Hydrogen Backbone (2020). Extending the European Hydrogen Backbone. https://gasforclimate2050.eu/wp-content/uploads/2021/06/European-Hydrogen-Backbone_April-2021_V3.pdf

Table A-15. Repurposed Gas Transmission CAPEX (CAD $M/km)

Diameter	Pipeline CAPEX	Compression CAPEX	Total CAPEX
48-inch	0.8	0.9	1.7
36-inch	0.6	0.2	0.8
20-inch	0.5	0.1	0.6

Table A-16. Gas T&D OPEX (CAD$)

	OPEX
Transmission	H2: $0.9/GJ-year NG/RNG: $0.4/GJ-year
Distribution	H_2: $1/GJ-year NG/RNG: $0.4/GJ-year

Integration costs capture the costs of grid pipeline connection to production sites as well as injection costs. The T&D OPEX and integration costs for hydrogen are based on the 2019 Decarbonising Gas Networks in Great Britain report.[141] The integration costs for RNG are based on values provided by Enbridge Gas from recent in-house example projects. The integration costs account for upgrading and injection.

Table A-17. RNG Integration CAPEX and OPEX (CAD$)

	CAPEX	OPEX
Integration (Injection)	H2: $6.74/GJ RNG: $5.23/GJ	H_2: $0.48/GJ-year NG/RNG: $3.42/GJ-year

Cost of Electricity Infrastructure

The electricity infrastructure costs used in our analysis reflect the cost of building electric transmission and distribution lines. These costs are presented in Table A-18. The electricity T&D infrastructure costs are based on CIGRE (2019) and IESO (2017), which present a blended cost including overhead lines and buried lines, with the assumption that buried lines comprise less than 5% of total.[142,143] Distribution infrastructure costs were converted from annualized units ($/kW-year) to upfront CAPEX ($/kW) and OPEX ($/kW-year) by de-annuitizing them based on an assumed cost of capital of 4.5% (consistent with inputs presented below) and a useful asset lifetime of 70 years.

Table A-18. Intra-Regional Electricity Transmission Infrastructure Investment Cost Inputs /u

Cost Component	Unit	New Overhead Line
CAPEX	[Million CAD$/ MW-km]	376
OPEX	% of CAPEX	1%

141 Decarbonising Gas Networks in Great Britain (2019). https://www.northerngasnetworks.co.uk/wp-content/uploads/2019/11/Navigant-Pathways-to-Net-Zero-2-min.pdf

142 CIGRE (2019). Available here: https://e-cigre.org/publication/775-global-electricity-network-feasibility-study

143 IESO (2017). Local Avoided Costs – Overview. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/engagement/Toronto-LAC-20170926-Local-Avoidable-Costs.ashx

Table A-19. Ontario Electricity Distribution Infrastructure Investment Cost Inputs /u

Component	Unit	Distribution
Annualized CAPEX + OPEX	[CAD$/kW-year]	4.7
Lifetime	[year]	70
Cost of Capital	[%]	4.5%
Overnight cost of Infrastructure (CAPEX+OPEX)	[CAD$/MW]	81,204

End-User Costs

In addition to electricity and gas system costs, this analysis also captures costs associated with end-user investments in building heating equipment and building insulation and renovation work. Because this report does not distinguish between demand side management (DSM) and activities mandated through regulation, the figures presented here are not prescriptive forecasts of DSM activities. This analysis does not include wood or biomass heating or district heating, nor the cost of existing heating system and end-of-life replacements.

End-user costs associated with the transport and industrial sector are not captured in the analysis. In other words, costs associated with GHG emissions reduction for transport (e.g., electric vehicles [EVs], electric buses or trucks, charging infrastructure, investments in ships, aircrafts) and industry (e.g., electric arc furnaces, electric kilns, hydrogen furnaces, CCS equipment) are not included.

The end-user costs include CAPEX and installation costs of gas furnaces (hydrogen/methane), gas heat pumps, hybrid heat pumps, and electric heat pumps. The costs for end-user equipment are from Enbridge Gas's 2021 answer to interrogatory from OEB.[144] This excludes the cost of electric geothermal heat pumps in existing homes, which is from The Economic Value of Ground Source Heat Pumps for Building Sector Decarbonization prepared for the HRAI by Dunsky[145]. This value was then scaled for new builds using ground-source heat pump program data from the Massachusetts Clean Energy Center[146]. These values are given in Table A-20 below.

Table A-20. Building Heat Equipment Costs

Heating Equipment	Unit	Existing Homes	New Builds
Gas Heat Pump with A/C Unit	[CAD$/unit]	12,200	12,200
Cold Climate Electric Air-Source Heat Pump with Electric Resistance Backup	[CAD$/unit]	11,100	11,100
Electric Geothermal Heat Pump	[CAD$/unit]	27,500	24,655
Hybrid Heat Pump	[CAD$/unit]	11,350	11,350

Costs associated with building insulation retrofit requirements (for new and existing homes) are also included. Insulation costs vary based on the type of heating system used (e.g., different insulation needs for a home with a gas furnace vs. electric heat pumps; electric heat pumps require better building insultation). Homes with electric heat pumps are assumed to undergo deep energy efficiency retrofits.[147] All other homes are assumed to undergo moderate energy efficiency retrofits. Our analysis assumes that not all Ontario homes will be retrofitted due to technical and economic suitability, among

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[144] Enbridge Gas Inc. (2021). Answer to Interrogatory from Ontario Energy Board, pp.343-356. Available: https://www.rds.oeb.ca/CMWebDrawer/Record/732115/File/document

[145] Dunsky (2020). The Economic Value of Ground Source Heat Pumps for Building Sector Decarbonization. Available: https://ontariogeothermal.ca/downloads/dunsky--hrai-benefitsofgshps--2020-10-30-.pdf/

[146] Massachusetts Clean Energy Center (2022). Ground-Source Heat Pump Residential Projects Database. Available: https://www.masscec.com/public-records-requests

[147] To provide adequate heating in winter conditions, electrically heated homes need to be well-insulated and weatherized to minimize heat leakage. Reduction of heat loss is important for electrically heated homes because the heating capacity of air-source heat pump systems is less than gas furnaces, especially at low outdoor temperatures. A regular-sized gas furnace usually provides 20 to 35 kW of heat output, while a whole-home heat pump may only provide 5 to 15 kW of heat output at colder outdoor temperatures

other reasons. In total, 70% of homes are assumed to be retrofitted by 2050. The costs of moderate and deep retrofits are based on the open-source Energy Transition Model tool.[148] The Energy Transition Model tool has previously been used in comparable studies in other jurisdictions.[149] /u

Table A-21. Building Energy Efficiency Insulation/Retrofit Costs /u

Retrofit Type	Home Type	2020	2030	2040	2050
Moderate Retrofit	[thousand CAD$/household]	13	12	11	10
Deep Retrofit	[thousand CAD$/household]	31	29	26	24

To calculate the total cost of heating equipment and building retrofits, a forecast of Ontario households is used. Our analysis adopts the IESO's APO household forecast.[150]

Table A-22. Number of Households in Ontario

	2020	2030	2040	2050
Households (# Millions)	5.8	6.6	7.2	8.0

[148] Energy Transition Model (2021). Insulation. https://docs.energytransitionmodel.com/main/insulation

[149] For example, the Energy Transition Model has been used by Gasunie, TenneT, and regional grid operators to help better understand the necessary required investments to reach a Climate-neutral energy system in the Netherlands by 2050 (https://www.netbeheernederland.nl/dossiers/toekomstscenarios-64). In addition, the Energy Transition Model has been used by the UK Government Department for the Economy to develop an energy strategy for Northern Ireland (https://www.economy-ni.gov.uk/consultations/consultation-policy-options-new-energy-strategy-northern-ireland).

[150] IESO (2020). Annual Planning Outlook. https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

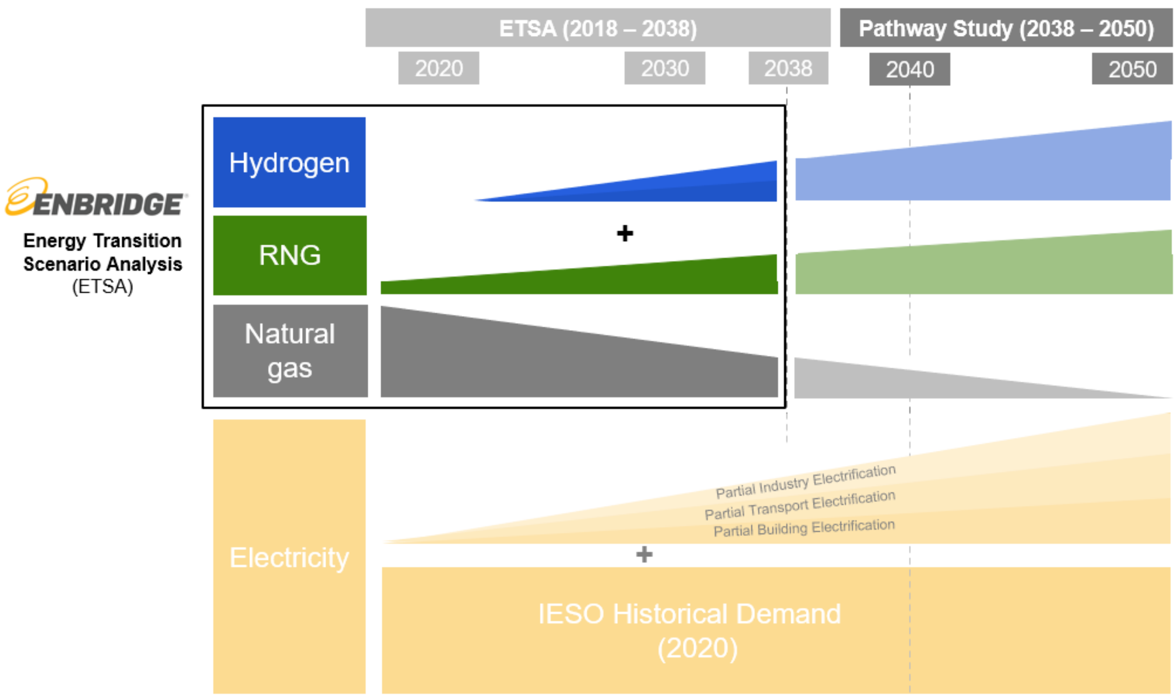
Appendix B. Development of Net Zero Scenarios

B.1 Using Previous Enbridge Gas Scenario Development as a Starting Point

This study expands on previous energy transition scenario analysis (ETSA) done by Enbridge Gas that forecasts gas demand from 2020 to 2038. More specifically, this study expands the Enbridge Gas forecasts from 2038 to 2050 and develops electricity demand scenarios that are internally aligned with the underlying assumptions of Enbridge Gas's gas forecasts. This section describes the forecasting methodology and presents the gas and electricity demand forecasts for the Diversified and Electrification scenarios. The Diversified and Electrification scenarios are intended to represent plausible, potential future visions of the Ontario energy system by 2050. They are not intended to represent the most optimal or perfect scenarios.

The Enbridge Gas scenarios establish gas demand (hydrogen, RNG, and natural gas) for 2018-2038 by forecast gas demand in the residential, commercial, and industrial sectors. In this study, these forecasts are extended out to 2050 assuming continued GHG emissions reduction in all sectors. Electricity demand is also forecasted out to 2050. The study uses IESO historical electricity demand figures as baseline demand and incorporates future electricity demand associated with the electrification of industry, transportation, and buildings in each of the Diversified and Electrification scenarios. A graphical representation of the forecasting exercise is shown in Figure B-1.

Figure B-1. Graphical Representation of the Extrapolation Used to Develop the Demand Scenarios



The examination of several demand sub-sectors were outside of the scope captured by the Enbridge Gas scenarios: namely **non-heavy road transport** (e.g., light road transport, aviation, marine transport) and **non-natural gas fossil fuel use from industry** (e.g., coal, coke). This study's Diversified and Electrification scenarios do account for these sub-sectors. Incorporating these areas in our analysis is critical because this ensures the Diversified and Electrification scenarios represent economy-wide, net zero futures by 2050.

- **Non-heavy road transport:** The Enbridge Gas scenarios focus exclusively on the adoption of CNG in heavy road transport.[151] This study expands the scope of transport to all modes of transport. This study uses a bottom-up approach to model GHG emissions reduction for light road transport, aviation, and marine transport via electrification, RNG, and hydrogen. For consistency in approach across all modes of transport, this study also applies a bottom-up approach to heavy road transport in place of the Enbridge Gas approach. Appendix B.2.2 describes the approach and assumptions used in reducing GHG emissions from transportation.
- **Non-gas fossil fuel industry demand:** The Enbridge Gas scenarios do not account for the emissions reduction of fossil fuel use by industry, other than natural gas. For example, the use of coke and coal by the steel and mining industries is not captured. This study, however, does account for emissions reductions of non-gas fossil fuels via electrification, hydrogen, RNG, and natural gas + CCS. The inclusion of non-gas fossil fuel demand in our analysis results in additional gas demand relative to the baseline gas demand. Appendix B.2.3 describes the approach used to model the GHG emissions reductions of non-gas fossil fuel use by industry.

The impact of incorporating these areas not covered by the Enbridge Gas scenarios is that the gas demand forecasts developed in this study are higher than the Enbridge Gas scenarios.

B.2 GHG Emissions Reduction Assumptions by Sector

B.2.1 Buildings

The demand forecast for reducing GHG emissions from buildings was based off the Enbridge Gas demand forecasts per sector (residential and commercial) and per end use (space heating, water heating, cooking, and washing/drying appliances). For residential buildings, the gas consumption for each end use was extrapolated out to 2050 based on a linear trendline from the last 5 years of the Enbridge Gas forecasts (2033-2038). This way, the forecasts were able to capture the change in demand more relevant to 2040 and 2050. The IESO's residential household projections, less the number of gas households each year per end use from the Enbridge Gas scenarios, yielded the annual rate of electrification in the province. For commercial buildings, the growth rate of the total commercial building stock from the IESO's 2019 Conservation Achievable Potential Study was used to determine annual new builds.[152] The total commercial gas stock and gas consumption per area of floorspace came from the Enbridge Gas scenarios and was extrapolated out to 2050 using the last 5 years of the forecast (2033-2038).

- **Space heating**: This end use predominantly relies on natural gas and accounts for most of the energy requirements in residential and commercial buildings. Although energy efficiency retrofits and new building codes are expected to reduce heating loads per building, both scenarios assume a large increase of electric energy demand in this end use due to electrification. Moving toward 2050, the adoption of electric and hybrid heat pumps through full or partial fuel-switching plays the dominant role in reducing GHG emissions from buildings. In the Diversified scenario, 55% of Ontario space heating load will still be met by gas but with hydrogen or RNG instead of natural gas, and 40% of the load will be electrified. The Electrification scenario assumes that by 2050, 85% of Ontario space heating load will be met by electricity and 10% by gas. Trends up to 2040 are based on the trajectory of Enbridge Gas's Diversified scenario. The remaining 5% of load in 2050 for both scenarios is met by other fuel sources such as wood and propane, down from 11% today.

  The Enbridge Gas scenarios do not make any explicit assumptions around the transition of building heating equipment mix (e.g., mix of furnaces, electric heat pumps); rather, it only defines the electric versus gas fuel shares. Embedded within those fuel shares is a mix of

[151] The Enbridge Gas scenarios determined the use of CNG in heavy road transport by assuming some fixed proportion of the energy demand forecast (developed by the CER) adopted CNG.

[152] IESO (2019). 2019 Conservation Achievable Potential Study. Available: https://www.ieso.ca/2019-conservation-achievable-potential-study

heating equipment. As a result, we have made assumptions on how those fuel shares break down into individual heating equipment in our analysis. For example, in 2050, the Diversified scenario assumes that 55% of households have gas heating provided by gas heat pumps, an extrapolation of the Enbridge Gas scenario. To comply with the Pan-Canadian Framework, gas-equipped buildings are assumed to shift to gas-powered heat pumps post-2035. In addition, 40% of household heating is electric heating, which is assumed to be a mix of air-source and geothermal heat pumps. In 2050, the Electrification scenario assumes that 85% of households have electric heating, an extrapolation of the Enbridge Gas scenario. The 85% is assumed to be 75% air-source heat pumps and 10% geothermal heat pumps. Geothermal heat pumps are assumed to be primarily installed in new builds to bring down costs and so they are applicable to a large share of homes. The 10% of household heating powered by RNG is entirely gas heat pumps. The share of household heating technologies are given in Table B-1 and Table B-2 for the Diversified and Electrification scenarios, respectively.

Table B-1. Share of Households per Space Heating Technology Type – Diversified Scenario

/u

Space Heating	2020	2030	2040	2050
Gas Heat Pump	0%	6%	34%	55%
Air-Source Heat Pump	7%	13%	24%	30%
Geothermal Heat Pump	0%	4%	7%	10%
Natural Gas Furnace	82%	68%	28%	0%
Other	11%	10%	7%	5%

Table B-2. Share of Households per Space Heating Technology Type – Electrification Scenario

/u

Space Heating	2020	2030	2040	2050
Gas Heat Pump	0%	4%	6%	10%
Air-Source Heat Pump	7%	14%	52%	75%
Geothermal Heat Pump	0%	4%	7%	10%
Natural Gas Furnace	82%	68%	27%	0%
Other	11%	10%	8%	5%

- **Water heating:** Most Ontario homes rely on natural gas for hot water. Increased fuel switching to electric water heaters, both instant and storage-based, drive the GHG emissions reductions for this end use. The Electrification scenario assumes that by 2050, all Ontario homes will rely on electricity for hot water. The Diversified scenario assumes that just over half of homes will still rely on gas via hydrogen or RNG. This is consistent with space heating since a high penetration of integrated space and water heating systems is assumed.
- **Cooking:** One in four Ontario homes rely on gas cooking appliances today. This stock slowly and steadily declines over time based on the Enbridge Gas forecasts. By 2050, one in five homes will still rely on gas cooking appliances in the Diversified scenario while one in 10 will in the Electrification scenario.
- **Washing/drying appliances:** This end use is predominately electric. The Diversified scenario assumes that approximately half of homes with gas laundry appliances will switch to electric appliances by 2050. The Electrification scenario assumes that more than half of homes with gas laundry appliances will switch to electric appliances by 2050. Both scenarios assume new builds with gas washing and drying appliances are negligible.

B.2.2 Transport

The Pathways scenarios account for areas of transport not covered by the Enbridge Gas scenarios. Incorporating these areas is critical because this ensures the Diversified and Electrification scenarios are net zero by 2050. The Enbridge Gas scenarios adopted a forecast by the Canada Energy

Regulator to simulate the adoption of CNG in heavy road transport. This study follows a different methodology and expands the scope to all modes of transportation. This study uses a bottom-up approach to model reductions in GHG emissions from road, aviation, and maritime transportation via electrification, RNG, and hydrogen. For light and heavy duty road transport, passenger kilometers from NRCan's Comprehensive Energy Use Database multiplied by the appropriate fuel energy intensities are used to project energy use over time.[153] For aviation, rail, and marine transport, the energy use from NRCan's Comprehensive Energy Use Database is linearly forecasted to project the overall energy use over the study period. These energy use projections, in combination with the assumed fuel share breakdowns provided in the tables below, encompass the assumptions made regarding transportation electrification in this study.

- **Light duty road transport** (cars and light commercial vehicles): The adoption of EVs is the most effective and common way of reducing GHG emissions for light transportation. Both scenarios are based on a large adoption of EVs. The Diversified scenario assumes light duty road transport is largely electrified, with gas only playing a limited role via hydrogen in niche applications. The Electrification scenario assumes light duty road transport is fully electrified.

Table B-3. Light Duty Road Transport Fuel Share Breakdown for the Diversified and Electrification Scenarios

		Diversified	Electrification
Fuel	**2020**	**2050**	**2050**
Gasoline	100%	0%	0%
Electricity	0%	95%	100%
Hydrogen	0%	5%	0%

- **Heavy road transport (buses and trucks):** The Diversified scenario assumes that for buses, hydrogen and electricity play major roles, while for trucks, only hydrogen plays a major role, complemented by electricity and CNG. The Electrification scenario assumes that for buses, electricity plays a dominant role, with only a limited role for hydrogen. Similarly, for trucks, electricity also plays a dominant role in reducing GHG emissions, with a limited role for CNG and biodiesel. RNG is not expected to play a major role in reducing GHG emissions from buses. Both scenarios reach 0% CNG by 2050. In the Diversified scenario, CNG is forecast to play an intermediate role, with 10% of buses in 2030 being CNG powered and 5% in 2040.

Table B-4. Bus Fuel Share Breakdown for the Diversified and Electrification Scenarios /u

		Diversified	Electrification
Fuel	**2020**	**2050**	**2050**
Gasoline	98%	0%	0%
Electricity	0%	75%	90%
Hydrogen	0%	25%	10%
CNG	2.5%	0%	0%

Table B-5. Truck Fuel Share Breakdown for the Diversified and Electrification Scenarios

		Diversified	Electrification
Fuel	**2020**	**2050**	**2050**
Diesel/ Gasoline	100%	0%	0%
Electricity	0%	40%	70%
Hydrogen	0%	35%	0%

[153] Natural Resources Canada (2021). Comprehensive Energy Use Database: Transportation Sector - Ontario. Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_tran_on.cfm

CNG	0%	5%	0%
Biodiesel	0%	20%	30%

- **Aviation:** The reduction of GHG emissions from jet fuel is expected to be driven by global aviation trends rather than by unique market drivers in Ontario or Canada. Driven by this global dependence, the treatment of the aviation sector is the same in both scenarios, with biojet fuel and synthetic kerosene playing equal roles. Synthetic kerosene, or e-kerosene, is produced with hydrogen.

Table B-6. Aviation Fuel Share Breakdown for the Diversified and Electrification Scenarios

		Diversified	Electrification
Fuel	**2020**	**2050**	**2050**
Jet Fuel	100%	0%	0%
Electricity	0%	0%	0%
E-Kerosene (H_2)	0%	40%	40%
Biojet Fuel	0%	60%	60%

- **Marine:** The Diversified scenario assumes that ammonia (produced via hydrogen) plays a dominant role in reducing GHG emissions of marine transport, primarily in long distance shipping. Bio-LNG is also expected to play a role in long distance shipping. Electricity is expected to play a major role in short distance, domestic marine transport. The Electrification scenario assumes electricity is the largest contributor to reducing marine transport emissions, primarily in short distance, domestic shipping. Bio-LNG and biodiesel are the drivers of GHG emissions reduction in long-distance shipping.

Table B-7. Shipping fuel share breakdown for the Diversified and Electrification scenarios

		Diversified	Electrification
Fuel	**2020**	**2050**	**2050**
Heavy Fuel Oil/ Marine Fuel Oil	100%	0%	0%
Electricity	0%	30%	50%
LNG	0%	0%	0%
Ammonia (H_2)	0%	60%	0%
Biodiesel	0%	10%	50%

B.2.3 Industry

The reduction of GHG emissions from the industrial sector via hydrogen, RNG, and natural gas + CCS is primarily based on the methodology defined by the Enbridge Gas scenarios for individual sectors. However, as described in the previous section, because this analysis aims to model emissions reduction of the Ontario-wide economy, additional gas demand associated with the reducing emissions from non-gas fossil fuel demand is also considered.

Our analysis assumes this also captures a small share of natural gas demand from industry for use as feedstock in non-energy purposes – roughly 1.5% or 15 PJ.[154] /u

- **In 2030:** Industrial gas demand is adopted directly from Enbridge Gas's Diversified and Electrification scenarios.
- **In 2040:** Industrial gas demand in 2040 is determined by extrapolating linearly Enbridge Gas's Diversified and Electrification scenarios from 2038 to 2040. This extrapolation is based

[154] The Ontario Fuels Technical Report (2016), prepared by Navigant (now Guidehouse) for the Ministry of Energy estimated non-energy natural gas demand by industry at 15 PJ in 2015.

on the last 5-year period of the Enbridge Gas forecast (i.e., 2034-2038). This exercise is performed on all gases: natural gas, natural gas + CCS, hydrogen, and RNG. Hydrogen does not play a role in the Electrification scenario, only in the Diversified scenario.

- **In 2050:** Total gas demand in 2050 is determined by extrapolating Enbridge Gas's Diversified and Electrification scenarios to 2050. The mix of gases used to meet total gas demand is determined differently for each gas.
  - **RNG:** In both scenarios, RNG supply is assumed to grow at a more moderate pace during 2040-2050, compared to 2030-2040. The analysis assumes RNG supply increases more moderately over the 2040-2050 period compared to the 2030-2040 growth in RNG supply. We assume the 2040-2050 growth is 25% of the 2030-2040 growth in RNG supply. A more aggressive assumption (e.g., 50%) would likely result in Ontario's RNG supply approaching the theoretical maximum potential.
  - **Natural Gas + CCS and hydrogen:** The share of natural gas + CCS and hydrogen is determined based on their potential to replace natural gas in each industrial segment. Some industrial segments will replace natural gas with hydrogen, whereas others will replace natural gas with natural gas + CCS. This segment-specific approach is consistent with and based on the Enbridge Gas scenarios.

    In the Diversified scenario, hydrogen and natural gas + CCS are assumed to displace natural gas in all process heating uses (e.g., direct process heating, or indirect via water or steam), while electricity displaces natural gas in non-process heating end uses (e.g., heating, ventilation, and air conditioning, process cooling, and a small share of other processes).

    In comparison, the Electrification scenario does not assume a role for hydrogen. This means natural gas + CCS is the only option for reducing GHG emissions from process heating uses. The Electrification scenario also incorporates a modification to the Enbridge Gas scenario approach. In the spirit of the Electrification scenario, with more aggressive economy-wide electrification assumptions, we assume the development of advanced industrial electrification technologies targeted for medium and high temperature industrial applications. Our analysis assumes that by 2050, the reduction of GHG emissions from 25% of direct process heating energy demand is achieved via electrification, while the remaining 75% is achieved via natural gas + CCS.

For industrial applications that use natural gas as feedstock for non-energy purposes – estimated to be approximately 15 PJ based on historical data[155] –our analysis assumes that this natural gas demand continues towards 2015.

GHG Emissions Reduction Approach for Non-Gas Fossil Fuel Demand

Non-gas fossil fuel energy demand from industry is estimated as roughly 240 PJ.[156] Nearly 80% of this is coke, petroleum coke, and coal, of which the vast majority is associated with the iron and steel industry. Our analysis assumes most fossil fuel use in the iron and steel sector is displaced by hydrogen in both scenarios. This is based on the adoption of HDRI technology by industry players in Ontario.[157]

The remaining 20% of non-gas fossil fuel use relates to heavy, medium, and light fuel oil and kerosene. Our analysis assumes these fuels are displaced by hydrogen, electricity, and biofuel. The Diversified scenario assumes GHG emissions reductions for these fuels is equally via hydrogen and

[155] Ministry of Energy (2015). Ontario's Fuels Technical Report (see Figure 21). Available: https://www.ontario.ca/document/fuels-technical-report/state-system-10-year-review

[156] NRCan. Comprehensive Energy Use Database. Industrial Sector – Aggregated Industries, Ontario. https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=agg&juris=on&rn=1&page=0

[157] Green Car Congress (2021). "*ArcelorMittal plans major EAF, DRI investments for decarbonizing steel production in Canada*". https://www.greencarcongress.com/2021/07/20210731-arcelor.html

electricity. The Electrification scenario, however, assumes electricity plays a dominant role complemented by biofuel.

Table B-8. Fuel Switching Assumptions for Heavy, Medium, and Light Fuel Oil and Kerosene

	Diversified	Electrification
Fuel	**2050**	**2050**
Hydrogen	50%	0%
Electricity	50%	70%
Biofuel	0%	30%

Appendix C. Integrated Energy System Modelling

To determine the cost-optimal way to reduce GHG emissions from the Ontario energy system, this study used Guidehouse's Low Carbon Pathways (LCP) model, our in-house energy system model. The LCP model optimizes the build out of supply capacity, transmission interties, and gas and electric storage assets to meet future energy demand, simulating the hourly dispatch of electricity, hydrogen, and methane resources. The analysis models an integrated electricity and gas system, reflecting the linkages and dependencies that exists between electricity, methane (both geologic and renewable natural gas), and hydrogen.

In this project, Guidehouse applied the LCP model to optimize the supply of electricity, hydrogen, and methane to meet demand in two 2050 net zero demand scenarios: the Diversified and the Electrification scenarios. The following describe some of the major features of the LCP model as applied in this project:

- **Capacity expansion and dispatch optimization:** Optimization of generation, storage, and interconnections assets across the electricity and gas (methane and hydrogen) networks.
- **Lowest-cost net zero pathway:** Optimized pathways to achieve net zero carbon emissions targets in 2050.
- **Intra-annual temporal resolution:** Uses representative and peak days to reflect the seasonal variability of electricity and gas demand loads and supply resources.
- **Geographical resolution:** Simulates the Ontario energy system and five neighbouring systems – Western Canada (WC), Quebec (QC), MISO (MI), New York (NY), and PJM.

The LCP model is an integrated capacity expansion and dispatch optimization model used to identify the lowest-cost pathway to a low carbon energy system. The cost-optimization engine of the LCP model minimizes the net present value of the total system costs over the analysed study timeframe while considering various constraints at the energy system level (e.g., the buildout and availability of supply resources, the development of interconnections) and operational constraints at the individual technology level (e.g., the operation of power generation plants). The analysis *solves* the expansion and GHG emissions reduction of the electricity and gas (hydrogen and methane) system by adding new supply capacity over time (e.g., onshore/offshore wind, solar).

As an integrated energy system model, the cross-sector interactions between electricity, hydrogen, and methane are an integral part of the analysis (e.g., electrolyzers increase demand for electricity, hydrogen gas turbine increase hydrogen demand). The analysis also models the use of transmission interties across regions (e.g., power lines and pipelines) and storage assets (e.g., gas and electricity storage) to balance supply and demand. The modelling methodology is based on a "copper plate" for each region, meaning the focus of the analysis is primarily on inter-connections (across regions) rather than intra-connections (i.e., network capacity within each region; although nominally allowed for in the energy system costs, it is not the focus of the modelling).

The LCP model uses a nodal network to model an interconnected energy system, each node with its unique energy supply and demand varying over time. The LCP model is configured to a geographical scope of Ontario and the five neighbouring regions previously mentioned. All existing electricity and gas interties between regions are simulated in the model. The model also allows for existing interties to be expanded or for new ones, where applicable, to be constructed and for the option to repurpose methane interties for hydrogen.

A description of the main configuration parameters of the LCP model and several other modelling considerations is presented in Figure C-1.

Figure C-1. LCP Model Configuration and Key Modelling Considerations

Geographic Scope

This study models Ontario (ON) and five neighbouring regions: Western Canada (WC), Quebec (QC), MISO (MI), New York (NY), and PJM.

All six regions are modelled as individual copper-plate nodes, each with its unique energy supply and demand conditions varying over time.

Regions are modelled as an interconnected network of nodes with energy infrastructure connecting a node with its neighbouring nodes. Figure C-2 maps the current electricity (yellow solid lines) and natural gas (green solid lines) interties between ON and its neighbouring regions. The yellow dashed line represents the planned electricity intertie between ON and PJM.

- **Electricity** transport between each region is optimized model-endogenously. Electricity demand and supply capacities in each of the five neighbouring regions is scenario-defined and largely based on publicly available information.
- **Methane** is imported from WC and NY. **Hydrogen** can be imported from any neighbouring region, however, based on the cost-competitiveness of hydrogen supply from WC and QC, availability of hydrogen for imports in ON is limited to these two regions.

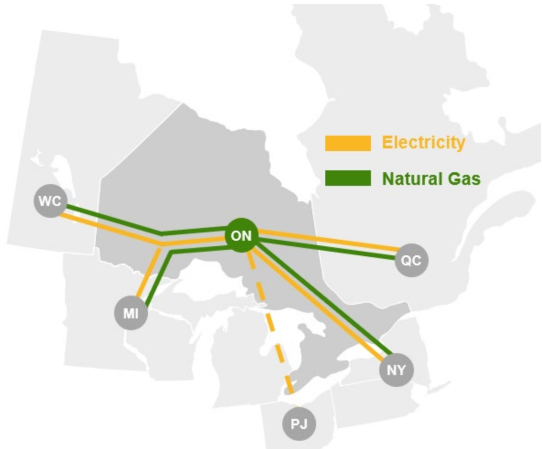


Figure C-2. Electricity and Natural Gas Interties between ON and Neighboring Regions

Energy Carriers

Our demand scenarios forecast energy demand in ON across three energy carriers: **electricity**, **hydrogen, methane**. Methane reflects demand for natural gas, RNG, and natural gas + CCS.

The two net zero demand scenarios only reflect *direct* energy demand (e.g., energy demand from end users) but not *indirect* energy demand (e.g., electricity demand needed for hydrogen production). Indirect energy demand is determined within our model and is impacted by various factors including the availability of surplus electricity, gas/electricity storage and energy imports.

Analysis Timeframe

Our demand scenarios extend from 2020 to 2050, creating snapshots of the Ontario energy system every 10 years: 2030, 2040, and 2050. 2020 is used as the base year of the analysis and is calibrated to match the current supply mix of the Ontario electricity and gas systems. 2050 is used as the final year of the analysis as it is the target year for Ontario to achieve net zero emissions.

Temporal Resolution

Employing four representative seasonal days—winter, spring, summer, and fall—and one peak day—winter peak—to reflect the variability of demand loads and supply resources in Ontario and in neighbouring jurisdictions.

Emissions and Sectoral Scope

The focus of our analysis is on achieving the 2050 net zero target. Because the scope of our analysis is on the energy system—more specifically energy demand from buildings, industry, transport, and the power sector—some sectors are excluded from the study. The analysis does not capture emissions from agriculture, land use, waste, or embedded emissions from products or materials. These external sectors are assumed to reduce GHG emissions in step with the rest of the economy.

Discount Rate

The analysis uses a real discount rate of 4% within the optimization of the LCP model, to compute the net present value of energy system costs. This discounting is done to enable the optimization of all decision variables across all analysis years at the same time. This 4% real discount rate is consistent with the OEB's

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guidance to gas and electric utilities on the evaluation of demand-side management programs, as per the Conservation First Framework.[158]

[158] Ontario Energy Board (OEB) (2014, December 22). Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020). https://www.oeb.ca/oeb/_Documents/EB-2014-0134/Filing_Guidelines_to_the_DSM_Framework_20141222.pdf

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ENBRIDGE GAS'S ENERGY TRANSITION PLAN (ETP) AND SAFE BET ACTIONS

CARA-LYNNE WADE, DIRECTOR, ENERGY TRANSITION PLANNING
JENNIFER MURPHY, MANAGER, CARBON AND ENERGY TRANSITION PLANNING

1. This evidence describes emerging federal, provincial, and municipal climate change policies and the uncertainty around what energy transition pathway may unfold due to the differing greenhouse gas (GHG) emission reduction targets and areas of focus at each level of government. The evidence then describes Enbridge Gas's Energy Transition Plan (ETP) and the actions outlined within the ETP that Enbridge Gas proposes to move forward with during the rebasing term despite current policy uncertainty. Enbridge Gas's ETP ensures that progress towards 2030 targets and a net-zero future continues despite policy uncertainty, while also ensuring Ontario's energy demands are met in the most reliable, resilient, secure, and cost-effective manner.

2. This evidence is organized as follows:
    1. Emerging Climate Change and Energy Transition Policies
    2. Enbridge Gas's Energy Transition Plan (ETP) to Reduce GHG Emissions
    3. Summary of GHG Reductions Driven from Enbridge Gas's ETP
    4. Evolution of Enbridge Gas's ETP

1. Emerging Climate Change and Energy Transition Policies

1.1 Introduction

3. The need to act against climate change has led the federal, provincial, and municipal governments to develop targets, plans, and policies to reduce GHG emissions, to develop lower carbon sources of energy and to transition to a low-carbon economy. Please see Exhibit 1, Tab 10, Schedule 3, Section 2 where Enbridge Gas describes the current climate policies that impact the Company. This

Climate Change and Energy Transition Policies section discusses emerging or evolving federal and provincial climate targets, plans, strategies, and regulations, as well as energy and climate change planning actions being planned or taken by municipalities, that may impact Enbridge Gas's business, and specifically its ETP.

1.2 Federal and Provincial Climate Targets

4. In 2016, the federal government committed to taking long-term climate action by setting a national target under the Paris Agreement to reduce Canada's GHG emissions by 30% below 2005 levels by 2030.[1] To support this commitment, Canada's first national climate strategy, the Pan-Canadian Framework on Clean Growth and Climate Change, was developed.[2]

5. As a signatory to the Pan-Canadian Framework, the Ontario government has also committed to reducing emissions by 30% below 2005 levels by 2030.

6. In 2020, the federal government released a strengthened climate plan[3], committing to achieving further GHG emission reductions by 2030. In 2021, the Net-Zero Emissions Accountability Act[4] was enacted to enshrine in law the enhanced 2030 GHG emissions reduction target of 40% to 45% below 2005 levels, and a target of

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[1] 196 countries have agreed to the Paris Agreement, which is a legally binding international treaty on climate change that entered into force in November 2016. The goal of the Paris Agreement is to limit global warming to well below 2, preferably to 1.5, degrees Celsius, compared to pre-industrial levels. (United Nations. The Paris Agreement. United Nations Framework Convention on Climate Change. https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement)
[2] Pan-Canadian Framework on Clean Growth and Climate Change: Canada's Plan to Address Climate Change and Grow the Economy, 2016, https://publications.gc.ca/collections/collection_2017/eccc/En4-294-2016-eng.pdf.
[3] A Healthy Environment and a Healthy Economy: Canada's strengthened climate plan to create jobs and support people, communities and the planet, 2020, https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/climate-plan/healthy_environment_healthy_economy_plan.pdf
[4] Canadian Net-Zero Emissions Accountability Act, 2021, https://laws-lois.justice.gc.ca/PDF/C-19.3.pdf

net-zero by 2050. These targets replace those previously announced in the Pan-Canadian Framework.

7. To date, Ontario has not committed to the steeper 2030 GHG target set by the federal government in the Canadian Net-Zero Emissions Accountability Act and has not set GHG reduction targets beyond 2030. Ontario, however, is the second largest emitting province in Canada and, therefore, further GHG reductions will need to occur in Ontario for the country to achieve net-zero emissions by 2050.[5]

8. While both the federal and provincial governments are aligned on the need to reduce GHG emissions, the disparity between 2030 targets and the lack of provincial targets beyond 2030 creates uncertainty about the amount and pace of future GHG reductions in Ontario.

1.3 Provincial Climate Policies

9. To achieve the province's GHG emission reduction targets, the Ontario government developed the Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan (Made-in-Ontario Environment Plan) in November 2018.[6] The plan is intended to guide development of new environmental policies in Ontario to create a focused approach to mitigating the impacts of climate change and reducing the province's GHG emissions. The actions outlined in the Made-in-Ontario Environment Plan aim to achieve a reduction of 18 million tCO_2e to reach Ontario's 2030 emissions target, which equates to annual GHG emissions of

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[5] Government of Canada, Greenhouse gas emissions, Environment and natural resources, https://www.canada.ca/en/environment-climate-change/services/environmental-indicators/greenhouse-gas-emissions.html

[6] Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan, 2018, https://prod-environmental-registry.s3.amazonaws.com/2018-11/EnvironmentPlan.pdf

143 million tCO_2e. The Made-in-Ontario Environment Plan aims to achieve these reductions through a range of sources, including higher uptake of clean fuels (ethanol gasoline, renewable natural gas etc.), natural gas conservation through gradual expansion of energy efficiency programs delivered by utilities, low-carbon vehicle uptake, industry performance standards regulating large GHG emitters and innovation in energy storage and fuel switching.

10. Ontario's GHG emissions have declined relative to the 2005 target baseline year (204 million tCO_2e). Ontario's GHG emissions were 19% below 2005 levels in 2019 (166 million tCO_2e) and 27% below 2005 levels in 2020 (150 million tCO_2e).[7]

11. Depending on any potential rebound in emissions post-pandemic, the province requires additional reductions of 3% to 11% to achieve its 2030 target. Ontario has released an updated forecast[8]. It does not include sectoral targets, but it shows that the remainder of the GHG reductions by 2030 will be achieved predominantly from the Emissions Performance Standards (EPS), gasoline renewable content requirements and supporting industrial coal phase-out via natural gas. Additional GHG reductions will be achieved through natural gas conservation, transit initiatives and reducing emissions from landfills.

12. Ontario is taking important additional steps to review the impact of energy transition in the province. In April 2022, the Government of Ontario announced the launch of

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[7] National Inventory Report 1990 – 2020: Greenhouse Gas Sources and Sinks in Canada, Part 3, p.50, https://unfccc.int/documents/461919
[8] Ontario Emissions Scenario as of March 25, 2022, 2022, https://prod-environmental-registry.s3.amazonaws.com/2022-04/Ontario%20Emissions%20Scenario%20as%20of%20March%2025_1.pdf

an Electrification and Energy Transition Panel.[9] The Electrification and Energy Transition Panel will operate until at least March 2023 and will provide advice to the Minister of Energy on how to coordinate long-term energy planning, considering growing energy demand, low-carbon fuel switching, and emerging technologies, while delivering on sustainability and affordability. The Electrification and Energy Transition Panel's goal is to keep energy rates low and provide market signals for the long-term development of Ontario's energy sector.

13. The Electrification and Energy Transition Panel will be providing guidance on a pathways study being coordinated by the Ministry of Energy. This pathways study will be used to provide advice on long-term energy planning to reach Ontario's climate change goals. It is expected to begin in October 2022, with delivery of the main analysis examining cost-effective pathways by September 2023 and completion of the entire project and 10 deliverables by February 2024.[10]

14. The provincial government has also released two discussion papers regarding initiatives it is exploring to reduce GHG emissions, including:
    a) Geological Carbon Storage[11] – provides an overview of possible legislative changes to remove barriers for the storage of carbon dioxide; and

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[9] https://twitter.com/ToddSmithPC/status/1517564792772386816?s=20&t=--_U_6raC2LiB6V9NC83qg
[10] Ontario Tenders Portal. Cost-Effective Energy Pathways Study for Ontario. https://ontariotenders.app.jaggaer.com/esop/toolkit/opportunity/past/116724/detail.si
[11] Discussion Paper: Geologic Carbon Storage in Ontario. January 2022. https://prod-environmental-registry.s3.amazonaws.com/2022-01/Geologic%20Carbon%20Storage%20Discussion%20Paper%20-%20FinalENG%20-%202022-01-04_0.pdf

b) Low-Carbon Hydrogen Strategy[12] – provides a vision and the immediate actions that can be taken to enable hydrogen production and to expand the low-carbon hydrogen economy.

1.4 Federal Climate Policies

15. Efforts by the federal, provincial, and territorial governments across Canada to reduce GHG emissions have flattened Canada's GHG emissions. GHG emissions have been maintained at close to the same level as the 2005 target baseline year, despite growth in the economy over the same period. Canada's emissions in 2020 were approximately 9% lower than in 2005[13]; however, this may be because of the confinement measures introduced in 2020 due to the pandemic.[14] Canada's emissions in 2019, the year before the pandemic, were less than 1% lower than the emissions in 2005.[15] Depending on any potential rebound in emissions post-pandemic, the federal government requires additional GHG reductions of 31 to 39% to achieve a 40% reduction relative to 2005 levels by 2030.

16. To enable these GHG reductions, the federal government has released its 2030 Emissions Reduction Plan[16], which is further supported by the release of discussion papers on the following topics:

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[12] Ontario's Low-Carbon Hydrogen Strategy: A Path Forward. April 2022. https://www.ontario.ca/files/2022-04/energy-ontarios-low-carbon-hydrogen-strategy-en-2022-04-11.pdf
[13] National Inventory Report 1990 – 2020: Greenhouse Gas Sources and Sinks in Canada, Part 3, p.11, https://unfccc.int/documents/461919
[14] National Inventory Report 1990 – 2020: Greenhouse Gas Sources and Sinks in Canada, Part 3, p.11, https://unfccc.int/documents/461919
[15] Ibid.
[16] 2030 Emissions Reduction Plan: Canada's Next Steps for Clean Air and a Strong Economy, 2022, https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf

a) Canada's Hydrogen Strategy[17] – provides a framework for actions for the use of hydrogen as a tool to achieve goal of net-zero emissions by 2050;
b) Clean Electricity Standard[18] – provides preliminary details regarding the regulation of GHG emissions from fossil fuel supplied electricity generating facilities;
c) Reducing Methane Emissions from Canada's Oil and Gas Sector[19] – provides an overview of potential emission reduction technologies and approaches to reduce methane emissions from the oil and gas sector;
d) Oil and Gas Emissions Cap[20] – provides two potential regulatory approaches to cap and cut emissions from the oil and gas sector; and
e) Canada's Green Buildings Strategy[21] – to provide details on potential themes and actions for reducing GHG emissions from residential, commercial, and institutional buildings.

1.5 Municipal Climate Policies

17. Municipalities across Ontario are also increasingly taking action to address climate change within their boundaries. Municipalities are developing Municipal Energy

[17] Hydrogen Strategy for Canada: Seizing the Opportunities for Hydrogen, 2020, https://www.nrcan.gc.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen%20Strategy%20for%20Canada%20Dec%2015%202200%20clean_low_accessible.pdf.
[18] A Clean Electricity Standard in Support of a Net-Zero Electricity Sector: A Discussion Paper, 2022, https://www.canada.ca/content/dam/eccc/documents/pdf/cepa/CleanElectricityStandardDiscussionPaper-eng.pdf.
[19] Reducing Methane Emissions from Canada's Oil and Gas Sector: Discussion Paper, 2022, https://www.canada.ca/content/dam/eccc/documents/pdf/cepa/20220325_OilGasMethaneDD-eng.pdf.
[20] Options to Cap and Cut Oil and Gas Sector Greenhouse Gas Emissions to Achieve 2030 Goals and Net-Zero by 2050: Discussion Document, 2022, https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/oil-gas-emissions-cap/Oil%20and%20Gas%20Emissions%20Cap%20Discussion%20Document%20-%20July%2018%202022_EN.pdf.
[21] The Canada Green Buildings Strategy: Discussion Paper, 2022, https://www.nrcan.gc.ca/sites/nrcan/files/engagements/green-building-strategy/CGBS%20Discussion%20Paper%20-%20EN.pdf.

Plans (MEPs), Community Energy Plans (CEPs) and Climate Change Action Plans (CCAPs). These plans are approved by municipal councils and lay out the municipality's vision to meet GHG reductions via energy efficiency and low-carbon energy, while continuing to meet local energy needs, mitigate and adapt to the impacts of climate change, and enhance the quality of life for residents and businesses.

18. As part of these plans, some municipalities are also introducing green development standards to further advance sustainable design and building performance in new construction to help meet their jurisdictions' energy plan goals. These green development standards go beyond the Ontario Building Code (OBC) requirements currently in place for new building construction in Ontario. Developers are asked to comply with their green standards as part of the development application cycle.

19. To date, 95 out of 444 Ontario municipalities have completed (or have near-completed) MEPs, CEPs, and/or CCAPs. A discussion of Enbridge Gas's engagement with municipalities in the development of these plans is provided at Exhibit 1, Tab 10, Schedule 5, Section 2.

1.6 Summary of Climate Policies Informing Enbridge Gas's ETP

20. As provided in Sections 1.2 to 1.5, in the six years since signing the Paris Agreement, climate and energy transition targets and plans in Canada have progressed significantly by the federal, provincial and many municipal governments; however, there remains a significant lack of detail on how these targets will be met and funded, and development of detailed policies is still in progress.

21. Although the key objective of climate policies is to reduce GHG emissions, not to electrify, there appears to be some partiality at all three levels of government towards achieving GHG reductions and meeting net-zero via electrification. Although electrification often receives the focus, there are no policies mandating electrification or that provide specific direction on the future of the gas delivery system in Ontario. Furthermore, there appears to be a lack of consideration about the magnitude of infrastructure and costs required to replace the critical role that the gas system currently plays in safely and reliably heating homes and fueling industry and electricity generation in Ontario. Considering this in detail would enable a discussion about what role the gas delivery system can play in supporting Ontario in achieving its climate and energy transition goals.

22. What is clear to Enbridge Gas, however, is that the governments' ambitious GHG reduction targets will require a reduction in energy use in combination with a shift from unabated fossil fuels to low-carbon sources of energy.

23. The federal 2030 Emission Reduction Plan and federal discussion papers combined with the Made-in-Ontario Environment Plan and discussion papers demonstrate that these two levels of government are taking action to reduce GHG emissions through a diverse set of policies and funding across all sectors, including buildings, industry, transportation, and electricity generation. Actions being explored include support for energy efficiency, electrification, low-carbon fuels, and carbon capture, utilization, and sequestration (CCUS).

24. Reduction in energy usage via energy efficiency programs has been, and continues to be, fundamental to emission reduction plans at all levels of government. For example, in the 2030 Emissions Reduction Plan, the federal government states "Energy efficiency measures such as upgrading the building

envelope with improved insulation, replacing windows and doors, or air sealing are also essential for decarbonization."[22]

25. Interest in shifting from unabated fossil fuels to low-carbon sources of energy, including electricity and low-carbon fuels, has also been signaled by both the federal and provincial government.

26. The federal government's hydrogen strategy states "In a net-zero future, Canada's economy will be powered by electricity and low carbon fuels – with low carbon fuels expected to provide up to 60% or more of our energy needs."[23] Hydrogen is expected to play a role in reducing emissions from energy intensive and hard to abate end-use sectors, such as heavy-duty transportation and high-temperature industrial applications. The potential role of hydrogen in buildings is also recognized by the federal hydrogen strategy:

> Hydrogen provides an opportunity to utilize Canada's valuable natural gas pipeline infrastructure investments to deliver energy intense low carbon fuel for high-grade heating applications where electric heating is not the best option. In regions with heat pumps, hydrogen can also be used to provide heat during winter season with hybrid heating systems.[24]

27. The provincial government has also developed a hydrogen strategy, which recognizes that both hydrogen and RNG will be critical to meeting the province's

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[22] 2030 Emissions Reduction Plan: Canada's Next Steps for Clean Air and a Strong Economy, 2022, p.33, https://publications.gc.ca/collections/collection_2022/eccc/En4-460-2022-eng.pdf
[23] Hydrogen Strategy for Canada: Seizing the Opportunities for Hydrogen – A Call to Action, 2020, p.IX, https://www.nrcan.gc.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf
[24] Hydrogen Strategy for Canada: Seizing the Opportunities for Hydrogen – A Call to Action, 2020, p.62. https://www.nrcan.gc.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

environmental goals, alongside electrification.[25] Furthermore, the provincial government also recognizes the many applications that hydrogen can be used for, including space and water heating:

> The province's Made-in-Ontario Environment Plan speaks to the important role that hydrogen can play as a low-carbon fuel that can support low-carbon vehicle adoption (e.g., public transportation, forklifts, heavy-duty trucks), decarbonization of space and water heating for homes and businesses and helping industry to decarbonize their processes and meet compliance obligations under Ontario's Emissions Performance Standards program.[26]

28. In addition to low carbon fuels, natural gas paired with CCUS will also be used to reduce emissions from industry and to produce hydrogen to support the federal and provincial GHG reduction targets. This has been signaled in Canada's 2030 Emission Reduction Plan, which includes the intention to develop a comprehensive CCUS strategy, investments into research and development of CCUS technologies and the development of a CCUS investment tax credit.[27] The provincial government is also investigating CCUS, as signaled by development of a discussion paper on geological carbon storage.[28]

29. It is important to note, that to achieve GHG reductions in the industrial sector in the near term, while solutions such as hydrogen and CCUS are being developed,

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[25] Ontario's Low-Carbon Hydrogen Strategy: A Path Forward, 2022, p.18, https://www.ontario.ca/files/2022-04/energy-ontarios-low-carbon-hydrogen-strategy-en-2022-04-11.pdf
[26] Ibid, p.10.
[27] 2030 Emissions Reduction Plan: Canada's Next Steps for Clean Air and a Strong Economy, 2022, https://publications.gc.ca/collections/collection_2022/eccc/En4-460-2022-eng.pdf
[28] Discussion Paper: Geologic Carbon Storage in Ontario, 2022, https://prod-environmental-registry.s3.amazonaws.com/2022-01/Geologic%20Carbon%20Storage%20Discussion%20Paper%20-%20FinalENG%20-%202022-01-04_0.pdf

natural gas will have a role to play in replacing higher emitting fuels, particularly replacing coal/coke use in the steel industry. This is supported by Ontario's updated Emissions Scenario[29] and funding announcements[30] from the Ontario Government made earlier in 2022.

30. The combination of federal targets, aggressive municipal net-zero plans and a lack of provincial GHG emissions reduction goals beyond 2030 creates great uncertainty around the pace and nature of the energy transition pathway that the Ontario Government will take. Energy policy resides with Ontario Government and absent provincial policies or frameworks, Enbridge Gas does not have clarity on what pathway will unfold. It is for this reason, that the Ontario Electrification and Energy Transition Panel's pathways report and the continued consultation on energy related discussion papers is so critical. The information gained via these initiatives will help to define Ontario's energy transition pathway and its associated climate policies, plans and targets. This will provide clarity around how Ontario's electric and gas systems can together support an orderly transition to a net-zero future while also maintaining today's level of energy security, reliability, resiliency, and affordability for all Ontarians.

31. An understanding of these evolving climate policies, plans, and targets will remain a key input into Enbridge Gas's ETP. This ensures that Enbridge Gas complies, where applicable, and aligns its business processes, plans and activities with policies as they are implemented.

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[29] Ontario Emissions Scenario as of March 25, 2022, 2022, https://prod-environmental-registry.s3.amazonaws.com/2022-04/Ontario%20Emissions%20Scenario%20as%20of%20March%2025_1.pdf
[30] Government of Ontario. (2022 February 15). Province Invests in Clean Steelmaking Technology in Hamilton to Support Future of Ontario's Auto Sector. https://news.ontario.ca/en/release/1001604/province-invests-in-clean-steelmaking-technology-in-hamilton-to-support-future-of-ontarios-auto-sector

32. The above has been used to inform Enbridge Gas's vision of Ontario's energy sector, provided at Exhibit 1, Tab 10, Schedule 5, Section 3, Enbridge Gas's ETP and its related proposals, which are provided in Section 2, and has been considered in the Company's forecasting and planning, as provided at Exhibit 1, Tab 10, Schedule 4, Sections 1 and 2.

2. Enbridge Gas's Energy Transition Plan (ETP) to Reduce GHG Emissions

33. Enbridge Gas has developed an ETP, including some "safe bet" actions and proposals, to recognize and incorporate, where possible, the current impacts of energy transition and to ensure that progress towards Ontario's 2030 GHG emissions reduction targets and a net-zero future can continue despite the current pathway uncertainty.

34. The objectives of Enbridge Gas's ETP are to:
    a) Support an orderly energy transition in Ontario;
    b) Provide cost-effective, secure, reliable, and resilient energy for customers during the transition to a low-carbon economy and once net-zero is achieved; and
    c) Maintain alignment with Ontario's energy objectives and with provincial and federal energy transition and climate change targets and policies.

35. Enbridge Gas believes in its vision of a diversified pathway for Ontario, as provided at Exhibit 1, Tab 10, Schedule 5, Section 3; however, it also acknowledges that there are alternate views and, as noted above, that GHG reduction targets and supporting policies have not yet been developed in Ontario beyond 2030. As a result, uncertainty exists with regards to what path will unfold and at what pace, including which policies and investments will be made and when. While the

government and stakeholders work to determine how best to achieve net-zero, Enbridge Gas believes that if energy transition is to be implemented in an orderly manner, that delaying all action is not an option. Despite the uncertainty that exists, there are safe bet actions that can and need to be taken now.

36. Enbridge Gas considers an action to be a safe bet if it:
    a) Supports Ontario's near term GHG reductions, including achievement of the 2030 target; and/or
    a) Is required, regardless of whether a diversified or an electrification pathway unfolds in Ontario; and/or
    b) Maintains consumer choice, a safe and reliable gas system in a manner that considers pathway uncertainty, and/or pathway optionality until greater certainty around how best to transition is obtained.

37. The safe bet actions that have shaped Enbridge Gas's ETP are:
    a) Maximizing energy efficiency;
    b) Increasing the amount of RNG in the gas supply;
    c) Reducing GHG emissions from the industrial and transportation sectors via fuel switching and CCUS;
    d) Integrating gas and electric system planning; and
    e) Supporting consumer choice and the energy transition journey.

38. With the ETP based upon these identified safe bets and objectives, Enbridge Gas believes the ETP, and its associated rebasing application proposals, are prudent as they support continued progress towards a net-zero future despite current policy uncertainty, but they don't overinvest in a particular pathway prior to the Ontario government defining its future energy transition plans in more detail.

39. Enbridge Gas's ETP includes actions ranging from those which Enbridge Gas has been undertaking for some time, such as Demand Side Management (DSM), to actions that the Company is in the early stages of exploring, such as CCUS. Enbridge Gas notes that not all actions discussed within its ETP have associated proposals within the rebasing application. In some cases, where noted, the safe bet action requires additional provincial government policies, investments, and/or OEB support to move forward. A discussion of all actions Enbridge Gas is exploring, or pursuing has been included to provide the OEB with a full picture of the role Enbridge Gas can play in supporting Ontario's energy transition, both during the rebasing term and over the longer term. Enbridge Gas may bring forward applications in the future to implement additional actions contemplated in its ETP or in future iterations.

40. Table 1 identifies, for each safe bet, the ETP rebasing proposal, where applicable. Following Table 1 is a more detailed overview of each safe bet and the associated actions that Enbridge Gas is proposing, pursuing, or exploring.

Table 1
Summary of Energy Transition Related Rebasing Proposals

Safe Bet	Enbridge Initiative	Rebasing Proposal	Proposal Related Evidence
Maximizing Energy Efficiency	DSM	• No proposal. • The DSM Plan for 2023-2027 is currently pending OEB approval through a separate application[31]	Not applicable

[31] EB-2021-0002

Investing in Renewable Natural Gas (RNG)	Voluntary RNG Program	Proposal: • Discontinue the current pilot Voluntary RNG (VRNG) program and establish a Low-Carbon Voluntary Program (LCVP) for large volume sales service customers. • Procure up to 1% of the planned gas supply commodity purchases as low-carbon energy beginning in 2025 and increasing by 1% annually up to 4% in 2028. • Include any costs not recovered through the LCVP in the cost of gas supply commodity purchases.	Exhibit 4, Tab 2, Schedule 7
	RNG upgrading	• No proposal. • Note: Enbridge Gas's Asset Management Plan (AMP) includes strategies to support investments for RNG injection stations.	Exhibit 2, Tab 6, Schedule 2
Decarbonizing the Industrial and Transportation Sectors	Industrial fuel switching	• No proposal. • Note: Enbridge Gas's AMP includes strategies to support investments for RNG injection stations.	Exhibit 2, Tab 6, Schedule 2
	Carbon Capture and Sequestration (CCS)	• No proposal.	Not applicable

	Natural Gas Vehicle (NGV) Program	Proposal: • Expand the NGV program in the EGD rate zone to all Enbridge Gas franchise areas, continued operation of the NGV Program as part of the utility business activities. • Modify the current regulatory treatment to remove the need for revenue imputation, such that the NGV Program is funded solely by the monthly service rates charged to participating customers over the life of the program. • Note: Enbridge Gas's AMP includes strategies to support investments for NGV stations.	Exhibit 1, Tab 14, Schedule 2 Exhibit 2, Tab 6, Schedule 2
Integrating Gas and Electric System Planning	Optimizing energy system planning	• No proposal.	Not applicable
Supporting Consumer Choice and the Energy Transition Journey	Hydrogen Blending Grid Study (HBGS)	Proposal: • Conduct a full evaluation of the hydrogen-readiness of the natural gas grid in Ontario. Costs are estimated at $12 million.	Exhibit 4, Tab 2, Schedule 6
	Low Carbon Energy Project (LCEP) Phase 2	• No proposal in the Rebasing application. • Enbridge Gas intends to pursue approval for and implementation of Phase 2 of the LCEP through	Exhibit 4, Tab 2, Schedule 7

		an upcoming Leave-to-Construct application. An estimate of the cost of Phase 2 of LCEP is currently projected at $7.0 million.	
	Energy Transition Technology Fund (ETTF)	Proposal: • Approval of an Energy Transition Technology Fund in the amount of $5 million per year, totaling $25 million over the 2024 to 2028 period. Enbridge Gas is proposing to fund the ETTF through a rate rider.	Exhibit 1, Tab 10, Schedule 7
	Maintaining the Gas System – via Integrated Resource Planning (IRP) and Scope 1 & 2 emissions reductions focus	• No proposal in the Rebasing application • Note: Enbridge Gas's AMP (Appendix B) provides information on IRP alternatives. • Note: Enbridge Gas's AMP includes projects to support scope 1 and 2 GHG emission reductions.	IRP: Exhibit 2, Tab 6, Schedule 2, Appendix B Scope 1 & 2: Exhibit 2, Tab 6, Schedule 2

41. The following sub-sections describe each safe bet and the associated actions within each that Enbridge Gas is proposing, pursuing, or exploring.

2.1 Maximizing Energy Efficiency

42. Maximizing energy efficiency is considered to be a safe bet because it will be required regardless of the pathway to net-zero taken. Energy efficiency is well recognized in the climate change and energy transition plans developed by all levels of government, as discussed above. In addition, energy efficiency provides near term GHG emission reductions, it supports any energy transition pathway that unfolds, and it supports customer choice.

43. GHG emissions from buildings and industrial processes account for 25% and 27% respectively of Ontario's GHG emissions[32]. By continuing to increase the energy efficiency of buildings and industry, not only are immediate GHG reductions realized from a decrease in gas consumption, but future energy demands, regardless of type (i.e., RNG, hydrogen or electricity) are minimized. Lowering energy demand also has the benefit of reducing customer energy costs and/or increasing customers' productivity.

44. Between 1995 and 2021[33], EGD and Union, and now Enbridge Gas, have driven a cumulative reduction of 57.8 million tCO_2e via natural gas Demand Side Management (DSM) programs. Enbridge Gas will continue to support the maximization of energy efficiency in Ontario through the implementation of energy efficiency and conservation measures to reduce gas demand from the Company's residential, commercial, and industrial customers. Enhanced targeted energy efficiency programming completed as part of IRP projects will also contribute to maximizing energy efficiency.

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[32] Based on 2020 data from Canada's National Inventory Report 1990 – 2020, April 14, 2022, Part 3, p.50, https://unfccc.int/documents/461919
[33] Enbridge 2021 Sustainability Report, June 22, 2022, p.26. https://www.enbridge.com/~/media/Enb/Documents/Reports/Sustainability%20Report%202021/Enbridge-SR-2021.pdf

45. On May 3, 2021, Enbridge Gas filed an application[34] which, after amendments, consists of a proposed DSM Framework (Proposed Framework), and a five-year DSM Plan for 2023 to 2027 (DSM Plan). The DSM Plan Application is currently pending OEB approval, following an extensive and comprehensive discovery and oral hearing process. Information related to DSM is, therefore, being provided in this Application for context only, acknowledging that Enbridge Gas is dedicated to continuing to support this safe bet action. The Company is not requesting any relief, variation, or other adjustment to the DSM Plan Application as part of this Application.

46. The transition to net-zero will require coordination between all levels of government (federal, provincial, and municipal), utilities, and energy consumers. Enbridge Gas will continue to focus on the evolution of DSM programs including leveraging opportunities to collaborate with government in the furtherment of energy efficiency across the province. In so doing, it will be important to clarify roles, to ensure all are focused on the most effective action items to avoid duplication and confusion in the marketplace.

2.2 Increasing the Amount of RNG in the Gas Supply

47. RNG is produced from decomposing organic matter (e.g., food waste, human and animal wastes), which creates biogas that is upgraded to pipeline quality methane. RNG is a “drop-in” fuel that can be consumed at blends up to 100% without compatibility issues or modification to customer equipment.

[34] EB-2021-0002.

48. Given this, increasing the RNG in the gas supply is considered a safe bet because growing the use of RNG (1) supports an immediate opportunity to reduce GHG emissions within Ontario's building, transportation, industrial and electricity generation sectors, (2) develops an Ontario-based RNG market that, regardless of the pathway that unfolds, is required to supply RNG to the difficult to decarbonize heavy transportation sector as well as industrial processes, and (3) provides customers with choice on how they can achieve their own GHG emission reduction goals while maintaining optionality until greater certainty on which pathway will unfold is gained.

49. The Made in Ontario Environment Plan includes a requirement for natural gas utilities to implement a voluntary RNG option for customers. On March 5, 2020, Enbridge Gas filed an application for a Voluntary RNG (VRNG) Program.[35] The VRNG Program was approved on a pilot basis on September 25, 2020, and the program was launched in April 2021. An update on the results of the VRNG Program is provided at Exhibit 4, Tab 2, Schedule 7.

50. Enbridge Gas supports the growth of Ontario-based RNG supply through its regulated services to interconnect RNG production with the Company's natural gas infrastructure. Interconnection services are required for RNG producers to deliver and sell this energy to the North American marketplace. These interconnection services also support organizations, such as municipalities, that own waste management facilities and may be seeking to self-consume their RNG to reduce their own GHG emissions from buildings or fleets that may not be located where the RNG is produced. As of 2022, four RNG production sites have successfully delivered RNG to Enbridge Gas's natural gas infrastructure.

[35] EB-2020-0066.

51. Enbridge Gas is continuing to support the development of the RNG market in Ontario and increasing the amount of RNG in the gas supply through inclusion of the following actions in the Company's ETP, each of which is discussed below:
    a) Proposed Low-Carbon Voluntary Program (LCVP);
    b) Proposed Energy Transition Technology Fund (ETTF);
    c) Continued support of RNG producers through injection services; and
    d) Proposed Natural Gas Vehicle (NGV) Program.

52. Enbridge Gas is proposing a Low-Carbon Voluntary Program (LCVP) that aims to provide Large Volume sales service customers an option to upgrade a portion of their supply to RNG, with the goal of reducing GHG emissions by realizing a one to four percent blend of total system supply with RNG between 2025 and 2028. Please see Exhibit 4, Tab 2, Schedule 7 for the proposed program details.

53. Enbridge Gas is proposing an ETTF to advance and accelerate research, development, and commercialization of low-carbon technologies. As provided at Exhibit 1, Tab 10, Schedule 7, the ETTF can support the further development and advancement of technologies that can maximize potential RNG supplies. The ETTF is discussed further below.

54. Enbridge Gas anticipates significant growth of Ontario-based RNG supplies based on the RNG industry expectations in Canada and North America.[36] [37] Capital

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[36] Canadian Biogas Association 2022 report Hitting Canada's Climate Targets with Biogas & RNG, March 2022, https://biogasassociation.ca/images/uploads/documents/2022/resources/Hitting_Targets_with_Biogas_RNG.pdf
[37] Coalition for Renewable Natural Gas. (2022 May). RNG Facilities. Coalition for Renewable Natural Gas. https://www.rngcoalition.com/infographic/

expenditures required to support Enbridge Gas's RNG infrastructure has been included in the data provided at Exhibit 2, Tab 5, Schedule 2.

55. Enbridge Gas is also proposing an expansion of the Company's Natural Gas Vehicle (NGV) Program, which will enable RNG use and the reduction of GHG emissions within the transportation market. The NGV Program is discussed further below and more information provided at Exhibit 1, Tab 14, Schedule 2.

2.3 Reducing GHG Emissions from the Industrial and Transportation Sectors Via Fuel Switching and CCUS

56. Reducing GHG emissions from the industrial and transportation sectors via fuel switching and CCUS is a safe bet because these low-carbon solutions (1) support near term GHG emission reductions, (2) are required, regardless of the pathway, for these two particularly difficult to decarbonize sectors, and (3) provide customers a choice on how they can achieve their own GHG emission reduction goals, while controlling costs to remain competitive.

57. GHG emissions from industry and transportation make up 27% and 32% of Ontario's GHG emissions respectively.[38]

58. Enbridge Gas is supporting GHG emission reductions in the industrial and transportation sectors in Ontario through inclusion of the following initiatives in the Company's ETP, each of which is discussed below:

a) Industrial fuel switching
b) CCUS
c) Transportation fuel-switching

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[38] Canada's National Inventory Report 1990 – 2020, April 14, 2022, Part 3, p.50, https://unfccc.int/documents/461919

Industrial fuel switching

59. Enbridge Gas works closely with its industrial customers to deliver solutions specific to their individual energy needs and business requirements, for today and the future. Solutions provided to industrial customers include energy efficiency offerings as noted in Section 2.1, providing access to natural gas to fuel their operations safely and reliably, as well as support in reducing and/or avoiding the consumption of higher carbon intensity fuels or feedstocks. Solutions provided to industrial customers also include educating them about the GHG emission reduction benefits of new low-carbon solutions such as RNG, hydrogen, district energy systems, compressed natural gas and liquified natural gas.

60. To remain competitive in a global marketplace, industrial customers are primarily focused on their production output, safe and reliable energy supply, and switching away from higher cost, higher GHG emission hydrocarbon fuels (such as coal and petroleum products). Customers attaching to the gas distribution system to switch away from higher hydrocarbon fuels immediately realize GHG emission reductions, which will grow over time as the gas supply is decarbonized. This supports Ontario's 2030 emissions reductions targets and a net-zero future.

61. An example of an industrial segment that is going through transformational changes is the steel sector. For example, ArcelorMittal Dofasco is investing in equipment that can use natural gas or RNG, and eventually hydrogen, instead of coal and will reduce annual GHG emissions at its Hamilton, Ontario operations by

approximately 3 million tCO_2e.[39] It is important to note that although these projects increase the use of natural gas in the shorter-term and, therefore, increase Enbridge Gas's scope 3 emissions, they drive significant GHG emissions reductions for ArcelorMittal Dofasco, and contribute greatly to the achievement of Ontario's 2030 target. In addition, projects such as this provide a bridge to the use of low-carbon fuels in the future, which supports a net-zero future.

62. In addition to supporting customers switching from higher emitting fuels to natural gas, Enbridge Gas is also working with a number of large emitter customers, in sectors such as manufacturing, refining, and power generation to explore and understand how low-carbon hydrogen can benefit their operations. These customers have expressed interest in working with Enbridge Gas to provide hydrogen-based solutions related to their transportation, storage, and distribution needs. Successful culmination of these explorative energy solutions by Enbridge Gas's customers along with Enbridge Gas's plans to understand blending in the entire natural gas grid it owns in Ontario will drive the development of larger commercial hydrogen hubs in the province.

Carbon Capture Utilization and Storage (CCUS)

63. CCUS refers to the capture of carbon dioxide (CO_2) emissions from facilities or directly from the air, which are then compressed and transported to be permanently stored in geological formations underground or to be used to create products.[40]

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[39] ArcelorMittal. (2021, July 30). New DRI and EAF installations at ArcelorMittal Dofasco in Hamilton, Ontario will reduce carbon emissions by approximately 60%. ArcelorMittal. https://corporate.arcelormittal.com/media/press-releases/arcelormittal-and-the-government-of-canada-announce-investment-of-cad-1-765-billion-in-decarbonization-technologies-in-canada
[40] Government of Canada. (2021, November 2). Carbon capture, utilization, and storage strategy. Canada's green future. https://www.nrcan.gc.ca/climate-change/canadas-green-future/carbon-capture-utilization-and-storage-strategy/23721

64. CCUS is considered a safe bet as it is required to significantly reduce Ontario's GHG emissions, regardless of the pathway chosen, from hard to abate industrial sectors such as steel and cement production, oil and gas refining, and petrochemical production. Industries with significant process emissions, such as the cement industry, are particularly difficult to decarbonize as process emissions may be unaffected from fuel switching (to either low-carbon gases or electricity for heating) or energy efficiency activities. For example, approximately 60% of GHG emissions from cement manufacturing come from the chemical reaction inside the kiln.[41] In addition to industrial applications, CCUS can also be used to capture CO_2 emissions from gas-fired power generation and from the production of low-carbon hydrogen from natural gas.

