Bonnie Jean Adams
Regulatory Coordinator
Regulatory Affairs

tel 416-495-5499
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

VIA RESS

June 4, 2025

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

Dear R. Murray:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2025-0065 - 5-Year Gas Supply Plan
Affidavit of Service

On May 26, 2025, the OEB issued the Letter of Direction for the above referenced proceeding.

As directed by the OEB, enclosed please find the Affidavit of Service.

Please contact the undersigned if you have any questions.

Sincerely,

Bonnie Jean Adams

Bonnie Jean Adams
Regulatory Coordinator

EB-2025-0065

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B, as amended;

AND IN THE MATTER OF the review of Enbridge Gas Inc.'s the 5-Year Gas Supply Plan.

<u>AFFIDAVIT OF SERVICE</u>

I, Bonnie Jean Adams of the City of Vaughan, make oath and say as follows:

1. I am in the employ of Enbridge Gas Inc. (Enbridge Gas) and as such have knowledge of the matters hereinafter deposed to.

2. Pursuant to the May 26, 2025, Letter of Direction from the Ontario Energy Board (OEB), I caused to be served by email the Notice of Hearing in (Exhibit A), and the 5-Year Gas Supply Plan (Exhibit B) upon the parties listed in the Letter of Direction.

3. Attached hereto is proof in the form of an email (Exhibit C) that the relevant Notice of Hearing, and 5-Year Gas Supply Plan was served on all parties on the following parties:
    a) all intervenors in past proceedings EB-2024-0067, EB-2022-0200, EB-2019-0137 and EB-2017-0129
    b) All Rate-Regulated Natural Gas Utilities
    c) All Licensed Gas Marketers
    d) City of Kingston
    e) All interested parties

4. In accordance with the Letter of Direction, I caused a copy of the Notice of Hearing and the 5-Year Gas Supply Plan to be placed in a prominent place on the Enbridge Gas website. Attached as Exhibit D is proof of the information posted to the website.

5. As directed in the Letter of Direction, I arranged for the message to be posted with the link to the Notice of Hearing on Enbridge Gas's social media accounts: X (formerly Twitter), LinkedIn, and Facebook (Exhibit E).

SWORN before me in the City of Toronto, this 4th day of June, 2025.

Lesley M Austin

Digitally signed by Lesley M Austin
Date: 2025.06.04 10:03:38 -04'00'

A Commissioner for taking Affidavits

Bonnie Jean Adams

Bonnie Jean Adams
Regulatory Coordinator

Exhibit A

NOTICE OF A HEARING

Lesley M Austin Digitally signed by Lesley M Austin Date: 2025.06.04 10:04:04 -04'00'

A hearing on Enbridge Gas Inc.'s five-year gas supply plan

The Ontario Energy Board (OEB) is holding a hearing to review Enbridge Gas Inc.'s five-year gas supply plan. The gas supply plan describes how Enbridge Gas Inc. plans to procure natural gas during the November 1, 2025 to October 31, 2030 period.

YOU SHOULD KNOW

There are three types of OEB hearings: oral, electronic and written. If you have a preference for the hearing type, you can write to us to explain why. Participants that have registered as intervenors will have an opportunity to ask questions about the application and to make arguments.

HAVE YOUR SAY

You have the right to information about this application and to participate in the process. Visit www.oeb.ca/notice and use file number **EB-2025-0065** to:

- Review the application
- File a letter with your comments
- Apply to become an intervenor

IMPORTANT DATES

You must engage with the OEB on or before **June 5, 2025** to:

- Provide input on the hearing type (oral, electronic or written)
- Apply to be an intervenor

If you do not, the hearing will move forward without you, and you will not receive any further notice of the proceeding.

PRIVACY

If you write a letter of comment, your name and the content of your letter will be put on the public record and the OEB website. If you are a business or if you apply to become an intervenor, all the information you file will be on the OEB website.

This hearing will be held under section 36 of the ***Ontario Energy Board Act, 1998***.

Ce document est aussi disponible en français.

Ontario Energy Board

LEARN MORE

Ontario Energy Board

1 877-632-2727 TTY: 1-877-632-2727

Monday - Friday 8:30 AM - 5:00 PM

oeb.ca/notice

Enbridge Gas Inc.

1-877-362-7434

Monday - Friday 8:00 AM - 6:00 PM

https://www.enbridgegas.com/

This hearing will be held under section 36 of the ***Ontario Energy Board Act, 1998***.

Ce document est aussi disponible en français.

Ontario Energy Board

Lesley M Austin Digitally signed by Lesley M Austin Date: 2025.06.04 10:04:29 -04'00'

Exhibit B

Richard Wathy
Technical Manager
Regulatory Applications
Regulatory Affairs

Cell: 519-365-5376
Email: Richard.wathy@enbridge.com
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
P.O. Box 2001
50 Keil Drive N.
Chatham, Ontario, N7M 5M1
Canada

VIA RESS and EMAIL

May 1, 2025

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

Dear Nancy Marconi:

Re: EB-2025-0065 – Enbridge Gas Inc. (Enbridge Gas)
5-Year Gas Supply Plan

The Framework for the Assessment of Distributor Gas Supply Plans (EB-2017-0129) (Framework) included a submission schedule which outlined the second 5-Year Gas Supply Plan for the following implementation year be filed on January 1, 2024.

Given the expected timing of the OEB decision in the 2024 Rebasing application (EB-2022-0200), Enbridge Gas requested and was granted a one-year extension to the deadline to file its next 5-Year Gas Supply Plan.

On January 15, 2025, the OEB issued the OEB Staff Report to the OEB: Review of 2024 Annual Update to Enbridge Gas Inc. Natural Gas Supply Plan. The report recommended that the next 5-Year Gas Supply Plan should be subject to an adjudicative process by a panel of OEB Commissioners, with an expected filing date of March 1, 2025. An extension to May 1, 2025 was subsequently approved.

Attached is Enbridge Gas's 5-Year Gas Supply Plan covering the November 1, 2025 to October 31, 2030 period. For continuity purposes, Enbridge Gas has also provided annual update information for November 1, 2024 to October 31, 2025. The evidence includes all items specified in the Filing Requirements for a Gas Supply Plan, as outlined in the Framework.

To facilitate the OEB's planned adjudicative process for reviewing the 5-Year Gas Supply Plan, Enbridge Gas has prepared a Draft Issues List for this proceeding, which is included following this letter.

Should you have any questions on this matter please contact the undersigned.

Sincerely,

Richard Wathy

Richard Wathy
Technical Manager, Regulatory Applications

cc: David Stevens, Aird & Berlis LLP
All Interested Parties, EB-2024-0067, EB-2019-0137, EB-2017-0129

DRAFT ISSUES LIST

Enbridge Gas's 5-Year Gas Supply Plan

1) Does the 5-year gas supply plan appropriately reflect and balance the three OEB gas supply guiding principles in a way that is prudent and delivers value to customers?

2) Does the 5-year gas supply plan appropriately address the gas supply plan criteria set out in the OEB's Framework for the Assessment of Gas Distributor Gas Supply Plans (Framework):
    a. Demand forecast analysis
    b. Supply option analysis
    c. Risk mitigation analysis
    d. Achieving public policy objectives
    e. Procurement process and policy analysis
    f. Performance measurement

3) Does the 5-year gas supply plan provide appropriate gas supply plan outlook information?

4) Is Enbridge Gas's planned approach to execution of the 5-year gas supply plan appropriate, including implementing changes resulting from Phases 2 and 3 of the 2024 Rebasing Proceeding in future Annual Updates?

5) Has Enbridge Gas responded appropriately to previous commitments and direction from OEB staff reports and OEB decisions related to the 5-year gas supply plan?

Enbridge Gas's 2025 Annual Update

6) Has Enbridge Gas filed appropriate evidence and explanation to support its 2025 Annual Update to the previous 5-year gas supply plan?

OEB Gas Supply Framework

7) Is there a requirement for the OEB to review and potentially amend the Framework based on the findings in this proceeding?

EB-2025-0065

Enbridge Gas
5-Year Gas Supply Plan

November 1, 2025 to October 31, 2030

May 1, 2025

Table of Contents

1. Executive Summary

This document is Enbridge Gas Inc.'s (Enbridge Gas, EGI, or the Company) second five-year gas supply plan submission to the Ontario Energy Board (OEB) since the establishment of the Framework for the Assessment of Distributor Gas Supply Plans (the Framework).[1] It includes a comprehensive five-year gas supply plan (5-Year GSP) for each gas year of the period 2025/26 to 2029/30 (November 1, 2025, to October 31, 2030), and an annual gas supply plan update (Annual Update) for the 2024/25 gas year. Both the 5-Year GSP and Annual Update are based on the multi-year gas supply plan (Plan) the Company prepares annually for the EGD rate zone and Union rate zones through its gas supply planning process.

The 5-Year GSP has been prepared reflecting the gas supply plan impacts from Phase 1 of the 2024 Rebasing Decision[2] and the recommendations from the OEB Staff Report to the OEB: Review of 2024 Annual Update (OEB Staff Report).[3]

Enbridge Gas's 5-Year GSP adheres to the OEB's Guiding Principles for gas supply plans of cost-effectiveness, reliability and security of supply, and public policy. The 5-Year GSP achieves the OEB's Guiding Principles by maintaining a gas supply portfolio that includes a diversity of gas supply purchase points, gas supply producers and marketers, contract terms, and transportation service providers.

The development of the comprehensive 5-Year GSP begins with the determination of annual and design day demand forecasts (as described in Section 4) that reflect external factors such as industrialization, energy transition, and weather fluctuations. Following the completion of the demand forecasts, Enbridge Gas identifies any Plan shortfalls based on its current portfolio of transportation and storage assets by delivery area. Enbridge Gas next evaluates and adjusts its transportation, storage, and commodity portfolio to ensure sufficient natural gas is available in each delivery area to meet the annual and design day demand forecasts. A description of the current portfolio of assets and available options is provided in Section 5.

Enbridge Gas ensures the Plan complies with the OEB's Guiding Principles and other external public policy (as described in Section 6), and continuously monitors risks that may impact the Plan (as described in Section 7) throughout its execution (as described in Section 8). The Plan's inter-dependence with other regulatory applications (as described in Section 9) is continuously monitored, a three-year historical review of the Plan's actual performance is conducted (as described in Section 10), and the Plan's

[1] EB-2017-0129 Report of the Ontario Energy Board, Framework for the Assessment of Distributor Gas Supply Plans, October 25, 2018.
[2] EB-2022-0200, Decision and Order, Enbridge Gas Inc. Application for 2024 Rates – Phase 1.
[3] EB-2024-0067, OEB Staff Report to the Ontario Energy Board, Review of 2024 Annual Update to Enbridge Gas Inc Natural Gas Supply Plan, January 15, 2025.

historic effectiveness is evaluated using a set of performance metrics (as described in Section 11).

The 5-Year GSP was prepared based on the approach that has been endorsed by the OEB over the first five-year gas supply plan term, updated for various directives received since the Framework was established. The evidence that follows demonstrates that Enbridge Gas's Plan meets the OEB's expectations and meets customer demand in a balanced way while maintaining flexibility to adapt to a dynamic operating environment.

2. Administrative Information

2.1. Introduction

Enbridge Gas is an integrated natural gas distribution, transmission and storage company that serves over 3.9 million residential, commercial, and industrial customers across more than 300 municipalities and more than 20 First Nations throughout Ontario.

In 2018, the OEB issued a Report of the Ontario Energy Board establishing the Framework that requires regulated natural gas distributors submit a comprehensive five-year gas supply plan every five years. In addition, distributors are to submit an annual update in the interim years that provides a retrospective view of the five-year gas supply plan's performance and explanation of changes to supply and demand conditions since the last five-year gas supply plan. This is Enbridge Gas's second five-year gas supply plan since the OEB established the Framework.

This document includes a 2025 Annual Update (2025 AU) for the 2024/25 gas year covering the period from November 1, 2024, to October 31, 2025, and a 5-Year GSP covering the period from November 1, 2025, to October 31, 2030, reported on an annual basis.

Enbridge Gas develops a multi-year gas supply plan through its annual gas supply planning process and uses it as the basis for the 5-Year GSP and Annual Update submissions. The gas supply planning process, as described in Section 2.3, begins annually each April with a Plan prepared for execution prior to November 1, the start of the gas year. The objective of Enbridge Gas's gas supply planning process is to identify an efficient manner to serve Enbridge Gas's customers, using a combination of supply purchases, transportation, and storage assets. The goal of Enbridge Gas's gas supply planning process is to meet customers' gas supply requirements while adhering to the Company's gas supply planning principles and practices, which are as follows:

- **Cost-effectiveness** – If the supply/service option is intended to satisfy average day needs, Enbridge Gas will evaluate it based on landed costs (i.e. $/GJ/d). If the option is intended to meet design day needs, annual costs (i.e. $/GJ/yr) are calculated.
- **Reliability and security of supply** – Characteristics of supply/service option reliability and security evaluated by Enbridge Gas include, but are not limited to: liquidity, nomination performance, delivery performance, transportation distance, service quality, system connectivity, and the magnitude of existing third-party services (e.g., peaking and delivered services) in the Company's portfolio. Related, characteristics of supply/service option flexibility evaluated by Enbridge Gas include, but are not limited to: contracting lead time, contract term, availability of third-party services, number of nomination windows accessible, and renewal rights. Related characteristics of supply/service option diversity evaluated by Enbridge Gas include but are not limited to access to transportation paths, and access to gas supplies.

See Section 5 and for additional discussion regarding the Company's gas supply planning principles and practices, gas supply, transportation, and storage portfolio, and related procurement strategies.

The Company's gas supply planning principles are aligned with the OEB's Guiding Principles for the assessment of gas supply plans. The OEB's Guiding Principles, as set out in the Framework, are:[4]

- **Cost-effectiveness** – The gas supply plans will be cost-effective. Cost-effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner.
- **Reliability and security of supply** – The gas supply plans will ensure the reliable and secure supply of gas. Reliability and security of supply is achieved by ensuring gas supply to various receipt points to meet planned peak day and seasonal gas delivery requirements.
- **Public policy** – The gas supply plans will be developed to ensure that it supports and is aligned with public policy where appropriate.

As the 5-Year GSP clearly demonstrates, Enbridge Gas's gas supply planning practices are consistent with the OEB's Guiding Principles as the Company routinely evaluates supply/service options relative to the OEB's Guiding Principles and maintains a gas supply portfolio that includes a diversity of: gas supply purchase points, gas supply producers and marketers, contract terms, and transportation service providers.

[4] EB-2017-0129 Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans, October 25, 2018, Section 3.1, pp. 7-8.

Similarly, Enbridge Gas owns and contracts for storage capacity to further improve the diversity of its gas supply portfolio. This approach allows Enbridge Gas to effectively manage costs while maintaining the flexibility needed to adapt to dynamic market conditions and weather fluctuations. This balanced approach ensures Enbridge Gas's customers have access to secure and reliable natural gas at a prudently incurred cost.

2024 Rebasing

Enbridge Gas filed its 2024 Rebasing application on October 31, 2022.[5] The application was subsequently split into three phases by the OEB. The Plan filed in the Rebasing application was prepared on a consolidated basis using harmonized methodologies and inputs. The consolidated Plan uses all storage and transportation assets to meet demand requirements in each of the Enbridge Gas delivery areas served (9 in total) on the lowest-cost basis without regard to rate zones. Certain elements of each phase impact the Plan as described below.

Phase 1

Phase 1 gas supply plan impacts include updated methodologies for the determination of the annual and design day demand forecast and an update to the 2024 Test Year gas costs.[6] As part of the Phase 1 Settlement Proposal, parties agreed to the as-filed 2024 gas supply costs, subject to the determination of the load balancing costs including storage, which was deferred until Phase 2 of the proceeding.[7] Based on the approved Phase 1 Settlement Proposal, Enbridge Gas has updated its 2025 demand forecasts using the methodologies underpinning the 2024 OEB-approved volumes forecast.[8]

Phase 2

Enbridge Gas filed Phase 2 of the 2024 Rebasing application on April 26, 2024.[9]

The Phase 2 Partial Settlement Proposal was approved by the OEB on November 29, 2024. Approved Phase 2 impacts include:[10]

---

[5] EB-2022-0200.

[6] As part of the Phase 1 Partial Settlement Proposal, parties agreed to as-filed 2024 gas supply costs excluding load balancing costs to be determined in Phase 2. EB-2022-0200, Exhibit O1, Tab 1, Schedule 1, p. 11.

[7] Enbridge Gas received OEB approval of a Partial Settlement Proposal on August 17, 2023. The OEB released its Decision and Order on the remaining Phase 1 issues on December 21, 2023, which did not impact the Plan directly.

[8] The methodologies utilized are those set out in the Company's pre-filed evidence for EB-2022-0200 without the adjustment for customer additions agreed to in the Settlement Proposal for that proceeding.

[9] EB-2024-0111.

[10] EB-2024-0111, Exhibit N, Tab 1, Schedule 1, pp. 9-10.

- Cost-based storage for in-franchise customers maintained at 199.7 PJ.[11]
- Total storage requirement included in rates based on the aggregate excess methodology of 217.7 PJ,[12] including 18 PJ of market-based storage.
- Maximum firm storage withdrawal and injection capabilities for in-franchise customers fixed at 4.0 PJ/day and 1.7 PJ/day, respectively.[13]
- 15.6 PJ of storage for operational contingency managed using inventory targets.

A final decision from the OEB on the Phase 2 issue of the procurement of lower-carbon energy as part of the gas supply commodity portfolio, including the Lower-Carbon Voluntary Program, remains outstanding as of the time of this filing.

Enbridge Gas intends to address gas supply impacts from Phase 2 within the next iteration of the Plan that is being prepared over the course of 2025 and which will be reflected within the 2026 Annual Update which is expected to be filed with the OEB by March 1, 2026. Phase 2 impacts will see Enbridge Gas reduce the amount of contracted market-based storage by 8 PJ, to 18 PJ from the current level of 26 PJ. The reduction in market-based storage in the Plan will result in an increase in planned winter purchases and a reduction in planned summer purchases. Enbridge Gas will also implement the maximum firm storage withdrawal and injection capabilities of 4.0 PJ/d and 1.7 PJ/d, respectively, within the Plan which will serve as a cap on utility withdrawals from and injections into storage. The implementation of a maximum withdrawal capability will result in increased planned Dawn purchases on design day. The transition to managing operational contingency in the Plan using inventory targets as part of the harmonized storage portfolio of 217.7 PJ does not add to the total storage requirement beyond the amount determined by the aggregate excess methodology for bundled customers and contracted storage space by semi-unbundled customers.

Phase 3

Enbridge Gas filed Phase 3 of the 2024 Rebasing application on February 28, 2025.[14] Phase 3 issues that could have a Plan impact include the proposal for harmonization of distribution and gas supply services and the proposal for rate classes and rate design based on one rate zone.

Service harmonization proposals could impact certain demand and/or supply forecasts used as inputs into the Plan. The impact of service harmonization, however, is not

[11] Includes Crowland Storage.
[12] The 2024 storage requirement reflects the aggregate excess methodology for bundled customers and contracted storage space by semi-unbundled customers.
[13] Does not include Crowland Storage.
[14] EB-2025-0064.

expected to have a material impact on asset utilization in the Plan or result in incremental Plan contracting.

The proposal for one rate zone will not impact the gas supply planning process but could impact the allocation of gas supply costs to customers. Changes to the rate zone structure could also impact the format of the Plan presentation in future OEB filings. The 5-Year GSP (and the previous five-year gas supply plan and subsequent Annual Updates) reflects certain information presented based on Enbridge Gas's current rate zones.

Enbridge Gas intends to update the Plan for impacts related to the outcome of Phase 3 through the first available gas supply planning process following an OEB decision on Phase 3 of the Rebasing application.

2.2. Significant Changes and Continuous Improvement

Appendix F provides a complete list of directives received and commitments made in prior proceedings related to the current 5-Year GSP along with evidentiary references indicating where they are addressed within the current evidence.

On January 15, 2025, the OEB issued the OEB Staff Report.[15] The OEB Staff Report found no issues with the 2024 Annual Update that would require further review in a hearing. However, the OEB Staff Report recommended that the next 5-Year GSP be reviewed in an adjudicative proceeding and that subsequent annual updates continue to be held as consultations.