65. The Government of Canada considers CCUS as critical to Canada achieving a prosperous net-zero economy, while the International Energy Agency considers global net-zero goals impossible to reach without CCUS.[42] Commercial scale CCUS projects are currently in operation in North America and across the globe and have demonstrated that CCUS is a safe, environmentally responsible way of reducing GHG emissions. Currently there are no commercial scale CCUS projects in Ontario; however, studies show Ontario's unique geology is well suited to store carbon. For example, the Southwest Ontario basin is ranked third out of 11 basins in Canada in terms of potential to store carbon subsurface.[43]

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[41] Cement Association of Canada. Our Roadmap to Net-Zero. https://cement.ca/sustainability/our-roadmap-to-net-zero/
[42] Canada's CO2 Capture & Storage Technology Roadmap, March 2006, Table 3.2., https://publications.gc.ca/collections/collection_2014/rncan-nrcan/M154-16-2008-eng.pdf
[43] Ibid.

66. Currently, Ontario is lacking regulations that approve the storage of carbon dioxide subsurface and a regulatory framework that will provide a known approval process for developing CCUS projects; however, the Government of Ontario is taking steps to enable CCUS in the province. In January 2022, the Ontario Ministry of Northern Development, Mining, Natural Resources and Forestry released a discussion paper on geological carbon storage.[44] The discussion paper outlines proposed changes to regulations that will enable underground storage of CO_2 in the province.

67. Enbridge Gas can leverage the Company's extensive experience in underground storage and transportation of natural gas to support CCUS in Ontario. Enbridge Gas is completing studies to further evaluate potential subsurface CO_2 storage regions in Ontario and is in discussion with government, academia and large industrial emitters to advance the development of CCUS.

68. Enbridge Gas also intends to support CCUS using the ETTF to research, test and pilot promising CCUS technologies for commercial and industrial applications, please see Exhibit 1, Tab 10, Schedule 7.

69. At this time, Enbridge Gas is not requesting OEB approval for any costs or activities related to CCUS (outside of the proposal for the ETTF). Pending the outcome of the studies mentioned above, as well as the update of relevant regulations by the provincial government, Enbridge Gas may take additional steps to explore the commercialization of CCUS in Ontario and may come forward at a future date with specific proposals regarding CCUS.

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[44] Discussion Paper: Geological Carbon Storage in Ontario, January 2022, https://prod-environmental-registry.s3.amazonaws.com/2022-01/Geologic%20Carbon%20Storage%20Discussion%20Paper%20-%20FinalENG%20-%202022-01-04_0.pdf

Transportation Fuel Switching

70. Enbridge Gas considers the transition to natural gas as a vehicle fuel a safe bet, particularly in the case of heavy trucks and public transportation vehicles, as it represents an immediate and significant opportunity for Ontario to reduce GHG emissions from the heavy-duty transportation sector, which is a sector that is difficult to electrify.

71. Compared to gasoline or diesel as a transportation fuel, natural gas offers both fuel savings and GHG reductions. This means that fleet owners can make business cases for converting gasoline and diesel fleet vehicles to natural gas and installing natural gas fueling stations.

72. RNG can also be used in NGVs without any additional infrastructure or vehicle modification. For the heavy-duty transportation market, where few low-carbon technologies and commercially ready options exist, the use of NGV with RNG represents an immediate cost-effective GHG emission reduction opportunity.

73. Enbridge Gas's proposed NGV program and requested OEB-approvals are provided at Exhibit 1, Tab 14, Schedule 2.

2.4 Integrating Gas and Electric System Planning

74. Enbridge Gas believes that energy system planning in Ontario can be done in a more coordinated and collaborative manner, involving assessments of how developing regional energy needs can be met by both the gas and electricity systems together. The need for more integration between gas and electricity planning was also discussed as part of the OEB's Framework for Energy Innovation

Working Group (FEIWG) and as part of the Regional Planning Process Advisory Group. Specifically, the FEIWG report notes "The need for more integration between gas and electricity planning was discussed on numerous occasions. Natural gas and electricity utilities may need to consider one another's system plans to optimize their respective assets. These issues were also identified by the Regional Planning Process Advisory Group in its recommendations to the OEB."[45]

75. Integrating gas and electric system planning is a safe bet as it supports near term GHG reductions, it is required regardless of which pathway comes to fruition and it supports maintaining the gas system in a way that considers pathway uncertainty. Beyond these benefits, integrating gas and electric system planning would enable optimized pathway modeling for Ontario and by region, ensuring that the most cost-effective, safe, reliable, and resilient transition is planned for and implemented. Without an integrated electric and gas approach to planning, decisions could be made based on a shorter-term, siloed view and not on the long-term implications for the province.

76. Integrated gas and electric system planning would support cost-effective near term GHG emission reductions via the two sectors working together to identify, plan for and implement initiatives that maximize the use of existing infrastructure while also fulfilling energy needs and reducing GHG emissions.

77. An example of this integration is hybrid heating. Hybrid heating can drive significant annual gas use reductions as compared to a furnace, thereby driving reduced GHG emissions, and reduce peak electricity needs as compared to an electric heat

[45] Framework for Energy Innovation Working Group Report – Report to the OEB. June 30, 2022. https://www.rds.oeb.ca/CMWebDrawer/Record/750359/File/document

pump, thereby driving reduced electrification costs. With the gas and electric sectors working together, the benefits and the potential of this solution could be understood and planned for within each region and the implementation could be done in partnership to ensure success within the market.[46]

78. Evolving the integration of gas and electric system planning will be required regardless of the pathway that unfolds, to ensure that required energy system changes are properly understood, planned for, and implemented in a safe, reliable, resilient, and secure manner throughout the transition.

79. Finally, the integration of gas and electric system planning supports the maintenance of the gas system amidst uncertainty, as it ensures that the same need is not forecasted or planned for by both sectors, and that the potential to co-deliver an IRP alternative, for example a demand response program, in a co-constrained area is identified. This concept was discussed as part of the OEB's Framework for Energy Innovation Working Group (FEIWG). Specifically, "the FEIWG recommends that the distributors (natural gas and electricity), transmitters and IESO co-ordinate planning and forecasting in the energy sector. The FEIWG recognized that through improved OEB guidance in relation to BCAs, utility incentives and integration of DERs distributors, transmitters, and the IESO will be aided in coordinating and integrating their planning."[47], and "we also acknowledged the importance of breaking down energy silos including those between natural gas and electricity planning, as reflected in the OEB's recent acceptance of the

[46] A good example of gas and electric utilities working together is the partnership between Énergir and Hydro-Quebec to convert gas heating systems to a hybrid heating system. Énergir. (2022 May 19). Green light to launch dual energy offer to decarbonize the heating of buildings. https://www.energir.com/en/about/media/news/decision-decarbonation-des-batiments-binergie/
[47] Framework for Energy Innovation Working Group Report – Report to the OEB. June 30, 2022. p.16. https://www.rds.oeb.ca/CMWebDrawer/Record/750359/File/document

Regional Planning Process Advisory Group's recommendation to enhance the coordination of other planning processes with regional planning. More work in this area is warranted."[48]

80. Enbridge Gas believes that having the OEB and government support and endorse integrated gas and electric planning would help to ensure that Ontario's energy transition is successful; that is, that the most cost-effective, reliable, and resilient pathway to net-zero is understood, planned for, and implemented.

2.5 Supporting Consumer Choice and the Energy Transition Journey

81. As noted above, uncertainty currently exists around which energy transition pathway will unfold within Ontario. The last safe bet action does not involve any particular GHG emissions reduction technology; instead, it is based on two concepts:
    a) Energy consumers should have the ability to choose solutions that suit their individual needs on the path to net-zero; and
    b) Until the path to net-zero in Ontario is clear, steps should be taken to ensure all pathways remain open and available.

82. Initiatives within this safe bet action are safe bets, because they maintain (1) consumer choice amidst uncertainty, (2) a safe and reliable gas system in a manner that considers pathway uncertainty, and/or (3) pathway optionality until greater certainty around how best to transition is obtained.

83. Specifically, the initiatives that enable this safe bet are:

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[48] Framework for Energy Innovation Working Group Report – Report to the OEB. June 30, 2022. P.16. https://www.rds.oeb.ca/CMWebDrawer/Record/750359/File/document

a) Taking steps to plan for hydrogen blending;
b) Supporting the continued advancement of low-carbon gaseous-energy technologies; and
c) Implementing projects that address identified distribution, transmission, and storage needs, including Integrated Resource Planning Alternative (IRPA) plans.

Planning for Hydrogen Blending

84. Low-carbon hydrogen, produced from low-carbon or zero-carbon electricity (called green hydrogen) or from natural gas with CCUS (called blue hydrogen) can be used on its own or blended with natural gas to lower GHG emissions.

85. As demonstrated in the P2NZ Study provided at Exhibit 1, Tab 10, Schedule 5, Attachment 1, dedicated hydrogen infrastructure is needed in either scenario in the long-term to deliver 100% hydrogen for industrial and heavy-duty transportation applications. The Diversified scenario in the P2NZ Study showed that hydrogen can also play a role in reducing GHG emissions for all sectors in the near-term through blending increasing amounts of hydrogen into the natural gas distribution system, growing to 100% hydrogen in segments of the system by 2050.

86. The role of hydrogen in reducing GHG emissions is supported by hydrogen strategies developed by both the provincial and federal governments, as provided above; however, while both levels of government appear to support hydrogen, there remains some uncertainty on how exactly it will contribute to the pathway to net-zero in Ontario.

87. Despite current uncertainty, to maintain pathway optionality and the role that hydrogen could play in a diversified pathway, Enbridge Gas must, at minimum, take the following steps to prepare for wider-scale hydrogen blending:
    a) Implement Phase 2 of the Low-Carbon Energy Project (LCEP); and
    b) Complete a Hydrogen Blending Grid Study (Grid Study).

88. Enbridge Gas filed an application with the OEB for phase 1 of the LCEP on December 20, 2019, proposing to blend up to 2% hydrogen by volume into a closed loop of Enbridge Gas's distribution system in Markham, Ontario.[49] This project, the first of its kind in North America, was approved by the OEB on October 29, 2020. Beginning in October 2021, the LCEP began blending up to 2% hydrogen for approximately 3,600 customers. Further updates on the LCEP phase 1 are provided at Exhibit 4, Tab 2, Schedule 6.

89. Through phase 1 of the LCEP, Enbridge Gas has gained valuable experience in producing and blending hydrogen. Enbridge Gas is planning phase 2 of the LCEP, expanding hydrogen blending to approximately 16,000 customers, to validate learnings from phase 1 and understand implications for different customer classes. This phase 2 expansion will be the subject of an upcoming Leave-to-Construct application to the OEB.

90. To determined if it is feasible to blend hydrogen in other areas of Enbridge Gas's system and potentially at an increased blend ratio of hydrogen to natural gas, the Company is proposing a Hydrogen Blending Grid Study (Grid Study).

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[49] EB-2019-1220.

91. These proposals and associated costs and estimated GHG emission reductions are provided at Exhibit 4, Tab 2, Schedule 6.

92. By taking these steps to gain additional experience blending hydrogen, and to understand the feasibility of blending system-wide, Enbridge Gas will ensure that hydrogen blending remains a viable solution for a diversified pathway. As the results of the Grid Study become known, Enbridge Gas may come forward at a future date with specific proposals regarding hydrogen blending.

93. Additional support from the Government of Ontario and from the OEB will be required to implement both wide-scale hydrogen blending and dedicated hydrogen pipelines in the future. Specifically, an expanded mandate for the OEB from the provincial government enabling the OEB to regulate hydrogen pipelines and hydrocarbon pipelines with blended hydrogen would advance and accelerate the use of hydrogen in Ontario in a manner that considers safety, reliability, and customer impacts, and would be in line with and in support of the Provincial hydrogen strategy provided at Exhibit 1, Tab 10, Schedule 6.

Energy Transition Technology Fund (ETTF)

94. Energy sector innovation and technology development is critical for ensuring customers have access to timely and flexible low-carbon solutions. This includes supporting solutions that are not yet readily available in Ontario today, which leverage gas infrastructure and support the diversified pathway.

95. As outlined in the P2NZ Study, low-carbon gases, and the associated technologies will play a meaningful role in a diversified pathway. To maintain consumer choice amidst the transition and to maintain pathway optionality, Enbridge Gas must accelerate the pace of research, development, and commercialization of these low-

carbon technologies in Ontario. To do this, Enbridge Gas is proposing to create an ETTF in the amount of $25M over the period of 2024 to 2028. Full details of the ETTF proposal are provided at Exhibit 1, Tab 10, Schedule 7.

Maintaining the gas delivery system

96. As noted above, uncertainty exists around what GHG emissions reduction targets will be set in Ontario beyond 2030 and how these targets will be met. Both a diversified pathway and an electrification pathway will have impacts on Enbridge Gas's delivery system; therefore, Enbridge Gas must continue to satisfy its obligation to serve the firm demands of its customers in a safe, reliable, resilient, and affordable manner, while also considering both future potential pathways. To do this, Enbridge Gas is:

    a) Considering energy transition related assumptions within the forecasts used to create the AMP; and
    b) Evaluating options that could delay and/or avoid new infrastructure, as doing so could support demand reduction alternatives and/or provide time for greater certainty about which pathway will unfold in Ontario. Enbridge Gas will use IRP to determine if it can delay and/or avoid new infrastructure. IRP has been integrated into the AMP process, including the creation of the new IRP Appendix B in the AMP, provided at Exhibit 2, Tab 6, Schedule 2. This IRP Appendix B will continually evolve.

97. In addition to maintaining the system during the energy transition, Enbridge Gas believes it is prudent to reduce emissions from the Company's operations. Reducing emissions from operations supports the achievement of federal and provincial GHG emission reduction targets in the near and long-term.

98. Enbridge Gas is developing and implementing a scope 1 and 2 GHG emission reduction strategy. The strategy, which is provided at Exhibit 1, Tab 10, Schedule 8, provides an overview of the initiatives identified and evaluated to date. Enbridge Gas will continue to evolve this strategy by identifying cost-effective emission reduction opportunities.

2.6 Summary

99. This ETP has been informed by Enbridge Gas's understanding of current and emerging energy transition and climate policies, stakeholder input and a review of research and studies. Implementing the safe bet actions proposed within this ETP will support an orderly energy transition to net-zero in Ontario; however, a number of these safe bet actions require provincial government and OEB support now to ensure that the appropriate investments are made in new technologies, processes, and infrastructure. Changes to the planning environment, such as changes to existing policies, the development of new policies, setting of provincial targets beyond 2030 and future stakeholder engagement, could influence what Enbridge Gas has laid out in this ETP. At such a time that this occurs, Enbridge Gas may need to adjust the pace, or the actions included in the ETP.

3. Summary of GHG Reductions Driven from Enbridge Gas's (ETP)

100. Following the development of Enbridge Gas's ETP, the Company retained Posterity Group (Posterity) to model a scenario that examines the gas demand and GHG emissions between 2019 and 2050 based on the energy transition initiatives proposed within this rebasing application, as well as energy transition initiatives under review or already approved by the OEB in separate applications (e.g. DSM Plan, LCEP phase 1). The scenario, titled Energy Transition Initiative Scenario (ETI scenario) is included in the Rebasing Scenario Report provided at Attachment 1.

101. The ETI scenario allows Enbridge Gas to compare the GHG emissions reductions achieved from current and proposed initiatives to the province's 2030 GHG reduction target and to a target of net-zero in 2050 and to the scenarios modeled in the ETSA Project (please see Exhibit 1, Tab 10, Schedule 5, Section 1.2). Like the ETSA Project, the ETI scenario is based upon Enbridge Gas's customer gas demand and associated emissions and does not represent economy-wide energy use or emissions for Ontario. The methodology and input assumptions, and how they compare to the ETSA scenarios is provided at Attachment 1, page 5.

102. The results of the ETI scenario show that Enbridge Gas's energy transition initiatives can assist the Company's customers in reducing GHG emissions by five million tCO_2e per year by 2030.[50] This represents a significant contribution towards meeting 2030 Ontario's GHG emission reduction target (please see Section 2.4 for further discussion of Ontario's target).

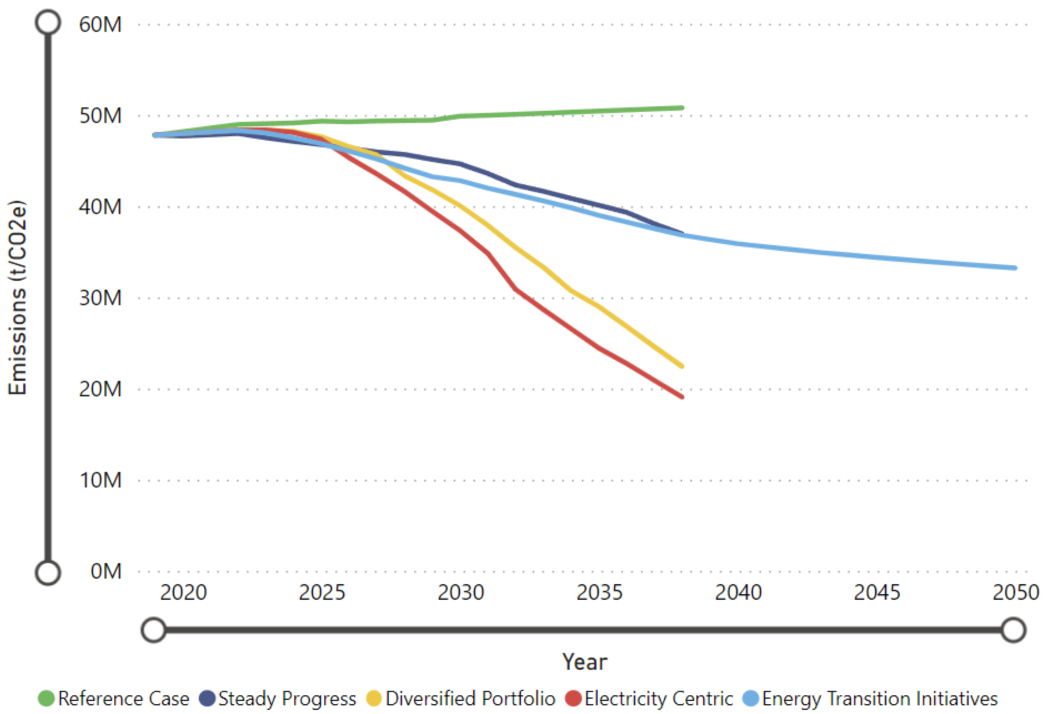
103. By 2050, the ETI scenario shows Enbridge Gas's customer GHG emissions are reduced to 33 million tCO_2e[51] which represents a GHG emission reduction of 30% between 2019 and 2050. While this is a significant reduction, in this scenario Ontario will fall short of achieving net-zero by 2050 unless additional actions are undertaken.

104. By contrast, the Diversified Portfolio scenario in the ETSA Project shows Enbridge Gas customer emissions could be decreased to 22 million tCO_2e in 2038, representing a GHG reduction of 53% over this time and on trajectory to achieve

[50] With the changes in RNG percentage in the LCVP from five to four percent by 2028, an estimated 0.2 million $tCO2_e$ fewer GHG emission reductions are expected to occur in 2030.
[51] In 2050, an additional 0.18 million $tCO2_e$ of GHG emissions are expected from changing the RNG percentage from five to four.

2050 net-zero emission needs. Figure 1 provides a comparison of the GHG emissions for the ETI and ETSA scenarios, which are provided at Attachment 1, page 22.

Figure 1: Annual GHG Emissions by Scenario



105. Figure 1 demonstrates that Enbridge Gas's current and proposed energy transition initiatives will make a meaningful impact on GHG emissions in Ontario, including achieving the 2030 GHG emission reduction target, and making a significant contribution to achieving net-zero in the future. However, these initiatives on their own will not be enough to achieve Enbridge Gas's vision of a diversified pathway to net-zero.

4.Evolution of Enbridge Gas's Energy Transition Plan (ETP)

106. As noted above, the Ontario Electrification and Energy Transition Panel is completing a pathways report that will provide advice to the Minister of Energy on how to coordinate long-term energy planning, considering growing energy demand, low-carbon fuel switching and emerging technologies. Completion of this work is critical, as it will provide market signals for the long-term development of Ontario's energy sector. When the pathways report is completed (entire project to be completed by February 2024, main analysis examining cost-effective pathways to be completed by September 2023[52]), Enbridge Gas will further evolve its ETP to reflect its findings.

107. While Enbridge Gas awaits the above noted provincial energy transition policy work, it remains dedicated to implementing those ETP safe bet actions that are approved and to evolving elements of its ETP that are not entirely dependent upon future government policy, plans and targets. These elements of the ETP include evolving:

a) Stakeholder engagement – Enbridge Gas will continue to evolve its stakeholder engagement processes to obtain energy transition insights that can be considered within its forecasts. This will help to ensure that the investments included within Enbridge Gas's AMP properly reflect the energy needs within each region and that IRP alternatives are properly evaluated. In addition to IRP stakeholder engagement activities, the Company intends to continue gathering additional energy transition insights via its direct engagement with municipalities and Indigenous communities, and via its engagement with other key stakeholders and market participants in industry

[52] Ontario Tenders Portal. Cost-Effective Energy Pathways Study for Ontario. https://ontariotenders.app.jaggaer.com/esop/toolkit/opportunity/past/116724/detail.si

associations, customer meetings (e.g. distribution contract customers via sales representatives), DSM engagements, and Leave-To-Construct (LTC) community outreach. As required under the IRP Framework[53] [54] Enbridge Gas will implement a regional and geo-targeted stakeholder engagement plan, including separate indigenous engagement sessions. Enbridge Gas will gather energy transition related insights during these engagements that can be considered within the Company's forecasts;

b) IRP – Enbridge Gas will continue to evolve its IRP alternative evaluation processes and will implement an IRP alternative wherever technically and economically feasible; and

c) Coordination with the electricity sector – Enbridge Gas will explore ways to advance integrated and optimized energy transition planning with the IESO and local electricity utilities.

108. Enbridge Gas will also continue to evolve how it maintains its system amidst pathway uncertainty. Enbridge Gas will continue to satisfy its obligation to serve the firm demands of its customers in a safe, reliable, resilient, and affordable manner, while also considering future potential energy transition pathways.

[53] EB-2020-0091, Decision and Order, Section 10, pp.63-67.
[54] Ibid, Section 11, pp.68-70.

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Rebasing Scenario Report

Energy Transition Scenario Analysis

September 22, 2022

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Contents

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Executive Summary

Enbridge Gas Inc. (Enbridge Gas) retained Posterity Group Consulting (PG) to conduct the Energy Transition Scenario Analysis (ETSA) project. The ETSA project provided Enbridge Gas with four theoretical scenarios of the future to help assess the impacts from climate policies and economic conditions that Enbridge Gas' system could experience over the next 20 years. Following the completion of the ETSA project, an additional "Energy Transition Initiative" (ETI) scenario was created to support Enbridge Gas' rebasing plans. The ETI scenario reflects the proposed 2024 rebasing application, and this report documents how it was created and discussed the key results.

The following are some key results of the ETI scenario:

- While the energy demands of the ETI and the Diversified Portfolio scenarios are similar over the modeled periods, there are distinct differences in end-user gas volume demands and greenhouse gas (GHG) emissions between the scenarios;
- Annual gas volume decreases 8% by 2030, 21% by 2038, and 29% by 2050, relative to 2019 in the ETI scenario, whereas an overall increase in annual gas volume is observed in the Diversified Portfolio scenario. The increasing annual gas volumes observed in the Diversified Portfolio scenario are attributed to comparatively higher proportions of hydrogen being blended into the gas distribution network, in relation to the ETI scenario where the introduction of hydrogen is limited to proposed Phase 2 of the Low Carbon Energy Project;
- End-user GHG emissions decrease 10% by 2030, 23% by 2038 and 30% by 2050 relative to 2019 in the ETI scenario. While the reduction in GHG emissions is similar between the ETI scenario (5.0 Mt CO2/yr) and the Diversified Portfolio scenario (7.7 Mt CO2/yr) in 2030, the trajectory of GHG emission reductions diverges between the scenarios after 2030. This divergence is attributed to deployment of carbon capture and sequestration, and the continued introduction of RNG and hydrogen in the Diversified Portfolio scenario at rates that go beyond the proposed initiatives in the rebasing application as reflected in the ETI scenario; and,
- The 2050 end-user GHG emissions were modeled at 33 Mt CO2/yr, with the annual gas volumes being composed of 97% natural gas, about 3% RNG, and <1% of hydrogen in the ETI scenario. In contrast, the 2038 end-user emissions for the Diversified Portfolio Scenario were 22 Mt CO2/yr, which highlight the emission reduction effectiveness of measures assumed within the Diversified Portfolio scenario.

1 Introduction

Enbridge Gas Inc. (Enbridge Gas) retained Posterity Group Consulting (PG) to work on the Energy Transition Scenario Analysis (ETSA) project. The ETSA project provides Enbridge Gas with theoretical scenarios of the future to help assess the impacts from climate policies and economic conditions that Enbridge Gas' system could experience over the next 20 years. The project and the underlying model are not intended to replace Enbridge Gas' current forecasting methods and are to be used for illustrative purposes only. Initially, four scenarios of future gas demand and greenhouse gas (GHG) emissions were developed. An additional "Energy Transition Initiatives (ETI)" scenario has been created to support Enbridge Gas' rebasing plans. This report documents the process to develop the ETI scenario and discuss the results.

1.1 Objectives and Outcomes

For the ETSA project, PG supported Enbridge Gas by modeling future load and associated customer emissions at the granular level of energy end-uses, different building types, rate classes, and regions. System load and customer emissions were forecasted under several scenarios to explore various possible economic and policy conditions under which Enbridge Gas may operate. The four scenarios developed were the Reference Case, Steady Progress, Electricity Centric, and Diversified Portfolio. For details of how these scenarios were developed and the results of the modelling, please see the ETSA Study Report.

PG developed the ETI scenario for Enbridge Gas to complement the four scenarios produced for the ETSA project. The ETI scenario demonstrates how Enbridge Gas' rebasing plans will support the provincial government's environmental commitments. The ETI scenario contains many of the same assumptions as the Diversified Portfolio scenario, with the following key modifications:

- Adjusted the volumes of renewable natural gas (RNG), hydrogen and carbon capture and sequestration (CCS) to align with Enbridge Gas' rebasing application forecasts for low carbon gases.
- Extended the forecast end date from 2038 to 2050, and extrapolated trends using a similar approach to Guidehouse's "Pathways to Net-Zero for Ontario" study to align with the scenarios they developed for Enbridge Gas that go to 2050.

The "Pathways to Net-Zero for Ontario" study provides an economy-wide analysis of the Diversified Portfolio and Electricity Centric scenarios modeled in the ETSA project. Since the study takes an economy-wide approach and includes energy demand and emissions that are outside of the scope of the ETSA project and the ETI scenario (i.e., transportation and hydrogen production), a direct comparison of results is not appropriate.

This document details the method used to create the ETI scenario including data inputs, assumptions, and modelling approach, and summarizes the results. Please see the ETSA Study Report for more context on the project and further details on the model data inputs and modelling method.

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2 Method for Developing the ETI Scenario

The ETI scenario is mainly based on the Diversified Portfolio with some specific modifications that reflect energy transition initiatives proposed in Enbridge Gas' rebasing application. The ETI scenario reflects a future where GHG reductions are achieved by some decarbonization of the gas grid in combination with electrification in specific sectors. In contrast, the Diversified Portfolio is intended to represent one possible pathway to achieve net zero by 2050 and assumes innovation in electrical storage, hydrogen equipment, carbon capture and sequestration (CCS), and low-carbon fuels. Policies assumed to support both scenarios include the 2020 Federal Climate Action Plan, the Clean Fuel Regulation, and more stringent building codes including for new construction and retrofits. The ETI scenario has limited deployment of hydrogen, RNG, and CCS unlike the Diversified Portfolio scenario. This section details how the ETI scenario was developed.

2.1 Changes to Input Assumptions in the ETI scenario compared to the Diversified Portfolio scenario

The following changes were made to the Diversified Portfolio scenario to create the ETI scenario:

- Removed CCS due to current uncertainty over when and how it will be implemented in Ontario.
- Updated RNG and hydrogen volumes to align with Enbridge Gas' proposals in the rebasing application.
- Adjusted demand-side management (DSM) program spending to be a 3% increase year-over-year (similar to application EB-2021-0002 currently in front of the Ontario Energy Board).
- Extended the forecast end year to 2050 using trends developed by Guidehouse (ETSA scenario forecast period was 2020 to 2038).

For the remaining model inputs, Guidehouse provided direction on how to extend trends to 2050 based on their approach to model scenarios for the "Pathways to Net-Zero for Ontario" study. The following content explains how each model input/assumption was extrapolated to 2050:

- 'Enbridge ETI Scenario - extending trends to 2050 - Guidehouse input' memo summarizes Guidehouse's approach. Guidehouse projections for hydrogen and RNG were not used, because Enbridge Gas provided PG with hydrogen and RNG forecasts out to 2050.
- Sections 2.3, 2.4, and 2.5 details how PG calibrated the ETSA model to align with the forecast produced by Guidehouse.
- Section 2.6 explains how hydrogen was treated by sector.
- Section 2.7 describes the method used to calculate DSM savings.

2.2 Critical Driver Adjustments

The ETSA scenarios were built by combining various 'settings' (e.g., low, high, accelerated) of 'Critical Drivers' (i.e., model variables) to create distinct narratives of potential futures. Please see the ETSA study report for a description of each Critical Driver and their settings. Exhibit 1 summarizes the setting for each Critical Driver used for the Diversified Portfolio scenario and the ETI scenario for comparison, and the corresponding modelling approach for the ETI scenario.

Exhibit 1 - ETI Scenario Input Assumptions & Modeling Approach

Critical Driver	Diversified Portfolio Scenario Input Assumptions	ETI Scenario Input Assumptions	ETI Scenario Modeling Approach
Carbon & Natural Gas Commodity Price	Moderate • $15/tonne CO2e annual increase beyond 2022 • $170/tonne CO2e by 2030 $200/tonne CO2e in 2038	Same as Diversified Portfolio Scenario input assumption	• The moderate carbon price for 2038-2050 was extrapolated assuming it continues to increase at a rate of 2% from 2038 onwards. The moderate carbon price forecast (the forecast used in the Diversified Portfolio scenario) was developed by Enbridge Gas and PG based on federal announcements as of late 2020. • Natural gas commodity prices were extended from 2038-2050 using a growth rate of 2.1%. This value corresponds to the rate from 2035, the last available projection year in the consensus Dawn Hub increase provided by Enbridge Gas in the 'Driver Variables.xlsx' workbook.
Customer Account forecast	Reference case for all sectors.	Reference case for all sectors.	• Residential accounts were extrapolated to 2050 using a linear

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Critical Driver	Diversified Portfolio Scenario Input Assumptions	ETI Scenario Input Assumptions	ETI Scenario Modeling Approach
			projection of the trend from 2019-2038. • Commercial and industrial accounts were extrapolated to 2050 using a linear projection of the trend from 2034-2038.
Non-price driven fuel switching	New Construction (**Residential, Commercial sectors**) • Starting in 2030, 10% of new residential and commercial buildings across the province do not connect to the gas grid in select communities (due to policy or incentives); by 2038, 20% of new construction don't connect Existing Buildings (**Residential, Commercial sectors**) • Starting in 2026, province wide, 10% of gas-fired space & water heating equipment that is being replaced annually (due to equipment reaching end-of-life) is replaced with electric equipment (due to policy or incentives). • 10% of the customers installing new electric space heating equipment will disconnect from the gas system (the assumption is these	• Same as Diversified Portfolio Scenario input assumption	New Construction (**Residential, Commercial sectors**) • Starting in 2030, 10% of new residential and commercial buildings do not connect to the gas grid. By 2038, 20% of new construction does not connect. • After 2038, the number of new residential buildings that do not connect grow using a 2019-2038 linear projection of the trend. • After 2038, the number of new commercial buildings that do not connect grow using a 2034-2038 linear projection of the trend. Existing Buildings (**Residential, Commercial sectors**) • 10% of gas-fired space & water heating equipment is being replaced annually, a trend which was carried from 2026-2050.

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Critical Driver	Diversified Portfolio Scenario Input Assumptions	ETI Scenario Input Assumptions	ETI Scenario Modeling Approach
	customers only have 1 gas appliance)		• 10% of the customers installing new electric space heating equipment will disconnect from the gas system, a trend which was carried from 2026-2050.
Codes & Standards	High Stringency: • High stringency codes and standards lowers overall gaseous demand • NECB code: Tier 2 (2025), Tier 3 (2030), Tier 4 (2035) • NBC code: Tier 3 (2025), Tier 4 (2030), Tier 5 (2035) • Retrofit code implemented	Same as Diversified Portfolio Scenario input assumption	• Codes and standards effect unit energy consumption (UEC) therefore UECs were extended to 2050 based on Guidehouse direction (see Section 2.3).
RNG supply	**High setting:** • Renewable content policies build demand for RNG (please see ETSA report for more details)	RNG supply forecast representing rebasing application proposal: • 2019-2023 blend percentages: reference case • 2024: 1% for the 47.1% system supply customers • 2025: 2% for the 46.8% system supply customers • 2026: 3% for the 45.5% system supply customers	• Calculated the total amount of fuel consumption per sector for each year between 2019-2050. • Enbridge Gas provided RNG blend percentages and system supply percentages which were multiplied together and used to determine the RNG target volumes by sector. • Note that the system supply percentage was applied equally to all sectors as a simplifying

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Critical Driver	Diversified Portfolio Scenario Input Assumptions	ETI Scenario Input Assumptions	ETI Scenario Modeling Approach
		• 2027:4% for the 45.5% system supply customers • 2028 – 2050: 5% for the 45.5% system supply customers	assumption. This may result in more RNG going to the industrial sector.
Hydrogen supply	**High:** • Renewable content policies build demand for hydrogen • Hydrogen strategy overcomes equipment barriers (see ETSA report for more details) • **Residential, Commercial Sectors**: blended the hydrogen into the residential and commercial sectors without differentiation between those with dedicated hydrogen and those with a 10% blend. • **Industrial Sectors**: all end-uses, except for 'other process' because this includes direct feedstock uses. Hydrogen is deployed in the following segments: 'Agriculture', 'Fabricated Metals Mfg', 'Food and Beverage Mfg', 'Plastic and Rubber Mfg', 'Pulp; Paper; and Wood Products Mfg', 'Transportation and Machinery Mfg', 'Water & Wastewater Treatment'	• Represents Phase 1 and the proposed Phased 2 of Low Carbon Energy Project (LCEP) Hydrogen as forecasted from Enbridge Gas Annual Hydrogen Demand (m3/year): 2022-2024 175,148 2025-2050 778,437 •	• Hydrogen is only delivered to the residential and commercial sectors. • Enbridge Gas provided hydrogen volumes which were divided proportionally between commercial and residential customers based on the fraction of combined overall volume in both sectors.

Critical Driver	Diversified Portfolio Scenario Input Assumptions	ETI Scenario Input Assumptions	ETI Scenario Modeling Approach
	• Industrial segments start converting in 2030 and convert at rate of equipment turnover **Transportation Sector**: See ETSA report for further details		
Climate change/weather	Intergovernmental Panel on Climate Change Scenario RCP 2.6 - Global GHG emissions result in 1-2.5C of warming by 2100	Same as Diversified Portfolio Scenario input assumption	• Changes in temperature due to climate change are reflected in adjusting space heating energy requirements. • UEC was extended to 2050 based on Guidehouse direction (see Section 2.3).
Carbon capture & sequestration	CCS included as a fuel	No CCS	CCS excluded as a fuel.
Natural gas transportation	CER Reference Forecast • Compressed Natural Gas (CNG) replaces diesel used in heavy duty transportation. CNG demand is modelled as an increase in volume and emissions on Enbridge Gas' system.	Same as Diversified Portfolio Scenario input assumption	• Hydrogen excluded as a fuel from transportation (and industrial sector). • Trend from 2034-2038 used to project transportation accounts from 2038-2050; transportation UECs kept constant. • Used natural gas transportation volume forecast from 2020 to 2040; from 2041-2050 we extrapolated account growth using 2034-2038 linear projection. • Transportation is a segment within the industrial sector.

Critical Driver	Diversified Portfolio Scenario Input Assumptions	ETI Scenario Input Assumptions	ETI Scenario Modeling Approach
DSM Spending	Starting with $132 million in 2019, increasing by 3% from 2021-2027 and then increasing by 10% in 2028-2038.	Start with $132 million in 2021, then 3% increase over inflation every year from 2022 to 2050.	Starting in 2022, increase budget spending 3% every year until 2050[1].

[1] Dollar values are used in real terms (not nominal) so inflation is excluded.

2.3 Unit Energy Consumption Extrapolation

Unit energy consumption (UEC) is the annual average energy consumption for an end-use in a building with that end-use. UECs were previously calculated in the Diversified Portfolio scenario between 2019 and 2038.

For the ETI scenario, UEC's from 2038 to 2050 were extrapolated based on the Guidehouse direction provided in the memo 'Enbridge ETI Scenario - extending trends to 2050 - Guidehouse input'.

While Guidehouse extrapolated consumption, PG extrapolated UEC as a proxy for consumption:

Consumption = UEC x End Use Count

PG extrapolated UEC inputs because consumption is an output of our model and cannot be extrapolated. Guidehouse's extrapolation of consumption is equivalent to extrapolating UEC and End Use Count (see Section 2.4). Exhibit 2 shows the methods applied to extend the UECs for each sector from 2038 to 2050.

Exhibit 2 - UEC Projections for 2038-2050

Sector	Projection Method
Residential	Extended to 2050 using 2019-2038 linear projection.
Commercial	Extended to 2050 using 2019-2038 linear projection.
Industrial	Extended to 2050 using 2034-2038 linear projection.

2.4 End-Use Count Extrapolation

Guidehouse extrapolated the Diversified Portfolio scenario using this output. End-use count is a factor of the number of units (e.g., dwellings), end-use market saturation, and fuel share:

End-Use Count = Units x Saturation x Fuel Share

Fuel shares were adjusted to calibrate the ETI scenario, matching the extrapolated forecast Guidehouse produced:

- *Units and Fuel Share extrapolated:* To mirror the revisions Guidehouse made using PG's bottom-up end-use modelling method, we extrapolated unit and fuel share assumptions, then held the end-use saturation constant.
- *Calibrated with Fuel Share:* We modified fuel share to calibrate end-use count outputs as closely as possible to Guidehouse's data, for each sector. The most accurate outputs we generated contained minor deviations from Guidehouse's forecast in some years of the model (including pre-2038 years).

2.5 Industrial Electrification Assumptions

Guidehouse assumed that the HVAC, Process Cooling and Other Process end-uses fully electrify by 2050 in the Diversified Scenario.

HVAC and Process Cooling are electrified in the ETI scenario, except for a few specific industrial segments. Exhibit 3 presents the segments where the HVAC and Process Cooling end-uses do not fuel switch (electrification occurs in remaining segments and at the rate of equipment turnover). To be consistent with the Diversified Portfolio scenario modelling method, these segments are not electrified because their base year natural gas fuel shares are very close to 0% or 100%. If a fuel share is close to 0% or 100%, it is assumed that the end use cannot easily fuel switch (relative to those with a fuel share near 50%).

Exhibit 3 – Segments where HVAC and Process Cooling End uses are not Electrified

End-Use	Non-Electrified Segments
HVAC	Petroleum Manufacturing Water & Wastewater Treatment
Process Cooling	Non-metallic Minerals Product Manufacturing Other Industrial Primary Metals Manufacturing Transportation and Machinery Manufacturing Water & Wastewater Treatment

We also assume the Other Process end use cannot fuel switch because it is an end-use category that includes natural gas used in industrial processes instead of for combustion.

2.6 Hydrogen Distribution by Sector

Hydrogen volumes are modelled at the sector level and are allotted to commercial and residential sectors and excluded from the industrial sector, as to reflect the customers present within the Phase 1 and proposed Phase 2 of Enbridge Gas' Low Carbon Energy Project (LCEP). Enbridge Gas provided PG with volume (m^3) of hydrogen by year which was incorporated into the ETI scenario. Hydrogen was distributed to the residential and commercial sectors proportionally based on the fraction of combined overall consumption of both sectors. Although hydrogen is delivered to residential and commercial customers via regional hydrogen loops, time and budget constraints prevented modelling the deployment of hydrogen to specific regions.

2.7 Demand-Side Management

DSM potential was estimated for the ETI scenario based on the DSM budget amount using the following steps:

- Determine the avoided cost based on the gas price and carbon price.

- Apply the Total Resource Cost (TRC) effectiveness test to determine which measures are cost-effective.
- Update the payback acceptance curves based on the avoided costs and the resulting measures that pass the economic screen.
- Define the DSM budget in each year, and then solve for the combination of measures and incentive levels that provide the most savings in each year within that year's budget.
- Apply the energy savings potential.

Measure input assumptions were primarily from the Achievable Potential Study, with some adjustments made to specific measures in collaboration with Enbridge Gas. DSM is applied to all segments except for Transportation.

3 Results and Analysis

This section summarizes the results of the ETI scenario and compares the ETI scenario to the Diversified Portfolio scenario and Reference Case scenario.

3.1 ETI Scenario Results

This section summarizes the results of the ETI scenario for annual volume, hourly and daily peaks, and GHG emissions. This scenario is derived from the Diversified Portfolio scenario, as described in Section 2.1.. Please refer to the ETSA Study Report for the other ETSA scenario results.

3.1.1 Annual Volume and Energy

In the ETI scenario, annual gas volume decreases 8% by 2030, 21% by 2038, and 29% by 2050, relative to 2019. The decrease in volume over the forecast period is a result of higher carbon price and non-price driven fuel switching, high stringency codes and standards, and DSM programming. Similarly, annual gas energy demand decreases 8% by 2030, 21% by 2038, and 29% by 2050, relative to 2019.

Exhibit 4 and Exhibit 5 provide annual volume composition by fuel in 2019, 2030, 2038, and 2050.

Exhibit 4 - ETI Scenario: Annual Volume Composition by Fuel (m^3) in 2019, 2030, 2038, and 2050

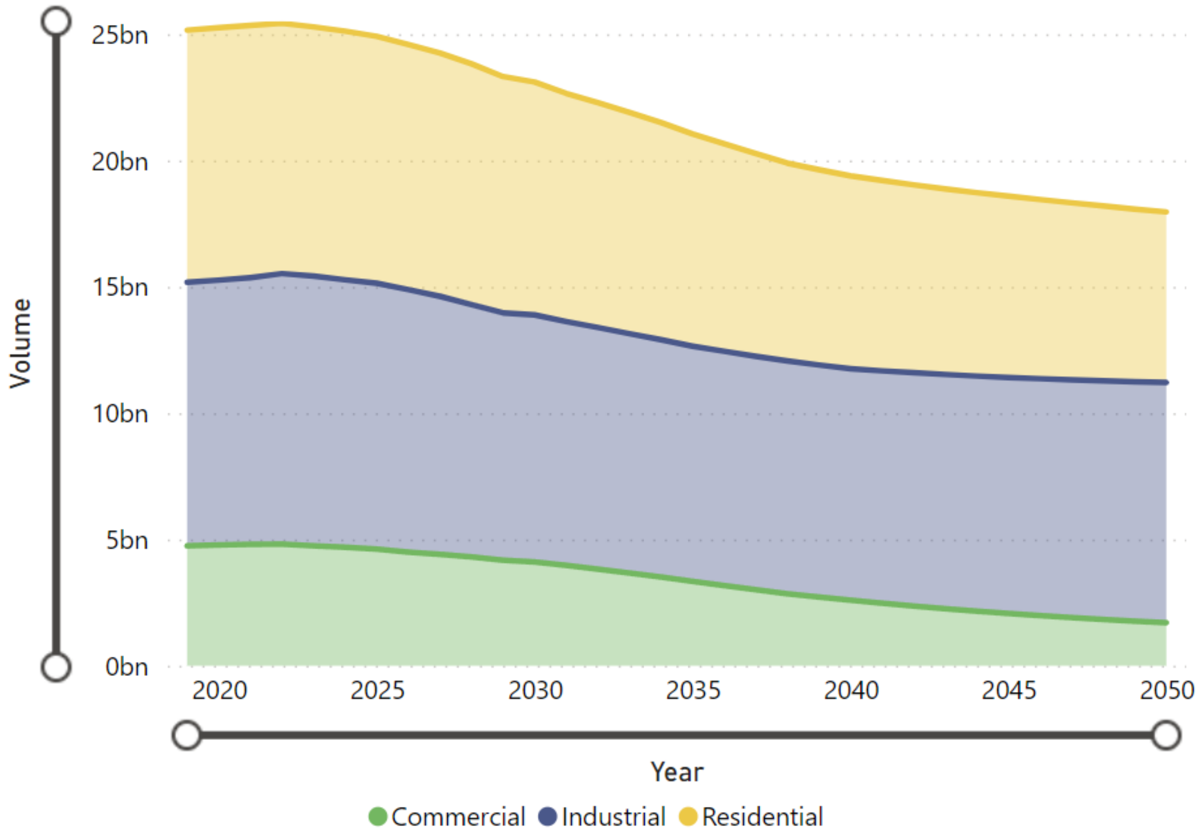
Year	Hydrogen	Natural Gas	Renewable Natural Gas	**Total**
2019		25,162,582K		**25,162,582K**
2030	778K	22,537,140K	568,418K	**23,106,336K**
2038	778K	19,391,669K	506,630K	**19,899,077K**
2050	777K	17,486,670K	479,480K	**17,966,926K**

Exhibit 5 - ETI Scenario: Annual Volume Composition by Fuel (%) in 2019, 2030, 2038, and 2050

Year	% Hydrogen Volume	% Natural Gas Volume	% RNG Volume
2019	0%	100%	0%
2030	<1%	98%	2%
2038	<1%	97%	3%
2050	<1%	97%	3%

Exhibit 6 presents annual volume by sector.

Exhibit 6 - ETI Scenario: Annual Volume by Sector (m^3)



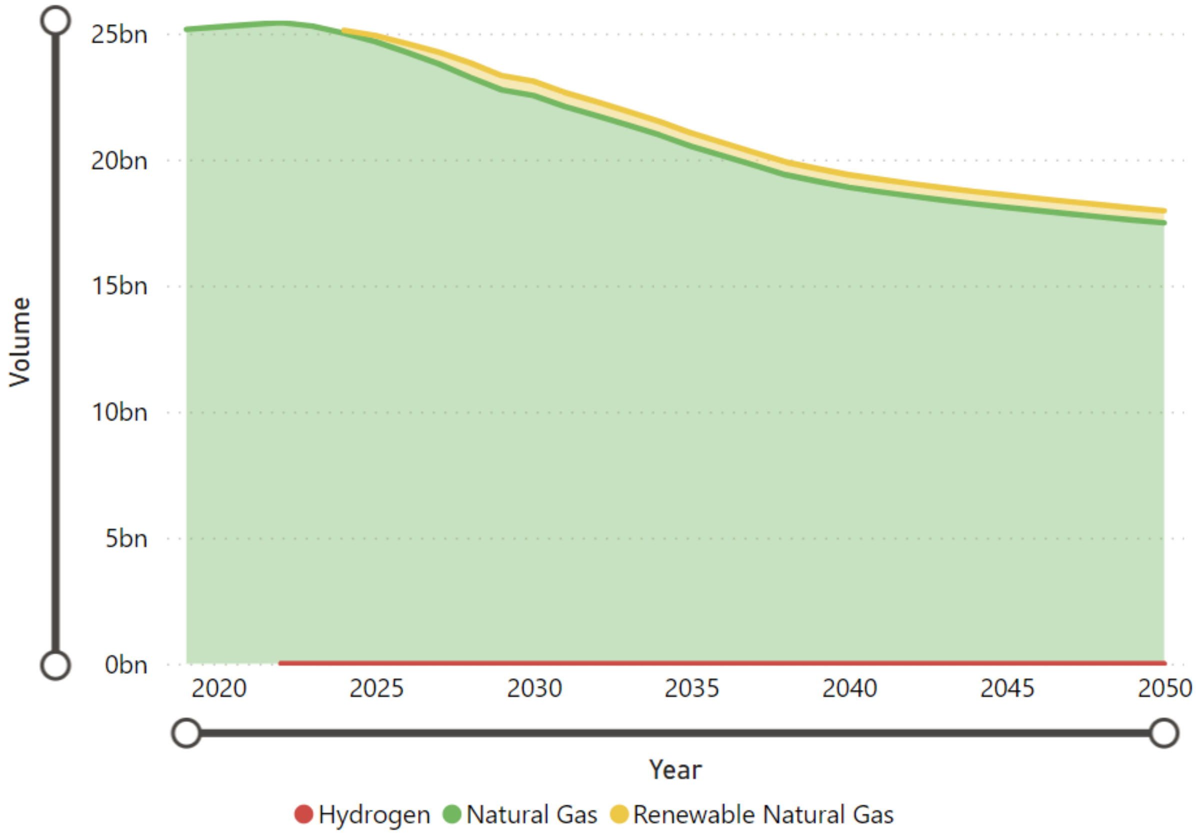
Residential, commercial, and industrial volumes decrease 23%, 40%, and 12% by 2038, respectively. By 2050, residential and commercial volumes fall by 32% and 64%, while industrial volume increases slightly to 9% below 2019 volumes.

The residential and commercial sectors follow similar timeline trajectories for codes and standards but are impacted differently: The National Energy Code for Buildings ('NECB', applicable to the commercial sector) and National Building Code ('NBC', applicable to the residential sector) have different savings assumptions, where improvements to commercial facilities are expected to be higher (as a percentage compared to current code) than residential improvements over the forecast period. For example, under the high stringency performance targets, the first round of upgrades for building codes occurs in 2025, where the required savings over code are 14% higher for commercial buildings compared to residential buildings. The next round of code changes in 2030 are even more significant.

The industrial sector experiences the least decline in volume compared to the other two sectors. While fuel switching and DSM reduce volumes, the growth in demand from the Transportation segment contributes to an increase in volumes which outpaces sector wide volume declines by 2040.

Exhibit 7 presents annual volume by fuel.

Exhibit 7 - ETI Scenario: Annual Volume by Fuel (m^3)



Natural gas volume decreases 23% by 2038 and 31% by 2050, compared to 2019. The decline is due to a combination of critical drivers which lower natural gas demand: higher carbon price and non-price driven fuel switching, high stringency codes and standards, and DSM programming. The ETI scenario fuel mix is primarily natural gas, with some hydrogen and RNG replacing natural gas over the forecast period. From 2038 to 2050, the annual fuel volumes remain relatively consistent with 97% natural gas, less than 1% hydrogen, and 3% RNG.

3.1.2 Peak

Decreased natural gas demand cause the peak hour to decrease 37% by 2038 and 50% by 2050, as seen in Exhibit 8 below. Hydrogen volumes are not significant enough to case a meaningful impact to peak.

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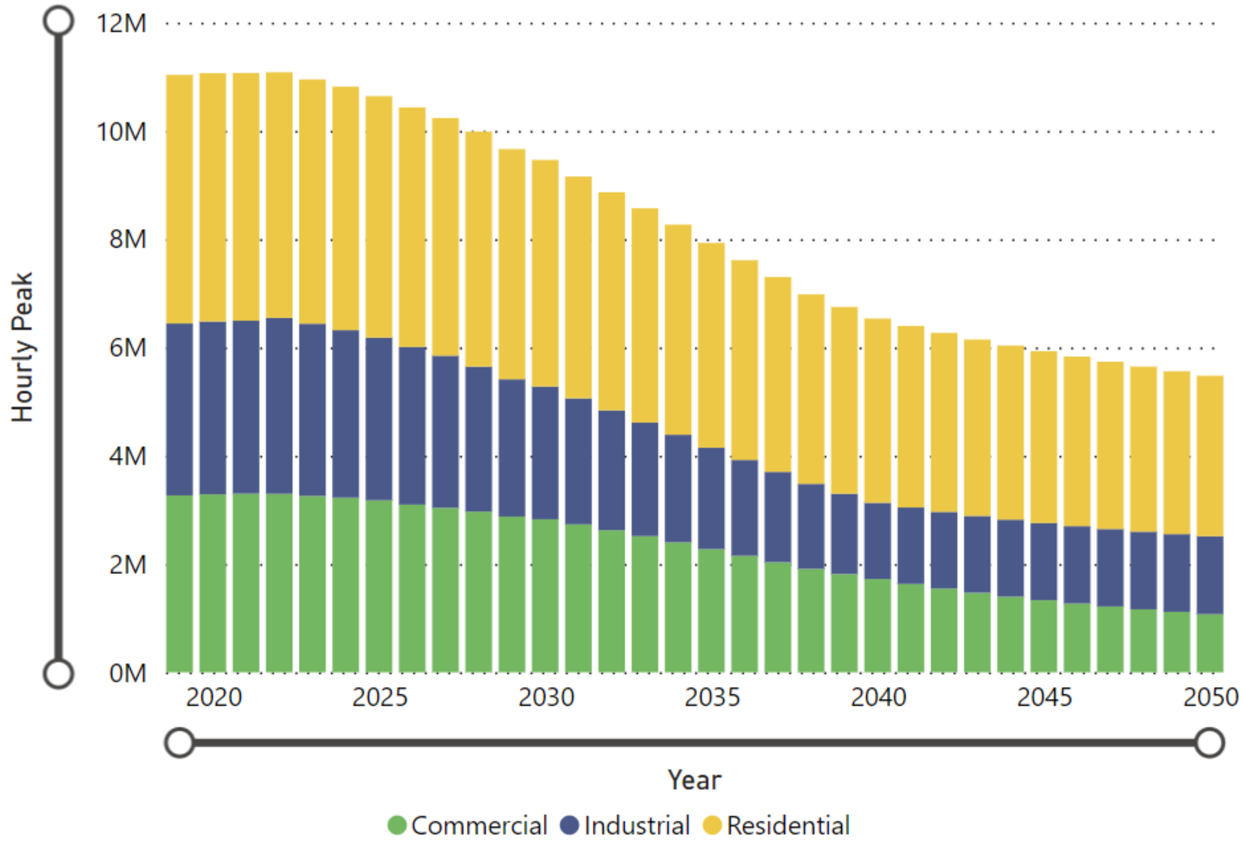
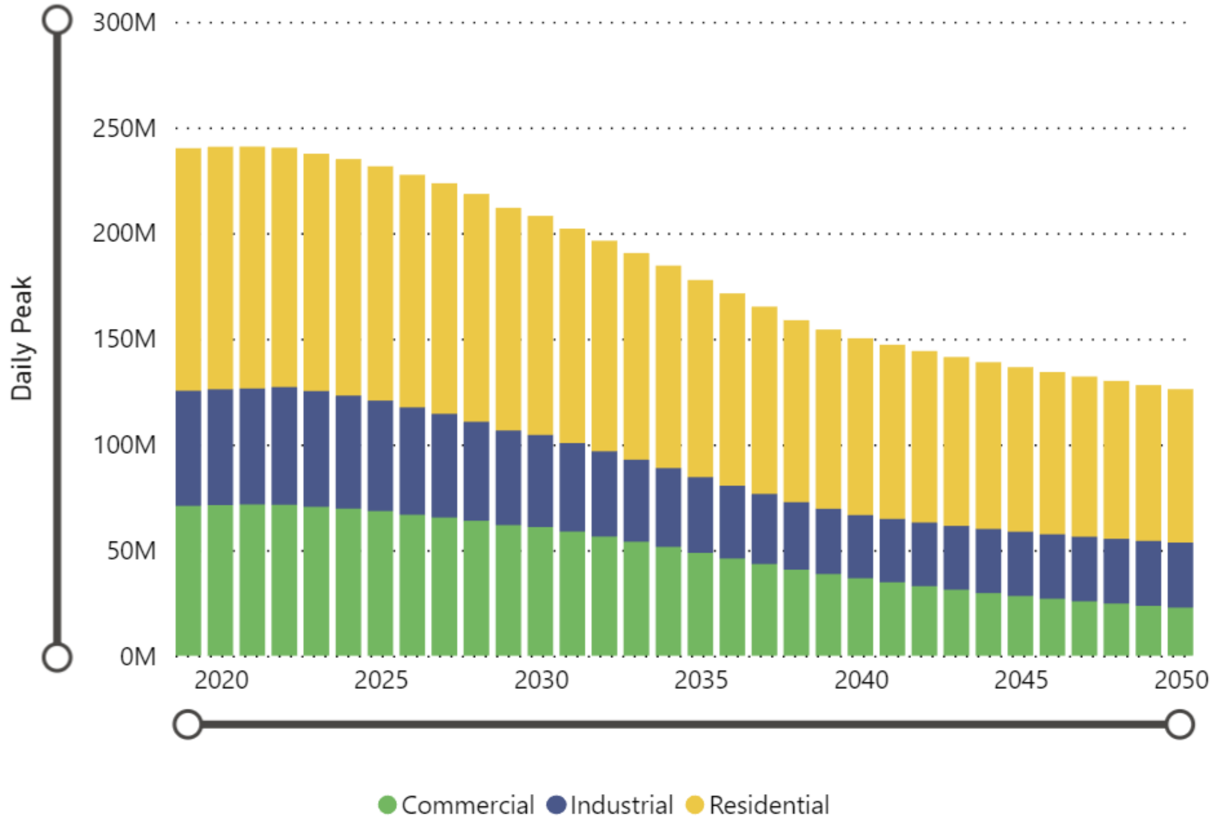
Exhibit 8 - ETI Scenario: Peak Hour by Sector (m³/hour)



The hourly peak decreases in all three sectors by 2050: 35% in residential, 67% in commercial, and 55% in industrial. Hourly peaks in all sectors are decreased because of DSM spending and fuel switching. Increasingly stringent building codes cause peak hour to decrease most significantly in the commercial sector by 2050. The industrial sector hourly peak declines due to electrification of the HVAC end-use. If HVAC is excluded, the peak hour increases over the forecast period.

Exhibit 9 presents peak day by sector.

Exhibit 9 - ETI Scenario: Peak Day by Sector (m^3/day)



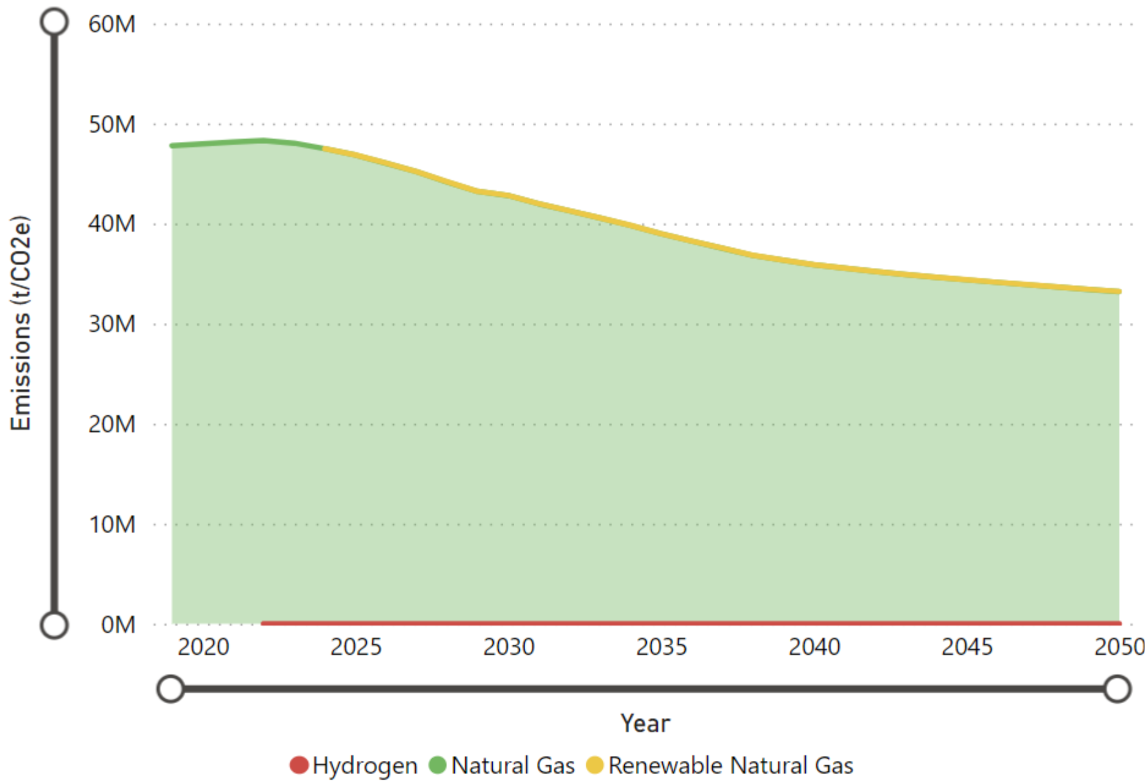
The daily peak decreases 37%, 68%, and 43% in the residential, commercial, and industrial sectors, respectively, by 2050. Similar to hourly peak, daily peak in all sectors decreases because of DSM programming and fuel switching. Increasingly stringent building codes cause peak day to decrease most significantly in the commercial sector by 2050.

3.1.3 End-User GHG Emissions

In the ETI scenario, end-user GHG emissions decrease 23% by 2038, and 30% by 2050, relative to 2019. Emissions decline because of decreased natural gas demand from stricter codes and standards, DSM spending, and fuel switching to electricity due to policies and increasing carbon prices. RNG and hydrogen displacing natural gas also contribute to emission reductions.

Exhibit 10 presents GHG emissions by fuel.

Exhibit 10 - ETI Scenario: Annual GHG Emissions by Fuel (t/CO_2e)



Nearly all GHG emissions are from natural gas, since RNG emissions are minimal (low volume and end-user emission factor), and end-user emissions from hydrogen are zero.

Exhibit 11 and Exhibit 12 provide GHG emissions by fuel in 2019, 2030, 2038, and 2050.

Exhibit 11 - ETI Scenario: GHG emissions by Fuel (t/CO_2e) in 2019, 2030, 2038, and 2050

Year	Hydrogen	Natural Gas	Renewable Natural Gas	**Total**
2019		47,792,674		**47,792,674**
2030	0	42,806,028	6,454	**42,812,482**
2038	0	36,831,665	5,753	**36,837,418**
2050	0	33,213,393	5,444	**33,218,837**

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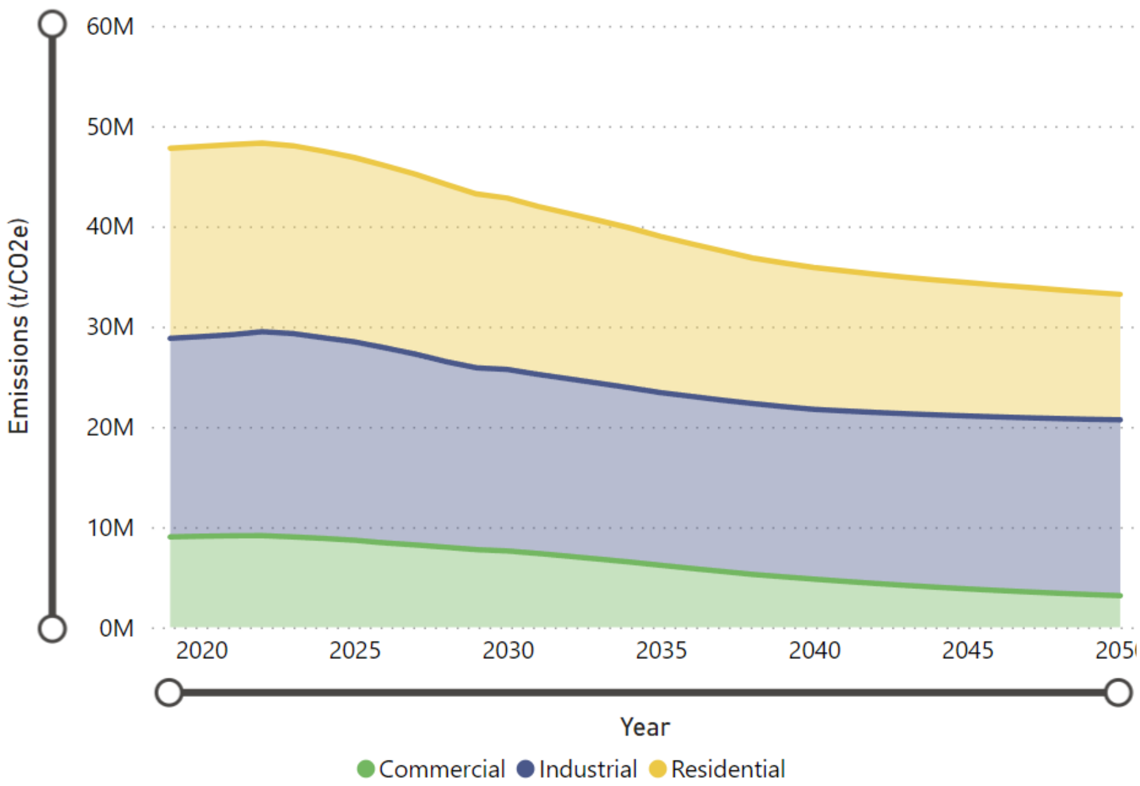
Exhibit 12 - ETI Scenario: GHG emissions by Fuel (%) in 2019, 2030, 2038, and 2050

Year	% H2 Emissions	% Natural Gas Emissions	% RNG Emissions
2019	0%	100%	0%
2030	0%	99.9%	<0.1%
2038	0%	99.9%	<0.1%
2050	0%	99.9%	<0.1%

Exhibit 13 presents GHG emissions by sector.

Exhibit 13 – ETI Scenario: Annual GHG Emissions by Sector (t/CO_2e)



Each sector sees GHG emission decline by 2050. The residential, commercial, and industrial sector emissions decrease 34%, 65%, and 11%, respectively, by 2050. The industrial sector emissions decrease the least relative to the other sectors because the sector does not receive hydrogen and sees an increase in volumes from the Transportation segment.

4 Scenario Comparison: ETI, Diversified Portfolio, and Reference Case

This section compares the ETI scenario to the Diversified Portfolio and Reference Case scenarios in terms of annual energy demand and volume, and end-user GHG emissions. The ETI scenario forecast periods ends in 2050, while the Diversified Portfolio scenario and Reference Case go to 2038, therefore comparison is only possible until 2038. Although the assumptions for the ETI and Diversified Portfolio scenarios are similar, the results differ due to differences in alternative fuel volumes and modeling methods. These differences are discussed briefly in the sub-sections below. Please refer to the ETSA Study Report for details on the results of all the ETSA scenarios.

4.1 Energy and Volume

Annual energy demand in the ETI scenario is slightly lower than in the Diversified Portfolio demand over the forecast period because of minor differences introduced from extrapolation and calibration activities. Appendix A provides further details on these differences.

Exhibit 14 compares the energy demand change relative to 2019 for the Reference Case, Diversified Portfolio, and ETI scenarios.

Exhibit 14 – Energy Demand in ETI and Diversified Portfolio Scenarios (GJ)

	2019		2030		2038		2050	
Scenario	Energy Demand (GJ)	% Change from 2019	Energy Demand (GJ)	% Change from 2019	Energy Demand (GJ)	% Change from 2019	Energy Demand (GJ)	% Change from 2019
REFERENCE CASE	969,513,189	-	1,011,754,795	4%	1,030,260,202	6%	-	-
DIVERSIFIED PORTFOLIO	969,513,235	-	911,381,337	-6%	794,772,612	-18%	-	-
ETI	969,514,266	-	890,267,034	-8%	766,691,333	-21%	692,245,594	-29%

The ETI scenario has lower volumes than the Diversified Portfolio scenario mainly due to lower volumes of hydrogen. Exhibit 15 shows annual volume for all scenarios. To account for the difference in energy content of hydrogen and natural gas, Exhibit 16 presents annual energy demand. This illustrates that the ETI scenario has slightly lower energy demand than the Diversified Portfolio scenario and significantly lower demand than the Reference Case.

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Exhibit 15 – All Scenarios Volume (m^3)

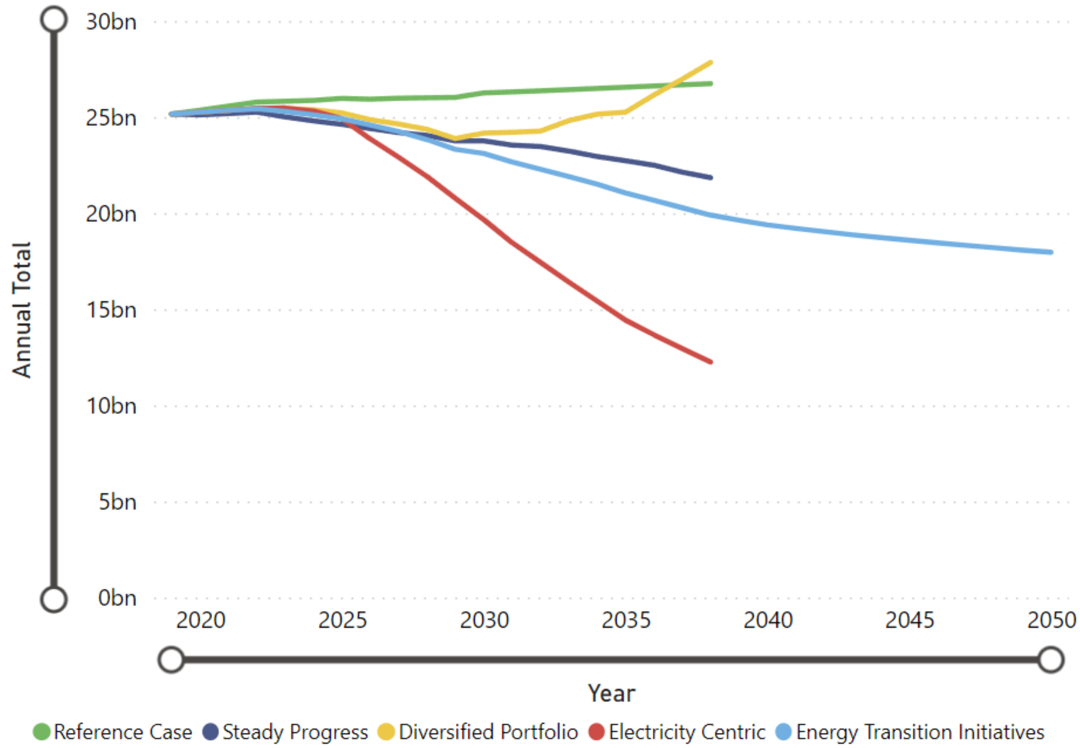
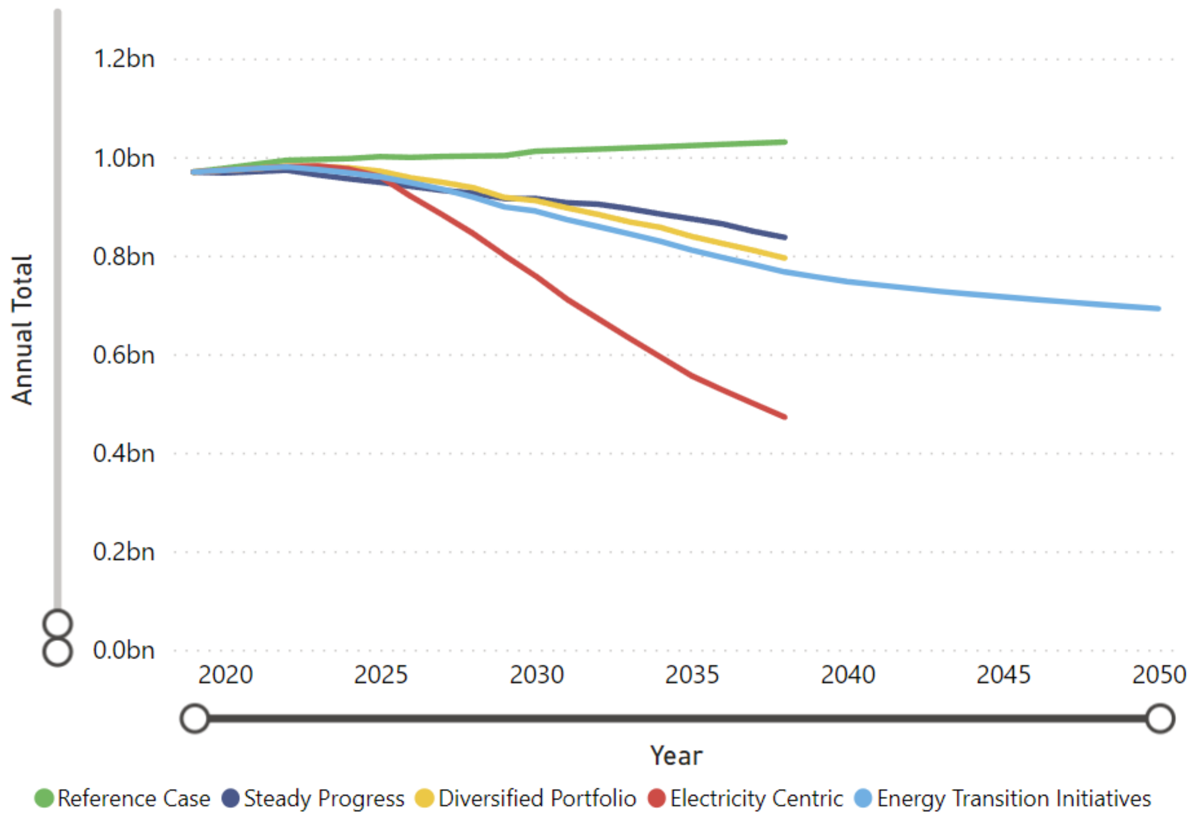


Exhibit 16 – All Scenarios Energy Demand (GJ)



4.2 End-User GHG Emissions

While the ETI scenario demonstrates a similar energy demand to that of the Diversified Portfolio scenario, the ETI scenario has higher end-user emissions than the Diversified Portfolio scenario due to lower volumes of RNG and hydrogen, and absence of CCS. The ETI scenario has lower GHG emissions compared to the Reference Case over the forecast period, due to differences in volumes of RNG and hydrogen and higher stringency assumptions in the ETI scenario that reduce volumes of natural gas. Exhibit 17 shows the GHG emissions of each scenario.

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Exhibit 17 – All Scenarios GHG Emissions (t/CO_2e)

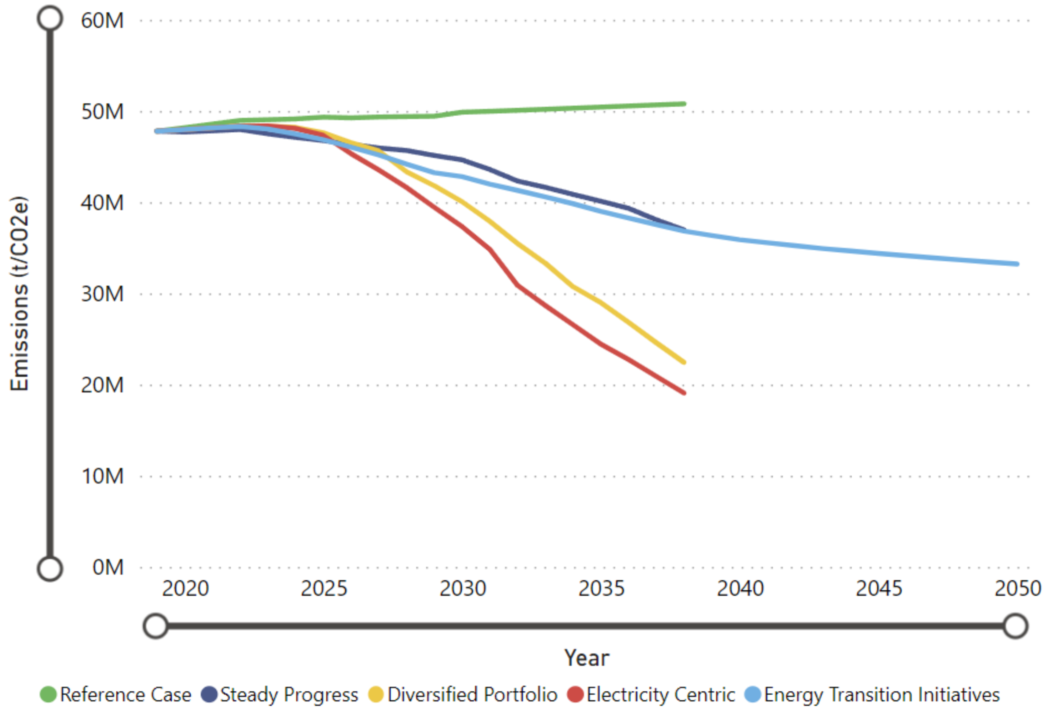

Exhibit 18 compares the GHG emissions change relative to 2019 for the Reference Case, Diversified Portfolio, and ETI scenarios. While the Diversified Portfolio scenario was not modeled to 2050 in the ETSA project, the trajectory of the GHG reductions suggest that this scenario is on track to achieve net-zero emissions by 2050, which is further demonstrated in Guidehouse's Pathway to Net-Zero for Ontario study. In contrast, the ETI scenario only results in 30% fewer emissions (from 2019 levels) by 2050.

Exhibit 18 – GHG Emissions in ETI and Diversified Portfolio Scenarios (t/CO_2e)

	2019		2030		2038		2050	
Scenario	GHG Emissions (t/CO2e)	% Change	GHG Emissions (t/CO2e)	% Change	GHG Emissions (t/CO2e)	% Change	GHG Emissions (t/CO2e)	% Change
REFERENCE CASE	47,792,623	-	49,871,931	4%	50,783,032	6%	-	-
DIVERSIFIED PORTFOLIO	47,792,623	-	40,048,224	-16%	22,424,218	-53%	-	-

	2019		2030		2038		2050	
Scenario	**GHG Emissions (t/CO2e)**	**% Change**	**GHG Emissions (t/CO2e)**	**% Change**	**GHG Emissions (t/CO2e)**	**% Change**	**GHG Emissions (t/CO2e)**	**% Change**
ETI	47,792,674	-	42,812,482	-10%	36,837,418	-23%	33,218,837	-30%

5 Conclusion: Summary of Key Results

The following are some key results of the ETI scenario:

- While the energy demands of the ETI and the Diversified Portfolio scenarios are similar over the modeled periods, there are distinct differences in end-user gas volume demands and greenhouse gas (GHG) emissions between the scenarios;
- Annual gas volume decreases 8% by 2030, 21% by 2038, and 29% by 2050, relative to 2019 in the ETI scenario, whereas an overall increase in annual gas volume is observed in the Diversified Portfolio scenario. The increasing annual gas volumes observed in the Diversified Portfolio scenario are attributed to comparatively higher proportions of hydrogen being blended into the gas distribution network, in relation to the ETI scenario where the introduction of hydrogen is limited to proposed Phase 2 of the Low Carbon Energy Project;
- End-user GHG emissions decrease 10% by 2030, 23% by 2038 and 30% by 2050 relative to 2019 in the ETI scenario. While the reduction in GHG emissions is similar between the ETI scenario (5.0 Mt CO_2/yr) and the Diversified Portfolio scenario (7.7 Mt CO_2/yr) in 2030, the trajectory of GHG emission reductions diverges between the scenarios after 2030. This divergence is attributed to deployment of carbon capture and sequestration, and the continued introduction of RNG and hydrogen in the Diversified Portfolio scenario at rates that go beyond the proposed initiatives in the rebasing application as reflected in the ETI scenario; and
- The 2050 end-user GHG emissions were modeled at 33 Mt CO_2/yr, with the annual gas volumes being composed of 97% natural gas, about 3% RNG, and <1% of hydrogen in the ETI scenario. In contrast, the 2038 end-user emissions for the Diversified Portfolio Scenario were 22 Mt CO_2/yr, which highlight the emission reduction effectiveness of measures assumed within the Diversified Portfolio scenario.

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Appendix A Differences between the ETI and Diversified Portfolio Scenarios

This appendix discusses the reasons why the ETI and Diversified Portfolio scenario volumes differ over the period of 2020 to 2038.

There are four reasons why the ETI and Diversified Portfolio scenario volumes differ over the period of 2020 to 2038:

1) *Lower volume of hydrogen:* Because the volumetric energy density of hydrogen is about one-third of natural gas, blending hydrogen increases sales volumes, even if energy demand stays the same. Compared to the Diversified Portfolio scenario, the ETI scenario has significantly less volume of hydrogen beginning in 2029. <u>This is the *main* reason why the ETI scenario has lower volumes compared to the Diversified Portfolio scenario post 2029.</u>
2) *Fuel switching method:* The method used to calculate fuel switching targets depends on the last year of the forecast period and is based on the fuel switching critical driver settings. The Diversified Portfolio scenario ends in 2038 and the ETI scenario ends in 2050, and the price and non-price driven fuel switching assumptions were extrapolated out to 2050 for the ETI scenario. The model solves for the target amount of fuel share change based on the fuel switching instructions (there is also an associated amount of account defection that is dictated by fuel share change in the residential and commercial sectors). However, the amount of fuel switching that occurs in each year reflects the trajectory of the fuel switching for the forecast period, which is dictated by the difference in price signals between the Reference Case and the given scenario. Since the ETI Scenario has a longer forecast period, the trajectory of fuel switching has a slightly different shape than the Diversified Portfolio scenario. <u>This slightly increases the ETI scenario volumes after 2029 compared to the Diversified Portfolio scenario.</u>
3) *Errors introduced due to End Use Count calibration:* PG adjusted electrification amounts to calibrate the ETI scenario to the extrapolated forecast produced by Guidehouse. We aligned the amount of electrification in the 2038 to 2050 period as closely as possible with the Guidehouse forecast. We can calibrate the model to produce the desired electrification response for a specific target year (e.g., 2050), but calibration errors are introduced in preceding years when the targets are not developed using a bottom-up physics-based model (as was the case for Guidehouse's extrapolated data). We calibrated the residential and industrial sectors, but calibration was not required for the commercial sector because our iterations indicated that the uncalibrated model was the most accurate. <u>For the ETI scenario, this slightly decreases volume in the residential sector between 2029 and 2033, and moderately decreases volume in the industrial sector after 2023 compared to the Diversified Portfolio scenario.</u>
4) *DSM savings higher in ETI scenario:* The ETI scenario experiences more DSM savings than the Diversified Portfolio scenario because there are higher volumes of natural gas available to be saved. There are no savings for hydrogen or RNG since it is assumed that any savings applied to the mixture of gaseous fuels is used to reduce the purchase of natural gas. DSM savings experienced in the ETI scenario are comparable to DSM savings in other scenarios where there are higher volumes of natural gas, like in the Reference Case or Steady Progress scenarios. <u>Increased DSM savings decrease ETI scenario volume over the forecast period.</u>

Exhibits of Differences in Accounts

The number of accounts in the Commercial and Residential sectors differ slightly between the ETI and Diversified Portfolio scenarios. The ETI scenario has a different forecast end year and fuel switching targets compared to the Diversified Portfolio scenario, which impact account defection rates over the forecast period. As a result, there are slightly different numbers of accounts in both sectors starting in 2023, as displayed in Exhibit 19 and Exhibit 20.

Exhibit 19 – Residential Accounts by Scenario

Year	Diversified Portfolio Scenario	Energy Transition Initiatives Scenario
2019	3,457,953	3,457,953
2020	3,520,112	3,520,112
2021	3,556,705	3,556,705
2022	3,597,624	3,597,624
2023	3,637,535	3,637,490
2024	3,675,763	3,675,619
2025	3,712,254	3,711,970
2026	3,745,966	3,746,080
2027	3,778,627	3,779,077
2028	3,809,996	3,810,725
2029	3,840,222	3,841,177
2030	3,859,214	3,860,346
2031	3,875,889	3,877,172
2032	3,890,442	3,894,630
2033	3,902,876	3,909,792
2034	3,913,195	3,922,666
2035	3,921,404	3,933,257
2036	3,927,512	3,941,575
2037	3,931,529	3,947,632
2038	3,933,468	3,951,441

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Exhibit 20 – Commercial Accounts by Scenario

Year	Diversified Portfolio Scenario	Energy Transition Initiatives Scenario
2019	254,934	254,934
2020	256,272	256,272
2021	257,146	257,146
2022	258,399	258,399
2023	259,120	259,530
2024	259,662	260,526
2025	260,164	261,390
2026	260,520	262,036
2027	260,853	262,593
2028	261,147	263,053
2029	261,398	263,422
2030	261,046	263,147
2031	260,692	262,702
2032	260,235	262,108
2033	259,627	261,368
2034	258,870	260,484
2035	258,042	259,534
2036	257,156	258,531
2037	256,211	257,474
2038	255,208	256,364

Industrial accounts do not defect, so they are identical in the ETI and Diversified Portfolio scenarios. Exhibit 21 shows the accounts for the ETI and Diversified Portfolio scenarios.

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Exhibit 21 – Industrial Accounts by Scenario

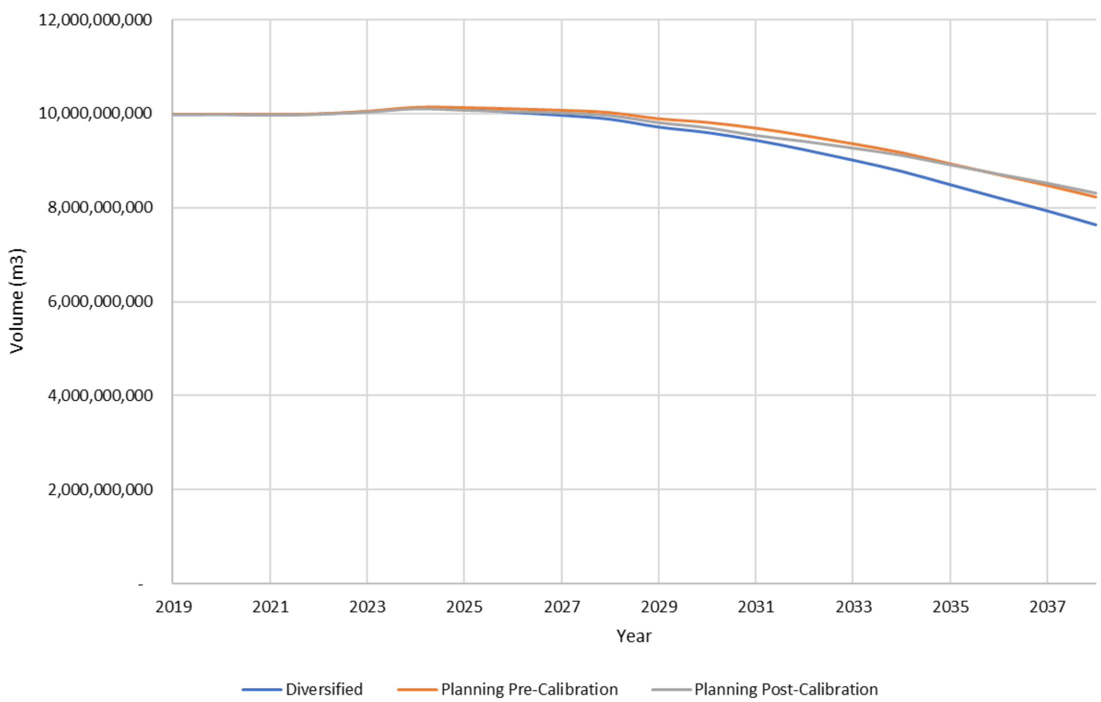
Year	Diversified Portfolio Scenario	Energy Transition Initiatives Scenario
2019	22,734	22,734
2020	22,566	22,566
2021	22,416	22,416
2022	22,412	22,412
2023	22,408	22,408
2024	22,406	22,406
2025	22,402	22,402
2026	22,402	22,402
2027	22,405	22,405
2028	22,406	22,406
2029	22,406	22,406
2030	22,406	22,406
2031	22,405	22,405
2032	22,404	22,404
2033	22,404	22,404
2034	22,403	22,403
2035	22,402	22,402
2036	22,402	22,402
2037	22,401	22,401
2038	22,401	22,401

Exhibits of Differences in Gas Volumes

The following exhibits illustrate the pre-DSM pre-alternative fuel (e.g., RNG, hydrogen, and CCS) volumes for the draft ETI and Diversified Portfolio scenarios, with the draft ETI scenario outputs shown for pre- and post- calibration. These outputs show the impact of the fuel switching method (pre-calibration) and calibration (post-calibration) on the ETI scenario between 2019 and 2038.

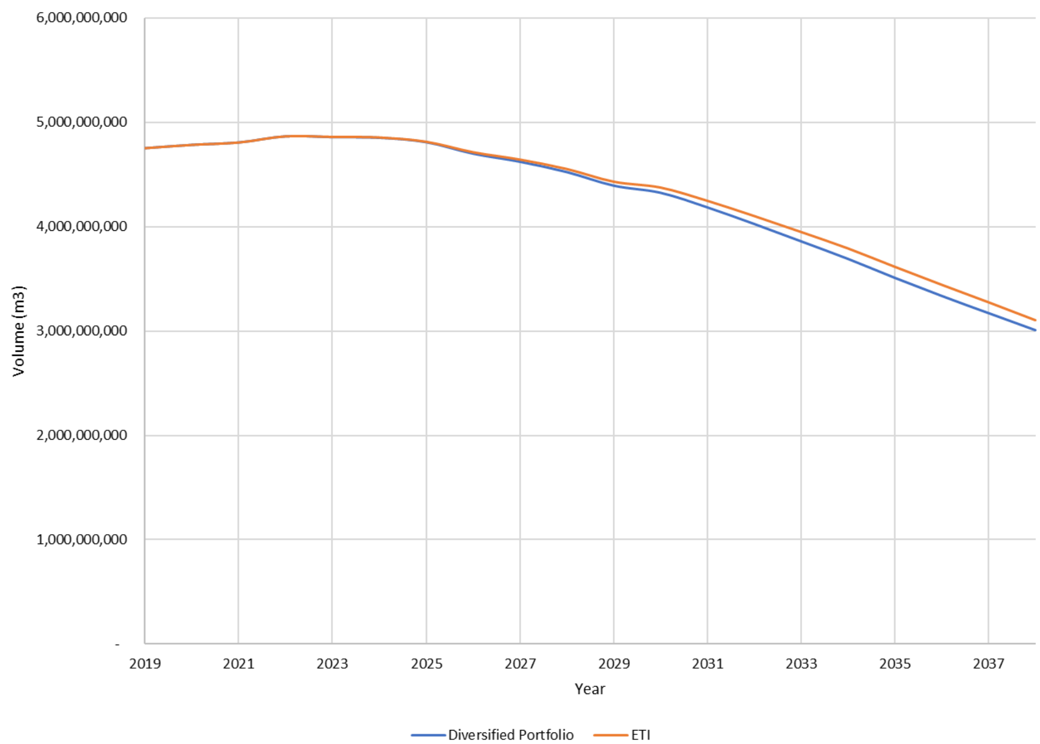
Fuel switching and calibration in the Residential sector drive the scenario differences shown in Exhibit 22 for pre-DSM pre-alternative fuel volumes between 2019 and 2038. Decreased price driven fuel switching in the ETI scenario generates higher volumes compared to the Diversified Portfolio scenario starting in 2026. The calibration process reduces the error between 2026 and 2034 but has little impact between 2034 and 2038.

Exhibit 22 – Residential Sector Gas Volumes Pre-DSM Pre-Alternative Fuels



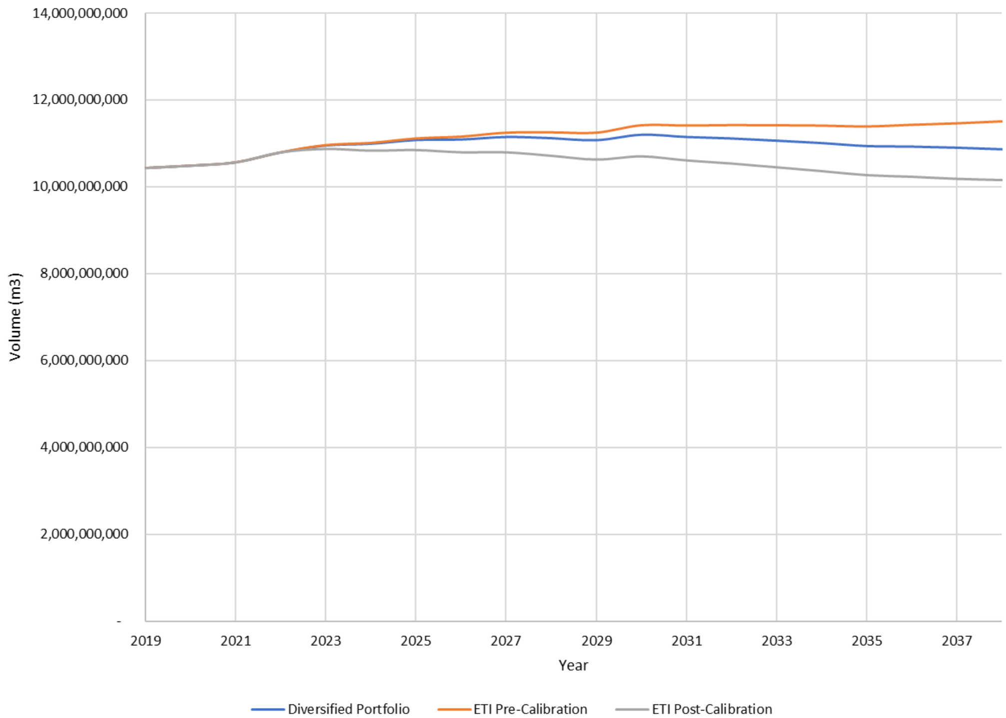
As illustrated in Exhibit 23, fuel switching in the Commercial sector creates the differences in pre-DSM pre-alternative fuel volumes between 2019 and 2038. Decreased price driven fuel switching in the ETI scenario generates higher volumes compared to the Diversified Portfolio scenario starting in 2029.

Exhibit 23 - Commercial Sector Gas Volumes Pre-DSM Pre-Alternative Fuels



Fuel switching and calibration in the Industrial sector causes the scenario differences shown in Exhibit 24 for pre-DSM pre-alternative fuel volumes between 2019 and 2038. Decreased price driven fuel switching in the ETI scenario generates higher volumes compared to the Diversified Portfolio scenario starting in 2023. Complete electrification of the HVAC and Process Cooling end-uses in the calibration process drives volumes lower than the Diversified Portfolio scenario over the forecast period, starting in 2023. We can see that the ETI scenario energy output in the Industrial sector is higher than in the Diversified Portfolio until 2033. DSM reduces the total energy output of the Diversified Portfolio scenario, but results for the ETI scenario are pre-DSM so they appear higher until 2033.

Exhibit 24 – Industrial Sector Gas Volumes Pre-DSM Pre-Alternative Fuels



ENERGY TRANSITION TECHNOLOGY FUND (ETTF)

JANE HUANG, SUPERVISOR COMMERCIAL/INDUSTRIAL TECHNOLOGIES

1. The purpose of this evidence is to request OEB-approval of Enbridge Gas's proposed Energy Transition Technology Fund (ETTF).

2. This evidence is organized as follows:
    1. Rationale
    2. Description of ETTF
    3. Low Carbon Innovation Funding in Other Jurisdictions
    4. Funding of ETTF
    5. Bill Impacts
    6. Summary

1. Rationale

3. Enbridge Gas is proposing to create an ETTF in the amount of $5 million annually, for a total of $25 million over the period of 2024 to 2028. This funding is proposed to be collected through a rate rider rather than through base rates, with a new variance account established to record variances between the amounts collected by the ETTF rate rider and actual costs incurred for ETTF initiatives. Details on the proposed regulatory treatment are provided in Section 4.

4. Enbridge Gas is committed to supporting the achievement of emissions reduction in Ontario. While the province is on track to achieve its 2030 emissions reduction target of 30% below 2005 levels, the post-2030 target of net-zero will be challenging to meet. Regardless of the energy transition pathway that is chosen, the target is only achievable with significant technology development and investments in innovative technologies, which must be made immediately. As a part

of the Enbridge Energy Transition Plan “safe bet” approach provided at Exhibit 1, Tab 10, Schedule 6, Enbridge Gas proposes the ETTF to advance and accelerate research, development, and commercialization of low-carbon technologies.

5. Customers have had access to reliable and well-understood natural gas fired equipment in homes and businesses for many years. To help them achieve their emission reduction goals, Enbridge Gas can play an integral role in ensuring the low-carbon technologies developed are safe, reliable and cost effective. For example, across the customer base today, there are many different types of gas-burning equipment such as gas turbines, gas-fired combined heat and power units and industrial boilers in operation, with long remaining operating lives. Enbridge Gas’s efforts in developing, testing, and validating new technologies to convert this existing gas-burning equipment to run on low-carbon fuels such as hydrogen could enable continued safe and reliable usage of that equipment, thus avoiding significant capital investment in brand new low-carbon equipment for customers.

6. There is a mature natural gas market today where prices of natural gas correspond to market conditions. Enbridge Gas can procure natural gas to meet customer demands cost effectively when it is needed. As low-carbon fuels are brought into the energy supply mix to reduce emissions, one of the key challenges is limited supply and high costs. Fuels such as renewable natural gas (RNG) are currently priced so that project developers can recover their costs. Technology innovation to maximize supply and lower costs is necessary to make low-carbon fuels accessible and affordable for customers.

7. For high-temperature industrial applications and heavy-duty transportation where electrification is not feasible, carbon capture, utilization and storage (carbon capture and sequestration (CCUS)) can help effectively lower GHG emissions. However,

customers are faced with high upfront investment in CCUS, and those located far from storage sites lack utilization options. Based on a report by Decarb Connect in association with Carbon Clean, 91% of industrial customers believe that CCUS is important to reaching 2030/2050 emission reduction goals, yet a vast majority of them do not see a clear path for their business currently offered in the market.[1] Enbridge Gas can leverage the ETTF to support innovation to allow CCUS technologies to become more modular and scalable based on customer needs, as well as to support the utilization of captured carbon to create high value products.

8. Currently, Enbridge Gas has OEB-approved funding and has proposed similar funding in the DSM Plan Application[2] earmarked for investments in technology research, development, and pilots for energy conservation. The current DSM funding is intended to support the objectives and guiding principles of the current DSM Framework and DSM Plan, and the proposed Research and Innovation Fund (RIF) is intended to continue in a similar fashion. Both the current funding and the RIF are to be used for: funding technical research and maintaining the Technical Resource Manual, funding pilots for collaborative DSM initiatives, research on market barriers for energy efficiency, and technology development activities for energy efficiency technologies and measures for DSM programs. While reduction of GHG emissions may be a by-product of energy efficiency, the primary objective of DSM is helping consumers lower natural gas consumption and manage their energy bills and should align with the requirements set out in the DSM Plan approval. DSM funding is currently not applicable to GHG reduction initiatives that

1 Scaling up CCUS- market insights, p.13, https://fs.hubspotusercontent00.net/hubfs/7845802/Scaling%20up%20CCUS%20-%20market%20insights%20final%2019.10.21%20(1).pdf?utm_campaign=Decarb%20Connect%20Report&utm_medium=email&_hsmi=172177672&_hsenc=p2ANqtz-_1OEMp7fzErl5Hvh7UfIbBilcB9pgBNAnc1tshdbrVDcdYzakHOTPs-Ngj_MTXcz5LGiLQwb8SvuKgCSAH246aafs_41MiwVzish1jxs7UWordHE0&utm_content=172177672&utm_source=hs_automation

[2] EB-2021-0002, Exhibit E, Tab 4, Schedule 3.

do not explicitly reduce natural gas consumption. In contrast to the DSM funding, the ETTF will have a primary focus on technology innovation to drive emission reductions.

9. While Enbridge Gas will continue to leverage this DSM funding to develop innovative energy efficiency technologies and programming, important aspects of energy transition “safe bet” like RNG, hydrogen and CCUS also require significant technology development in the province, thus requiring meaningful funding levels. For example, while initiatives such as blending renewable content into fossil fuels and increasing production of biogas and RNG have started, the full potential of related technologies is yet to be unlocked through technology advancement on a commercial scale.

10. While the pathway toward net-zero in Ontario has yet to be determined, there are “safe bet” actions that should be taken immediately as they are required regardless of the path chosen and rely on technological advancements to make them possible. Please see Exhibit 1, Tab 10, Schedule 6 for more information regarding the “safe bet” actions. Both the diversified and electrification scenarios presented in the Pathways to Net Zero Study provided at Exhibit, 1, Tab 10, Schedule 5, Attachment 2 rely on RNG, hydrogen and CCS, particularly in sectors that are difficult to electrify like high-temperature industrial processes and heavy-duty long-haul transportation.

11. Enbridge Gas has a long history of leading technology innovation in Ontario. In recent years, by working closely with manufacturers, industry associations, other utilities and government, Enbridge Gas has successfully led technology development projects in a number of areas, such as hybrid heating and gas heat pumps. For example, Enbridge Gas has directly managed and completed field trials

in over 40 single family homes to advance hybrid heating technology. With this project, Enbridge Gas supported the development of the hybrid heating systems including smart controllers to optimize cost, increase efficiency and reduce GHG. This technology has now been fully commercialized and has been installed in 100+ homes in London, Ontario through a pilot program. Building on the success, a second phase of the program (with support from the province) is underway for 1000 homes, creating momentum to accelerate market adoption for hybrid heating. This is a clear demonstration of the impact of Enbridge Gas's leadership in technology development.

12. As the main natural gas utility in Ontario servicing over 3.8 million customers, with deep knowledge of customer needs, expertise in managing energy infrastructure along with strong relationships with stakeholders, Enbridge Gas can play a central role with the ETTF in accelerating technology innovation and providing consumer choices for energy transition.

2. Description of ETTF

13. The ETTF will be used to advance and accelerate research, development, and commercialization of low-carbon technologies in line with Canada and Ontario's Energy Transition and emission reduction goals.

14. Enbridge Gas plans to use the fund to accelerate low-carbon technology development in the following ways:
    a) Accelerate technology development and deployment: Enbridge Gas will lead and support R&D initiatives, field trials and technology demonstration projects to evaluate and improve product performance in Ontario, and to provide training opportunities for contractors to ensure quality installation of equipment;

b) Drive market adoption and transformation: Enbridge Gas will engage with manufacturers, end-use customers, contractors, policy makers and other stakeholders to improve various aspects of the 5A's of Market Transformation: Availability, Awareness, Accessibility, Affordability, Acceptance[3]; and
c) Drive economies of scale by collaborating with other utilities, manufacturers, industry associations and research organizations such as NRCan CANMET, Gas Technology Institute (GTI), and Natural Gas Technology Centre (NGTC).

15. The design of the fund takes into consideration the following principles:
    a) Predictability - Technology development projects often span over multiple years. It is important that there is reliable funding available to consistently support timely advancement of low-carbon technologies without interruptions;
    b) Flexibility - Flexibility of the fund provides the ability to move budget from one year to the next depending on portfolio mix and opportunities for partnerships/co-funding. It also allows for adaptation to the prioritization of technologies, sector allocations and timing needs; and
    c) Leverage - Projects will leverage funding from government organizations and associations where possible and appropriate.

16. To address the energy transition needs and support consumer choices, the ETTF will prioritize technology innovation initiatives that:
    a) Reduce GHG emissions;

[3] Five A's: Barrier Classification and Market Transformation Program Design for Energy Efficient Technologies, https://www.aceee.org/files/proceedings/2004/data/papers/SS04_Panel6_Paper10.pdf

b) Provide safe, reliable and affordable low-carbon options for customers;
c) Are outside of those needs already funded through DSM;
d) Are compliant with stringent industry codes and standard;.
e) Range from pre-commercial to commercial activities; and
f) Cover residential, commercial, and industrial sectors, with appropriate pace of commercialization timeline.

17. The ETTF portfolio will focus on several areas of technology innovation, consistent with the "safe bet" actions identified in the energy transition plan.

2.1. Supply and Cost of Low-Carbon Fuels

18. Regardless of the pathway chosen to reach net-zero target by 2050, low-carbon fuels such as RNG and blue and green hydrogen will play an important role in the energy mix. Take RNG as an example. It can use the existing natural gas infrastructure and be blended into natural gas applications to fuel fleets and heat homes and businesses. For customers, there is no need to change appliances or equipment, carbon charges can be avoided, and it costs less than electricity to run. Currently, the supply of RNG is mainly from biogas generated through anaerobic digestion of landfill and municipal waste and is priced to allow project developers to recover their costs. ETTF can be used to support further development of alternative technologies such as gasification, to enable access to a variety of feedstocks (e.g. agriculture waste, forestry residues), thus increasing supply and over time, lower cost.

2.2. Emission reductions through end-use technology innovation

19. Emissions from combustion of natural gas by Enbridge Gas's end-use customers are approximately 32% of Ontario's emissions[4]. As Enbridge Gas procures and blends more low-carbon fuels into the pipeline in the effort to reduce emissions, end-use equipment must be modified and/or upgraded to work safely, effectively and reliably with the changing fuel mix. For example, hydrogen is emerging as an attractive, low-carbon alternative for space heating, power generation, industry and in fuel-cells for transportation. As Enbridge Gas pursues increasing the hydrogen blending percentage into the existing natural gas pipeline, technical challenges such as combustion instability and combustion component durability must be addressed. ETTF will support technology development projects to enable end-use equipment working with low-carbon fuel mix.

2.3. CCUS

20. Enbridge Gas intends to use ETTF dollars to research, test and pilot promising CCUS technologies for commercial and industrial applications. There are numerous areas within the CCUS supply chain where research and development activities will advance its adoption.

21. Greater experience with the various methods (e.g., pre-combustion or post-combustion) and types (e.g. chemical/physical absorption, membrane separation, cryogenic, or chemical looping) of carbon capture systems and their compatibility with various industrial processes is needed. The majority of commercial scale capture systems have been limited to natural gas processing or chemical

[4] Provincial GHG emissions as reported in "National Inventory Report 1990 – 2020: Greenhouse Gas Sources and Sinks in Canada", Part 3, Table A11–13. https://unfccc.int/documents/461919

manufacturing facilities, with few to no capture systems currently operating at cement, steel or power generation facilities[5].

22. The utilization of captured carbon to create higher value products is an important area of research that could increase plant yields and minimize transportation and sequestration requirements, particularly where emission sources are not situated in reasonable proximity to storage reservoirs. In order to ensure solutions developed could be used by a wide variety of customers, Enbridge Gas's focus will be on technologies that are modular, scalable and serve various industries based on their specific emissions qualities.

3. Low-Carbon Innovation Funding in Other Jurisdictions

23. Support for and existence of customer funded innovation funds managed by utilities are available in a number of jurisdictions. A 2018 report[6] prepared by Concentric Energy Advisors identified programs in jurisdictions across the globe where regulators have determined that they "meet specific innovation or demonstration project requirements to merit customer funding". The Clean Growth Innovation Fund in British Columbia and the Green Economy Fund under Great Britain's Revenue = Incentives + Innovation + Outputs (RIIO) Program are two examples that focus on clean energy innovation.

24. In June of 2020, FortisBC Energy Inc. (FEI)'s proposed British Columbia's Clean Growth Innovation Fund for $24.5 million to "accelerate the pace of clean energy innovation, to achieve performance breakthroughs and cost reductions, and to

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[5] `Global CCS Institute. 2020. Global Status of CCS 2020.
[6] REGULATOR RATIONALE FOR RATEPAYER-FUNDED ELECTRICITY AND NATURAL GAS INNOVATION, April 2018, https://ceadvisors.com/wp-content/uploads/2018/05/Concentric-Final-Innovation-Report-4.23.18.pdf

provide cost effective, safe and reliable solutions”[7] for their customers from 2020 to 2024. The British Columbia Utilities Commission (BCUC) found that there is clearly a need for innovation to help meet the aggressive targets for GHG emissions in BC, and that the basic charge fixed rate rider of $0.40/month is reasonable and not unduly discriminatory, thus warranting approval. This fund is incremental to FEI’s DSM programming funds.

25. In 2013, Great Britain’s energy regulator Ofgem set up RIIO as a performance-based regulatory model that rewards companies that innovate and run their networks to better meet the needs of their customers. As part of the RIIO business plan, the £20 million Green Economy Fund was established in 2018 by Scotland’s electric utility SP Energy Networks to support the Scottish Government’s ambitious energy strategy and the UK’s drive to a low-carbon economy[8].

26. The Green Economy fund supported four project categories[9]: 1) Transport Projects: promoting the uptake and infrastructure provision of electric vehicles or other low-carbon solutions; 2) Heat Projects that centre on the provision of affordable low-carbon energy for the communities; 3) Renewables Projects that look at innovative low-carbon solutions, and energy utilization at a local level; and 4) Education Projects focusing on the creation of a low-carbon workforce. As outlined in the Green Economy Fund Final Report 2021, the fund has supported 35 projects,

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[7] British Columbia Utilities Commission Decision and Orders G-165-20 and G-166-20, June 22, 2020, Page 145
https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/481438/1/document.do
[8]SP Energy Networks. GREEN ECONOMY FUND (GEF). Investment & Innovation.
https://www.spenergynetworks.co.uk/pages/green_economy_fund_gef.aspx
[9] Green Economy Fund final report 2021, p4,
https://www.spenergynetworks.co.uk/userfiles/file/35387_SPEN_GEFReport_v8.pdf

reduced 637 tons of CO2 emissions, and created green economy jobs, a big step towards "creating and accelerating a green economy"[10].

4. Funding of ETTF

27. Enbridge Gas is proposing to fund the ETTF through a rate rider rather than through base rates. This regulatory treatment will provide transparency and certainty, as the amounts collected will be earmarked for the stated purpose and nothing else. This approach underscores the importance of having a dedicated, continuous, reliable funding stream for technology research and innovation, giving ratepayers confidence that this is an on-going priority for Enbridge Gas.

28. The rate rider will be a fixed monthly customer charge to be collected from in-franchise customers so that each customer contributes equally to the development of low-carbon energy technologies. The forecast amount to be collected from customers is $5 million per year, totaling $25 million over the 2024 to 2028 period. As a result, the $5 million proposed to be collected for the ETTF is incremental to the proposed 2024 revenue deficiency. Please see Exhibit 8, Tab 1, Schedule 2 for the rate design and recovery proposal of the ETTF.

29. Enbridge Gas proposes a new variance account to capture the variance between the actual amounts collected by the ETTF rate rider and actual costs incurred for ETTF initiatives. The request for the proposed variance account is provided at Exhibit 9, Tab 1, Schedule 3. Enbridge Gas proposes to review the future evolution of the ETTF and the balance in the ETTF variance account in its next rebasing application.

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[10] Green Economy Fund final report 2021, p3, https://www.spenergynetworks.co.uk/userfiles/file/35387_SPEN_GEFReport_v8.pdf

5. Bill impacts

30. The monthly bill impact of the ETTF is $0.11 per customer. Enbridge Gas's recent customer engagement shows that the majority of customers support contributing towards an innovation and technology fund with the goal of advancing low-carbon technologies. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 16-17 for a summary of these customer engagement results.

6. Summary

31. Enbridge Gas is requesting $5 million annually, for a total of $25 million over the period of 2024 to 2028 for an ETTF to advance and accelerate the development of low-carbon technologies to help achieve net-zero by 2050, and to provide safe, reliable, and affordable technology options for customers. The fund focuses on advancing technology development initiatives that reduce GHG emissions outside of the activities already funded by DSM. To support the "safe bet" actions outlined in the energy transition plan, the ETTF will initially be focused on the supply and cost of low-carbon fuels, the reduction of customer emissions through end-use technology innovation, and the advancement of CCUS technologies.

32. The fund is proposed to be collected through a rate rider, with a monthly bill impact of $0.11 to in-franchise customers. This approach provides transparency and focus on technology innovation and demonstrates a commitment to ratepayers that Enbridge Gas is committed to a dedicated, reliable, and steady stream of funding to support accessible, low-carbon energy technologies for our customers.

33. With a track record of technology innovation leadership, knowledge of customer needs, expertise in managing energy infrastructure along with strong relationships with stakeholders, Enbridge Gas can play a central role in accelerating technology innovation that supports customer choice with the ETTF.

REDUCING EMISSIONS FROM OPERATIONS

CARA-LYNNE WADE, DIRECTOR ENERGY TRANSITION AND PLANNING
PETER MUSSIO, MANAGER CARBON STRATEGY

1. In this section of evidence, Enbridge Gas describes the efforts the Company is taking to reduce emissions from its operations. Scope 1 GHG emissions result from Enbridge Gas's operations, and scope 2 emissions result from off-site generation of electricity, which Enbridge Gas buys and consumes. Please see Exhibit 1, Tab 10, Schedule 3, Section 1, pages 1-4, for further details of Enbridge Gas's scope 1 and 2 GHG emissions.

2. Enbridge Gas is committed to reducing GHG emissions from Company facilities. Historically, opportunities have been identified to address various government requirements for the oil and gas industry, including the Federal Regulations Respecting Reduction in the Release of Methane and Certain Organic Volatile Organic Compounds (Upstream Oil and Gas Sector) (the Federal Methane Regulations).

3. At this time, only Enbridge Gas's storage and transmission facilities are covered under the Federal Methane Regulations, and the Company's combustion-related GHG emissions from transmission compressor stations are covered under the Ontario Emissions Performance Standards Program (previously the federal Output-Based Pricing System). The federal government is also consulting on emission caps for the oil and gas sector, which may include the transmission sector. As targets and policies for the oil and gas sector change over time, it is possible that distribution system related GHG emissions could also be included in the future. Please see Exhibit 1, Tab 10, Schedule 3, Section 2, pages 4-12, for further details on climate policies that impact Enbridge Gas.

4. To support achievement of the federal and provincial GHG emission targets, as well as the Enbridge GHG reduction targets, discussion provided at Exhibit 1, Tab 10, Schedule 3, Section 1, Enbridge Gas is developing and implementing a scope 1 and 2 GHG emission reduction strategy.

5. The strategy will continue to identify and assess cost effective emission reduction opportunities. Opportunities have been identified over several years through the Asset Management Plan (AMP), updated operating practices, equipment modernization/innovation, compliance with regulatory requirements, and corporate initiatives.

6. Within its scope 1 and 2 GHG emission reduction strategy, Enbridge Gas has classified reduction opportunities into two tiers:
    a) Tier A: Business as Usual (BAU) Opportunities – planned reductions included in the AMP, improved operating practices, modernization, and current and emerging policies and regulations. Although these opportunities have been identified as part of GHG reduction strategy work, they are being driven by Enbridge Gas’s standard operational maintenance program. Tier A initiatives are listed in Table 1.
    b) Tier B: High Impact Opportunities requiring economic analysis – potential opportunities which are not already included in the AMP but may be cost-effective or eligible for subsidies. Examples include adoption of innovative solutions or emerging technologies such as electrification, hydrogen and RNG. These initiatives may require regulatory rate relief or additional funding to implement.

Table 1
Tier A Opportunities with Annual GHG Reductions

Line No.	Timing	In-Service Date (ISD)	Project Name	Forecasted Project Emissions Reductions (tCO2e) (2)
1	In Flight	2018	Copper Service Replacement	80
2		2019	Direct Inspection and Maintenance Program/Leak Detection and Repair (LDAR)	118,200
3		2019	Station Heating Equipment – BAU	700
4		2019	Storage and Transmission Operations (STO) Online Monitoring	1,100
5		2020	Rod Packing Replacement	800
6		2021	Air Filter Replacements for Turbines	1,500
7		2021	Control Valves (Pneumatic Devices) - High Bleed to low/electric – Transmission	10,500
8		2021	Effective Use of Existing Blowdown Compressors	8,000
9		2021	Fugitive Emissions Management - Reduce Backlogs	16,700
10		2022	Damage Prevention	9,700
11	Near Term (2023)	2023	Pipeline Looping - Dawn to Parkway System (Corunna, Waubuno)	700
12		2023	Hydrogen CHP	300
13	Medium Term (2024+)	2025	Leak Quantification at Gate Stations	3,300
14		2026	Compressor Modernization Strategy - Dawn C Plant (2)	600
15		2026	Compressor Modernization Strategy - Bright B Plant	600
16	To Be Determined	TBD	Compressor Modernization Strategy - Lobo A1	300
17		TBD	Compressor Modernization Strategy - Lobo A2	200
18		TBD	Compressor Modernization Strategy - Lobo B Plant	200
19		TBD	Compressor Modernization Strategy - Parkway A Plant	800
20		TBD	Compressor Modernization Strategy - Dawn D Plant	600
21		TBD	Compressor Modernization Strategy - Dawn E Plant	300
22		TBD	Compressor Modernization Strategy - Dawn G Plant	900
23	Total GHG Reduction Annual			66,100

Notes:

(1) Forecasted annual project emissions reductions once project is fully implemented.

(2) The Compression Modernization Strategy in the AMP is a long-term plan to replace identified compression. Under this project several factors are being considered in the evaluation of alternatives, including meeting the operating requirements for the storage and transmission systems, reliability, environmental compliance, and GHG emissions reduction strategy.

7. As shown on Table 1, Tier A initiatives will reduce Enbridge Gas's scope 1 and 2 GHG emissions by approximately 66,100 tCO_2e per year once all initiatives are fully implemented, which represents an 8% reduction over the Company's GHG emissions in 2018. As these initiatives are already being undertaken as part of Enbridge Gas's AMP or operational maintenance programs, there is no incremental costs to achieve these GHG reductions.

8. Tier B opportunities have undergone an initial economic analysis to confirm if they are cost effective under the Federal Carbon Pricing Program and Ontario Emission Performance Standards (with the federal carbon charge anticipated to increase to $170/$tCO_2e$ by 2030).[1] The economic analysis has been included in Table 2. Projects will be assessed and prioritized as part of the annual AMP update and managed through the approved capital envelope.

[1]Government of Canada. (2021 August 5). The federal carbon pollution pricing benchmark. Environment and natural resources. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information.html

Table 2
Tier B Opportunities with Annual GHG Reductions

Line No.	Timing	Project Name	Forecasted Project Emissions Reductions (tCO2e) (1)	Project Life	Estimated Project Lifetime GHG Reduction (tCO2e)	Estimated Net Present Value (net cost) (20yrs)	Cost per Tonne of GHG Emissions (savings) ($/tCO$_2$e)
1	2023	Portable Blowdown Recovery – Distribution	3,100	20	62,140	$ (260,404.00)	$4
2	2024	Portable Blowdown Recovery – Transmission	7,200	20	144,240	$ 54,713.00	$0
3	2025	Vented Gas Capture at Compressor Stations	17,000	40	632,785	$ (2,014,146.00)	$3
4	2026	Compressor Fuel Switch to RNG	275,000	20	4,521,652	$(749,777,419.00)	$166
5	2026	Own Use Gas Fuel Switch to RNG Blend (5%)	1,600	20	29,648	$ (4,566,469.00)	$154
6	2026	Electric Drive Compressors – Plant C Replacement	16,000	40	633,720	$ (66,481,116.00)	$105
7	2026	Hagar Boil-Off	11,300	40	453,080	$ (5,815,490.00)	$13
8	2028	Control Valves (Pneumatic Devices) – High Bleed to low/electric – Distribution	3,800	20	63,234	$ (3,184,381.00)	$50
9	TBD	Electric Drive Compressors – Parkway	12,000	40	489,320	$ (97,257,500.00)	$199
10	TBD	Rewheeling Turbines	3,100	20	62,799	$ (11,980,088.00)	$191
11	TBD	Electric Starters	900	20	11,590	$ (3,784,730.00)	$327
12	Total Emissions		351,000		7,074,560		

Note:
(1) Forecasted annual project emissions reductions once project is fully implemented.

9. As shown on Table 2, Tier B initiatives could reduce Enbridge Gas's scope 1 and 2 GHG emissions by approximately 351,000 tCO_2e per year if all initiatives are fully implemented, which represents a 40% reduction over Enbridge Gas's GHG emissions in 2018. A discounted cash flow analysis was conducted to calculate the $/$tCO_2e$ cost (represented by a positive $/$tCO_2e$ figure) or savings (represented by a negative $/$tCO_2e$ figure) of Tier B opportunities. Cash outflows include incremental capital costs of each opportunity. Cash inflows include resulting natural gas savings, avoided carbon charges, any other incremental O&M costs or savings, income tax impacts and any operating costs or savings resulting from the opportunity. The net present value (NPV) of cash inflows and outflows is divided by total expected emissions avoided to determine the $/$tCO_2e$.

10. Enbridge Gas has included two Tier B initiatives from Table 2 in the 2023 to 2032 AMP and these will be managed through the approved capital envelope. These two projects, Portable Blowdown Recovery – Distribution and Hagar Boil-Off, were selected based on their favourable economics, emission reduction potential and technical feasibility.

11. Additional opportunities, including Portable Blowdown Recovery – Transmission and Vented Gas Capture at Compressor Stations are currently undergoing more detailed assessments and may be included in the annual AMP update, and managed through the approved capital envelope.

12. Enbridge Gas is proposing the inclusion of RNG as part of its gas supply commodity portfolio, beginning in 2025. This RNG will be offered to large volume sales service customers on a voluntary basis, through a Low-Carbon Voluntary Program (LCVP). If less than the annual blend target is elected to be consumed

voluntarily by the large volume sales service customer, the remaining volumes will be included in the system sales portfolio, which includes company use and compressor fuel consumption, and therefore could result in additional reductions to Enbridge Gas's scope 1 emissions. Further details of this program are provided at Exhibit 4, Tab 2, Schedule 7.

13. As part of Enbridge Gas's GHG emissions reduction strategy, identified opportunities will be reviewed on an annual basis, including revisiting any previous assumptions, project costs and the cost of carbon. Part of the process is to continue to identify new opportunities, and further assess those opportunities that have been previously identified.

14. As an important component in reaching Canada's emissions reduction targets, the Federal Methane Regulations aim to reduce methane emissions from the Oil and Gas Sector by 40% to 45% below 2012 levels by 2025. Environment and Climate Change Canada has begun consultations on the Federal Methane Regulations to support further development of federal regulations for Canada to achieve a more ambitious target of a 75% methane reduction from 2012 levels from the Oil and Gas Sector by 2030. The updated Federal Methane Regulations may impact the implementation of potential emissions reduction opportunities.

DAWN PARKWAY SYSTEM LONG-TERM UTILIZATION

MAX HAGERMAN, MANAGER, CAPACITY MANAGEMENT AND UTILIZATION

1. The purpose of this evidence is to forecast the long-term utilization of the Dawn Parkway System as set out in the Settlement Agreement for the 2016 Dawn Parkway System Expansion Project[1]. In that proceeding, parties expressed concern with the potential for substantial turnback on the Dawn Parkway System. As part of the Settlement Agreement for the 2016 Dawn Parkway Expansion Project, parties agreed that the issue of Dawn Parkway System capacity turnback risk should be addressed as part of the next cost of service application. Union agreed to address these concerns and to provide an expected utilization forecast for the next IRM term. The relevant passage from the Settlement Agreement is set out below:

> "CME, FRPO and OGVG submitted evidence relating to concerns regarding potential capacity turnback and the resulting rate impacts. To address these concerns, the intervenor evidence called for conditions of approval that would extend the terms of existing transportation contracts and set a floor on the ex-franchise demand factors used for allocating Dawn to Parkway costs for a period of ten years. The parties do not agree on the risk of Dawn Parkway capacity turnback post-2018. For the purposes of settlement, while the parties agree that leave to construct should be granted, there is no agreement of how turnback risk should be dealt with in the context of the proposed facilities. Parties agree that this issue will be dealt with in Union's next cost of service proceeding. For greater certainty, intervenors are in no way restricted or precluded from making any argument before the Board in that proceeding that it is appropriate that certain cost allocation measures should be put in place to insulate ratepayers from the effect of unutilized and underutilized

[1] EB-2014-0261, Settlement Agreement, February 27, 2015.

> capacity on the Dawn Parkway system due to potential turnback risk. Accordingly, parties agree that no conditions related to capacity turnback are required at this time."

2. This evidence is organized as follows:
    1. Dawn Parkway System Overview
    2. Dawn Parkway System Utilization
    3. Dawn Parkway System Turnback Risk
    4. Summary

1. Dawn Parkway System Overview

3. The Dawn Parkway System remains critical for Ontario, Québec and U.S. Northeast consumers. The liquidity and diversity of competitively priced supply at the Dawn Hub coupled with the flexible storage services available support the continued utilization of the Dawn Parkway System.

4. The Dawn Hub is one of the most liquid natural gas trading Hubs in North America, is the largest integrated underground natural gas storage facility in Canada and is connected to most of North America's major supply basins. The Dawn Parkway System connects the Dawn Hub to eastern, downstream pipelines and consuming markets and will continue to be a critical transportation path for customers through the next IR term.

5. Utilization of the Dawn Parkway System has increased significantly since 2013 as North American natural gas markets continue to experience considerable change. While reserves still exist in mature natural gas basins, the economics of natural gas production and transportation have favoured shale gas and tight gas formations, some of which are closer to the consuming markets. As a result, the flow of natural

gas on the Canadian and U.S. pipeline grid has significantly changed and shippers have continued to shift from contracting for long haul transportation to contracting for short haul transportation.

6. With these changes in the North American natural gas supply, market participants in Ontario, Québec, and the U.S. Northeast have restructured their natural gas supply portfolios, sourcing less Western Canadian Supply Basin (WCSB) supply and purchasing more supply from production basins and liquid market centres located closer to their end-use markets. Consequently, less long-haul transportation from the WCSB is being held by utilities and end users as they have contracted for more short-haul transportation to the markets. With these changes the Dawn Parkway System will continue to be critical to the gas supply needs for customers in Ontario as well as Quebec, eastern Canada and the U.S. Northeast.

7. More recently, increased Liquified Natural Gas (LNG) exports from the Gulf of Mexico and incremental demand for natural gas-fired generation in the southern U.S. have reversed the traditional South to North pipeline flows making the Dawn Parkway System more critical to serve the demands in Ontario, eastern Canada and the U.S. Northeast.

2. Dawn Parkway System Utilization

8. Following the completion of the 2017 Dawn Parkway Project[2], a Dawn Parkway System capacity surplus existed. All surplus Dawn Parkway System capacity was subsequently contracted to serve the demands of EGD rate zone, Union rate zones, and ex-franchise Eastern Canadian and U.S. Northeast utility customers commencing in each of winter 2018/2019, winter 2019/2020 and winter 2020/2021.

[2] EB-2015-0200.

The U.S. Northeast customers were also able to contract for downstream capacity on the TransCanada Mainline and Portland Natural Gas Transmission System systems.

9. The amalgamation of EGD and Union on January 1, 2019, has connected all major customer centres in Ontario under one utility structure – Enbridge Gas. Enbridge Gas is forecasting in-franchise growth throughout the IR term which could also increase demand on the Dawn Parkway System. Please see Exhibit 2, Tab 7, Schedule 1, Table 1.

3. Dawn Parkway System Turnback Risk

10. The Dawn Parkway System currently has excess capacity available in 2023 and 2024. This excess capacity will be offered to shippers on a long-term or short-term basis for service starting in 2022, 2023 or 2024.

11. The Dawn Parkway System ex-franchise contracts are provided in Table 1, with further itemization of contracts reaching their renewal stage by customer segment. The majority of ex-franchise contracts maturing in the 2024 to 2028 period are held by three main customer groups: 1) U.S. Northeast utility customers, 2) Ontario natural gas-fired power generation customers, and 3) Québec and Eastern Canadian utilities. Ex-franchise customers hold almost 2.5 PJ/d of Dawn Parkway System capacity and more than half of that capacity is contracted beyond the IR term.

Table 1
Rate M12/M12-X Contracted Capacity

Line No.	Particulars (GJ/d)	Total Contracted Capacity 23-Nov	Contracts in Renewal Stage 24-Nov	25-Nov	26-Nov	27-Nov	28-Nov
		(a)	(b)	(c)	(d)	(e)	(f)
1	Utilities	647,334	5,000	350,142	-	65,000	-
2	TransCanada	335,518	173,852	-	-	-	-
3	U.S. Northeast	726,021	423,884	-	-	-	-
4	Power	520,929	87,654	-	-	-	140,000
5	Other	136,981	36,751	-	-	-	-
6	Total	2,366,783	727,141	350,142	-	65,000	140,000

3.1. U.S. Northeast Customers (Utilities)

12. There is limited risk that U.S. Northeast customers will turn back existing Dawn Parkway System capacity during the IR term as this customer group relies on the flexibility of the Dawn Parkway System to meet their gas supply needs, particularly in the winter months. Several U.S. Northeast utilities have contracted for additional long-term capacity on the Dawn Parkway System commencing in 2019, 2020 and 2021. These customers also use the Dawn storage facilities to support their gas supply portfolio and contract for storage injections/withdrawals in alignment with their Dawn Parkway System capacity. Customers in the U.S. Northeast continue to be in a pipeline constrained area with limited access to storage in the region ensuring the continued reliance on the Dawn Hub. While there is some risk that specific customers could turn back capacity, this capacity could be re-contracted after it was released.

3.2. Ontario Natural Gas-Fired Power Generation Customers

13. Ontario natural gas-fired power generation customers also hold considerable capacity on the Dawn Parkway System and that capacity is required to meet the demand for electricity in Ontario. Ontario's natural gas-fired generation market relies on a healthy, liquid Dawn Hub and power generation contracts are commercially structured based on the price of natural gas at Dawn. Natural gas-fired generators have access to unique services at the Dawn Hub that provide operational flexibility through firm all day storage and transportation services allowing natural gas-fired generators to match natural gas supply needs to the electricity market that is priced hourly and dispatched every five minutes. These services and the reliability of the Dawn Parkway System remain critical for the Ontario Power Generation market particularly during the nuclear refurbishment that is scheduled to last until 2033. The schedule for the nuclear refurbishment is detailed in Section 3.2.1 of the Independent Electricity System Operator (IESO)'s Annual Planning Report for 2021[3]. Enbridge Gas has recently received inquiries from existing power customers for potential incremental Dawn Parkway System services to satisfy generating requirements during nuclear refurbishment.

14. During 2021, the IESO commissioned a study to examine the potential to phase out natural gas-fired generation in the province by 2030. The results of the study[4], released in October 2021, concluded that a phase out was not feasible by 2030. As such, the risk of significant turnback from this group of customers is low during the IR term. Some of the main conclusions of the 2021 IESO Study are:

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[3] Annual Planning Outlook, Ontario's electricity system needs: 2023-2042, December 2021, https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook
[4] Decarbonization and Ontario's Electricity System, Assessing the impacts of phasing out natural gas generation by 2030, October 7, 2021, www.ieso.ca/en/Learn/Ontario-Supply-Mix/Natural-Gas-Phase-Out-Study

a) Natural gas generation provides a level of flexibility to respond to changing system needs that would be impossible to replace in the span of just eight years. As a highly flexible resource, gas delivers energy when it is needed most, providing almost three quarters of the system's ability to respond quickly to changes in demand; and
b) Analysis shows that a complete phase-out of gas generation by 2030 would lead to blackouts, as electricity would not always be available where and when needed.

3.3. Québec and Eastern Canada Utilities

15. Québec and Eastern Canada Utilities also hold considerable capacity on the Dawn Parkway System with some turnback potential during the IR term. These customers have highly seasonal loads and use Dawn storage in conjunction with the Dawn Parkway System transportation path to manage their natural gas supply needs, minimizing the risk of substantial turnback on the system.

4. Summary

16. Enbridge Gas expects the Dawn Parkway System to remain fully contracted through to the end of its next IR term (2028). The Enbridge Gas in-franchise demand forecasts indicate continued reliance and growth on the Dawn Parkway System. Ex-franchise customers will continue to rely on the liquidity of the Dawn Hub and the reliability of the Dawn Parkway System to satisfy their gas supply needs, particularly in the U.S Northeast with limited access to infrastructure to serve growing peak day demands. This position is further supported by a market study completed by ICF International Inc. (ICF). ICF is a Fairfax, Virginia-based global consulting and technology services company which provides a range of services for governments and businesses, including strategic planning, management, marketing

and analytics. The ICF analysis, provided at Attachment 1, provides a detailed review of the continued need for natural gas in the markets served by the Dawn Parkway System.

17. The ICF analysis concludes that the Dawn Parkway System is highly likely to remain contracted through to 2034 at levels similar to today. The main conclusions of the ICF Dawn Parkway Utilization Report are:
    a) The system is highly utilized today, recently setting a daily south to north flow volume record. This is due in part because of the recent expansion of the Portland Natural Gas Transmission System and subsequent flow volume record on that pipeline. The region's reliance on the Dawn Parkway System is increasing as LDCs meet their growing winter and peak day demand requirements;
    b) Per ICF's Q2 2022 base case, the U.S. and Canada domestic natural gas demand is expected to grow while residential, commercial, and industrial demand in Ontario, New York, and New England is sustained or grows slightly. Driven by the need to ensure reliable access to natural gas supply and storage to meet winter and peak day demand, utilities serving residential, commercial, and industrial demand will continue to contract for service on the system. With this sustained demand, contracting on the Dawn Parkway System will remain near today's levels. With limited alternative infrastructure options in Eastern Canada and in the U.S. Northeast, the Dawn Parkway System will remain a reliable way for LDCs and marketers to source natural gas from Dawn storage; and
    c) Over the past two decades, many of the existing customers have exercised their right of first refusal and have renewed their contracts on the Dawn Parkway System. Even though the current contracted capacity decreases

significantly between now and 2024, ICF expects most of the customers will re-contract the capacity as they have done in the past.

Assessment of the Future Utilization of the Enbridge Gas Dawn to Parkway System

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Table of Contents

1 Introduction

ICF was engaged by Enbridge Gas Inc. (Enbridge Gas) to assess the market and understand the risk of de-contracting on the Dawn to Parkway system in the future. This assessment evaluates the future utilization of the Dawn to Parkway system for the next rebasing term (2024-2028). The study also examines the current firm contracts and the supply and demand balance to forecast the utilization of the Dawn to Parkway system beyond those contract terms until 2028.

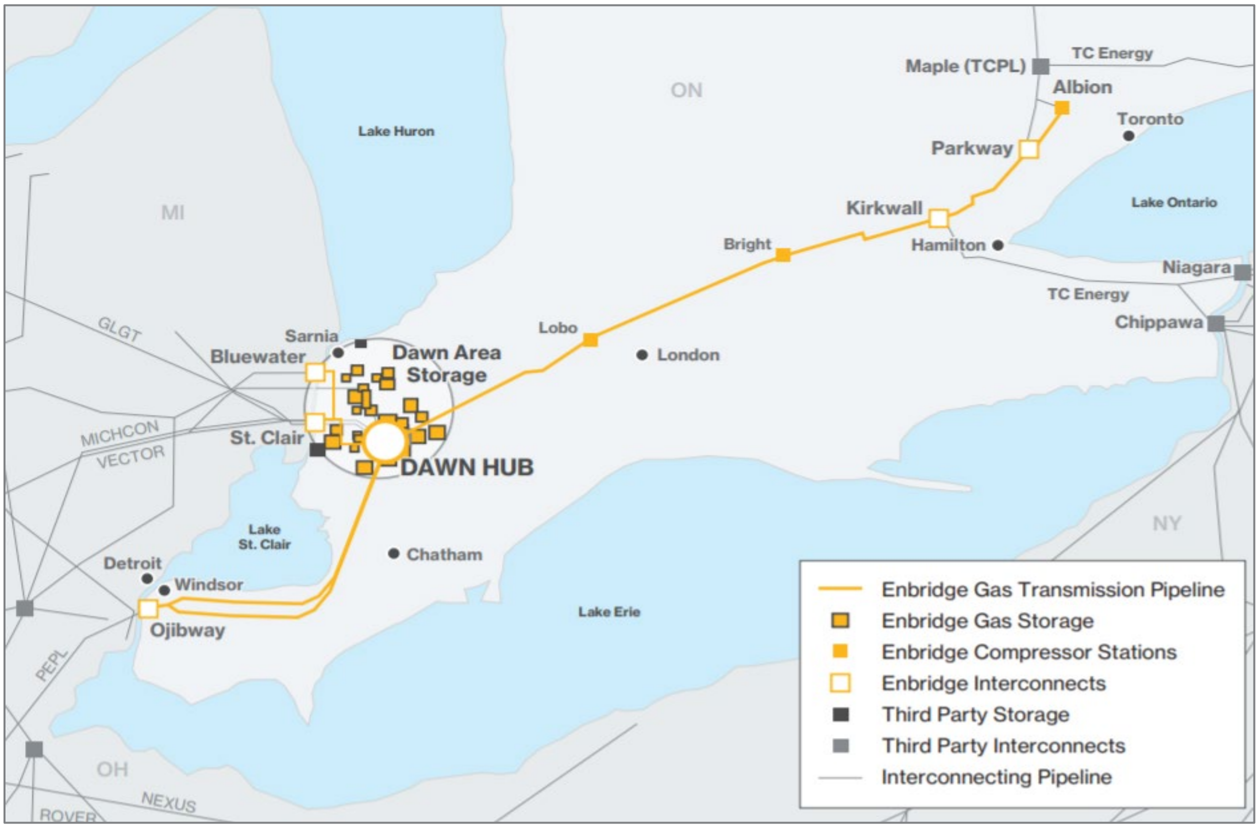
ICF concludes that the Enbridge Gas Dawn to Parkway system likely will remain contracted through 2028 at levels similar to today's levels. The region's reliance on the Dawn to Parkway system is increasing as LDCs meet their growing winter and peak day demand requirements. The system recently set a daily south to north flow volume record. In ICF's base case forecast, U.S. and Canada domestic natural gas demand is expected grow while residential, commercial, and industrial demand in Ontario, New York, and New England is sustained or grows slightly. Driven by the need to ensure reliable access to natural gas supply and storage to meet winter and peak day demand, utilities serving residential, commercial, and industrial demand will continue to contract for service on the system. There will continue to be limited alternative infrastructure options in Eastern Canada and in the Northeast U.S. and the Dawn to Parkway system will remain a reliable way for LDCs and marketers to source natural gas from Dawn storage. Over the past two decades, many of the existing customers have exercised their right of first refusal and have renewed their contracts on the Dawn to Parkway system and ICF expects most of the customers will recontract the capacity as they have done in the past.

1.1 The Dawn to Parkway System

The Dawn natural gas market and storage hub, located in southwestern Ontario, is one of the largest integrated natural gas storage facilities in North America. It provides shippers with direct access to natural gas supply from across North America and natural gas storage. Since the Dawn hub is connected to multiple supply routes from Western Canada, the Midcontinent, the Rockies, and the Gulf of Mexico, it serves markets in Ontario, Quebec, Eastern Canada and the Midwest and Northeast United States (U.S.).

The Dawn to Parkway system (shown in Exhibit 1-1) is owned by Enbridge Gas and connects the markets in eastern Canada and the Northeast U.S. to the Dawn hub. With a total system capacity of 8.2 petajoules per day (PJ/d) (7.6 billion cubic feet per day), it is one of the most vital pipeline systems in North America.

Exhibit 1-1 Dawn Parkway System



Source: Enbridge Gas Inc.

2 Review of the Existing Transportation Contracts

Based on the February 2022 firm transportation capacity contracts, the Dawn to Parkway corridor is fully contracted for the year 2022 (Exhibit 2-1). Local distribution companies (LDCs), power generation facilities, and natural gas marketers in New England, New York, and Eastern Canada other than Enbridge Gas are utilizing 2.1 PJ/d of the capacity, while 5.5 PJ/d of the total system capacity is being utilized by Enbridge Gas to serve in-franchise customers in the EGD Zone and Union South and North Zones.

For 2023 and 2024, the capacity contracts by all customers other than Enbridge Gas are almost at par to those in 2022. Beyond that there are contracts in the renewal stage that are regularly renewed for one-to-three-year periods. The LDCs in the U.S. and Canada have short-term capacity contracts which are renewed year on year based on the market evaluation.

With the current long-term capacity contracts, the Dawn to Parkway system has an average 1.2 PJ/d of contracts in place between 2024-2028 with all of the customers other than Enbridge Gas. The contracts range for a period of 10 to 22 years and half of the contracts were signed before 2014. This low level of contracted capacity in the late 2020s is expected, given that customers tend to renew their capacity closer to the expiration dates. Most of the customers holding capacity have right of first refusal and are expected to recontract as they have done for 2022 based on ICF's analysis of the long-term market fundamentals that are covered in this report.

Exhibit 2-1 Dawn to Parkway Transportation Contracts

Source: Enbridge Gas Inc. Transport Shippers as of February 1, 2022

As shown in Exhibit 2-2, the LDCs hold most of the capacity in the long-term, as they anticipate having to meet sustained winter peak demand.