Enbridge Gas has implemented the following changes to the Plan and 5-Year GSP since the 2024 Annual Update proceeding:

1. Implementation of the demand forecast methodologies from the 2024 Rebasing Phase 1 Decision,[16] as outlined in Section 4.
2. Implementation of OEB Staff Report recommendations from the 2024 Annual Update and OEB directives from the 2021 Vector Contracting Decision,[17] as summarized in Appendix F.
3. Various formatting adjustments, including relocation of the Market Outlook and the Description of Gas Supply and Asset Options to Appendix A and Appendix B, respectively.

---

[15] EB-2024-0067, OEB Staff Report to the Ontario Energy Board, Review of 2024 Annual Update to Enbridge Gas Inc Natural Gas Supply Plan, January 15, 2025.
[16] EB-2022-0200, OEB Decision on Phase 1 Settlement Proposal, August 17, 2023, p. 27 (annual demand) and p. 35 (design day demand).
[17] EB-2024-0067, OEB Staff Report to the Ontario Energy Board, January 15, 2025; EB-2023-0326, Decision and Order, March 5, 2024.

4. An explanation of the gas supply portfolio contracting decisions made since the 2024 Annual Update is provided in Section 5.

2.3. Process, Resources, and Governance

The gas supply planning process at Enbridge Gas uses transportation and storage assets to efficiently and reliably meet customer demand requirements. On an annual basis, the multi-year Plan is prepared as part of the corporate budget process. The preparation of the Plan incorporates a wide range of inputs, including demand forecasts (Section 4), market information (Appendix A), and changes to contracting and supply options (Section 5). The annual gas supply planning process is illustrated in Figure 1, with the aim to ensure Enbridge Gas is operationally ready for November 1, the date that marks the commencement of the gas year winter season.

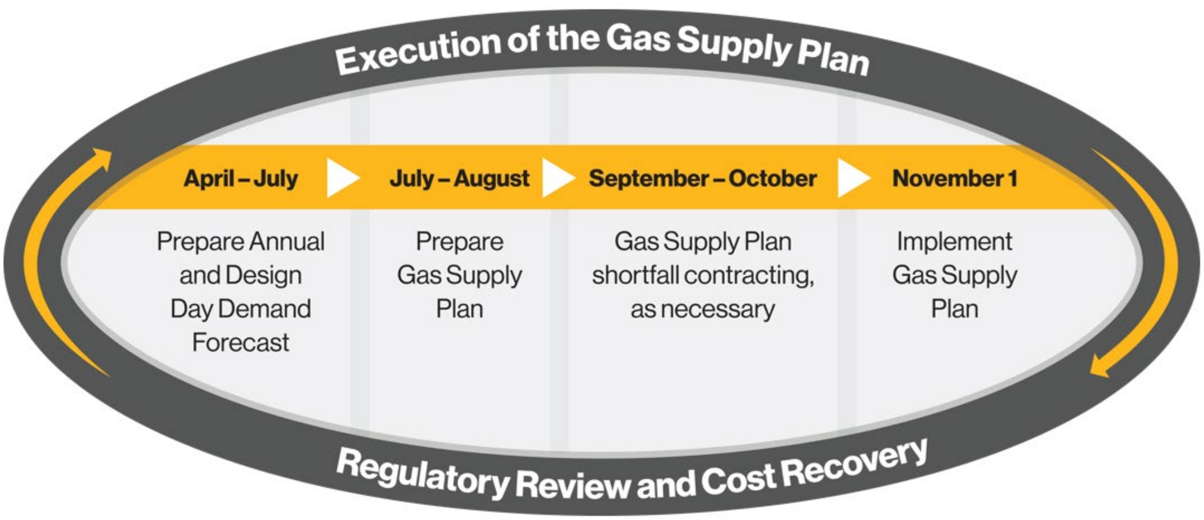
The first step in the annual gas supply planning process is the update to the annual and design day demand forecasts that occurs from April to July each year. Updating the demand forecasts requires an in-depth analysis that focuses on key factors impacting demand including customer growth, normalized weather, design day requirements, customer consumption patterns, and economic outlooks.

Following the completion of the demand forecasts, Enbridge Gas updates the design day surplus or shortfall positions for each of the nine delivery areas served. This step is completed using an optimization tool that optimizes existing storage and transportation assets to determine a cost-effective mix of commodity purchases and storage utilization to meet forecasted demand requirements. The purpose of the optimization process is to determine the most appropriate combination of transportation contracts and storage assets to meet in-franchise customers' annual, seasonal and design day demand requirements. The intent of the optimization process is to ensure the Plan does not include excess assets; only those assets necessary to meet firm customer requirements. These updates to the Plan typically occur from July to August each year and result in an operational version of the Plan for the upcoming winter that receives internal senior management review and approval. The results of the Plan are then communicated to key stakeholders throughout the Company to support ongoing operations.

Once the Plan for the upcoming winter is finalized and approved by senior management, Enbridge Gas implements its recommendations by adjusting transportation and storage service contracts (as required), procuring other (e.g., third-party) services required, and using a staggered and layered approach to commodity supply procurement at a variety of points over the course of the relevant gas year. This approach provides the flexibility necessary to adapt rapidly to changing customer, market, environmental, and operational conditions.

Throughout the year, Enbridge Gas regularly monitors the execution of the Plan and adjusts its procurement strategy in response to forecast and actual weather and inventory positions. In addition, Enbridge Gas prepares for regulatory (OEB) filings throughout the year to support review of the Plan and recovery of costs related to the Plan.

Figure 1
Annual Gas Supply Planning Process



3. Description of Enbridge Gas Services

The following section describes the existing service offerings[18] by Enbridge Gas that impact the Plan.

Distribution Services

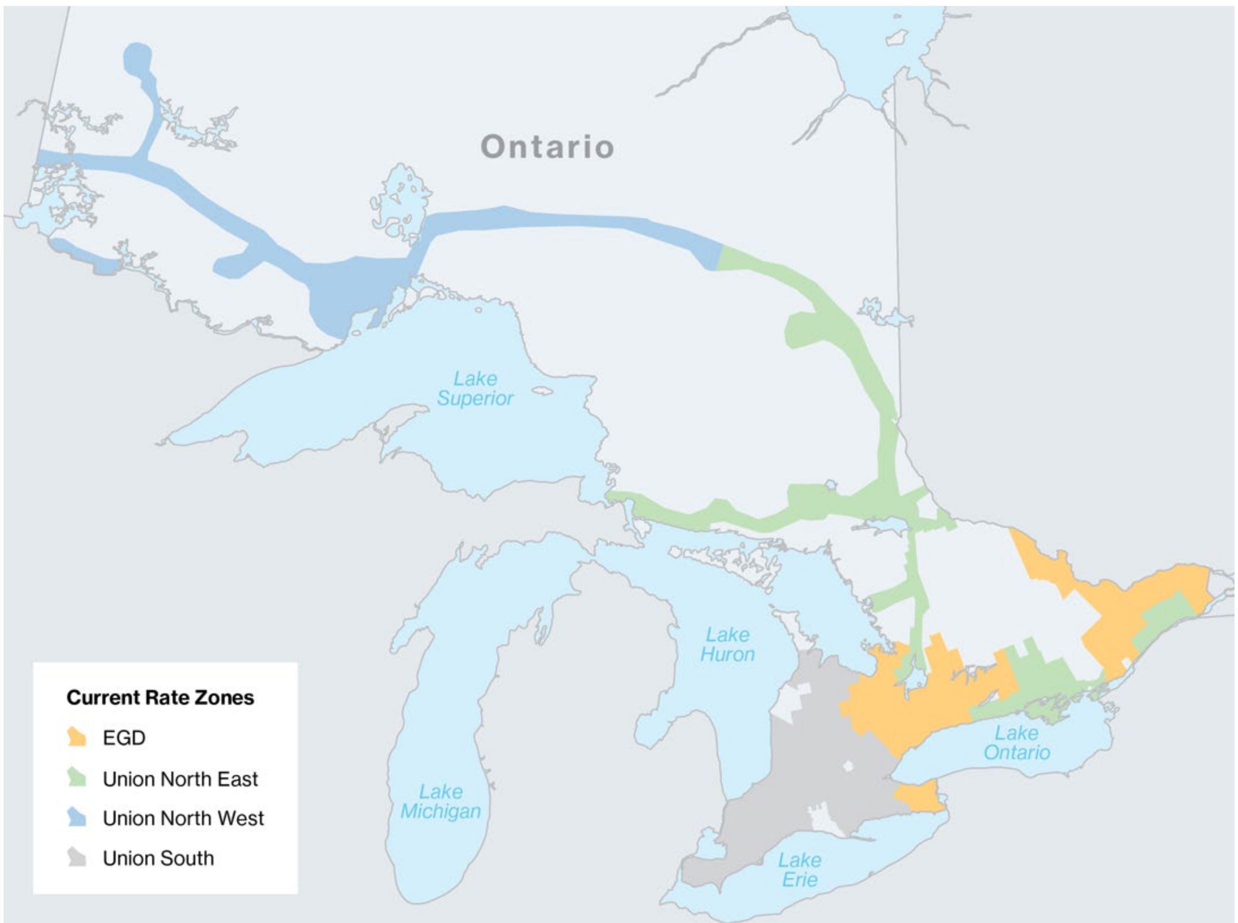
Enbridge Gas provides distribution services to in-franchise customers in two customer market segments:[19] general service and contract. General service is offered without a service contract and this segment is primarily represented by residential customers, and

[18] As noted in Section 2, Phase 3 of the rebasing proceeding could result in changes to the current rate zone structure and harmonization of existing services. Following the outcome of Phase 3, Enbridge Gas expects to include any impacts in a future Annual Update.
[19] Distribution service refers to the delivery of gas by Enbridge Gas to the customer's point(s) of consumption.

small commercial and industrial customers. Contract service requires a service contract and has defined criteria to determine a customer's eligibility for the service. The criteria vary based on the characteristics of service, which include firm, interruptible and seasonal. Customers who take contract service are large volume customers within the greenhouse, steel, chemical, power, refinery, and mining segments, among others.

Distribution services are provided by Enbridge Gas in its three rate zones: EGD, Union North, and Union South. There are four rate zones for gas supply services with Union North being split between Union North West and Union North East. An illustration of the rate zones is provided in Figure 2.

Figure 2
Enbridge Gas Rate Zones



As noted above, Enbridge Gas's Plan is prepared based on the nine delivery areas served. Enbridge Gas calculates annual and design day demands and determines the optimal supply mix for each delivery area. The Plan is an aggregation of the outcomes for each delivery area by rate zone. The delivery areas contracted by Enbridge Gas are outlined below and align to the commercial structure of the TC Energy (operating as

TransCanada Pipelines Limited or TCPL) Mainline.[20] The TC Energy delivery areas embedded within the Enbridge Gas rate zones are described below:

EGD rate zone

- Eastern Delivery Area (Enbridge EDA) – Containing Peterborough, Brockville, Ottawa, Gatineau and the surrounding area.
- Central Delivery Area (Enbridge CDA) – Containing the Greater Toronto Area (GTA), the Niagara Peninsula, Barrie, Midland and the surrounding area.

Union North West rate zone

- Manitoba Delivery Area (MDA) – Containing Fort Frances and surrounding areas.
- Western Delivery Area (WDA) – Spanning from Longlac to Kenora and containing Thunder Bay, Dryden and the surrounding areas.
- Sault Ste. Marie Delivery Area (SSMDA) – Containing Sault Ste. Marie and the surrounding areas.

Union North East rate zone

- North Delivery Area (NDA) – Spanning from North Bay to Calstock and containing North Bay, Sudbury, Timmins and the surrounding areas.
- North Central Delivery Area (NCDA) – Spanning from Orillia to North Bay and containing Parry Sound, Huntsville and the surrounding areas.
- Eastern Delivery Area (EDA) – Spanning from Coburg to Cornwall and containing Belleville, Kingston and the surrounding areas.

Union South rate zone

- Enbridge Gas's Plan reflects Union South as a single delivery area. From a gas supply contracting perspective, Enbridge Gas contracts to the following TC Energy delivery areas to deliver gas to the Union South rate zone:
  - Union Central Delivery Area (UCDA)
  - Union Eastern Central Delivery Area (UECDA)
  - Union/Enbridge South Western Delivery Area (SWDA/Dawn)
- Union South spans from Windsor to Owen Sound to Oakville and containing Sarnia, London, Goderich, Waterloo, Cambridge, Guelph, Burlington, Milton, Brantford, Hamilton and the surrounding areas.

---

[20] A map of the TC Energy Mainline system showing the delivery areas within Enbridge Gas's franchise area can be found at Appendix B – Figure B-1.

Gas Supply Services

Enbridge Gas offers customers a choice to either purchase their gas supply from Enbridge Gas under sales service or to provide their own gas supply under direct purchase (DP). Enbridge Gas provides four gas supply service options for customers:

Sales Service

- Under the sales service option, Enbridge Gas purchases the gas supply commodity on behalf of the customer. This option is considered a fully bundled service for customers, as the utility manages all aspects of the service including the gas supply, transportation, storage, balancing, and distribution. Sales service is available as a gas supply option for many rate classes in all rate zones.
- Of the 3.9 million Enbridge Gas customers, approximately 3.8 million are sales service that rely on Enbridge Gas to provide their gas supply and transportation capacity. Sales service customers are primarily residential (approximately 3.6 million) and small commercial customers.

Bundled DP

- Bundled DP service is offered by Enbridge Gas to customers who provide their own gas supply commodity through a fixed Daily Contract Quantity (DCQ)[21] at an obligated point of delivery to meet the planned annual consumption at their point(s) of consumption. The utility manages all non-commodity aspects of the service including transportation from the obligated delivery point, storage, balancing, and distribution. Bundled DP is available under the following services:
  - EGD rate zone: Dawn Transportation Service (DTS), Ontario Transportation Service (OTS), and Western Transportation Service (WTS),
  - Union South rate zone: Southern Bundled T, and
  - Union North rate zones: Northern Bundled T.

Semi-Unbundled DP

- Semi-Unbundled DP – Semi-unbundled DP service is offered by Enbridge Gas to customers who provide their own gas supply commodity through a fixed DCQ obligated at Dawn, and who contract for an allocation of storage services to meet demand at the customer’s point(s) of consumption. The

[21] The DCQ is determined by dividing a forecast of annual consumption at the associated point(s) of consumption by the number of days in the contract term, typically 365 days.

utility manages the transportation from the obligated delivery point to the point(s) of consumption. The customer is responsible for managing balancing through their storage account within its contracted parameters. The semi-unbundled DP service is only available in the Union South rate zone as Southern T Service.

Unbundled DP

- Unbundled DP service is offered by Enbridge Gas to customers who nominate the delivery of gas supply[22] each day to meet daily demand at the customer's point(s) of consumption. Some customers may also have a storage account which, depending on the service, they nominate as part of managing their gas supply. This service is available in all rate zones to eligible customers.

Generally, the Plan considers all customer demands and appropriate gas supply service options, apart from demands and services for unbundled DP customers. However, if an unbundled DP customer contracts for certain gas supply services with the utility, such as the bundled (T Service) storage service or transportation service from Dawn for Union North unbundled customers, those services are included in the Plan.

4. Gas Supply Plan Outlook – Demand Forecast

4.1. Demand Forecast Analysis

Enbridge Gas's annual demand forecast is comprised of the general service market and the contract market. Figure 3 below illustrates the proportion that each of these segments represents relative to total in-franchise customer demand, as well as the proportion of sales service and DP customers within each segment.

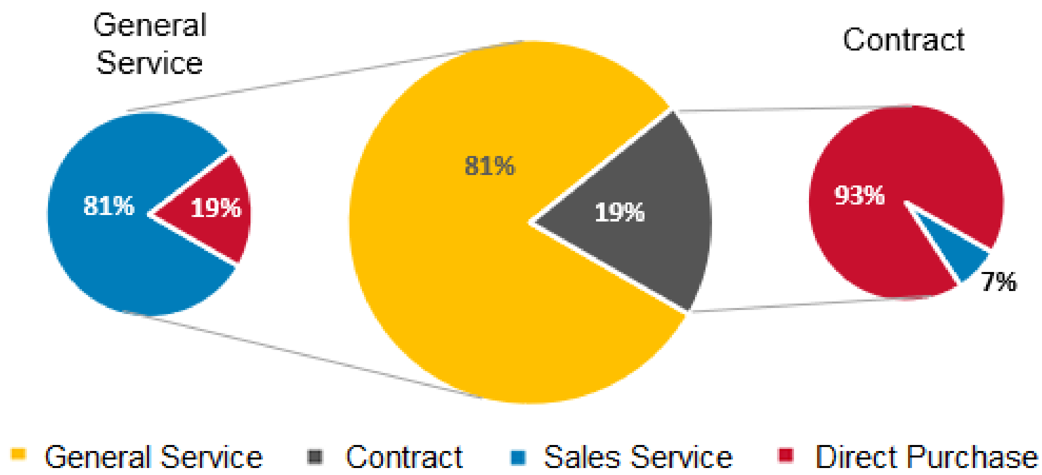
General service customers consist of residential and non-residential (commercial and industrial) customers. Residential consumption is primarily attributable to space heating in the winter season. As such, residential customer consumption follows a seasonal consumption profile based on temperature throughout the year. Non-residential consumption is largely influenced by the strength of the economy. During periods of economic growth, increases in demand for goods and services from the commercial and industrial sectors tend to increase natural gas consumption. Therefore, their consumption is less weather sensitive than the residential sector.

[22] Unbundled DP customers nominate the delivery of gas supply to the delivery area of their point(s) of consumption.

Contract customers consist mostly of large commercial and industrial businesses, whose consumption tends to follow a steadier baseload pattern throughout the year.

Figure 3

Proportion of Customer Demand Volumes by Service Type



4.2. Annual Demand

The annual demand forecast underpinning the Plan was developed using the same methodologies as those utilized to establish the Company's OEB-approved annual demand forecast for the 2024 Rebasing proceeding.[23] The annual demand forecast is the sum of the general service market volume and contract market volume forecasts. The following section explains how Enbridge Gas develops its annual demand forecasts, including the factors that impact those forecasts (i.e., historical demand and customer trends, changing weather patterns, and energy transition), and any associated risks.

General Service Market Demand Forecast

The base general service annual demand forecast is derived by multiplying the forecasted number of customers (unlocks) by their respective average use forecasts. The base forecast is then adjusted for future Demand Side Management (DSM) activity,

[23] The methodologies utilized are those set out in the Company's pre-filed evidence for 2024 Rebasing (EB-2022-0200) without the adjustment for customer numbers agreed to in the 2024 Rebasing Phase One Settlement Proposal.

and certain additional factors not captured through the forecasting methodology,[24] to obtain the final total general service annual demand forecast.

General Service Average Number of Customers Forecast

The base number of general service customers forecast is derived by adding the current year annual customer additions forecast to the latest available number of customers.

The customer additions forecast is compiled from new construction and replacement additions for each sector, namely the residential, commercial and industrial sectors. On average, over the past five years, approximately 94% of the Company's total customer additions came from the residential sector. Enbridge Gas's customer additions forecast is prepared using the housing starts forecast and historical trend as a base, then adjusted for community expansion and energy transition impacts. The customer additions forecast is reviewed, and adjusted if required, by Enbridge Gas's Construction, Operations, and Sales teams, who have market information through direct contact with builders, developers, and municipalities.

The final number of general service customers forecast is derived by adjusting the base forecast with an energy transition (ET) adjustment, which considers potential loss of customers over time (egress of the natural gas system).

Enbridge Gas annually reviews internal data and external factors related to policy signals (federal/ provincial/municipal), market trends (such as builder and consumer preferences), and stakeholder feedback (customer, municipal, and Indigenous) to support the ET adjustments applied in the 10-year forecast period.[25]

General Service Average Use Forecast

The base average use forecast is initially developed at the residential and non-residential level using regression methodology. Then, the average use forecasts by general service rate class (Rate 1, Rate 6, Rate M1, Rate M2, Rate 01, Rate 10) and sector (residential, commercial, industrial) are determined using historical proportions.

Major demand driver variables in the residential models include calendar month heating degree days, and vintage variables. While natural gas prices and certain other economic variables were included when developing the models, they were excluded from the final forecast as they were found not to be statistically significant in the

[24] Announced government policies to reduce greenhouse gas (GHG) emissionsandfuture building code changes (energy transition adjustments), community expansion rate stability period(s).

[25] Further detail on Enbridge Gas's ET adjustments is provided in EGI's Asset Management Plan (2025-2034) filed as EB-2020-0091, November 8, 2024, Section 4.5.

residential models. Major demand driver variables in the non-residential models include calendar month heating degree days, employment, and real natural gas prices.