Exhibit 2-2 Capacity Contracts (PJ/d) by Customer Type

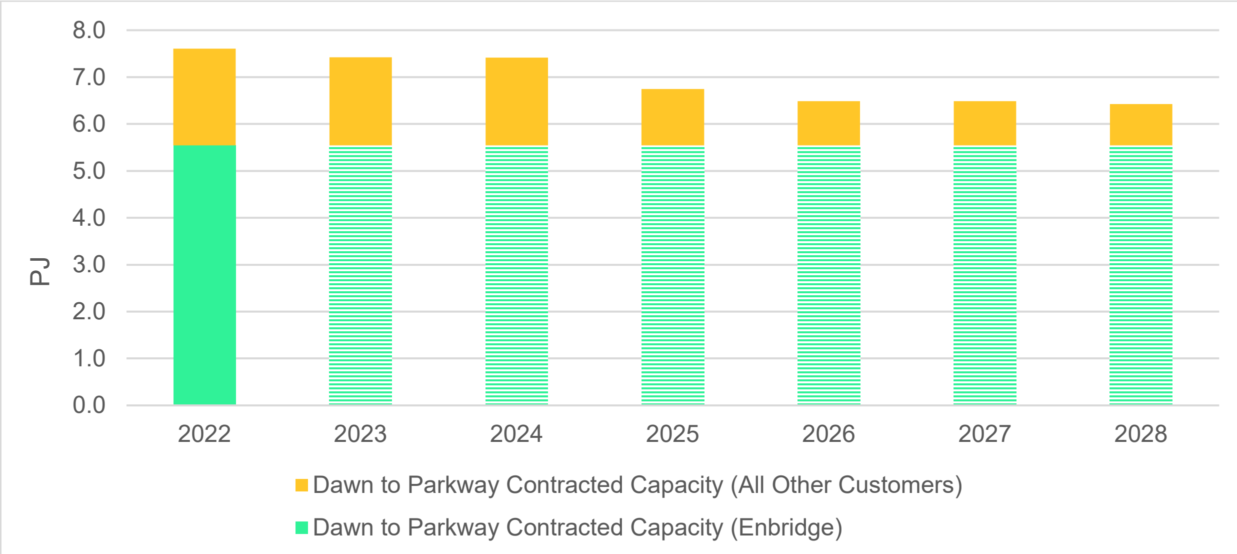
Customer Type	2022	2023	2024-28
Enbridge Gas	5.54	0.00	0.00
LDCs, New York	0.20	0.20	0.05
LDCs, New England	0.55	0.53	0.33
LDCs, Ontario and Canadian Maritimes	0.62	0.62	0.38
Others (Marketers & Power Generators)	0.51	0.48	0.40
Pipeline (TransCanada Pipelines Limited)	0.19	0.06	0.01
TOTAL	7.61	1.89	1.17

Source: Enbridge Gas Inc. Transport Shippers as of February 1, 2022

The history of contract renewal on the Dawn to Parkway system shows that despite the short tenure of the contract, they are consistently renewed and will continue to be renewed in the future. This is demonstrated by the fact that average contract term of the existing contracts on February 1, 2022, was 14 years. In other words, the average contract in the February 1, 2022, Transport Shippers list went into force in 2014 and has been renewed before it could expire ever since then. Boston Gas Company, for example, has two capacity contracts with Enbridge Gas on the Dawn to Parkway system. The first contract of 17,915 GJ/d began in 2010 and the latest, which began in 2018, has a contracted capacity of 60,328 GJ/d, more than three times of the first contract. Similarly, Energir, L.P. by its General Partner Energir Inc has multiple contracts in place, all over 10 years period and an average contracted capacity of 96,607 GJ/d.

ICF believes that there is a high likelihood that these companies will renew their capacity contracts going forward. The system is needed to meet the growing demand requirements in Ontario and to support the peak day demand in New York and New England which rely heavily on imports due to lack of alternative pipeline infrastructure. Natural gas distribution companies – including Enbridge Gas – across Ontario, Quebec, New York, and New England rely on the storage at Dawn and the transportation from that storage on the Dawn to Parkway system throughout the winter and during peak demand periods. If the existing Enbridge Gas in-franchise customers renew the existing contracts until 2028, the Dawn to Parkway system would still be at least 70% contracted, as shown in Exhibit 2-3. Additionally, ICF forecasts Ontario’s demand to grow going forward compared to the 2022 levels, which implies that Enbridge Gas could have even more in-franchise contracts in the future. Section 3 justifies this expectation using ICF’s supply and demand fundamentals forecast and highlights the utilization on the Dawn to Parkway system.

Exhibit 2-3 Expected Utilization on the Dawn to Parkway System with Existing 2022 Enbridge Gas In-Franchise Contracts Renewed Until 2028



Source: Enbridge Gas Inc. Transport Shippers as of February 1, 2022

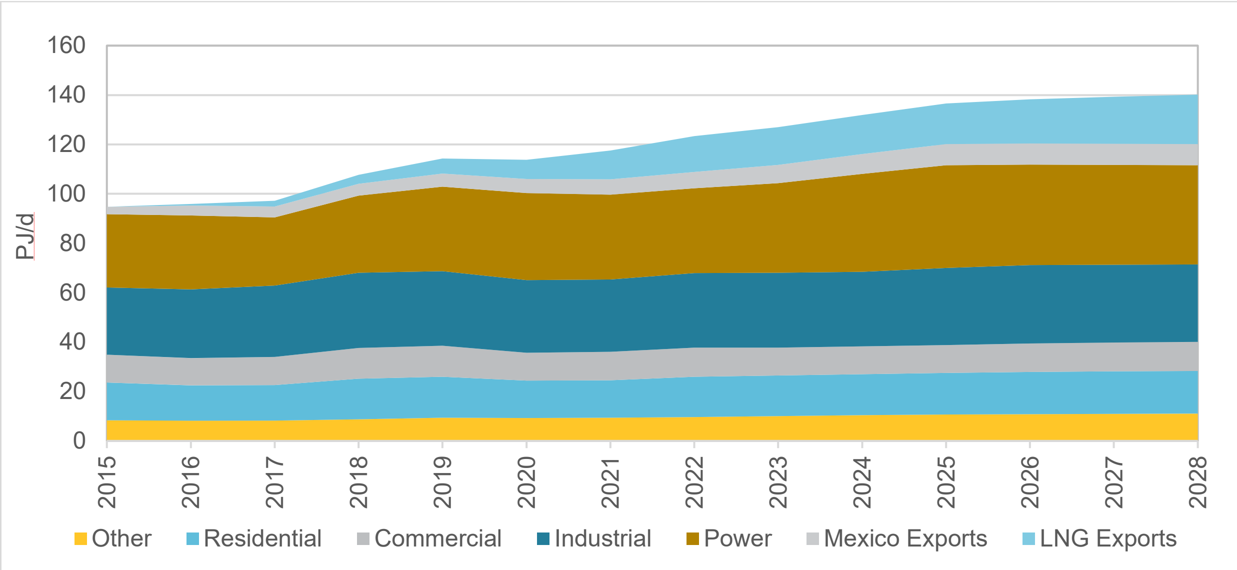
3 ICF's Natural Gas Market Forecast

This section highlights the ICF Q2 2022 base case market fundamentals demand projections and utilization on the modeled Dawn to Parkway corridor in its Gas Market Model (GMM).

3.1 Demand Forecast

Exhibit 3-1 shows the total U.S. and Canada natural gas demand by sector from ICF's Q2 2022 base case. ICF projects U.S. and Canadian domestic and export demand for natural gas to increase by 16.8 PJ/d between 2022 and 2028 and the key drivers for this demand growth are liquified natural gas (LNG) exports, pipeline exports to Mexico, and power generation demand. The natural gas demand from residential, commercial, and industrial sectors shows steady growth between 2022 to 2028. Overall, the forecast shows a continued need for natural gas infrastructure across North America and the region served by the Dawn to Parkway system as natural gas demand continues to increase. Even as North America experiences an energy transition in order to reduce greenhouse gas emissions, natural gas demand for heating, power generation, and exports increases.

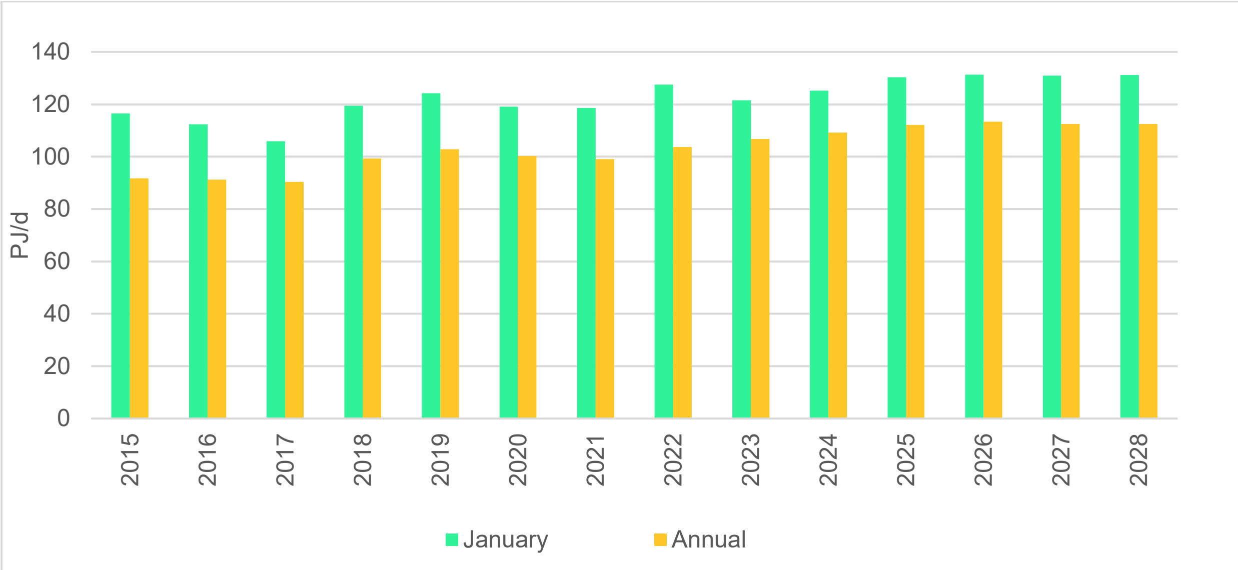
Exhibit 3-1 U.S. and Canada Natural Gas Demand by Sector



Source: ICF Q2 2022

Exhibit 3-2 below shows how the annual average domestic demand in ICF's U.S. and Canada forecast differs from the peak month demand. In the U.S. and Canada, domestic demand stays above 120 PJ/d between 2022 to 2028 during the peak winter month of January in the ICF Q2 2022 forecast. It is 18.3 PJ/d higher on average than the annual average domestic demand. Furthermore, this forecast understates the difference between the annual average and peak contracting requirements for two reasons. First, the January totals in this forecast are monthly average totals rather than peak day totals, which pipeline customers plan for. Second, this forecast assumes normal weather based on the past twenty years of weather data (2002-2021) instead of a design day or even a design month. Thus, even this disparity between the annual average and January average does not fully capture how much higher the contracting needs could be.

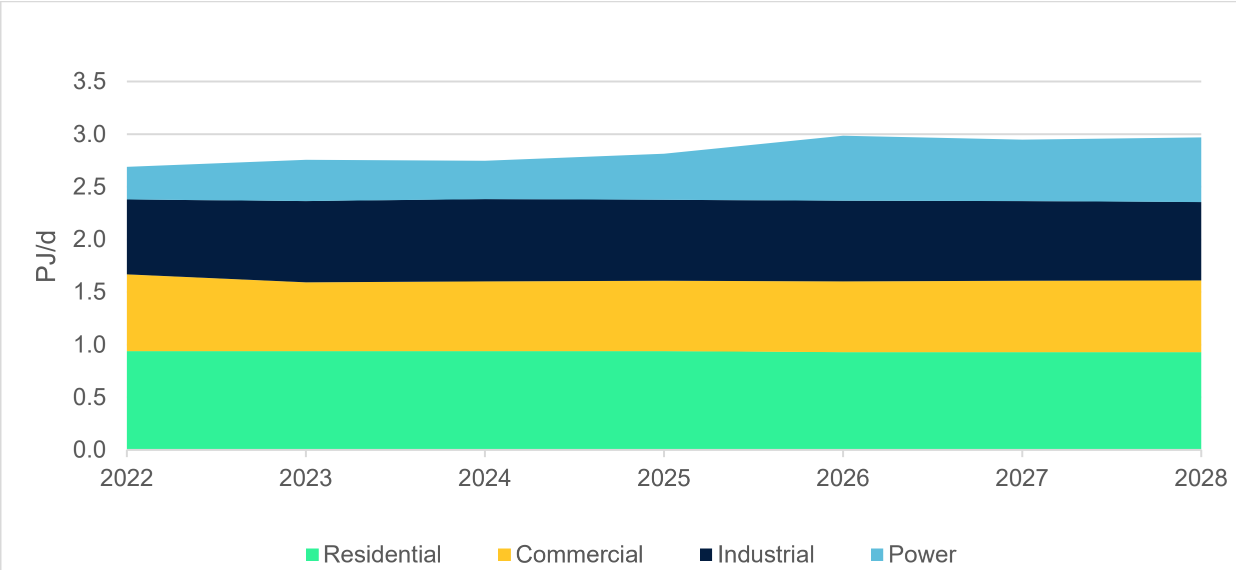
Exhibit 3-2 U.S. and Canada Domestic Natural Gas Demand Excluding Exports – January vs Annual average



Source: ICF Q2 2022

The Dawn to Parkway system utilization is influenced by Ontario's natural gas demand, which is expected to grow in the years to come, due to incremental gas-fired generation that replaces declines in nuclear generation arising from nuclear plant maintenance, refurbishment, and retirements. Ontario's natural gas demand for the power sector is expected to double by 2028 compared to where it stands in 2022, which is 0.3 PJ/d, as shown in Exhibit 3-3. The projected growth in Ontario’s natural gas consumption suggest that Enbridge Gas could have even more in-franchise contracts in future and thus higher utilization of Dawn to Parkway system. ICF’s residential, commercial, and industrial natural gas demand forecast for Ontario is based on the Canada Energy Regulator’s 2021 Canada’s Energy Future Current Policies forecast and it expects a small decline (0.02 PJ/d) in demand between 2022 and 2028 on an annual average basis. This decline is not expected to have a notable impact on the demand for firm transportation contracts on the Dawn to Parkway system.

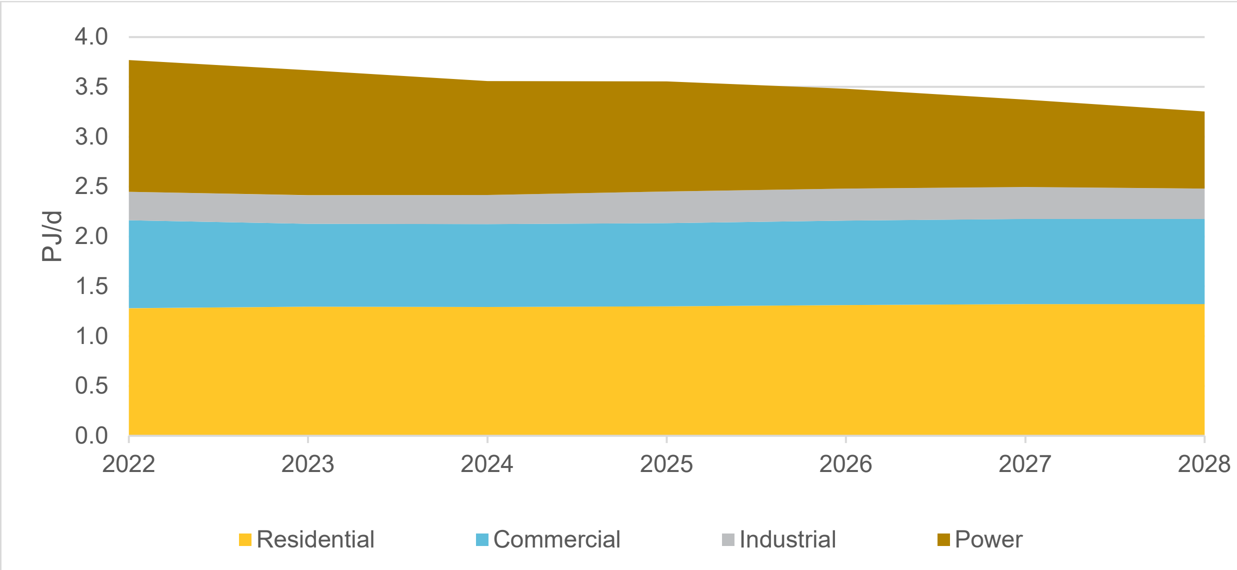
Exhibit 3-3 Ontario Natural Gas Demand by Sector



Source: ICF Q2 2022

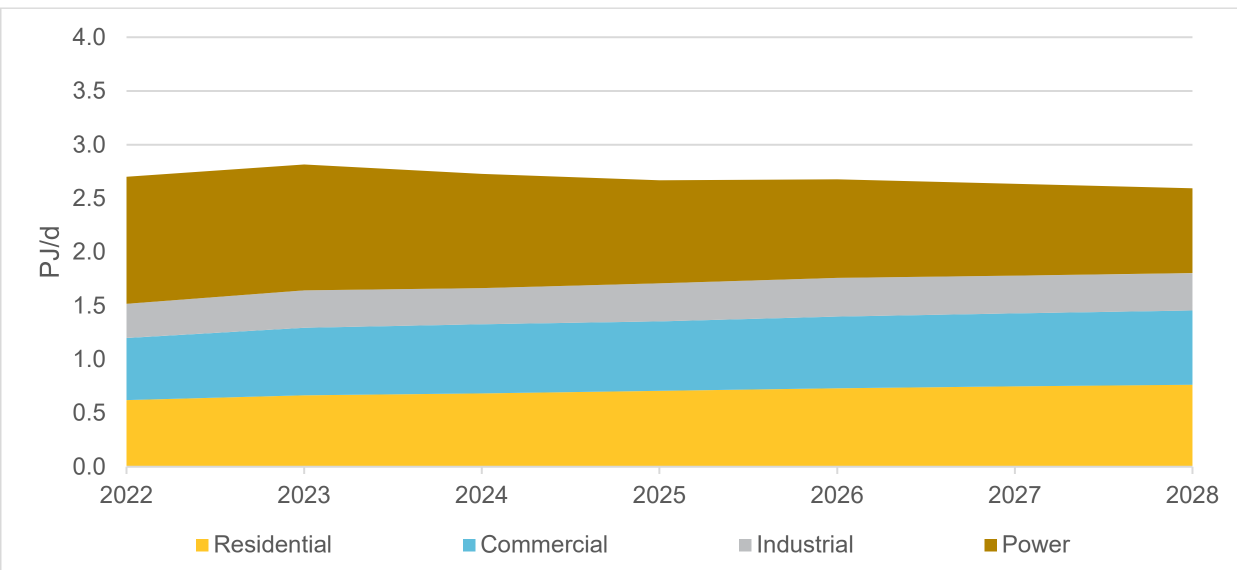
In New York and New England, the two primary ex-franchise markets that the Dawn to Parkway system serves, ICF projects that the power sector gas use will show a decline over the long term. The natural gas demand in New York from all other sectors is expected to stay flat, however, New England shows modest growth between 2022 to 2028. Capacity from Canada to New England has increased by 0.2 PJ/d between 2017 and 2022, as LDCs in New England have prepared for increasing demand. Compared to 2022 levels, the residential, commercial, and industrial natural gas demand in New England increases by 0.3 PJ/d to 1.8 PJ/d by 2028. This is an important driver of the expected continued utilization of the Dawn to Parkway system because the majority of the firm transportation customers in the U.S. are utilities and marketers that serve residential, commercial, and industrial LDC demand. No U.S. power generation facilities contract directly for transportation on the Dawn to Parkway system.

Exhibit 3-4 New York Natural Gas Demand by Sector



Source: ICF Q2 2022

Exhibit 3-5 New England Natural Gas Demand by Sector

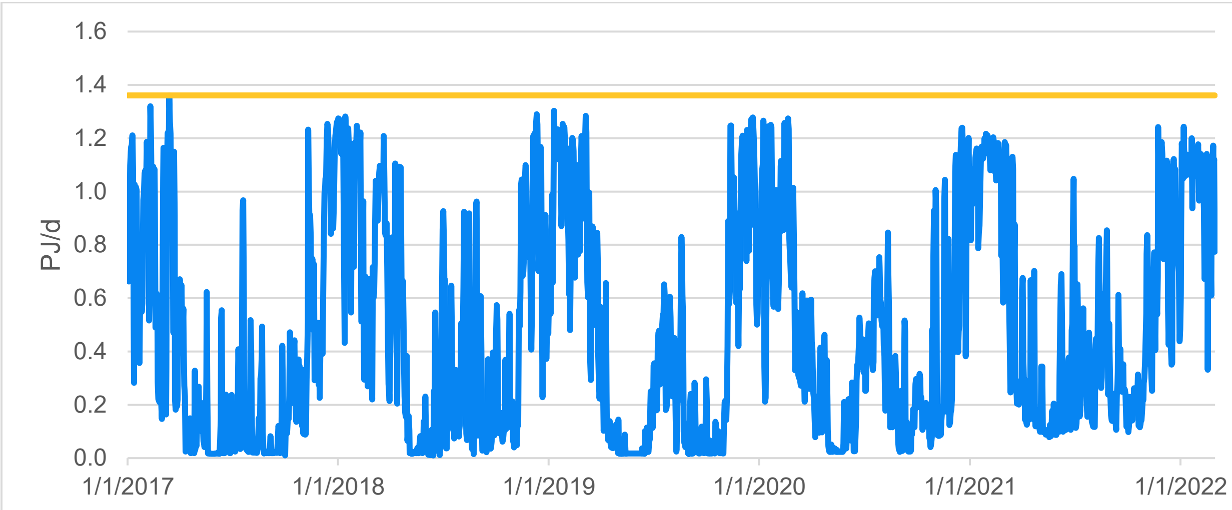


Source: ICF Q2 2022

3.2 Historical Natural Gas Flows from Canada to the Northeast U.S.

The reported design capacity on the Iroquois Gas Transmission pipeline for flows from Ontario to New York at Waddington is close to 1.3 PJ/d. On March 17th, 2017, the daily flows peaked at 1.4 PJ/d. Also, as shown in Exhibit 3-6, the daily flows during the peak winter days have kept close to the design day capacity primarily due to heating demand.

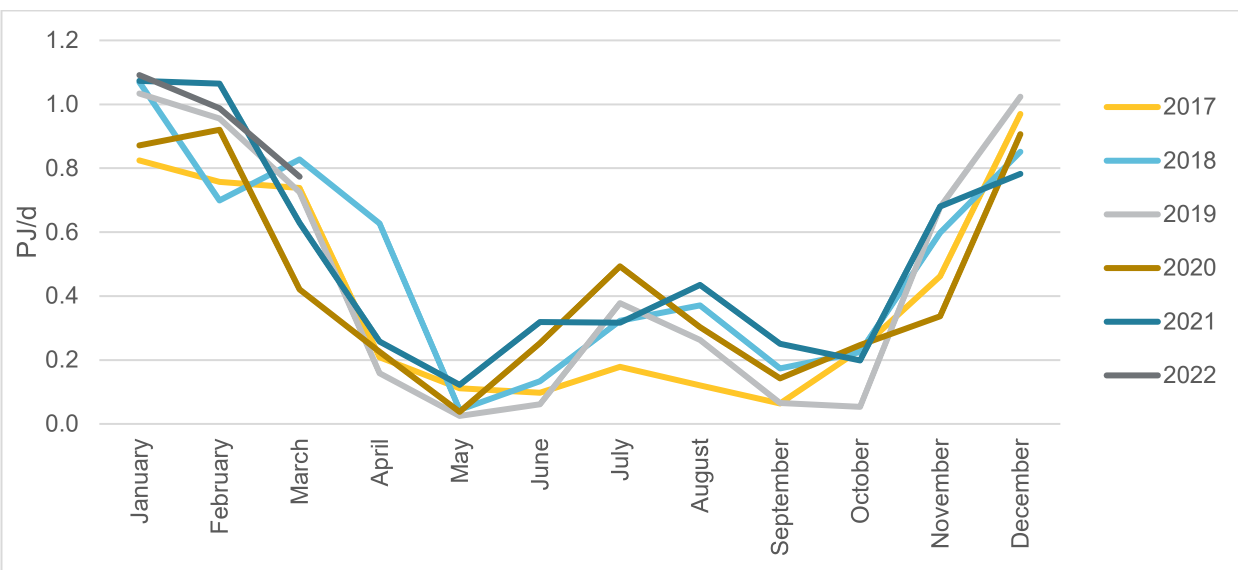
Exhibit 3-6 Daily Imports from Ontario to New York on Iroquois Gas Transmission



Source: ABB Velocity Suite

Exhibit 3-7 captures the historical monthly average flows from Ontario to New York on the Iroquois Gas Transmission pipeline. During the peak winter months, the flows average close to 1 PJ/d. To source supply from Dawn storage during the peak demand days, numerous LDCs in New York rely heavily on the Dawn to Parkway system. Thus, the Iroquois Gas Transmission pipeline's peak monthly demand is significantly greater than its annual average demand and its peak daily demand is much greater than its peak monthly demand. This dynamic is why LDCs in New York contract for capacity upstream on the Dawn to Parkway system to ensure that they can meet the extreme peaks in demand.

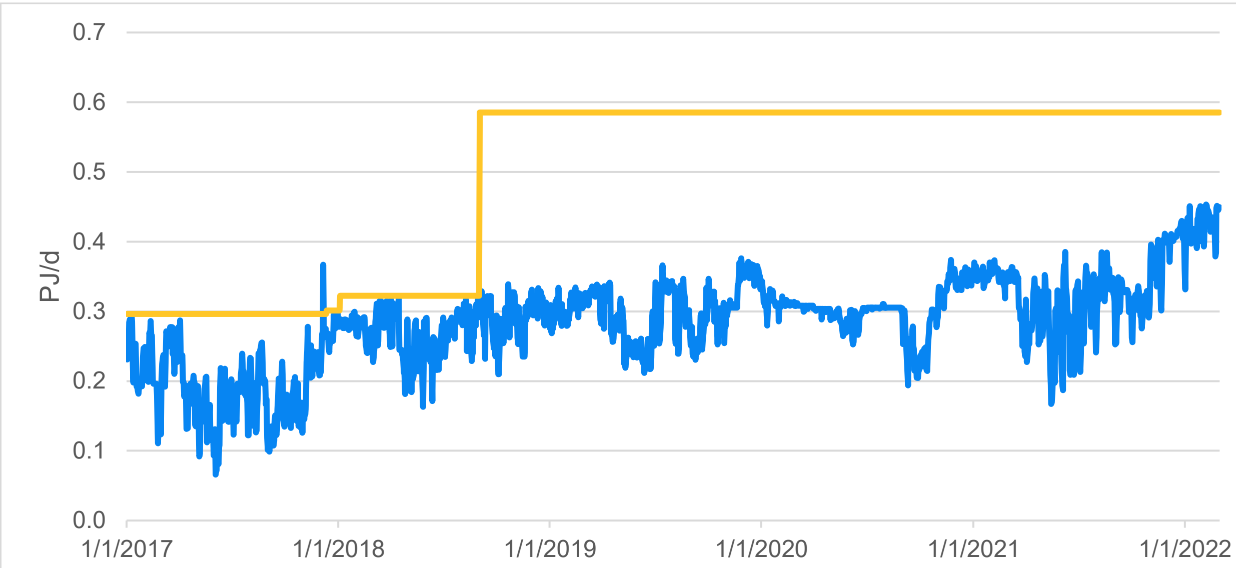
Exhibit 3-7 Monthly Imports from Ontario to New York on Iroquois Gas Transmission



Source: ABB Velocity Suite

The Dawn to Parkway system also supports various LDCs in New England, which import natural gas on the Portland Natural Gas Transmission System. The design day capacity of the Portland Natural Gas Transmission System is 0.42 PJ/d. As per the Exhibit 3-8, the daily flows from Ontario to New England were below 0.4 PJ/d until December 2021. The Westbrook Xpress phase II and III were completed in December 2021 and it increased the pipeline capacity into New England from the Pittsburg interconnect. This has increased natural gas flows from Ontario into New England, with flows staying above 0.4 PJ/d this past winter and reaching a peak of 0.453 PJ/d on February 6, 2022.

Exhibit 3-8 Daily Flows from Quebec to New England on the Portland Natural Gas Transmission System[1]

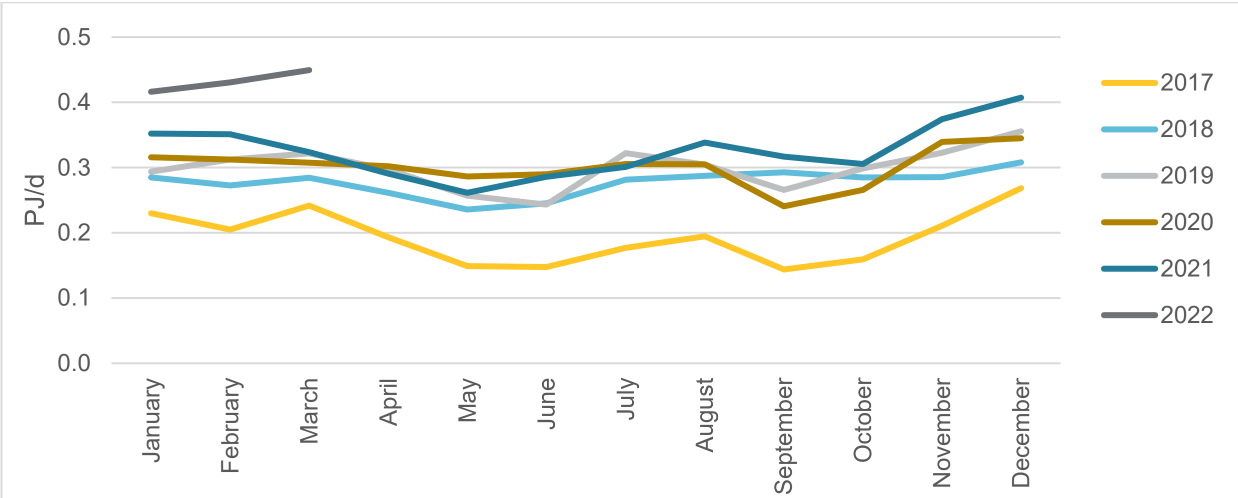


Source: ABB Velocity Suite

Exhibit 3-9 shows the flows into New England, which on average were about 0.3 PJ/d during the winter months (December – February) before the final two phases of the Westbrook Xpress expansion. Even though demand on the Portland Natural Gas Transmission System is not as "peaky" as demand on the Iroquois Gas Transmission pipeline, the flows are consistently near the capacity and are expected to be close to their January and February 2022 levels. This too will lead to sustained demand for firm capacity on the Dawn to Parkway system.

[1] The chart includes data only for dates where positive flows were reported

Exhibit 3-9 Monthly Flows from Quebec to New England on the Portland Natural Gas Transmission System

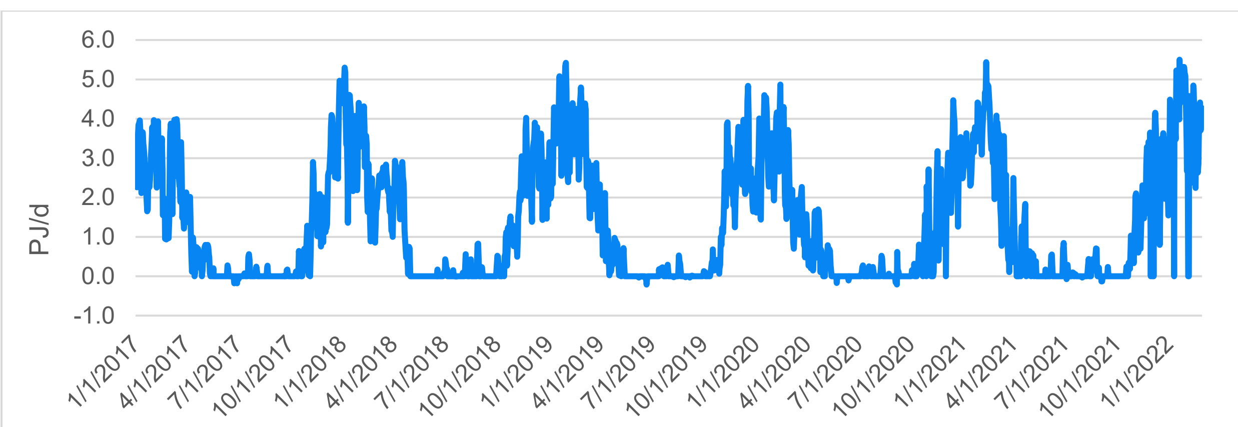


Source: ABB Velocity Suite

3.3 Dawn Parkway Utilization between 2022-2028

ICF forecasts a similar utilization of the Dawn to Parkway system as has been seen historically and thus similar levels of contracting for capacity on the system. The historical 6-year average flows for the month of January in 2017-2022 between Dawn and Parkway was 3.5 PJ/d, keeping the utilization levels close to 62% on average (using the winter 2021/22 peak operating capacity from the Dawn to Parkway segment of the system of 5.6 PJ/d reported by Enbridge Gas). Observed winter daily flows regularly reached over 5 PJ/d between January 2017 to February 2022 with the peak flows reaching 5.5 PJ on January 20, 2022. Exhibit 3-10 shows the daily flows on the system during the same timeframe. The Northeast U.S. has limited supply options and no indigenous production; therefore, it relies heavily on the pipeline deliveries into New York and New England from Eastern Canada. Recently, due to the expansion of the Westbrook Xpress Portland Natural Gas Transmission System, that reliance has only increased.

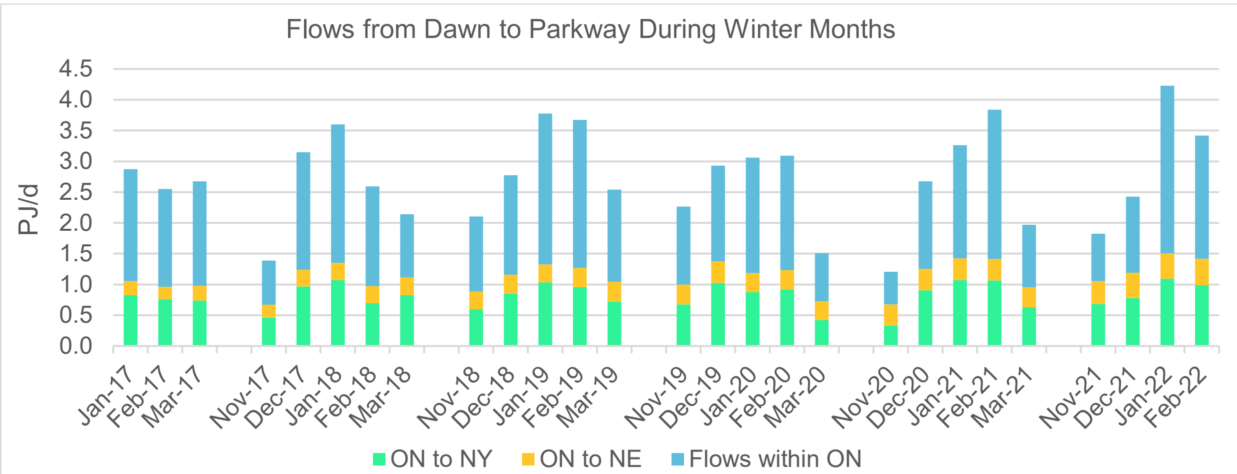
Exhibit 3-10 Historical Daily Dawn to Parkway Flows



Source: ABB Velocity Suite

Per ICF's Q2 2022 case, the Dawn to Parkway system utilization in the winter months is 65% on average for the months of December-February between 2022-2028 to meet the demand requirements in Ontario, Northeast U.S., and Eastern Canada. It is important to note that daily peak and design day utilization would far exceed the average monthly utilization and the peak day requirements are primarily what drive the firm contracting on the Dawn to Parkway system. In the month of March, as the heating demand requirements decline, the system still maintains an average utilization of 59%. This consistent winter flow forecast, based on ICF's natural gas market fundamentals forecast demonstrates the basis for its conclusion that the total volume of the firm transportation contracts on the Dawn to Parkway system will remain close to the levels seen today.

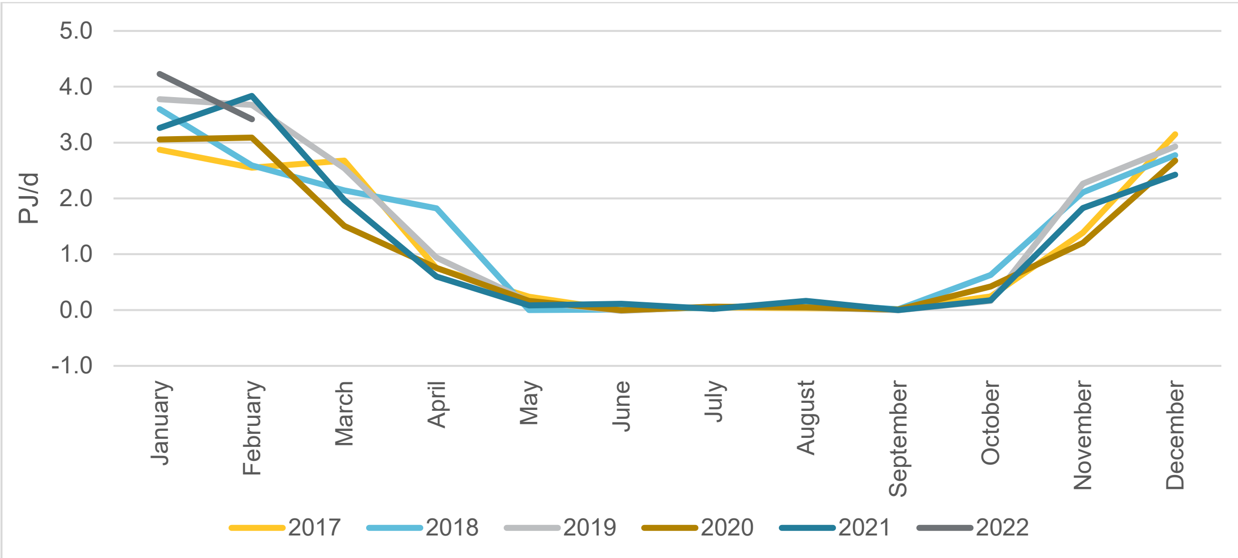
Exhibit 3-11 Flows from Dawn to Parkway During Winter Months



Source: ABB Velocity Suite

Exhibit 3-12 shows the monthly average flows. As a result of winter peaking demand in Eastern Canada and the Northeast U.S., the highest volumes of flows in the winter months of January, February, and December.

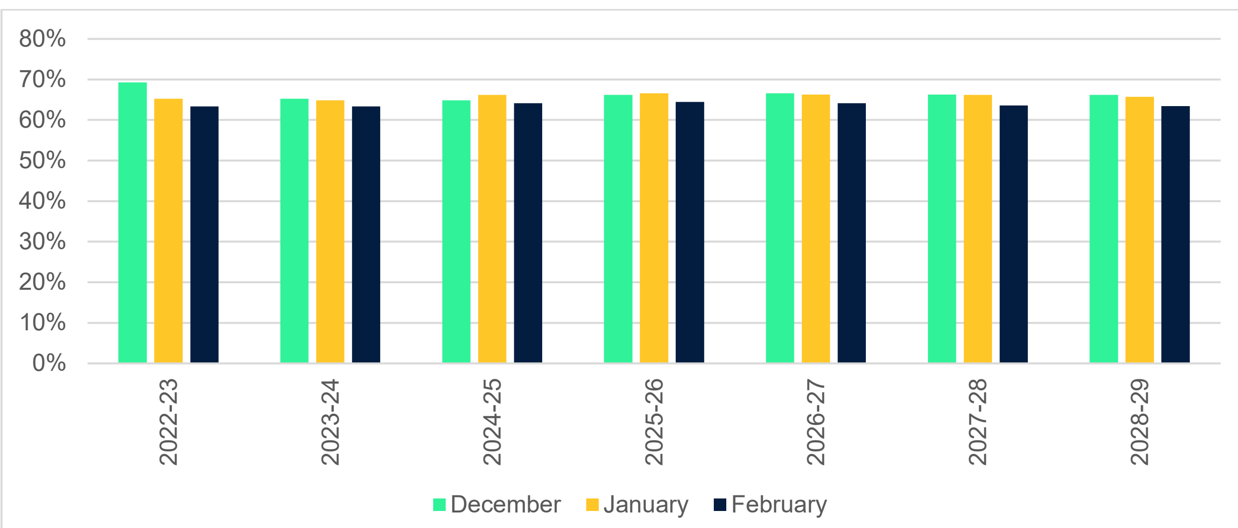
Exhibit 3-12 Historical Monthly Dawn to Parkway Flows



Source: ABB Velocity Suite

As shown in Exhibit 3-12, out of the total gas flowing on the Dawn-Parkway system, more than half is being consumed within Ontario to serve the local demand during the peak winter months.

Exhibit 3-13 ICF Q2 2022 Dawn Parkway Winter Utilization (%)



Source: ICF Q2 2022

4 Conclusion

ICF concludes that the Enbridge Gas Dawn to Parkway system likely will remain contracted through 2028 at levels similar to today's levels for three primary reasons:

1. The system is highly utilized today, recently setting a record daily south to north flow volume record. This is due in part because of the recent expansion of the Portland Natural Gas Transmission System and subsequent flow volume record on that pipeline. The region's reliance on the Dawn to Parkway system is increasing as LDCs meet their growing winter and peak day demand requirements.

2. Per ICF's Q2 2022 base case, the U.S. and Canada domestic natural gas demand is expected grow while residential, commercial, and industrial demand in Ontario, New York, and New England is sustained or grows slightly. Driven by the need to ensure reliable access to natural gas supply and storage to meet winter and peak day demand, utilities serving residential, commercial, and industrial demand will continue to contract for service on the system. With this sustained demand, contracting on the Dawn to Parkway system will remain near today's levels. And with limited alternative infrastructure options in Eastern Canada and in the Northeast U.S., the Dawn to Parkway system will remain a reliable way for LDCs and marketers to source natural gas from Dawn storage.

3. Over the past two decades, many of the existing customers have exercised their right of first refusal and have renewed their contracts on the Dawn to Parkway system. Even though the current contracted capacity decreases significantly between now and 2024, ICF expects most of the customers will recontract the capacity as they have done in the past.

Appendix A: Enbridge Gas Inc. Transportation Contract Database

The review of current transportation contracts in section 2 of this report is based on an analysis of transportation contract data provided by Enbridge Gas.

The Enbridge Gas index of storage customers: https://www.enbridgegas.com/-/media/Extranet-Pages/Storage-and-transportation/operational-information/Index-of-customers/Transport_Report.ashx?rev=c3ca7ff97ae24dff80ccdd1228c43edf&hash=8CD263051C8E81B58380DF77AF8E220C

Appendix B: ICF's Gas Market Model (GMM)

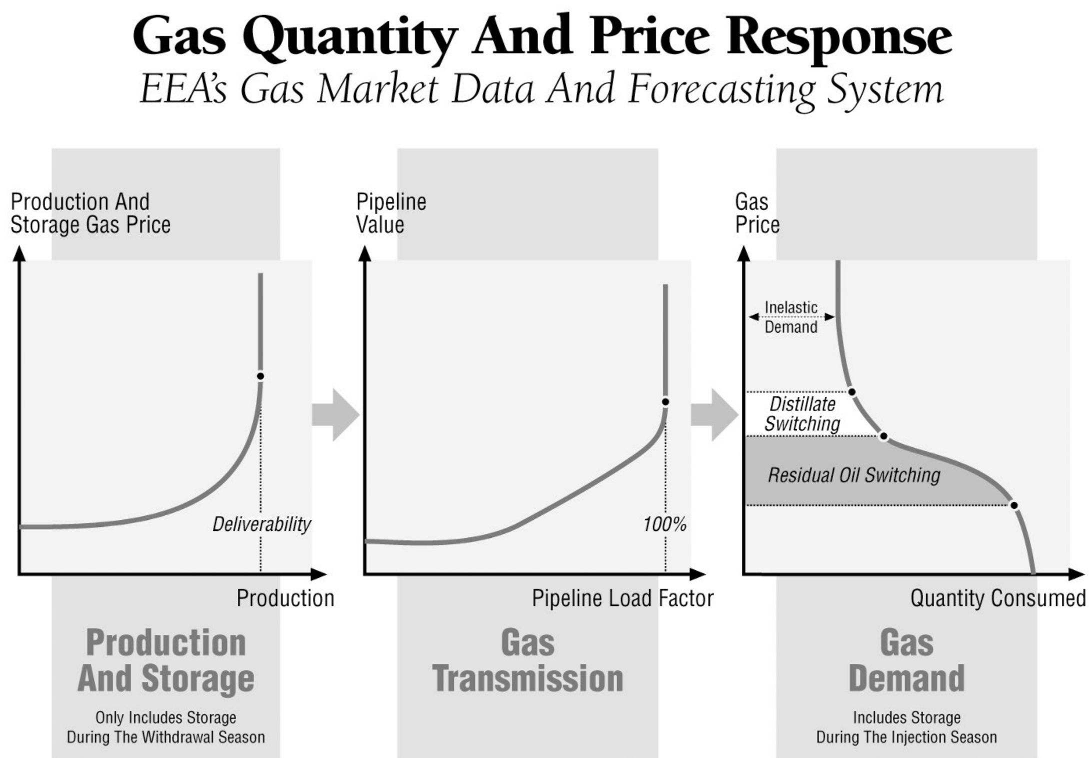
ICF's Gas Market Model (GMM) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed in the mid-1990s to provide forecasts of the U.S. and Canada natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace. Subsequently, GMM has been used to complete strategic planning studies for many private sector companies. The different studies include:

- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

In addition to its use for strategic planning studies, the model has been widely used by a number of institutional clients and advisory councils, including Interstate Natural Gas Association of America (INGAA), which has relied on the GMM for multiple studies over the past ten years. The model was also the primary tool used to complete the widely referenced study on the North American Gas market for the National Petroleum Council in 2003, and the 2010 Natural Gas Market Review for the Ontario Energy Board.

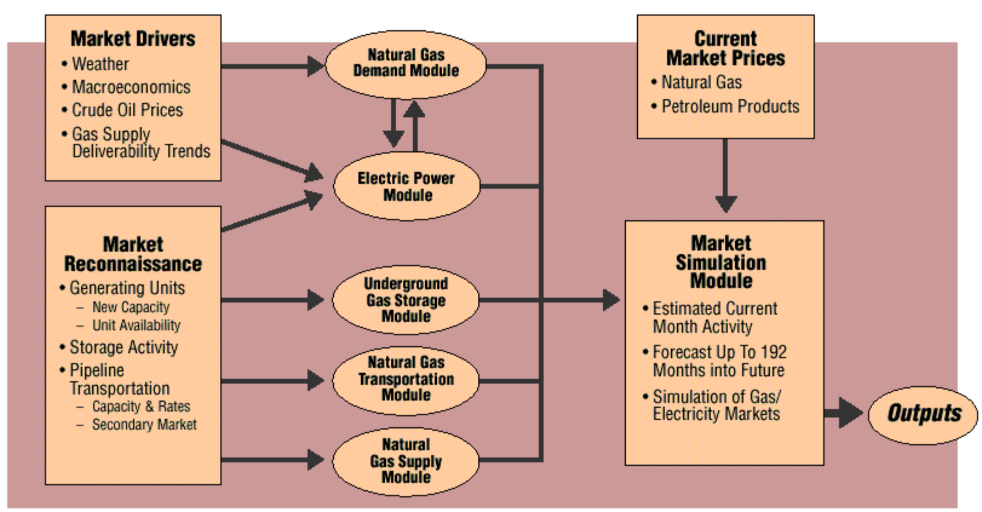
GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by scenario. Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Exhibit C-1) Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. Unlike other commercially available models for the gas industry, ICF does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

Exhibit B-1 ICF's Gas Market Data and Forecasting System



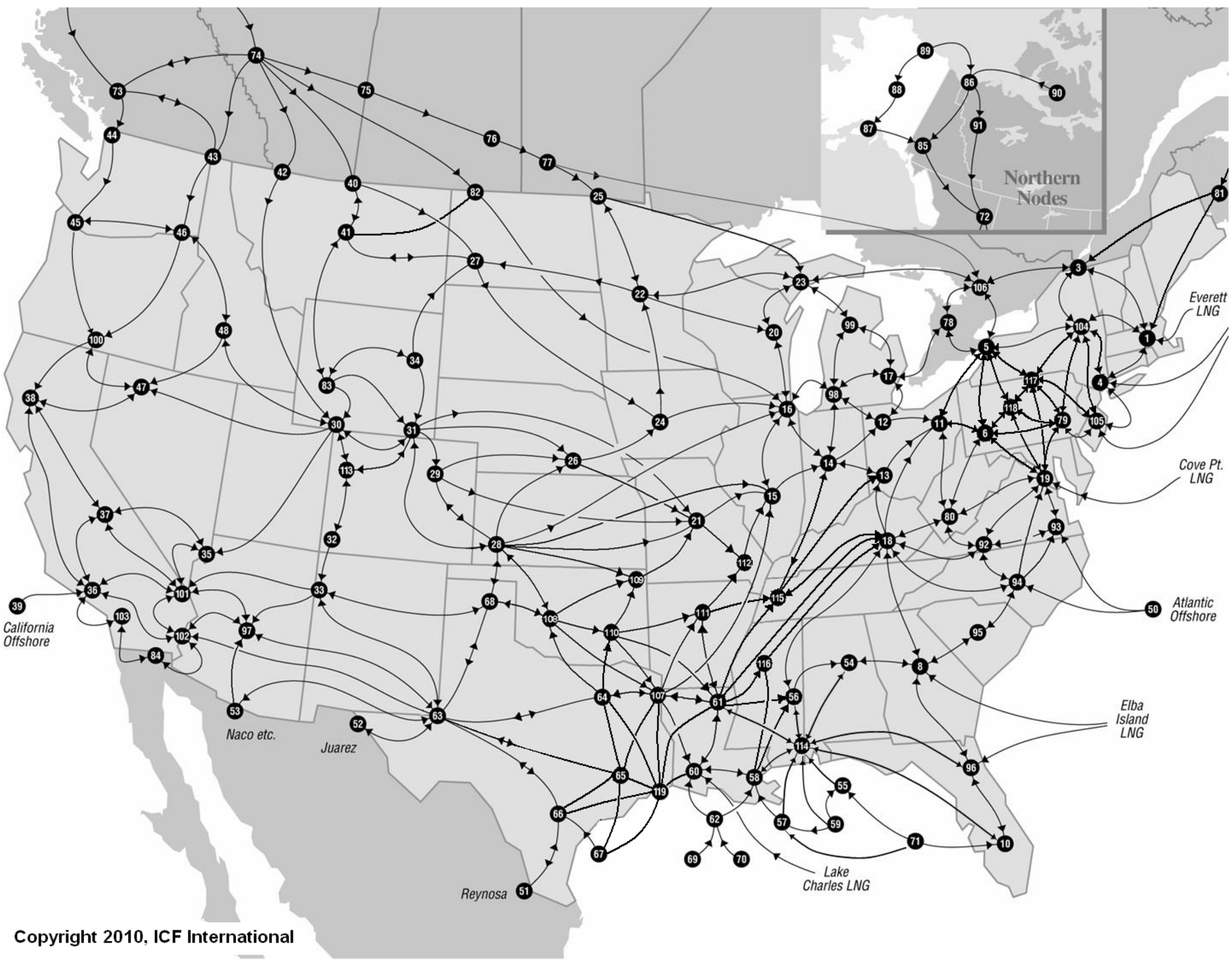
There are nine different components of GMM, as shown in Exhibit C-2. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

Exhibit B-2 GMM Components



The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Exhibit B-3. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import and export levels. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

Exhibit B-3 GMM Transmission Network



POST CONSTRUCTION FINANCIALS

ADAM STIERS, MANAGER, REGULATORY APPLICATIONS – LEAVE TO CONSTRUCT

1. Post Construction Financial Reporting

1. In accordance with Conditions of Approval imposed by the OEB on Leave to Construct (LTC) approvals to file a Post Construction Financial Report in the proceeding where actual capital costs of the Project are proposed to be included in rate base, Enbridge Gas has compiled Post Construction Financial Reports for several projects. The Post Construction Financial Reports provide variance analysis of actual project cost compared to the estimates filed in each LTC proceeding wherever such variance exceeds 5% of total project cost (organized by cost category).

2. Prior to Q2 2015, within the Conditions of Approval, the OEB regularly included the requirement to file a Post Construction Financial Report within 15 months of the Project's final in-service date:

> Condition 1.5: Within 15 months of the final in-service date, Union shall file with the Board Secretary a Post Construction Financial Report. The Report shall indicate the actual capital costs of the project and shall explain all significant variances from the estimates filed in the proceeding.[1]

3. In accordance with those Conditions of Approval, for projects that received OEB approval prior to Q2 2015, Enbridge Gas[2] filed Post Construction Financial Reports within 15 months of the Project in-service date.

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[1] EB-2014-0261, Decision and Order, April 30, 2015, Appendix D, Condition 1.5.
[2] Including both Enbridge Gas Distribution Inc. and Union Gas Limited prior to their amalgamation in 2019.

4. Starting with the OEB's Decision and Order for the Panhandle Replacement Project[3], the OEB no longer required a Post Construction Financial Report to be filed within 15 months of the Project in-service date and instead required Enbridge Gas to file a Post Construction Financial Report in the proceeding where actual capital costs of the Project are proposed to be included in rate base:

> Condition 5: Union shall file, in the proceeding where the actual capital costs of the project are proposed to be included in rate base, a Post Construction Financial Report, which shall indicate the actual capital costs of the project and shall provide an explanation for any significant variances from the cost estimates filed in this proceeding.[4]

5. In accordance with this Condition of Approval, Enbridge Gas is providing Post Construction Financial Reports for the following Projects at Attachment 1:
   - Burlington Oakville Pipeline Project (EB-2014-0182)
   - Panhandle 2015 Replacement Project (EB-2015-0041)
   - Sudbury Expansion Project (EB-2015-0120)
   - Kettle Point & Lambton Shores Community Expansion (EB-2015-0179)
   - Milverton, Rostock, Wartburg Community Expansion (EB-2015-0179)
   - Moraviantown Island Community Expansion (EB-2015-0179)
   - Prince Township Community Expansion (EB-2015-0179)
   - Canadian Nuclear Laboratories (EB-2015-0194)
   - Leamington Pipeline Expansion Project (EB-2016-0013)
   - Seaton Land Development Project (EB-2016-0054)
   - Sudbury Replacement Project (EB-2016-0122)
   - Panhandle Reinforcement Project (EB-2016-0186)

[3] EB-2015-0041, Decision and Order, June 4, 2015.
[4] Ibid, Appendix B, Condition 5.

- Sudbury Maley Replacement Project (EB-2016-0222)
- 2017 Panhandle Replacement Project (EB-2017-0118)
- Fenelon Falls Community Expansion Project (EB-2017-0147)
- Terminus Well and Pipe Project (EB-2017-0162)
- 2018 Sudbury Replacement Project (EB-2017-0180)
- Saugeen First Nation Community Expansion (EB-2019-0187)[5]
- North Bay Community Expansion Project (EB-2019-0188)[6]
- Low Carbon Energy Project (EB-2019-0294)[7]

6. Beginning with the OEB's Decision and Order on the Oxford Reinforcement Project[8], the OEB adjusted Condition 5 to include a requirement to file a Post Construction Financial Report concurrent with the Final Monitoring Report, which is due no later than 15 months after the in-service date, or where the deadline falls between December 1 and May 31, the due date is extended to the following June 1:

> Condition 5: Concurrent with the final monitoring report referred to in Condition 6(b), Union shall file a Post Construction Financial Report, which shall indicate the actual capital costs of the project and shall provide an explanation for any significant

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[5] As an exception to the timing described in Paragraph 6, the Decision and Order in the EB-2019-0187 Proceeding was issued on February 6, 2020, and included no requirement to file a Post Construction Financial Report within 15 months of the Project in-service date. In accordance with Condition 5 at Schedule B, a Post Construction Financial Report will only be filed in the current proceeding, as there is no requirement to file within 15 months of the Project in-service date.
[6] As an exception to the timing described in Paragraph 6, the Decision and Order in the EB-2019-0188 Proceeding was issued on May 7, 2020, and included no requirement to file a Post Construction Financial Report within 15 months of the Project in-service date. In accordance with Condition 6 at Schedule B, a Post Construction Financial Report will only be filed in the current proceeding, as there is no requirement to file within 15 months of the Project in-service date.
[7] As an exception to the timing described in Paragraph 6, the Decision and Order in the EB-2019-0294 Proceeding was issued on October 29, 2020, and included no requirement to file a Post Construction Financial Report within 15 months of the Project in-service date. In accordance with Condition 5 at Schedule C, a Post Construction Financial Report will only be filed in the current proceeding, as there is no requirement to file within 15 months of the Project in-service date.
[8] EB-2018-0003, Decision and Order, May 17, 2018.

variances from the cost estimates filed in this proceeding. Union shall also file a copy of the Post Construction Financial Report in the proceeding where the actual capital costs of the project are proposed to be included in rate base…[9]

7. In accordance with this Condition of Approval, Enbridge Gas is providing a copy of Post Construction Financial Reports for the following Projects at Attachment 2:
   - Scugog Island Community Expansion Project (EB-2017-0261)
   - Dow Moore Storage Pool Drilling (EB-2017-0354)
   - 2018 Oxford Reinforcement Project (EB-2018-0003)
   - Kingsville Transmission Reinforcement Project (EB-2018-0013)[10]
   - Liberty Village Project (EB-2018-0096)
   - Bathurst Reinforcement Project (EB-2018-0097)
   - Don River 30" Pipeline Project (EB-2018-0108)
   - Chatham-Kent Rural Project (EB-2018-0188)
   - Georgian Sands Pipeline Project (EB-2018-0226)
   - Stratford Reinforcement Project (EB-2018-0306)
   - St Laurent Pipeline Project (EB-2019-0006)
   - Windsor Line Replacement Project (EB-2019-0172)[11]
   - Owen Sound Reinforcement Project (EB-2019-0183)
   - Sarnia Reinforcement Project (EB-2019-0218)[12]

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[9] EB-2018-0003 Decision and Order, May 17, 2018, Schedule B, Condition 5.
[10] This report was previously filed in the EB-2018-0013 and has been updated in this proceeding to reflect the final actual Project costs.
[11] This report was not previously filed in the EB-2019-0172 proceeding, as the in-service date for the Project was September 10, 2021. A copy of this report will be filed concurrent with the Final Monitoring Report in the EB-2019-0172 proceeding within 15 months of the in-service date.
[12] This report was not previously filed in the EB-2019-0218 proceeding, as the in-service date for the Project was November 1, 2021. A copy of this report will be filed concurrent with the Final Monitoring Report in the EB-2019-0218 proceeding within 15 months of the in-service date.

2. NPS 20 Waterfront Relocation Project - Licence Agreement Update

8. In the OEB's Decision and Order dated July 7, 2022, for the NPS 20 Waterfront Relocation Project (EB-2022-0003), the OEB ordered Enbridge Gas to bring forward the cost associated with the updated licence agreement between the City of Toronto and Enbridge Gas for the use of the utility corridor for the permanent Enbridge Gas pipeline in its rebasing application to demonstrate its prudence.[13]

9. At the time of submission of Enbridge Gas's responses to interrogatories in the NPS 20 Waterfront Relocation proceeding, Enbridge Gas indicated that the licence agreement was expected to be finalized in August 2022.[14] However, terms and conditions under the licence agreement remain under negotiation and therefore the costs associated with the licence agreement can not be provided at this time. The Company will provide the cost associated with the licence agreement and will file a copy of the executed agreement upon finalization.

[13] EB-2022-0033, Decision and Order, July 7, 2022, p.18.
[14] EB-2022-0003, Exhibit I.STAFF.1, part a).

EB-2014-0182: Burlington Oakville Pipeline Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
	Pipeline Costs				
1	Materials	4,174,000	3,847,909	(326,091)	-8%
2	Construction, Labour and Land	77,698,000	62,314,504	(15,383,496)	-20%
3	Contingency	16,374,000	-	(16,374,000)	-100%
4	IDC	1,662,000	898,451	(763,549)	-46%
5	Subtotal Pipeline Costs	99,908,000	67,060,864	(32,847,136)	-33%
	Station Costs				
6	Materials	4,853,000	4,059,450	(793,550)	-16%
7	Construction, Labour and Land	11,211,000	12,181,627	970,627	9%
8	Contingency	3,213,000	-	(3,213,000)	-100%
9	IDC	292,000	-	(292,000)	-100%
10	Subtotal Stations Cost	19,569,000	16,241,077	(3,327,923)	-17%
8	Total	119,477,000	83,301,941	(36,175,059)	-30%

Variance Explanations:

Item No.	Category	Variance Explanation
2	Construction, Labour and Land	Actual cost for land rights (easements) were significantly lower than the original estimate which was based upon historical land values from similar projects.
3, 8	Contingency	Contingency was not utilized.

EB-2015-0041: 2015 Panhandle Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
1	Materials	995,000.00	1,185,409.00	190,409.00	19%
2	Construction and Labour	7,558,000.00	7,786,948.00	228,948.00	3%
3	Contingency	1,104,000.00	-	(1,104,000.00)	-100%
4	IDC	80,000.00	44,469.00	(35,531.00)	-44%
8	Total	9,737,000.00	9,016,826.00	(720,174.00)	-7%

Variance Explanations:

Item No.	Catgeory	Variance Explanation
3	Contingency	Contingency was partially utilized to offset cost overages in Materials, prime contractor and third-party costs.

EB-2015-0120: Sudbury Expansion Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($) (a)	Actual Cost ($) (b)	Variance to Estimate ($) (c) = (b) - (a)	Variance to Estimate (%) (d) = (c) / (a)
	Pipeline Costs				
1	Pipeline and Equipment	695,000	1,185,242	490,242	71%
2	Construction and Labour	6,444,000	6,767,010	323,010	5%
3	Internal Costs (1)	1,731,000	1,684,721	(46,279)	-3%
4	Contingency	1,331,000	-	(1,331,000)	-100%
5	Subtotal Pipeline Cost	10,201,000	9,636,973	(564,027)	-6%
	Station Costs				
6	Station Equipment	145,000	171,920	26,920	19%
7	Construction and Labour	389,000	425,005	36,005	9%
8	Internal Costs (1)	30,000	64,148	34,148	114%
9	Land	3,000	-	(3,000)	-100%
10	Contingency	57,000	-	(57,000)	-100%
	Subtotal Pipeline Cost	624,000	661,073	37,073	6%
11	Total	10,825,000	10,298,046	(526,954)	-5%

(1) Includes: Company Labour, Inspection, X-Ray, Construction Survey, Legal, Environmental, Archeology, and Permitting

Variance Explanations:

Item No.	Category	Variance Explanation
1	Pipeline and Equipment	Pipeline and Equipment costs were higher than the original estimate due to construction delays and significantly higher steel costs at the time of material purchase than when estimates were completed. Increases in Pipeline and Equipment Costs were offset by Contingency.
2	Construction and Labour	Construction and Labour costs were higher than the original estimate. Deferred construction associated with the northern terminus relocation and postponed City of Sudbury road reconstruction resulted in inflationary increases. Increases to Construction and Labour Costs were offset by Contingency.
4	Contingency	Contingencies were applied to the increase in Pipeline and Equipment, Construction and Labour, and certain Station cost overruns. A small percentage of Contingency was not required.

EB-2015-0179: Community Expansion Proposal
Post Construction Financial Report

Kettle Point & Lambton Shores Expansion Project

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
1	Materials	175,880	186,989	11,109	6%
2	Contract Cost	935,741	1,506,303	570,562	61%
3	Company Costs	22,220	49,376	27,156	122%
4	Miscellaneous	113,510	24,866	(88,644)	-78%
5	Station Labour and Materials	208,239	165,300	(42,939)	-21%
6	Service Costs (10 year)	581,389	164,248	(417,141)	-72%
7	Contingency	58,367	-	(58,367)	-100%
8	Total	2,095,346	2,097,084	1,738	0%

Variance Explanations:

Item No.	Catgeory	Variance Explanation
2	Contract Cost	Contract Costs were higher than estimated due to challenges and resulting cost impacts resulting from Winter Construction and utility locate issues resulting in increased hydrovac costs. Miscellaneous costs are captured in Company & Contract costs (Item No. 2 and 3) due to financial system mapping.
4	Miscellaneous	Miscellaneous costs are captured in Company & Contract costs (Item No. 2 and 3) due to financial system mapping at the time.
6	Service Costs (10 year)	The Company did not track Service Costs for Years 2-9 on a project-specific basis. Community Expansion Service Costs for Year 1 were recorded in the Community Expansion Budget. For the 9 years of service connections following, Service Costs were recorded in regional budgets. As such, the actual variance for this line item is unknown.

Milverton, Rostock, Wartburg Expansion Project

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
1	Materials	702,533	870,145	167,612	24%
2	Contract	2,827,919	4,671,245	1,843,326	65%
3	Company Costs	153,399	175,086	21,687	14%
4	Miscellaneous	458,443	267,819	(190,624)	-42%
5	Station Labour and Materials	348,703	315,512	(33,191)	-10%
6	Service Costs (10 year)	1,289,294	644,878	(644,416)	-50%
7	Contingency	196,000	-	(196,000)	-100%
8	Total	5,976,291	6,944,686	968,395	16%

Variance Explanations:

Item No.	Catgeory	Variance Explanation
2	Contract	Contract Costs were higher than estimated due to challenges with hydrostatic testing, dewatering and odourization of the steel main as well as challenges with the running line. The Milverton portion of the Project also required additional contracted resources to accomodate a compressed timeline.
6	Service Costs	The Company did not track Service Costs for Years 2-9 on a project-specific basis. Community Expansion Service Costs for Year 1 were recorded in the Community Expansion Budget. For the 9 years of service connections following, Service Costs were recorded in regional budgets. As such, the actual variance for this line item is unknown.

Moraviantown Island Expansion Project

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
1	Materials	55,393	68,347	12,954	23%
2	Contractor Costs	252,100	366,436	114,336	45%
3	Company Costs	22,220	31,497	9,277	42%
4	Miscellaneous	99,145	11,306	(87,839)	-89%
5	Service Costs	100,630	113,723	13,093	13%
6	Contingency	34,385	-	(34,385)	-100%
7	Total	563,873	591,309	27,436	5%

Variance Explanations:

Item No.	Catgeory	Variance Explanation
2	Contractor Costs	Contractor costs were higher than estimated due to a change in construction method from ploughing to drilling (requiring additional time), as a result of location of abandoned cable preventing ploughing method. Significant utility congestion also increased hydrovac costs.
4	Miscellaneous	Miscellaneous costs are captured in Company & Contractor costs (Item No. 2 and 3) due to financial system mapping.
5	Service Costs	The Company did not track Service Costs for Years 2-9 on a project-specific basis. Community Expansion Service Costs for Year 1 were recorded in the Community Expansion Budget. For the 9 years of service connections following, Service Costs were recorded in regional budgets. As such, the actual variance for this line item is unknown.
6	Contingency	Contingency was utilized to offset cost overages in Contractor Costs.

Prince Township Expansion Project

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
1	Materials	151,280	185,666	34,386	23%
2	Contractor Costs	1,561,098	1,591,763	30,665	2%
3	Company Costs	14,850	27,843	12,993	87%
4	Miscellaneous	150,675	263,205	112,530	75%
5	Station Labour and Materials	2,500	-	(2,500)	-100%
6	Services	752,161	346,028	(406,133)	-54%
7	Contingency	88,395	-	(88,395)	-100%
8	Total	2,720,959	2,414,505	(306,454)	-11%

Variance Explanations:

Item No.	Catgeory	Variance Explanation
4	Miscellaneous	Miscellaneous costs were higher than estimated due to unforecasted tree clearing & associated clean-up. As a result of the tree clearing an ornithologist was required to be on site to ensure no bird species had nested in any areas with planned tree removal.
6	Services	The Company did not track Service Costs for Years 2-9 on a project-specific basis. Community Expansion Service Costs for Year 1 were recorded in the Community Expansion Budget. For the 9 years of service connections following, Service Costs were recorded in regional budgets. As such, the actual variance for this line item is unknown.

EB-2015-0194: Canadian Nuclear Laboratories Pipeline Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($) (a)	Actual Cost ($) (b)	Variance to Estimate ($) (c) = (b) - (a)	Variance to Estimate (%) (d) = (c) / (a)
1	Materials				
2	Main	826,606	610,187	(216,419)	-26.18
3	Distribution	101,711	111,304	9,593	9.43
4	Stations	894,420	1,182,662	288,242	32.23
5	Construction and Labour			-	
	Main	5,730,322	6,257,705	527,383	9.20
	Distribution	1,694,250	1,786,615	92,365	5.45
	Stations	1,041,238	1,679,270	638,032	61.28
6	External Costs	848,500	1,218,943	370,443	43.66
7	Land Costs	96,500	66,902	(29,598)	-30.67
8	Internal Cost	814,500	484,453	(330,047)	-40.52
9	Contingency	3,358,309		(3,358,309)	-100.00
10	IDC	96,785	243,346	146,561	151.43
8	Total	15,503,141	13,641,387	(1,861,754)	-12.01

Variance Explanations:

Item No.	Category	Variance Explanation
5	Construction and Labour	**Main -** The Company experienced cost overages to perform required pipeline conditioning as a result of the customer decreasing the initial forecasted load below the level required to enable dynamic conditioning. **Station** - The Station drawings were not available at the time of the Project RFP and as such, the duration of construction was underestimated by the contractor. Additionally, the station design needed to be altered due to an unanticipated permit restriction (depth of cover requirements) along the main route. This resulted in the station outlet needing to be reconfigured, significantly more tree clearing and resulting additional costs.
6	External Costs	External Costs overages were due to the Company requiring an external contractor to be used for records related to the Project due to internal resource constraints.
9	Contingency	Contingency was partially utilized to offset overages in Construction and Labour and External Costs.

EB-2016-0013: 2016 Leamington Expansion Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
	Pipeline Costs				
1	Pipeline and Equipment	1,473,000	1,883,988	410,988	28%
2	Construction and Labour	5,868,000	7,434,635	1,566,635	27%
3	Contingency	1,101,000	-	(1,101,000)	-100%
4	IDC	95,000	82,959	(12,041)	-13%
5	Subtotal Pipeline Costs	8,537,000	9,401,582	864,582	10%
	Station Costs				
6	Station Equipment	678,000	715,324	37,324	6%
7	Construction and Labour	2,029,000	438,378	(1,590,622)	-78%
8	Lands	565,000	577,445	12,445	2%
9	Contingency	491,000	-	(491,000)	-100%
10	IDC	44,000	9,111	(34,889)	-79%
11	Subtotal Station Costs	3,807,000	1,740,258	(2,066,742)	-54%
12	Total Cost	12,344,000	11,141,840	(1,202,160)	-10%

Variance Explanations:

Item No.	Catgeory	Variance Explanation
2	Construction and Labour	Actual costs for the pipeline prime contractor were higher than the original estimate. At the time of submission of the Project Application to the OEB, certain contractor estimates remained outstanding and were ultimately higher than initial estimates. Additionally, certain Station Construction and Labour costs were incorrectly recorded under Pipeline Construction and Labour costs and have been adjusted on an actual basis.
3	Contingency	Pipeline Contingency was applied to Pipeline and Equipment and Construction and Labour costs.
7	Construction and Labour	The recorded Station Construction and Labour costs were significantly lower the estimates filed with the OEB. This is a result of Station related contractor costs being incorrectly recorded as Pipeline Construction and Labour costs.

EB-2016-0054: Seaton Development Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
1	Material Cost	524,000	490,243	(33,757)	-6%
2	Labour and Construction Cost	2,366,000	2,258,612	(107,388)	-5%
3	External Costs	338,000	204,484	(133,516)	-40%
4	Land Costs	42,000	21,167	(20,833)	-50%
5	Internal Costs	72,000	98,389	26,389	37%
6	Contingency	668,000	-	(668,000)	-100%
7	IDC	40,672	88,961	48,289	119%
8	Total Cost	4,050,672	3,161,856	(888,816)	-22%

Variance Explanations:

Item No.	Catgeory	Variance Explanation
6	Contingency	Contingency was not utilized as Project risks did not materialize.

EB-2016-0122: 2016 Sudbury Replacement Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($) (a)	Actual Cost ($) (b)	Variance to Estimate ($) (c) = (b) - (a)	Variance to Estimate (%) (d) = (c) / (a)
1	Pipeline and Equipment	98,307	305,847	207,540	211%
2	Construction and Labour	1,838,104	2,285,257	447,153	24%
3	Contingency	251,733	-	(251,733)	-100%
8	Total	2,188,144	2,591,104	402,960	18%

Variance Explanations:

Item No.	Category	Variance Explanation
1	Pipeline and Equipment	Pipeline and Equipment costs were higher than original estimates (based upon historical average unit cost). Steel costs were significantly higher at the time of purchase than when estimates were completed. Increases were offset by using Project Contingency.
2	Construction and Labour	Construction and Labour costs were higher than the original estimate. At the time of Project Application to the OEB, Costruction and Labour cost estimates were based on preliminary engineering design and some third party contractor estimates were still undetermined. Further, late completion of the western section resulted in deferred construction for the eastern section and exposed the Project to inflationary cost increases. Increases were partially offset by contingencies.
3	Contingency	Contingencies were applied to the overages in Pipeline and Equipment as well as Construction and Labour costs.

EB-2016-0186: Panhandle Reinforcement Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($) (a)	Actual Cost ($) (b)	Variance to Estimate ($) (c) = (b) - (a)	Variance to Estimate (%) (d) = (c) / (a)
	Mainline Costs				
1	Materials	16,578,000	15,478,272	**(1,099,728)**	**-7%**
2	Construction and Labour	176,147,000	171,416,630	**(4,730,370)**	**-3%**
3	Contingency	28,909,000	-	**(28,909,000)**	**-100%**
4	IDC	2,321,000	1,582,405	**(738,595)**	**-32%**
5	Subtotal Mainline Costs	223,955,000	188,477,307	**(35,477,693)**	**-16%**
	Dawn M&R Costs				
6	Materials	3,958,000	4,697,105	**739,105**	**19%**
7	Construction and Labour	17,399,000	19,188,066	**1,789,066**	**10%**
8	Contingency	3,204,000	-	**(3,204,000)**	**-100%**
9	IDC	251,000	134,890	**(116,110)**	**-46%**
10	Subtotal Dawn M&R Costs	24,812,000	24,020,061	**(791,939)**	**-3%**
	Dover Center Stn Costs				
11	Materials	381,000	371,285	**(9,715)**	**-3%**
12	Construction and Labour	2,056,000	905,665	**(1,150,335)**	**-56%**
13	Contingency	365,000	-	**(365,000)**	**-100%**
14	IDC	43,000	80,598	**37,598**	**87%**
15	Subtotal Dover Center Stn Costs	2,845,000	1,357,548	**(1,487,452)**	**-52%**
	Dover Transmission Stn Costs				
16	Materials	2,162,000	2,777,597	**615,597**	**28%**
17	Construction and Labour	5,362,000	8,507,163	**3,145,163**	**59%**
18	Contingency	1,128,000	-	**(1,128,000)**	**-100%**
19	IDC	116,000	91,291	**(24,709)**	**-21%**
20	Subtotal Dover Trans Stn Costs	8,768,000	11,376,051	**2,608,051**	**30%**
	Mersea Gate Stn Costs				
21	Materials	721,000	1,155,402	**434,402**	**60%**
22	Construction and Labour	2,790,000	2,285,132	**(504,868)**	**-18%**
23	Contingency	527,000	-	**(527,000)**	**-100%**
24	IDC	50,000	19,062	**(30,938)**	**-62%**
25	Subtotal Mersea Gate Stn Costs	4,088,000	3,459,596	**(628,404)**	**-15%**
26	Total	264,468,000	228,690,563	(35,777,437)	**-14%**

Variance Explanations:

Item No.	Category	Variance Explanation
3, 8, 13, 18, 23	Contingency	Contingency was assigned to address the risk that the Project would be constructed over a two-year period if land rights were not obtained. All lands rights were ultimately obtained for this Project eliminating the need for use of contingency for this Project.

EB-2016-0222: Sudbury Maley Replacement Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($) (a)	Actual Cost ($) (b)	Variance to Estimate ($) (c) = (b) - (a)	Variance to Estimate (%) (d) = (c) / (a)
	Maley Drive Extension Costs				
1	Pipeline and Easement	355,912	571,769	215,857	61%
2	Construction and Labour	4,953,781	5,133,276	179,495	4%
3	Contingency	639,442	-	(639,442)	-100%
4	Subtotal Marley Dr Ext Costs	5,949,135	5,705,045	(244,090)	-4%
	Notre Dame Crossing Costs				
5	Pipeline and Easement	17,270	19,112	1,842	11%
6	Construction and Labour	306,307	306,245	(62)	0%
7	Contingency	31,029	-	(31,029)	-100%
8	Subtotal Notre Dame Crossing Costs	354,606	325,357	(29,249)	-8%
9	Total	6,303,741	6,030,403	(273,338)	-4%

Variance Explanations:

Item No.	Category	Variance Explanation
1	Pipeline and Easement	Pipeline and Easement costs for the Maley Drive Extension were higher due to an increase in steel pipe wall thickness (as the Company was unable to purchase thinner wall pipe), additional land rights, additional temporary land use and delayed completion of construction of the east section. Increases were covered by contingency.
3	Contingency	Contingencies for the Maley Drive Extension were applied to the increase in Pipeline and Easement as well as Construction and Labour. Approximately forty percent of Contingency was unused.

EB-2017-0118: Panhandle Jefferson Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($) (a)	Actual Cost ($) (b)	Variance to Estimate ($) (c) = (b) - (a)	Variance to Estimate (%) (d) = (c) / (a)
1	Pipeline and Easement	250,000	250,471	471	0%
2	Construction and Labour	1,085,000	891,918	(193,082)	-18%
3	Contingency	133,500	-	(133,500)	-100%
4	IDC	50,000	-	(50,000)	-100%
5	Total	1,518,500	1,142,390	(376,110)	-25%

Variance Explanations:

Item No.	Category	Variance Explanation
2	Construction and Labour	Construction and Labour costs were lower than the original estimate (based on historical average unit cost). Unforseen construction efficiencies with nearby projects sharing resources also contributed to an overall reduction.
3	Contingency	Contingency for the project was not utilized as Project risks did not materialize.

EB-2017-0147: Fenlon Falls Community Expansion Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($) (a)	Actual Cost ($) (b)	Variance to Estimate ($) (c) = (b) - (a)	Variance to Estimate (%) (d) = (c) / (a)
1	Materials	2,579,787	1,586,249	(993,538)	-39%
2	Construction and Labour	16,581,601	23,091,904	6,510,303	39%
3	External Costs	1,401,180	2,213,808	812,628	58%
4	Station Cost	60,000	53,367	(6,633)	-11%
5	Contingency	2,062,257	-	(2,062,257)	-100%
6	IDC	370,663	965,414	594,751	160%
7	Total	23,055,488	27,910,741	4,855,253	21%

Variance Explanations:

Item No.	Category	Variance Explanation
2	Construction and Labour	Construction encountered more rock than originally anticipated based on desktop information, increasing construction costs for both pipelin main and customer services significantly. As a condition of issuing permits, the MTO required deeper installation than anticipated on all highway
5	Contingency	Contingency for the Project was fully utilized for Construction and Labour cost overages.

EB-2017-0162: Terminus Well Drilling Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
	Materials				
1	Casing	168,000	168806	806	0%
2	Wellhead	128,000	126517	(1,483)	-1%
3	Gathering Pipe	96,000	93778	(2,222)	-2%
4	Subtotal Materials	392,000	389101	(2,899)	-1%
5	**Labour**	61,000	61366	366	1%
6	**Contracts**				
7	Drilling Contracts	255,000	334550	79,550	31%
8	Minor Contracts	300,000	369354	69,354	23%
9	Surface Piping	330,000	179610	(150,390)	-46%
10	Seismic Interpretation	100,000	100544	544	1%
11	Site Construction/Restoration	125,000	130519	(942)	-1%
12	Subtotal Contracts	1,110,000	1114577	(1,884)	0%
13	**Contingency**	234,000	-		
12	Total Cost	1,797,000	1,565,044	(231,956)	-13%

Variance Explanations:

Item No.	Category	Variance Explanation
7	Drilling Contracts	Drilling activities took longer than originally estimated.
9	Surface Piping	The original estimate for Surface Piping was derived with the assumption that an external contractor would install the Surface Pipe. Due to the size of the Project and timing, internal employee labour was utilized and significantly lowered the Surface Piping costs.

EB-2017-0180: 2018 Sudbury Replacement Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($) (a)	Actual Cost ($) (b)	Variance to Estimate ($) (c) = (b) - (a)	Variance to Estimate (%) (d) = (c) / (a)
1	Materials	5,379,000.00	5,518,192.49	139,192.49	3%
2	Construction and Labour	58,361,000.00	76,568,168.46	18,207,168.46	31%
3	Contingency	9,561,000.00	-	(9,561,000.00)	-100%
4	IDC	756,000.00	689,876.85	(66,123.15)	-9%
5	Total	74,057,000.00	82,776,237.80	8,719,237.80	12%

Variance Explanations:

Item No.	Category	Variance Explanation
2	Construction and Labour	Construction and Labour costs were higher than estimated due to permit conditions and challenges during pipeline installation. Environmental permitting was required (in several areas along the right of way) to be completed earlier than planned, requiring additional resources and overtime to meet permit conditions. Environmentally sensitive areas along the right of way were larger than expected resulting in the use of several thousand additional access mats. Construction and Installation costs also exceeded the Project Estimate due to unexpected rocky conditions. Further, safety processes and procedures required to work within Vale property were more costly than anticipated.
3	Contingency	Contingency was fully used to manage cost overages associated with the general contractor (additional resources and overtime), environmental permitting and mitigation as well as construction management.

EB-2019-0187: Saugeen First Nation Community Expansion Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($) (a)	Actual Cost ($) (b)	Variance to Estimate ($) (c) = (b) - (a)	Variance to Estimate (%) (d) = (c) / (a)
1	Materials	45,331	86,759	41,428	91%
2	Contract Costs	1,553,796	2,426,718	872,922	56%
3	Company Costs	94,500	102,135	7,635	8%
4	Miscellaneous	176,041	209,115	33,074	19%
5	Stations	67,468	33,608	(33,860)	-50%
6	Contingency	195,909	-	(195,909)	-100%
7	IDC	23,315	1,894	(21,421)	-92%
8	Service Costs (10 year)	381,000	198,770	(182,230)	-48%
9	Total	2,537,360	3,058,999	521,639	21%

Variance Explanations:

Item No.	Category	Variance Explanation
2	Contract Costs	Several areas of archeological significance were identified, as well as challenging ground conditions due to water table levels, increased depth of cover requirements and additional hydrovac required to locate utilities, all of which led to increased Contractor Costs.
8	Service Costs (10 year)	The total Service Costs associated with the 10-year customer attachment forecast were estimated to be $381,000. The actuals to date total $198,770. The table above shows a positive variance for service costs as a result of timing, as actuals have not occurred for the majority of year 3 or years 4-10. However, the Company is forecasting total Service Costs to be higher than estimated due to actual connection costs on a per-service basis being higher than the amount estimated due to challenging ground conditions from high water tables, archeologically sensitive areas (sometimes requiring additional permitting) and additional utility locating and hydrovac costs.

EB-2019-0188: North Bay Community Expansion Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($) (a)	Actual Cost ($) (b)	Variance to Estimate ($) (c) = (b) - (a)	Variance to Estimate (%) (d) = (c) / (a)
1	Materials	192,456	225,503	33,047	17%
2	Contract Cost	5,886,463	8,583,306	2,696,843	46%
3	Company Costs	257,355	286,865	29,510	11%
4	Miscellaneous	702,110	719,429	17,319	2%
5	Station Cost	257,632	366,798	109,166	42%
6	Contingency	729,602	-	-	-
7	IDC	98,632	36,343	(62,289)	-63%
8	Service Costs	1,971,000	1,643,397	(327,603)	-17%
10	Total	10,095,250	11,861,640	1,766,390	17%

Variance Explanations:

Item No.	Category	Variance Explanation
2	Contract Cost	Challenges and increased costs due to excess soil management & policy requirements, sewer lateral locate process, additional Contractors compared to estimate, additional land requirements compared to estimate, survey and material costs due to shared driveways not originally identified, and significant rock encountered on Northshore Road that was not identified in the construction pre-work.
8	Service Costs (10 year)	The total Service Costs associated with the 10-year customer attachment forecast were estimated to be $1,971,000. The actuals to date total $1,643,397. The table above shows a positive variance for service costs as a result of timing, as actuals have not occurred for Years 3-10. However, the Company is forecasting Service Costs to be higher than estimated due to an increase in service connections compared to forecast. The Project forecasted 134 service connections over the 10-year attachment forecast period, to date there have been 151 connections.

EB-2019-0294: Low Carbon Energy Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
	Material Costs				
1	Pipeline Material	133,000	213,732	80,732	61%
2	Other Stations Material	115,000	409,317	294,317	256%
3	Hydrogen Blending Station	693,000	1,149,691	456,691	66%
4	**Total Material Costs**	941,000	1,772,740	831,740	88%
	Labour Costs				
5	Pipeline Labour Costs	947,000	1,574,045	627,045	66%
6	Stations Labour Cost	337,000	823,536	486,536	144%
7	**Total Labour Cost**	1,284,000	2,397,581	1,113,581	87%
8	External Permitting, Land, Environmental & Regulatory Cost	20,000	15,703	(4,297)	-21%
	Outside Services				
9	Outside Services - Pipeline	716,000	792,501	76,501	11%
10	Outside Services - Stations	45,000	281,689	236,689	526%
11	Total Outside Services	761,000	1,074,190	313,190	41%
12	Direct Overheads	105,000	174,286	69,286	66%
13	Contingency Costs	778,000		(778,000)	-100%
14	**Project Cost**	3,889,000	5,434,500	1,545,500	40%
15	Indirect Overheads	1,260,395	1,241,231	(19,164)	-2%
16	IDC	82,870	103,598	20,728	25%
17	**Total Cost**	5,232,265	6,779,329	1,547,064	30%

Notes: Clean up and restoration work on the Low Carbon Energy Project is still ongoing. Within the actual cost column, Enbridge Gas has included $11,200 of forecasted remaining capital costs and $44,834 of forecasted IDC charges to be incurred until Dec 2022.

Variance Explanations:

Item No.	Category	Variance Explanation
3	Hydrogen Blending Station	The primary driver in the variance within the Hydrogen Blending Station Materials was largely due to the additional components that were identified as a requirement by Engineering through the design process that were not included in the class 4 estimate in the original LTC application. At high level, this included: the Gas Chromatograph ($175k), Filter Station ($128k), as well as other station safety features and critical station spare parts.
5	Pipeline Labour Costs	Pipeline Labour Costs were higher than estimated due to various attributes during the project. Extra costs were attributed to welding procedures; specified procedures required to weld the pipeline took extra time to complete. The tie in excavation was deeper than anticipated and took extra time to hydrovac and shore excavation. Civil/grading designs were at a preliminary stag, Enbridge Gas incurred additional costs to grade and restore adjacent lands to the station for topsoil and seed.
6	Stations Labour Cost	At the time of the LTC application, electrical and civil were not yet designed. Higher labour costs are attributed to the high cost for electrical trenching/cabling to feed the new station as well as civil labour costs for the Hydrogen Blending Station Compound.
13	Contingency	Contingency for the Project was fully utilized on Materials and Labour Cost overages.

Scugog Island – Community Expansion Project (EB-2017-0261)

Post Construction Financial Report on Costs and Variances

Aug 12, 2021

Introduction

On December 15, 2017, Enbridge Gas Distribution Inc. ("Enbridge Gas" or the "Company") applied to the Ontario Energy Board ("OEB") under sections 36, 90 and 97 of the *Ontario Energy Board Act* (the "Act") for approvals to serve the community of Scugog Island, in the Town of Scugog, in the Regional Municipality of Durham (the "Project"). In its May 31, 2018, Decision and Order the OEB granted Enbridge Gas:

- Leave to Construct ("LTC") 7 km of NPS 4 extra high-pressure steel natural gas pipeline;
- Approval of the proposed form easement (land use) agreements; and
- Approval to charge a System Expansion Surcharge ("SES") of $0.23 per cubic metre of natural gas for the term of 40 years to all new customers taking distribution service from the facilities in the community of Scugog Island.

Construction activities for the Project commenced on December 9, 2019 and the related facilities were placed into service on May 12, 2020.[1]

This Post Construction Financial Report was prepared to satisfy Condition 5 of the Conditions of Approval set out in the OEB's Decision and Order:

> 5. Concurrent with the final monitoring report referred to in Condition 6(b), Enbridge shall file a Post Construction Financial Report, which shall indicate the actual capital costs of the project and shall provide an explanation for any significant variances from the cost estimates filed in this proceeding. Enbridge shall also file a copy of the Post Construction Financial Report in the proceeding where the actual capital costs of the project are proposed to be included in rate base or any proceeding where Enbridge proposes to start collecting revenues associated with the project, whichever is earlier.

This report summarizes estimated[2] and actual capital costs of the Project (see Table 1), and provides explanations for significant variances.

[1] Construction is ongoing on related distribution mains and customer services.
[2] EB-2017-0261, Exhibit E, Tab 2, Schedule 1, P. 1

Table 1: Total Project Costs

Item	Project Estimate ($)	Actual Cost ($)	Variance ($)
1.0 Material Cost	550,767	433,364	117,403
2.0 Labour and Construction Cost	2,040,000	5,642,759	(3,602,759)
3.0 External Costs	459,600	919,124	(459,524)
4.0 Station Cost	60,000	62,168	(2,168)
5.0 Contingency	311,037	-	311,037
6.0 Interest During Construction	27,542	52,962	(25,420)
Total	**3,448,946**	**7,110,377**	**(3,661,431)**

1.0 Overview

The actual costs of construction for the Project exceeded project estimates by approximately $3.60 million. Two common factors that impacted nearly all cost categories set out in Table 1 were:

- **Inflation:** Project estimates were forecast and filed with the OEB in December 2017. Construction of the Project was not completed until July 6, 2020 leading to overall increased costs due to inflation.
- **Complexity of Construction:** While the original project estimate was prepared with the best information available at the time, the cost of construction proved to be significantly higher, mainly driven by changes in the design and permitting stage requirements, as described below.

2.0 Labour and Construction

Final Labour and Construction costs were approximately $3.66 million higher than originally estimated, due to: (i) changes to methods of construction; (ii) unanticipated Ministry of Transportation (“MTO”) permit requirements and related permit delay; (iii) the requirement to construct during the winter season; and (iv) the unprecedented and ongoing COVID-19 pandemic.

2.1 Methods of Construction Change

When Project costs were estimated, the Company assumed that most construction work would be done via open cut adjacent to the road edge. This was not possible due to unforeseen ground conditions, environmental sensitivities and MTO requirements for permit issuance.

Geotechnical and hydrogeological data collected during the design phase indicated a high water table with high hydraulic conductivity type soil, particularly in the western segment of the highway (wetland area). As a result, the Company needed to change the method of construction from open cut to directional drill, to minimize the environmental impact of potential excessive dewatering.

Targeted Species at Risk ("SAR") field surveys were conducted during the design phase, which identified the likelihood of encountering Blanding's Turtle (*Emydoidea blandingii*). Modifying the construction method from open trench to directional drill was preferred to mitigate impacts to Blanding's Turtle, and was approved by the Ministry of Conservation and Parks ("MECP") as a mitigation measure.

With the aim of minimizing its exposure to future costs and risk when working in the vicinity of buried natural gas pipelines, and as a condition of issuing a permit, the MTO requested that the pipeline be installed at a greater minimum depth and closer to the Right-of-Way ("ROW") street line than the Company's standard. Both the increased depth and running line requirement necessitated the pipeline be installed via horizontal directional drill, to avoid deep trenched excavations with shoring and to avoid vegetation clearing in the ROW. The MTO also requested a complex traffic control plan and a special condition for the pipeline construction along Highway 7A in response to highway structural concerns. This involved conducting an engineered settlement discharge and monitoring plan to mitigate the risk of potential road collapse during pipeline drilling.

2.2 MTO Requirements and Permit Delay

Iterative engineering re-design work and the additional engineered plan associated with the conditions discussed in section 2.1 above, significantly delayed the MTO permit and consequently the Project execution start date. The permit delay resulted in idle staff and an accelerated construction schedule consisting of additional contractor crews and equipment, and overtime hours, required to meet the environmental species at risk construction window for Blanding's Turtles.

2.3 Winter Construction

The MTO permit delays described in section 2.2 forced the timing of pipeline construction into the winter months of February to March where weather and ground conditions impacted the cost of construction. Winter construction was also determined to be the preferred timing of construction to mitigate impacts to Blanding's Turtle (which have an active nesting season from April 1 – September 30), as well as to limit the amount of potential dewatering that may be required during project work due to frost and frozen ground conditions, as discussed in Section 2.1.

2.4 COVID-19 Pandemic

The unprecedented and ongoing COVID-19 pandemic began while the project was in execution. In response to government mandates, changes were made to day-to-day construction operations, including additional: sanitization and PPE, washing stations, and trucks to meet social distancing requirements.

3.0 External Costs

Final External Costs were approximately $0.5 million higher than originally estimated, due to: (i) additional geotechnical and hydrogeological work; (ii) external pipeline inspection; and (iii) pipeline conditioning.

3.1 Additional Geotechnical and Hydrogeological Work

As discussed in section 2.1 above, as a condition of permit approval, MTO required a settlement discharge and monitoring plan along highway 7A to address highway structural concerns. This engineered design and associated field support was completed by external third parties.

3.2 External Pipeline Inspection

In December 2017, when the LTC application for this project was originally filed with the OEB, it was determined that internal company pipeline inspectors would be used for the Project. However, additional external pipeline inspectors were required for the entirety of the Project due to the accelerated schedule discussed in section 2.2 above.

Further, due to unforeseen environmental sensitivities and complexities of the Project, including dewatering and SAR, an external environmental inspector was also hired to support construction execution in the field to support and ensure all mitigation measures were followed during the accelerated schedule.

3.3 Pipeline Conditioning

As a result of the MTO permit delay and project in service date requirements, the 7 km of steel NPS 4 extra high-pressure pipeline required additional resources to prepare, manage and execute the conditioning plan.

POST CONSTRUCTION FINANCIAL REPORT

DOW-MOORE STORAGE POOL WELL DRILLING PROJECT

1. In compliance with Condition No. 6 of the Ontario Energy Board's ("OEB") Proposed Conditions of License included in its February 21, 2019 Report to the Minister of Natural Resources and Forestry ("MNRF") regarding the application of Enbridge Gas Inc. ("Enbridge Gas") to drill wells in the Dow-Moore Storage Pool ("Report") (EB-2017-0354), Table 1 below summarizes the capital costs (pre-spend, estimated, and actual) for the Project and provides variance explanations.

2. As discussed by the OEB in its Report to the MNRF,

> The two new horizontal wells will form part of Enbridge's regulated storage operations and the abandoned and converted wells are a part of regulated storage assets…The capital costs will be capitalized and included in rate base…There is not anticipated to be a rate impact to Enbridge customers from the drilling of the wells until the costs are included in rate base in 2024.[1]

3. As set out in Table 1, actual Project costs were $10,185,186 compared to the projected/estimated Project cost of $8,877,796 resulting in a capital cost variance of $1,307,390 (15%). In addition, Enbridge Gas has included certain pre-spend Project costs that were not included in its original application.

[1] Report, p. 3.

Table 1: Capital Costs of Dow-Moore Storage Pool Project

	Pre-spend [1] Project Costs *(2016 to 2018)* $ *a*	Estimated Project Costs *(Exhibit D, Tab 1, Schedule 1)* $ *b*	Total Estimated Project Costs $ *a + b = c*	Actual Project Costs $ *d*	Variance $ *(d - c)*	Variance % *(c ÷ d)*
TD 26 – A-1 Observation Well [2]	$ 212,040	$ 1,363,900	$ 1,575,940	$ 2,531,889	$ 955,949	61%
TD 27 – Guelph Observation Well [3]	$ 0	$ 1,534,100	$ 1,534,100	$ 1,249,532	$ (284,568)	(19)%
TD 28H – Horizontal Storage Well [4]	$ 1,076,631	$ 1,800,000	$ 2,876,631	$ 3,049,308	$ 172,677	6%
TD 29H – Horizontal Storage Well [5]	$ 1,015,225	$ 1,875,900	$ 2,891,125	$ 3,354,457	$ 463,332	16%
Total Project Capital Costs	**$ 2,303,896**	**$ 6,573,900**	**$ 8,877,796**	**$ 10,185,186**	**$ 1,307,390**	**15%**

Variance Discussion Notes:

(1) Pre-spend Project Costs (2016-2018)

The Estimated Project Costs set out in Enbridge Gas's application and pre-filed evidence,[2] excluded Pre-spend Project Costs incurred from 2016 to 2018. As part of its 2024 Rebasing application, Enbridge Gas expects that it will seek to recover all prudently incurred Project costs from ratepayers (both Pre-spend and Estimated Project costs). Accordingly, the Total Estimated Project Costs include Pre-spend and Estimated Project costs (columns a and b) compared to Actual Project Costs (column d) to calculate the respective Variance ($ and %) for each aspect of the Project.

(2) TD 26 – A1 Observation Well Variance

Costs (i.e. fuel, labour and daily drilling costs) for the drilling of TD 26 were higher than original estimates due to the need to utilize a smaller diameter wellbore and a drilling rig capable of handling smaller diameter drill pipe (Enbridge Gas originally intended to utilize a single drilling rig for all wellbores). The purchase price for gravel required to build the drill pad and laneway

[2] Exhibit D, Tab 1, Schedule 1.

(as well as the required length of laneway) was also higher than estimated.

(3) TD 27 – Guelph Observation Well

Costs for the drilling of TD 27 were lower than original estimates due to reduced material costs.

(4) TD 28H – Horizontal Storage Well

Costs (i.e. fuel, labour and daily drilling costs) for the drilling of TD 28H were higher than original estimates due to the need to utilize a snubbing unit to safely remove the drill string from the well. The purchase price for gravel required to build the drill pad and laneway was also higher than estimated.

(5) TD 29H – Horizontal Storage Well

Costs (i.e. fuel, labour and daily drilling costs) for the drilling of TD 29H were higher than original estimates due to the need to strand approximately 61 metres of drilling tools in the initial well that was drilled. After several failed attempts to recover those drilling tools, a portion of the original well was abandoned and subsequently re-drilled. The purchase price for gravel required to build the drill pad and laneway was also higher than estimated.

POST CONSTRUCTION FINANCIAL REPORT
2018 Oxford Replacement Project

In compliance with the Ontario Energy Board Order EB-2018-0003 and Condition 5, the following is a report on the capital pipeline and station cost for the 2018 Oxford Replacement project.

The Project actual cost was $4,662,754 or 37% lower than estimated. The following explains any significant variances.

		Baseline	Actual Costs	Variance	Variance
		$	$	$	%
	Mainline				
(1)	Pipeline and Equipment	$ 1,071,000	$ 1,028,840	$ 42,160	4%
(2)	Construction and Labour	$ 5,360,000	$ 3,602,590	$ 1,757,410	33%
(3)	Contingency	$ 965,000	$ -	$ 965,000	-100%
(4)	IDC		$ 31,324	-$ 31,324	100%
	Total Project Capital Costs	$ 7,396,000	$ 4,662,754	$ 2,733,246	37%

1) Actual cost for Material and Equipment for the Project were slightly lower than original estimates which were based upon historical average unit cost.

2) Actual cost for Prime Contractor, Miscellaneous Outside Services, and Land were all lower than the original estimate. Key reasons for being under budget include: excellent weld production rates (low repair rate), contractor efficiencies with nearby projects sharing resources, NDE contractor time on site was optimized, and limited inclement weather impact.

3) Contingency for the project was not used because other forecast costs came in lower than estimated.

4) Interest During Construction actuals are shown separately. These costs were not separated during the OEB application.

EB-2018-0013: Kingsville Transmission Reinforcement Project
Post Construction Financial Report Update

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
	Pipeline Costs				
1	Materials *Updated	5,514,000	4,839,525	(674,475)	-12%
2	Construction and Labour *Updated	76,917,000	57,347,855	(19,569,145)	-25%
3	Contingency	12,365,000	-	(12,365,000)	-100%
4	IDC	1,332,000	689,392	(642,608)	-48%
5	Subtotal Pipeline Costs	96,128,000	62,876,772	(33,251,228)	-35%
	Station Costs				
6	Materials	2,210,000	4,075,070	1,865,070	84%
7	Construction and Labour	6,014,000	10,088,613	4,074,613	68%
8	Contingency	1,234,000	-	(1,234,000)	-100%
9	IDC	130,000	2,104	(127,896)	-98%
10	Subtotal Station Costs	9,588,000	14,165,787	4,577,787	48%
11	Total	105,716,000	77,042,559	(28,673,441)	-27%
12	Previously Reported Total	105,716,000	77,536,741	(28,179,259)	-27%
11	Update (Variance Decrease)	-	(494,182)	(494,182)	

Variance Explanations:

Item No.	Catgeory	Variance Explanation
1	Materials *Updated	Costs for Project Materials were lower than original estimates (based upon historical average unit cost). In its Post Construction Financial Report filed January 13, 2021 (See Page 10 of Attachment 1), Enbridge Gas reported Materials costs of $4,857,359. However, at that time Enbridge Gas had not yet recorded all Project Materials costs. Accordingly, the final costs of Materials for the pipeline is $4,839,525.
2	Construction and Labour *Updated	Costs for pipeline Construction and Labour were lower than estimated due to the favorable negotiation of lands rights and expropriation costs not being utilized. Expected environmental and contractor costs were also not realized. In its Post Construction Financial Report filed January 13, 2021 (See Page 10 of Attachment 1), Enbridge Gas reported $57,824,204 as the actual cost of Construction and Labour for the pipeline. However, at that time Enbridge Gas had not yet recorded all pipeline costs for Construction and Labour. Accordingly, the final costs of Construction and Labour for the pipeline is $57,347,855.
3	Contingency	Pipeline contingency was not utilized as Project risks did not materialize.
4	IDC	Original Interest During Construction calculation accounted for the use of contingency and risk which did not occur.
7	Construction and Labour	Costs for station Construction and Labour were higher than estimated due to design changes and unexpected clean up work required.

Liberty Village Reinforcement Project

EB-2018-0096

Post-Construction Financial Report on Costs and Variances

June 24, 2020

Introduction

Enbridge Gas Distribution Inc. ("Enbridge") filed an application with the Ontario Energy Board (the "Board") on April 9, 2018, under section 90 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B for an order granting Leave to Construct of approximately 1.2 kilometers of natural gas pipeline in the City of Toronto. The project is comprised of two sections of pipeline. The first section of pipeline is reinforcement to the existing distribution system and the second section of pipeline will allow the provision of gas distribution service to new customers in the Liberty Village. The first section of the proposed pipeline is 900 m of Nominal Pipeline Size ("NPS 8") Intermediate Pressure ("IP") steel natural gas main. The second section of the proposed pipeline consists of two individual segments of pipe. The first segment, which is approximately 200 m of Nominal Pipeline Size ("NPS 6") Intermediate Pressure ("IP") plastic gas main on Strachan Avenue and the second segment is approximately 85 m of Nominal Pipeline Size ("NPS 4") Intermediate Pressure ("IP") plastic gas main on Western Battery Road.

The Board assigned the file number EB-2018-0096 to the application and granted Leave to Construct on September 27, 2018.

Pipeline construction activities for the Liberty Village Reinforcement Project commenced in October 2018 and were completed in March 2019. Most of the restoration activities were completed in March 2019. Additional restoration activities were completed in June and July of 2019.

This Post-Construction Financial Report summarizes the actual capital costs of the project and provides an explanation of significant variances from the original estimates.

Cost and Variance Reporting

The total project cost was $4,151,681. This project total was approximately $528 thousand greater than the original estimate of $3.6 million reported in **EB-2012-0438**, Exhibit D, Tab 2, Schedule 1.

A comparison of actual versus estimated project costs is shown in Table 1 below.

Table 1 – Total Project Costs

Liberty Village Reinforcement Project

Item No.	Breakdown	Budgeted Cost ($)	Actual Cost ($)	Variance ($)
1.0	Material Costs	98,750	76,490	(22,260)
2.0	Labour Costs	2,778,066	4,048,493	1,270,427
3.0	Land Costs	47,170	11,128	(36,042)
4.0	Contingency Costs	687,997	0	(687,997)
5.0	Interest During Construction	11,279	15,570	4,291
6.0	Total Project Cost	3,623,263	4,151,681	528,418

The primary factors which contributed to the actual costs exceeding the original filed budget was the estimated cost of permanent restoration at the time of filing the application, scope changes due to utility conflicts, running line changes, and costs associated with encountering contaminated soil.

Weather was another factor affecting the costs during the construction phase. Approximately 15 days of downtime due to weather increased contractor labour costs and extended the construction schedule.

The cost variances in the specific categories are described below.

1.0 The final 'Material Costs' were $ 76,490, approximately $22 thousand less than expected at the time of filing.

2.0 The final labour cost was $4 million, approximately $1.3 million higher than the estimate originally provided.

Contaminated Soil - The labour budget at the time of the LTC filing did not account for the removal and disposal of contaminated soils. Contaminated soils were encountered on Ordnance St, King St and parts of East Liberty St. As a result, a Suspect Soil Management Plan was developed and a Consultant was hired to test the soil quality both during and ahead of construction to ensure the Contractor was aware of the soil contaminates and how to protect the safety of the workers. The contaminated soils had to be hauled to an alternative site for disposal at a higher rate for disposal than what was anticipated.

Restoration work – The original budgetary estimate provided by Enbridge's City of Toronto approved restoration contractor, Bevcon, was based on a preliminary pipeline route drawing which had several field changes during construction. A summary of changes which led to the increased costs are listed below:

- The original estimate for road work was based on a 1m wide trench. Actual road trench varied in size from 1.5m to over 3m. This increased the area of roadwork required. The reason for inconsistent trench widths were mainly due to line changes as a result of utility conflicts.
- The City of Toronto standard which requires the contractor to remove all pavement up to the closest curb line if the work area is within 1m of the curb line. A significant portion of the road trench along East Liberty Street fell under this guideline. The drawings at the time of the estimate had the pipeline right on the border of 1 meter from the curb line. In construction, it was not possible to maintain the 1 meter clearance which resulted in complete restoration right up to the curb line.
- The original cost estimate was based on a composite pavement structure roadway. No boreholes or geo-technical investigation was available at the time of the estimate. Without boreholes or Geo-technical reports available there was no way to know exactly what the pavement was composed of. The City of Toronto uses 3 different pavement structures; flexible pavements, which are composed entirely of asphalt; Composite pavements, which combine a concrete road base with an asphalt surface course; and Rigid pavements, which are constructed entirely out of concrete. Generally, from experience and past projects in the area of Liberty Village, the pavement is of a composite structure. Once onsite however, it was determined that approximately 65% of the pavement was composed of flexible pavement of varying depths ranging from 160mm - 220mm. This in turn increased the amount of asphalt required.
- Changes in proposed gas line location: Due to conflicts with other underground utilities the new gas line was installed wherever space with the appropriate clearances could be found. This increased the area that required restoration on Atlantic Ave. as the roadway was already cut as per the original location of the proposed pipeline.
- Reconstruction of tree pits: Due to the way the streetscape was constructed and the City of Toronto restoration standards, various tree pits along Hanna Ave. required reconstruction. What was originally estimated was to simply remove and replace the basic concrete sidewalk surface. Once onsite and after a meeting with City of Toronto representatives, it was determined that various tree pits required reconstruction. This in turn significantly increased the cost for the work related to Hanna Ave.
- Restricted working hours and limitations: The original cost estimate accounted for standard working hours and restrictions. After meeting the City of Toronto Traffic Work Zone Coordinator, Bevcon was given restrictions on both working hours and lane closures. This in turn increased the cost of required traffic control measures.

Pipeline - Many complexities associated with construction of the final pipeline route in a dense urban environment increased costs of the pipeline construction. Challenges encountered included limited working space, weather, work period restrictions due to traffic congestion and conflicting projects in the area. As a result of these factors, the construction phase which was originally anticipated to take four months, required approximately five months to complete.

3.0 The final land costs were $11 thousand, approximately a quarter of the original estimate. This is due to the fact an internal Pipeline Inspector completed the records and not an external consultant as originally forecasted.

4.0 The contingency amount that was forecasted for this project was used.

Conclusion

The Liberty Village Pipeline Reinforcement Project was completed with a total project cost of $4,151,681, approximately $500 thousand higher than the application estimate. The primary reason for the variance was encountering contaminated soils in the area and cost associated with the removal and disposal of the soil. Liberty Village is undergoing significant development as many condominiums are being built in the area and in very close proximity to where our Contractor was installing the pipeline. This led to significant delays and presented many challenges to ensure the work was done safely and as efficiently as possible while maintaining traffic flow and ensuring the other developers were not impacted as a result of our work. In addition, Liberty Village is very congested with underground utilities (both active and abandoned). These utilities were not all represented in the design drawings which resulted in several field changes compared to the designed line location as well as elevation changes to go above or below existing utilities to ensure proper clearances were met.

Bathurst Street Reinforcement Project

EB -2018-0097

Post Construction Financial Report on Costs and Variances

April 23, 2021

Introduction

Enbridge Gas Inc. (then Enbridge Gas Distribution Inc) (Enbridge) filed an application with the Ontario Energy Board (OEB) under sections 90 and 97 of the Ontario Energy Board Act, 1998 (OEB Act) on August 1, 2018 for an order granting a Leave to Construct to install a natural gas pipeline in the City of Toronto (the Bathurst Reinforcement Project, or the Project).

The project, a) Under section 90 of the OEB Act, encompassed installing 3.2 kilometers of Nominal Pipe Size (NPS 12) High Pressure (HP) steel natural gas pipeline, 69 meters of Nominal Pipe Size (NPS 8) Intermediate Pressure (IP) steel natural gas pipeline and b) Under section 97 of the OEB Act, an associated pressure regulating equipment (District Regulator Station) in the City of Toronto.

The proposed route begins at the intersection of Bathurst Street and Steeles Avenue West, travels south along the west side of Bathurst Street, and terminates on the east side of Bathurst Street, south of the intersection of Bathurst Street and Ellerslie Avenue. The Project will supply gas to meet current demand and future growth in the area.

The OEB assigned the file number EB -2018-0097 to the application and granted Leave to Construct on January 3, 2019.

Pipeline construction activities for the Bathurst Street Reinforcement Project commenced in June 2019 and was completed in December 2019. Most of the soft surface restoration activities were completed by November 2019. One section of hard surface restoration (sidewalk, curb, pattern concrete apron and road) was completed on the east and west side of Bathurst Street south of Ellerslie Avenue in 2019. All remaining hard surface restorations (sidewalk, pattern concrete, curb and asphalt) and soft surface restorations were completed by the fall of 2020.

This Post Financial Construction Report summarizes the actual capital costs of the project and provides an explanation of significant variances from the original estimates.

A comparison of actual versus estimated project costs is shown in Table 1 below.

Table 1 – Total Project Costs

Bathurst Street Reinforcement Project

Item No.	Item	Project Estimate ($)	Actual Cost ($)	Variance ($)
1.0	Material Cost	$ 800,232	$ 575,427	$ (224,805)
2.0	Labour and Construction Cost	$ 5,501,110	$ 7,936,442	$ 2,435,332
3.0	External Costs (Geotechnical, Environmental, Surveying, External Engineering, Insurance)	$ 272,000	$ 415,973	$ 143,973
4.0	Land	$ 10,000	$ 81,170	$ 71,170
5.0	Internal Costs	$ 272,300	$ 144,416	$ (127,885)
6.0	Station Cost	$ 60,000	$ 200,672	$ 140,672
	Project Subtotal	**$ 6,915,642**	**$ 9,354,100**	**$ 2,438,458**
7.0	Contingency	$ 2,074,692	$ -	$ (2,074,692)
8.0	Interest During Construction	$ 157,317	$ 88,514	$ (68,803)
	Total Project Costs	**$ 9,147,651**	**$ 9,442,615**	**$ 294,964**

The cost variances in the specific categories are described below:

1.0 The final Material Costs was $575,427, approximately $225,000 less than expected at the time of filing. At the time of the filing, some material costs were estimated which contributed to the higher initial anticipated costs as compared to actual costs.

2.0 The final Labour and Construction Costs was $7,936,442 approximately $2.4 million higher than the estimate originally provided mostly for the reasons outlined below.

Construction costs were higher due to unfavourable ground conditions resulting in slower productivity. Deeper drill shots with hard ground conditions was encountered which increased actual costs. In some areas along Bathurst Street, open cut trenching had to be completed to avoid utility conflicts which further increased construction duration and costs.

When the application was originally filed with the OEB, it was anticipated that internal Company Pipeline Inspectors and Surveyors would complete the pipeline inspection and surveying on the project. However, during the time of construction, Company resources were assigned to concurrent projects requiring the use of third party inspectors and surveyors instead. Additionally, an external Engineering Company was contracted to assist in re-designing the HDD profiles for the pipeline to be installed at a deeper depth to avoid utility conflicts.

Third party approvals were required for a portion of the project that crossed the foreign oil pipelines necessitating testing in three separate sections resulting in project delays and the incurrence of additional costs.

Soft surface restorations completed in the fall of 2019 and spring of 2020 had to be recompleted because some areas did not adequately rehabilitate due to a hot and dry spring/summer.

3.0 The final External cost (Geotechnical, Environmental, Surveying, External Engineering, Insurance) was $415,973 approximately $144,000 higher than expected at the time of filing.

As previously mentioned, external Pipeline inspectors and surveyors were required to complete survey and inspection work and a third party Engineering Company was contracted resulting in increased costs. Also, during construction to obtain the information necessary to redesign the HDD profiles, an external resource was required onsite to GPS all underground infrastructure exposed for construction.

4.0 The final Land cost was $81,170 approximately $71,000 more than originally estimated at the time of filing. The additional costs are attributed to the costs of obtaining necessary permits, removal of 41 trees and replanting fees from the City of Toronto as well as external costs required for standby Inspection when working in the foreign pipeline corridor.

5.0 The final internal costs were $144,416, approximately $128,000 less than what was estimated.

At the time of filing, it was anticipated that internal resources would be utilized for pipeline inspection of the project but as they were unavailable during project construction these costs were offset by third party contractor costs.

6.0 The final station cost was $200,672, approximately $141,000 greater than what was estimated at the time of filing.

At the time of filing, the design called for two smaller district stations but it was subsequently determined that one station capable of managing the required capacity would be incorporated into the design for greater efficiency. Higher costs than anticipated were incurred for station materials and for hiring an external resource to design the station.

7.0 The contingency amount that was forecasted for this project was used.

Conclusion

The Bathurst Street Reinforcement Project was completed with a total project cost of $9,442,615, approximately $295,000 higher than estimated. Overall, the variance between the final actual project costs and project estimates was reasonable and prudently incurred.

The primary reasons for the higher costs can be summarized as follows:

1. Unfavourable ground conditions resulting in slower productivity and higher than anticipated construction costs.

2. Congested utilities resulting in additional costs for redesign work and additional construction costs, such as open trenching and deeper digging, associated with this issue.
3. Third party contractors were hired because internal resources were working on concurrent projects and unavailable for this project resulting in increased costs. Overall, the variance between the final actual project costs and project estimates was reasonable.

DON RIVER NPS 30 REPLACEMENT PROJECT (EB-2018-0108) POST CONSTRUCTION FINANCIAL REPORT ON COSTS AND VARIANCES JULY 16, 2021

Introduction

Enbridge Gas Inc. (then Enbridge Gas Distribution Inc. "Enbridge") filed an application with the Ontario Energy Board (the "OEB") under sections 90 and 97 of the Ontario Energy Board Act, 1998 (OEB Act) on July 18, 2018 and an update on August 14, 2018 for an order granting a Leave to Construct to install a natural gas pipeline in the City of Toronto (the Don River NPS 30 Replacement Project, or the Project).

The project, a) Under section 90 of the OEB Act, encompassed installing 310.3m of Nominal Pipe Size ("NPS 30") Extra High Pressure ("XHP") steel natural gas pipeline in the City of Toronto.

The segment of pipeline that was replaced was located on an infrastructure bridge (the "Bridge") owned by Enbridge that spans the Don River. Enbridge had determined that the Bridge should be removed, and the segment of pipeline located on the Bridge should be abandoned and replaced as it posed a risk to the safe operation and reliability of the Don Valley Pipeline.

The Board assigned the file number EB-2018-0108 to the application and granted Leave to Construct on November 29, 2018.

Pipeline construction activities for Project commenced in May 2019 and was completed in May 2020. Hard surface restoration activities were completed by July 2020.

This Post Financial Construction Report summarizes the actual capital costs of the project and provides an explanation of significant variances from the original estimates.

A comparison of actual versus estimated project costs is shown in Table 1 below.

Table 1 – Total Project Costs

Don River NPS 30 Replacement Project

Item No	Item	Project Estimate ($)	Actual Cost ($)	Variance ($)
1.0	Material Costs			
1.1	Pipe	$441,490	$329,422	$112,069
1.2	Fittings	$268,617	$350,147	($81,530)
Sub-Total	**Total Material Costs**	**$710,107**	**$679,569**	**$30,539**
2.0	Labour Costs			
2.1	Labour	$15,614,109	$16,099,628	($508,590)
2.2	Inspection	$900,000	$1,136,711	($236,711)
2.3	Non-Destructive Testing	$82,500	$183,212	($100,712)
2.4	Bypass Support	$463,676	$29,224	$425,152
Sub-Total	**Total Labour Costs**	**$17,060,285**	**$17,481,147**	**($420,862)**
3.0	External & Regulatory Costs			
3.1	External & Regulatory Costs e.g. Environmental/Archeological Assessment, Environmental Inspector, Surveying for Drafting and Pre-Construction Mark-Ups, Insurance, external legal fees, OEB filing, etc.	$860,000	$1,506,394	($655,425)
Sub-Total	**Total External & Regulatory Costs**	**$860,000**	**$1,506,394**	**($655,425)**
4.0	Land			
4.1	Land Costs (e.g. easements, temporary working areas, title search, permits) Total Land Costs	$301,000	$3,316,836	($3,031,836)
Sub-Total	**Total Land**	**$301,000**	**$3,316,836**	**($3,031,836)**
5.0	Overhead Costs			
5.1	Engineering, Planning and Design	$544,100	$754,045	($209,945)
Sub-Total	**Total Overhead Costs**	**$544,100**	**$754,045**	**($209,945)**
6.0	Contingency Costs			
6.1	Project contingency (30% of project subtotal)	$5,842,647	-	-
Sub-Total	**Total Contingency Costs**	**$5,842,647**		
7.0	Total Estimated Project Cost			
7.1	**Total Project Cost**	**$25,318,141**	$23,706,759	$1,611,382

The cost variances in the specific categories are described below:

1.0 The final Material Costs were $679,569, approximately $30,539 less than expected at the time of filing. At the time of the filing, some material costs were estimated which contributed to the higher initial anticipated costs as compared to actual costs.

2.0 The final Labour Costs were $17,481,147 approximately $420,862 higher than the estimate originally provided mostly for the reasons outlined below.

2.1 Labour costs were slightly higher mostly due to the extension of the project from the projected in-service date of December 2019 to actual in-service date of April 2020. A portion of the contingency budget was used to offset the higher actual labour costs.

2.2 Inspection costs were slightly higher than estimated due to the extension of the project timing from the estimated in-service date of December 2019 to actual in-service date of April 2020.

2.3 Non-Destructive testing (NDT) costs were higher due to a field change. It was originally anticipated that an NDT crew would be contacted to complete testing as it was required, however, due to timing of actual construction it was more expedient to maintain the same NDT crew on-site to avoid construction delays resulting in higher than anticipated testing costs.

2.4 Bypass support costs came in under budget because project tie-ins were completed during the planned tie-in schedule. The original budget amount was unrealized and would only have been required if the tie-ins were not completed within the planned tie-in timeframe. Thus, labor costs related to building bypasses did not materialize.

3.0 The final External & Regulatory Costs was $1,506,394 approximately $655,425 higher than expected at the time of filing. Cost increases for this item was related to additional environmental protection measures required by third party regulatory agencies to obtain the necessary permits. Additionally, separate soil settlement monitoring was requested by Metrolinx and the TRCA that is more than what is typically required.

4.0 The final Land costs were $3,316,836 approximately $3,031,836 higher than originally estimated. The additional costs are attributed to the need for multiple agreements for temporary and permanent easements, including a tri-party agreement between the City of Toronto and the TRCA. Also, expropriation activities had to be undertaken for a portion of the pipeline route, further causing cost and schedule pressures.

5.0 The final Overhead costs were $754,045, approximately $209,945 higher than what was estimated due to additional work required to obtain permits and easements and the extension of the project from the projected in-service date of December 2019 to actual in-service date of April 2020.

6.0 The contingency amount that was forecast for this project was only partially used to cover realized risks and higher easement costs leaving approximately $1,611,382 unused.

Conclusion

The Don River NPS 30 Replacement Project was completed with a total project cost of $23,706,759, approximately $1,611,382 below the estimated cost. Overall, the variance between the final actual project costs and project estimates was reasonable and prudently incurred.

The primary reasons for the cost variances can be summarized as follows:

1. Difficulties and costs associated with obtaining easements.
2. Several construction risks did not realize, lowering the amount of contingency needed for these items.
3. Special permitting requirements led to an increase in environmental inspection costs.

POST CONSTRUCTION FINANCIAL REPORT

2019 Chatham-Kent Rural Project

In compliance with the Ontario Energy Board Order EB-2018-0188 and Condition 6, the following is a report on the capital pipeline and station cost for the 2019 Chatham-Kent Rural Project.

The Project actual cost was $14,797,615, or 23% lower than estimated. The following explains any significant variances.

	Baseline Estimate $	Actual Costs $	Variance $	Variance %
Materials (1)	$ 2,098,968	$ 2,418,194	$ 319,226	15%
Construction and Labour (2)	$ 14,339,292	$ 12,285,258	$ (2,054,034)	-14%
Contingency (3)	$ 2,492,037	$ -	$ (2,492,037)	-100%
Interest During Construction (4)	$ 169,703	$ 94,163	$ (75,540)	-45%
Total Project Capital Costs	$ 19,100,000	$ 14,797,615	$ (4,302,385)	-23%

(1) Actual cost for Material and Equipment for the Project were higher than original estimates which were based upon historical average unit cost.

(2) Actual cost for Prime Contractor, Miscellaneous Outside Services, and Land were all lower than the original estimate. Key reasons for being under budget include: high installation productivity due to excellent weld production rates and the use of a pipe trenching machine to install the NPS 8 portion of the pipeline, NDE contractor time on site was optimized, and limited inclement weather impact.

(3) Contingency for the project was not used because other forecast costs came in lower than estimated.

(4) Interest During Construction actuals are shown separately. These costs were not separated during the OEB application.

Georgian Sands Pipeline Project

EB-2018-0226

Post Construction Financial Report on Costs and Variances

Sept 1, 2021

Introduction

On February 27, 2019 Enbridge Gas Distribution Inc. ("Enbridge Gas" or the "Company") applied to the Ontario Energy Board ("OEB") under section 90 of the *Ontario Energy Board Act* (the "Act"), for an order granting Leave to Construct of approximately 6.4 km of natural gas pipeline in Simcoe County. The Georgian Sands Pipeline Project (the "Project") is a system expansion project that was built to serve the Georgian Sands planned subdivision in Simcoe County. The project is comprised of two sections of pipeline and a district station. The first section of pipeline is approximately 8 m in length and its purpose is to connect the existing Extra High Pressure ("XHP") pipeline to the newly installed district station. The district station was constructed at Flos Road 4 West and Vigo Road to reduce the pressure of natural gas supply from Extra High Pressure ("XHP") to Intermediate Pressure ("IP"), which is the operating pressure of the second section of pipeline. The second section of pipeline is approximately 6.4 km in length and runs along Vigo Road to Flows Road 8 where it travels west until it terminates at the Georgian Sands subdivision.

The OEB granted Leave to Construct the Project on July 25, 2019.

Pipeline construction activities for the Project commenced on October 7, 2019 and the related facilities were placed into service on June 1, 2020.

This Post Construction Financial Report was prepared to satisfy Condition 6 of the Conditions of Approval set out in the OEB's Decision and Order:

> 6. Concurrent with the final monitoring report referred to in Condition 7(b), Enbridge shall file a Post Construction Financial Report, which shall indicate the actual capital costs of the project and shall provide an explanation for any significant variances from the cost estimates filed in this proceeding. Enbridge shall also file a copy of the Post Construction Financial Report in the proceeding where the actual capital costs of the

project are proposed to be included in rate base or any proceeding where Enbridge proposes to start collecting revenues associated with the project, whichever is earlier.

This report summarizes estimated[1] and actual capital costs of the Project and provides explanations for significant variances.

Cost and Variance Reporting

The actual costs of construction for the Project were approximately $0.715 million less than the project estimates filed as part of the Company's original Project application and evidence.

A comparison of actual versus estimated project costs is set out in Table 1 below.

Table 1 – Total Project Costs

Item	Project Estimate ($)	Actual Cost ($)	Variance ($)
Material Cost	277,125	318,568	41,443
Labour and Construction	1,698,496	1,542,383	(156,113)
Internal Costs	115,000	71,760	(43,240)
Consultant Costs	239,480	178,018	(61,462)
Land	16,375	1,803	(14,572)
Contingency	469, 295	0	(469,295)
Interest During Construction	11,766	8,703.93	(3,063)
Total Project Cost	2,827,537	2,112,532	715,003

Significant category-specific cost variances are discussed below:

1.0 Labour and Construction

The actual Labour and Construction cost was $1.5 million, approximately $0.150 million less than originally estimated. This Project had a relatively simple construction, including no significant issues arising from traffic, utilities, ground conditions or weather, resulting in lower than estimated Labour and Construction costs.

2.0 Contingency

The actual Contingency cost for this Project was $0, approximately $0.470 million less than originally estimated. For the same reasons outlined in section 1.0 above, the contingency estimated for this project was not required.

[1] EB-2018-0226, Exhibit D, Tab 2, Schedule 1.

ENBRIDGE

POST CONSTRUCTION FINANCIAL REPORT

2019 Stratford Reinforcement Project EB-2018-0306

In compliance with the Ontario Energy Board Order EB-2018-00306 and Condition 5, the following is a report on the capital pipeline and station cost for the 2019 Stratford Reinforcement Project

The Project actual cost was $24,796,716 or 13% lower than estimated. The following explains any significant variances.

	Estimated			Actuals			Variance			Variance %		
	Mainline	Stations	**Total**	Mainline	Stations	**Total**	Mainline	Stations	**Total**	Mainline	Stations	**Total**
Materials	$2,155,087	$451,000	**$2,606,087**	$2,113,853	$491,968	**$2,605,821**	-$41,234	$40,968	**-$266**	-2%	9%	**0%**
Construction & Labour (1)	$16,782,000	$2,018,000	**$18,800,000**	$15,319,451	$2,805,118	**$18,124,569**	-$1,462,549 (1)	$787,118 (1)	**-$675,431** (1)	-9% (1)	39% (1)	**-4%** (1)
Contingency (2)	$2,656,435	$494,000	**$3,150,435**				-$2,656,435	-$494,000	**-$3,150,435** (2)	-100%	-100%	**-100%** (2)
Interest During Construction (3)	$261,000	$39,000	**$300,000**	$126,735	$1,706	**$128,440**	-$134,265 (3)	-$37,294 (3)	**-$171,560** (3)	-51% (3)	-96% (3)	**-57%** (3)
Total (4)	**$21,854,522**	**$3,002,000**	**$24,856,522**	$17,560,039	$3,298,791	**$20,858,830**	-$4,294,483	$296,791	**-$3,997,692** (4)	-20%	10%	**-16%** (4)
Indirect Overheads (5) (6)			$3,683,478 (5)			$3,937,886 (6)			$254,408 (6)			7% (6)
Total Capital Costs (4)			**$28,540,000**			**$24,796,716**			**-$3,743,284** (4)			**-13%** (4)

(1) Actual construction & Labour costs for the pipeline were lower than estimated which were based upon historical average unit cost.
(1) Actual construction & Labour costs for the stations were higher than estimated due to the complex nature of the tie-in work that took place within the stations' compounds.
(2) Contingency was not utilized since risks, mostly associated with the numerous trenchless installations, did not materialize during execution.
(3) Original Interest During Construction (IDC) calculation accounted for the use of Contingency, which did not occur.
(4) Overall cost was lower mostly due to lower than estimated construction costs and the release of contingency.
(5) Estimated Indirect Overheads was based on average 15% of the total costs (excluding IDC) which changes from year to year.
(5) At the time of filing, Indirect Overheads were not shown separately.
(6) Based on actual Indirect Overheads charged to the project as of October 31st 2020 reflecting an average of 19.1%

POST CONSTRUCTION FINANCIAL REPORT

St. Laurent Pipeline Project
EB-2019-0006

In compliance with the Ontario Energy Board Order EB-2019-0006 and Condition 5, the following is a report on project cost, schedule and scope compared to the estimates filed in this proceeding.

The Project actual cost was $6,546,818 or 19% higher than estimated. The following explains any significant variances.

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
1	Materials	119,000	98,285	(20,715)	-17%
2	Construction and Labour	3,021,787	4,682,018	1,660,231	55%
3	Internal Costs	80,000	163,602	83,602	105%
4	Consultant Costs	83,807	1,289,976	1,206,169	1439%
5	Land	51,000	3,415	(47,585)	-93%
6	Contingency	826,327		(826,327)	-100%
7	IDC	20,274	106,962	86,688	428%
8	Indirect Overheads	1,308,324	202,561	(1,105,763)	-85%
9	Total	5,510,519	6,546,818	1,036,299	19%

Item No.	Category	Variance Explanation
2	Construction and Labour	This Project experienced challenges and increased Construction and Labour costs as a result of adherence to COVID-19 Pandemic Protocols, which required additional measures for field workers, facilities and rentals to ensure social distancing as well as increased cleaning costs. The Company also incurred additional costs to address issues found at the Montreal Road Intersection. Due to the volume of unknown structures, deep structures, and congestion of utilities Enbridge Gas had to do significant unplanned hydrovac excavation. Overtime and additional labour required for Hydrovac Excavation accounted for $300K of this variance. The cost of Hydrovac accounted for approximately $1.2 M of this variance.
4	Consultant Costs	The City required construction to be complete by early September 2020 in order to allow for paving on St. Laurent Blvd. When the Project Cost Estimate was filed, Enbridge Gas understood that temporary restoration was required on St. Laurent Blvd at construction completion. During Construction, the City alerted Enbridge Gas that because they would be doing minimal asphalt, Enbridge Gas would need to complete a full restoration. This resulted in approximately $500K in additional costs. External inspector & records personnel were required to meet the City's paving timeline due to internal resource constraints. This resulted in $400K of additional costs.
6	Contingency	Contingency was utilized for additional costs of Construction and Labour as described above.

EB-2019-0172: Windsor Pipeline Replacement Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($) (a)	Actual Cost ($) (b)	Variance to Estimate ($) (c) = (b) - (a)	Variance to Estimate (%) (d) = (c) / (a)
	Pipeline Costs				
1	Materials	4,164,000	4,454,908	290,908	7%
2	Construction and Labour	62,521,000	51,375,933	(11,145,067)	-18%
3	Contingency	9,975,000	-	(9,975,000)	-100%
4	IDC	725,000	478,015	(246,986)	-34%
5	Indirect Overheads	11,729,000	11,258,614	(470,386)	-4%
6	Subtotal Pipeline Costs	89,114,000	67,567,470	(21,546,530)	-24%
	Stations Cost				
7	Materials	1,572,000	1,460,783	(111,217)	-7%
8	Construction and Labour	9,031,000	9,139,852	108,852	1%
9	Contingency	1,591,000	-	(1,591,000)	-100%
10	IDC	120,000	-	(120,000)	-100%
11	Indirect Overheads	1,866,000	2,137,680	271,680	15%
12	Subtotal Stations Cost	14,180,000	12,738,315	(1,441,685)	-10%
	Services Cost				
13	Materials	133,000	102,315	(30,685)	-23%
14	Construction and Labour	2,515,000	2,081,357	(433,643)	-17%
15	Contingency	397,000	-	(397,000)	-100%
16	IDC	-	-	-	
17	Indirect Overheads	466,000	440,350	(25,650)	-6%
18	Subtotal Services Cost	3,511,000	2,624,021	(886,979)	-25%
19	Total	106,805,000	82,929,806	(23,875,194)	-22%

Variance Explanations:

Item No.	Category	Variance Explanation
2	Construction and Labour	Anticipated additional installation depth for the pipeline was not required, as a result the Company incurred lower costs to install the pipeline. Removal of the existing NPS 10 from road allowance was not required, resulting in additional construction and labour savings .
3	Contingency	The Company identified a risk that the pipeline would need to be installed at a greater depth than standard practice. This was not necessary and as a result Contingency was not utilized.

POST CONSTRUCTION FINANCIAL REPORT

Owen Sound Reinforcement Project
EB-2019-0183

In compliance with the Ontario Energy Board Order EB-2019-0183 and Condition 6, the following is a report on project cost, schedule and scope compared to the estimates filed in this proceeding.

The Project actual cost was $70,121,772 or 2% higher than estimated. The following explains any significant variances.

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
1	Materials	5,518,000	5,176,240	(341,760)	-6%
2	Construction and Labour	46,343,000	53,029,331	6,686,331	14%
3	Contingency	7,439,000	-	(7,439,000)	-100%
4	IDC	770,000	408,483	(361,517)	-47%
5	Indirect Overheads	8,895,000	11,507,717	2,612,717	29%
6	Total	68,965,000	70,121,772	1,156,772	2%

1) Actual material cost was less than budget because the budget amount was based upon historical assumptions rather than vendor quotes.

2) Actual construction cost was higher than planned due to increased cost to construct the pipeline through environmentally sensitive areas, along a narrow road allowance, stakeholder management, vandalism to the pipeline during construction, challenging HDD crossings for two watercourses and a rain event during an open-cut water crossing that resulted in the crossing being delayed. This cost category includes $220K of Project clean-up costs that are expected to be incurred in 2022.

3) About 90% of the contingency was used in order to cover the increase in prime contractor costs. The remaining contingency was never used since the project came in under budget.

4) IDC was lower than planned due to the project coming in under budget.

5) Actual overheads were higher than estimated due to the revised EGI overhead capitalization policy implemented in January 2020.

EB-2019-0218: Sarnia Reinforcement Project
Post Construction Financial Report

Project Cost Forecast to Actual:

Item No.	Description	Project Estimate ($)	Actual Cost ($)	Variance ($)	Variance (%)
	Pipeline				
1	Materials and Equipment	2,858,000	3,852,000	994,000	35%
2	Construction and Labour (incl. lands)	14,580,000	16,322,000	1,742,000	12%
3	Contingency	3,487,000	49,000	(3,438,000)	-99%
4	IDC	275,000	141,000	(134,000)	-49%
	Indirect Overheads	2,239,000	4,097,000	1,858,000	83%
5	Total Pipeline Cost	23,439,000	24,461,000	1,022,000	4%
6	**Station**				
7	Materials and Equipment	1,554,000	2,971,000	1,417,000	91%
8	Construction and Labour (incl. lands)	3,905,000	7,032,000	3,127,000	80%
9	Contingency	1,092,000	60,000	(1,032,000)	-95%
10	IDC	70,000	73,000	3,000	4%
11	Indirect Overheads	701,000	2,369,604	3,515,000	501%
12	Total Station Cost	7,322,000	12,505,604	7,030,000	96%
13	Total Cost	30,761,000	36,966,604	6,205,604	20%

Notes: Clean up and restoration work on the Sarnia Reinforcement Project is still ongoing. Within the actual cost column, Enbridge Gas has included $1,518,273 of forecasted remaining direct capital cost, and $335,372 of indirect overhead cost.

Variance Explanations:

Item No.	Category	Variance Explanation
3	Pipeline Contingency	Pipeline Contingency was fully utilized and applied to Pipeline Materials and Equipment overages as well as Pipeline Construction and Labour overages. Pipeline Material Costs were higher than origionally estimated for the Project. Pipeline Construction and Labour Costs were higher than estimated as a result of construction method changes, including increased environmental protection measures throughout the construction of the Project.
8	Station Construction and Labour	The Station Construction and Labour charges were higher than anticipated due to unexpected site conditions. Crews encountered third party pipelines at a conflicting depth that required a redesign and greater depth of cover for installation.
11	Indirect Overheads	Indirect Overheads were higher than the origional estimate due to the implementation of the revised indirect overhead capitalization policy which became effective in 2020.

DIRECTIVE AND COMMITMENT RESPONSE SUMMARY

The following summarizes the status of outstanding directives and commitments addressed in this Application and includes an evidentiary reference pointing to where further information is provided.

OEB File No.	Utility	Directive/Commitment	Response
2016 Dawn-Parkway Expansion Project EB-2014-0261	Union	Parties agreed as part of Settlement that the issue of Dawn Parkway capacity turnback post-2018 and how turnback risk should be dealt with in the context of the proposed facilities.	Exhibit 1, Tab 11, Schedule 1
EB-2022-0003 – City of Toronto	EGI	The OEB orders Enbridge Gas to bring the cost associated with the licence agreement forward in its upcoming rate rebasing application to demonstrate its prudence. The OEB also orders Enbridge Gas to file the executed licence agreement on the record of this proceeding.	Exhibit 1, Tab 12, Schedule 1
2021/22 Storage Enhancement Project EB-2020-0256	EGI	Address the allocation of all costs between Enbridge Gas's rate regulated and unregulated storage business as part of Enbridge Gas's next rate rebasing application.	Exhibit 1, Tab 13, Schedule 2
EB-2020-0293 - St Laurent	EGI	The OEB urges Enbridge Gas to thoroughly examine other alternatives such as the development and implementation of an in-line inspection and maintenance program using available modern technology, and propose appropriate action based on its findings as part of its next rate rebasing application.	Exhibit 1, Tab 13, Schedule 3
2019 Rate Proceeding EB-2018-0305	EGI	Customer Connection Policies: File detailed evidence regarding EGI customer connection policies.	Exhibit 1, Tab 15, Schedule 1
MAADs and Rate Setting Mechanism Proceeding EB-2017-0306/EB-2017-0308	EGI	Consolidated Utility System Plan (USP) and Asset Management Plan (AMP): The OEB expects that a consolidated USP will be filed for any ICM request for 2021 Rates and beyond.	Exhibit 2, Tab 6, Schedule 1 and Exhibit 2, Tab 6, Schedule 2

OEB File No.	Utility	Directive/Commitment	Response
MAADs and Rate Setting Mechanism Proceeding EB-2017-0306/EB-2017-0307	EGI	Normalized Average Consumption, Average Use and Lost Revenue Adjustment Mechanism (LRAM): File a proposal addressing Average Use/Normalized Average Consumption at the next rebasing application with supporting evidence for the approach. This proposal should address an LRAM mechanism that includes general service customers.	Exhibit 3, Tab 2, Schedule 5
MAADs and Rate Setting Mechanism Proceeding EB-2017-0306/EB-2017-0307	EGI	The OEB requires the applicants to develop a proposal to be filed with its next rebasing application. This should include a proposal for an LRAM mechanism that includes general service customers. If Amalco proposes to continue using the NAC/AU, it must file evidence in support of that approach.	Exhibit 3, Tab 2, Schedule 5
EB-2021-0149	EGI	Enbridge Gas has agreed to file evidence in its rate rebasing application (for rates as of January 1, 2024, which will include requests for approvals for the pass-through of gas supply costs) demonstrating that it has fully considered the opportunity to reduce storage costs through inclusion, as part of its load balancing portfolio, of cost-effective market-based alternatives to the purchase of third-party storage. That evidence will include consideration of: (i) the cost of delivered supply (including the commodity cost) in winter in lieu of contracting for additional storage; versus (ii) the cost (savings) of buying gas in summer and the associated additional storage and related costs required to store and redeliver that gas in the winter.	Exhibit 4, Tab 2, Schedule 1 and Exhibit 4, Tab 2, Schedule 1, Attachment 6
MAADs and Rate Setting Mechanism Proceeding EB-2017-0306/EB-2017-0307	EGI	Rate Harmonization: File a proposal for rate harmonization in the next rate rebasing application, including a proposal with respect to the use of excess utility storage from the Union rate zones.	Exhibit 4, Tab 2, Schedule 1 and Exhibit 8, Tab 2, Schedule 1

OEB File No.	Utility	Directive/Commitment	Response
Bright to Owen Sound Dawn-Trafalgar Facilities	Union	Union is directed to report in each rates case for the next 30 years, an update to the peak day volume forecast shown for 1996/1997 in Appendix A to its supplementary evidence. (please see Exhibit B1, Tab 5 of EB-2011-0210).	Exhibit 4, Tab 2, Schedule 2
Voluntary RNG Program EB-2020-0066	EGI	Voluntary RNG Program Cost Proposal: Present a proposal for the funding of the costs to operate Enbridge Gas's Voluntary RNG Program (i.e. funded in rates or funded by participants)	Exhibit 4, Tab 2, Schedule 7
Voluntary RNG Program EB-2020-0067	EGI	Reporting on the RNG Program: Enbridge Gas will provide “reporting on Program results (participation, costs, RNG volumes etc.), RNG procurement approaches and experience, observations on the competitive market, discussion of the impact of the CFS, and details relating to go-forward proposals for the future of the Program” as part of Enbridge Gas's rate rebasing application or a future stand-alone application for the program.	Exhibit 4, Tab 2, Schedule 7
2020 Rate Proceeding EB-2019-0194	EGI	Unaccounted for Gas (UFG): Implementation of recommendation from ScottMadden's UFG Report: Provide a progress report on the implementation of the UFG Report's recommendations to address UFG and other related matters as part of its 2024 Rebasing proceeding.	Exhibit 4, Tab 3, Schedule 1
2020 Rate Proceeding EB-2019-0194	EGI	Unaccounted for Gas (UFG): Forecasting Methodology: Present a proposal for consistent forecasting and management of UFG across the full franchise area as part of the 2024 Rebasing Application.	Exhibit 4, Tab 3, Schedule 1
2020 Rate Proceeding EB-2019-0194	EGI	Unaccounted for Gas (UFG): provide reporting of UFG results, segregated by rate zone and activity (distribution, transmission, storage), with such recent historical information as is available as part of the rebasing filing.	Exhibit 4, Tab 3, Schedule 1

OEB File No.	Utility	Directive/Commitment	Response
2021/2022 Storage Enhancement Project EB-2020-0256	EGI	Unaccounted for Gas (UFG): address the impact of increasing the storage pool pressure gradient on UFG.	Exhibit 4, Tab 3, Schedule 1
MAADs and Rate Setting Mechanism Proceeding EB-2017-0306/EB-2017-0308	EGI	Enbridge Gas made commitments that were documented in the OEB's Conditions of Approval in the MAADs Decision. The commitments included ensuring any employment impacts resulting from the amalgamation be managed on a roughly proportionate basis between the Municipality of Chatham-Kent and the City of Toronto, and that employment within Chatham-Kent would reflect a mixture of entry, middle, and senior level roles.	Exhibit 4, Tab 4, Schedule 3
Other Non-Reporting Obligations	EGD	Site Restoration Costs: Enbridge to look at discount rate to be used and examine issue of establishment of segregated fund of site restoration collections.	Exhibit 4, Tab 5, Schedule 1
MAADs and Rate Setting Mechanism Proceeding EB-2017-0306/EB-2017-0308	EGI	Parkway Delivery Obligation: Track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing term and report on these amounts at the time of rebasing.	Exhibit 4, Tab 7, Schedule 1
Rate for interruptible LNG service at Hagar service at Hagar EB-2014-0012	Union	Union was directed to file in the 2019 Rebasing Application a more robust and comprehensive cost allocation study that appropriately allocates costs for the new service.	Exhibit 7, Tab 1, Schedule 4

OEB File No.	Utility	Directive/Commitment	Response
2020 Rates EB-2019-0194	EGI	In the MAADs Decision, Enbridge Gas was directed to file a cost allocation study in 2019 for consideration in the proceeding for 2020 Rates that proposes an update to the cost allocation to take into account the following projects: Panhandle Reinforcement, Dawn-Parkway expansion including Parkway West, Brantford Kirkwall/Parkway D and the Hagar Liquefaction Plant. This should also include a proposal for addressing TransCanada's C1 Dawn to Dawn TCPL service. In 2020 Rates, the OEB found that changes to the methodology and implementation of Enbridge Gas's cost allocation shall be examined as part of the 2024 Rebasing Application.	Exhibit 7, Tab 1, Schedule 4
2013 COS EB-2011-0210	Union	File evidence to support the allocation of Union North and Union South Distribution Maintenance - Equipment on Customer Premises costs to rate classes in proportion to the allocation of customer station gross plant, including a definition for this maintenance category and a delineation of what has changed since EB-2005-0520.	Exhibit 7, Tab 1, Schedule 4
Union's 2017 Rates EB-2016-0245	Union	Union agreed as part of Settlement to report on the revenue neutrality of the new Customer Managed Service (CMS) and revisit the appropriateness of the service design at the time of its rebasing proceeding.	Exhibit 8, Tab 4, Schedule 5

OEB File No.	Utility	Directive/Commitment	Response
Integrated Resource Planning Proposal EB-2020-0091	EGI	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. This initiative is expected to help reduce peak demand, and the study should be filed as part of the next rate rebasing application.	Exhibit 8, Tab 4, Schedule 7

UNREGULATED STORAGE COST ALLOCATIONS AND ELIMINATIONS

COLIN HEALEY, DIRECTOR FINANCIAL PLANNING & ANALYSIS
RACHEL GOODREAU, MANAGER REVENUE AND COST OF GAS
DANIELLE DREVENY, MANAGER CAPITAL FINANCIAL PLANNING & ANALYSIS

1. This section of evidence presents the proposed harmonized unregulated storage allocation methodology for Enbridge Gas as directed by the OEB[1]. The purpose of this evidence is to summarize the storage allocation methodologies previously in place at EGD and Union and to describe and request approval for the proposed harmonized methodology. Ernst & Young LLP (EY) was retained by Enbridge Gas to assist management in its determination of the Company's harmonized unregulated storage allocation methodology.