Finally, ET adjustments are applied to the base average use forecast.

General Service Market Risk Analysis

The risks associated with the general service annual demand forecast reside mostly in the assumptions used for each major demand driver variable, such as weather (Heating Degree Day or HDD), customers, gas price, and employment (as applicable). If actual demand drivers occur differently than forecast (relative to the assumed demand driver variables included), consumption will be affected by the corresponding estimated sensitivities as determined through an impact analysis and set out below:

- Approximately 7% higher/lower if the actual weather is 10% colder/warmer than forecast.
- Approximately 0.1% higher/lower if the actual number of customers is 3,000 higher/lower than forecast.
- Approximately 0.4% higher/lower if the real natural gas price is 10% higher/lower than forecast.[26]
- Approximately 0.4% higher/lower if actual employment is 10% higher/lower than forecast.

There is also a risk that additional factors, not explicitly considered within the models (e.g., changes to typical customer behavior, natural disasters, economic recession, or geo-political events) will affect consumption and cause a variance to the forecast. Because such factors are not included in the models, it is very difficult to estimate any related impacts on customer consumption.

Contract Market Demand Forecast

The contract market is made up of approximately 1,000 customers. The volume forecast in the Plan for these customers is generated using Enbridge Gas's bottom-up forecast methodology. This involves a combination of historical consumption data, consultation with customers, and knowledge of specific customers' production plans and expectations.

[26] The annual demand forecast underpinning the Plan was completed mid-2024 and therefore considers the carbon levy within the forecast natural gas price used in forecasting non-residential average use. Without the carbon levy, the forecast natural gas price would have been approximately 30-40% lower. Please see EB-2022-0200, Exhibit 3, Tab 2, Schedule 5 for the impact of gas price changes on the annual demand forecast.

Forecasted DSM consumption savings are then removed from the total contract market volume forecast. Current year DSM consumption savings are derived using the 2023 savings approved by the OEB in its Decision and Order on Enbridge Gas's 2022-2027 DSM Plan Application[27] and escalated to 2025 using the approved target adjustment mechanism, assuming 100% achievement in previous years.

Contract Market Risk Analysis

The risks associated with the contract market annual demand forecast are primarily driven by economic factors. As a result, significant changes in economic conditions relative to expectations (e.g., due to geopolitical events, recessionary impacts to demand, changes in customer operations, DSM-related demand reductions) can lead to variances to forecast. Additionally, customer switching (between delivery service options) as part of the annual contract renewal process can also result in forecast variances.

Importantly, energy transition and climate change risks are managed at the individual customer level for the contract market. Customers manage related impacts to their own demands and adjust their contract parameters annually accordingly. For these reasons, Enbridge Gas does not incorporate such energy transition and climate change related assumptions into the annual demand forecast for the contract market segment.

<u>Annual Demand Forecast</u>

The annual demand forecast for the general service and contract markets is prepared on a weather normalized basis. The current forecast (see Table 1) was produced in the Spring of 2024 and reflects the best information available at that time, including actual 2023 consumption data, and updated demand driver variables for the general service market.

As demonstrated in Table 1, annual demand is forecast to decline on average by approximately 0.4% over the six-year forecast period (2024/25 to 2029/30) driven primarily by declining general service demand and partially offset by increasing contract market demand. Over this period, general service market demand is forecast to decline on average by approximately 0.5% driven by declining average use, energy transition impacts, and DSM consumption savings. By contrast, contract market demand is forecast to remain relatively stable, increasing slightly for the EGD and Union South rate zones due to customer growth.

[27] EB-2021-0002, Decision and Order on an Application for Multi-Year Natural Gas Demand Side Management Plan, November 15, 2022.

Table 1
Annual Demand Forecast

Line No.	Particulars (TJ)	2025 AU 2024/25	5-Year GSP 2025/26	2026/27	2027/28	2028/29	2029/30	Growth/ (Decline) 2024 to 2030
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	EGD							
1	General Service	393,499	391,530	389,558	387,260	384,159	381,002	(12,497)
2	Contract	79,968	78,910	81,809	81,214	80,618	80,022	54
3	Total EGD	473,467	470,440	471,367	468,474	464,777	461,024	(12,443)
	Union North West							
4	General Service	14,045	14,025	14,000	13,969	13,915	13,851	(194)
5	Contract	2,507	2,505	2,504	2,502	2,500	2,498	(9)
6	Total Union North West	16,552	16,530	16,504	16,471	16,415	16,349	(203)
	Union North East							
7	General Service	37,671	37,599	37,516	37,416	37,255	37,065	(606)
8	Contract	3,778	3,772	3,767	3,761	3,756	3,750	(28)
9	Total Union North East	41,449	41,371	41,283	41,177	41,010	40,816	(634)
	Union South							
10	General Service	173,757	173,820	173,814	173,710	173,325	172,783	(974)
11	Contract	60,646	60,567	61,393	61,458	61,334	61,210	564
12	Total Union South	234,403	234,386	235,207	235,168	234,659	233,993	(410)
13	Total Demand Forecast	765,871	762,727	764,361	761,290	756,861	752,182	(13,689)

4.3. Average Day Requirement

As part of the gas supply commodity procurement strategy for meeting annual and design day demand requirements, it is important for Enbridge Gas to understand the average day demand requirements for sales service customers, as this informs the Company’s firm upstream transportation capacity requirements and approach to procuring supply for these customers throughout the year. Enbridge Gas can purchase supply at Dawn or upstream of Dawn and transport it to meet customer demands. The average day analysis places a greater emphasis on determining if a need exists for transportation capacity from a particular supply basin or hub (e.g., WCSB, Appalachia, Chicago, or Dawn).

Enbridge Gas considers the annual demand of sales service customers only in its gas supply commodity procurement strategy because DP customers provide their own gas supply commodity through a fixed DCQ.

Table 2 provides both the annual and average daily demand for sales service customers forecast over the forecast period (2024/25 to 2029/30).

Table 2
Average Day Demand for Sales Service Customers

Line No.	Demand (TJ)	2025 AU 2024/25	5-Year GSP 2025/26	2026/27	2027/28	2028/29	2029/30	Growth/ (Decline) 2024 to 2030
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	EGD							
1	Annual Demand (1)	314,826	313,681	312,535	311,141	309,218	307,216	(7,609)
2	Average Daily Demand	863	859	856	852	845	842	(21)
	Union							
3	Annual Demand (1)	187,469	187,471	187,420	187,283	186,866	186,316	(1,152)
4	Average Daily Demand	514	514	513	513	511	510	(3)
	Total							
5	Annual Demand (1)	502,294	501,152	499,956	498,425	496,084	493,532	(8,762)
6	Average Daily Demand	1,376	1,373	1,370	1,366	1,355	1,352	(24)

Notes:
(1) The annual demand for sales service customers is based on the annual demand forecast in Table 1, excluding DP customer demands.

As presented in Table 2, the annual demand for sales service customers in the EGD rate zone is forecast to decrease by roughly 7,609 TJ (approximately 2.4% or 18 TJ/d) over the six-year forecast period, and the annual demand for sales service customers in the Union rate zones is forecast to decrease by 1,152 TJ (less than 1% or approximately 3 TJ/d) over the six-year forecast period. As a result, Enbridge Gas is not currently seeking to increase gas supply assets to serve annual demand changes and will adjust Dawn purchases as required based on actual demands and changes to forecasted demand in future Plans. A supply option analysis for average day requirements presented at Section 5.7 considers whether additional transportation assets upstream of Dawn could provide additional cost-effective, reliable, flexible, and/or diverse options.

4.4. Design Day Demand

As the system operator and supplier of last resort, Enbridge Gas must ensure sufficient assets (i.e., firm storage and transportation capacity and volumes of gas in storage) are available to meet the demands of sales service, bundled DP and semi-unbundled DP customers on an extreme cold weather day referred to as a design day, which is measured in HDDw (wind speed adjusted heating degree day). Since Enbridge Gas is required to contract for upstream transportation services to meet design day demand, there are days when these assets are not fully utilized.[28] The following section explains how Enbridge Gas develops its plans to serve design day demands, including certain factors that impact those demands (i.e., design criteria, design demands, and demand forecast changes), and any associated risks. Harmonized design day planning methodologies were discussed in detail in the 2024 Rebasing application.[29]

Design Criteria - Weather

Enbridge Gas uses the design criteria of the coldest observed day between Winter 1993/94 and Winter 2022/23[30] to determine the design day HDDw for each delivery area.[31] The HDDw are calculated using Environment Canada hourly temperature and wind speed data. The hourly temperature data is adjusted to account for the impact of hourly wind speed using a widely accepted method developed by Marquette Analytics. Once the hourly wind speed adjusted temperatures are calculated they are converted into HDDw using a base temperature of 15°C. The 24 hourly HDDw are averaged to align with the gas day. The design day HDDw used for the Plan is provided in Table 3.

[28] The process to address unutilized transportation capacity is discussed further in Section 5.4.
[29] EB-2022-0200, Exhibit 4, Tab 3, Schedule 3 and EB-2022-0200, Exhibit O1, Tab 1, Schedule 1, p. 36, part c).
[30] EB-2022-0200, Exhibit O1, Tab 1, Schedule 1, Part c), p. 36.
[31] Further detail is provided in EB-2022-0200 at Exhibit 4, Tab 2, Schedule 3, Section 3.

Table 3
Design Criteria

Line No.	Delivery Area	HDDw (Celsius)	Weather Station Location
	(a)	(b)	(c)
1	EGD CDA Niagara	37.8	St. Catharines
2	EGD CDA GTA	41.4	Toronto
3	EGD EDA	47.5	Ottawa
4	Union MDA	51.0	Fort Frances / International Falls
5	Union SSMDA	43.4	Sault Ste Marie
6	Union WDA	48.4	Thunder Bay
7	Union EDA	43.0	Kingston
8	Union NCDA	48.5	Muskoka
9	Union NDA	47.2	Sudbury
10	Union South	40.8	London

Design Day Demands - Firm Customer Demand

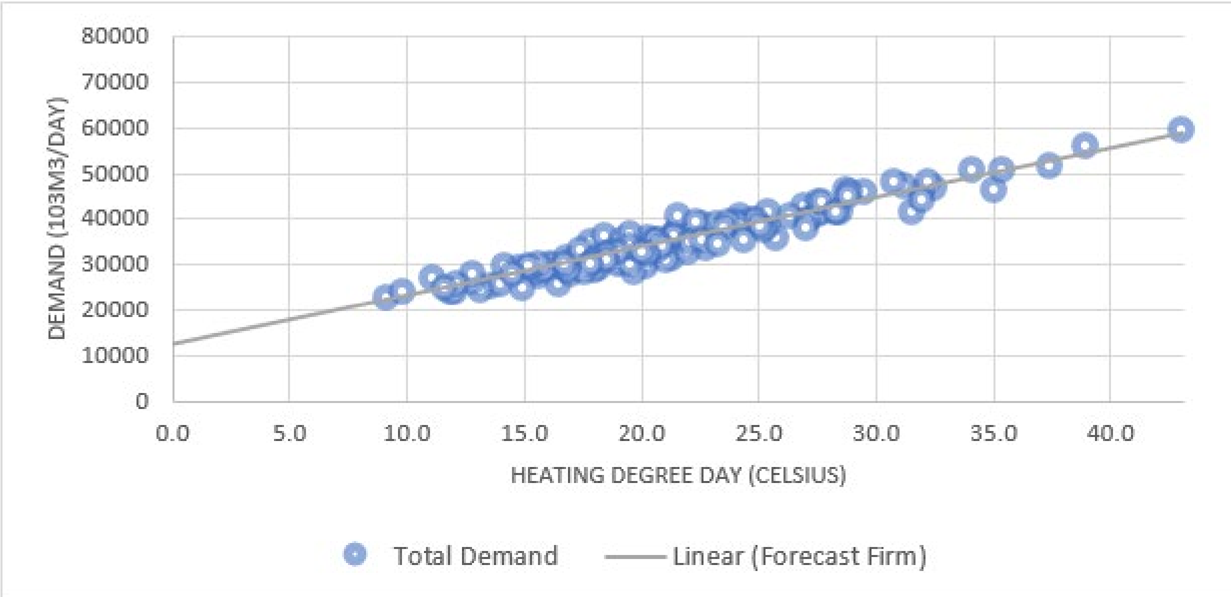
The design day demand is the highest firm volumetric amount of natural gas estimated to be consumed by customers on the coldest day.[32] A regression analysis is completed by delivery area listed in Table 3, using actual daily measured volumetric demand (typically without weekends and holidays) from the prior winter and HDDw from geographically associated weather stations. The resulting regression line is extrapolated to the design day HDDw. On design day, the interruptible demand is curtailed.

The existing general service market demands are calculated using city gate station flows with contract customer demands removed. The use of gate station data ensures demand diversity is included.[33] This data is adjusted by the design day use per customer factor.[34] The existing contract market demands are aggregated for groups of contract customers to include demand diversity and demand reservations for some

[32] Further information on Enbridge Gas's design day demand process is provided at EB-2022-0200, Exhibit 4, Tab 2, Schedule 3, Section 4.3.
[33] Non-coincident (also known as demand diversity) means that customers' equipment and processes cycle and that they do not consume their maximum demand at the same time. This non-coincident usage is termed demand diversity and results in a lower demand compared to the sum of each customer's peak demand.
[34] The existing customer general service design day demand is adjusted using the ratio of general service demand divided by the number of general service customers. The use per customer has a gradual downward trend over time which reflects observed energy efficiency gains, or process or behavioural changes in demand.

process customers.[35] An illustrative example of the actual daily demand and HDDw data and the regression line is provided in Figure 4.

Figure 4
Example of Actual Daily Demand vs. HDDw



Design Day Demand Forecast Changes

Enbridge Gas forecasts the design day demands of new customers and adjusts the design day demands of existing customers annually (i.e., general service and contract customer demands). Enbridge Gas's design day demand forecast incorporates historical design day use per customer trends for existing general service customers, which reflects observed DSM consumption savings, process or behavioural changes, and general service customer growth (including ET adjustments).[36] Contract market demand forecasts reflect DSM consumption savings and known or forecast demand changes.

Design Day Demand Risk Analysis

Enbridge Gas is currently using the coldest day observed HDDw between Winter 1993/94 and Winter 2022/23 for each delivery area,[37] to determine the design day demand requirement. However, should these conditions (and customer demands) be

[35] Some contract customers require a demand reservation and are not subject to this process. Customer design day demand in this case is based on equipment ratings and historical usage which is reflected in the customer contracted demand which is contained in the customer's distribution contract with Enbridge Gas.
[36] EB-2020-0019, 2025-2034 Asset Management Plan Addendum, Section 4.5.
[37] EB-2022-0200, OEB Decision on Phase 1 Settlement Proposal, August 17, 2023, p. 36.

exceeded, Enbridge Gas will not have procured sufficient transportation assets to meet that demand and is at risk of experiencing customer outages in its downstream distribution systems.

Design Day Demand Forecast

The current design day demand forecast was produced in the spring of 2024 and reflects the best information available at that time. As demonstrated in Table 4, design day demand is forecast to increase over the six-year forecast period (2024/25 to 2029/30) driven primarily by contract market customer demands in the EGD CDA, EGD EDA, and Union South delivery zones.

Table 4
Design Day Demand

Line No.	Delivery Area (TJ/d)	2025 AU 2024/25	5-Year GSP 2025/26	2026/27	2027/28	2028/29	2029/30	Growth/ (Decline) 2024 to 2030
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	EGD							
1	EGD CDA	3,578.3	3,594.1	3,622.3	3,624.1	3,622.6	3,619.2	40.8
2	EGD EDA	723.0	725.5	727.5	729.1	730.2	730.8	7.8
3	Total EGD	4,301.4	4,319.6	4,349.8	4,353.1	4,352.8	4,349.9	48.6
	Union							
4	Union MDA	5.6	5.6	5.6	5.6	5.6	5.6	0
5	Union SSMDA	42.0	42.0	42.0	42.0	42	41.9	(0.1)
6	Union WDA	84.8	84.7	84.6	84.4	84.3	84.0	(0.8)
7	Union EDA	191.7	192.1	192.4	192.6	192.7	192.7	1.0
8	Union NCDA	50.6	50.7	50.8	50.8	50.8	50.8	0.2
9	Union NDA	179.3	179.1	178.9	178.6	178.2	177.7	(1.6)
10	Union South	3,433.2	3,505.8	3,521.2	3,538.0	3,672.5	3,686.8	253.6
11	Total Union	3,987.0	4,060.0	4,075.5	4,092.0	4,226.1	4,239.5	252.5
12	Total	8,288.4	8,379.6	8,425.3	8,445.2	8,578.8	8,589.5	301.0

As detailed in Table 4, design day demand is forecast to increase by roughly 301.0 TJ/d (3.6%) over the six-year forecast period. The increase is largely driven by forecast design day demand increases in the Union South rate zone (representing an increase of 7.4%).

4.5. Design Day Demand Position Analysis

Enbridge Gas conducts a design day position analysis in which forecast design day demand is compared against existing contracted assets for each delivery area. A design day shortfall occurs when forecast demand exceeds existing capacity to meet design day demands (i.e., firm storage and transportation capacity, and volumes of gas in storage). Forecast shortfalls are monitored and re-assessed annually. However, the Plan does not include any excess assets; only those necessary to meet firm design day requirements.

As part of its design day position analysis, Enbridge Gas considers the availability of assets into each delivery area and assesses all viable alternatives. If there are no constraints in the delivery area or risk to the future availability of capacity, services will be acquired on a short-term basis to give Enbridge Gas the flexibility to adjust contracted capacity as needed. If the delivery area is constrained, Enbridge Gas may contract for a longer period to ensure the required assets are available to meet design day demand long term. A requirement to secure long-term capacity could result in Enbridge Gas bidding into an open season with a minimum commitment term.

Enbridge Gas's design day position for each delivery area for the 2024/25 gas year is summarized at Table 5 and includes shortfalls in the Enbridge CDA, Enbridge EDA, Union EDA and Union NDA prior to the transportation portfolio changes discussed at Section 5.2. After the portfolio changes, Enbridge Gas did not have a surplus or shortfall in the 2024/25 gas year.

Table 5

2024/25 Design Day Position

Line No.	Particulars (TJ/d)	Enbridge CDA	Enbridge EDA	Union MDA	Union SSMDA	Union WDA	Union EDA	Union NCDA	Union NDA	Union South	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Demand										
1	Design Day Demand	3,578.3	723.0	5.5	42.0	84.8	191.7	50.6	179.3	3,433.2	8,288.4
	Supply										
2	Great Lakes	-	-	-	-	-	-	-	-	21.1	21.1
3	In-franchise Supply (1)	2,249.3	-	-	-	-	-	-	-	3,116.9	5,366.2
4	NEXUS	-	-	-	-	-	-	-	-	105.5	105.5
5	PEPL	-	-	-	-	-	-	-	-	60.1	60.1
6	TCPL Long-haul	5.0	260.0	5.6	20.9	54.8	5.0	1.0	2.1	3.0	357.4
7	TCPL Short-haul	787.2	368.1	-	-	-	158.4	11.8	126.6	21.1	1,473.3
8	TCPL STS	283.9	80.6	-	21.0	30.0	26.4	37.8	39.7	-	519.4
9	Vector	-	-	-	-	-	-	-	-	105.5	105.5
10	Total Supply	3,325.4	708.7	5.6	42.0	84.8	189.8	50.6	168.4	3,433.2	8,008.5
11	Supply Shortfall (2)	(252.9)	(14.3)	-	-	-	(1.9)	-	(10.8)	-	(279.9)

Notes:

(1) Includes supply arriving directly into the franchise area (i.e. Dawn, storage, DP deliveries, Crowland, Hagar, delivered supply, etc.).

(2) Supply shortfall prior to transportation portfolio changes are addressed in Section 5.2.

The design day position for each delivery area over the forecast period (2024/25 to 2029/30) is summarized at Table 6 with further detail provided in Appendix H.