2. This evidence is organized as follows:
    1. Background and History
    2. Proposed Harmonized Methodology
    3. Impact of the Proposed Harmonized Methodology

1. Background and History

3. Prior to amalgamation, EGD and Union both sold storage services to in-franchise and ex-franchise customers. In-franchise customers could purchase cost-based storage and all customers could purchase market-based storage services. Since the amalgamation, the combined storage facility continues to offer the same suite of storage services to meet customers' storage demands. Enbridge Gas's underground storage assets are one of the largest facilities in North America with

[1] EB-2020-0256 Decision and Order, April 22, 2021, p.4.

approximately 280 billion cubic feet (Bcf) of net working storage capacity at the Dawn Hub.

4. In 2006, as part of its Natural Gas Electricity Interface Review (NGEIR)[2] the OEB determined that EGD and Union operated in competitive storage markets. Consequently, the OEB determined it would no longer regulate prices for either Utility's storage services offered to ex-franchise customers, for new storage services offered to in-franchise customers, and for all storage services offered by other storage operators.

5. As a result of the OEB's NGEIR decision[3], storage services at EGD and Union were separated into regulated and unregulated storage operations. Separate and independent reviews were carried out by each company to determine the appropriate cost allocation process for its regulated and unregulated storage operations. Union's methodology, which assigned storage-related expenses on an asset basis, was approved in 2011[4]. EGD's methodology, which relied on storage activity, was approved in 2012[5]. The methodologies continue to be in place until the end of 2023.

6. Following amalgamation, EY was commissioned to undertake an unregulated storage cost allocation study that would facilitate management's selection of an integrated cost allocation methodology that best represented the separation of activity and costs between regulated and unregulated storage operations. Enbridge Gas is proposing to implement the changes set out in the study and harmonize the

[2] EB-2005-0551.
[3] EB-2005-0551, OEB Decision with Reasons, November 7, 2006.
[4] EB-2011-0038, OEB Decision and Order, January 20, 2012.
[5] EB-2011-0354, Decision on Revised Settlement Agreement, November 2, 2012.

unregulated storage allocation methodology effective January 1, 2024. The Unregulated Storage Cost Allocation Study is provided at Attachment 1.

2. Proposed Harmonized Methodology

7. The harmonized methodology was guided by the NGEIR Decision[6], and subsequent OEB decisions on EGD's and Union's unregulated storage allocation methodologies referenced in paragraph 5. The following guiding principles were applied to ensure the methodology selected was appropriate and adhered to established regulatory principles. These are:
    a) Fair allocation of costs based on the underlying activities;
    b) Consistency of assumptions, decisions, and approach;
    c) Transparency and traceability throughout the allocation process;
    d) Consistency with prior OEB findings and decisions;
    e) Conformity with operational or organizational changes due to amalgamation;
    f) Ease of implementation to support regular updates; and
    g) Adaptability to current or future IT systems.

8. The harmonized methodology is largely consistent with the previously approved Union storage allocation methodology which is appropriate and expected considering the relative size and scope of Union's storage operations compared to EGD's. Modifications to the methodology are in line with the guiding principles Enbridge Gas seeks to achieve. Allocated costs are based on the underlying amalgamated unregulated storage operations. A consistent set of assumptions and approach will be applied to harmonized cost groupings within the amalgamated storage operations structure. Calculations are transparent and traceable and support regular updates as part of the annual budget process.

[6] EB-2005-0551, OEB Decision with Reasons, November 7, 2006.

9. The following section provides an overview of the proposed harmonized approach. Supporting rationale is detailed in the Unregulated Storage Cost Allocation Study provided at Attachment 1. Table 1 summarizes asset and expense cost elements in scope along with the harmonized allocation approach including page references to the Unregulated Storage Cost Allocation Study. For each element, the harmonized methodology is either 1) consistent with the Union approach, or 2) a modification of the Union approach. Where no change is indicated, the EGD and Union OEB-approved methodologies align and no further alignment is required. In addition to meeting guiding principles, Enbridge Gas believes that the proposed changes are appropriate as they best represent the costs incurred by the unregulated storage business and remain consistent with historical OEB decisions.

Table 1

Summary of Methodology Changes

Allocation Area	EGI Harmonized Allocation Methodology	Unregulated Storage Allocation Study
Assets		Page References
2.1 Materials and Supplies	Modified Union methodology	Not included in study
2.2 New Storage assets (net)	No change – EGD and Union methodologies aligned	9-11
2.3 General plant assets (net)	Modified Union methodology	11-14
Expenses		
2.4 Cost of gas: Unaccounted for gas	Modified Union methodology	14-17
2.5 Cost of gas: Fuel used to move gas	Union methodology	16-17
2.6 Operating & Maintenance: Storage operations	Modified Union methodology	17-20
2.7 Operating & Maintenance: Storage support – administrative and general	Modified Union methodology	20-21
2.8 Operating & Maintenance: Storage support – variable	Union methodology	21-22
2.9 Depreciation expense: Storage Assets	No change – EGD and Union methodologies aligned	22-24

Allocation Area	EGI Harmonized Allocation Methodology	Unregulated Storage Allocation Study
2.10 Depreciation expense: General Plant Assets	Union methodology	22-24
2.11 Property tax expense: Storage Assets	Union methodology	24-25
2.12 Property tax expenses: General Plant Assets	Union methodology	24-25
2.13 Unutilized in-franchise capacity	No change – allocation area only applicable to Union	25-27
2.14 Interest expense on long-term debt	Union methodology	26-27

2.1 Materials and Supplies

10. Prior to 2019, Union allocated materials and supplies inventory to unregulated storage in proportion to unregulated storage plant as a percentage of total plant. Throughout the 2019 to 2023 deferred rebasing term, Enbridge Gas continues to apply a portion of materials and supplies inventory to its unregulated business leaving only the utility portion in its working capital component for the Union rate zones. Prior to 2019, EGD did not allocate any of its materials and supplies inventory to unregulated storage operations, which continued through the deferred rebasing term for the EGD rate zone.

11. To harmonize, Enbridge Gas will allocate a portion of materials and supplies inventory to the unregulated storage using a composite rate, based on the proportion of the Company's unregulated Operating & Maintenance (O&M) expenses relative to total O&M expenses. The portion allocated to unregulated storage operations will be excluded from Enbridge Gas's utility working capital.

12. This is a modification of the Union methodology which serves to enhance the accuracy of the allocations.

2.2 New Storage Assets

13. Storage assets are directly attributable to either the regulated or unregulated storage operations. At the time of the NGEIR decision[7], EGD's storage assets were allocated 100% to the regulated business as the existing assets were required to serve in-franchise customers. Union's assets were split between the regulated and unregulated business based on a one-time allocation. Allocations of new storage assets to the unregulated storage business are made on a one-time basis for each new storage asset placed in-service. This enables maintenance of plant accounting records at the individual asset level for unregulated storage operations. In addition, the split between unregulated storage assets and regulated utility assets at each individual storage pool is updated annually to reflect additions and retirements that occurred throughout the prior year, for the purposes of allocating costs associated with capital maintenance of the assets.

14. No change is required for harmonization as the EGD and Union OEB-approved methodologies align and are consistent with unregulated storage cost allocation studies approved by the OEB.

2.3 General Plant Assets

15. The harmonized allocation of general plant assets first requires an aligned definition of general plant assets to include certain EGD buildings and land assets. These assets were historically classified as distribution plant assets and were not allocated to EGD's unregulated storage operations. Union historically allocated all general

[7] EB-2005-0551, OEB Decision with Reasons, November 7, 2006.

plant assets by applying different allocators for vehicles and heavy work equipment, and all other general plant assets. Under the harmonized methodology, new Enbridge Gas general plant assets are allocated monthly to the unregulated storage operations using a composite allocation rate based on the proportion of the Company's unregulated assets and O&M expenses relative to total assets and O&M expenses. To implement the harmonized methodology, a one-time allocation of EGD general plant assets will use this approach using EGD input values.

16. The modification of the Union methodology will be implemented to simplify and improve the traceability of the allocator.

2.4 Cost of Gas: Unaccounted for Gas

17. Enbridge Gas will allocate unaccounted for gas, which includes all components of gas loss, such as leakages, venting, meter errors and other similar considerations to unregulated storage monthly using actual gross unregulated storage activity as a percentage of total actual gross storage and transportation activity. Gross activity is the sum of the absolute volumes as it relates to both injections and withdrawals.

18. The change to allocating based on monthly volumetric activity is a modification of Union's annual allocation of unaccounted for gas to capture activity fluctuations as well as gas reference price fluctuations throughout the year.

2.5 Cost of Gas: Fuel Used to Move Gas

19. Enbridge Gas will allocate compressor fuel to the unregulated storage business using actual net daily unregulated storage activity as a percentage of total actual net daily storage and transportation activity. Net activity is composed of injections less withdrawals.

20. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology for this allocation area.

2.6 O&M: Storage Operations

21. Enbridge Gas will allocate O&M costs directly related to storage operations based on the proportion of underlying storage assets assigned to the unregulated storage operations. This proportion will be updated annually and will be used to derive a single allocator per storage asset category that aggregates all storage asset locations. The harmonized approach is simplified in comparison to the more complex, multi-factor (i.e. asset category and asset location) approach previously used by Union.

22. This is a modification of the Union methodology so that an average storage asset allocator will be used to simplify and increase the transparency of the calculation while maintaining a causal linkage that results in a fair allocation.

2.7 O&M: Storage Support - Administrative and General

23. Enbridge Gas will allocate actual administrative and general O&M support costs (excluding the variable O&M support costs provided in Section 2.8) in proportion with O&M expenses incurred by the unregulated storage operations.

24. This is a modification of the Union methodology which serves to enhance the accuracy of the allocations by removing the influence of storage support costs in the allocator.

2.8 O&M: Storage Support – Variable

25. Enbridge Gas will allocate, by department, variable storage support O&M costs based on time spent on unregulated storage support activities carried out by these

departments. Support costs vary from year to year depending on the nature and level of unregulated storage activity being carried out by departments or functions such as Business Development, Asset Management, Lands and Permitting, Engineering and Regulatory Affairs.

26. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology.

2.9 Depreciation Expense: Storage Assets

27. The depreciation rates for underground storage assets were approved by the OEB in 2013 and 2014 for Union[8] and EGD[9], respectively. Depreciation expense is calculated at the individual asset account level using the applicable rates for the storage class.

28. No change is required for harmonization as the Union and EGD OEB-approved methodologies are aligned.

2.10 Depreciation Expense: General Plant Assets

29. The depreciation expense related to the general plant assets is allocated to unregulated storage according to the proportion of unregulated general plant assets to total general plant assets.

30. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology.

[8] EB-2011-0210, Decision and Order, October 24, 2012.
[9] EB-2012-0459, Decision and Order, August 22, 2014.

2.11 Property Tax expense: Storage Assets

31. Actual property taxes related to storage assets will be allocated to unregulated storage operations based on the proportion of unregulated storage assets (excluding general plant assets) to total storage assets.

32. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology.

2.12 Property Tax expense: General Plant Assets

33. Property tax related to general plant assets will be allocated to the unregulated storage operations using the same allocator used to allocate new general plant assets provided in Section 2.3.

34. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology

2.13 Cost of Unutilized In-franchise Storage Capacity

35. Unutilized in-franchise (regulated) storage capacity is the difference between the amount of storage reserved for in-franchise customers and the amount required by in-franchise customers. The portion of storage capacity that is not being used by in-franchise customers is made available to ex-franchise customers for short-term storage. As such, the costs associated with the unutilized capacity are assigned to unregulated storage operations through the excess utility storage space non-utility cross charge. The OEB deemed 11.3 PJ of space to be unutilized in-franchise storage capacity in the Union rate zone.[10] The OEB also approved $3.81 million of O&M costs to be allocated to the revenue associated with the unutilized in-franchise

[10] EB-2011-0210, Decision and Order, October 24, 2012.

storage capacity, in the determination of the balance in the Short-term Storage Deferral account for Union.[11] The allocation of O&M costs associated with the unutilized capacity is adjusted annually in proportion to the actual amount of unutilized in-franchise storage capacity relative to the 11.3 PJ OEB-approved amount.

36. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology. There is no equivalent methodology for the EGD rate zone to consider, as there is no unutilized in-franchise storage capacity in the EGD rate zone

37. In 2024, there is no longer a requirement for an excess utility storage space non-utility cross charge as there is no unutilized in-franchise storage capacity available. Please see Exhibit 4, Tab 2, Schedule 1, Section 1.4, page 16 for further detail.

2.14 Interest Expense on Long-term Debt

38. The cost of long-term debt is allocated between regulated and unregulated operations based on regulated and unregulated rate base as a percentage of total rate base.

39. This approach is consistent with Union's OEB-approved methodology and was adopted for the EGD rate zone in 2019.

3. Impact of the Proposed Harmonized Methodology

40. Table 2 summarizes the forecasted impact of implementing the harmonized unregulated storage allocation methodologies relative to the previously approved methodologies for the 2024 Test Year.

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[11] EB-2011-0210, Decision and Order, October 24, 2012.

Table 2
Increase/(Decrease) in Unregulated Storage Cost Allocations Resulting from Harmonized Methodology

Line No.	Particulars ($ millions)	2024 Test Year	
		(a)	
	Unregulated Storage Asset Balances		
1	Materials and Supplies Inventory	(0.7)	
2	Net Underground Storage Plant	-	
3	Net General Plant	8.7	
4	Total Increase to Net Unregulated Storage Assets	8.0	
	Unregulated Storage Operating Expenses		
5	Cost of Gas: Unaccounted For Gas	0.6	
6	Cost of Gas: Fuel Used to Move Gas	0.2	
7	O&M: Storage Operations	4.1	
8	O&M: Storage Support – Administrative and General	2.0	/u
9	O&M: Storage Support – Variable	0.6	
10	Depreciation Expense: Storage Assets	-	
11	Depreciation Expense: General Plant Assets	1.4	
12	Property Tax Expense: Storage Assets	0.0	
13	Property Tax Expense: General Plant Assets	0.1	
14	Unutilized In-franchise Capacity	-	
15	Interest Expense on Long Term Debt	-	
16	Total Increase to Unregulated Storage Operating Expenses	9.0	/u

41. The overall annual impact is a net increase to unregulated storage assets and expenses, and therefore, a net decrease to regulated storage assets and costs. The net decrease to regulated storage costs is primarily driven by a higher allocation of O&M and depreciation expense to unregulated storage operations.

42. The increase in O&M costs allocated to unregulated storage is attributable to the impact of adopting Union’s methodology, or a modified version of it, on EGD rate

zone costs. Storage operations O&M will be allocated to unregulated storage using an asset-based allocation. This approach reflects the larger unregulated storage operation of Enbridge Gas as compared to the capacity or commodity-based allocations previously applied at EGD. Additionally, support costs were previously based on a markup of direct labour for storage. Instead, the harmonized methodology applies an allocation for unregulated storage based on a more comprehensive pool of administrative and general costs that is based on the proportion of unregulated storage O&M to total O&M, as well as activity-based allocations for variable support costs.

43. The increase in net general plant assets and depreciation expense to unregulated storage is attributable to adopting Union's methodology, or a modified version of it, on EGD rate zone assets. General plant assets will now be allocated to unregulated storage using an allocator derived from asset information and O&M expenses. The approach supports the nature of general plant assets as their function is to support the day-to-day operations of Enbridge Gas, which includes storage operations.

Ernst & Young LLP (EY) prepared the attached Report only for Enbridge Gas Inc. (Client) pursuant to an agreement solely between EY and Client. EY did not perform its services on behalf of or to serve the needs of any other person or entity. Accordingly, EY expressly disclaims any duties or obligations to any other person or entity based on its use of the attached Report. Any other person or entity must perform its own due diligence inquiries and procedures for all purposes, including, but not limited to, satisfying itself as to the financial condition and control environment of Client, as well as the appropriateness of the accounting for any particular situation addressed by the Report.

EY did not perform an audit, review, examination or other form of attestation (as those terms are identified by CPA Canada, the AICPA or by the Public Company Accounting Oversight Board) of Client's financial statements. Accordingly, EY did not express any form of assurance on Client's accounting matters, financial statements, any financial or other information or internal controls. EY did not conclude on the appropriate accounting treatment based on specific facts or recommend which accounting policy/treatment Client should select or adopt.

The observations relating to accounting matters that EY provided to Client were designed to assist Client in reaching its own conclusions and do not constitute our concurrence with or support of Client's accounting or reporting. Client alone is responsible for the preparation of its financial statements, including all of the judgments inherent in preparing them.

This information is not intended or written to be used, and it may not be used, for the purpose of avoiding penalties that may be imposed on a taxpayer.

Enbridge Gas Inc: Unregulated Storage Cost Allocation

21 June 2020

Building a better working world

Table of Contents

I. Executive Summary

EY was retained by Enbridge Gas Inc. (Company or EGI) to assist management in defining the Company's harmonized unregulated storage cost allocation methodology, subsequent to a January 2019 amalgamation of Enbridge Gas Distribution (Enbridge Gas or EGD) and Union Gas Limited (Union Gas or UG).

EY obtained an understanding of the current practices and methodology at the legacy entities EGD and UG through review of third-party cost allocation reports and discussions with EGI personnel. This included developing an understanding of the nature of costs incurred, the causation of these costs as they relate to unregulated storage operations, and the criteria by which the cost allocations are determined. As part of EY's assistance to management in developing a single integrated cost allocation methodology between regulated and unregulated storage operations, EY documented management's rationale in determining the cost drivers, basis for allocations, and causality to unregulated storage activities.

EY observed that the updated methodology for EGI incorporates cost allocations which management has determined to best represent unregulated activity for storage operations. Based on our understanding of the current practices, prior cost allocation reports and applicable regulatory precedents established by the Ontario Energy Board (Board or OEB), the harmonized methodology for EGI unregulated storage cost allocation proposed by management attempts to fairly and reasonably reflect costs incurred by the unregulated and regulated business and based on our observations, is consistent with applicable regulatory precedents established by the OEB in relation to the respective historical filings of EGD and UG.

II. Purpose and Scope

As of January 1, 2019, Enbridge Gas Inc. amalgamated Union Gas and Enbridge Gas to form EGI. At the time of amalgamation, both legacy entities had unregulated storage operations, which per the OEB's Natural Gas Electricity Interface Review ("NGEIR") in EB-2005-0551, meant that these storage services operated in a competitive market and would not be subject to rate regulation. The two legacy entities were required to identify and separate costs between the regulated and unregulated storage operations for the purposes of setting regulated utility rates and for calculating earning sharing. The two legacy entities each developed and utilized their own methodology, which was previously and separately approved by the OEB.

As a result of the amalgamation, EGI requires a harmonized cost allocation methodology for unregulated storage operations. The purpose of this report is to summarize the current unregulated storage cost allocation methodology being utilized at the legacy entities, and document the harmonized allocation methodology for the amalgamated entity going forward. As part of our engagement, EY obtained an understanding of the current approved methodology at the two legacy entities and assisted management in determining a harmonized and streamlined policy for the amalgamated entity that meets the OEB regulatory requirement of ensuring that costs are allocated fairly based on the underlying business operations. EY did not confirm adherence and compliance to the approved methodology. EY has assisted management in determining the implementation requirements of the harmonized policy for the amalgamated entity, however, the implementation of the new policy is anticipated for January 1, 2021 (or at a future date to be determined by management) and will be undertaken by management without EY assistance. The expected impacts detailed in this report are limited to the structure and operational decisions of the organization as at the issuance of this report.

The scope of this report is limited to cost allocations for unregulated storage operations and does not include other unregulated businesses and the costs associated with those areas respectively. This report has been prepared for Enbridge Gas Inc.

III. Background

Natural gas storage

Natural gas can be stored for an indefinite period in natural gas storage facilities for later consumption. EGI offers storage services to wholesale market participants and power generation customers. The legacy entities (EGD and UG) have operated large underground gas storage facilities in southwestern Ontario, and with the amalgamation, EGI's underground storage assets have become one of the largest facilities in North America. Other characteristics of the storage services provided include[1]:

- Services are offered on a firm basis and range from high deliverability storage (10- or 20-day service) to seasonal storage;
- Customers pay a monthly demand charge, as well as variable charges including commodity and fuel;
- Contract terms range from 1 to 10 years; and
- Customers have the option to cycle volumes within their contractual parameters and pay variable charges on the cycled volumes.

NGEIR decision

In 2006, the OEB determined that the Ontario storage operators (EGD and UG) compete in a competitive market because the geographic market includes part of the US in which neither EGD nor UG has market power. The OEB concluded that the Ontario storage operators will not be required to share the profits on long-term storage transactions that use storage space not needed to serve in-franchise needs because that capacity now constitutes a "non-utility" asset for which the shareholders appropriately bear the risk. [2]

Impact of NGEIR decision on EGD and UG

The impact of the decision was that storage services at each legacy entity had to be separated into regulated and unregulated operations. While regulated storage must operate within the parameters of OEB guidelines, unregulated storage is not monitored by the Board. Unregulated storage provides wholesale market participants and power generation customers with capacity to store gas product in facilities stationed across Canada. The storage services that fall within the unregulated service parameter for EGD and UG include storage services for customers outside the franchise areas, new storage services for in-franchise customers, and all other storage services offered by other storage operators (including operators affiliated with the two entities).

At the time of the NGEIR decision, EGD's existing storage investment was required to serve its in-franchise customers, while UG had storage operations that served ex-franchise customers. As a result, UG carried out a cost allocation study[3] to determine a one-time separation and transfer of its storage assets existing at the time of the NGEIR decision to their unregulated operations. This was not required

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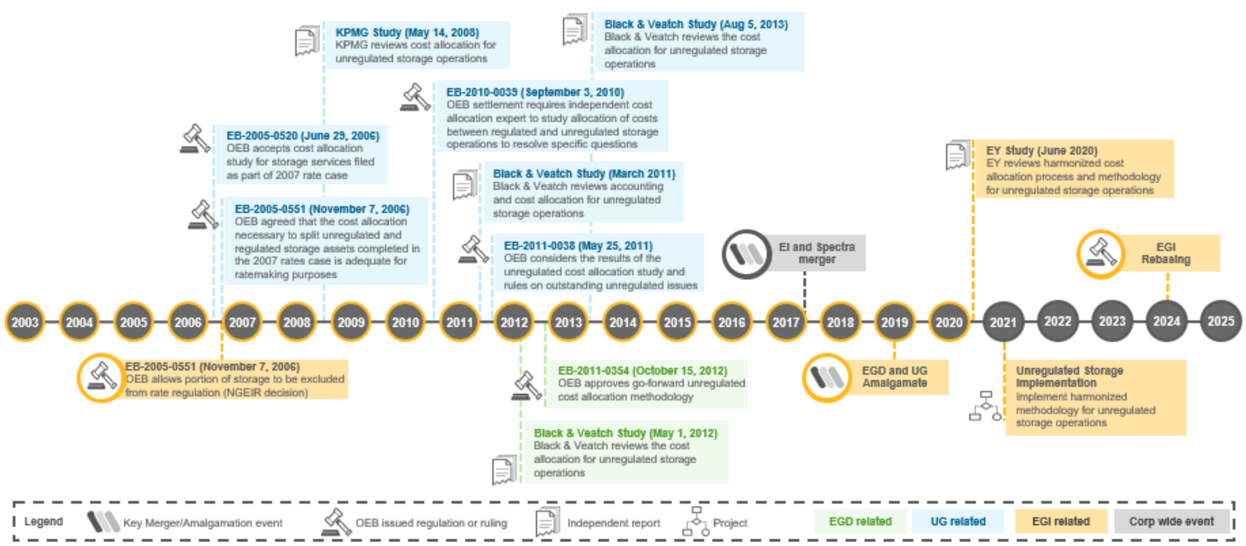
[1] Enbridge, https://www.enbridgegas.com/Commercial-and-Industrial/Data-Sources/Gas-Storage (Accessed May 11, 2020)
[2] EB-2005-0551 – NGEIR Decision with Reasons dated November 7, 2006, page 4
[3] KPMG Report for Union Gas – Unregulated Operations Accounting and Reporting Documentation (May 14, 2008)

for EGD because EGD did not have excess storage capacity at the time to service ex-franchise customers. Instead, EGD utilized an incremental costing approach for identification of new storage assets to either its regulated or unregulated operations. In the early 2010s, the legacy entities, EGD and UG, each had independent reviews of the cost allocation process for regulated and unregulated underground storage operations[4,5,6].

Since the NGEIR decision, both entities were required to identify capital investments related to their unregulated operations, maintain separate plant records, and separate expenses between regulated and unregulated operations. The two legacy entities chose different methodologies that were each separately approved by the OEB[7,8] using the third-party cost allocation reports as independent evidence. Specifically, the legacy UG methodology for assigning storage-related expenses was largely based on an asset basis whereas it was based on storage activity at legacy EGD. Given the magnitude of legacy UG's unregulated operations compared to that of legacy EGD, the cost allocation methodology at legacy UG has received greater guidance and input from the Board. For the year ended 2019, unregulated operating expenses at UG were $28.6M, compared to $5.7M at EGD.

Unregulated storage cost allocation timeline



[4] EB-2011-0354, Exhibit D2, Tab 5, Schedule 1 – Black & Veatch Independent Review
[5] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[6] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[7] EB-2011-0038 – Decision and Order (January 20, 2012) and EB-2013-0365 – Settlement Agreement (June 3, 2014)
[8] EB-2011-0354 – Decision on Settlement Agreement (October 15, 2012), EB-2015-0114 – Decision and Interim Rate Order (December 10, 2015)

IV. Methodology Design Principles

Although each legacy methodology remains appropriate, the amalgamation has created the need for a single harmonized cost allocation methodology for unregulated storage operations. The following key principles were used in developing EGI's harmonized cost allocation process for its unregulated and regulated storage operations:

- The harmonized methodology is a fair allocation of costs that accurately represents the underlying activities of the unregulated and regulated operations
- There is a consistency of assumptions, decisions and approach taken in each component of the methodology to determine regulated and unregulated costs
- The cost allocation process allows for transparency and traceability, such that the rationale for the structure, methodology, and computational results can be understood, evaluated internally and externally by independent third parties, and updated as required
- The allocation methodology continues to address prior OEB findings and is consistent with decisions made by the Board with respect to allocation methodology for storage operations
- The methodology appropriately addresses any operational or organizational changes as a result of the amalgamation
- The allocation methodology is feasible and practical in cost and effort to implement
- The approach taken for each component of the methodology can be customized and adapted to current and expected future IT systems

V. EGI Cost Allocation Methodology for Unregulated Storage Operations

This section details the current state cost allocation methodology used at legacy EGD and UG that was reviewed in prior unregulated storage cost allocation studies and approved by the OEB, as well as the harmonized EGI cost allocation methodology to be implemented in 2021 (or at a future date to be determined by management), including expected impact.

Overall structure

Based on the previous independent studies[9,10,11,12], inspection of the unregulated trial balance at legacy EGD, and inspection of the unregulated allocator model at legacy UG, the following cost elements related to underground storage operations were identified:

Asset allocation

A. New storage assets
B. New general plant assets

Expense allocation

C. Cost of gas: Fuel used to move gas and lost and unaccounted for gas
D. Operating & maintenance expenses
   i. O&M: Storage operations
   ii. O&M: Storage support costs related to administrative and general activities, and corporate administrative and general overheads
   iii. O&M: Variable storage support costs
E. Depreciation expense
F. Property tax
G. Cost of unutilized in-franchise storage capacity
H. Interest expense on long-term debt

A portion of each of these cost elements are allocated to the unregulated storage operations either on a one-time basis, monthly or an annual basis with allocators that are updated periodically. Each of these elements are discussed in further detail below. Please refer to *Appendix A* for a summary of the 2019 unregulated actual asset and expense cost elements, and the timing of the cost allocations to the unregulated storage operations.

A. New Storage Assets

New storage assets are assets constructed after the NGEIR decision for use in storage operations and currently, they include the following asset classes: structures and improvements, storage wells, field

[9] KPMG Report for Union Gas – Unregulated Operations Accounting and Reporting Documentation (May 14, 2008)
[10] EB-2011-0354, Exhibit D2, Tab 5, Schedule 1 – Black & Veatch Independent Review
[11] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[12] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review

lines, compressor equipment, measuring and regulating equipment and dehydration. Storage assets also include base pressure gas, which represents gas held within the gas storage system to provide the base, or minimum pressure needed to meet operational requirements with the underground assets currently in place.

Legacy EGD and UG unregulated storage cost allocation methodology summary

Storage assets are directly attributable to either the regulated or unregulated storage operations. Allocations of new storage assets to the unregulated storage business are made on a one-time basis for each new storage asset added and enable the legacy entities to maintain plant accounting records at the individual asset level for its unregulated storage operations. In addition, the split between unregulated storage assets and the regulated utility assets at each individual storage pool is updated annually to reflect additions and retirements that occurred throughout the prior year, for the purposes of allocating costs associated with capital maintenance of the assets at both legacy EGD and legacy UG. At legacy UG, the split between unregulated storage assets and the regulated utility assets is applied to allocate O&M expenses between the regulated and unregulated storage operations.

New storage assets constructed can be classified into three categories for the purpose of allocation to the unregulated storage operations:

1) New storage asset resulting in additional capacity and deliverability

   These projects consist of storage-related assets that are installed to increase storage capacity or deliverability, ultimately providing growth opportunities for the unregulated storage business. As the storage requirements of the in-franchise customers at legacy EGD and UG are satisfied by existing storage assets and third-party storage (in the case of legacy EGD), these projects are driven by the operational needs of the unregulated storage business. Therefore, the capital project costs of these new storage assets are directly allocated to the unregulated storage operations at the two legacy entities.

2) New storage asset to maintain existing assets or replace existing end-of-life asset

   These projects consist of storage-related assets that only replace existing storage assets without providing any operational efficiencies or growth opportunities. This includes costs incurred to replace the asset, recondition the asset, or enable the asset to comply with regulatory or environmental conditions. As these projects are undertaken to maintain current storage capabilities, the new assets are allocated between the regulated and unregulated storage operations based on the allocations of the original asset.

3) New storage asset to replace and enhance existing asset

   These projects consist of storage-related assets that replace existing storage assets and provide incremental storage capacity or deliverability. Under this category, there can be a further two scenarios:

   a) the new asset is replacing and enhancing an existing asset that is at the end of its useful life; or

b) the new asset is replacing and enhancing an existing asset that is not at the end of its useful life.

Under the first category, the replacement of the existing utility asset is driven by the need to replace the existing asset which has reached the end of its useful life, and not by the desire to increase storage capacity and deliverability to service the ex-franchise customers. As a result, the cost of replacing the existing asset is allocated between the regulated and unregulated storage operations based on the historic allocation of asset being replaced, without enhancements to capacity or deliverability, and the incremental cost of enhancing the asset is allocated to the unregulated business.

Under the second category, the replacement of the existing utility asset is driven by the desire to increase storage capacity and deliverability for the unregulated operations. As the replacement of the asset would not have occurred if not for the operation needs of the unregulated operations, the cost of the entire replacement asset is allocated to the unregulated business.

Base pressure gas

Historical base pressure gas was allocated to the unregulated storage operations at legacy UG as part of the one-time separation and transfer of its storage assets existing at the time of the NGEIR decision, and legacy EGD agreed to allocate a portion of its historical base pressure gas to the unregulated storage operations as part of the 2016 rate case[13]. Additions and removals to the base pressure gas are allocated to the unregulated storage operations in proportion with the allocations of the relevant asset pools.

Proposal for harmonized EGI unregulated storage cost allocation methodology

The current treatment for new storage assets is aligned at legacy EGD and UG and appropriate as the methodology for new storage assets is consistent with the unregulated storage cost allocation studies approved by the OEB.

No additional methodology updates are required for EGI in this area going forward.

Impact

No quantitative impact.

B. New General Plant Assets

General plant assets relate to assets used in the utility's general plant facilities. General plant assets are capital assets used to support day-to-day business and operations activities but are not specified assets used solely in distribution, transmission, or storage systems. These assets include land and buildings, computer software and hardware, tools and equipment, transportation and heavy-work equipment, natural gas vehicle fuel equipment and communication equipment.

[13] EB-2015-0114 – Decision and Interim Rate Order (December 10, 2015)

The current definition of general plant assets differs between legacy EGD and UG with respect to the inclusion of head office buildings and land. At legacy UG, head office buildings are designated as general plant assets that support their storage, transmission and distribution businesses, whilst at legacy EGD, head office buildings are designated as distribution assets rather than general plant assets.

Legacy UG unregulated storage cost allocation methodology summary

New general plant assets are allocated to the unregulated storage business annually, by applying two different allocators to the new general plant assets added within the year: one for vehicles and heavy work equipment, and another for all other general plant assets. General plant assets at legacy UG include IT software, office buildings and land, office equipment, vehicles and heavy work equipment.

a) Vehicles and heavy work equipment

   Vehicles and heavy work equipment are attributed to the unregulated storage operations in a multistep process. Firstly, a storage and transmission operations asset allocator is calculated based on the proportion of storage and transmission vehicles and heavy equipment assets (current year gross value) to the total vehicles and heavy equipment assets (current year gross value) used in legacy UG's operations. Next, a composite allocator derived from storage space, deliverability and horsepower is applied to the storage and transmission asset allocator described above, and that product is applied to the value of new vehicles and heavy work equipment in order to calculate the portion of new assets that are attributed to the unregulated storage operations. Refer to *Appendix B* for details on the calculation of the allocator described above.

b) All other general plant assets (general plant assets other than vehicles and heavy work equipment)

   Allocations for all other new general plant assets are based on a composite allocator derived from asset information and O&M expenses. The asset information used in the allocation is based on the gross total value of unregulated storage plant as a percentage of the total company gross plant value (both values excluding construction work in progress, asset retirement obligations and general plant). The O&M expense information used in the allocation is based on O&M expenses related to unregulated storage operations as a percentage of total company net O&M expenses. The asset and O&M expense allocators are averaged in equal portions to generate the composite factor used to allocate new general plant asset additions to the unregulated business. Refer to *Appendix B* for details on the calculation of the allocator described above.

   As the allocation to the unregulated storage operations is not tracked on an individual asset basis, general plant assets are treated as a pool for the purposes of the annual allocations described above. New additions to general plant assets are allocated using the allocators described above and added to the pool of unregulated general plant assets.

Legacy EGD unregulated storage cost allocation methodology summary

Legacy EGD does not currently allocate any general plant assets to the unregulated storage operations.

Proposal for harmonized EGI unregulated storage cost allocation methodology

Allocation methodology

EGI will allocate a portion of its new general plant assets to the unregulated storage operations on a monthly basis going forward, using the legacy UG method of determining the allocations with slight modifications to better align the harmonized methodology for EGI within the framework of the design principles. Allocation of general plant assets to the unregulated storage business is fair as the purpose of general plant assets is to support day-to-day operations, which includes storage operations. The legacy UG methodology to allocate a portion of new general plant assets to the unregulated storage business is supported by UG's board-approved 2007 cost allocation study[14] and board-approved 2011 and 2013 independent unregulated storage cost allocation studies[15, 16].

The refined methodology will result in the following change to the existing legacy UG methodology for allocation of new general plant asset additions in the year:

- All new general plant assets, including vehicle and heavy work equipment will be allocated using one allocator (Refer to *Appendix B* for details of the calculation of the allocator)

As EGI, total EGI O&M expenses will be used to determine the allocators for the legacy entities. The modified legacy UG methodology continues to maintain a fair allocation that represents underlying business activities, whilst simultaneously streamlining the cost allocation methodology related to general plant assets. The current allocator for vehicles and heavy equipment, using a composite of capacity, storage and horsepower, is overly complex and not easily traceable or reproducible by other parties. Replacing this allocator with the simpler general plant allocation method will increase transparency of the vehicles and heavy equipment asset allocations to unregulated storage, in line with design principles.

General plant assets definition

A harmonized definition of general plant assets for the purposes of unregulated storage allocations will be required at EGI. The inclusion of head office buildings and land in the definition of general plant assets, and the determination to allocate a portion to the unregulated storage business is supported by UG's board-approved 2007 cost allocation study[17] and board-approved 2011 and 2013 independent unregulated storage cost allocation studies[18,19].

To ensure consistency of the general plant asset definition between the two legacy entities, EGI will include the following EGD assets as general plant assets for the purpose of determining allocations to the unregulated operations from an asset perspective as well as for the related depreciation and property tax expense allocations:

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[14] KPMG Report for Union Gas – Unregulated Operations Accounting and Reporting Documentation (May 14, 2008)
[15] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[16] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[17] KPMG Report for Union Gas – Unregulated Operations Accounting and Reporting Documentation (May 14, 2008)
[18] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[19] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review

- Administrative buildings and accompanying land, which currently includes: Markham – Technology & Operations Centre, Ottawa – Conventry Road, Thorold – Schmon Parkway and North York – Victoria Park Complex

Legacy EGD: One-time split for existing general plant assets

Legacy EGD does not currently allocate any general plant assets to the unregulated storage operations. Given that EGI will be allocating general plant assets to the unregulated storage operations going forward, legacy EGD will perform a one-time allocation of its existing general plant assets as at December 31, 2020 (or at a future date to be determined by management dependent on the timing of the new harmonized methodology implementation) to the unregulated storage operations. The existing legacy EGD general plant assets will be assigned to the unregulated storage function using legacy EGD O&M expense information in a manner consistent with the EGI methodology described above.

Impact

See below for unregulated general plant asset balances under current and proposed harmonized EGI unregulated storage cost allocation methodology. All amounts are based on 2020 budgeted figures.

	Unregulated General Plant Asset Balance (Net)		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage assets)
EGD	-	$2.48M	+ $2.48M
UG	$7.35M	$6.93M	- $0.42M
EGI	**$7.35M**	**$9.41M**	**+ $2.05M***

*Difference of $0.01M due to rounding

C. Cost of Gas

Both legacy EGD and UG incur unregulated storage gas costs related to lost and unaccounted for gas, fuel consumed to move gas (compressor fuel), customer-supplied fuel and external storage costs related to purchasing storage space from third parties. Lost and unaccounted for gas includes all components of gas loss, such as leakages, venting, meter errors and other similar considerations.

Allocators are required for both lost and unaccounted for gas and fuel used to move gas as these costs are related to both regulated and unregulated storage activities. No allocator is required for customer-supplied fuel and external storage costs related third-party storage, as these are driven by services, activities and contracts which are either exclusively regulated or exclusively unregulated.

Legacy UG unregulated storage cost allocation methodology summary

Lost and unaccounted for gas (“UFG”)

Unaccounted for gas (“UFG”) at legacy UG relates to gas losses from storage and transportation. Total actual unaccounted for gas incurred is allocated to the unregulated storage operations on an annual basis using a volumetric allocator based on actual gross unregulated storage activity as a percentage of total actual gross storage and transportation activity. Gross activity is the sum of absolute volumes as it relates to both injections and withdrawals (i.e., 100GJ injections and 100GJ of withdrawals = 200GJ of gross activity). Refer to *Appendix C* for details on the calculation of the allocation described above.

Fuel consumed to move gas (compressor fuel)

Total actual fuel consumed is allocated to the unregulated storage operations daily using a volumetric allocator based on net daily unregulated storage activity as a percentage of net daily total activity for storage and transportation. Net activity is composed of injections less withdrawals (i.e., 100GJ injections and 100GJ of withdrawals = 0GJ of net activity). Refer to *Appendix D* for details on the calculation of the allocation described above.

Legacy EGD unregulated storage cost allocation methodology summary

Lost and unaccounted for gas ("LUF")

Lost and unaccounted for gas ("LUF") at legacy EGD relates to gas losses from storage operations (as opposed to storage and transportation operations at legacy UG). Expected annual lost and unaccounted for gas volumes for storage operations were determined to be 23,763.6 10^3m^3 or about 0.835 bcf[20]. The total LUF provision has not been updated since before the commencement of legacy EGD's unregulated storage business. Currently, 14.3%[21] of the total LUF provision for storage (0.12 bcf) is designated as being related to the unregulated storage operations, based on volumetric drivers for storage capacity measured in 2015, and the capacity-based allocator used to determine the LUF related to the unregulated storage operations has not been updated with current capacity.

The 0.12 bcf of LUF associated with the unregulated storage business is applied to the Quarterly Rate Adjustment Mechanism ("QRAM") reference price of gas to determine the cost.

Refer to *Appendix C* for details on the calculation of the allocation described above.

Fuel consumed to move gas (compressor fuel)

Total actual storage fuel consumed is allocated to the unregulated storage operations on a monthly basis. The unregulated portion is calculated by first determining a compressor fuel consumption percentage (total fuel consumed for storage as a percentage of total monthly storage activity, represented as the difference between the opening and closing balance), and applying that fuel consumption percentage to the monthly unregulated activity (represented as the difference between the opening and closing unregulated balance). Refer to *Appendix D* for details on the calculation of the allocation described above.

Proposal for harmonized EGI unregulated storage cost allocation methodology

In determining the harmonized EGI unregulated storage cost allocation methodology, management considered aligning the volumetric activity basis (gross activity as opposed to net activity), used to allocate the two gas costs as well as the frequency at which the allocations of volumetric activity will be presented (monthly activity as opposed to daily activity). Due to the nature of the fuel consumption and use of counteracting fuel movement within the storage operations, management determined that

[20] EB-2015-0114, Exhibit A1, Tab 5, Schedule 1, Page 3 of 6
[21] EB-2015-0114, Exhibit A1, Tab 5, Schedule 1, Page 2 of 6

different bases for allocation of the two gas costs to the unregulated storage business as outlined below would more accurately attribute costs between the unregulated and regulated operations.

Lost and unaccounted for gas

EGI will allocate lost and unaccounted for gas to the unregulated storage business on a monthly basis using actual gross unregulated storage activity as a percentage of total actual gross activity consistent with the operations contributing to the total lost and unaccounted for gas volume (i.e., total actual gross activity for storage and transportation is used to allocate UFG, as it relates to gas losses from storage and transportation operations; total actual gross activity for storage is used to allocate LUF, as it relates to gas losses from storage operations). This methodology is consistent with the legacy UG allocation methodology with a slight modification to better align the harmonized methodology for EGI within the framework of the design principles. The legacy UG methodology is supported by the cost allocation studies[22,23,24] previously reviewed and approved by the OEB[25].

The revision to the methodology is related to the basis for which the volumetric gross activity is being determined. Legacy UG previously performed the allocation of lost and unaccounted for gas once a year using volumetric activity for the entire year. Going forward, EGI will be performing allocations using volumetric activity by month, to consider activity fluctuations throughout the year and to provide a more accurate cost for lost and unaccounted for gas, given gas reference price fluctuations. This enhances cost causality and is in line with the methodology design principles. Furthermore, using monthly activity as a basis for allocation to the unregulated operations is in line with EGI's process of recording monthly entries into the financial systems.

Refer to *Appendix C* for details on the calculation of the allocation described above.

Fuel consumed to move gas (fuel consumed)

EGI will allocate fuel consumed to the unregulated storage business on a monthly basis using actual net unregulated storage activity as a percentage of total actual net storage activity. The allocation of fuel consumed to the unregulated storage operations will be determined on a daily basis (daily fuel consumed will be allocated to the unregulated storage operations based on daily net activity). This methodology is consistent with the legacy UG allocation methodology per the cost allocation studies[26,27] previously reviewed and approved by the OEB[28].

Refer to *Appendix D* for details on the calculation of the allocation described above.

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[22] KPMG Report for Union Gas – Unregulated Operations Accounting and Reporting Documentation (May 14, 2008)
[23] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[24] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[25] EB-2011-0038 – Decision and Order (January 20, 2012)
[26] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[27] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[28] EB-2011-0038 – Decision and Order (January 20, 2012)

Impacts

See below for cost of gas expenses under current and proposed harmonized EGI unregulated storage cost allocation methodology. All amounts are based on 2020 budgeted figures.

	Unregulated Storage Lost and Unaccounted for Gas Expense		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	$0.50M	$0.54M	+ $0.04M
UG	$1.83M	$1.76M	- $0.06M*
EGI	**$2.33M**	**$2.30M**	**- $0.02M**

* Difference of $0.01M due to rounding

	Unregulated Storage Fuel Consumed to Move Gas (Fuel Consumed) Expense		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	$0.46M	$0.24M	- $0.22M
UG	$2.43M	$2.43M	-
EGI	**$2.89M**	**$2.67M**	**- $0.22M**

D. Operating & Maintenance Expenses

Operating and maintenance (O&M) expenses represent expenses incurred to operate and maintain all EGI natural gas distribution, storage and transmission activities. These expenses can be directly or indirectly attributable to the storage operations and are incurred by EGI or by Corporate.

The components to address O&M cost allocations to the unregulated storage business are:

1) O&M: Storage Operations
2) O&M: Storage Support Costs Related to Administrative and General Activities, and Corporate Administrative and General Overheads
3) O&M: Variable Storage Support Costs

1. O&M: Storage Operations

Legacy UG unregulated storage cost allocation methodology summary

Legacy UG organizes its expense in internal work orders (known as IOs), and the IOs are categorized based on the underlying activity for the purposes of allocating costs to the unregulated storage operations.

Table 1: O&M Expense Classification Categories for Storage Operations

O&M Classification	Description
Storage-General	Underlying activity related to storage operations
Storage-Shared	Underlying activity related to storage and transmission operations
Storage-Unregulated	Underlying activity related to unregulated storage operations
Storage-Regulated	Underlying activity relating to regulated storage operations
Storage-Support	Underlying activity supports storage operations and all other operations

O&M expenses directly related to storage operations at legacy UG are classified under the following O&M classification categories: Storage-General, Storage-Shared, Storage-Unregulated, and Storage-Regulated. IOs under Storage-General and Storage-Shared are further categorized by asset-related categories to enable the allocation: Supervision, wells, lines, compressors, measuring and regulating equipment (M&R), dehydration, rents and others. Allocations classified as Storage-Support are described in Section 2 below (O&M: Storage Support Costs Related to Administrative and General Activities, and Corporate Administrative and General Overheads).

Allocations are not required for Storage-Unregulated and Storage-Regulated categories as these costs capture operating and maintenance expenses that can be traced directly to either the regulated or unregulated storage operations.

The expenses categorized under Storage-General and Storage-Shared are incurred to operate and maintain storage assets utilized to provide storage services for both the unregulated and regulated storage operations, as well as transmission services in the case of Storage-Shared. As a result, allocations are required to identify the costs related to the unregulated storage operations. These allocations to the unregulated storage operations are performed based on the underlying asset for which the expenses are incurred to support. The underlying asset percentage allocations (unregulated storage assets as a percentage of total storage assets) for each storage asset category at each individual storage pool is updated annually, for the purposes of O&M allocations.

Refer to *Appendix E* for details on the allocation described above.

Legacy EGD unregulated storage cost allocation methodology summary

Legacy EGD incurs operating and maintenance costs for its unregulated storage operations mostly through its integrated storage operation, although certain costs can be directly related to its unregulated storage operations. Legacy EGD performs cost allocations from its integrated storage operations for its unregulated storage operations on a monthly basis, using allocators with both a fixed and variable component. Fixed activity allocators are determined for each cost element (i.e., contract services, materials and supplies) based on three activity drivers:

- Capacity: An annual component for space or capacity, derived from storage models[29]

[29] EB-2011-0354, Exhibit D2, Tab 5, Schedule 1, Black & Veatch Independent Review – Page 26 of 53

- Commodity: A variable component for each unit of gas injected into or withdrawn from storage[30]
- Deliverability: A peak component for the maximum daily rate at which the gas may be withdrawn from storage[31]

The variable portion of the allocator considers the activity drivers (listed above) expected to be related to unregulated or regulated storage operations for the current period; capacity and deliverability are updated periodically, and commodity is updated monthly.

Refer to *Appendix E* for details on the allocation described above.

Proposal for harmonized EGI unregulated storage cost allocation methodology

EGI will allocate its O&M costs directly related to storage operations based on the proportion of underlying storage assets assigned to the unregulated storage operations (which is updated on an annual basis) following the legacy UG approach with slight modifications to better align the harmonized methodology for EGI within the framework of the design principles. The legacy UG methodology is consistent with the storage unregulated cost allocation methodology per the cost allocation studies[32,33] previously reviewed and approved by the OEB[34]. Further, the fixed activity allocator used at legacy EGD incorporated management estimates, and thus was less transparent to other parties. Therefore, an asset-based allocation that can be readily traced to the assets supporting the unregulated storage operations will further increase transparency and enhance the causation linkage within the allocation methodology.

The refined methodology will result in the following change to the existing legacy UG methodology for the allocation of O&M expenses directly related to storage operations:

- O&M costs will continue to be classified into asset-specific cost pools and will be allocated using the storage asset category. However, asset-specific cost pools will now be allocated using a storage asset allocator averaged across all asset locations for each asset category (as opposed to allocators being calculated by location for each asset).

The modified legacy UG methodology continues to maintain a fair allocation that represents underlying business activities, whilst simultaneously streamlining the cost allocation methodology related to O&M expenses directly related to storage operations. Using one allocator per storage asset category across the various storage pool locations will increase the transparency of the allocations and allow outside parties to more easily reproduce the allocator, in line with design principles.

Impact

See below for the O&M: Storage operations expenses under current and proposed harmonized EGI unregulated storage cost allocation methodology. All amounts are based on 2020 budgeted figures.

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[30] EB-2011-0354, Exhibit D2, Tab 5, Schedule 1, Black & Veatch Independent Review – Page 26 of 53
[31] EB-2006-08-25, Exhibit G2, Tab 1, Schedule 1, Page 16 of 26
[32] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[33] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[34] EB-2011-0038 – Decision and Order (January 20, 2012)

	Unregulated Storage O&M: Storage Operations Expense		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	$1.63M	$2.63M	+ $1.00M
UG	$3.92M	$3.80M	- $0.12M
EGI	**$5.55M**	**$6.43M**	**+ $0.88M**

2. O&M: Storage Support Costs related to Administrative and General Activities, and Corporate Administrative and General Overheads

Legacy UG unregulated storage cost allocation methodology summary

O&M expenses related to administrative and general activities that support storage operations at legacy UG are classified under the Storage-Support O&M classification bucket listed out in **Table 1**. Administrative and general activities include support from IT, Finance, HR and other administrative areas, as well as the net Corporate overhead allocation charges. These administrative and general expenses are allocated in proportion to UG's unregulated storage O&M expenses (O&M expenses related to unregulated storage operations as a percentage of total company net O&M expenses). Refer to *Appendix F* for details on the calculation of the allocation described above.

Legacy EGD unregulated storage cost allocation methodology summary

Labour expenses for salary staff within storage operations is marked up to account for administrative and general overheads, which include Enbridge corporate overheads as well as performance-based compensation that is included as part of Enbridge's employee compensation plan. An overhead markup of 65% to 70% has been applied to the total integrated storage operation labour expenses, which is then allocated to unregulated storage using the fixed and variable volume activity allocators described under EGD's current state treatment for O&M storage costs. Refer to *Appendix F* for details on the calculation of the allocation described above.

Proposal for harmonized EGI unregulated storage cost allocation methodology

EGI will allocate actual administrative and general O&M support costs (excluding the variable O&M support costs documented in Section 3 below) in proportion with O&M expenses incurred by the unregulated storage operations following a modified legacy UG approach.

Currently, O&M support costs are allocated based on the total unregulated storage operations O&M costs as a percentage of total O&M costs (including O&M support costs). Going forward, EGI will exclude O&M costs related to storage support from the determination of the allocator to be applied to storage support departments. Refer to *Appendix F* for details on the calculation of the allocation described above.

The legacy UG approach is consistent with the unregulated storage cost allocation methodology studies[35,36] previously reviewed and approved by the OEB[37]. The legacy UG approach of allocating actual administrative and general O&M costs results in increased traceability of costs as compared to the approved legacy EGD methodology of marking up labour expenses to account for administrative and general overhead costs. The proposed modification to the existing legacy UG methodology further enhances accuracy of the storage support allocations, as it will remove O&M support costs in the determination of the allocator that is used to allocate O&M support costs to unregulated storage.

Impact

See below for the O&M: Storage support costs related to administrative and general activity expenses under current and proposed harmonized EGI unregulated storage cost allocation methodology. All amounts are based on 2020 budgeted figures.

	Unregulated Storage O&M: Storage Support Costs (Related to Administrative and General Activity) Expense		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	$0.47M	$3.58M	+ $3.11M
UG	$5.83M	$3.78M	- $2.05M
EGI	**$6.30M**	**$7.36M**	**+ $1.06M**

3. O&M: Variable Storage Support Costs

Legacy UG unregulated storage cost allocation methodology summary

There are storage support areas that can vary in terms of the support that they provide to the storage business year to year. For instance, the Business Development group would be involved to the extent of planning or development of an unregulated storage asset. If there were no upcoming unregulated storage projects for the year, their involvement would be negligible. Other variable storage support groups include asset management, lands and permitting, engineering, and regulatory affairs.

At legacy UG, these department IOs are a subcategory of the Storage-Support O&M classification bucket listed out in **Table 1**. The costs incurred under these areas for a given year are based on activities to be conducted by the departments.

Please refer to *Appendix G* for a list of the departments identified to provide variable support to the unregulated storage operations.

[35] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[36] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[37] EB-2011-0038 – Decision and Order (January 20, 2012)

Legacy EGD unregulated storage cost allocation methodology summary

As discussed above, legacy EGD applies a general markup to costs and therefore does not determine the separate cost associated with storage support activities.

Proposal for harmonized EGI unregulated storage cost allocation methodology

EGI will allocate variable storage support O&M costs in accordance with the activities to be conducted by these departments, consistent with the existing legacy UG methodology. Activity templates will be completed by these departments on an annual basis to determine expected unregulated activities.

Based on discussions with management over the nature of the support provided by these departments, the use of activity templates correlates the nature of the cost to the type of storage operation to ensure costs (unregulated or regulated) are allocated appropriately. The legacy UG approach is consistent with the storage unregulated cost allocation methodology per the cost allocation studies[38,39] previously reviewed and approved by the OEB[40].

Impact

See below for the O&M: Variable storage support expenses under current and proposed harmonized EGI unregulated storage cost allocation methodology. All amounts are based on 2020 budgeted figures and activity templates completed in 2020.

	Unregulated Storage O&M: Variable Storage Support Expense		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	-	$0.43M	+ $0.43M
UG	$1.37M	$1.37M	-
EGI	**$1.37M**	**$1.80M**	**+ $0.43M**

E. Depreciation Expense

Depreciation expense is calculated on the asset balances allocated to the unregulated storage business, which include storage assets and general plant assets.

Legacy EGD and UG unregulated storage cost allocation methodology summary

Depreciation expense: Storage assets

The determination of the depreciation expense related to storage assets allocated to the unregulated business is aligned at the legacy entities. The annual depreciation rates for underground storage assets were approved by the Board in 2013 and 2014 for UG and EGD. respectively. Depreciation expense (and accumulated depreciation amount) is calculated at the individual asset level using the applicable rates

[38] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[39] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[40] EB-2011-0038 – Decision and Order (January 20, 2012)

for the storage class. See *Appendix H* for the annual depreciation rates for the unregulated storage assets.

Depreciation expense: General plant assets

The determination of depreciation expense related to general plant assets allocated to the unregulated business was only applicable to legacy UG, as legacy EGD has not allocated general plant assets to its unregulated storage operations. Due to the nature of general plant assets and the complexity involved in individually tracking general plant assets, the depreciation expense related to the general plant assets is allocated to the unregulated storage in the same proportion of unregulated general plant assets to total general plant assets (using the two general plant asset allocators described in the *New General Plant Assets* section above).

Proposal for harmonized EGI unregulated storage cost allocation methodology

Depreciation expense: Storage assets

The current treatment for storage asset depreciation is aligned at legacy EGD and UG and appropriate as the methodology for new storage assets is consistent with the unregulated storage cost allocation studies approved by the OEB.

No additional methodology updates are required for EGI in this area.

Depreciation expense: General plant assets

EGI will be adopting the legacy UG method of allocating depreciation expense related to general plant assets (using the general plant allocator used to allocate new general plant assets to the unregulated storage operations). As a result of the adoption, EGI will have an aligned methodology when incurring depreciation expense for general plant assets. This is appropriate given that this method is consistent with the storage unregulated cost allocation methodology per the cost allocation studies[41,42] previously reviewed and approved by the OEB[43].

Impact

See below for the depreciation expense related to general plant assets under current and proposed harmonized EGI unregulated storage cost allocation methodology. All impacts to depreciation expense are related to general plant assets, as there was no quantitative impact relating to depreciation expense related to storage assets. All amounts are based on 2020 budgeted figures.

[41] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[42] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[43] EB-2011-0038 – Decision and Order (January 20, 2012)

	Unregulated Storage Depreciation Expense (Related to General Plant Assets)		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	-	$1.16M	+ $1.16M
UG	$1.33M	$1.33M	-
EGI	**$1.33M**	**$2.49M**	**+ $1.17M***

* Difference of 0.01M due to rounding

F. Property Tax

Property tax is the levy issued by the government based on the current use and value of the property. Legacy EGD and UG pay property taxes on their wells, lines, buildings, compressors and land.

Legacy UG unregulated storage cost allocation methodology summary

On an annual basis, actual property taxes related storage assets are allocated to UG's unregulated storage operations based on the proportion of unregulated storage assets (excluding general plant assets) to total storage assets.

Property tax related to general plant assets is allocated to the unregulated storage operations using the same allocator used to allocate new general plants.

Legacy EGD unregulated storage cost allocation methodology summary

At legacy EGD, property taxes are allocated to the unregulated storage operations based on a combination of fixed and variable activity allocators for capacity and deliverability. As there are no general plant assets allocated to the unregulated business, there is no allocation for property taxes related to the general plant assets.

Proposal for harmonized EGI unregulated storage cost allocation methodology

EGI will allocate property taxes related to storage assets based on the underlying storage assets, in accordance with the legacy UG method. EGI will also allocate property tax related to general plant assets on a monthly basis using the same allocator used to allocate new general plant assets, in accordance with the legacy UG methodology. EY has observed that the underlying assets are a direct driver of property taxes and therefore, this is appropriate and consistent with the guiding principles previously outlined. The harmonized approach is consistent with the storage unregulated cost allocation methodology per the cost allocation studies[44,45] previously reviewed and approved by the OEB[46].

[44] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[45] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[46] EB-2011-0038 – Decision and Order (January 20, 2012)

Impact

See below for the property tax expenses under current and proposed harmonized EGI unregulated storage cost allocation methodology. All impacts related to legacy UG are related to general plant assets allocators, as there will no longer be a separate allocator for vehicles and heavy work equipment (as described in Section B above). All amounts are based on 2020 budgeted figures.

	Unregulated Storage Property Tax Expense (Storage Assets)		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	$0.28M	$0.30M	+ $0.01M*
UG	$1.44M	$1.44M	-
EGI	**$1.72M**	**$1.74M**	**+$ 0.01M***

* Difference of 0.01M due to rounding

	Unregulated Storage Property Tax Expense (General Plant Assets)		
Entity	Current Methodology (2020)	Proposed Methodology (2020)	Impact of Change (increase (+) or decrease (-) to unregulated storage expense)
EGD	-	$0.01M	+ $0.01M
UG	$0.03M	$0.02M	- $0.01M
EGI	**$0.03M**	**$0.03M**	**+ $0.01M ***

* Difference of 0.01M due to rounding

G. Cost of Unutilized In-Franchise Storage Capacity

Unutilized in-franchise (regulated) storage capacity can be defined as the difference between the amount of storage reserved for in-franchise customers and the amount required by in-franchise customers. The portion of storage capacity that is not being used by in-franchise customers is made available to ex-franchise (unregulated) customers for short-term storage. As such, the costs associated with the unutilized capacity are assigned to the unregulated storage operations, and actual net revenues from the excess capacity must be compared with the net revenues expected during rate application to ensure there is no cross subsidization or recovery by ratepayers.

Legacy UG unregulated storage cost allocation methodology summary

Storage reserved for in-franchise customers at legacy UG is set at 100PJ[47] per the NGEIR decision, and the amount required by in-franchise customers is updated every year. For 2019, the storage capacity required for UG's in-franchise customers was 97PJ. As UG's rates were last determined in 2013 with the assumption that the in-franchise customers would require 89PJ of storage capacity, the difference in

[47] EB-2005-0551, Decision with Reasons, Page 83

expected revenues and costs related to actual short-term unregulated storage sales must be determined.

Legacy EGD unregulated storage cost allocation methodology summary

There is no unutilized in-franchise storage capacity at legacy EGD.

Analysis

As there is no unutilized in-franchise storage capacity at legacy EGD, no harmonized EGI methodology is required. The existing methodology in use at legacy UG is consistent with the unregulated storage cost allocation studies[48,49] approved by the OEB[50].

Proposed for harmonized EGI unregulated storage cost allocation methodology

No immediate harmonization activities are required for EGI going forward.

Impact

No quantitative impact.

H. Interest Expense on Long-Term Debt

Interest expense related to long-term debt is incurred to fund capital expansion.

Legacy EGD and UG unregulated storage cost allocation methodology summary

Interest expense related to long-term debt for EGI will be appropriately allocated to regulated and unregulated activities through rate setting and earning sharing mechanisms. Commencing with the 2019 earning sharing calculation, the allocation of interest expense related to long-term debt to the unregulated storage business has been aligned at the two legacy entities, following the legacy UG methodology.

EGI calculates Rate Base on an average of monthly averages basis for each the regulated and unregulated segments of the business (with the regulated segment being utilized for rate setting/earning sharing mechanism purposes). Similarly, the effective cost of long-term debt over the year is also calculated on an average of monthly averages basis, reflecting that debt issuances and retirements in the year are partially effective. The split of regulated and unregulated Rate Base as a percentage of total Rate Base is then applied to the effective cost of long-term debt, and the unregulated amount is excluded from utility results. For example, if Rate Base is 90% regulated and 10% unregulated, then EGI would apportion 10% of its effective long-term debt costs to the unregulated business, consistent with unregulated Rate Base, to be excluded from utility results.

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[48] EB-2011-0038, Exhibit A, Tab 4 – Black & Veatch Independent Review
[49] EB-2013-0365, Exhibit A, Tab 2 – Black & Veatch Independent Review
[50] EB-2011-0038 – Decision and Order (January 20, 2012)

Proposal for harmonized EGI unregulated storage cost allocation methodology

The treatment of interest expense for long-term debt is expected to be aligned at legacy EGD and UG as part of the 2019 earnings sharing and deferral clearance application, in a manner that is consistent with the allocation methodology that has been utilized in previous regulatory filings to the OEB[51] by UG.

No additional methodology updates are required for EGI in this area going forward.

Impact

No quantitative impact.

I. Summary of Impact

See chart for a summary of changes under the current and proposed harmonized EGI unregulated storage cost allocation methodology. All amounts are based on 2020 budgeted figures.

Allocation Area	EGI Harmonized Allocation Methodology	Summary of Impact (+/- to unregulated storage operations)		
		Legacy EGD	Legacy UG	EGI
Assets				
Storage assets (net)	No change – methodology is aligned at the legacy entities	-	-	-
General plant assets (net)	Modified legacy UG method	+ $2.48M	- $0.42M	+ $2.05M[52]
Total assets		+ $2.48M	- $0.42M	+ $2.05M
Expenses				
Cost of gas: Lost and unaccounted for gas	Modified legacy UG method	+ $0.04M	- $0.06M	- $0.02M
Cost of gas: Fuel used to move gas	Legacy UG method	- $0.22M	-	- $0.22M
O&M: Storage operations	Legacy UG method	+ $1.00M	- $0.12M	+ $0.88M
O&M: Storage support – administrative and general	Modified legacy UG method	+ $3.11M	- $2.05M	+ $1.06M
O&M: Storage support – variable	Legacy UG method	+ $0.43M	-	+ $0.43M
Depreciation expense: Storage Assets	No change – methodology is aligned at the legacy entities	-	-	-
Depreciation expense: General Plant Assets	Legacy UG method	+ $1.16M	-	+ $1.17M[53]
Property tax expense: Storage Assets	Legacy UG method	+ $0.01M	-	+ $0.01M

[51] EB-2019-0105
[52] Difference of $0.01M due to rounding
[53] Difference of $0.01M due to rounding

Allocation Area	**EGI Harmonized Allocation Methodology**	**Summary of Impact** (+/- to unregulated storage operations)		
		Legacy EGD	**Legacy UG**	**EGI**
Property tax expenses: General Plant Assets	Legacy UG method	+ $0.01M	- $0.01M[54]	+ $0.01M[55]
Unutilized in-franchise capacity	No change – allocation area only applicable to legacy UG	-	-	-
Interest expense on long-term debt	No change – methodology will be aligned at the legacy entities by planned implementation date	-	-	-
Total expenses		+ $5.55M[56]	- $2.23M[57]	+ $3.32M

[54] Impact for legacy UG due to change in determination of general plant asset allocators
[55] Difference of $0.01M due to rounding
[56] Difference of $0.01M due to rounding
[57] Difference of $0.01M due to rounding

VI. Procedures Performed by EY in Providing Management Assistance

EY performed the following tasks to assist management in determining a harmonized cost allocation methodology for unregulated storage operations:

1. Obtained an understanding of the unregulated storage allocations at the legacy companies through interviews with key personnel, supported by review of existing documentation such as models, policies, processes to allocate costs, unregulated storage operation studies and OEB rate filings;

2. Identified key differences between the unregulated storage activities conducted at both legacy entities based on the understanding of current storage allocations;

3. Assisted management by identifying suggested alternatives for a harmonized methodology;

4. Assisted management in determining an appropriate harmonized methodology;

5. Assisted management in determining expected impact of modifications to cost allocation methodology; and

6. Worked collaboratively with the Company to assist in documenting an updated framework (including policies and processes) for unregulated storage allocations for the amalgamated Company.

VII. Summary of Observations

The harmonized EGI cost allocation methodology for unregulated storage that will be used by EGI includes assessment of cost drivers for allocation via management's analysis of assets, completion of the activity templates, and identification of related causality to unregulated activities. Based on EY's understanding of EGI's harmonized storage allocation process and methodology, the underlying methodologies and rationale described in Section V are generally consistent with previous OEB guidance and/or decisions in their treatment of storage related assets and expenses and continues to maintain and uphold the design principles. The methodologies chosen for each of the asset and expense areas are based on underlying assets and their respective activities.

As part of EY's procedures to gain an understanding of the current methodologies at the legacy entities through discussion with management, EY also observed the following:

- **O&M – Storage Operations**: Discussions with management and review of the existing classifications revealed that there were a limited number of O&M sub-classifications that were not currently being used (i.e., did not have IOs associated to the expense category). After further analysis and discussions, EGI revisited classifications of IOs to Storage-General – M&R to identify IOs capturing costs at locations that support both the storage and transmission operations, consistent with the underlying asset allocations. Eight IOs associated with four asset locations (Dow A Plant, Dawn 167, Edys Mills, and Oil Springs East) were reclassified from Storage-General – M&R to Storage-Shared – M&R. This reallocation resulted in a $25,679 decrease in costs associated to unregulated storage for 2019. Based on our understanding of the original cost allocation methodology and discussions with management about the functions of the underlying assets, the reclassification of the IOs attempts to better reflect the nature of costs incurred to support the unregulated operations.
- **O&M – Variable Storage Support**: As part of the discussions with management over the impact of operational and organizational changes resulting from the amalgamation, EGI identified an additional storage support department (Asset Management – Storage and Transmission) that would provide fluctuating levels of support to the unregulated storage operations. Management noted that this was an additional department that would be considered as a variable storage support area and would be completing activity templates going forward for the purposes of determining unregulated cost allocations. Based on our understanding of this department through discussions with management, the addition of that department is consistent with the harmonized EGI methodology.
- **Property Tax**: For the year ended 2019, approximately $27,000 in property taxes related to general plant assets at UG was not allocated to the unregulated business. It is suggested through designating overall accountability and oversight with respect to unregulated storage cost allocations, EGI will monitor the expense allocations made by the accountable parties for accuracy and timeliness. Furthermore, by establishing robust process and policy documentation for the new harmonized EGI methodology, EGI will enable outside parties to clearly understand the methods and calculations used in determining unregulated storage costs.

VIII. Appendices

A. Current State Materiality and Timing of Allocations

The chart below summarizes the 2019 unregulated actual asset and expense information for the purpose of understanding the materiality of the allocation areas, and the timing of the cost allocations. The chart below does not include expenses that do not require an allocator (i.e. customer supplied fuel, which are exclusively regulated or unregulated).

Allocation Area	Methodology Alignment	2019 Unregulated Costs		2019 Timing of Allocations	
		Legacy EGD	Legacy UG	Legacy EGD	Legacy UG
Assets					
New storage assets (Net)	Aligned	$70.5M	$277.8M	Ad-hoc	Ad-hoc
General plant assets (Net)	Not aligned	-	$6.0M	N/A	Monthly
Total assets		*$70.5M*	*$283.8M*		
Expenses					
Cost of gas: Lost and unaccounted for gas	Not aligned	$0.5M	$1.7M	Monthly	Annual
Cost of gas: Fuel used to move gas	Not aligned	$0.4M	$3.2M	Monthly	Annual
O&M: Storage operations	Not aligned	$2.7M	$15.9M	Monthly	Annual
O&M: Storage support – administrative and general	Not aligned			Monthly	Annual
O&M: Storage support – variable	Not aligned			N/A	Annual
Depreciation	Partially aligned	$1.9M	$9.0M	Monthly	Monthly
Property tax	Not aligned	$0.2M	$1.4M	Monthly	Annual
Unutilized in-franchise capacity	Aligned[58]	N/A	$(1.2)M	N/A	Annual
Total expenses		*$5.7M*	*$30.0M*		

[58] Allocation area only applicable to legacy UG, therefore no further alignment is required

B. New General Plant Assets: Allocator Details

Legacy EGD and UG Allocators	
Legacy EGD:	N/A – no allocation
Legacy UG: For Vehicles and Heavy Work Equipment (V&HWE)	$\frac{\text{Gross S\&T V\&HWE}}{\text{Gross Total V\&HWE}} \times \left[\frac{(\text{STORAGEEXCESS+NETFROMSTOR})}{2} \times \text{HorsePower Allocator}\right]$
Legacy UG: For General Plant Assets	$\frac{\frac{\text{Gross unregulated storage assets (Excluding General Plant)}}{\text{Gross total plant (Excluding General Plant)}} + \frac{\text{Unreg O\&M costs}}{\text{Net O\&M costs for the company}}}{2}$

EGI Harmonized Allocator
EGI: For all General Plant Assets $\frac{\frac{\text{Gross unregulated storage assets (Excluding General Plant)}}{\text{Gross total plant (Excluding General Plant)}} + \frac{\text{Unreg O\&M costs}}{\text{Net O\&M costs for the company}}}{2}$

Legend:

- **STORAGEXCESS**: Storage space allocator (in proportion to forecasted use of storage space)
- **NETFROMSTOR**: Storage deliverability allocator (in proportion to peak day demands from storage)
- **HORSEPOWER ALLOCATOR**: Allocates costs in proportion to the forecasted compression horsepower at Dawn required to provide S&T services on design day

C. Cost of Gas – Lost and Unaccounted for Gas: Allocation Details

Legacy EGD and UG Allocation	
Legacy EGD	Total LUF provision of 0.835 bcf × 14.3% unregulated storage capacity allocator
Legacy UG	$\frac{\text{Gross annual activity for unregulated storage}}{\text{Gross annual activity for total storage and transportation}} \times \text{Annual total UFG}$

EGI Harmonized Allocation
$\frac{\text{Gross monthly activity for unregulated storage}}{\text{Gross monthly activity for total storage (and transportation for legacy UG*)}} \times \text{Monthly lost and unaccounted for gas (LUF or UFG) [Note2]}$

Legend:

- **Gross activity**: Injections and withdrawals (i.e., 100GJ injections and 100GJ of withdrawals = 200GJ of gross activity)
- **UFG**: Unaccounted for gas at legacy UG representing gas losses from storage and transportation operations
- **LUF**: Lost and unaccounted for gas at legacy EGD representing gas losses from storage operations

Note:

1. Total lost and unaccounted for gas at legacy UG (“UFG”) is calculated for storage and transportation operations, whereas total lost and unaccounted for gas at legacy EGD (“LUF”) is for storage operations only. Therefore, the denominator in the allocator used at legacy UG will include transportation activity.
2. As the LUF provision at legacy EGD is an annual provision, the monthly LUF in the allocation illustrated above represents the annual LUF profiled throughout the year (initially profiled based on budget, and re-profiled using actuals at the end of the year).

D. Cost of Gas – Fuel Consumed to Move Gas: Allocation Details

Legacy EGD and UG Allocation	
Legacy EGD	$\frac{\text{Total monthly fuel consumed for storage}}{\text{OB monthly for the month} - \text{CB for the month}} \times (\text{Unreg storage monthly OB} - \text{Unreg storage monthly CB})$
Legacy UG	$\frac{\text{Net daily activity for unregulated storage}}{\text{Net daily activity for total storage}} \times \text{Daily fuel consumed}$

EGI Harmonized Allocation
$\frac{\text{Net daily activity for unregulated storage}}{\text{Net daily activity for total storage}} \times \text{Daily fuel consumed}$

Legend:

- **OB**: Opening storage balance
- **CB**: Closing storage balance
- **Net activity**: Injections less withdrawals (i.e., 100GJ injections and 100GJ of withdrawals = 0GJ of net activity)

E. O&M – Storage Operations: Allocation Details

Legacy EGD Allocation

O&M Expenses	Fixed Allocator	Variable Allocator
O&M expenses are organized into cost elements (i.e., labour, materials and supplies)	Fixed allocators are determined for each cost element, based on activity drivers: capacity, commodity and deliverability	Variable allocators are applied to allocate the costs between regulated and unregulated storage operations for each activity driver

Legacy UG Allocation and Harmonized EGI Allocation

O&M Classification	O&M Sub-Categorizations	Allocation Factor
Storage-General	Wells	Asset-based unregulated allocator for wells
	Lines	Asset-based unregulated allocator for lines
	Compressors	Asset-based unregulated allocator for compressors
	Measuring and Regulating (M&R)	Asset-based unregulated allocator for M&R
	Rents and Others	Weighted-average allocator for unregulated storage
Storage-Shared	Compressors	Asset-based unregulated allocator for compressors
	Measuring and Regulating (M&R)	Regulatory cost study – M&RRECL-PT
	Dehydration	Regulatory cost study – Dehydration Demand
	Supervision and Others	Regulatory cost study – O&M STO Split

<u>Regulatory Cost Study Allocators</u>:

1. STO O&M Split: This factor is calculated as the gross plant value of the unregulated assets as a percentage of the total company storage and transmission assets.

2. Dehydrator Demand: Allocates costs in proportion to dehydrator demand on design day.

3. M&RRECL-PT: Allocates costs in proportion to forecast storage and transmission activity at Dawn.

F. O&M – Storage Support (Administrative and General): Allocation Details

Legacy EGD and UG Allocation	
Legacy EGD	A markup of 65%-70% is applied to storage operation labour expenses to account for administrative and general storage support
Legacy UG	$\frac{\text{Unregulated O\&M Expenses}}{\text{Total Company Net O\&M Expenses}} \times$ O&M expenses related to Administrative & General Storage Support

EGI Harmonized Allocation
$\frac{\text{Unregulated O\&M Expenses (Excl. O\&M Storage Support)}}{\text{Total Company Net O\&M Expenses (Excl. O\&M Storage Support)}} \times$ O&M expenses related to Administrative & General Storage Support

G. O&M – Storage Support (Variable): Time Study Results

Group	Department	CC/IOs	O&M - Unreg %
Regulatory	Regulatory Applications & Strategy	IO312652	10%
		CC25240	10%
System Improvement	Lands, Permitting & Environment	IO340051	22%
		IO340052	22%
		IO340055	22%
		IO340056	22%
		IO340059	22%
		IO340060	22%
		IO340061	22%
		IO340062	22%
		IO340064	22%
		IO340065	22%
		IO340066	22%
		IO340067	22%
		IO340068	22%
		IO340100	22%
		IO340101	22%
		IO340104	22%
		IO340200	22%
		IO340201	22%
		IO340220	22%
		IO340221	22%
		IO340300	22%
		IO341200	22%
		IO341900	46%
		IO342400	46%
		IO343001	46%
		IO343160	22%
		IO343161	22%
		IO343162	22%
S&T Business Development	S&T Business Development Other	IO240892	20%
S&T Engineering	Underground Storage & Reservoir Engineering	CC25124	35%
		IO340037	35%
Asset Management	Storage Asset Management	CC25161, T161G	40%
		IO342675	40%
Core Projects	Project Design & Execution, Project Controls, Engineering Services	N/A – all capitalized 0%	

H. Depreciation Expense: Annual Depreciation Rates for Unregulated Storage Assets

Storage Asset Class	EGD	UG
Land Rights	1.16 %	2.10 %
Structures and Improvements	1.84 %	2.50 %
Wells	1.52 %	2.69 %
Well Equipment	5.56 %	2.05 %
Field Lines	1.49 %	2.48 %
Compressor Equipment	2.60 %	2.68 %
Measuring and Regulating Equipment	2.99 %	3.11 %

I. Details on Calculations for 2020 Impacts

Summary of 2020 Impacts
Unregulated Cost Allocation Harmonization
Enbridge Gas Inc.

Purpose: To summarize expected 2020 impacts as calculated in the individual tabs.

Allocation Area	Relevant Tabs	Current Methodology		Harmonized Methodology		Impact		
		A	B	C	D	E=C-A	F=D-B	E+F
		EGD	UG	EGD	UG	EGD	UG	EGI
Assets								
Storage Assets	N/A	Not Assessed - No Changes		Not Assessed - No Changes		-	-	-
General Plant Assets	**GP - UG; GP- EGD**	-	7,353,237	2,478,622	6,929,081	2,478,622	- 424,156	2,054,466
Total Assets						**2,478,622**	**- 424,156**	**2,054,466**
Expenses								
Cost of Gas: Lost and Unaccounted for Gas	**COG1 - UG; COG1 - EGD**	495,544	1,826,554	537,215	1,764,792	41,671	- 61,763	- 20,092
Cost of gas: Fuel used to Move Gas	**COG2 - EGD**	464,092	Not Assessed - No Changes	242,657	Not Assessed - No Changes	- 221,435	-	- 221,435
O&M: Storage Expenses	**O&M1**	1,627,959	3,922,812	2,631,015	3,799,239	1,003,057	- 123,573	879,484
O&M: Storage Support - Admin and general	**O&M2**	471,494	5,827,981	3,577,724	3,777,378	3,106,229	- 2,050,603	1,055,627
O&M: Storage Support - Variable	**O&M3**	-	1,370,658	434,096	1,370,658	434,096	-	434,096
Depreciation Expense: Storage Assets	N/A	Not Assessed - No Changes		Not Assessed - No Changes		-	-	-
Depreciation Expense: General Plant Assets	**DE - GP**	-	1,326,355	1,160,007	1,333,183	1,160,007	6,829	1,166,836
Property Tax: Storage Assets	**PT - Storage**	283,297	1,439,923	295,521	1,439,923	12,223	-	12,223
Property Tax: General Plant Assets	**PT - GP**	-	26,728	13,995	22,258	13,995	- 4,469	9,526
Unutilized in-franchise capacity	N/A	Not Assessed - No Changes		Not Assessed - No Changes		-	-	-
Total Expenses						**5,549,844**	**- 2,233,579**	**3,316,265**

Determining 2020 Impact
General Plant Assets
Legacy UG

Data Sources:
2020 Capital Asset Forecast
2018 Capital Asset PPE Schedule (Schedule 5)
2018 O&M data from the O&M team (SAP and Oracle)

New General Plant Assets for 2020 Under Harmonized Methodology

		Based on Actuals as at December 31, 2018
A	Total Gross Plant (Dec 31 - excluding WIP, ARO, and General Plant)	9,780,807,383
B	Total Unregulated Gross Storage (Dec 31 - excluding WIP, ARO and General Plant)	424,390,931
B / A = C	% Unregulated Storage to Total Plant	4.34%
D	UG Unregulated storage O&M costs	13,451,431
D	EGD Unregulated storage O&M costs	2,627,515
E	UG total net O&M costs for the company	461,872,369
E	EGD total net O&M costs for the company	468,081,238
m of D / Sum of E = F	O&M Storage Support Allocator	1.73%
(C+F) / 2 = G	**General Plant Allocation Factor**	**3.03%**

	AA	BB	CC	DD = BB+CC	EE = DD * G	FF=AA+BB
	Unregulated General Plant Assets: Beginning Balance as at Jan 1, 2020	**General Plant Asset: Additions (Based on 2+10 Forecast)**	**General Plant Assets: Retirements (Based on 2+10 Forecast)**	**General Plant Assets: Net New Assets (Based on 2+10 Forecast)**	**Unregulated General Plant Assets: Net New Assets (Based on 2+10 Forecast)**	**Unregulated General Plant Assets: Ending Balance, as at Dec 31, 2020**
Land	20,796	-	-	-	-	20,796
Structures & improvements	2,781,771	10,031,612	-2,782,899	7,248,714	219,927	3,001,698
Office furniture & equipment	1,241,999	250,000	-90,019	159,981	4,854	1,246,853
Office equipment - computers	3,248,619	52,160,464	-18,470,351	33,690,114	1,022,162	4,270,781
Office Equipment - computers 10%	497,628	-		-	-	497,628
Transportation equipment	2,448,394	7,600,000	-5,683,572	1,916,428	58,145	2,506,539
Heavy work equipment	741,627	-	-736,705	-736,705	-22,352	719,275
Tools & work equipment	1,416,593	2,089,020	-1,452,146	636,874	19,323	1,435,916
NGV Equipment	75,151	-200,000	-1,452,146	-1,652,146	-50,126	25,025
Communication equipment	536,840	138,687	-379,283	-240,596	-7,300	529,540
Total	**13,009,418**	**72,069,784**	**-31,047,120**	**41,022,664**	**1,244,632**	**14,254,051**

	GG	HH	II = GG+HH
	Unregulated General Plant Assets - Accumulated Depreciation: Beginning Balance, as at Jan 1, 2020	**Unregulated General Plant Assets - Change in Accumulated Depreciation (Based on 2+10 Forecast model)**	**Unregulated General Plant Assets - Accumulated Depreciation: Ending Balance, as at Dec 31, 2020**
Land	-	-	-
Structures & improvements	558,432	-83,607	474,825
Office furniture & equipment	681,622	182,887	864,509
Office equipment - computers	2,568,113	-181,615	2,386,498
Office Equipment - computers 10%	223,933	324,862	548,794
Transportation equipment	1,698,476	-104,647	1,593,830
Heavy work equipment	192,176	146,724	338,901
Tools & work equipment	699,069	5,793	704,862
NGV Equipment	50,476	-41,455	9,022
Communication equipment	320,814	82,915	403,729
Total	**6,993,111**	**331,858**	**7,324,969**

New General Plant Assets for 2020 Under Existing Methodology

	AA	JJ	KK	LL = JJ+KK	MM = AA+LL
	Unregulated General Plant Assets: Beginning Balance as at Jan 1, 2020	**Unregulated Additions to General Plant Assets (Based on 2+10 Forecast)**	**Unregulated Retirements (Based on 2+10 Forecast)**	**Net new Unregulated General Plant Assets - Gross**	**Unregulated General Plant Assets: Ending Balance, as at Dec 31, 2020**
Land	20,796	-	-	-	20,796
Structures & improvements	2,781,771	367,180	-101,861	265,320	3,047,091
Office furniture & equipment	1,241,999	9,175	-3,295	5,880	1,247,879
Office equipment - computers	3,248,619	1,897,929	-676,057	1,221,872	4,470,490
Office Equipment - computers 10%	497,628	-	-	-	497,628
Transportation equipment	2,448,394	278,920	-208,032	70,888	2,519,283
Heavy work equipment	741,627	-	-26,965	-26,965	714,662
Tools & work equipment	1,416,593	76,007	-53,152	22,855	1,439,448
NGV Equipment	75,151	-8,000	-53,152	-61,152	13,999
Communication equipment	536,840	4,430	-13,883	-9,453	527,387
Total	**13,009,418**	**2,625,641**	**-1,136,396**	**1,489,245**	**14,498,663**

	NN	OO	PP = NN+OO
	Unregulated General Plant Assets - Accumulated Depreciation: Beginning Balance, as at Jan 1, 2020	**Unregulated General Plant Assets - Change in Accumulated Depreciation (Based on 2+10 Forecast model)**	**Unregulated General Plant Assets - Accumulated Depreciation: Ending Balance, as at Dec 31, 2020**
Land	-	-	-
Structures & improvements	558,432	-100,943	457,489
Office furniture & equipment	681,622	182,339	863,961
Office equipment - computers	2,568,113	-282,811	2,285,302
Office Equipment - computers 10%	223,933	324,862	548,794
Transportation equipment	1,698,476	-139,849	1,558,627
Heavy work equipment	192,176	142,038	334,214
Tools & work equipment	699,069	-3,217	695,852
NGV Equipment	50,476	-50,631	-155
Communication equipment	320,814	80,527	401,341
Total	**6,993,111**	**152,315**	**7,145,426**

Expected Impact for 2020 (+/- to unregulated business)

	JJ = FF-II *Under Harmonized Methodology*	QQ =MM-PP *Under Current Methodology*	RR = JJ-QQ
	Unregulated General Plant Assets - Net of Accumulated Depreciation: Ending Balance, as at Dec 31, 2020	**Unregulated General Plant Assets - Net of Accumulated Depreciation: Ending Balance, as at Dec 31, 2020**	**Impact**
Land	20,796	20,796	-
Structures & improvements	2,526,873	2,589,602	-62,729
Office furniture & equipment	382,344	383,918	-1,574
Office equipment - computers	1,884,283	2,185,189	-300,906
Office Equipment - computers 10%	-51,167	-51,167	-
Transportation equipment	912,709	960,655	-47,946
Heavy work equipment	380,375	380,448	-73
Tools & work equipment	731,054	743,596	-12,542
NGV Equipment	16,003	14,155	1,849
Communication equipment	125,811	126,046	-235
Impact for 2020	**6,929,081**	**7,353,237**	**-424,156**

Determining 2020 Impact
General Plant Assets
Legacy EGD

Data Sources:
2020 Capital Asset Forecast
2020 O&M Budget
2020 Unregulated Budget and LRP

Calculating One-Time Split as at Dec 31, 2020

		As at Dec 31, 2020 (Based on 2+10 forecast for assets, and 2020 Budget for O&M)
	Total Gross Plant (Dec 31 - excluding WIP, ARO, and General Plant)	10,221,798,024
	Adjustment for administrative buildings and accompanying land (considered general plant for the purposes of unregulated allocations)	
	Markham TOC	37,000,909
	Ottawa	11,737,671
	Thorold	16,272,082
	VPC	63,267,411
A	Adjusted Total Gross Plant (Dec 31 - excluding WIP, ARO, and General Plant)	10,093,519,951
B	Total Unregulated Gross Storage (Dec 31 - excluding WIP, ARO and General Plant)	120,526,051
B / A = C	% Unregulated Storage to Total Plant	1.18%
D	Unregulated storage O&M costs	3,227,660
E	Total net O&M costs for the company	460,877,268
D / E = F	O&M Storage Support Allocator	0.70%
(C+F) / 2 = G	**General Plant Allocation Factor**	**0.94%**
	2020 General Plant Assets - Gross PPE	679,597,766
	Adjustments for EGD:	
	Administrative buildings and accompanying land	
	Markham TOC	37,000,909
	Ottawa	11,737,671
	Thorold	16,272,082
	VPC	63,267,411
H	2020 General Plant Assets - Gross PPE adjusted for unreg allocation purposes	807,875,839
	2020 General Plant Assets - Accumulated depreciation	513,284,387
	Adjustments for EGD:	
	Administrative buildings and accompanying land	
	Markham TOC	5,850,165
	Ottawa	2,198,232
	Thorold	5,920,044
	VPC	16,860,957
I	2020 General Plant Assets - Accumulated depreciation adjusted for unreg allocation purposes	544,113,785
H-I = J	2020 General Plant Assets - Net	263,762,054
G * J = K	**2020 Unreg General Plant Assets - Net**	**2,478,622**

Determining 2020 Impact
Cost of Gas: Unaccounted for Gas
Legacy UG

Data Sources:
2020 Gas Supply Budget

Allocation for 2020 Under Harmonized Methodology

	2020 Budget	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
A	UFG Costs	1,543,409	1,395,471	1,310,171	937,984	706,546	616,559	681,679	706,235	673,341	777,231	1,079,961	6,328,791	16,757,378
B	Monthly %	13.7%	12.1%	9.1%	9.8%	9.6%	12.2%	10.7%	14.1%	12.2%	6.0%	8.9%	10.0%	10.5%
C = A*B	**Monthly $**	**211,447**	**168,852**	**119,226**	**91,922**	**67,828**	**75,220**	**72,940**	**99,579**	**82,148**	**46,634**	**96,117**	**632,879**	**1,764,792**

Allocation for 2020 Under Existing Methodology

	2020 Budget	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
A	UFG Costs	1,543,409	1,395,471	1,310,171	937,984	706,546	616,559	681,679	706,235	673,341	777,231	1,079,961	6,328,791	16,757,378
D	Annual %	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%
E = A*D	**Annual $**	**168,232**	**152,106**	**142,809**	**102,240**	**77,014**	**67,205**	**74,303**	**76,980**	**73,394**	**84,718**	**117,716**	**689,838**	**1,826,554**

Expected Impact for 2020 (+/- to unregulated business)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
C-E	**Impact for 2020**	**43,215**	**16,746**	**- 23,583**	**- 10,318**	**- 9,185**	**8,015**	**- 1,363**	**22,600**	**8,753**	**- 38,084**	**- 21,599**	**- 56,959**	**- 61,763**

Determining 2020 Impact
Cost of Gas: Fuel Consumed to Move Gas
Legacy EGD

Data Sources:
2020 Gas Supply Budget, including budgeted PGVA reference price
2020 January to April actual activity from Capacity Planning group

Allocation for 2020 Under Harmonized Methodology

A Budgeted PGVA Reference Price $ 163.52

	2020 Budget	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
B	2020 Fuel - Actuals (Jan-April) / Budget (May-Dec)	1,080	1,069	1,131	702	1,007	1,838	1,987	2,187	1,619	476	624	827	14,547
C	% Fuel Allocation to Unreg (Actual Jan-Apr 2020) - Note 1	0%	36%	3%	0%	-	-	-	-	-	-	-	-	-
D	% Fuel Allocation to Unreg (Actual 2019) - Note 1, 2	-	-	-	-	27%	5%	11%	11%	3%	30%	10%	0%	13%
E = B*C (Jan-Apr) E = B*D (May-Dec)	2020 Unregulated Fuel - Actuals (Jan-April) / Budget (May-Dec)	3	380	30	0	271	91	213	245	42	143	62	4	1,484
F = A*E	**Annual $**	**422**	**62,181**	**4,911**	**0**	**44,267**	**14,926**	**34,853**	**40,093**	**6,835**	**23,415**	**10,150**	**605**	**242,657**

Note 1: While the data is presented in a monthly format, the percentage allocators are calculated using net daily activity for the respective months.
Note 2: Fuel allocations for May to Dec 2020 are assumed to be comparable to May to Dec 2019 on a net daily basis, and as such, the 2019 Fuel Allocation % for these months are applied to 2020 budget for fuel.

Allocation for 2020 Under Existing Methodology

A Budgeted PGVA Reference Price $ 163.52

	2020 Budget	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
G	2020 Unregulated Fuel - Actuals (Jan-April) / Budget (May-Dec)	1	301	333	702	155	303	174	174	174	174	174	174	2,838
H = A*G	**Annual $**	**180**	**49,270**	**54,503**	**114,777**	**25,297**	**49,548**	**28,419**	**28,419**	**28,419**	**28,419**	**28,419**	**28,419**	**464,092**

Expected Impact for 2020 (+/- to unregulated business)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
C-E	**Impact for 2020**	**242**	**12,911**	**- 49,592**	**- 114,777**	**18,969**	**- 34,623**	**6,433**	**11,673**	**- 21,584**	**- 5,005**	**- 18,269**	**- 27,815**	**- 221,435**

Determining 2020 Impact
Cost of Gas: Lost and Unaccounted for Gas
Legacy EGD

Data Sources:
2020 Gas Supply Budget, including budgeted QRAM reference prices
2020 Jan-Apr actual volume activity from Capacity Planning group
2019 Actual Fuel Activity from Capacity Planning Group

Allocation for 2020 Under Harmonized Methodology

A	Q1 2020 QRAM Reference Price (Actual)	$ 144.88
	Q2 2020 QRAM Reference Price (Actual)	$ 131.75
	Q3 2020 QRAM Reference Price (Budget)	$ 153.33
	Q4 2020 QRAM Reference Price (Budget)	$ 153.33
B	Total annual LUF (Volume)	23,763

		Q1			Q2			Q3			Q4			
	2020 Budget	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
C	Fuel Profile - Based on 2020 Actuals for Jan-April, 2019 Actuals for May-Dec	7.34%	7.61%	7.90%	5.00%	6.82%	8.64%	10.12%	16.41%	17.23%	10.88%	0.39%	1.64%	100.00%
D = B*C	LUF Profile based on Fuel Profile (103m3)	1,745	1,809	1,878	1,189	1,620	2,054	2,405	3,900	4,094	2,587	93	391	23,763
E	% Fuel Allocation to Unreg Based on Activity - Based on actual activity for Jan-Apr, 2019 Actual Activity for May-Dec (Note 1)	0.44%	28.05%	20.92%	30.34%	21.67%	5.89%	14.66%	15.75%	3.19%	32.15%	0.30%	0.24%	
F = D*E	Unreg LUF Allocation (103m3)	7.75	507.29	392.94	360.75	350.95	120.98	352.60	614.30	130.45	831.58	0.28	0.94	3,670.81
G = A*F	**Annual $**	**1,123**	**73,496**	**56,929**	**47,531**	**46,239**	**15,940**	**54,066**	**94,192**	**20,002**	**127,509**	**43**	**144**	**537,215**

Note 1 The percentage allocators are calculated using gross monthly activity data.
Jan - Apr: The allocators are calculated using 2020 actual data.
May - Dec: 2019 Gross Storage Activity is used as a representation for 2020 Gross Storage Activity

Allocation for 2020 Under Existing Methodology

		Q1			Q2			Q3			Q4			
	2020 Budget	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
H	Unregulated LUF Allocation (103m3) - Note 2	283	283	283	283	283	283	283	283	283	283	283	283	2,838
I = A*H	**Annual $**	**41,028**	**41,028**	**41,028**	**37,311**	**37,311**	**37,311**	**43,422**	**43,422**	**43,422**	**43,422**	**43,422**	**43,422**	**495,544**

Note 2 Under the existing methodology, 14.3% of the total LUF provision for storage (0.12 bcf) is designated as being related to the unregulated storage operations, based on volumetric drivers for storage capacity measured in 2015.

Expected Impact for 2020 (+/- to unregulated business)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
C-E	**Impact for 2020**	**- 39,905**	**32,468**	**15,901**	**10,220**	**8,929**	**- 21,371**	**10,645**	**50,771**	**- 23,419**	**84,088**	**- 43,378**	**- 43,277**	**41,671**

Determining 2020 Impact
O&M: Storage
Legacy EGD and UG

Data Sources:
2020 O&M Budget (EGD and UG)
2018 O&M Storage Asset Information

Allocation for 2020 Under Harmonized Methodology

O&M Classifcation	O&M Sub-Classifcation	Allocator Description	Allocator	EGD: EGD 2020 Budget	EGD: EGD Unregulated O&M		UG: UG 2020 Budget	UG: UG Unregulated O&M	
Storage General	Wells	Asset-based unregulated allocator for wells	48.59%	$ -	$ -		$ 264,090	$ 128,311	
	Lines	Asset-based unregulated allocator for lines	35.31%	$ -	$ -		$ 45,739	$ 16,152	
	Compressors	Asset based unregulated allocator for compressors	34.98%	$ 3,864,999	$ 1,352,002		$ 817,030	$ 285,803	
	Measuring and Regulating (M&R)	Asset based unregulated allocator for M&R	47.07%	$ 492,213	$ 231,660		$ 215,065	$ 101,221	
	Rents and Others	Weighted-average allocator for unregulated storage	30.32%	$ 3,453,943	$ 1,047,353		$ 1,900,478	$ 576,290	
Storage Shared	Compressors	Asset-based unregulated allocator for compressors	29.85%	$ -	$ -		$ 4,641,041	$ 1,385,556	
	Measuring and Regulating (M&R)	Regulatory cost study – M&RRECL-PT	40.82%		$ -		$ 44,045	$ 17,979	
	Dehydration	Regulatory cost study – Dehydration demand	64.70%	$ -	$ -		$ 180,907	$ 117,054	
	Supervision and Others	Regulatory cost study – O&M STO Split	9.41%	$ -	$ -		$ 12,439,149	$ 1,170,875	
Total					**$ 2,631,015**	a		**$ 3,799,239**	b

Total EGI Unregulated O&M — **$ 6,430,254** AA

Allocation for 2020 Under Existing Methodology

Unregulated Storage O&M Allocations - Based on 2020 Budget		
Legacy EGD - allocated O&M, property tax and labour markup	$ 2,382,750	
Calculated labour markup (per **O&M2**)	$ 471,494	
Caluclated property tax (per **PT - Storage**)	$ 283,297	
Adjusted legacy EGD unregulated storage O&M	**$ 1,627,959**	c
Legacy UG - Excluding Storage Support (Admin and Variable)	$ 3,922,812	d
Total Unregulated Storage O&M	**$ 5,550,770**	BB

Expected Impact for 2020 (+/- to unregulated business)

Impact for EGD	$ 1,003,057	
Impact for UG	-$ 123,573	
Impact for 2020	**$ 879,484**	AA-BB

Determining 2020 Impact
O&M: Storage Support - Admin and General
Legacy EGD and UG

Data Sources:
2020 O&M Budget (EGD and UG)
2018 O&M Storage Actuals (Regulated and Unregulated)
2019 and 2020 Cost Allocation Models (EGD)

Allocation for 2020 Under Harmonized Methodology

		Based on Actuals as at December 31, 2018
A	UG Unregulated Storage O&M costs	13,451,431
A	EGD Unregulated Storage O&M costs	2,627,515
B	UG Unregulated Storage Support Normalization	6,057,834
B	EGD Unregulated Storage Support Normalization - Note 1	104,437
C = (Sum of A) - (Sum of B)	EGI Adjusted Unregulated Storage O&M costs	9,916,675
D	UG Regulated Net O&M costs	448,420,938
D	EGD Regulated Net O&M costs	465,453,723
E	UG Regulated Storage Support Normalization	205,676,758
E	EGD Regulated Storage Support Normalization - Note 2	192,766,405
F = C + (Sum of D) - (Sum of E)	Total EGI Net O&M for the Core Business	525,348,173
G = C / F	**O&M Storage Support Allocator**	**1.89%**

		Based on 2020 Budget
H	2020 UG Budget for Storage Support IOs	200,111,295
I	2020 EGD Budget for Storage Support	189,534,352
Sum of H and I	**Total Storage Support**	**389,645,647**
H*G	UG Unregulated Storage O&M costs	3,777,378
I*G	EGD Unregulated Storage O&M costs	3,577,724
J = G * (Sum of H and I)	**Unregulated Storage Support O&M**	**7,355,102**

Note 1: Storage support represents the unregulated portion of the 65-70% markup on storage labour for 2018.
Note 2: Regulated storage support costs at legacy EGD are estimated by applying the proportion of total 2020 budget storage support costs and total 2020 budget O&M EGD expenses to the 2018 EGD Regulated Net O&M costs.

Legacy UG: Allocation for 2020 Under Existing Methodology

		Based on Actuals as at December 31, 2018
K	UG Unregulated storage O&M costs	13,451,431
L	UG Regulated storage O&M costs	448,420,938
M = K + L	UG Total Net O&M costs for the company	461,872,369
N = K / M	**O&M Storage Support Allocator**	**2.91%**

		Based on 2020 Budget
H	2020 UG Budget for Storage Support IOs	200,111,295
O = N * H	**UG Unregulated Storage Support Allocation Based on 2020 Budget**	**5,827,981**

Legacy EGD: Allocation for 2020 Under Existing Methodology

	AA Fixed Allocator	BB Unregulated Variable Allocator	CC = AA * BB Unregulated Allocator	
Commodity - Note 3	5.00%	18.72%	0.94%	
Capacity - Note 3	73.00%	14.29%	10.43%	
Deliverability - Note 3	22.00%	17.20%	3.78%	
			15.15%	aa

		Based on 2020 Budget
P	Total Storage Labour Budget	4,644,948
Q	Average Labour Mark-Up % - Note 4	67%
R = P*Q	**Storage Support Labour Mark-Up (Prior to Allocation to Unreg)**	**3,112,115**

		Based on 2020 Budget
	Unregulated Storage Support Allocation:	
	Commodity	29,129
	Capacity	324,602
	Deliverability	117,762
S = aa * R	**Total Unregulated Storage Support Allocation Related to Mark Up**	**471,494**

Note 3: The fixed and varriable allocators used in this calculation are an an average of the respective allocators across all storage cost centres at legacy EGD, over 12 months.
Note 4: The average mark-up applied to labour is 67% across the different cost centres at legacy EGD.

Expected Impact for 2020 (+/- to unregulated business)

	EGD		UG	EGI
Harmonized method	3,577,724		3,777,378	7,355,102
Legacy method	471,494		5,827,981	6,299,475
Impact for 2020	**3,106,229**	-	**2,050,603**	**1,055,627**

Determining 2020 Impact
O&M: Storage Support - Variable
Legacy UG and Legacy EGD

Data Sources:
2020 O&M Budget
Activity templates completed for 2021

Allocation for 2020 Under Harmonized Methodology

Activities Template Rates

			EGD					UG				EGI
	Group	**Department**	**Cost Centre**	**Task**	**O&M Unreg Rate**	**2020 Budget (Net)**	**2020 Unreg O&M**	**IO**	**O&M Unreg Rate**	**2020 Budget (Net)**	**2020 Unreg O&M**	
	Regulatory	Regulatory Applications & Strategy	CC25240	No Task	10%	$ 3,701,455	$ 370,145	IO312652	10%	$ 1,265,635	$ 126,563.45	
	System Improvement	Lands, Permitting and Environment	N/A	N/A	N/A	N/A	$ -	IO340051	22%	$ 39,266	$ 8,638.50	
								IO340052	22%	$ 4,943	$ 1,087.48	
								IO340055	22%	$ 87,602	$ 19,272.51	
								IO340056	22%	$ 11,415	$ 2,511.38	
								IO340059	22%	$ 55,540	$ 12,218.78	
								IO340060	22%	$ 18,861	$ 4,149.47	
								IO340061	22%	$ 69,613	$ 15,314.95	
								IO340062	22%	$ 56,288	$ 12,383.26	
								IO340064	22%	$ 74,433	$ 16,375.20	
								IO340065	22%	$ 75,395	$ 16,586.98	
								IO340066	22%	$ 37,763	$ 8,307.95	
								IO340067	22%	$ 72,690	$ 15,991.90	
								IO340068	22%	$ 49,595	$ 10,910.87	
								IO340100	22%	$ 74,034	$ 16,287.47	
								IO340101	22%	$ 243,401	$ 53,548.15	
								IO340104	22%	$ 122,878	$ 27,033.24	
								IO340200	22%	$ 34,605	$ 7,613.12	
								IO340201	22%	$ 10,040	$ 2,208.81	
								IO340220	22%	$ 53,947	$ 11,868.29	
								IO340221	22%	$ 71,096	$ 15,641.13	
								IO340300	22%	$ 54,367	$ 11,960.72	
								IO341200	22%	$ 55,660	$ 12,245.20	
								IO341900	46%	$ 58,592	$ 26,952.26	
								IO342400	46%	$ 22,534	$ 10,365.86	
								IO343001	46%	$ 98,504	$ 45,311.75	
								IO343160	22%	$ 229,647	$ 50,522.25	
								IO343161	22%	$ 109,503	$ 24,090.62	
								IO343162	22%	$ 2,000	$ 440.06	
	Storage and Transmission	S&T Business Development	N/A	N/A	N/A	N/A	$ -	IO240892	20%	$ 547,838	$ 109,567.63	
	Storage and Transmission	Underground Storage and Reservoir Engineering	CC25124	T_65040	35%	$ 123,993	$ 43,397	IO340037	35%	$ 1,718,798	$ 601,579.19	
	Asset Management	Storage Asset Management	CC25161	T161G	40%	$ 51,382	$ 20,553	IO342675	40%	$ 182,773	$ 73,109.09	
A	**Total**						**$ 434,096**				**$ 1,370,657.51**	**$ 1,804,753.32**
	Total EGI											

Allocation for 2020 Under Existing Methodology

B	**Total**						**$ -**				**$ 1,370,657.51**	**$ 1,370,657.51**

Expected Impact for 2020 (+/- to unregulated business)

C	**Impact for 2020**						**$ 434,095.81**				**$ -**	**$ 434,095.81**

Determining 2020 Impact
Depreciation Expense - General Plant Assets
Legacy UG and Legacy EGD

Data Sources:
2020 Capital Asset Forecast

Data Sources for General Plant Allocators:
2018 O&M data from the O&M team (SAP and Oracle)
2020 Capital Asset Forecast
2020 O&M Budget

Depreciation Expense for General Plant Assets: Calculating Allocation for 2020 Under Harmonized Methodology

		EGD	UG
	2020 General Plant Assets (based on 2+10 forecast) - Depreciation Expense	67,461,357	43,941,280
	Adjustments for EGD:		
	IT Software (CIS acquired software, software acquired intangibles, software developed intangibles, WAMS)	48,660,375	-
	Administrative buildings and accompanying land		
	Markham TOC	726,880	-
	Ottawa	516,464	-
	Thorold	535,090	-
	VPC	5,541,805	-
A	2020 General Plant Assets (based on 2+10 forecast) - Depreciation expense adjusted for unreg allocation purposes	123,441,971	43,941,280
B	General Plant Allocation Factor	0.94%	3.03%
C = A*B	**2020 Unreg Depreciation Expense related to General Plant Assets**	**1,160,007**	**1,333,183**

Depreciation Expense for General Plant Assets: Allocation for 2020 Under Existing Methodology

		EGD	UG
D	**2020 Unreg Depreciation Expense (based on 2+10 forecast) - General Plant Assets**	**-**	**1,326,355**

Depreciation Expense for General Plant Assets: Expected Impact for 2020 (+/- to unregulated business)

		EGD	UG
E = C-D	**Impact for 2020**	**1,160,007**	**6,829**

Determining 2020 Impact
Property Tax - Storage Assets
Legacy UG and Legacy EGD

Data Sources:
2018 Capital Asset PPE Schedule (Schedule 5)
2020 Property Tax Budget
2020 EGD storage allocation model for Jan-Mar

Calculating Allocation for 2020 Under Harmonized Methodology

	EGD			UG		
	A	B	C = A/B	AA	BB	CC = AA/BB
Storage Property tax	**2018 Unreg Storage Assets**	**2018 Total Storage Assets for Tecumseh**	**2018 Unreg Percentages**	**2018 Unreg Storage Assets**	**2018 Total Storage Assets**	**2018 Unreg Percentages**
Mains (Pipelines)	29,794,165	132,107,655	22.55%	51,539,012	97,918,504	52.63%
Well (including well equipment)	14,772,476	84,025,779	17.58%	95,168,027	142,044,272	67.00%
Land	1,127,303	5,923,679	19.03%	2,244,659	7,765,501	28.91%
Buildings	286,182	31,561,989	0.91%	25,723,513	94,654,198	27.18%
Compressors	22,736,252	158,622,313	14.33%	162,201,324	627,802,304	25.84%
	68,716,379	412,241,414	16.67%	336,876,534	970,184,779	34.72%

		D	DD	EE	FF = DD*EE
Note 1	**Storage Property tax**	**Expected 2020 Tecumseh Property**	**2019 Property Tax**	**Inflation**	**Expected 2020 Property Taxes**
	Mains (Pipelines)	812,691	1,093,578	1.25%	1,107,248
	Well	70,668	157,240	1.25%	159,206
	Land	35,334	172,597	1.25%	174,754
	Buildings	212,006	344,953	1.25%	349,265
	Compressors	636,019	2,312,869	1.25%	2,341,780
		1,766,718 a	4,081,237		4,132,252

	E = C*D	GG = CC * FF
Unregulated Storage Property Tax	**Expected 2020 Property Taxes Allocated to Unreg**	**Expected 2020 Property Taxes Allocated to Unreg**
Mains (Pipelines)	183,286	582,795
Well	12,424	106,666
Land	6,724	50,514
Buildings	1,922	94,917
Compressors	91,164	605,031
Total Unregulated Storage Property Tax	**295,521**	**1,439,923** aa

Note 1: For EGD: Only storage property tax that are shared between regulated and unregulated activites (to be allocated) are included here. This does not include storage property taxes that can be directly attributed to the unregulated storage operations and booked in the unregulated LOB (CC25371), or storage operations related to Crowland (100% regulated).

Allocation for 2020 Under Existing Methodology

	EGD				UG
For Legacy EGD:	F	G	H = F*G		
Split of Balance:	**Fixed Allocator**	**Unregulated Variable Allocator**	**Unregulated Allocator**		
Capacity	40%	14.29%	6%		
Deliverability	60%	17.20%	10%		
Expected 2020 Property Tax		a	1,766,718		
Unregulated Property Tax:					
Capacity			100,972		
Deliverability			182,325		
Total Unregulated Property Tax		a*H	**283,297**	b	

For Legacy UG:		**Expected 2020 Property Taxes**	
Total Unregulated Property Tax	aa	**1,439,923**	bb

Expected Impact for 2020 (+/- to unregulated business)

Impact for 2020	a-b	**12,223**	aa-bb	-

Determining 2020 Impact
Property Tax - General Plant Assets
Legacy UG and Legacy EGD

Data Sources:
2020 Property Tax Budget
2018 Capital Asset PPE Schedule (Schedule 5)

Data Sources for General Plant Allocators:
2018 O&M data from the O&M team (SAP and Oracle)
2020 Capital Asset Forecast
2020 O&M Budget

Calculating Allocation for 2020 Under Harmonized Methodology

	EGD			UG				
	A	B	C = A*B	AA	BB	CC = AA*BB	DD	EE = CC*DD
	Estimated 2020 Taxes	General Plant Allocator	Taxes attributed to Unreg Storage	2019 Property Tax	Inflation	Expected 2020 Property Taxes	General Plant Allocator	Taxes attributed to Unreg Storage
General Plant Assets subject to Property Tax				724,573	1.25%	733,630	3%	22,258.43
Markham - TOC	273,865	0.94%	2,573.56					
Ottawa - Conventry Rd	218,890	0.94%	2,056.95					
Thorold - Schmon Pkwy	152,651	0.94%	1,434.49					
North York - VPC	843,847	0.94%	7,929.79					
Total	1,489,253		**13,994.80**			733,630.45		**22,258.43**

Allocation for 2020 Under Existing Methodology

	A	D	E = A*D	AA	BB	CC = AA*BB	FF	GG = CC*FF
	Estimated 2020 Taxes	General Plant Allocator	Taxes attributed to Unreg Storage	2019 Property Tax	Inflation	Expected 2020 Property Taxes	General Plant Allocator	Taxes attributed to Unreg Storage
Taxes	1,489,253	0%	-	724,573	1.25%	733,630	3.64%	**26,727.57**

Expected Impact for 2020 (+/- to unregulated business)

	EGD Taxes attributed to Unreg Storage	UG Taxes attributed to Unreg Storage
Impact for 2020	**13,994.80**	**- 4,469.14**

ENHANCED DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM (DIMP)

ANGELA SCOTT, MANAGER INTEGRITY MANAGEMENT

1. The purpose of this evidence is to outline Enbridge Gas's proposed Enhanced Distribution Integrity Management Program (DIMP), including the cost implications and benefits of the proposed program. The program will enable Enbridge Gas to assess the condition of a subset of distribution assets[1] that are approaching end of life, which allows for appropriate action to be taken, whether that is maintenance work or replacement of the pipe.

2. Enbridge Gas is proposing to introduce the Enhanced DIMP in response to the OEB's Decision in the St. Laurent Ottawa North Replacement Project Decision,[2] which stated the following, in regard to the distribution system:

> The OEB urges Enbridge Gas to thoroughly examine other alternatives such as the development and implementation of an in-line inspection and maintenance program using available modern technology, and to propose appropriate action based on its findings as part of its next Rebasing Application.

3. Enbridge Gas is also requesting approval of a new deferral account as part of this Application for the Enhanced DIMP, to record general administrative costs, as well as operating and maintenance and ongoing integrity inspection-related costs incurred to implement and execute the Enhanced DIMP. Details of the proposed new Enhanced DIMP Deferral Account are provided at Exhibit 9, Tab 1, Schedule 3.

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[1] The distribution system takes gas from higher-pressure transmission systems and distributes it to residential, commercial and industrial customers. The distribution assets include a series of pipelines of various operating pressures, regulation points that safely manage the pressure of the gas, and delivery points where the gas is measured.
[2] EB-2020-0293.

4. The following sections of evidence are organized as follows:
    1. Current Integrity Management at Enbridge Gas
    2. Proposed Enhanced DIMP
    3. Cost Recovery

<u>1. Current Integrity Management at Enbridge Gas</u>

5. Integrity Management is a key component in the life cycle of an asset, by maintaining the integrity of assets, potentially extending the asset life and ensuring compliance with codes, standards and procedures. A description of the life cycle delivery is provided at Exhibit 2, Tab 6, Schedule 2, Section 4.1.3, starting at page 44 of Enbridge Gas's Asset Management Plan (AMP). The maintenance strategies currently employed for distribution assets, which are also referred to as DIMP pipelines[3], are provided at Exhibit 2, Tab 6, Schedule 2, Section 5.2.3.2, page 82, Pipe Condition and Strategy Overview. These strategies, listed below, meet or exceed both code requirements and industry standards.
    a) Leak Management Operating Standard including Survey Program conducted with defined frequency depending on material, age, cathodic protection (CP) and presence of wall-to-wall hard surface area;
    b) Corrosion Control Operating Standard including CP survey;
    c) Valve Maintenance Operating Standard including inspection;
    d) Bridge Crossing Survey Program;
    e) Watercourse Crossing Survey Program;
    f) Vital Main Damage Prevention Program (for vital main subset);
    g) Distribution Integrity Management Program (DIMP) Asset Health Review operating process; and

[3] Includes most pipelines operating below 30% Specified Minimum Yield Strength (SMYS).

h) Condition assessment programs including integrity assessments and Quality Material Equipment Reports (QMER) to identify and assess failure mechanisms of assets.

6. Enbridge Gas has a Transmission Integrity Management Program (TIMP) for transmissions assets that provide an additional maintenance strategy, which is referred to as the TIMP Condition Monitoring Operating Standard[4]. This enhanced maintenance strategy of condition monitoring is not applied to distribution assets at Enbridge Gas, or any other Canadian Gas Association Company. Enbridge Gas initiated a 2022 American Gas Association Survey and of the 28 respondents, only 2 identified they completed in-line inspection (ILI) for a sub-set of their distribution pipeline assets, while the remaining 26 did not.

2. Proposed Enhanced DIMP

7. Enbridge Gas is proposing to introduce an Enhanced DIMP to improve the understanding of the condition of distribution pipeline assets. This program would ensure that Enbridge Gas has the ability to thoroughly assess the condition of these assets to allow appropriate action to be taken, whether that is maintenance work or replacement of the pipeline.

8. The proposed Enhanced DIMP addresses the concerns raised by the OEB in Enbridge Gas's St. Laurent Ottawa North Replacement Project[5], which stated:

> The OEB suggests Enbridge Gas take a proactive approach to inspecting and maintaining the subject pipeline until it can be

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[4] There is also a TIMP asset subclass that is a subset of steel mains that are part of a TIMP In-Line Inspection (ILI) Program or are subject to other periodic condition monitoring techniques such as external corrosion direct assessment, as provided in Section 5.2.3.3 of the AMP.
[5] EB-2020-0293, page 16, May 3rd, 2022

> demonstrated that pipeline replacement is necessary. This may include development and implementation of an in-line inspection and maintenance program using available modern technology as discussed in the next section. The evidence in this proceeding revealed that Enbridge Gas does not currently have the necessary infrastructure to carry out such in-line inspections in the St. Laurent Pipeline.

9. Based upon this direction from the OEB, Enbridge Gas has initiated a multi-pronged integrity plan to further establish the condition of St. Laurent Ottawa North Pipeline.

10. As part of the Enhanced DIMP, Enbridge Gas has identified a sub-set of the DIMP pipelines that could benefit from a more extensive condition monitoring program. Given available monitoring technique limitations as well as the cost/benefit assumptions, the recommendation is to include distribution pipeline assets in the Enhanced DIMP that are:
    a) Operating at pressures above 700 kPa;
    b) NPS 6[6] or greater;
    c) Over 1 km in length; and
    d) Greater than 50 years old.

11. Pipelines meeting these criteria, referred to as Enhanced DIMP pipelines in this evidence, would be prioritized based upon several factors including projects that are already in the AMP, pipeline operating pressure, and the relative risk of the assets as determined in the DIMP Risk Model[7]. Currently within the AMP, there are DIMP replacement projects for assets greater than NPS 6 with a forecast cost of over $500 million for the next 10 years.

[6] Normal pipe size of 6 inches.
[7] The DIMP Risk Model provides insight into the distribution pipe system risk, as described in Section 5.2.3.4.1.3.1 of the AMP.

12. Given that the Enhanced DIMP is not work currently carried out by Enbridge Gas, the initial task will be to create detailed desktop reviews of each of the priority Enhanced DIMP pipelines and to create an Integrity Plan document which summarizes the asset characteristics (e.g. age, materials, coatings, method of construction, operating pressure, known history of failures, etc.), the potential active threats on the asset (e.g. external corrosion, external interference, etc.), the recommended inspection methods, and confirmation of fitness for service.

13. Once the desktop assessments are complete, the inspection recommendations will be prioritized and initiated. These inspections will include leveraging opportunistic digs to gather direct examination data of the condition of the pipeline and consideration of Direct Current Voltage Gradient (DCVG) Surveys, Close Interval Surveys, Depth of Cover Surveys, and Integrity digs to further assess the pipe condition.

14. Distribution pipeline assets are not inspectable with the traditional free-swimming ILI, however robotic crawler tools can be leveraged. The outcomes of the St. Laurent Integrity review will provide further insight to determine whether ILI should be considered, and if so, on which assets and the portion of the pipeline to be inspected. Enbridge Gas anticipates the results of this review will be available in early to mid-2023.

15. The goal of the Enhanced DIMP will be to provide a substantive rigorous review of the condition of the Enhanced DIMP pipelines and to identify specific areas that could benefit from proactive mitigation projects which may extend the life of the asset. Such solutions may be implemented to delay or avoid costly and time-consuming pipeline replacement projects.

16. The benefits of the Enhanced DIMP include:
    a) Potentially extending the life of the assets, which may defer or delay pipeline replacements which typically will be more cost effective than replacing the pipeline, ensuring lower rates are provided to customers;
    b) Supporting energy transition and Integrated Resource Planning, by potentially deferring projects should a replacement not be required; and,
    c) Proactively identifying pipeline anomalies that can be mitigated to prevent failures from occurring and improve pipeline safety and reliability.

17. In the event that the review of the Enhanced DIMP pipelines validates that the asset condition is approaching end of life, the Enhanced DIMP will provide substantive justification to support the replacement project. These details will be included in the evidence for the leave to construct application at the time of filing.

<u>3. Cost Recovery</u>

18. The Enhanced DIMP responds to the OEB's Decision in the St. Laurent Ottawa North Replacement Project Decision,[8] and is above and beyond the requirements set out in code as well as industry best practices. As such, the costs for the Enhanced DIMP are all incremental to the amounts included in the revenue requirement for the 2024 Test Year Forecast.

19. Enbridge Gas anticipates the costs of the program are approximately $10 million annually, which includes the costs for inspections of the Enhanced DIMP pipelines plus additional resources to support the program.

20. As part of this Application, Enbridge Gas is requesting approval of a new deferral account to recover the costs of the Enhanced DIMP, which is provided at Exhibit 9,

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[8] EB-2020-0293.

Tab 1, Schedule 3. Any costs incurred for the Enhanced DIMP would be subject to review and OEB approval prior to disposition as part of the annual earnings sharing and deferral and variance account disposition proceedings.

ANCILLARY SERVICES OVERVIEW

JOEY CYPLES, SPECIALIST CNG
AMIR HASAN, MANAGER THIRD PARTY PROGRAMS

1. The purpose of this evidence is to summarize Enbridge Gas's ancillary programs and to provide a description of the evidence set out in Exhibit 1, Tab 14.

2. Enbridge Gas provides a number of ancillary services which are viewed as complementary to the core utility services of the sale, transmission, distribution and storage of natural gas. These ancillary programs include:
   - Natural Gas Vehicle (NGV) Program;
   - Distributor Consolidated Billing (DCB) Program; and
   - Open Bill Access (OBA) Program.

3. The NGV Program, offered in the EGD rate zone, currently consists of three components: Compressed Natural Gas (CNG) refuelling facilities, NGV fuel cylinders and vehicle refuelling appliances, and CNG tube trailers. Enbridge Gas is proposing to harmonize the NGV Program between the EGD and Union rate zones and to request approval of the regulatory treatment of the NGV Program, which includes continuing the program as a utility business activity, consistent with the EGD rate zone, and removing the requirement to impute revenue.

4. The DCB Program, also known as Agency, Billing and Collection (ABC), provides energy marketers and others the ability to bill end-use customers for their gas supply on Enbridge Gas's bill. Enbridge Gas is proposing to harmonize the DCB Program between the EGD and Union rate zones and to continue the program as a utility program, consistent with the Union rate zones.

5. The OBA Program provides other companies that sell energy-related products and services the ability to include their charges on Enbridge Gas's bill. The OBA Program was offered in the EGD rate zone since 2007 and in the Union rate zones since 2020 on a limited basis for energy-efficient products. Enbridge Gas plans to wind down the OBA Program as of October 31, 2024, which includes an optional 10-month extension period from December 31, 2023 to October 31, 2024. Enbridge Gas is proposing an extension of the existing financial terms of the OBA Program for the 10-month extension period. The only modification is that Enbridge Gas would credit all net revenues to ratepayers for 2024, rather than sharing the net revenues.

6. Further details regarding each of the ancillary programs are provided at Exhibit 1, Schedule 14 as set out below:

Exhibit 1, Tab 14, Schedule 2	NGV Program
Exhibit 1, Tab 14, Schedule 3	DCB Program
Exhibit 1, Tab 14, Schedule 4	OBA Program

ANCILLARY SERVICES – NATURAL GAS VEHICLE (NGV) PROGRAM

JOEY CYPLES, SPECIALIST CNG

1. The purpose of this evidence is to request OEB approval of the regulatory treatment of the Natural Gas Vehicle (NGV) Program. Specifically, Enbridge Gas is requesting OEB approval to a) continue the NGV Program as a utility activity b) expand the current NGV Program for the EGD rate zone to all Enbridge Gas franchise areas, and c) remove the requirement to impute revenue in any fiscal year that the NGV Program's annual rate of return (RoR) does not meet or exceed the required RoR.

2. This evidence is organized as follows:
    1. Background
    2. NGV Market
    3. Enbridge's Role in the NGV Market
    4. Current Regulatory Model
    5. Proposed Regulatory Model

1. Background

1.1. EGD Rate Zone

3. The NGV Program has been operating within the EGD rate zone since the mid-1980s. The current NGV Program supports the use of natural gas as fuel for Company vehicles, encourages the growth and development of natural gas as a substitute for gasoline and diesel fuel in transportation markets, and coordinates natural gas supply for public and private refuelling stations. The NGV Program has also evolved over the years, mainly in response to changes in the marketplace for vehicle fuels.

4. The NGV Program offered in the EGD rate zone currently consists of three components: Compressed Natural Gas (CNG) refuelling facilities, NGV fuel cylinders and Vehicle Refuelling Appliances (VRAs), and CNG tube trailers. The value of the assets associated with these components is comprised within the Company's utility rate base.

CNG Refuelling Facilities

5. Enbridge Gas owns, coordinates and facilitates the design, construction, and maintenance of CNG refuelling facilities using third-party contractors and leases these facilities to customers. The natural gas used at these facilities is delivered to these customers through Enbridge Gas's natural gas distribution system. Enbridge Gas also assists in the conversion of vehicles to natural gas, which provides customers with turnkey NGV solutions that help customers reduce operating costs and their environmental footprints.

NGV Fuel Cylinders and VRAs

6. Enbridge Gas also continues to rent NGV fuel cylinders and VRAs, primarily to the operators of smaller passenger vehicles. NGV fuel cylinders are gas cylinders that act as a vehicle fuel tank by storing pressurized natural gas. VRAs are small refuelling systems that are attached to the gas distribution system and are used to refuel these vehicles. The NGV fuel cylinders and VRAs are one of the original components of the NGV Program.

CNG Tube Trailers

7. In 2019, Enbridge Gas started to provide mobile CNG delivery capability through the use of tube trailers that can provide the safe transport of CNG (conventional natural gas and renewable natural gas (RNG)). The tube trailer solution enables gas from CNG refuelling facilities that are attached to the natural gas distribution

system to be filled, stored, transported on the road to remote refuelling stations, and used to fuel vehicles through a remote refuelling station that is not physically connected to the distribution system. Enbridge Gas has procured tube trailers and makes them available for rent through the NGV Program. Customers of the rental program manage the sourcing of natural gas, transportation, fuelling, and end-use customer relationships.

8. In addition to the current NGV Program, CNG tube trailers have been used to serve the distribution system and have been identified as an integrated resource planning alternative (IRPA) initiative. The use of CNG tube trailers for these purposes is outside of the NGV Program. As an IRPA, CNG tube trailers could be used in the future to provide additional natural gas peaking supply to communities attached to the Company's distribution system that are subject to delivery capacity constraints as either a short-term or long-term initiative.

1.2. Union Rate Zones

9. There is no comparable NGV Program in the Union rate zones. Union embarked on its NGV Program in the mid-1980s and provided services that were similar to those offered by EGD at the time. However, Union exited the NGV line of business in 2000. Before the amalgamation of EGD and Union in 2019, Union began to reintroduce NGVs into their fleet of utility service vehicles to reduce fuel costs and vehicle emissions. Union also worked with the City of Hamilton on the installation of a refuelling station. Enbridge Gas continues to own, operate, and manage the refuelling station's maintenance for the City of Hamilton on a cost-recovery basis.

2. NGV Market

10. While the NGV market has been slow to develop over the years, there is significant growth potential for the market, as NGVs present an opportunity to reduce

greenhouse gas (GHG) emissions from transportation. As described in Enbridge Gas's Energy Transition Plan provided at Exhibit 1, Tab 10, Schedule 6, Section 2.2 and 2.3, NGV represents a safe bet opportunity for the utility and the province from both a transportation fuel switching perspective and also in terms of increasing RNG content in transportation fuels. In terms of size, the energy demand for transportation accounts for 30% of total energy demand,[1] which is the second largest sector for energy demand, while natural gas has less GHG emissions than other transportation fuels, such as gasoline and diesel.

11. There are four recent developments that are expected to drive growth in the NGV market: environmental benefits, clean energy regulations, price competitiveness, and technology improvements.

2.1. Environmental Benefits

12. There are environmental benefits associated with moving from diesel fuel to natural gas as a transportation fuel, particularly concerning heavy trucks, smaller return to base fleet vehicles, and public transit. The benefits include:
    - NGVs have an emission factor that is 20% lower than heavy-duty diesel vehicles.[2]
    - NGVs emit up to 90% less Nitrogen Oxide (NOx) levels compared to current U.S. Environmental Protection Agency (EPA) standards.[3] The NOx gases can be harmful to human health and the environment and are one of the primary contributors to the formation of ground-level ozone.

[1] Government of Canada. (2022 July 28). Provincial and Territorial Energy Profiles – Ontario. Canada Energy Regulator. https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html
[2] National Inventory Report 1990 – 2020: Greenhouse Gas Sources and Sinks in Canada, 2020, Part 2, p.262, https://publications.gc.ca/collections/collection_2022/eccc/En81-4-2020-2-eng.pdf
[3] Cummins, Natural Gas by the Numbers. https://www.cummins.com/engines/natural-gas

- NGVs emit much less particulate matter, the harmful microscopic component of air pollution that penetrates deep into the lungs, at levels of 90% below the current EPA standard.[4]

13. In addition to reducing GHG and air pollutant emissions, the environmental benefit of moving to natural gas as a transportation fuel for heavy trucks, return to base fleet vehicles and public transit can be enhanced by integrating RNG into the NGV fuel supply. This benefit, however, cannot be achieved without first converting vehicles from diesel fuel to natural gas in these market segments.

14. RNG, with a cost up to 50% less than diesel fuel, blended into the NGV fuel supply has the opportunity to fully decarbonize the vehicle fuel supply, and depending on the RNG feedstock mix, provides a carbon-negative solution.[5]

2.2. Clean Energy Regulation

15. Recently, the Government of Canada implemented a Clean Fuel Regulation (CFR) that was published in Canada Gazette Notice, Part II on July 6, 2022. CNG refuelling facilities can generate, trade and sell credits under the CFR Program. The credits generated through the CFR should further strengthen the NGV business case in Ontario and will enable further adoption in NGV projects. For details on the CFR please see Exhibit 1, Tab 10, Schedule 6, page 9.

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[4] Cummins, Natural Gas by the Numbers. https://www.cummins.com/engines/natural-gas
[5] Renewable natural gas as a complementary solution to decarbonizing transit, June 30, 2022, p.23, https://cutric-crituc.org/wp-content/uploads/2022/06/CUTRIC_Renewable-Natural-Gas-as-a-Complementary-Solution-to-Decarbonizing-Transit_June-30-2022.pdf

16. To help decarbonize vehicles already on the road, the Government of Canada's 2022 Budget[6] proposed to provide $199.6 million over five years to Natural Resources Canada (NRCan) to expand the Green Freight Assessment Program, which will be renamed the Green Freight Program (GFP). The additional funding of this program will support the purchase of alternatively fueled vehicles for a greater diversity of fleet and vehicle types. Funding for NGVs reduces the total cost of ownership for fleets which should further strengthen the NGV business case.

17. Surveying the Canadian utility NGV offerings elsewhere in Canada, in comparison to Enbridge's NGV Program, the most noteworthy is the FortisBC Energy Inc. (FEI) CNG Program. The objectives of the NGV Program are consistent with what is being done in British Columbia, but unlike the FEI model, the NGV Program does not impact non-participating ratepayers.

18. In 2012, the BC government issued the Greenhouse Gas Reduction (Clean Energy) Regulation.[7] The legislation enables FEI to subsidize the costs of their CNG Program from ratepayers. CNG customers are required to fund a portion of direct capital costs dependent on the contract length. As demonstrated with FEI's CNG Program, having government regulation in place can generate strong growth in the CNG market.

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[6] 2022 Budget - A Plan to Grow Our Economy and Make Life More Affordable, April 7, 2022, https://budget.gc.ca/2022/pdf/budget-2022-en.pdf
[7] Greenhouse Gas Reduction (Clean Energy) Regulation, May 25, 2021, https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/102_2012

2.3. Price Competitiveness

19. Using natural gas in vehicles has a price advantage compared to diesel fuel on an energy equivalent basis, natural gas is approximately 60% less expensive.[8] While the price advantage has been apparent for a number of years, the spread has grown since 2021, making natural gas even more attractive than diesel fuel.[9]

20. The price advantage is even greater when including the federal fuel charge, as natural gas is charged at a lower rate[10] compared to gasoline and diesel fuel. The rate reflects the lower carbon content emissions of natural gas.

21. The use of natural gas as a vehicle fuel is already helping reduce the operating cost of waste collection in some Ontario municipalities. The City of Hamilton[11] is piloting CNG along with RNG blending to reduce its public transit system's operational cost and emissions. The use of CNG in other sectors can help to increase Ontario's competitiveness by lowering the cost of transporting goods throughout the province and the operating costs of municipal transit systems.

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[8] Renewable natural gas as a complementary solution to decarbonizing transit, June 30, 2022, p.23, https://cutric-crituc.org/wp-content/uploads/2022/06/CUTRIC_Renewable-Natural-Gas-as-a-Complementary-Solution-to-Decarbonizing-Transit_June-30-2022.pdf

[9] Ibid.

[10] The carbon price in dollars per tonne of GHG emissions is converted to a charge per unit of fuel by the federal government based on the fuels' carbon intensity, as published in the Greenhouse Gas Pollution Pricing Act. Government of Canada (2022 September 8). Fuel Charge Rates. Canada Revenue Agency. https://www.canada.ca/en/revenue-agency/services/forms-publications/publications/fcrates/fuel-charge-rates.html

[11] The Bay Observer. (2022 January 9). City Garbage Trucks Going Greener. https://bayobserver.ca/city-garbage-trucks-going-greener/

2.4. Technology Improvements

22. In addition to the environmental and economic benefits of natural gas as a vehicle fuel, technological improvements have greatly improved the operating characteristics of NGVs. At present, the engine size for NGVs are available up to 12 litres, with applications in the school bus, refuse, transit and truck markets. At the end of 2021, Cummins[12], a leader in producing natural gas engines in North America, announced it would bring a 15-litre natural gas engine for class 8 heavy-duty trucks to market as early as 2024.[13] The 15-litre engine supports the adoption of CNG in Canadian heavy-duty transport, as many fleets haul more than 80,000 lbs in gross vehicle weight, which is where the current 12-litre engine is capped. Additionally, the natural gas engine is expected to weigh 500 lbs less than the comparable 15-litre diesel engines currently available.

23. NGV deployments are making significant strides. There are more than 175,000 on U.S. roads and more than 23 million NGVs worldwide.[14] Enbridge Gas is not aware of any practical Battery Electric Vehicle (BEV) or Fuel Cell Electric Vehicle (FCEV) alternatives to decarbonize heavy-duty trucking. Until BEV and FCEV technology and infrastructure becomes readily available, NGV using RNG provides the most effective way of decarbonizing heavy-duty trucking.

[12] Cummins is the leader in producing engines that operate 100% on natural gas. At present, Cummins has over 80,000 natural gas engines in service worldwide. These include 6-litre, 9-litre, and 12-litre natural gas engines.
[13] DieselNet. (2021 October 14). Cummins to offer 15L natural gas engine. https://dieselnet.com/news/2021/10cummins.php
[14] NGVAmerica. Vehicles. https://ngvamerica.org/vehicles/

3. Enbridge Gas's Role in the NGV market

24. Although the NGV market has been in place and active for many years, the market has been slow to develop. Enbridge Gas performs the role of a facilitator in the NGV marketplace, acting in collaboration with the market participants. Enbridge Gas works with these participants and its partners rather than competes with them.

25. As a facilitator, Enbridge Gas utilizes its long and extensive experience with NGV fuels and equipment to bring potential customers, suppliers and other market participants together. The rental options offered by Enbridge Gas have and continue to provide customers with viable options to avoid and defer the initial cost of moving to NGV fuels. Enbridge Gas also supports the market by working with third parties to design, construct, test, commission, operate and maintain the station when an NGV facility within the program is to be constructed.

26. Enbridge Gas is unaware of any other market participant that coordinates and delivers turnkey NGV fleet refuelling services comparable to Enbridge Gas's. As such, Enbridge Gas is in a unique position to contribute to the development of the NGV market and intends to continue to expand its NGV Program in the future.

4. Current Regulatory Model

27. The NGV Program offered in the EGD rate zone is currently offered as a regulated ancillary program subject to OEB requirements described in this section of evidence.

28. The first OEB requirement is to fully allocate the NGV Program's assets and operating costs to the program to ensure that the costs incurred by Enbridge Gas for the NGV Program are recovered from the customers taking NGV service.

29. The second OEB requirement for the NGV Program is that the program meets or exceeds the OEB-approved RoR in each fiscal year. In the event that the NGV Program's annual RoR does not meet or exceed the required RoR, revenue is imputed to bring the program's RoR up to the required level. Should the RoR requirement be exceeded, any revenue beyond that required to meet Enbridge Gas's approved RoR would contribute to utility earnings.

30. Due to capital cost allowance (CCA) treatments[15] and the cost of capital (finance carrying charge) declines over time as the asset is depreciated, the annual RoR of a specific project is non-linear throughout the life of the asset. As such, NGV projects can have annual sufficiencies and deficiencies solely due to tax and carrying charge considerations, which do not reflect the project's lifecycle profitability. For example, the NGV project may be required to impute revenue in the middle years and to contribute to earnings sharing in the early and later years. As such, the need to impute revenue in a given year would be unnecessary since, over the life of the project, the project would meet the RoR.

31. In EGD's 2013 Cost of Service[16] proceeding, $0.5 million in revenue was imputed for the NGV Program to equate the program's overall return to the required regulated return. In subsequent years beyond 2014, the program has had a sufficiency. Please see Attachment 1 for the revenue and costs of the NGV Program and the calculated deficiency/sufficiency from 2013 to 2024.

[15] The accelerated deductibility/expensing of capital costs for tax purposes, versus the expensing through depreciation for accounting purposes.
[16] EB-2011-0354, Exhibit C3, Tab 1, Schedule 1, January 2012, p.3.

5. Proposed Regulatory Model

32. Enbridge Gas is proposing to expand the current NGV Program in the EGD rate zone to all Enbridge Gas franchise areas and to continue to operate its NGV Program as part of its utility business activities. Enbridge Gas sees its NGV Program as assisting Ontario in the reduction of GHG emissions through the conversion of diesel fuel powered fleet vehicles and heavy trucks to natural gas. As a facilitator, Enbridge Gas utilizes its long and extensive experience with NGV fuels and equipment to bring potential customers, suppliers and other market participants together. With this experience with the NGV Program and supporting the CNG market more broadly, Enbridge Gas is also well positioned to introduce CNG tube trailers as a potential IRPA.

33. Enbridge Gas is also proposing to modify the current regulatory treatment of the NGV Program to remove the need for revenue imputation, such that the program is funded solely by the monthly service rates charged to participating customers over the life of the program. This is consistent with the regulatory treatment of all other utility assets.

34. In lieu of the current RoR-based regulatory treatment, Enbridge Gas has sufficient measures in place to ensure there is no ratepayer subsidy over the term of the NGV Program. Specifically, Enbridge Gas will continue to set a monthly NGV service charge to recover the fully allocated cost of providing the NGV service, and provide measures to protect against default risk. Enbridge Gas is also proposing to provide reporting on the profitability of the NGV Program at its next rebasing proceeding.

5.1. NGV Service Charge

35. Enbridge Gas is proposing to continue to use the same mechanism that is currently in place for the NGV Program to set the NGV service charge. Enbridge Gas sets a

custom project specific charge that is levelized and constant for each month for the term of the contract, such that NGV service customers will have cost certainty. Cost certainty is an important factor to enable and facilitate the acquisition of NGVs and/or the conversion of their existing vehicles to this fuel type.

36. To ensure there is no subsidy to ratepayers, Enbridge Gas proposes that the final NGV service charge included in the NGV customer's contract will be based on the actual costs of the facilities on a fully allocated basis and will be updated at the time the project is completed. This approach eliminates any over or under recovery risk associated with forecast variances. Enbridge Gas does not expect any substantial capital cost overruns associated with NGV Program projects as it will establish suitable warranties and protections from manufacturers and installation contractors to cover future unanticipated capital costs for the facilities.