Table 6
2024/25 to 2029/30 Design Day Position Summary

Line No.	Particulars (TJ/d)	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
		(a)	(b)	(c)	(d)	(e)	(f)
1	Enbridge CDA	(252.9)	(281.0)	(309.1)	(310.9)	(309.5)	(306.0)
2	Enbridge EDA	(14.3)	(16.8)	(18.8)	(20.3)	(21.4)	(22.1)
3	Union MDA	-	-	-	-	-	-
4	Union SSMDA	-	-	-	-	-	-
5	Union WDA	-	-	-	-	-	-
6	Union EDA	(1.9)	(2.3)	(2.7)	(2.9)	(3.0)	(3.0)
7	Union NCDA	-	-	-	-	-	-
8	Union NDA	(10.8)	(10.8)	(10.5)	(10.1)	(9.5)	(8.7)
9	Union South	-	-	-	-	-	-
10	Total Supply Shortfall (1)	(279.9)	(310.9)	(341.1)	(344.2)	(343.3)	(339.7)

Notes:
(1) Supply shortfall prior to transportation portfolio changes are addressed in Section 5.2.

Enbridge Gas's 2024/25 to 2029/30 design day position reflects a maximum annual shortfall of up to 344.2 TJ/d, forecast for 2027/28. For 2027/28, approximately 311 TJ/d, or 90% of the total shortfall is attributable to the Enbridge CDA. The remaining 10% of the total shortfall is attributable to the Enbridge EDA, Union EDA and Union NDA delivery areas.[38] Enbridge Gas has addressed the 2024/25 design day shortfall for all delivery areas as discussed in Section 5.7. Incremental design day shortfalls for each delivery area for future gas years will be evaluated as part of the gas supply planning process of each Plan year similar to that described for 2024/25. Enbridge Gas's preferred planning strategy is to meet design day shortfalls using third-party (peaking) services up to a maximum limit of 2% of design day demand for each delivery area. Once peaking services have been contracted to the preferred maximum by delivery area, Enbridge Gas will look to other alternatives to meet design day shortfall.

5. Portfolio Overview

Enbridge Gas's gas supply, transportation, and storage portfolio (Portfolio) has evolved in-tandem with North American and Ontario natural gas markets over decades. The

[38] The Enbridge EDA, Union EDA and Union NDA shortfalls amount to approximately 6%, 1% and 3% of the total annual shortfall, respectively.

Company's procurement strategies underpinning that Portfolio are aligned with the OEB's Guiding Principles and are designed to serve the needs of in-franchise customers in a cost-effective manner.

In support of this 5-Year GSP, an updated market outlook was completed using publicly available natural gas market information published by regulatory/government agencies and third-parties, including the Canada Energy Regulator (CER), the U.S. Energy Information Administration (EIA), and certain upstream transportation pipeline companies. The market outlook information is provided in Appendix A and is meant to provide some (in terms of potential magnitude, scope, and timing) insights into recent North American natural gas market conditions and events that have influenced current natural gas supply and demand dynamics in Ontario as well as the most recent (2023) CER and EIA forecasts for natural gas production, demand, and market prices. CER and EIA forecasts for production, demand, and market prices range according to the specific scenario and related assumptions adopted. Considering the various scenarios presented, Enbridge Gas anticipates:

- Overall natural gas production levels across North America will remain relatively steady through 2050.
- Total annual demand for natural gas in Canada may decline through 2050 due to undefined advancements in emission reduction technologies.
- Total annual demand for natural gas in the U.S. will remain relatively steady or grow, driven by economic growth.
- The price of natural gas will be relatively comparable to the current forward market prices set out in Appendix A (Figure A-5).

Appendix A goes on to discuss the nexus of long-term supply and demand uncertainty impacting natural gas transportation capacity across North America. A combination of energy transition-related factors has resulted in reductions to planned expansions of transportation capacity across North America despite demand growth in many regions, exacerbating transportation capacity scarcity on many paths upstream of Enbridge Gas's systems. Recognizing these conditions, transportation capacity providers are increasingly requesting higher tolls and longer-term contracts to secure existing capacity.

Appendix B describes sources of gas supply, transportation options, and storage options typically available to and evaluated by Enbridge Gas when seeking to determine the optimal means to serve customer demand in Ontario.

Enbridge Gas's overall procurement strategies and related supply/service option analyses are guided by the principles described in Section 2.1 and informed by several additional factors such as the nature of its existing service contracts (i.e., terms, and renewal rights), operational requirements, supply source constraints, and the Company's planning principles (reliability, flexibility, diversity, and cost-effectiveness). Additionally, each gas supply, transportation service, and storage service evaluation must be considered in terms of its impacts on the Company's overall Portfolio and procurement strategies. When Enbridge Gas considers a new supply basin or supply purchase point, new upstream transportation capacity, new storage assets, or renewal of existing services, multiple alternatives are typically evaluated. The results of such evaluations are filed in the next Annual Update or 5-Year GSP.

Scarcity of Existing Pipeline Transportation Capacity

As discussed above and in Appendix A, absent readily available capacity (new or existing), competition for existing transportation capacity typically increases. On pipelines where Firm Transportation (FT) tolls are fixed, shippers compete for capacity by bidding for extended contract terms. On FERC regulated (interstate) pipelines (e.g., Vector, PEPL, NEXUS, and GLGT), where a maximum toll is set but negotiated rates are permitted, pipelines have been increasingly seeking both maximum tolls and longer contract terms from shippers for capacity that becomes available. In both its 2023 and 2024 Annual Updates, [39] Enbridge Gas noted that the scarcity of transportation capacity on the TCPL Mainline had become a significant consideration when evaluating transportation alternatives. The scarcity of transportation capacity on the TCPL mainline continues to be a concern, and Enbridge Gas has observed that available capacity has become scarce on several other transportation paths the Company actively contracts.

In June 2023, TCPL closed an open season for existing capacity that included the Enbridge EDA, having awarded capacity to bids with terms of up to 26 years. The Company explained in its 2024 Annual Update that based on these results, to be awarded short-haul capacity (e.g., Parkway to Enbridge EDA) the Company might need to bid for an excessively long term (i.e., over 60 years) to be successful since it may be competing against bids for a higher toll path (e.g., Empress to Enbridge EDA).[40]

Enbridge Gas participated in the 2024 TCPL existing capacity open season (2024 TCPL ECOS) in which 34,457 GJ/d of Empress to Enbridge CDA was secured. However, this amount was awarded on a reduced, prorated basis as Enbridge Gas was not successful in contracting the full amount requested (40,000 GJ/d) through the bidding process.

[39] EB-2023-0072, Enbridge Gas Inc. 2023 Annual Update to 5 Year Gas Supply Plan (March 1, 2023), p. 14; EB-2024-0067, Enbridge Gas Inc. 2024 Annual Update to 5 Year Gas Supply Plan (March 1, 2024), p. 15.
[40] EB-2024-0067, Enbridge Gas Inc. 2024 Annual Update to 5 Year Gas Supply Plan (March 1, 2024), p. 15.

In January 2025, Great Lakes Gas Transmission (GLGT) held a Right of First Refusal (ROFR) open season for capacity associated with two ROFR agreements expiring on October 31, 2025.[41] Through the open season, GLGT offered up to 43,780 Dth/day of FT service on the Emerson to St. Clair path beginning November 1, 2025. Since the FT tolls and the length of path were fixed, the longest-term bid(s) was expected to win the open season. The results of the ROFR process were posted in February 2025,[42] with the winning bids having terms of 32 and 34 years. This example reinforces the value of Enbridge Gas's decision in 2023/24 to extend the term of its existing GLGT capacity by 5 years, as detailed in its 2024 Annual Update.[43]

Going forward, the scarcity of transportation capacity will impact Enbridge Gas's contracting decisions when transportation contracts come to the end of their term as the Company seeks to ensure that the Plan maintains a portfolio of secure and reliable gas supply. The Transportation Market Overview set out in Appendix A includes additional discussion regarding the scarcity of specific pipeline transportation capacity as it relates to Enbridge Gas's gas supply planning and related supply option analysis.

5.1. Transportation Portfolio

Enbridge Gas holds a diverse portfolio of transportation services (in terms of transportation path and contract term) to meet the demands of each delivery area (see Appendix G and Appendix N). This diverse portfolio reduces risk exposure to long-term variation in demand/supply, and short-term supply constraints and/or price spikes. As previously discussed, Enbridge Gas has recently observed increased scarcity of upstream transportation capacity. Absent any indication that additional (new) capacity will become available in the future, the Company expects such scarcity will influence its procurement strategies going forward, as competition for (existing) capacity continues to increase.

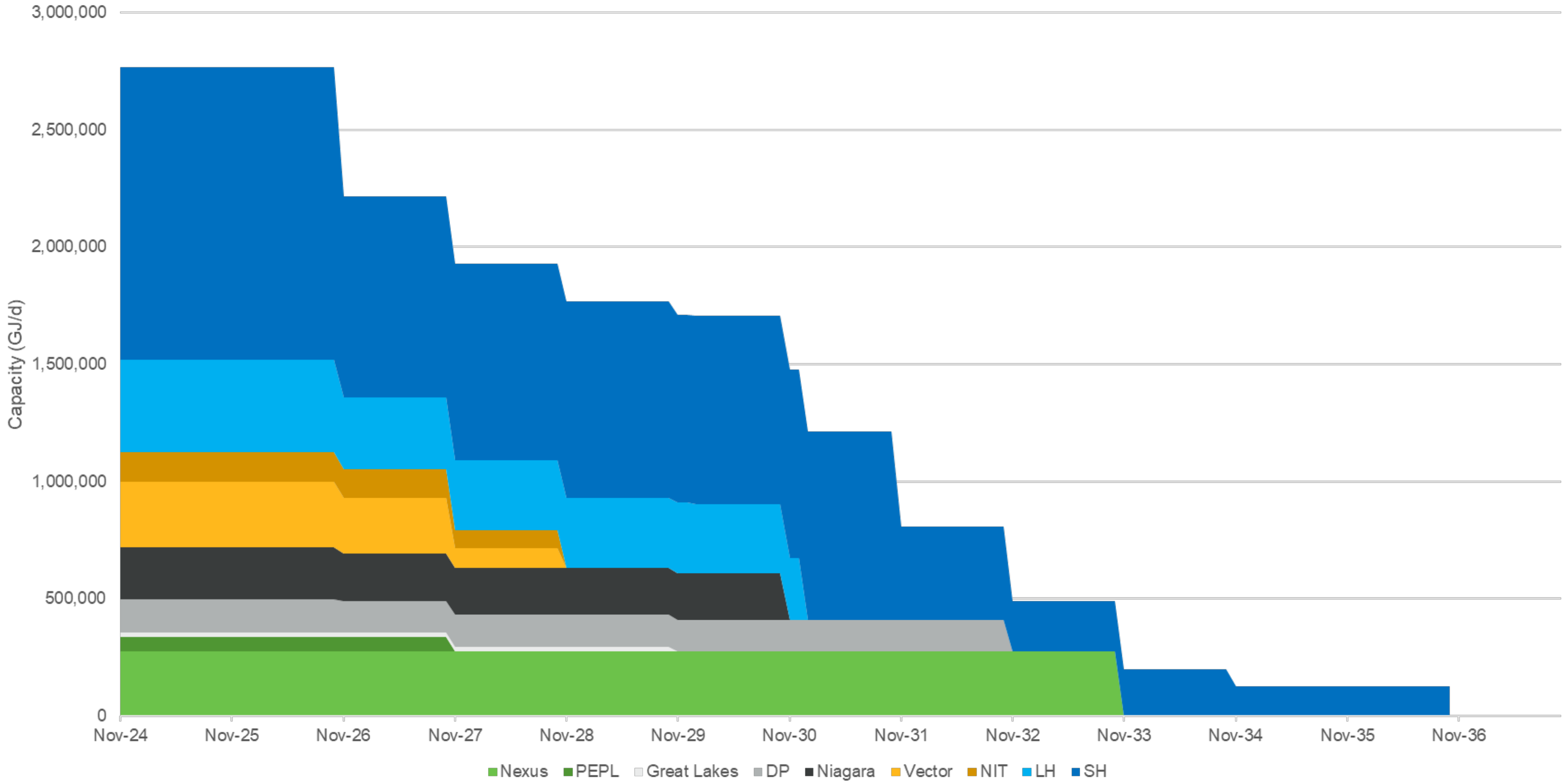
Figure 5 depicts Enbridge Gas's transportation portfolio as of November 1, 2024. Many of the contracts include renewal rights that can be exercised at the discretion of Enbridge Gas. Approximately 20% of transportation contracts (by volume) expire by November 2026, and approximately 55% of transportation contracts (by volume) expire by November 2030. As discussed in Section 7.3, as most capacity includes renewal rights, Enbridge Gas continues to gain shorter term contracting flexibility (to adjust

---

[41] https://www.tcplus.com/Great%20Lakes/Notice/ShowDetails/967; https://www.tcplus.com/Great%20Lakes/Notice/ShowDetails/968
[42] https://www.tcplus.com/Great%20Lakes/Notice/ShowDetails/1005; https://www.tcplus.com/Great%20Lakes/Notice/ShowDetails/1007
[43] EB-2024-0067, Enbridge Gas Inc. 2024 Annual Update to 5 Year Gas Supply Plan (March 1, 2024), p. 35.

quickly to changes in supply or demand) while maintaining portfolio diversity and reliability.

Figure 5
Transportation Portfolio Term



Enbridge Gas monitors and evaluates contracts with expiry dates that fall within the 6-year forecast period (2024/25 to 2029/30) to determine whether the contracts should be renewed based on the principles described in Section 2.1. Appendix N provides transportation contracts subject to renewal during the 5-Year GSP forecast period.[44] These renewals provide flexibility to adjust the transportation portfolio if demand declines.

As part of the 2024 Annual Update proceeding,[45] Enbridge Gas committed to developing additional performance metrics to demonstrate actual costs of contracting decisions as compared to forecast costs. To respond to this commitment, Enbridge Gas has prepared a cost-effectiveness analysis that provides the actual premium/discount paid by transportation path compared to the expected premium/discount assessed as part of the landed cost analysis prepared in prior years at the time of contracting decisions. Enbridge Gas has provided the cost-effectiveness analysis in Appendix I.

As part of Appendix I, landed cost forecasts are defined by the year the analysis was completed and the results of the analysis are listed for the applicable forward "Gas Year" period(s). The landed costs used for this analysis were previously provided as part of the Company's 2020-2024 Annual Updates (i.e., landed cost analysis completed in 2020 was included in the 2021 Annual Update). For example, the "AECO Premium/(Discount) to Empress" landed cost analysis set out in Appendix I was completed in 2020 for the 2021/22, 2022/23, and 2023/24 "Gas Years" and was subsequently filed as part of the Company's 2021 Annual Update.

Distinct forecasts for NYMEX settlement pricing has also been provided in Appendix I to contextualize the variability in forecast natural gas prices from 2019-2023. Variation between "Actual" prices and the "Landed Cost Analysis" forecast prices contained in Appendix I can in-part be attributed to the market conditions and economic and geo-political factors discussed in Appendix A.

5.2. Transportation Portfolio Changes

The following section discusses transportation portfolio changes made since the Company filed its 2024 Annual Update.

[44] Viable alternatives available to replace expiring design day-related contracts are restricted to firm transportation options. Average day-related contracts due for renewal are assets held upstream of Dawn or that provide diversity of supply.
[45] EB-2024-0067, Enbridge Gas Reply Submission, p. 5.

Transportation Contracting Analysis

During 2024, Enbridge Gas made the following transportation portfolio contracting decisions:

Centra Transmission Holdings Inc. (CTHI)

- Effective November 1, 2024, Enbridge Gas contracted for 7.78 $10^3 m^3/d$ (~206 GJ/d) less capacity from Spruce to Sprague and from Rainy River to Fort Francis for a 1-year term.

Centra Pipelines Minnesota Inc. (CPMI)

- Effective November 1, 2024, Enbridge Gas contracted for 276.31 mcf/d (~206 GJ/d) less capacity from Sprague to Baudette for a 1-year term.

Nova Gas Transmission Limited Pipeline (NGTL)

- Effective November 1, 2025, Enbridge Gas renewed 75,000 GJ/d of existing capacity from Nova Inventory Transfer (NIT) to Empress on NGTL for a 3-year term.

TransCanada Pipelines Limited (TCPL)

- Effective November 1, 2024, Enbridge Gas contracted for 34,457 GJ/d of incremental capacity from Empress to the Enbridge CDA on TCPL for a 6-year term.

TransCanada Pipelines Limited (TCPL) – Third-Party Assignment

- Effective December 1, 2024, Enbridge Gas contracted for 121,142 GJ/d of incremental capacity from Niagara to the Enbridge CDA on TCPL for a 5-year term. The TCPL capacity is assigned to Enbridge Gas by a third-party for the months of December to March each year. This capacity is coupled with a supply arrangement from the third-party.

Panhandle Eastern Pipe Line Company (PEPL)

- Effective November 1, 2025, Enbridge Gas renewed 35,000 Dth/d (36,927 GJ/d) of existing capacity from Field Zone (Markwest) to the US/Canadian border (Ojibway) for a 2-year term.

Vector Pipeline

- Effective November 1, 2025, Enbridge Gas renewed 80,000 Dth/d (84,404 GJ/d) of existing capacity from Chicago to the US/Canadian border (St. Clair) for a 3-year term.

- Effective November 1, 2025, Enbridge Gas renewed 84,404 GJ/d of existing capacity from the US/Canadian border (St. Clair) to Dawn for a 3-year term.

St. Clair Pipelines

- Bluewater River Crossing - Effective November 1, 2025, Enbridge Gas renewed 127,000 GJ/d of existing capacity with St. Clair Pipelines connecting the Bluewater Gas system in Michigan to the Enbridge Gas system near Sarnia for a 1-year term.
- St. Clair River Crossing - Effective November 1, 2025, Enbridge Gas renewed 214,000 GJ/d of existing capacity with St. Clair Pipelines connecting the NEXUS/DTE system in Michigan to the Enbridge Gas system near Courtright for a 1-year term.

In its 2024 Annual Update, in response to the OEB findings in the 2021 Vector Contracting Decision,[46] Enbridge Gas committed to providing the standardized contract decision templates completed prior to executing new transportation contracts. Accordingly, Enbridge Gas has provided Transportation Recommendation Documents completed to support the contracting decisions described above in Appendix J.

Rationale for CTHI and CPMI Capacity Adjustments

The Union MDA can only be served via the CTHI/CPMI system which flows from a point on the TCPL Mainline system in Manitoba into Minnesota and then back into Ontario, terminating near the town of Fort Francis, Ontario. There are only four shippers holding capacity along this path (in addition to Enbridge Gas), none of which are marketers. As a result, any solution to meet design day demands in the Union MDA must include firm transportation capacity on CTHI/CPMI. CTHI and CPMI pipelines have available capacity that can be contracted for 1-year increments at fixed-rate tolls by requesting capacity during the annual renewal process.

As detailed in Appendix H, design day demands for the Union MDA are projected to be lower during the forecast period (2024/25 to 2029/30). Enbridge Gas has reduced its contracted firm transportation capacity on CTHI/CPMI accordingly to align with upstream capacity on the TCPL Mainline from Empress.

Rationale for NGTL Renewal

Enbridge Gas holds firm transportation capacity on the TCPL Mainline from Empress for the EGD rate zone (at fixed-rate tolls) of 265,000 GJ/d until December 31, 2030. Rather

[46] EB-2023-0326, OEB Decision and Order, Hearing on the OEB's own Motion on Enbridge Gas Inc's 2021 Vector Contracting Decision, p. 11.

than procuring all related natural gas supply at Empress, NGTL transportation capacity provides Enbridge Gas with the ability to diversify its supply purchases between Empress and AECO. NGTL capacity is fully contracted, and if Enbridge Gas were to reduce its contract levels on NGTL, it would be unlikely to be able to recontract in the foreseeable future.

Contracting for a term of three years qualifies Enbridge Gas to continue to take advantage of a 5% reduction to the regulated NGTL toll. Further, landed cost analysis indicates that NGTL capacity provides an economic benefit to ratepayers when the toll reduction and liquids extraction savings are considered.[47] A comparison of landed costs for NGTL renewal options can be found in Appendix K and the forecasted premium/discount by contract year can be found at Appendix L.

As the NGTL capacity supports Enbridge Gas's objective of structuring a portfolio with a diversity of contract terms and supply purchase points and is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable and competitive cost, Enbridge Gas renewed the contract for existing capacity for a term of three years.

Rationale for Enbridge CDA New TCPL Capacity, New Third-Party TCPL Assignment Capacity, and Peaking Services

The forecasted 2024/25 design day shortfall for the Enbridge CDA is 252.9 TJ/d, as outlined in Table 5. Furthermore, the Enbridge CDA is forecast to have shortfalls each year over the forecast period (2024/25 to 2029/30) with the forecast maximum shortfall of approximately 311 TJ/d in 2027/28.

As a result of the 2024/25 shortfall of 252.9 TJ/d, Enbridge Gas made the following changes to its Portfolio in 2024:

- Contracted for peaking services of 97,289 GJ/d, equivalent to 2.7% of design day demand for the Enbridge CDA;[48]
- Contracted for 34,457 GJ/d Empress to Enbridge CDA capacity, secured through the 2024 TCPL ECOS; and

[47] Liquids-rich natural gas from the AECO production market flowing on the NGTL pipeline to Empress can have excess natural gas liquids extracted at an Empress extraction facility before entering the TCPL mainline. Enbridge Gas contracts to sell the extracted liquids at market-based rates to a third-party, thereby reducing the cost of the AECO supply to Enbridge Gas.

[48] Enbridge Gas will re-evaluate the proportion of reliance on peaking services before November 1 each year as part of its portfolio review, considering market changes and availability of pipeline capacity. The Company's preference remains to procure third-party (peaking) services for up to 2% of design day needs by delivery area going forward. Accordingly, the Company will continue to evaluate transportation options as they become available to manage future design day growth.

- Contracted for 121,142 GJ/d Niagara to Enbridge CDA capacity (four months of winter, third-party TCPL assignment capacity).

Enbridge Gas's approach to contracting for peaking services is outlined below. Enbridge Gas's rationale for contracting each of the above-noted transportation capacities, along with a holistic analysis of the same are set out in this section and Appendix C, respectively. The analysis included in Appendix C was prepared to evaluate the cost-effectiveness of various transportation alternatives and to consider their respective impacts to the gas supply portfolio in terms of flexibility, storage utilization, supply diversity, and scarcity of supply. Enbridge Gas used this holistic approach in lieu of a landed cost analysis to consider the potential unique and wide-ranging impacts of the alternatives on the gas supply portfolio.

Peaking Services

For the winter 2024/25, Enbridge Gas replaced its 2% tolerance for peaking services with an amount equivalent to the statistical variation within the design day model because of the increase in design day demand from implementing the new design day methodology. Enbridge Gas used statistical validation analysis of the design day model to determine the deviation between actual and forecasted design day demand. The statistical analysis resulted in a 2.7% variation, which Enbridge Gas used as the basis for increasing reliance on peaking services to approximately 2.7% of total demand in the Enbridge CDA. The increase in risk tolerance for peaking services reduces the amount that would otherwise be contracted as higher reliability, longer-term services that often come at higher fixed costs. It is important to note that while peaking services have low fixed costs, they are typically extremely expensive in the event supply is called upon and may not result in a lower total cost.

Peaking services addressed 97.3 TJ/d of the 252.9 TJ/d design day demand shortfall for the Enbridge CDA.[49] Enbridge Gas will review 2025/26 design day demand shortfalls and supply options again prior to contracting future peaking and supply services.

2024 TCPL ECOS and Third-Party TCPL Assignment Capacity

After procuring peaking services, 155.6 TJ/d of design day demand shortfall for 2024/25 remained for the Enbridge CDA (252.9 TJ/d less 97.3 TJ/d). To address the remaining

[49] The peaking services referenced were only contracted for the winter 2024/25 season and do not include any renewal rights.

shortfall, the Company evaluated two distinct options in terms of their respective impacts to Portfolio costs, flexibility, load balancing, supply diversity, and operations:

> **New FT Empress to Enbridge CDA Capacity** – A 2024 TCPL ECOS was held from July 5 to August 8, 2024, offering up to 84,457 GJ/d of FT and Non-Renewable Firm Transportation (FT-NR) services on the TCPL Mainline beginning November 1, 2024, and November 1, 2025.
>
> **New Third-Party TCPL Assignment Capacity** – A commercial service option whereby a third-party would temporarily assign FT TCPL capacity from Niagara to Enbridge CDA beginning November 1, 2024. Enbridge Gas evaluated three such scenarios with unique commercial parameters.

More specifically, the Company evaluated a variety of alternatives whereby the options were compared directly and in combination. To ensure the alternatives were evaluated consistently in all scenarios, the Company assumed the maximum volume of services contracted was equal to the capacity offered in the 2024 TCPL ECOS of 84,457 GJ/d, and that the remaining shortfall would be contracted via additional commercial services (71,543 GJ/d).

Based on the holistic review and analysis of alternatives provided in Appendix C, Enbridge Gas elected to bid for 40,000 GJ/d of new FT Empress to Enbridge CDA capacity on the TCPL Mainline through the 2024 TCPL ECOS and to contract for the remaining shortfall through the new third-party TCPL assignment capacity. Ultimately, Enbridge Gas was awarded 34,457 GJ/d of new TCPL capacity through the 2024 TCPL ECOS beginning November 1, 2024, for a six-year term. The capacity awarded has renewal rights and provides additional flexibility through diversions. However, as the Company was only awarded 34,457 GJ/d of the 40,000 GJ/d bid for new FT Empress to Enbridge CDA capacity, it was necessary to increase the volume of new third-party TCPL assignment capacity required to cover the remaining forecasted 2024/25 design day shortfall.

For 2024/25, new TCPL capacity addressed 34.5 TJ of the 252.9 TJ design day demand shortfall for the Enbridge CDA.

Third-Party TCPL Assignment Capacity

After securing peaking services (97.3 TJ) and new TCPL capacity (34.5 TJ), 121.1 TJ/d of design day demand shortfall for 2024/25 remained for the Enbridge CDA (252.9 TJ less 97.3 TJ less 34.5 TJ). To address the remaining shortfall, the Company sought out additional third-party services to manage the design day shortfall and contracted for 121,142 GJ/d of new third-party TCPL assignment capacity. As part of this arrangement, FT capacity from Niagara to Enbridge CDA is temporarily assigned for four months of the winter season and Enbridge Gas must purchase natural gas commodity to fill that capacity from the same third-party at Niagara at a fixed premium (which includes associated transportation costs) to the Dawn daily index price as published by S&P Global Platts. This contract has renewal rights and allows for annual volume increases over a five-year term up to a maximum of 255,618 GJ/d. No directly comparable supply/service options exist as this service was negotiated directly with a third-party.

The new third-party TCPL assignment capacity is a cost-effective alternative that supports Enbridge Gas's objective of structuring a portfolio with a diversity of contract terms and supply purchase points and is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable and competitive cost.

Rationale for PEPL Renewal

Enbridge Gas holds firm transportation capacity on PEPL from the Panhandle field zone to Enbridge Gas's integrated storage, transportation, and distribution system at Ojibway (Union south rate zone) of up to 57,000 Dth/d (~60,000 GJ/d) on two contracts. 35,000 Dth/d of Enbridge Gas's existing PEPL capacity had an initial term of five years and was set to expire on October 31, 2025, while the remaining 25,000 Dth/d of existing PEPL capacity expires on October 31, 2027.

Volumes delivered via the PEPL capacity are required to meet the design day demands of the Company's Panhandle Transmission System[50] (Panhandle) and have historically served the Windsor market area. Absent the PEPL capacity, additional transportation pipeline(s) infrastructure would be required to replace these volumes with supply transported from the Dawn Hub.[51] PEPL volumes not consumed in the Windsor market area can also be transported to the Dawn Hub, contributing to broader supply security and diversity.

Ojibway is not a liquid market trading point, but rather a trans-shipment point between two pipeline systems. To deliver supply to Ojibway, market participants must contract for transportation on the PEPL system to access more liquid upstream natural gas markets. PEPL capacity is currently fully contracted and if Enbridge Gas were to reduce its contract levels on PEPL it would be unlikely to be able to recontract in the foreseeable future. Because no directly comparable supply/service options exist, PEPL capacity is required to serve the Windsor market area (shorter paths on PEPL such as from Defiance are currently not available). Therefore, no landed cost analysis was completed for PEPL capacity.

---

[50] Enbridge Gas's Panhandle Transmission System is further described in Appendix B.
[51] EB-2022-0157, Panhandle Regional Expansion Project, Exhibit C, Tab 1, Schedule 1, p. 10.

As the PEPL capacity is required to meet the Company's design day demands on its Panhandle system, and supports Enbridge Gas's objective of structuring a portfolio with a diversity of contract terms (includes renewal rights) and supply purchase points, consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable and competitive cost, Enbridge Gas renewed contracts for existing capacity for a term of two years.

Rationale for Vector Renewal

Enbridge Gas holds firm transportation capacity on the Vector Pipeline (Vector) from Chicago to Dawn of 185,000 Dth/d (~195,000 GJ/d) on four contracts. 80,000 Dth/d of Enbridge Gas's existing Vector capacity was set to expire on October 31, 2025, while the remaining 105,000 Dth/d of existing Vector capacity expires on October 31, 2026 (40,000 Dth/d) and October 31, 2027 (65,000 Dth/d). Vector capacity to Dawn is fully contracted, and if Enbridge Gas reduced its contract levels on Vector it would be unlikely to be able to recontract in the foreseeable future.

Enbridge Gas has frequently explained that capacity on the Vector pipeline to Dawn provides a competitively priced, reliable and flexible[52] transportation option that offers supply diversity at Chicago as well as access to additional supply along the Vector pipeline route, and also provides an important secondary benefit of maintaining Enbridge Gas's ability to serve the Sarnia Industrial Line (SIL).[53] Additionally, this capacity also provides the potential benefit of providing Enbridge Gas the option to deliver to Michigan storage. As discussed in Section 5, the reliability of third-party supply deliveries to the SIL during peak demand events in the winter has reduced (e.g., during Winter Storm Elliott from December 23 to 27, 2022, both Vector and Great Lakes pipelines were physically exporting from Dawn, leaving no third-party deliveries that could be diverted to the SIL). Absent the Vector capacity, additional transportation capacity into the SIL or transportation pipeline(s) infrastructure would be required to avoid a design day shortfall in the Sarnia market area on a planned basis. Further, Portfolio supply diversity would be reduced as these volumes would be replaced by Appalachian or Dawn supply.

The natural gas market at Chicago has experienced volatility over the past few years and this has resulted in increases to forward settlement prices during winter months at Chicago. While Enbridge Gas does not use forward market settlement data to inform long-term contracting decisions, the divergence between long-term forecast pricing at

[52] The expiring/renewed capacity can also be segmented and utilized bi-directionally.
[53] EB-2014-0333 Sarnia Expansion Pipeline Project, pp. 4-11; EB-2019-0137 5-Year Gas Supply Plan, pp. 91-94; EB-2019-0218 Sarnia Industrial Line (SIL) Reinforcement, pp. 9-15; EB-2023-0072 2023 Annual Gas Supply Plan Update, Appendix F; EB-2024-0067 2024 Annual Gas Supply Plan Update, Appendix H; and EB-2023-0326 OEB Vector Contracting Decision p. 12.

Chicago and forward settlement pricing was a significant topic of interest with certain stakeholders in previous Annual Updates. Prior to renewing the Vector contract, Enbridge Gas engaged ICF to conduct an analysis of Chicago and Dawn pricing. The analysis discusses ICF's long-term price expectations at Chicago relative to Dawn and the importance of the supply diversity to Enbridge Gas provided by access to the Chicago market. The analysis also investigates the divergence of forward market settlement prices from ICF's fundamentals-based forecast. In summary:[54]

> ICF's Q3 2024 base case projects Chicago to be at a discount to Dawn, diverging from futures and recent day-ahead prices for the summer of 2024. The summer price spread between Chicago and Dawn has been influenced by the Midcontinent region. Increasing summer gas consumption in the Midcontinent is putting upward pressure on regional gas prices, impacting Chicago prices. Additionally, declining Midcontinent gas production due to the low gas price environment, aging wells, reduced drilling activity, and operational challenges has further exerted upward pressure on regional prices, affecting Chicago. Consequently, the summer spread between Chicago and Dawn day-ahead prices has increased. However, ICF's Q3 2024 base case forecasts an increasing gas production in the Midcontinent, which keeps Chicago prices at a discount to Dawn.
>
> …
>
> ICF advises Enbridge Gas to focus on long-term market fundamentals, supply diversity, and reliability when making re-contracting decisions for pipeline capacity. The interconnected pipeline network and the critical role of the Vector pipeline underscore the importance of maintaining capacity agreements. Although short-term market trends and risk premiums may cause temporary deviations, the long-term perspective should guide strategic decisions to ensure stability and cost-effectiveness in gas supply.

The full ICF report is provided at Appendix D.

Renewing 12 months in advance of contract expiration for a term of three years qualified Enbridge Gas to maintain the previously negotiated toll of $0.165 USD/Dth. A comparison of landed costs for Vector relative to alternative supply/service options can be found in Appendix M and the forecasted premium/discount by contract year can be found at Appendix L.

As the Vector capacity is required to meet the Company's design day demands on its SIL system, supports Enbridge Gas's objective of structuring a portfolio with a diversity of contract terms (includes renewal rights) and supply purchase points, and is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable and competitive cost, Enbridge Gas renewed contracts for existing capacity for a term of three years (beginning November 1, 2025).

---

[54] Appendix D, pp. 42 & 44.

Rationale for Bluewater River Crossing Renewal

Enbridge Gas holds firm transportation capacity on the Bluewater River Crossing from Bluewater Gas Storage to Enbridge Gas's integrated storage, transmission, and distribution system at the Bluewater interconnect of 127,000 GJ/d, renewed annually.

Bluewater Gas Storage is not a liquid market trading point but does provide interruptible wheeling services to move gas to different points on their system and firm storage services that could deliver to the Bluewater River Crossing on a firm basis. Volumes transported into Canada via the Bluewater River Crossing can benefit the Sarnia market by providing supply directly into the SIL. However, Enbridge Gas is not able to rely upon any interruptible service(s) to provide supply to the Sarnia market on a design day and the Company does not currently have a contract for firm storage service with Bluewater Gas Storage. Therefore, the Bluewater River Crossing contract provides a back-up supply option for the Sarnia market but is not relied upon in the design of the SIL.

In addition to being a back-up supply option for the Sarnia market, the Bluewater River Crossing capacity also facilitates ex-franchise services through Hub Services[55] and regulated short-term transportation services (Rate C1) supporting the liquidity and overall competitiveness of the Dawn Hub.

Enbridge Gas is not able to rely on interruptible services from Bluewater River Crossing to provide supply to the Sarnia market on a design day, and there is no directly comparable supply/service option (as the Bluewater River Crossing is the only link between Bluewater Gas Storage and the Enbridge Gas system(s)). Therefore, no landed cost analysis was completed for Bluewater River Crossing capacity.

As the Bluewater River Crossing capacity provides a back-up supply option for the Sarnia market and is used to offer regulated transportation services, Enbridge Gas renewed the contract for existing capacity for a term of one year.

Rationale for St. Clair River Crossing Renewal

Enbridge Gas holds firm transportation capacity on the St. Clair River Crossing from DTE St. Clair to Enbridge Gas's integrated storage, transmission, and distribution system at the St. Clair interconnect of 214,000 GJ/d, renewed annually.

The St. Clair River Crossing capacity provides a dual gas supply benefit of providing a path for Appalachian supply via NEXUS capacity to Ontario, as well as access to MichCon supply and storage services. Enbridge Gas's Appalachian supply and

[55] The Bluewater River Crossing is included as a receipt and delivery point for Hub Services. Further information on Hub Services can be found at: https://www.enbridgegas.com/storage-transportation/services/hub.

upstream capacity held on NEXUS of 158,258 GJ/d is dependent on maintaining equivalent St. Clair River Crossing capacity for delivery to Enbridge Gas's system(s). NEXUS volumes benefit the Sarnia market by providing firm supply that can be directed to the SIL for design day. St. Clair River Crossing also provides access to the MichCon/DTE system and MichCon supply and storage.

In addition to the gas supply-related benefits of the St. Clair River Crossing, the capacity also facilitates ex-franchise services through Hub Services,[56] and regulated short-term transportation services (Rate C1) supporting the liquidity and overall competitiveness of the Dawn Hub.

No directly comparable supply/service options exist as the St. Clair River Crossing is the only direct link between the DTE/MichCon system(s) and the Enbridge Gas system(s). Therefore, no landed cost analysis was completed for St. Clair River Crossing capacity.

As the St. Clair River Crossing capacity supports Enbridge Gas's objective of structuring a portfolio with a diversity of contract terms and supply purchase points and is consistent with the gas supply principle of ensuring secure and reliable gas supply, Enbridge Gas renewed contracts for existing capacity for a term of one year.

5.3. Unutilized Capacity

Currently, Enbridge Gas plans annually to fully utilize (100% load factor) all upstream (long-haul) capacity contracted to deliver natural gas volumes to the EGD and Union South rate zones. The Plan contains unutilized upstream (long-haul) capacity contracted to deliver natural gas volumes to some of the Union North rate zones (i.e., EDA, WDA, and MDA) because of the transportation portfolio required to meet design day in these delivery areas (see Table 7).

[56] The St. Clair River Crossing is included as a receipt and delivery point for Hub Services. Further information on Hub Services can be found at: https://www.enbridgegas.com/storage-transportation/services/hub.

Table 7
Planned Unutilized Capacity

Line No.	Particulars (TJ)	2025 AU 2024/25	5-Year GSP 2025/26	2026/27	2027/28	2028/29	2029/30
		(a)	(b)	(c)	(d)	(e)	(f)
1	EGD	-	-	-	-	-	-
2	North West	5.5	7.9	5.6	7.8	8.3	8.5
3	North East	13.0	10.3	12.8	11.3	10.5	10.7
4	South	-	-	-	-	-	-
5	Total Planned Unutilized Capacity	18.5	18.2	18.3	19.0	18.8	19.2

While Table 7 provides the forecast of planned unutilized capacity over the forecast period (2024/25 to 2029/30), Enbridge Gas expects the implementation of outcomes from the 2024 Rebasing Phase 2 Decision, specifically the implementation of a consolidated Plan beginning with the 2025/26 gas year, will impact the planned unutilized capacity of all future years of the 5-Year GSP. Enbridge Gas will update the forecast of planned unutilized capacity reflecting the 2024 Rebasing Phase 2 Decision with the 2026 Annual Update.

5.4. Storage Portfolio

Storage is a cost effective and reliable way to manage variances in annual supply and seasonal demand. In the summer, gas deliveries via pipelines to the franchise area exceed customer demand, allowing for excess supply to be injected into storage. Conversely, during the winter season, customer demand exceeds incoming supply, and this supply deficiency is made up with storage withdrawals. Storage helps lower gas supply costs by utilizing annual transportation contracts at a higher load factor and enabling supply to be procured at more cost-effective times of the year (relative to the peak winter season). Storage gas also provides the Company with a reliable and flexible source of supply.

As some rate zones are not directly (physically) connected to Dawn storage facilities, Enbridge Gas leverages the following additional services from TCPL to provide customers in those rate zones with a similar level of service:

- TCPL STS Injections – To transport TCPL STS Injections – To transport excess supply away from certain delivery areas to Parkway to be injected into Dawn storage in the summer.

- TCPL STS Withdrawals and Enhanced Market Balancing – To withdraw supply from Dawn storage and transport it to certain delivery areas during the winter season.
- STS Pooling Rights – To provide certain delivery areas with gas supply exceeding their respective STS rights (by aggregating the rights of all relevant delivery areas).

The storage requirement forecast for in-franchise customers is derived using the aggregate excess methodology for bundled customers and the contracted storage space for semi-unbundled customers.[57] The aggregate excess methodology determines the required storage space by calculating the difference between forecasted winter demand (November – March) and the annual average daily demand for a 151-day period:

Aggregate Excess = Forecasted Winter Demand – [(Total Annual Demand x 151/365)]

Table 8 details Enbridge Gas's storage requirement over the forecast period (2024/25 to 2029/30) as included in the current Plan.

[57] Semi-unbundled customers can select from up to four methods to calculate their contracted storage space: (i) aggregate excess; (ii) 15 x obligated DCQ; (iii) peak hour consumption x 24 x 4 days (certain power customers only); (iv) contract demand x 10 (CMS customers only).