37. Consistent with the current approach used in the EGD rate zone, each service charge will be derived from a discounted cash flow (DCF) analysis. The DCF analysis will be based on the principles and parameters set out in the Distribution System Expansion Report.[17] The charge for each service would be specific to each NGV project's assets and based on fully allocated costs. The NGV service charge will also be set to recover site specific operating and maintenance costs, capital investment, distributor's return on investment, and taxes while achieving a Profitability Index (PI) of 1.0 or greater over the term of the contract. By the application of fully allocated costs to the NGV Program's assets and operations and adhering to the OEB's E.B.O 188 Guidelines, non-participating ratepayers will not subsidize the NGV Program.

[17] E.B.O. 188, The Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, January 30, 1998.

5.2. Managing Default Risk

38. In terms of protection from customer default, Enbridge Gas will apply all of its existing credit checking, approval and security requirements. This approach is consistent with Enbridge Gas's current practice for the NGV Program and other large volume gas distribution customers. Enbridge Gas will assess the creditworthiness of counterparties and where appropriate, obtain financial assurances in the form of irrevocable letters of credit or parental guarantees to financially secure its NGV assets.

5.3. Reporting

39. Further, with respect to reporting on NGV Program, Enbridge Gas will file a report as part of its next rebasing proceeding. The report will provide the revenue and costs, including the RoR, of the NGV Program for each year during the next IR term from 2025 to 2028. The report will also provide a description of any new large projects added to the NGV Program over the IR term.[18]

40. In closing, Enbridge Gas requests that the OEB approve the NGV Program as described in this evidence. The services offered by the Company's NGV Program are one of the few means currently available to customers to economically achieve reduced operating costs and at the same time reduce their GHG emissions, thereby improving the province's competitiveness and providing environmental benefits. The NGV Program is a clear safe bet action which supports the province's climate goals and maintains customer choice and optionality while the province's energy transition unfolds.

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[18] E.B.O. 188, The Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, January 30, 1998.

41. Expanding the NGV Program to all Enbridge franchise areas will bring these benefits to a greater number of potential customers. The revised regulatory model proposed by Enbridge Gas for the NGV Program is also consistent with the regulatory treatment of all other utility assets and places no financial burden on non-participating ratepayers.

Natural Gas Vehicle (NGV) Program - Rate of Return Summary

Line No.	Particulars ($ millions)	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Operating Income													
1	Total Revenue	1.1	1.3	1.5	1.1	1.3	2.3	2.6	2.7	3.2	3.1	3.7	4.4	5.0
2	Total Expenses	1.2	1.1	1.2	0.6	0.8	1.5	1.6	1.6	1.7	1.1	1.2	1.1	0.9
3	Operating Income before Income Taxes	(0.1)	0.2	0.3	0.4	0.5	0.8	1.0	1.1	1.5	2.0	2.5	3.3	4.1
4	Operating Income after Income Taxes	(0.1)	0.1	0.1	0.4	0.5	0.9	1.1	0.9	1.3	1.9	3.4	3.7	4.2
	Investment													
5	Net Utility Investment	2.9	2.7	2.3	1.5	4.2	9.3	9.8	9.4	15.2	20.1	24.1	34.1	40.3
6	Rate of Return on Investment	(5.1%)	3.4%	6.2%	23.5%	12.8%	9.3%	11.1%	9.7%	8.4%	9.3%	14.2%	10.9%	10.5%
7	Required Rate of Return	6.8%	6.6%	6.6%	6.5%	6.3%	6.0%	6.1%	6.0%	5.8%	5.6%	5.8%	5.8%	5.9%
8	After Tax Deficiency/Sufficiency	(0.4)	(0.1)	(0.0)	0.3	0.3	0.3	0.5	0.3	0.4	0.7	2.0	1.8	1.9
9	Pre Tax Deficiency/Sufficiency	(0.5)	(0.1)	(0.0)	0.4	0.4	0.4	0.7	0.5	0.5	1.0	2.7	2.4	2.6

ANCILLARY SERVICES – DISTRIBUTOR CONSOLIDATED BILLING (DCB) PROGRAM

AMIR HASAN, MANAGER THIRD PARTY PROGRAMS

1. The purpose of this evidence is to request OEB approval of the regulatory treatment of the Distributor Consolidated Billing (DCB) Program. Consistent with the treatment of the Union program, Enbridge Gas proposes to change the treatment of the EGD program and plans to continue the DCB Program as a utility business activity, as described in this evidence.

2. This evidence is organized as follows:
    1. Background and Current Regulatory Treatment
    2. Proposed Regulatory Treatment

1. Background and Current Regulatory Treatment

3. The DCB service, also known as Agency, Billing and Collection (ABC), provides energy marketers and others the ability to bill end-use customers for their supply on Enbridge Gas's bill.

4. The regulatory treatment of the DCB service is currently different between the EGD and Union rate zones.

5. In the EGD rate zone, the current DCB service is a non-utility activity and, as such, the rates have been set and adjusted by Enbridge Gas periodically without OEB review and approval. The OEB deemed the service to be non-utility rather than ancillary through a 1999 Rate Case Decision.[1]

[1] E.B.O.179-14/179-15, OEB Decision and Order, March 31, 1999.

6. In the Union rate zones, the DCB service is a utility activity. In the 2004 Cost of Service Decision[2], the OEB approved the continuation of the DCB service for a period of five years from 2004 to 2008. The rate for the DCB service was last adjusted and approved by the OEB in Union's 2013 Cost of Service proceeding.[3] The DCB charge was set to recover allocated DCB Program administration costs including the salaries and benefits of employees, and bad debt costs.

<u>2. Proposed Regulatory Treatment</u>

7. Enbridge Gas proposes to treat the harmonized DCB Program as a utility business activity. This approach is consistent with the current treatment of the DCB service in the Union rate zones and is also consistent with Gas Distribution Access Rule (GDAR) requirement that gas distributors accommodate DCB. It is also consistent with the treatment of most, if not all, electricity distributors regulated by the OEB.

8. Having a harmonized approach across the franchise allows for consistency in the DCB Program offering, processes, and charges. A harmonized DCB Program also provides a consistent and improved customer experience, which creates less confusion in the market and makes Enbridge Gas easier to do business with. This proposal also enables Enbridge Gas to align business processes, which serve to deliver efficiencies and benefits over time.

9. The DCB service charges proposed as part of this Application will continue to be set to recover the costs to provide the service, which avoids rate payer impacts. The DCB service charges are provided at Exhibit 8, Tab 3, Schedule 2. The revenue associated with DCB services is provided at Exhibit 3, Tab 5, Schedule 1.

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[2] RP-2003-0063, OEB Decision and Order, March 18, 2004.
[3] EB-2011-0210, OEB Decision and Order, October 24, 2012.

ANCILLARY SERVICES – OPEN BILL ACCESS (OBA) PROGRAM

AMIR HASAN, MANAGER THIRD PARTY PROGRAMS

1. The purpose of this evidence is to inform the OEB of Enbridge Gas's plans to wind down the Open Bill Access (OBA) Program as of October 31, 2024, and to request the extension of existing financial terms of the OBA Program for 10 months until October 31, 2024. The only modification is that Enbridge Gas would credit all net revenues to ratepayers for 2024, rather than sharing those net revenues.

2. Recent developments in the OBA Program and the resulting proposals to the OEB include:
   a) Enbridge Gas decided to wind down the OBA Program and announced its intentions to Billers on June 2, 2022. Enbridge Gas's original proposal was for the program to conclude on December 31, 2023, coincident with the end of the deferred rebasing term.
   b) Enbridge Gas has facilitated a lengthy consultation process with the third-party billers who use the OBA Program (Billers). Based on input and feedback from Billers, Enbridge Gas created a transition plan which now allows for an optional 10-month extension to the original conclusion date, giving Billers the option to continue with the OBA Program until October 31, 2024.
   c) The existing OEB-approved financial terms of the OBA Program will continue until December 31, 2023. Enbridge Gas proposes that it will credit all of the net revenues from the 10-month extension of the OBA Program to ratepayers, with the net revenues to be determined using the same parameters as approved during the deferred rebasing term.
   d) Enbridge Gas is also requesting approval of a new Open Bill Extension deferral account as part of this Application, to record 10-month net revenues

for later disposition to ratepayers. Details of the proposed new deferral account are provided at Exhibit 9, Tab 1, Schedule 3, page 12.

3. This evidence is organized as follows:
    1. Background of the OBA Program
    2. OBA Wind-down Process
    3. Requested Relief for 2024

1. Background of the OBA Program

4. Enbridge Gas has offered the OBA Program in its current form since the Open Bill issues Decision[1].

5. In the OBA Services proceeding[2], Enbridge Gas proposed a two-year extension (for 2019 and 2020) of the financial terms of the OBA Program that were set out in EGD's 2014 OBA Settlement proceeding[3]. Through a settlement process, the interested parties agreed that it was acceptable for the OBA Program to continue to operate under the existing financial terms until the earlier of: "(i) December 31, 2023 (which is the last day of Enbridge Gas's deferred rebasing period); or (ii) an OEB Decision in any earlier application by Enbridge Gas to expand the OBA Program into the Union service area."[4]

6. In the OEB-approved Supplementary Partial Settlement Proposal, the parties acknowledged that Enbridge Gas has the right now, and should continue to have

[1] EB-2009-0043, OEB Decision. December 2, 2009.
[2] EB-2018-0319.
[3] EB-2013-0099, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, September 12, 2013, pp.6-7.
[4] EB-2018-0319, Supplementary Partial Settlement Proposal, Exhibit N1, Tab 2, Schedule 1, October 23, 2019, p.6.

the right, to terminate the OBA Program at any time as long as it complies with the Open Bill Agreement.[5]

7. In the OBA Services Decision and Order, the OEB stated:

> Enbridge Gas will file, as part of its next rebasing rate application, a detailed proposal for whether the OBA Program should be continued, and if so, whether it should be expanded to the Union Gas service area. The OEB's acceptance of the supplemental partial settlement proposal in this proceeding should not be interpreted as a determination on whether the OBA will continue beyond the next rebasing application.[6]

8. The balance of this Exhibit will provide context and procedural proposals for Enbridge Gas's decision to terminate the OBA Program.

2. <u>OBA Wind-Down process</u>

9. The OEB-approved Settlement Agreement outlines the following procedure in the event of termination of the OBA Program:

> All parties agree that it is appropriate for the Board to approve the ongoing operation of the OBA program, on an indefinite basis. This takes away any requirement for Enbridge to seek annual or periodic OEB approval to continue to operate the program. It will remain open at any time for any interested party to make application to the OEB asking for the OBA program to be terminated or changed. In the event that Enbridge decides to wind down the OBA program, it shall give notice of that intention to the OEB (and to all Billers and to registered

[5] EB-2018-0319, Supplementary Partial Settlement Proposal, Exhibit N1, Tab 2, Schedule 1, October 23, 2019, p.6.
[6] EB-2018-0319, Decision and Order, April 26, 2020, p.10.

participants in this proceeding and in Enbridge's most recent rate proceeding) at least 60 days before the Company begins any Program Termination Transition activities (set out in section 8.9.3 of the OBA contract).[7]

10. On June 2, 2022, Enbridge Gas started the process to wind down the OBA Program and served a notice of intention to terminate the OBA Program to the OEB, all Billers and all registered participants of 2019 and 2020 proceedings. The following process was followed:
    a) A notice of intent to wind down the OBA Program was sent on May 20, 2022, to all Billers and intervenors along with an agenda for the annual meeting, which was held on June 1, 2022.
    b) An official wind down notice was sent to the OEB, intervenors and Billers along with a proposed transition plan on June 2, 2022.
    c) Throughout the wind down process Enbridge Gas ensured that the Open Bill Agreement and Settlement Agreements were followed to effect an orderly transition of Billers and customers from the OBA Program. Enbridge Gas ensured that all Billers were afforded full opportunity to voice their concerns, ask questions and participate in the consultative process.
    d) Consistent with the Open Bill Agreement, all Intervenors who participated in the 2019 and 2020 OBA proceedings were sent wind down notices and were invited to participate in the consultative process.
    e) All Billers, operating in either or both of the OBA Programs were included in the consultative process.
    f) The objective of the consultative process was to develop a transition plan that would enable an orderly transition of Billers and customers from the

[7] EB-2013-0099, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, September 12, 2013, pp.4-5.

OBA Program to alternate billing platforms. The following activities were held during the consultative process:

i. Official consultations (with virtual participation options) commenced on June 15 with additional consultative meetings held on July 7, July 21, August 25 and September 12, in compliance with the required 60-day consultation period. These consultations concluded with a communication to participants on September 27, 2022, containing the final OBA transition plan and the Optional Extension Agreement. Attachment 1 and 2 provide the transition plan and optional extension agreement, respectively.
ii. Billers had until October 11, 2022 to sign the Optional Extension Agreement if they decided to take the 10-month extension.
iii. On October 14, 2022, Enbridge Gas notified all Billers and participating intervenors that they had enough interest in the optional extension to proceed with the extension until October 31, 2024.

11. Enbridge Gas has taken and will continue to take measures to help customers with the transition and protect their sensitive information:
    a) Enbridge Gas supported Billers in their outreach to customers to advise of the OBA Program wind down, and as they established new billing and payment arrangements directly with their respective customers.
    b) A comprehensive customer communications plan was prepared and shared with participating Billers and intervenors. The purpose of the plan was to provide Billers with key messages they could use to inform customers regarding the OBA Program wind down at appropriate time intervals. Enbridge Gas collected and incorporated Biller and Intervenor feedback as appropriate in preparing the customer communications plan. The customer communications plan is provided at Attachment 3.

c) The current customer dispute process will remain in place. The customer dispute process provides that the customers can have the OBA charges credited back in 15 days if they don’t agree to the OBA charges. Until the end of the OBA Program, Billers will have to maintain existing service levels to maintain a low number of disputes and high-resolution rates. Enbridge Gas will maintain the reporting and back-office support to the Billers so they will have the visibility and necessary tools to resolve disputes efficiently. Enbridge Gas will continue to collect and hold financial assurances from the Billers for the extended time to facilitate quick settlement of customer disputes.

d) The OBA transition plan makes it incumbent on the Billers to stop adding new customers to the OBA Program as well as adding new charges to the existing customers two months before the applicable end date of the OBA Program. This provision will protect customers from being added to the OBA Program for a very short period thereby reducing the risk of customer inconvenience.

3. Requested Relief for 2024

12. Since the OBA Decision[8], the OBA Program has continued to operate under the same financial terms, with net revenues credited to ratepayers up to a defined level and then shared between Enbridge Gas and ratepayers thereafter.

13. The net revenues are determined by subtracting OBA Program costs from revenues. Under this approach, the OBA Program net revenues are determined each year by subtracting the deemed OBA Program costs from the OBA Program revenues received by the Company from Billers. The deemed OBA Program costs

[8] EB-2013-0099, OEB Decision on Settlement Agreement, September 23, 2013.

are equal to the number of bills with Open Bill charges times the OEB-approved unit cost per bill. The OEB-approved unit cost per bill was approved for the period from 2014 to 2018.[9] As of 2018, the OEB-approved unit cost per bill was $0.7195 per shared bill and $1.8186 per standalone bill. Since that time, the OEB-approved unit cost per bill has been increased by CPI each year (capped at 2.5%).

14. In the OBA Services Decision and Order[10], Enbridge Gas was granted approval to extend these financial terms until December 31, 2023. The relevant portion of the OEB-approved Supplementary Partial Settlement Agreement states:

> The result of this agreement is that until December 31, 2023 (or the date of any earlier OEB Decision related to the OBA Program):
>
> (a) the Billing Fees to be applicable in the current year will be based on the Billing Fees applicable at the end of the previous year, subject to annual increases equal to the annual percentage change in the Canadian Consumer Price Index ("CPI"), All Items, but not to exceed 2.5% per year.
>
> (b) the costs used to determine net revenues for the OBA Program for the current year will be based on the costs applicable at the end of the previous year, adjusted in the same way as the Billing Fees.[11]

15. Enbridge Gas requests that the OEB approve the continued application of the determination of net revenues for the OBA Program to be in place from January 1, 2024, to October 31, 2024.

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[9] EB-2013-0099, OEB Decision on Settlement Agreement, September 23, 2013.
[10] EB-2018-0319, OEB Decision and Order, April 16, 2020.
[11] EB-2018-0319, Supplementary Partial Settlement Agreement, Exhibit N1, Tab 2, Schedule 1, October 23, 2019, p.6.

16. It is proposed that all of the net revenue for 10 months from January 1, 2024, to October 31, 2024 (determined as set out above), will be tracked in a separate deferral account. All net revenue will be credited to rate payers.

17. This 10-month proposal for 2024 as stated above is different from the current OEB-approved approach, where ratepayers receive the first $5.4 million of net revenues, and then Enbridge Gas retains the next $2 million in net revenues.

18. Enbridge Gas is requesting approval of a new Open Bill Extension Deferral Account as part of this Application, to record 10-month net revenues for disposition to ratepayers. Details of the proposed new deferral account are provided at Exhibit 9, Tab 1, Schedule 3, page 12.

OPEN BILL PROGRAM WIND-DOWN TRANSITION PLAN

To: All 'Open Billers' (each, a "**Biller**", and collectively, "**All Billers**") under the 'Open Bill Program' (the "**Open Bill Program**") operated by Enbridge Gas Inc. ("**Enbridge**")

Re: Wind-Down and Termination of the 'Open Bill Program'

And Re: Open Bill Access Billing and Collection Services Agreement or Amended and Restated Open Bill Access Billing and Collection Services Agreement (as applicable, the "**Agreement**") entered into between each Biller and Enbridge

Dated: September 27, 2022

The following is the transition plan (the "**Transition Plan**") to be implemented by Enbridge to effect the orderly transition and migration from Enbridge of Billing Services now provided by Enbridge under the 'Open Bill Program'.

Transition Timeline

Enbridge proposes to provide all Billers with the same period of transition. A Biller may opt to cease using the Open Bill Program earlier. Where a Biller opts to migrate their Customers out of the Program earlier, certain dates contemplated in the Transition Plan may also be earlier. In addition, if a Biller wishes to extend the delivery of Billing Services, and agrees to the terms of the Optional Extension Agreement attached as *Attachment 2*, then they may extend their transition period as outlined below.

Task / Milestone	**Date**
Annual Stakeholder Meeting	June 1, 2022
Notice of Termination	June 2, 2022
Consultation	June to September 2022
Notice of Transition Plan	September 27, 2022
Last Date to enter into the Optional Extension Agreement	October 11, 2022
Notify Billers re confirmation of Optional Extension	October 14, 2022
Notice of Run-Off Financial Assurances – all Billers	By a date to be determined[1]
Provide Run-Off Financial Assurances – all Billers	By a date to be determined[1]
Notice of Extension Financial Assurances – only for Billers which have entered into the Optional Extension Agreement	By a date to be determined[1]

[1] Refer to further detail below in this Transition Plan

Provide Extension Financial Assurances – only for Billers which have entered into the Optional Extension Agreement	By a date to be determined[1]
Last Date to add new Customers or new charges – for Billers which have not entered into the Optional Extension Agreement	November 1, 2023[2]
Final Billing Date – for Billers which have not entered into the Optional Extension Agreement	December 2023 Billing Period
Last Date to add new Customers or new charges – only for Billers which have entered into the Optional Extension Agreement	September 1, 2024[2]
Final Billing Date – only for Billers which have entered into the Optional Extension Agreement	October 2024 Billing Period
Termination of Agreement with Biller	12 months following the applicable Final Billing Date

Definitions

For the purposes of this Transition Plan the following terms shall have the meanings set out below. Capitalized terms not defined in this Transition Plan have the meanings given to them in the Agreement.

"**Notice Date**" means June 2, 2022 (being the date on which Company provided the Notice of Termination).

"**Final Billing Date**" means the last Cycle Day of: (a) the December 2023 Billing Period (being approximately 15 months following delivery of the Notice of the finalized Transition Plan) – for Billers which have not entered into the Optional Extension Agreement, or (b) the October 2024 Billing Period (being approximately 25 months following delivery of the Notice of the finalized Transition Plan) – for Billers which have entered into the Optional Extension Agreement.

"**Final Invoice Date**" means the Final Billing Date plus 6 Cycle Days.

Assumptions

- Biller will not require services from Company to migrate their billing data to Biller or to a third party service provider. Should this not be the case, Biller must advise Company in writing of its data migration requirements, and Company will consider and respond to such request. Any data migration request must be communicated at least two (2) months prior to a Biller migrating all of their Customers out of the Program. Company may charge Biller its reasonable costs, subject to the prior approval of the Biller, for the provision of Biller's data in an alternate format required by Biller in order to facilitate the transition of such data to another system.

[2] Refer to *Attachment 1 - Last Date to Add New Customers or New Charges Details*

- Company will add no new Billers to the Program after the Notice Date.

- A system freeze will be in effect after the Notice Date, and no new changes, including changes to Biller branding, will be made after the Notice Date. However, updates to Service Bill messages and contact numbers may be made until (a) November 2023 – for Billers which <u>have not</u> entered into the Optional Extension Agreement, or (b) September 2024 – for Billers which <u>have</u> entered into the Optional Extension Agreement.

<u>Optional Extension of Billing Services</u>

- Where a Biller:
  - enters in to the Optional Extension Agreement with Company, in the form attached to this Transition Plan as *<u>Attachment 2</u>*, on or before October 11, 2022; <u>and</u>
  - provides to Company the required Extension Financial Assurances on or before the date to be determined,

  then Company will extend the provision of Billing Services pursuant to the Agreement on the terms and conditions set out in the Optional Extension Agreement.

<u>Customer Related Transition Actions to be completed on or before the following dates:</u>

- **Biller's Actions – for all Billers:**

  - **From September 30, 2022** – Biller will extend any current Financial Assurances and provide Run-Off Financial Assurances as required pursuant to the Agreement and this Transition Plan.

    - Financial Assurances and Run-Off Financial Assurances will be required to remain in place until the applicable Final Billing Date plus 12 Billing Periods.

    - While Section 8.8.2 of the Agreement provides that Run-Off Financial Assurances are required for approximately 12 months following the end of Termination Transition, Company may agree to an earlier end date where a Biller migrates all their Customers out of the Program earlier.

  - **From October 1, 2022** – Billers should not expect that any request for assignment of their Agreement and the corresponding Biller ID will be consented to by Enbridge, and assignments under Section 11.7 of the Agreement will be considered by Enbridge on an exception basis only.

  - **By a date to be determined** – On the earlier of: (A) sixty (60) days prior to the relevant Biller's applicable Final Billing Date; and (B) five (5) Business Days following notice from the Company to the Biller that Biller's monthly billings under the Program (measured either by volume (i.e. number of Bills) or dollar value (i.e. Actual Billed Amounts)) has decreased by thirty percent (30%) or more from such billings in September 2022 (for certainty, regardless of whether such billings increase in a subsequent month), <u>Biller must provide Run-Off Financial Assurances</u> in an amount equal to the amount required by the Agreement.

  - **Throughout the transition period** – Biller will implement a Customer communications plan to effect an orderly transition.

- **Biller's Actions – for Billers which have not entered into the Optional Extension Agreement:**
  - **After November 1, 2023** – No new Customers or new charges may be added. Refer to *Attachment 1* for details.
  - **By November 15, 2023**, and in any event prior to Biller migrating any Customers out of the Program – Biller will send a written notice to all Customers to communicate that their charges will no longer appear on the Service Bill after the Final Billing Date, or an earlier date where Biller migrates all Customers out of the Program earlier.
  - **By December 31, 2023**, and in any event prior to Biller migrating any Customers out of the Program – Biller will update Biller call centre scripts to communicate that charges will no longer appear on the Service Bill.
  - **By February 10, 2024**, or earlier, as applicable – Biller will make payment of all Billing Fees, and, if applicable, any additional work requested by Biller in respect of termination services on a time and materials basis (including applicable Taxes thereon) without mark-up.
    - Company will not charge Billers for its general costs of terminating the Program; however, Company may charge Billers for additional work requests, subject to the prior approval of the Biller.

- **Biller's Actions – for Billers which have entered into the Optional Extension Agreement:**
  - **By a date to be determined** – On the earlier of: (A) December 1, 2023 (being approximately thirty (30) days prior to commencement of the Extended Term); and (B) five (5) Business Days following notice from the Company to the Biller that Biller's monthly billings under the Program (measured either by volume (i.e. number of Bills) or dollar value (i.e. Actual Billed Amounts)) has decreased by thirty percent (30%) or more from such billings in September 2022 (for certainty, regardless of whether such billings increase in a subsequent month), Biller must provide Extension Financial Assurances in an amount equal to the total amount of Minimum Billing Fees payable during the Extended Term.
  - **After September 1, 2024** – No new Customers or new charges may be added. Refer to *Attachment 1* for details.
  - **By September 15, 2024**, and in any event prior to Biller migrating any Customers out of the Program – Biller will send a written notice to all Customers to communicate that their charges will no longer appear on the Service Bill after the Final Billing Date, or an earlier date where Biller migrates all Customers out of the Program earlier.
  - **By October 31, 2024**, and in any event prior to Biller migrating any Customers out of the Program – Biller will update Biller call centre scripts to communicate that charges will no longer appear on the Service Bill.

  - **By December 10, 2024**, or earlier, as applicable – Biller will make payment of all Billing Fees, and, if applicable, any additional work requested by Biller in respect of termination services on a time and materials basis (including applicable Taxes thereon) without mark-up.
    - Company will not charge Billers for its general costs of terminating the Program; however, Company may charge Billers for additional work requests, subject to the prior approval of the Biller.

- **Company's Actions:**
  - **By a date to be determined** – On the earlier of: (A) not less than sixty (60) days prior to the relevant Biller's applicable Final Billing Date; and (B) Biller's monthly billings under the Program (measured either by volume (i.e. number of Bills) or dollar value (i.e. Actual Billed Amounts)) decreasing by thirty percent (30%) or more from such billings in September 2022, Company will notify Biller of the amount of Biller's Run-Off Financial Assurances requirements.
  - **By a date to be determined** – Company will notify Biller of the date on which Biller's Extension Financial Assurances are required, as contemplated in the Optional Extension Agreement.
  - **By December 31, 2023**, or earlier as appropriate – Company will update call centre scripts to communicate that Biller's charges will no longer appear on the Service Bill after the Final Billing Date.
  - **Until the Final Billing Date** – Company will continue to provide Billing Services for valid charges.
  - **By Final Invoice Date** – Company will complete invoicing to Biller for all Billing Fees, and, if applicable, invoice for any additional work requested by Biller on a time and materials basis (including applicable Taxes thereon) without mark-up.
  - **Throughout the transition period** – Company will implement a Customer communication plan to support an orderly transition, including advising Customers that Biller's or Billers' charges will no longer appear on the Service Bill after the Final Billing Date, and providing occasional reminders or updates. Company will also use reasonable efforts to provide advance notice to Billers prior to making any significant changes to communications, including implementing new tactics or channels, or major changes to messaging being used.
  - **Throughout the transition period** – Company will consult with Billers regarding Company's communication plans.
  - **Throughout the transition period** – In the event Biller does not fulfill its obligations under the Transition Plan, Company reserves the right to take such actions, as required, in order to implement the transition.

Open Bill Operations Transition Actions to be completed on or before the following dates:

- **Company's Actions:**
  - Until the earlier of (i) Biller migrating all its Customers out of the Program and (ii) the Final Billing Date – Company will continue reporting as required by the Agreement. Customer Billing Dispute related reporting will continue until termination of the Agreement with the Biller.
  - On the earlier of (i) Biller migrating all its Customers out of the Program and (ii) the Final Billing Date – Company will remove Biller's security access to their SFTP Input folder for billing purposes. Access will remain for Customer Billing Dispute purposes until termination of the Agreement with the Biller.
  - Upon or prior to, as applicable (i) Biller migrating all its Customers out of the Program and (ii) the Final Billing Date – Company will submit delete transactions for all remaining Customers.
  - Up to 21 calendar days after the Final Billing Date – Company will continue all daily/monthly, as applicable, net remittances to Biller.
  - Throughout the transition period – Company will revise all of Company's Biller lists to show that Biller's charges will no longer appear on the Service Bill.
  - At or before the end of the transition period – Company will return or release any applicable Extension Financial Assurances.
  - 12 months following the end of the transition period – Company will return or release Run-Off Financial Assurances.
  - 12 months following the end of the transition period – Company will release all registrations and priority agreements in respect of Receivable Entitlements.
  - As determinable – Company will advise Biller regarding any incremental costs incurred by Company with approval of Biller in connection with the transition.

Attachment 1 – Last Date to Add New Customers or New Charges Details
Attachment 2 – Optional Extension Agreement

Attachment 1
Last Date to Add New Customers or New Charges Details

Applicable November 2, 2023 to December 31, 2023 to Billers which have not entered into an Optional Extensions Agreement; and
Applicable September 2, 2024 to October 31, 2024 to Billers which have entered into an Optional Extensions Agreement

Enbridge will allow Billers to add new customers and new charges until November 1, 2023 or September 1, 2024 (as applicable). After November 1, 2023 or September 1, 2024 (as applicable), Billers will not be allowed to add new customers and new charges. Only existing customers and charges will continue to be billed after November 1, 2023 or September 1, 2024 (as applicable). New charges/new customers will not include the following, which may continue to bill to December 31, 2023 or October 31, 2024 (as applicable) (unless Billers migrate them earlier): (i) move-in customers, (ii) protection plan renewals, and (iii) existing, repeating Bill Ready charges for billing up to December 2023 or October 2024 (as applicable). The table below sets out further details regarding transactions that will be allowed or not allowed from November 2, 2023 or September 2, 2024 (as applicable) to December 31, 2023 or October 31, 2024 (as applicable).

Items	Transaction	Comments
General transactions		
Customer enrolment		
This means any new customer signed up by the Biller		
Match transaction from the Biller	Not Allowed	
Add transaction from the Biller	Not Allowed	
Force Adds from the Biller	Not Allowed	
Rate ready rentals		
Adds	Not Allowed	No new adds even if you received the OBA number before November 1, 2023 or September 1, 2024
Updates	Allowed	
Deletes	Allowed	
Move-in rentals	Allowed	
Final Enbridge Billing		Rentals will be billed and deleted on their respective cycles in December 2023 or October 2024
Rate ready standing request		
Adds	Not Allowed	No new adds even if you received the OBA number before November 1, 2023 or September 1, 2024
Deletes	Allowed	
Final Enbridge Billing		No bill out of remaining installments with December 2023 or October 2024 bill
Rate ready loans		
Adds	Not Allowed	No new adds even if you received the OBA number before November 1, 2023 or September 1, 2024
Deletes	Allowed	
Final Enbridge Billing		No bill out of loans with December 2023 or October 2024 bill
Bill Ready charges		
Accepted before November 1, 2023 or September 1, 2024	Allowed	Last date to accept repeating charges
OBAs accepted and billed last month (October 2023 or August 2024)	Allowed	Use the same OBAs & BTCs Billers have been billing in October 2023 or August 2024
OBAs provided through BR (Bill Ready) Move-in process	Allowed	
New OBAs never billed before and last month	Not Allowed	
OBA used last month but different BTC	Not Allowed	
Bill Ready Credits after December 31, 2023 or October 31, 2024	Not Allowed	Allowed only to settle disputes, TBD if Biller or EGI will complete
Rental table update		
Updates	Allowed	

Attachment 2
Form of Optional Extension Agreement

- **Refer to the nine (9) pages following**

ENBRIDGE GAS INC.

- and -

[insert name of Open Biller]

OPTIONAL EXTENSION AGREEMENT TO THE

[OPEN BILL ACCESS BILLING AND COLLECTION SERVICES AGREEMENT]

[AMENDED AND RESTATED OPEN BILL ACCESS BILLING AND COLLECTION SERVICES AGREEMENT]

XXXX, 2022

THIS OPTIONAL EXTENSION AGREEMENT (this "**Agreement**") is entered into and effective as of the 11th day of October, 2022 (the "**Extension Effective Date**")

B E T W E E N:

ENBRIDGE GAS INC., a corporation existing under the laws of Ontario,

(the "**Company**")

- and -

[insert name of Open Biller], a corporation incorporated and existing under the laws of XXXX

(the "**Biller**")

BACKGROUND

A. The Company and the Biller have entered into the [[Open Bill Access Billing and Collection Services Agreement]] / [[the Amended and Restated Open Bill Access Billing and Collection Services Agreement]] made and effective as of the <*> day of <*>, 20<*> (the "**OBA**").

B. Pursuant to a Notice of Wind-Down and Consultation Process dated June 2, 2022 issued by the Company (the "**Wind-Down Notice**") to all 'Open Billers' participating in the Open Bill Program, including the Biller, the Company notified all such participants in the Open Bill Program of the Company's intention to wind-down the Open Bill Program for all participants effective December 31, 2023, such that the Company will no longer perform the Billing Services after December 31, 2023.

C. As a result of, and in connection with, consultations among the Company and all 'Open Billers' participating in the Open Bill Program, in order to assist the Biller in effecting the orderly transition and migration of the Billing Services, the Biller wishes, and the Company has agreed, to extend the performance of the Billing Services by the Company to the Biller for the period (the "**Extended Term**") commencing January 1, 2024 and ending October 31, 2024 (the "**Extended Billing Services End Date**"), upon and subject to, and in the manner and to the extent specifically set out in this Agreement.

THEREFORE IN CONSIDERATION of the premises and mutual agreements contained herein and subject to the terms and conditions hereinafter set forth, the Parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Agreement, unless otherwise defined or the context otherwise requires, capitalized words or phrases shall have the meanings attributed to them in the OBA.

1.2 Interpretation

For all purposes of this Agreement, the same rules of interpretation as are set out in the OBA shall apply to this Agreement. Further, except as otherwise specifically provided herein, each of the amendments to the OBA set out in this Agreement shall have prospective effect beginning on the Extension Effective Date and for the duration of the [Term/Renewal Term] and the Extended Term.

1.3 Order of Priority

In the event of any inconsistency between any of the provisions of the OBA (including any Schedules thereto) and this Agreement, the provisions of this Agreement shall prevail.

1.4 Minimum Uptake Condition

In addition to the Company's rights of termination set out elsewhere in the OBA, the Company shall have the right to terminate this Agreement if, on October 11, 2022, the Minimum Billing Fees of the Biller, together with the minimum billing fees of all Other Billers who enter into an extension agreement on the same terms as this Agreement, is less than seven hundred and fifty thousand dollars ($750,000) (the "**Minimum Uptake Threshold**"), and upon written notice from the Company to the Biller to that effect, given at any time within thirty (30) days of October 11, 2022. For certainty, any such termination applies only to this Agreement, and not to the OBA itself, and in such event the terms of the OBA shall continue in full force as if this Agreement had not been executed by the Parties. Further, within thirty (30) days of October 11, 2022 the Company will provide a notice to the Biller as to whether or not the Minimum Uptake Threshold has been met or exceeded.

ARTICLE 2
EXTENSION OF BILLING SERVICES

2.1 Extension of Billing Services

Notwithstanding the issuance of the Wind-Down Notice, in order to assist the Biller in effecting the orderly transition and migration of the Billing Services, the Parties agree that:

(a) the Company will continue to perform the Billing Services for the Biller in accordance with the terms and subject to the conditions set out in the OBA, and as specifically supplemented or amended by this Agreement, to the Extended Billing Services End Date; and

(b) the Biller will continue to fulfill and comply with, and be subject to, the terms and conditions applicable to it set out in the OBA and this Agreement.

2.2 Acknowledgements

2.2.1 Notwithstanding:

(a) the agreements of the Parties in Section 2.1, or

(b) any obligation of the Company in the OBA, including any obligation to (A) "in good faith use commercially reasonable efforts to assist the other Party to provide for the transition of the Billing Services from the Company to a Person designated by the Biller"[1], or (B) "co-operate with the Biller to effect the orderly transition and migration from the Company to the Biller (or a third-party service provider undertaking, on behalf of the Biller, to provide the Billing Services …) of all Billing Services then being performed by the Company"[2], or

(c) any preparedness or lack of preparedness of the Biller to undertake, or to have any third-party service provider undertake, billing services the same as or similar to the Billing Services on or after the Extended Billing Services End Date,

in no event or circumstance shall the Company have any obligation to provide any Billing Services to the Biller after the Extended Billing Services End Date.

2.2.2 For certainty, the Parties acknowledge and agree that:

(a) the Company shall have no obligation to provide any Transition Services from or after the Extended Billing Services End Date, and

(b) for purposes of Section 8.8.2 of the OBA, "the end of the Termination Transition" and "the last date on which any Billing Services are provided to the Biller" is the Extended Billing Services End Date.

2.3 Financial Obligations

2.3.1 Minimum Billing Fees – Notwithstanding Section 4.3(a) of the OBA and regardless of the Biller's actual Service Bill volumes during each month of:

(a) the period from October 1, 2022 until December 31, 2023 (the "**Remainder Period**"); and

(b) the Extended Term,

for each month of the Remainder Period and the Extended Term, the Biller will pay to the Company in respect of its obligation to pay the Billing Fees as provided in Section 4.3(a) of the OBA, an amount equal to the greater of:

(i) seventy percent (70%) of the Billing Fees paid by Biller to Company in respect of May 2022 volumes (the "**Minimum Billing Fees**"); and

(ii) the actual Billing Fees calculated in accordance with Section 4.3(a) of the OBA.

[1] See OBA, section 8.8.1
[2] See OBA, section 8.10.1

2.3.2 Extension Financial Assurances

(a) Pursuant to Section 9.1 of the OBA, and in addition to the Run-Off Financial Assurances required to be posted by the Biller in accordance with Section 8.8.2(c) of the OBA, the Biller shall provide to the Company additional Financial Assurances (the "**Extension Financial Assurances**") consisting of an irrevocable Letter of Credit or cash, in either case in the amount and on or before the date provided for in this Section 2.3.2.

(b) The amount of the Extension Financial Assurances shall be equal to the total amount of Minimum Billing Fees payable during the Extended Term. For certainty, such total amount shall be equal to the Minimum Billing Fees times ten (10) (being the number of months in the Extended Term).

(c) The Biller will provide such Extension Financial Assurances to the Company on the earlier of:

(i) December 1, 2023 (being approximately thirty (30) days prior to the commencement of the Extended Term); and

(ii) five (5) Business Days following notice from the Company to the Biller that the Biller's monthly billings under the Open Bill Program (measured either by volume (i.e. number of Bills) or dollar value (i.e. Actual Billed Amounts)) have decreased by thirty percent (30%) or more from such billings in September 2022; for certainty, regardless of whether such billings increase in a subsequent month.

2.3.3 Method of Payment – Notwithstanding Section 4.7 of the OBA, during the Extended Term, unless the Parties agree otherwise in writing, the Biller hereby authorizes and directs the Company to effect the payment of any and all amounts owing by the Biller to the Company pursuant to the OBA (as amended by this Agreement) as follows:

(a) first, as a set-off against payment to the Biller of the Payment Amount;

(b) second, as a realization on the Extension Financial Assurances, to the extent that such Extension Financial Assurances were provided to the Company as cash; and

(c) finally, as a realization on the Extension Financial Assurances, to the extent that such Extension Financial Assurances were provided to the Company as one or more Letters of Credit.

2.3.4 Termination and Release of Extension Financial Assurances - At or before the end of the Extended Term, the Company will return or release any Extension Financial Assurances that have not been realized in accordance with Section 2.3.3(b) or Section 2.3.3(c), as applicable.

2.3.5 Termination of this Agreement for Failure to Comply with Financial Obligations - In the event the Biller fails at any time to either (a) pay the Minimum Billing Fees due in accordance with Section 2.3.1, or (b) provide the Extension Financial Assurances to the Company as required in Section 2.3.2, the Company shall have the right to terminate this Agreement effective immediately upon written notice to Biller.

2.4 Indemnity for Revenue Shortfall

2.4.1 The Biller hereby indemnifies the Company (the "**Shortfall Indemnity**") for the "Biller's Pro Rata Share" (as defined in Section 2.4.3) of any shortfall (a "**Revenue Shortfall**") between:

(a) subject to Section 2.4.4, any annualized amount that the OEB directs the Company to pay to ratepayers for the ongoing operation of the OBA Program in respect of 2024, prorated for the number of months of the Extended Term; and

(b) the aggregate of the "OBA Program net revenue" amount (as defined in Section 2.4.5) actually received by the Company in respect of 2024 from the Biller and all Other Billers who enter into an extension agreement on the same terms as this Agreement.

2.4.2 The Company will make a proposal to the OEB that, if accepted, would ensure that there will be no shortfall between the OBA Program net revenue amount recovered by the Company in respect of 2024 and amounts credited to ratepayers for the ongoing operation of the OBA Program in respect of 2024. Specifically, the Company will propose to the OEB that:

(a) all net revenues from the OBA Program in respect of 2024 will be credited to ratepayers;

(b) no amount of OBA Program net revenues be "guaranteed";

(c) the $5.389 million annual credit related to the OBA Program that is currently embedded in the Company's rates will be removed from and not included in 2024 rates;

(d) ratepayers would receive a credit equal to the full amount of 2024 OBA Program net revenues; and

(e) the amount of this credit be tracked in a new 2024 deferral account, with the applicable balance to be credited to ratepayers when all of the utility's 2024 Deferral and Variance Accounts are cleared (likely in mid-2025).

Provided that this Agreement has not been terminated in accordance with its terms, when the Company makes an application to the OEB in respect of this proposal, the Biller will either actively support the proposal or not otherwise object to or make any submissions contrary to it.

2.4.3 "Biller's Pro Rata Share" shall be calculated as follows:

(i) the amount of the Revenue Shortfall, times

(ii) the Minimum Billing Fees, divided by

(iii) the aggregate of (A) the Minimum Billing Fees, plus (B) the minimum billing fees of all Other Billers who enter into an extension agreement on the same terms as this Agreement.

2.4.4 Notwithstanding any determination by the OEB, the "annualized amount that the OEB directs the Company to pay to ratepayers for the ongoing operation of the OBA Program in 2024" (as contemplated in Section 2.4.1(a)) shall be the lower of (i) the amount determined by the OEB and (ii) $5.389 million. For certainty, and notwithstanding any other provision in this Agreement, the maximum aggregate amount of any Shortall Indemnity to be shared by the Biller and all Other Billers who enter into an extension agreement on the same terms as this Agreement is their respective pro rata share of $4.491 million.

2.4.5 "OBA Program net revenue" will be calculated in the same manner as previously approved by the OEB and reflected in the Company's Open Bill Revenue Variance Account from 2014 to present. Under this approach, the Open Bill Program net revenues are determined each year by subtracting the deemed Open Bill Program costs from the Open Bill Program revenues received by the Company from Billers. The deemed Open Bill Program costs are equal to the number of bills with Open Bill charges times the OEB-approved unit cost per bill. The OEB-approved unit cost per bill was approved in a 2014 Settlement Proposal (EB-2013-0099), for the period from 2014 to 2018. As of 2018, the OEB-approved unit cost per bill was $0.7195 per shared bill and $1.8186 per standalone bill. Since that time, the OEB-approved unit cost per bill has been increased by CPI each year (capped at 2.5%). This approach was confirmed in the OEB-approved October 23, 2019 Supplementary Partial Settlement Proposal in EB-2018-0319 (at page 6). For certainty, the above 'unit cost per bill' refer to Enbridge's costs for the purpose of determining 'OBA Program net revenue' and not the Billing Fees to Billers.

2.4.6 The Parties acknowledge that:

(a) there is risk that the OEB might not accept the Company's proposal, and might require the Company to continue with the current $5.389 million annual credit to ratepayers (or a different or prorated amount), regardless of the actual net revenues from the OBA Program in 2024;

(b) this could result in the Company paying or crediting ratepayers with amounts in excess of the 2024 OBA Program net revenues actually received by the Company; and

(c) in such event, this Shortfall Indemnity will apply.

2.4.7 Where this Shortfall Indemnity applies, the Biller will make payment to the Company within thirty (30) days of receipt of an invoice from the Company showing the amount and the calculation of the Biller's Pro Rata Share of the Revenue Shortfall.

2.5 <u>Confirmation of Set-Off Rights</u>

2.5.1 The Biller acknowledges and confirms that, as provided in the OBA, any amount otherwise payable by the Biller to the Company pursuant to the OBA (including any Billing Fees, Run-Off Financial Assurances, Extension Financial Assurances, or the Shortfall Indemnity) that is not paid by the Biller within thirty (30) days of the required payment date, or, in the case of the Extension Financial Assurances required pursuant to Section 2.3.2(c)(ii), within the five (5) Business Days contemplated in Section 2.3.2(c)(ii), may be set-off against any Payment Amount otherwise to be paid by the Company to the Biller.

2.5.2 The Biller further acknowledges and confirms that, as provided in the OBA, payments to be made by the Biller to the Company (including in respect of Billing Fees, Run-Off Financial Assurances, Extension Financial Assurance or the Shortfall Indemnity) shall be made in full, without set-off or counterclaim, and free of and without deduction or withholding.

ARTICLE 3
CONFIRMATION

3.1 Confirmation of Terms

In all other respects the OBA is in full force and effect, subject only to the additional terms and amendments referred to in this Agreement.

3.2 Counterparts and Facsimile Execution and Delivery

This Agreement may be executed in counterparts, each of which shall be deemed to be an original and all of which together shall constitute one and the same instrument. To evidence its execution of an original counterpart of this Agreement, a Party may send a copy of its original signature on the execution page hereof to the other Party in pdf by e-mail and such e-mail shall constitute delivery of an executed copy of this Agreement to the receiving Party as of the date of receipt thereof by the receiving Party or such other date as may be specified by the sending Party as part of such transmission.

[end of text]
[the next page is the signing page]

IN WITNESS WHEREOF the Parties have executed this Agreement effective as of the year and date first above written.

ENBRIDGE GAS INC.

By: ____
Name:
Title:

[name of Biller]

By: ____
Name:
Title:

Open Bill Access (OBA) program wind-down

Customer communications plan - high level

Last updated: Oct. 24, 2022

The following communication plan lays out high level tactics to be employed throughout the OBA wind-down transition period. Communication content and timing may adapt throughout the program wind-down implementation, taking into consideration utility activities, customer response and biller needs.

Background:

The Open Bill Program allows companies that offer energy-related products and services to include their charges on customer's Enbridge Gas bill. If a customer agrees to rent or buy a product or service from a participating company, the customer may have the option to have the charges included on natural gas bill. If the customer has selected this option for one or more of those products or services, the charges appear in the "Charges from Other Companies" section of the customer's Enbridge Gas bill along with the participating company's name and phone number.

Participating companies are not owned by or affiliated with Enbridge Gas and do not perform work on our behalf. Enbridge Gas does not recommend, endorse or guarantee the products or services they're offering or the prices they charge.

Key Messages to customers:

- Enbridge Gas will end the billing service for participating companies (your service provider(s)) that appear as "Charges from Other Companies" on your Enbridge Gas bill.
- Your service provider(s) whose charges currently appear on your Enbridge Gas bill will contact you to advise of their new billing method, and the procedures for paying their charges going forward. Your service provider(s) may ask you to provide your payment information directly to them.
- The majority of service providers will exit the billing service any time between now and Dec. 31, 2023. Certain service providers have opted to extend the Enbridge Gas billing service until Oct. 31, 2024. Visit enbridgegas.com/thirdpartycharges for the most current information.
- Your service provider(s) will notify you when their charges will stop on your Enbridge Gas bill and when they will start billing you through their billing method.
- Until your service provider(s) notify you of their new billing method, continue to pay the charges from other companies on your Enbridge Gas bill. Please refer to the "Charges from Other Companies" page of your Enbridge Gas bill to confirm your service provider(s).
- In the meantime, if you have any questions regarding these charges, please contact your respective service provider(s) at the number provided on the "Charges from Other Companies" page of your Enbridge Gas bill.

Third party billers must provide their own communications to customers regarding transition and payment options. The following plan is subject to change. Messages, tactics and timing may vary depending on availability of space and program wind-down requirements.

ENBRIDGE

Channel/Tactic	Key Messages	Status
Milestone: May 2022 Decision to wind-down OBA progam		
Call centre education – Swift communication	As above	Implemented and active
Website update	As above	Implemented and active
Email/Letter for billers to provide to customers	2 versions – messaging as above	Implemented and active
Web friendly url – provide to billers for easy customer access	Enbridgegas.com/ thirdpartycharges	Implemented and active

Channels/Tactics	Key Messages	Timing
Milestone: Oct. 12, 2022 - Consultation compete. Notice of transition plan and communication plan to be shared with billers.		
Call centre education	Confirmation of end date for biller and which billers are choosing the extended date.	Confirmed Oct. 13, 2022
Web page update	Confirmation of end dates and which billers are choosing the later end date. Update list of providers who opted for extension to Oct. 31, 2024.	Confirmed Oct. 17, 2022
Chatbot update	As above with confirmation of exit date for billers.	Planned November 2022 – pending Chatbot relaunch.
Bill Insert	As above	Confirmed February 2023
Ebill messaging	As above	Confirmed February 2023
Web tile on main webpage	Changes to third party billing information. Link to web page for more details.	Confirmed April 2023
Milestone: Ad hoc comms as needed throughout transition		
Call centre education Web page update Chatbot update Bill insert Ebill messaging Web tile on main webpage	Updates based on customer inquiries (faq's may be required) and biller transition.	As required. Tactics would be assessed based on communication required and customer impact.
Milestone: Nov. 1, 2023 - Last date to add new customer or new charges for billers exiting Dec. 31, 2023.		
Milestone: Nov. 15, 2023 – billers exiting Dec. 31, 2023 to have communicated written notice to customers that their charges no longer appear on Enbridge Gas' bill. Dec 31, 2023.		
Channels/Tactics	Key Messages	Timing
Biller communication requirement: By Nov. 15, 2023, billers exiting the third-party billing program on Dec. 31, 2023 must provide written notice to customers that their charges will no longer appear on Enbridge Gas' bill as of Dec. 31, 2023.		

ENBRIDGE

Call centre education	Continue to update messaging reminding customers to call billers if they have not received notification. Most billers exiting Dec. 31, 2023 and their customers will no longer be receiving third party charges from Enbridge Gas as of January 2024. Contact your biller if you have questions about transitioning payments or your service provider's bills.	Planned September 2023
Web page updates	As above.	Planned October 2023
Chatbot updates	As above.	Planned October 2023
Bill Insert	As above.	Planned November 2023
EBill messaging	As above.	Planned November 2023
Web tile on main webpage	Changes to third party billing. See page for more details.	Planned December 2023
Milestone: Sep. 15, 2024 – billers exiting Oct. 31, 2023, to have communicated written notice to customers that their charges no longer appear on Enbridge Gas' bill. Dec 31, 2023 – final billing date for billers exiting the program Dec 31, 2023		
Biller communication requirement: By Sep. 15, 2024, billers exiting the third-party billing program on Oct. 31, 2024, must provide written notice to customers that their charges will no longer appear on Enbridge Gas' bill as of Oct. 31, 2024.		
Call centre education	Continue to update messaging reminding customers to call billers if they have not received notification. Most billers exiting Dec. 31, 2023, and their customers will no longer be receiving third party charges from Enbridge Gas as of January 2024. Contact your biller if you have questions about transitioning payments or your service provider's bills.	Planned July 2024
Web page updates		Planned August 2024
Chatbot updates		Planned August 2024
Bill Insert		Planned September 2024
EBill messaging		Planned September 2024
Web tile on main webpage		Planned October 2024
Milestone – Oct. 31, 2024 – last date for billers who chose extension to have new charges or customers added to bill.		
Call centre education	Remaining customers will no longer be receiving third party charges from Enbridge Gas as of	Planned August 2024

	Oct 2024. Contact your biller if you have questions about transitioning payments or your service provider's bills.	
Web page update	As above	Planned September 2024
Chatbot updates	As above	Planned September 2024
Bill Insert	As above	Planned October 2024
EBill messaging	As above	Planned October 2024
Milestone: Dec. 31, 2024 – financial assurance and run-off financial assurances complete for billers that left the program Dec. 31, 2023		
Call centre education	Messaging if required for customers.	Planned November 2024
Web page update	Program ended/dispute process update.	Planned November 2024
Chatbot updates	Program ended/dispute process update.	Planned November 2024
Milestone: Oct. 31, 2025 – financial assurance and run-off financial assurances complete for billers that left the program Oct. 31, 2024.		
Call centre education	Messaging if required for customers.	Planned September 2025
Web page update	Program ended/dispute process update.	Planned October 2025
Chatbot update	Program ended/dispute process update.	Planned October 2025

CUSTOMER CONNECTION POLICIES

IAN MACPHERSON, DIRECTOR DISTRIBUTION IN-FRANCHISE SALES

1. The purpose of this evidence is to request approval of Enbridge Gas's harmonized customer connection policies effective January 1, 2024. This evidence is also intended to fulfill the OEB's directives related to new business policies from both the Enbridge Gas 2019 Rates Application[1] and the Company's Application for System Expansion Surcharge (SES), Temporary Connection Surcharge (TCS) and Hourly Allocation Factor (HAF).[2] The OEB directed Enbridge Gas to file detailed evidence regarding its customer connection policies. As well as to meet the filing requirements to discuss any changes made since the last cost of service application.

2. Enbridge Gas achieved partial harmonization of its connection policies as a result of the OEB's approvals in the SES, TCS and HAF Application.[3] The balance of connection policies not addressed within that proceeding are addressed by this proposal which have been developed in accordance with the principles and guidelines prescribed in various reports[4] and decisions[5].

3. EGD and Union policies have been and still are subject to the OEB's Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario (E.B.O. 188), which provides for a common analysis and reporting framework. As a result, Enbridge Gas's proposal to harmonize these policies results in minimal change.

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[1] EB-2018-0305, Decision and Order, September 12, 2019.
[2] EB-2020-0094, Decision and Order, November 5, 2020.
[3] Ibid.
[4] E.B.O. 188, The Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, January 30, 1998.
[5] EB-2020-0094, Decision and Order, November 5, 2020.

4. The proposed harmonized policies provided at Attachment 1 have been designed to harmonize Enbridge Gas's customer connection policies into a single policy to reflect the operations and services of the amalgamated utility. This single harmonized policy replaces the OEB-approved connection policies for the EGD and Union rate zones. The key changes of this proposal are as follows:
    a) The proposed harmonized policy elaborates on the principles, method and common parameters required for project feasibility assessment as prescribed in E.B.O. 188.
    b) CIAC allocation and collection policies not previously included in the policy have now been included
    c) In response to intervenor and OEB Staff inquiries during the SES/TCS/HAF[6] proceeding to extend the refund policy to apply to all Enbridge Gas rate zones, the Company agreed to consider this with its rebasing application. On further review, Enbridge Gas has extended the refund policy to all applicable customers to be consistent with the proposal to harmonize the EGD and Union rate zones into one rate zone. Please see Exhibit 8, Tab 2, Schedule 1 for a description of the rate zone proposal.
    d) Some minor adjustments to the polices have been included to better align with the E.B.O. 188 regulation. In addition, the Company proposes to expand the qualifying time period for a customer to request a CIAC refund from 5 to 10 years to match with the attachment horizon as prescribed in E.B.O. 188.

5. The harmonized customer connection policies include a policy for Residential Infill Service Connections. The details for this proposal and the request for approval of it and the associated Extra Length Charge is provided at Exhibit 8, Tab 3, Schedule 1.

[6] EB-2020-0094.

6. Upon approval of these harmonized customer connection policies, Enbridge Gas will post them at Enbridgegas.com.

ENBRIDGE GAS CUSTOMER CONNECTION POLICIES

1. Enbridge Gas's customer connection policies have been designed to facilitate the rational expansion of the natural gas system.[1] Adherence to these policies will ensure that system expansion projects meet all financial compliance requirements and will not result in undue cross subsidization.

2. The policies include the method of feasibility assessment, minimum profitability standard and portfolio approach, feasibility assessment inputs, and the CIAC collection, allocation, and refund policy. The document also summarizes the System Expansion Surcharge (SES), Temporary Connection Surcharge (TCS) and Hourly Allocation Factor (HAF) mechanisms.

1. Terms and Definitions

3. Table 1 is a list of terms found in this document and their definitions.

Table 1
Terms and Definitions

Term	Definition
After Tax Weighted Average Cost of Capital (AtWACC)	The AtWACC is a forecast cost of capital that uses the incremental after-tax cost of capital based on the capital structure, debt and preference share costs, and the latest OEB-approved equity return levels.

[1] These policies have been developed in accordance with the principles and guidelines prescribed in The Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, E.B.O. 188 (January 30, 1998) and the OEB Decision in the Enbridge Application for approval of a System Expansion Surcharge, a Temporary Connection Surcharge, and an Hourly Allocation Factor, EB-2020-0094 (November 5, 2020)

Area of Benefit	The Area of Benefit is determined by hydraulically modelling the pipeline network in the region around the proposed Development Project to determine the geographic extent of the area that will benefit from the incremental capacity of the project.
Commercial Customer	A customer operating a commercial business and uses natural gas to meet its energy needs (e.g., shops, restaurants, offices, and apartment buildings).
Contribution in Aid of Construction (CIAC)	The Company's calculation in accordance with its feasibility policy of the amount of customer financial contributions required to reduce the capital cost of a project to serve one or more customers so that the project becomes economically feasible.
Development Project (DP)	A project that is designed to provide incremental firm capacity to serve multiple large and small volume customers forecasted within an identified Area of Benefit.
Extra Length Charge (ELC)	Enbridge Gas provides 20 metres service at no cost to a residential customer (infill). Customers pay an ELC for each additional metre beyond 20 metres.
Hourly Allocation Factor (HAF)	A method of allocating capital cost of a DP designed to provide incremental firm capacity to serve multiple large volume customers (LVC) forecasted in an Area of Benefit. The allocation is done based on peak hourly demand of LVCs who receive the incremental capacity.
Investment Portfolio	The costs and revenues associated with all new distribution customers who are forecast to attach in a particular test year (including new customers attaching to existing mains). The Investment Portfolio includes a forecast of Normalized System Reinforcement Costs (NSRC).
Large Volume Customer (LVC)	Defined as a customer with an estimated gas consumption equal to or greater than 50,000 m^3 per year.

Normalized System Reinforcement Costs (NSRC)	This represents a method of socializing reinforcement cost to new customers included in the Utility's portfolio. The historical average for special and normal reinforcement costs are used as the normalized amount to be included in the portfolio analysis as a percentage of the total capital expenditure in the year.
Profitability Index (PI)	A ratio of the net present value (NPV) of the net cash inflows to the NPV of the net cash outflows for a system expansion project undertaken by the Company.
Residential Customer	A customer who uses natural gas to satisfy the energy needs of a residential dwelling.
Revenue Horizon	The length of time Enbridge Gas considers a customer type will provide revenue for the purposes of the feasibility calculation.
Rolling Project Portfolio (RPP)	An accumulation of the new business capital requisitions that are issued and approved within a 12-month period. This includes all future customer attachments, revenues, and costs based on the life cycle of each project. It also includes a forecast of NSRC and excludes service laterals from existing mains (infill customers).
Small Volume Customer (SVC)	Defined as a customer with an estimated gas consumption of less than 50,000 m^3 per year.
System Expansion Surcharge (SES)	Applicable to projects with >=50 customers. An economic contribution to financial feasibility of a customer attachment project through a temporary volumetric rate as set out in applicable rate schedules. The SES is used as an alternative to CIAC to achieve a PI of 1.0.
Temporary Connection Surcharge (TCS)	Applicable to projects with <50 customers. An economic contribution to financial feasibility of a customer attachment project through a temporary volumetric rate as set out in applicable rate schedules. The TCS is used as an alternative to CIAC to achieve a PI of 1.0.

2. Method of Project Feasibility Assessment

4. Economic feasibility of system expansion projects is conducted under the OEB's guidelines prescribed in E.B.O. 188. The following evidence describes the method

and the common elements used for evaluating all new connection projects except for residential infills.

5. A feasibility analysis determines whether a system expansion project meets financial requirements and ensures there is no undue cross subsidization caused by attaching new customers. This is accomplished by evaluating forecast project revenues and costs using a Discounted Cash Flow (DCF) analysis, as described in E.B.O. 188. Enbridge Gas uses an After Tax Weighted Average Cost of Capital (AtWACC) for discounting revenues and costs for DCF analysis.

6. The output of the DCF analysis is the Profitability Index (PI), which measures the value of a project's revenues against the project's costs. A PI of 1.0 or greater indicates a project's revenues over its life cycle will be equal to or greater than the costs, on a present value basis and validates that a project is economically feasible.

7. When a project PI is greater than or equal to 1.0, Enbridge Gas will build the project at no additional cost to the customer(s). If the PI is less than 1.0, a customer is required to cover the shortfall by one of the current OEB-approved methods, set out below:
    a) Pay an upfront CIAC to lower the capital cost of the project necessary to make the project feasible. The CIAC amount is calculated to be sufficient to bring the project PI up to the required threshold (i.e., PI equal to 1.0).
    b) Pay a volumetric surcharge at a rate of $0.23 / m^3$ for a pre-defined term. Currently there are two surcharge mechanisms available to Enbridge Gas, the SES and TCS, as approved by the OEB.[2] The surcharge term, either

[2] EB-2020-0094, OEB Decision and Order, November 5, 2020, page 5.

SES or TCS, is determined based on the number of years required to achieve a PI of 1.0, up to a maximum of 40 years.

c) Pay a premium to posted rates sufficient to bring the project PI up to the required threshold, may be negotiated with a customer.

3. A Minimum PI Threshold & Portfolio Approach

8. Enbridge Gas uses a portfolio approach to manage its system expansion activities to ensure the required profitability standards are achieved at both the individual project level and the portfolio level. The Investment Portfolio and Rolling Project Portfolio (RPP) are two OEB-prescribed portfolio approaches Enbridge Gas uses.

9. Investment Portfolio: The Company evaluates the costs and revenues associated with all new customers forecast to attach in a particular test year including new customers attaching to existing mains (infills). The Investment Portfolio includes an allowance for NSRC and is planned to achieve a PI of 1.0 or greater.

10. Rolling Project Portfolio: the RPP provides an ongoing method of determining the financial feasibility of system expansion projects over a rolling 12-month basis. The RPP includes all future customer attachments, revenues, and costs based on the life cycle of each project, however it excludes the costs and revenues associated with new customers attaching to existing mains built prior to the last 12-month period. The Company maintains a PI of greater than or equal to 1.0 for its RPP.

11. The minimum PI threshold for projects to be included in the RPP is 1.0 absent exceptional circumstances. The responsible Director may authorize exceptions, subject to a PI no lower than 0.8, as stipulated in E.B.O. 188.

4. Feasibility Assessment Inputs

12. The following are the key inputs for feasibility assessment of new distribution projects except for residential infills.

4.1. Project Revenue

13. The key inputs for estimating project revenues include a forecast of new customers, and their estimated annual gas consumption and/or demands over the project revenue horizon. Using these forecasts and OEB-approved natural gas distribution rates, Enbridge Gas estimates project revenues for use in the feasibility assessment of the project.

4.2. Consumption Estimates

14. Customer consumption estimates depend on various factors such as the type of customer, construction type, square footage, and number and type of appliances. For most residential customers, gas usage is estimated based on historical averages by customer type (e.g., single, semi-detached, townhouse, bungalow). Load estimation for non-residential customers is made using historical knowledge, and/or estimates provided by customers or HVAC contractors. For large volume commercial or industrial customers detailed equipment lists with connected load and hours of operation are used to estimate maximum hourly demand, contract demand and annual consumption.

4.3. Capital Cost Estimates

15. The project capital cost reflects all direct and indirect costs for attaching forecast customers. Direct cost includes costs of distribution mains, services, customer stations, new distribution stations, land and land rights. Indirect costs include an allowance for incremental overheads and NSRC.

16. When a main is upsized in anticipation of future growth potential, the cost of the minimum project design required to meet the customer’s load requirements is used for feasibility assessment.

17. Enbridge Gas uses various approaches for estimating capital costs for different types of projects. The objective is to derive estimates, which are closely aligned to costs reflective of the unique parameters of each project. Estimation techniques are dependent on project type and complexity and may include field visits and use of cost estimating systems that incorporate the cost estimating mechanisms of contract unit rates, bundled service pricing, contractor cost estimates and target pricing.

4.4. Normalized System Reinforcement Cost Estimates

18. Enbridge Gas includes an allowance for NSRC in the feasibility assessment of individual projects and the system expansion portfolio.

19. NSRC is determined using the procedure described in E.B.O. 188 Section 2.3.7 and is applied to individual project feasibilities, the Investment Portfolio and the RPP.

4.5. Common Elements for Feasibility Testing

20. The maximum customer attachment forecast horizon for a project is 10 years per E.B.O. 188.

21. The maximum customer revenue horizon is 40 years from the in-service date of the initial mains for residential and small commercial customers. For large volume customers (LVC) including contract customers the maximum revenue horizon is 20

years from the customer's initial service. A project specific revenue horizon is used when the project life cycle is determined to be shorter than the prescribed time horizons.

22. Incremental O&M expenses associated with new customer additions are included in the feasibility assessment.

23. The feasibility assessment uses a discount rate equal to the incremental after-tax cost of capital based on the prospective capital mix, debt, and preference share cost rates, and the latest OEB-approved rate of return on common equity.

24. Discounting reflects the time value of money and translates the future costs and benefits to a value at the beginning of the project. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted, as will revenue, gas related costs, and operating and maintenance expenditures.

5.1. Timing

25. The timing and method of CIAC collection for different market sectors is as follows:
    a) For general service residential and commercial projects, CIAC is collected from the customer prior to the start of construction.
    b) The ELC for residential infill customers on main is calculated based on the actual service length after the service is installed and will be collected through the customer's first gas bill.
    c) CIAC for large volume contract customers are collected prior to the start of construction except for rare situations where installment payments may be authorized. Customer requests for payment of CIAC in installments may be

authorized by the responsible Director and are subject to a credit review. All installments must be paid between the start of construction and the in-service date of the project.

5.2. Allocation

26. The following guidelines will be used in allocating CIAC between customers served by a new project.
    a) When a CIAC is required for a project that serves more than one general service residential and small commercial customers, the CIAC is allocated between the customers based on the annual consumption forecast.
    b) When the project serves more than one LVC, the CIAC will be allocated between the customers based on their forecast peak hourly demand.
    c) If the project serves a mix of general service and one or more LVCs, the CIAC will be allocated between customers based on forecast peak hourly demand.

Refund Policy

27. Refunds of CIAC may be requested by customers when the actual customer count on a system expansion project exceeds the original forecast.

28. General service customers: For general service customers, refund requests are evaluated upon customer request and will be accepted at any time within 10 years of the in-service date of the project. The system expansion project is then re-evaluated with the actual customer count and the timing of service connections to determine a revised contribution that is required to bring the PI to the original targeted level. If the revised CIAC amount is lower than the actual CIAC paid by customers, the difference will be refunded to those customers who paid it. Refunds

are made based on the proportionate contribution of customers who paid the CIAC. This policy applies to main extension projects involving conversion customers.

29. Large volume customers: Refunds for LVCs will be determined based on re-evaluation of the system expansion project, considering the timing and load associated with customers not forecasted in the original project. Refund requests are applicable only to the original project scope, the specific piece of main constructed to serve the initial customer(s) and does not consider subsequent main extensions coming off the original project main. Refund requests are evaluated upon customer request and will be accepted at any time up to 10 years from the in-service date of the project.

30. No interest is payable on refunds, and only those customers who made the original contribution are eligible for a refund.

31. In order to be eligible for a refund, the customer must be consuming natural gas at the address for which refund is being claimed.

32. The Refund Policy does not apply to:
    a) New construction builder developments
    b) Customers on a system expansion projects where either the SES or TCS rate riders have been applied in lieu of a CIAC.
    c) Customers in a Development Project where an Hourly Allocation Factor (HAF) has been used for allocating project costs amongst the prospective customers.

Residential Infill Service Connections

33. Enbridge Gas uses the extra length rule for new residential customers (infills) connecting to existing mains. The rule allows Enbridge Gas to attach residential infill customers at no cost to a maximum of 20 meters. Beyond 20 metres, customer pays an Extra Length Charge (ELC) per metre at a rate prescribed in Rider G of the Enbridge Rate Handbook.

34. The length of the service for applying this rule will be measured from the customer's property line to the location where the gas meter is installed.

SES, TCS and HAF Mechanisms

35. Enbridge Gas uses a SES, a TCS and a HAF which were OEB-approved in EB-2020-0094.[3]

36. Use of the SES and TCS surcharge provides a predictable rate and a consistent approach for customers to provide contribution to expansion projects to make them feasible. Use of the HAF results in allocation of the capital costs of a project to customers in a fair and equitable manner as costs are allocated over time to eligible customers seeking access to the incremental capacity generated by the project.

37. The following are key elements of the SES, TCS and HAF mechanisms.

SES and TCS

38. The SES and the TCS is a volumetric surcharge at the rate of $0.23/m^3 that applies to customers on a system expansion project with a PI of less than 1.0. The SES

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[3] EB-2020-0094, Application for approval of a System Expansion Surcharge, a Temporary Connection Surcharge, and an Hourly Allocation Factor, Decision and Order, November 5, 2020.

and TCS apply to both existing homes and businesses converting to natural gas as well as customers attaching to a new construction project.

39. The SES and TCS terms are determined in accordance with Enbridge Gas's feasibility policies, which follow the OEB's E.B.O. 188 Guidelines. The term will be based on the number of years it takes for the project to achieve a PI of 1.0 to a maximum of 40 years.

40. Projects that do not achieve a PI of 1.0 after factoring in the maximum term of 40 years of the SES or TCS, can not use CIAC in conjunction with the SES or TCS to bridge any economic shortfall.

41. Small volume customers (SVC) on a project that is denoted as SES or TCS, do not have the option of paying a CIAC in lieu of the SES or the TCS.

42. LVCs have the option of paying an upfront CIAC in lieu of the SES or the TCS or a combination of both. In addition to the SES or TCS, LVC's may enter a multi-year large volume distribution contract (if eligible) as a means of supporting the economics of the projects.

43. The SES and TCS is applied to the property such that if a new owner takes possession, they will assume payment of the SES or TCS for the balance of the applicable term.

HAF

44. The HAF is a method of allocating the upfront capital cost of a Development Project designed to provide incremental firm capacity to serve multiple LVC's forecasted

over a certain Area of Benefit. The capital cost of the Development Project is allocated based on the peak hourly demand of the LVCs who receive the incremental capacity.

45. The HAF is applied as a capital cost in addition to the direct capital cost of customer specific facilities (e.g., dedicated distribution main, service line, customer station, meter, etc.) to the individual economic analysis of customers receiving incremental capacity as they commit or contract for a firm gas service.

46. Once the total incremental capacity is fully allocated, the HAF will cease to be applied to the economic feasibility of new customers requesting a service in the Area of Benefit.

47. The threshold for applicability of the HAF is 50 m^3/hour or greater. This threshold will be set at the beginning of a project, and will remain fixed, until the project is fully allocated.

48. The HAF may be used for projects that are primarily distribution and also have a minor component of transmission.

49. SVCs on a project do not receive a capital cost allocation through the HAF process for their collective or individual feasibility analysis.