Table 8
Storage Requirement Forecast

Line No.	Particulars (PJ)	2025 AU 2024/25	5-Year GSP 2025/26	2026/27	2027/28	2028/29	2029/30
		(a)	(b)	(c)	(d)	(e)	(f)
	EGD rate zone						
1	In-franchise Storage Requirement	125.7	125.7	125.7	125.7	125.7	125.7
	Cost-Based Storage						
2	Tecumseh	99.4	99.4	99.4	99.4	99.4	99.4
3	Crowland	0.3	0.3	0.3	0.3	0.3	0.3
4	Market Based Storage	26.0	26.0	26.0	26.0	26.0	26.0
5	Space Allocated for In-franchise Use	125.7	125.7	125.7	125.7	125.7	125.7
	Union rate zones						
	In-franchise Storage Requirement						
6	System Integrity	9.5	9.5	9.5	9.5	9.5	9.5
7	In-franchise Customer Requirement	90.0	90.1	90.6	90.3	92.2	92.3
		99.6	99.6	100.2	99.8	101.7	101.8
	Cost-Based Storage						
8	Dawn	100.0	100.0	100.0	100.0	100.0	100.0
9	Excess Utility Space Available	0.4	0.4	-	0.2	-	-

While Table 8 provides the 5-Year GSP storage requirement forecast, Enbridge Gas expects the implementation of outcomes from the 2024 Rebasing Phase 2 Decision, specifically the implementation total storage space of 217.7 PJ and the management of operational contingency using inventory targets, will impact the storage requirement forecast of all future years of the 5-Year GSP.

Table 9 details Enbridge Gas's market-based storage contracts for the 2024/25 gas year.

Table 9
Summary of Enbridge Gas Market-Based Storage Contracts

Line No.	Capacity (GJ)	Effective Date	Expiration Date
	(a)	(b)	(c)
1	4,000,000	1-Apr-20	31-Mar-25
2	1,000,000	1-Apr-23	31-Mar-25
3	3,000,000	1-Apr-22	31-Mar-25
4	2,000,000	1-Apr-24	31-Mar-25
5	1,500,000	1-Apr-21	31-Mar-26
6	2,500,000	1-Apr-23	31-Mar-26
7	500,000	1-Apr-23	31-Mar-26
8	1,000,000	1-Apr-24	31-Mar-26
9	3,000,000	1-Apr-24	31-Mar-26
10	2,500,000	1-Apr-23	31-Mar-27
11	2,000,000	1-Apr-24	31-Mar-27
12	1,000,000	1-Apr-24	31-Mar-27
13	1,000,000	1-Apr-24	31-Mar-28
14	1,000,000	1-Apr-24	31-Mar-29
Total	26,000,000		

As noted in Section 2.2, changes to the Company's gas supply plan resulting from the Phase 2 Rebasing proceeding take effect for the 2025/26 gas year and will be addressed as part of the Company's 2026 Annual Update which is expected to be filed with the OEB by March 1, 2026. Included in Phase 2 impacts are adjustments to the total storage requirement (reduced from 227.7 PJ to 217.7 PJ) and market-based storage requirement (reduced from 26 PJ to 18 PJ).

Enbridge Gas has historically contracted for market-based storage services from third-party providers under contract terms ranging between one and five years. To limit exposure to storage service price fluctuations, provide annual flexibility to adjust the volumes contracted, and ensure cost-effectiveness, Enbridge Gas has strived to maintain a consistent level of contract term diversification in its third-party storage service portfolio (i.e., in terms of service term lengths and the volumes to be renewed annually). As a result of this strategy, and the flexibility inherent within the Company's market-based storage portfolio with 10 PJ of storage capacity expiring in 2025, Enbridge Gas was able to accommodate the adjustments to market-based storage requirements in 2025 resulting from the Phase 2 Rebasing proceeding. The details of the most recent blind storage RFP will be addressed within the Company's annual Disposition of Deferral and Variance Account Balances proceeding for 2025.

5.5. Commodity Portfolio

Enbridge Gas procures natural gas supply and transportation on behalf of its sales service customers. The Company's current commodity portfolio reflects many years of strategic planning and leverages much of the North American natural gas supply market, including supply from sources such as: WCSB, Dawn, the Appalachian basin, Niagara, Chicago, U.S. Mid-Continent, and Ontario Production. These supply sources, along with Enbridge Gas's transportation contracts which move the supply to both the distribution system and storage assets, have resulted in a commodity portfolio which is diverse, flexible, reliable, and cost-effective.

Figure 6
2024/25 Sources of Supply

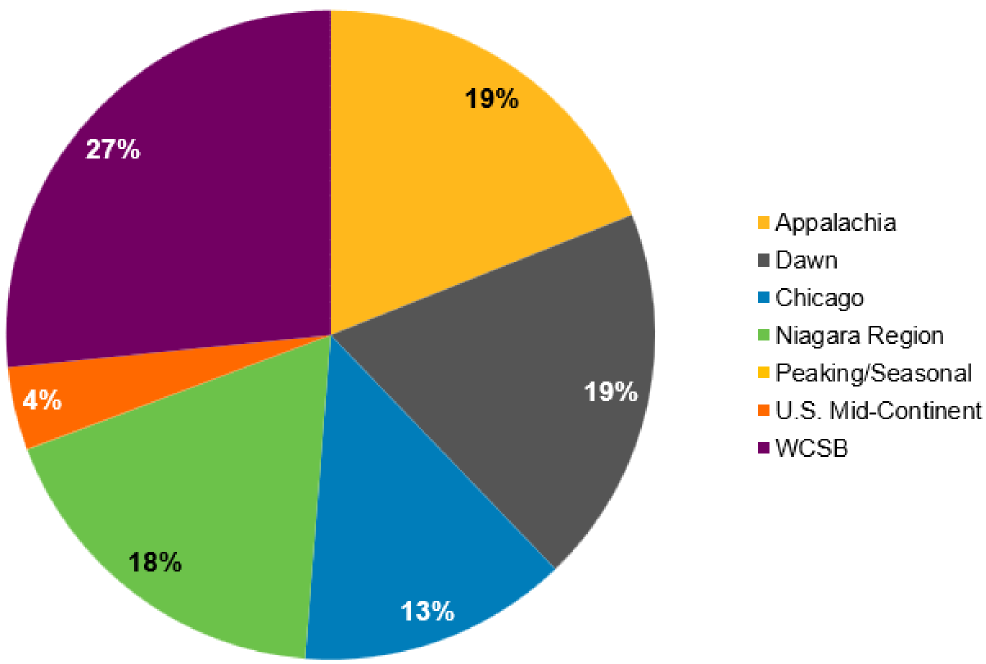


Figure 6 provides a detailed break-down of supply sources based on firm upstream transportation capacity held to each rate zone (EGD, Union North West, Union North East, and Union South). In addition, all rate zones can also procure supply from third-party service arrangements (e.g., peaking services) or delivered supply arrangements. Enbridge Gas's annual demand sources of supply is based on the annual demand forecast outlined in Section 4.2 and provided in Table 10, and excludes Bundled DP customers since these customers provide their own gas supply commodity.

Table 10
Annual Demand Sources of Supply

Line No.	Particulars (TJ)	2025 AU 2024/25 (a)	5-Year GSP 2025/26 (b)	2026/27 (c)	2027/28 (d)	2028/29 (e)	2029/30 (f)
	EGD						
1	Appalachia	42,988	42,988	42,988	43,106	42,988	42,988
2	Chicago	32,862	32,862	32,862	32,952	32,862	32,862
3	Niagara Region	87,944	91,399	94,854	95,486	94,955	94,555
4	Dawn	58,475	54,007	52,680	49,177	47,718	44,701
5	Peaking/Seasonal	112	114	116	117	118	118
6	WCSB	109,305	107,966	105,676	105,934	104,984	104,598
7	Total EGD	331,686	329,335	329,174	326,771	323,624	319,822
	Union North West						
8	WCSB	21,188	18,727	21,101	18,984	18,361	18,179
	Union North East						
9	Appalachia	19,255	19,254	19,255	19,308	19,255	19,255
10	Dawn	2,226	4,887	2,474	4,141	4,801	4,602
11	WCSB	1,980	1,980	1,980	1,982	1,980	1,980
12	Total North East	23,461	26,122	23,710	25,431	26,036	25,837
	Union South						
13	Appalachia	38,510	38,510	38,510	38,615	38,510	38,510
14	Chicago	38,509	38,509	38,509	38,601	38,509	38,509
15	Niagara Region	7,702	7,702	7,702	7,723	7,702	7,702
16	Dawn	39,480	38,569	39,847	37,452	37,800	36,632
17	U.S. Mid-Continent	21,950	21,950	21,950	22,011	21,950	21,950
18	WCSB	8,797	8,797	8,797	8,818	8,797	8,797
19	Total South	154,948	154,038	155,315	153,220	153,268	152,100
20	Total Supply Forecast	531,283	528,222	529,299	524,406	521,290	515,939

5.6. Design Day Supply/Service Option Analysis

The following section discusses various supply/service options available to serve delivery areas (Enbridge CDA, Enbridge EDA, Union EDA, and Union NDA) where design day shortfalls are projected. As noted in Section 4.5, Enbridge Gas has forecasted design day shortfalls for the Enbridge CDA, Enbridge EDA, Union EDA and Union NDA delivery areas in every year of the forecast period (2024/25 to 2029/30).

As outlined in Section 2.3, the Plan is updated annually and includes preparation of the annual and design day demand forecasts and updated design day surplus or shortfall positions for each of the nine delivery areas served. Enbridge Gas contracts for shortfall amounts forecasted in the first year of the forecast period (2024/25 for the current Plan), in advance of November 1 of that year. Shortfalls calculated in future years (2025/26 and beyond for the current Plan) will be updated as part of Enbridge Gas's annual gas supply planning process. In future Annual Updates, Enbridge Gas will include updated demand forecasts, applicable shortfalls and updated supply option analysis. Accordingly, this section provides an overview of supply options available to Enbridge Gas for the 2024/25 gas year. Supply/service options evaluated and procured to address the specific design day shortfalls for 2024/25 of 253 TJ/d for the Enbridge CDA, 14 TJ/d for the Enbridge EDA, 2 TJ/d for the Union EDA, and 11 TJ/d for the Union NDA are described below. Supply/service options to manage design day events are identified (in Tables 11,13,15,17) for each delivery area and evaluated (in Tables 12,14,16,18) based on a common set of characteristics (reliability, flexibility, diversity, and annual cost). Representative maps of each of the options identified are set out in Figures 7-10.

The supply/service options identified in Tables 11,13,15, and 17 represent viable supply/service options that may be available during the forecast period (2024/25 to 2029/30) to meet the design day shortfalls in the Plan for each of the respective service areas. Annual cost impacts are based upon contracting for 5 years to resolve the full design day shortfall for each respective delivery area. However, due to overall transportation capacity scarcity (as discussed in Section 5), the options identified are non-exhaustive and may have capacity limitations during the forecast period.

The symbols applied in evaluation Tables 12,14,16, and 18, describe whether a particular supply/service option is anticipated to have a positive, neutral, or negative impact on the Company's ability to satisfy a design day shortfall as compared to the current Portfolio.

Enbridge CDA

Table 11
Enbridge CDA Supply/Service Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Long-haul	TCPL	FT-LH	Empress	-	ECDA
Short-haul: D-P	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	ECDA
Short-haul: Dawn	EGI	D-P	Dawn	-	ECDA
Short-haul: Niagara	TCPL	FT-SH	Niagara	-	ECDA
Third-Party	Market Participants	Peaking, Del Serv	ECDA	-	ECDA

Table 12
Enbridge CDA Supply/Service Option Evaluation

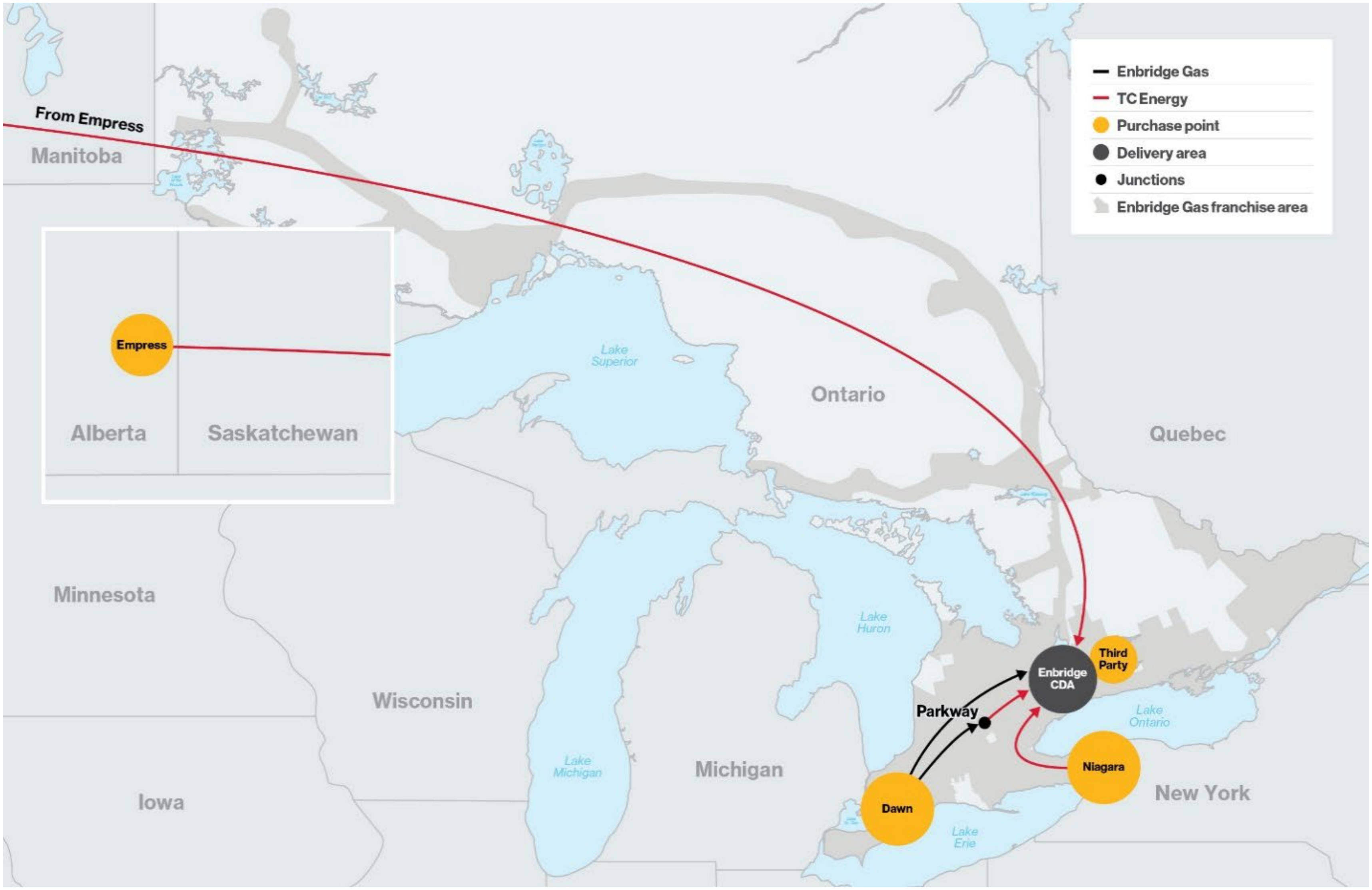
Option	Reliability	Flexibility	Diversity	Costs ($ million/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	→	→	↑	121.74	~3%	No (1)
Short-haul: D-P	↑	→	→	38.79	<1%	No
Short-haul: Dawn	↑	→	→	23.46	<1%	No
Short-haul: Niagara	→	→	→	28.30	<1%	No (2)
Third-Party	↓	↓	↑	29.05	<1%	Unknown

Note:
(1) There is currently no available long-haul capacity however, there was an existing capacity open season during 2024 where Enbridge Gas was able to secure incremental long-haul capacity for the Enbridge CDA.
(2) There is currently no available short-haul capacity from Niagara to Enbridge CDA on TCPL. Accordingly, and as discussed in Section 5.2, Enbridge Gas sought out third-party assignment of such capacity to manage the design day shortfall for the 2024/25 gas year

As a result of the 2024/25 design day shortfall in the Enbridge CDA of 253 TJ/d, Enbridge Gas contracted for the following in 2024: 34,457 GJ/d Empress to Enbridge CDA capacity, 121,142 GJ/d Niagara to Enbridge CDA capacity, and 97,289 peaking services (equivalent to 2.7% of design day demand for the Enbridge CDA).[58] These transactions are further described in Section 5.1.

[58] Enbridge Gas will re-evaluate the proportion of reliance on peaking services before November 1 each year as part of its portfolio review, considering market changes and availability of pipeline capacity.

Figure 7
Enbridge CDA Supply/Service Options Map



Enbridge EDA

Table 13
Enbridge EDA Supply/Service Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Long-haul	TCPL	FT-LH	Empress	-	EEDA
Short-haul: D-P	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	EEDA
Short-haul: Niagara	TCPL	FT-SH	Niagara	-	EEDA
Short-haul: Iroquois	TCPL	FT-SH	Iroquois	-	EEDA
Third-Party	Market Participants	Peaking, Del Serv	EEDA	-	EEDA

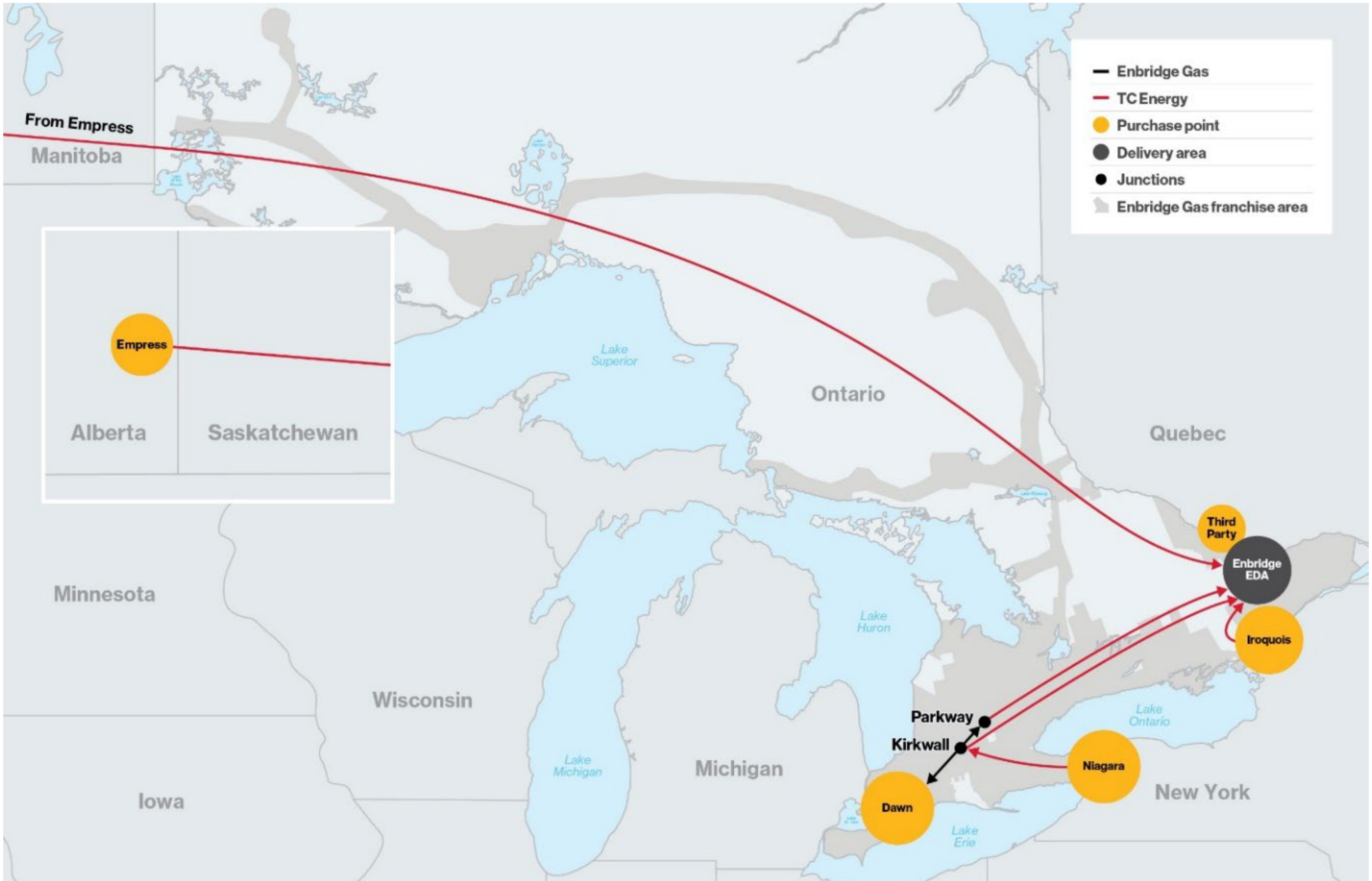
Table 14
Enbridge EDA Supply/Service Option Evaluation

Option	Reliability	Flexibility	Diversity	Costs ($ million/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	↑	↑	→	7.97	<1%	No
Short-haul: D-P	↑	→	→	4.05	<1%	No
Short-haul: Niagara	→	→	↑	3.75	<1%	No
Short-haul: Iroquois	→	→	↑	2.70	<1%	No
Third-Party	→	↓	↑	2.02	<1%	Unknown

As a result of the 2024/25 design day shortfall in the Enbridge EDA of 14 TJ/d, Enbridge Gas contracted for additional peaking services in 2024 of 14 TJ/d, equivalent to 2% of design day demand for the Enbridge EDA.[59]

[59] Enbridge Gas will re-evaluate the proportion of reliance on peaking services before November 1 each year as part of its portfolio review, considering market changes and availability of pipeline capacity.

Figure 8
Enbridge EDA Supply/Service Options Map



Union EDA

Table 15
Union EDA Supply/Service Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Long-haul	TCPL	FT-LH	Empress	-	Union EDA
Short-haul: D-P	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	Union EDA
Short-haul: Niagara	TCPL	FT-SH	Niagara		Union EDA
Short-haul: Iroquois	TCPL	FT-SH	Iroquois	-	Union EDA
Third-Party	Market Participants	Peaking, Del Serv	Union EDA	-	Union EDA

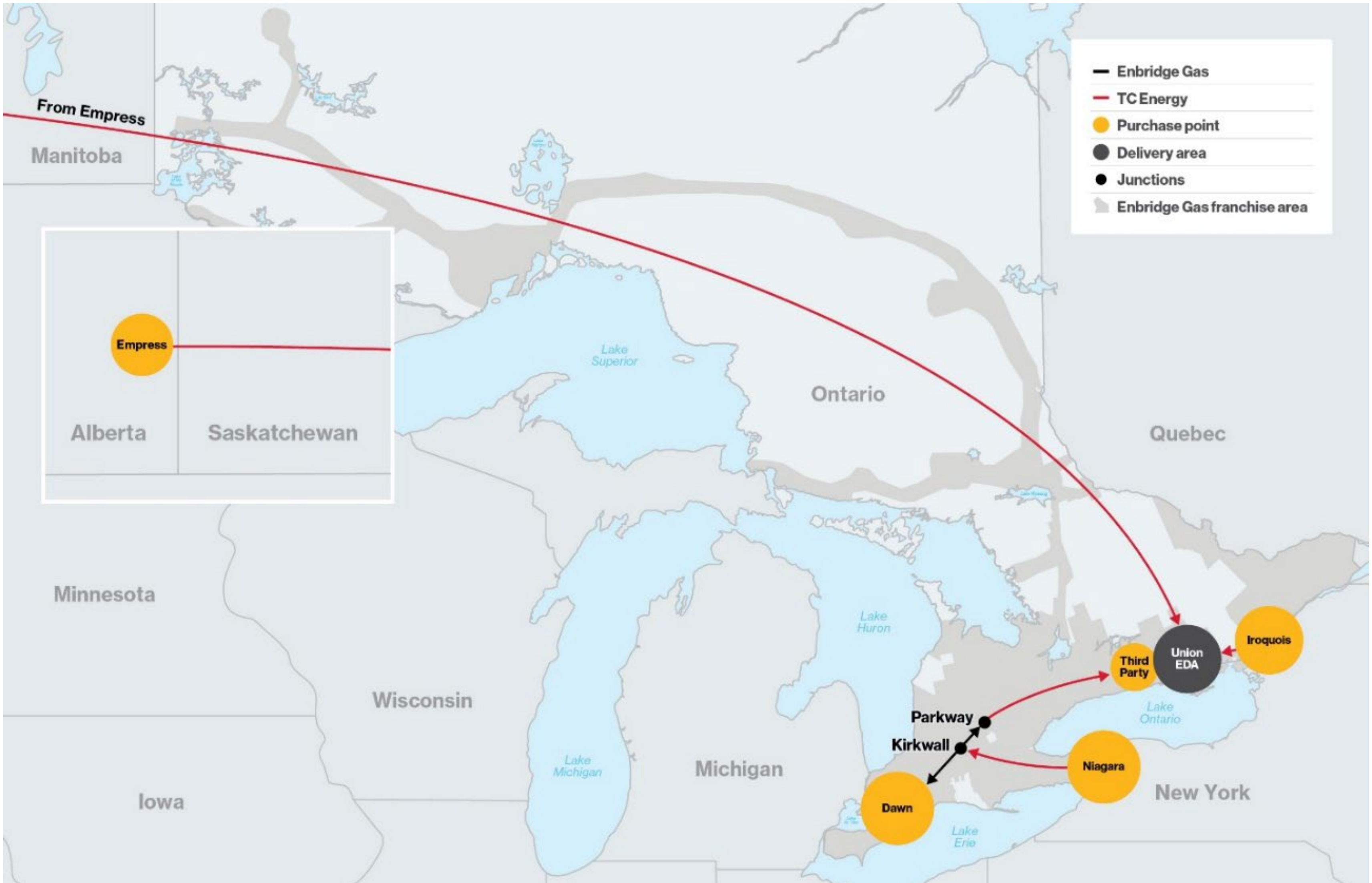
Table 16
Union EDA Supply/Service Option Evaluation

Option	Reliability	Flexibility	Diversity	Costs ($ million/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	↑	↑	↑	1.16	<1%	No
Short-haul: D-P	↑	→	→	0.50	<1%	No
Short-haul: Niagara	→	→	↑	0.53	<1%	No
Short-haul: Iroquois	→	→	↑	0.39	<1%	No
Third-Party	→	↓	↑	0.28	<1%	Unknown

As a result of the 2024/25 design day shortfall in the Union EDA of 2 TJ/d, Enbridge Gas contracted for additional peaking services in 2024 of 2 TJ/d, equivalent to 1% of design day demand for the Union EDA.[60]

[60] Enbridge Gas will re-evaluate the proportion of reliance on peaking services before November 1 each year as part of its portfolio review, considering market changes and availability of pipeline capacity.

Figure 9
Union EDA Supply/Service Options Map



Union NDA

Table 17
Union NDA Supply/Service Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Long-haul	TCPL	FT-LH	Empress	-	Union NDA
Short-haul: D-P	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	Union NDA
LNG	EGI	Liquefaction	Union NDA	-	Union NDA
Third-Party	Market Participants	Peaking, Del Serv	Union NDA	-	Union NDA

Table 18
Union NDA Supply/Service Option Evaluation

Option	Reliability	Flexibility	Diversity	Costs ($ million/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	↑	↑	→	3.09	<1%	No
Short-haul: D-P	↑	→	→	2.36	<1%	No
LNG	→	↑	↑	0.22	<1%	Yes
Third-Party	↓	↓	↑	1.14	<1%	Unknown

As a result of the 2024/25 design day shortfall in the Union NDA of 11 TJ/d, equivalent to 6% of the design day demand for the Union NDA, Enbridge Gas intends to utilize existing LNG facilities (Hagar) within the Union NDA, as available, to serve delivery area shortfalls.

Figure 10
Union NDA Supply/Service Options Map

5.7. Average Day Supply/Service Option Analysis

The following section discusses various supply/service options available to address changes in average day demand. Generally, Enbridge Gas manages changes in average day demand through purchases at Dawn. Going forward, Enbridge Gas will continue to monitor changes in average day demand and make supply and service procurement decisions using the best available information at the time.

Supply/service options to manage changes in average day demand are identified in Table 19 and evaluated in Table 20 based on a common set of characteristics (reliability, flexibility, diversity, and landed cost). A representative map of each of the options identified is set out in Figure 11.

The supply/service options identified in Table 19 represent viable supply/service options that may be available during the forecast period (2024/25 to 2029/30) to address changes in average day demand in each of the respective service areas. However, due to overall transportation capacity scarcity (as discussed in Section 5), the options identified are non-exhaustive and may have capacity limitations during the forecast period.

The symbols applied in evaluation Table 20 describe whether a particular supply/service option is anticipated to have a positive ⬆, neutral ➡, or negative ⬇ impact on the Company’s ability to satisfy changes in average day demand as compared to the current Portfolio.

Table 19
Average Day Supply/Service Options

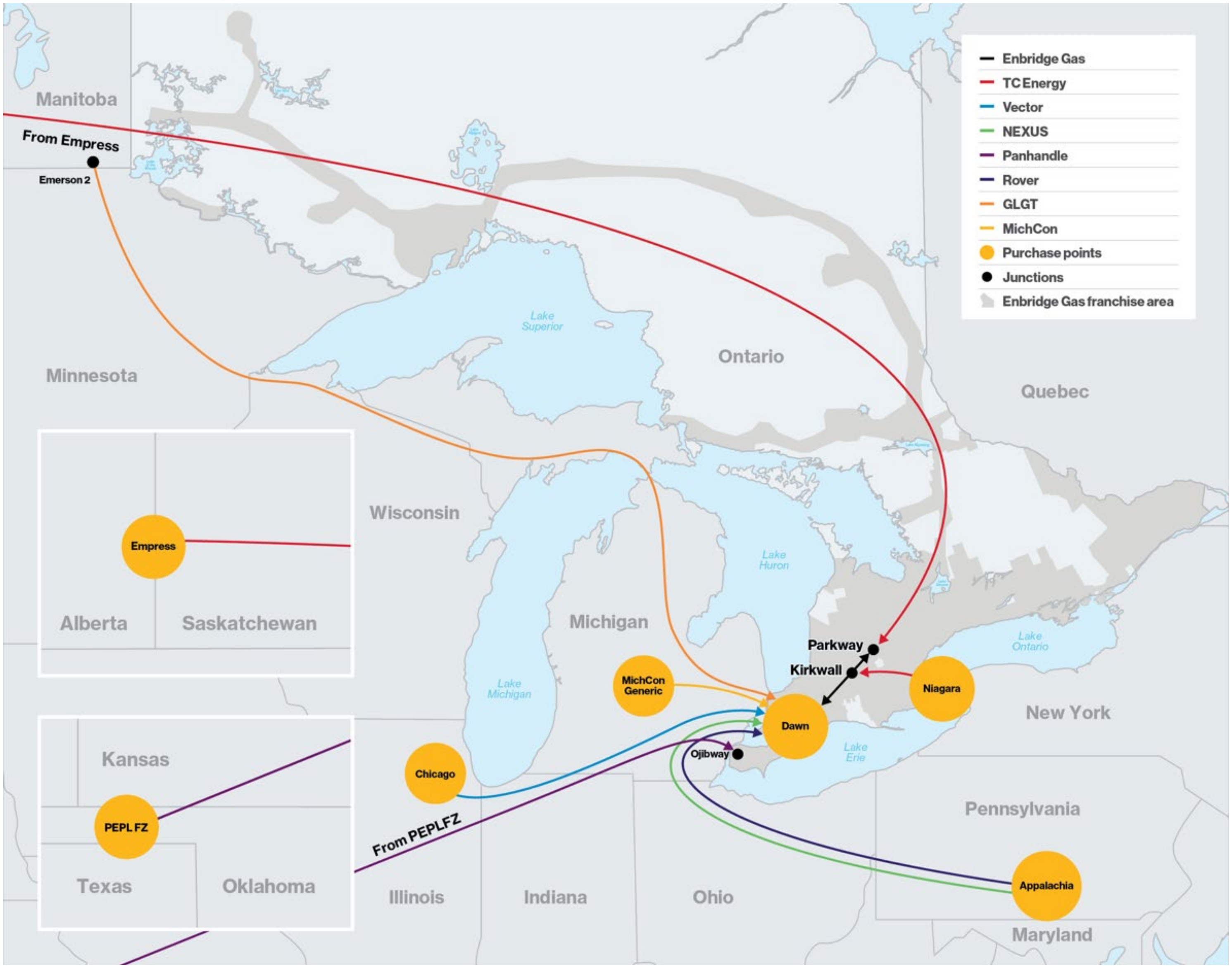
Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Dawn	-	-	Dawn	-	Dawn
Great Lakes	TCPL + GLGT	FT-LH + FT	Empress	Emerson	Dawn
MichCon	DTE + EGI	FT	MichCon	St. Clair	Dawn
Vector	Vector	FT-1	Chicago	-	Dawn
PEPL	PEPL + EGI	FT	Panhandle FZ	Ojibway	Dawn
NEXUS	NEXUS	FT	Dominion	-	Dawn
Rover	Rover	FT	Dominion	-	Dawn
Niagara	TCPL + EGI	FT	Niagara	Kirkwall	Dawn

Table 20
Average Day Supply/Service Option Evaluation

Option	Relative to Status Quo			Costs ($/GJ/d)	Average Cost/Customer Impact - Relative to Status Quo	Available Capacity
	Reliability	Flexibility	Diversity			
Dawn	-	-	-	4.34	-	Yes
Great Lakes	→	→	→	4.20	<1%	No
MichCon	→	→	↑	4.49	<1%	No
Vector	→	→	→	4.55	<1%	No
PEPL	→	→	→	4.81	<1%	Yes
NEXUS	→	→	→	5.07	<1%	Yes
Rover	→	→	↑	4.86	<1%	No
Niagara	→	→	→	4.18	<1%	No

As discussed in Section 4.3, Enbridge Gas is not currently seeking to increase gas supply assets to serve forecast annual demand changes.

Figure 11
Average Day Supply/Service Options Map



6. Achieving Public Policy

The following sections explain how the Plan was developed in support of and in alignment with public policy.

6.1. Global Policy Developments

This section discusses global policy developments that may impact the Plan. All climate and energy transition related global policy developments with the potential to impact/influence gas demand in Ontario that Enbridge Gas is currently aware of have been considered.

As discussed in Section 4, numerous factors (e.g., customer behaviour, weather, price, and economic conditions) beyond climate and energy transition policy influence natural gas demand.

Paris Agreement

In 2015, the Paris Agreement was established as a legally binding international treaty on climate change and was agreed to by 196 countries at the United Nations Climate Change Conference. The Paris Agreement sets long-term goals for all nations to substantially reduce greenhouse gas (GHG) emissions to keep global temperature increases to below 2 degree Celsius above pre-industrial levels. Since 2020, countries have been submitting their national climate action plans, known as nationally determined contributions (NDCs). Each successive NDC is meant to reflect an increasingly higher degree of ambition compared to the previous version. Currently 195 out of 198 United Nation countries have ratified the Paris Agreement. On January 20, 2025, an executive order was issued by the President of the United States to withdraw from the Paris Agreement under the United Nations Framework Convention on Climate Change.[61]

As a signatory to the Paris Agreement, the Government of Canada has committed to long-term climate action by setting GHG emissions reduction targets. Canada submitted its most recent NDC on February 11, 2025, setting emission reduction targets of 45-50% below 2005 levels by 2035.[62] As a mechanism to achieve Canada's NDCs, in 2016 the Pan-Canadian Framework on Clean Growth and Climate Change was adopted by the federal, provincial, and territorial governments as a framework for Canada's first national climate strategy. The establishment of the Pan-Canadian Framework has

[61] https://www.whitehouse.gov/presidential-actions/2025/01/putting-america-first-in-international-environmental-agreements/.

[62] https://unfccc.int/sites/default/files/2025-02/Canada%27s 2035 Nationally Determined Contribution_ENc.pdf.

driven the implementation of various climate policies throughout Canada, both at the federal and provincial level.

United States Trade Policy

The United States (U.S.) government has introduced tariffs under the International Emergency Economic Powers Act of 1977 (IEEPA) aimed at addressing trade imbalances, protecting domestic industries, and responding to trade actions by other countries. At the time of this filing, tariffs on non-USMCA compliant energy are 10%, however, Canadian origin natural gas imports into the U.S. from Canada fall within the USMCA exemption and are not subject to tariffs.[63] While the imposition of tariffs or the USMCA exemption are subject to change at any time without notice, the Plan does not import natural gas into the U.S. for consumption. The Plan does use U.S. located pipelines to transport gas originating from the WCSB through the U.S. to Ontario.

The Plan also uses U.S. located pipelines to transport and import gas originating in the U.S. to Canada. Should Canada impose retaliatory tariffs on U.S. origin natural gas imports, the costs of the Plan could be impacted by the imposition of Canadian tariffs.

Enbridge Gas will continue to closely monitor the U.S. trade policy related to tariffs on energy, including any response by Canada, and provide updates in future Annual Updates. The ultimate long-term impact of tariffs on natural gas demand in Ontario is currently unknown. Should the Plan be impacted by the cost of tariffs in the future, Enbridge Gas will record the incremental cost in the respective Purchased Gas Variance Account for the applicable rate zones and seek to recover the costs through future QRAM applications. To the extent possible, Enbridge Gas would consider the cost impact of tariffs and adjust the Plan execution accordingly. If such tariffs are anticipated to be ongoing, Enbridge Gas will consider the impacts in future contracting decisions.

Canada and Ontario

Discussions of federal and Ontario climate and energy policies have been provided in prior Gas Supply Plans,[64] Rebasing,[65] and Leave to Construct applications submitted as recently as June 2024.[66] These federal and provincial policies remain as previously described, apart from the following subsequent developments:

[63] All products of Canada and Mexico that comply with the United States-Mexico-Canada Agreement (USMCA) and are imported into the U.S. are currently exempt from tariffs.
[64] EB-2024-0067, 2024 Annual Gas Supply Plan Update, p. 20.
[65] EB-2022-0200, Enbridge Gas's 2024 Rebasing Application Exhibit 1, Tab 10, Schedule 3.
[66] EB-2024-0200, St. Laurent Replacement Project, Exhibit B, Tab 3, Schedule 1, Section 2, pp. 7-9.

Federal

- The Canada Green Building Strategy was released on July 16, 2024, and identified three strategic priorities: accelerate retrofits, build green and affordable from the start, and shape the building sector of the future.
- In 2024, the Canadian Board for Harmonized Construction Codes indicated that it is seeking to introduce Operational GHG performance standards with the 2025 National Building Code of Canada (NBC) and National Energy Code of Canada for Buildings (NECB).[67] Six Operational GHG performance levels are being proposed which seek to reduce operational building emissions by zero to 90 percent from a baseline level of performance.[68] The 2025 NBC and NECB are anticipated to be released in the second half of 2025, upon which provinces have 18 months to harmonize their provincial building codes with a performance level of their choosing. Since provincial governments may select the baseline level of operational GHG performance, it is not known to what extent the introduction of these operational GHG performance standards may impact the demand for natural gas in new buildings in Ontario.
- The Clean Electricity Regulation was finalized in December 2024 and came into force January 1, 2025.[69] The Clean Electricity Regulation sets emission performance standards that fossil-fuel based power generating facilities with a capacity of 25 MW or greater must adhere to starting on January 1, 2035. Fossil-fuel based power generating facilities have flexibility in how they can comply with the Clean Electricity Regulation. Facilities can lower their emissions and achieve compliance with the Clean Electricity Regulation using renewable natural gas (RNG), hydrogen, carbon capture and storage, or provide compliance or carbon offset credits for emission limit exceedances. At this time, it is not known what impact to the demand for natural gas or RNG may arise in 2035 and beyond because of the Clean Electricity Regulation.
- On March 15, 2025, the Government of Canada issued *Regulations Amending Schedule 2 to the Greenhouse Gas Pollution Pricing Act and the Fuel Charge Regulations*,[70] setting the federal carbon charge to zero after March 31, 2025. On March 26, 2025, Enbridge Gas received approval for the removal of the Federal Carbon Charge and Facility Carbon Charge from its distribution rates effective April 1, 2025.[71]

---

[67] https://cbhcc-cchcc.ca/en/archived-public-review-of-proposed-changes-to-the-2020-national-model-codes-winter-2024/.
[68] https://nrc-publications.canada.ca/eng/view/accepted/?id=af8d14da-5b71-46be-bb96-d114aeba5dee
[69] https://www.gazette.gc.ca/rp-pr/p2/2024/2024-12-18/html/sor-dors263-eng.html.
[70] https://www.gazette.gc.ca/rp-pr/p2/2025/2025-03-15-x2/html/sor-dors107-eng.html.
[71] EB-2025-0078, OEB Decision and Interim Rate Order, p. 7.

Ontario

- In March 2024, Ontario's Emissions Performance Standard (EPS) Program was amended to explicitly recognize pipeline delivered RNG as a means to reduce EPS covered facility emissions. RNG must be produced within Ontario for it to be eligible for recognition under the EPS.
- Ontario's Affordable Energy Future was released in October 2024 and discussed the important role that natural gas, RNG, hydrogen, carbon capture and storage, and natural gas infrastructure play within Ontario. The Ontario government also conducted a consultation on the role of natural gas between December 2024 to January 2025 and has indicated that it will release a Natural Gas Policy Statement to support the Integrated Energy Plan to be released in 2025.[72]

Natural Gas Expansion Program (NGEP)

In 2021, the Government of Ontario passed *Ontario Regulation 451 Expansion of Natural Gas Distribution Systems*. Under the regulation, 28 projects across 43 communities were selected for potential funding, 27 of these projects were proposed by Enbridge Gas. As of March 2025, Enbridge Gas has completed ten out of the 27 proposed projects, and the remaining projects are in the planning or construction stages.

In August 2023, the Government of Ontario sought input from the public on a potential Phase 3 of the NGEP.[73]

The number of new customers added and anticipated to be added to Enbridge Gas's system as part of these community expansion projects is relatively small in comparison to its existing customer base and forecasted growth. As a result, the increased gas demands from these projects can be accommodated within the existing Plan.

6.2. Gas Supply Impacts on Avoided Facilities

Included in the OEB Staff Report on the 2024 Annual Update was a recommendation that Enbridge Gas include a description of potential facility benefits that could result from gas supply contracting. OEB Staff's recommendation followed Enbridge Gas's Reply Submission, which stated:[74]

> Where relevant, Enbridge Gas will provide information about infrastructure requirements that are potentially avoided or reduced by gas supply decisions, as can be the case with third party gas supply contracts to serve the Sarnia market. The

[72] https://ero.ontario.ca/notice/019-9501.
[73] https://ero.ontario.ca/notice/019-7506.
[74] EB-2024-0067, Enbridge Gas Reply Submission, p. 5.

> Company notes, though, that this will often be more qualitative or narrative evidence than quantitative analysis, since the infrastructure being potentially avoided may not be a near-term requirement identified and costed within the Asset Management Plan. To be clear, Enbridge Gas does not plan to provide specific cost avoidance or cost-benefit quantification evidence in its filings that detail potential infrastructure avoidance benefits from gas supply decisions unless the costs of the potentially required future facilities have already been quantified in the Asset Management Plan or elsewhere.

Gas Supply Plan Impacts on Transmission Systems

Enbridge Gas defines its transmission system capacity as a function of: (i) pipeline and compressor facilities in operation; (ii) the location that demand is being consumed; and (iii) the location of supply delivery to the system (including Plan deliveries, customer obligations and firm receipt points).

Enbridge Gas utilizes forecasted gas supply contracts when developing its 10-year Asset Management Plan (AMP), which can impact the timing of transmission projects by providing firm supply at or flowing past known transmission system locations (e.g. Parkway, Ojibway or Courtright) and therefore enables Enbridge Gas to design transmission requirements including these deliveries.

On an annual basis, Enbridge Gas files an updated AMP with the OEB, where it outlines all forecasted capital projects/expenditures, including future transmission system expansion projects. In compliance with the Integrated Resource Plan (IRP) Framework,[75] Enbridge Gas conducts IRP screening and evaluation of all investments in the AMP.

The following subsections explain the inter-dependent nature of gas supply planning with regard to serving the needs of in-franchise customers and in terms of (transmission) facilities planning. Specific examples of Enbridge Gas infrastructure that has been avoided or reduced (i.e. in terms of scope) as a result of gas supply contracting are also discussed.

Panhandle Transmission System

As outlined in Section 5, Enbridge Gas currently contracts 60 TJ/d on PEPL. Since 2013, Enbridge Gas's Panhandle system has included the Plan supply received at the Ojibway Interconnect for purposes of Panhandle design day planning. The impact of including this upstream supply has offset and/or delayed facilities required on the Panhandle system since 2013. Enbridge Gas has subsequently expanded the Panhandle system in 2017, 2019, and most recently in 2024 to meet continued growing demands of in-franchise customers. However, without utilizing the upstream supply of

[75] EB-2020-0091, OEB Decision and Order, Section 8, July 22, 2021.

60 TJ/d delivered at Ojibway, the transmission expansions since 2013 would have needed to be advanced by multiple years.

Sarnia Industrial Line System

From an Enbridge Gas transmission system planning perspective, the SIL system developed independent of Dawn due to the proximity of large volume third-party pipelines and volumes of Enbridge Gas-contracted natural gas supplies flowing past the SIL system on its way to Dawn. These gas supply volumes have historically been greater than the demand requirements for the Sarnia market on design day. For this reason, the Plan considers natural gas supplies flowing past the Courtright station (on the SIL system) or gas flowing on MichCon (as it can only flow into SIL) as the primary source(s) of supply on a design day for the Sarnia market.

Reliance upon such supplies continues to defer the need for reinforcement from the Dawn Hub to the SIL system. In other words, if Enbridge Gas did not renew upstream transportation contracts with the ability to supply the SIL system (i.e., Vector, Great Lakes, NEXUS), reinforcement from the Dawn Hub would be required to meet the Sarnia market demands on design day.

Dawn Parkway Transmission System (Dawn Parkway)

Enbridge Gas relies on Parkway and Kirkwall deliveries for Dawn Parkway system design day planning purposes. Reliance on such delivery contracts, including third-party assignment contracts, as part of the Dawn Parkway system design reduces the facilities required to meet design day needs.

As discussed in Section 5.2, as result of growth and a change in design day demand methodology,[76] the Enbridge CDA has exhibited increased demand for the winter 2024/25. To meet this incremental demand, effective December 1, 2024, Enbridge Gas contracted for temporary assignment of incremental capacity from Niagara to the Enbridge CDA on TCPL for a five-year term to deliver additional natural gas to the Enbridge CDA through four months of the winter. This contract, alongside other gas supply contracts delivering into Parkway, Kirkwall or markets served by the Dawn Parkway system, offsets the need for additional facilities on the Dawn Parkway system as well as downstream markets like the Enbridge CDA. Absent these services, additional natural gas facilities would be required in both the Dawn Parkway system and the Enbridge CDA.

[76] EB-2022-0200, Exhibit 4, Tab 2, Schedule 3.

6.3. Lower-Carbon Energy in the Gas Supply Portfolio

Enbridge Gas recognizes the importance of emissions reductions in Ontario, as well as the important role that Enbridge Gas plays in supporting the achievement of the province's GHG emissions reduction targets.

Pursuing energy transition through Enbridge Gas's gas supply portfolio provides an opportunity for Ontario to meet its GHG emissions reduction targets in alignment with OEB's Guiding Principles. To date, Enbridge Gas has supported the energy transition through the purchase of RNG, the inclusion of certified gas in the gas supply portfolio, and the purchase of hydrogen through the Low Carbon Energy Project. Enbridge Gas has proposed to increase the volume of lower-carbon energy included in the gas supply portfolio as part of Phase 2 of its 2024 Rebasing Application.[77]

Renewable Natural Gas

RNG is a lower-carbon fuel that will play a role in Ontario's energy transition. Displacing conventional natural gas with RNG reduces GHG emissions on an end-use basis. RNG is produced from decomposing organic matter (e.g., food waste, human and animal wastes), which creates biogas that can be upgraded to pipeline quality methane. As a "drop-in" fuel, RNG can be used to fuel transit fleets, power industry, and heat homes and businesses, and is a solution to help companies and communities reduce GHG emissions.

On a lifecycle basis, RNG can provide two separate and distinct emissions reduction benefits:

1. Direct emissions reduced through displacing combustion of conventional natural gas. On an end-use basis, when RNG displaces a conventional natural gas molecule, the GHG emission avoidance is equivalent to 0.05 tonnes of carbon dioxide equivalent per gigajoule (tCO_2e/GJ) of RNG.[78] It is important to note that although 0.05 tCO_2e/GJ is emitted when a GJ of either conventional natural gas or RNG is burned, the CO_2 released from RNG is biogenic as the feedstocks for RNG production are ultimately produced from plants that consume atmospheric CO_2 as

[77] EB-2024-0111, Phase 2 Exhibit 4, Tab 2, Schedule 7.
[78] The emission factor for natural gas in Ontario can be calculated from the Marketable Natural Gas charge of $0.1525/cubic meter (Greenhouse Gas Pollution Pricing Act, June 20, 2024, Schedule 1, Table 5, p. 236, https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf), divided by 2024 carbon price of $80/$tCO_2e$ (Greenhouse Gas Pollution Pricing Act, June 20, 2024, Schedule 4, p. 257, https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf) and equals 0.001906 tCO2e/cubic meter.
Based on the Enbridge Gas South annual heating value of 0.03909 GJ/m^3, effective July 1, 2024, the emission factor in energy units is 0.04877 tCO_2e/GJ.

they grow, and therefore not a net increase in GHG emissions.[79] This is recognized by federal and provincial GHG reporting programs, including Ontario's EPS, which allow reporters to subtract the CO_2 emissions from combustion of RNG from their reportable GHG emissions.

2. Upstream and indirect emissions reductions vary according to the type of RNG produced. Organic wastes streams, such as livestock manure or food wastes, are typically managed in open air pits or landfills where methane is produced and released to the atmosphere. When these organic waste streams are alternatively processed in anaerobic digesters, the methane that would have otherwise been released to the atmosphere is instead captured and utilized to produce RNG.

Voluntary Renewable Natural Gas Program

Enbridge Gas launched the Voluntary Renewable Natural Gas (VRNG) program on April 1, 2021,[80] and as of March 31, 2025, there were 3,260 customers enrolled in the program. As of March 31, 2025, Enbridge Gas has made three purchases of RNG as part of the VRNG program, procuring 5,600 GJ in total, with 2,300 GJ procured in the 2023/24 gas year. Enbridge Gas continues to monitor the forecast 12-month contributions based on actual participants and will procure additional RNG based on these forecast contributions when this amount is sufficient to procure a tranche of RNG.

The VRNG program allowed Enbridge Gas to procure RNG on behalf of program participants, however, volumes were limited by lower-than-expected participation in the program. As outlined in Phase 2 of Enbridge Gas's 2024 Rebasing Application,[81] the marketing spends and timing of the VRNG program was strongly correlated with participant enrollment. Smaller volume customers do not interact often with the utility and there is a considerable amount of Company effort required to encourage taking specific actions such as electing participation in VRNG. In addition, Enbridge Gas identified challenges with the enrollment process including customers needing to input their account number, which they may not have available when completing the form.[82]

[79] Report Update: Biomethane Greenhouse Gas Emissions Review, March 31, 2017, https://www.cdn.fortisbc.com/libraries/docs/default-source/services-documents/offsetters-biomethane_greenhouse_gas_emissions_reviewe6fecb594de843768ae02951f4b8d3eb.pdf?sfvrsn=821688c4_2.
[80] EB-2020-0066, OEB Decision on Voluntary Renewal Natural Gas Program Application.
[81] EB-2024-0111, Exhibit 4, Tab 2, Schedule 7.
[82] EB-2024-0111, Exhibit I.4.2-SEC-34.

Lower-Carbon Voluntary Program (LCVP)

Phase 2 of Enbridge Gas's 2024 Rebasing Application includes a proposal to procure lower-carbon energy, with a focus on RNG, as part of the gas supply commodity portfolio beginning in 2026.[83] The LCVP provides the opportunity for large volume sales service customers with an annual consumption greater than 15,000 m^3 to elect a percentage of gas supply as RNG. The program is proposed following an assessment of experience gained through the VRNG program and more recent activities including the Customer Engagement Survey,[84] discussions with customers, and letters of support.[85] RNG supply not elected through the LCVP will be blended into the gas supply commodity portfolio for all sales service customers. The program seeks to procure up to 0.25% (1.3 PJ) of Enbridge Gas's supply as RNG in 2026, increasing to 2% (10.5 PJ) in 2029. If approved by the OEB, this program will replace the existing VRNG program.

Certified Natural Gas

Certified natural gas is conventional natural gas that has been produced to meet a specified set of standards and practices. Enbridge Gas supports the goals of certified gas and suppliers implementing practices to lower emissions and achieve environmental, social and governance (ESG) goals. Enbridge Gas procures certified natural gas as part of the gas supply commodity portfolio, however, does not pay a premium to include certified natural gas in the gas supply and currently does not have a strategy to actively increase procurement of certified gas. The proportion of certified natural gas of the total 2023/24 gas supply portfolio was 4.5%.

Low Carbon Energy Project

Enbridge Gas submitted a revised Leave to Construct application for the Low Carbon Energy Project (LCEP) with the OEB on March 31, 2020. Following OEB approval in the fall of 2020, construction started on the associated hydrogen blending facilities. Construction and commissioning were completed in September 2021, and the plant began blending up to 2% hydrogen by volume on October 1, 2021, for approximately 3,600 customers in Markham, Ontario. From November 2023 through the end of October 2024, the energy equivalent of hydrogen that has been blended into the system and purchased as part of the Plan is 1,216 GJ.

In its 2024 Rebasing Application, Enbridge Gas proposed to undertake a Hydrogen Blending Grid Study to evaluate the hydrogen-readiness of all aspects of Ontario's natural gas grid to accept greater amounts of hydrogen which would enable further

[83] EB-2024-0111, Exhibit 4, Tab 2, Schedule 7.
[84] EB-2020-0200, Exhibit 1, Tab 6, Schedule 1, Attachment 1.
[85] EB-2024-0111, Exhibit 4, Tab 2, Schedule 7, Attachments 1 and 3.

emission reductions and prepare for the future of hydrogen blending in the province.[86] The Hydrogen Blending Grid Study was initiated in 2023 and will be completed in 2026.[87]

7. Forecast Risk

The Plan is developed using forecasts that are underpinned by assumptions based on the best available information at the time. Accordingly, the forecasts set out within the Plan will differ from reality. The sections that follow discuss some of these inherent risks in the Plan forecasts. However, Enbridge Gas is not able to forecast all major market or geo-political events.

7.1. Variation to Planned Assumptions

Weather Variation Risk

Enbridge Gas assumes normal weather[88] when developing annual demand forecast for the Plan. However, normal weather is an assumption based on a trend, and it is expected that weather will vary from that trend each year. Temperatures can be colder which generally drives higher demand and market prices, or warmer which generally drives lower demand and market prices.

Demand Forecast Variation Risk

Annual Demand Variation

As mentioned in Section 4.2, there are risks associated with generating the annual demand forecast related to the underpinning assumptions. Variations in actual outcomes compared to the assumptions used to develop the annual demand forecast results in differences between the actual annual demand relative to the forecast.

Design Day Demand Variation

As mentioned in Section 4.4, Enbridge Gas bases design day demand on the coldest observed day in each delivery area and procures firm assets to meet those demands for the Union and EGD rate zones. This statistical condition sets the weather conditions that will yield the highest day of demand in each year of the 5-Year GSP forecast period (2024/25 to 2029/30).

[86] EB-2022-0200, Exhibit 4, Tab 2, Schedule 6, pp.16-18.
[87] EB-2024-0111, Exhibit I.1.1-ED-57.
[88] Normal weather refers to the HDD forecast developed by Enbridge Gas.

Pricing Variation Risk

Market prices can vary significantly from location-to-location daily as they are impacted by both local market conditions (e.g., weather) and the broader North American natural gas market supply/demand fundamentals. Enbridge Gas's procurement of supply is subject to prevailing market conditions.

Scenario Analysis

To illustrate the potential for weather volatility and its impact on annual demand and portfolio costs over the 5-Year GSP forecast period (2024/25 to 2029/30), Enbridge Gas used historical HDDs to estimate a range of weather impacts under cold and warm weather scenarios. Enbridge Gas used its own weather zone experiences by rate zone to simulate demand. Enbridge Gas substituted these demand values into its optimization model to generate a possible range of total portfolio costs.

Table 21 provides a summary of portfolio cost impacts by rate zone associated with changes in annual demand. The scenario analysis was completed using the commodity price forecast that underpins the Plan. Actual commodity prices experienced under extreme weather events can vary greatly and could result in significantly different impacts to portfolio costs relative to those included in Table 21.

Table 21
Changes in Annual Demand Impact on Portfolio Cost

Line No.	Rate Zone	% Change in Annual Demand	% Change in Portfolio Cost
		(a)	(b)
	High Demand Scenario		
1	EGD	+10%	+11%
2	Union North West	+6%	+12%
3	Union North East	+16%	+13%
4	Union South	+8%	+12%
	Low Demand Scenario		
5	EGD	-7%	-9%
6	Union North West	-9%	-4%
7	Union North East	-4%	-6%
8	Union South	-6%	-9%

Weather/Demand and Price Risk Mitigation

Enbridge Gas manages the risks associated with weather volatility and its impact on demand in multiple ways. The Company does this pro-actively, by contracting for sufficient transportation capacity to meet its design day demand forecast. More specifically, when executing the Plan, Enbridge Gas routinely reviews and analyses the prevailing weather conditions and demand patterns and performs in-season forecasts of demand that take into consideration up-to-date weather forecasts. These in-season demand forecasts provide Enbridge Gas with updated short-term expectations of demand that help to inform whether Enbridge Gas may need to make changes to its short-term gas supply procurement strategy.

Enbridge Gas manages the risks of price variation by maintaining diversity and flexibility in its commodity purchase plan by making purchases at nine purchase points (i.e., AECO, Empress, Niagara, Chippawa, Chicago, Dawn, Kensington, Clarington, and the Panhandle field zone) accessing three distinct production basins (i.e., WCSB, Appalachia, and U.S. Mid-Continent), for a variety terms (e.g., annual, seasonal, monthly, weekly, and daily), at different times throughout the year.

Storage capacity also enables mitigation of weather/demand and price volatility by allowing Enbridge Gas to inject excess gas supply if demands are low (e.g., when commodity prices tend to be lower and less volatile) and to withdraw the stored supply when demands increase (e.g., when prices tend to be higher and more volatile).

7.2. Supply Interruption Risk

Enbridge Gas manages the risks associated with the interruption of supply by contracting for supply with creditworthy counterparties and procuring supply at liquid supply purchase points which have numerous counterparties. These practices are consistent with Enbridge Gas's procurement policies and practices discussed in Section 8.1.

Enbridge Gas also manages supply interruption risks by maintaining a robust portfolio of storage capacity that enables the Company to withdraw stored supply if upstream supplies are interrupted. As discussed in Section 5.4, storage gas provides the Company with a reliable and flexible source of supply.

7.3. Transportation Interruption Risk

Enbridge Gas manages the risks associated with transportation service interruptions in multiple ways. One practice is to contract and procure transportation capacity with regulated upstream service providers, which have numerous risk mitigation policies underpinning their operations. Another practice is to contract for firm transportation services with the upstream service providers instead of interruptible or non-firm services. In doing so, the firm services guarantee the ability to schedule supply, as only during a force majeure would service be interrupted.

Enbridge Gas's portfolio of upstream transportation contracts includes a diverse mix of transportation providers. Holding capacity with multiple upstream service providers which are connected to multiple liquid supply hubs, provides Enbridge Gas the flexibility to contract for short-term services such as interruptible transportation and short-term firm transportation, if the need arises.

Further, by prioritizing shortened contract terms and renewal right options Enbridge Gas's portfolio of upstream transportation contracts provides valuable flexibility to adjust quickly should a transportation path or associated supply purchase point become less reliable in the future. To this end, more than 50% of the transportation portfolio is contracted for terms of 1-5 years (i.e., 2024/25 to 2028/2029), more than 40% is contracted for terms of 6-10 years (i.e., 2029/30 to 2034/35), and only 4% is contracted for a term greater than 10 years. As most capacity includes renewal rights, Enbridge Gas continues to gain shorter term contracting flexibility while maintaining portfolio diversity and reliability.

See Figure 12 and Figure 13 for maps depicting Enbridge Gas's transportation contracting diversity for the EGD and Union rate zones.

Finally, Enbridge Gas also manages transportation interruption risks by maintaining a robust portfolio of storage capacity that enables the Company to withdraw stored supply if upstream transportation volumes are curtailed. As discussed in Section 5.4, storage gas provides the Company with a reliable and flexible source of supply.

Figure 12
EGD Rate Zone Transportation Path Diversity

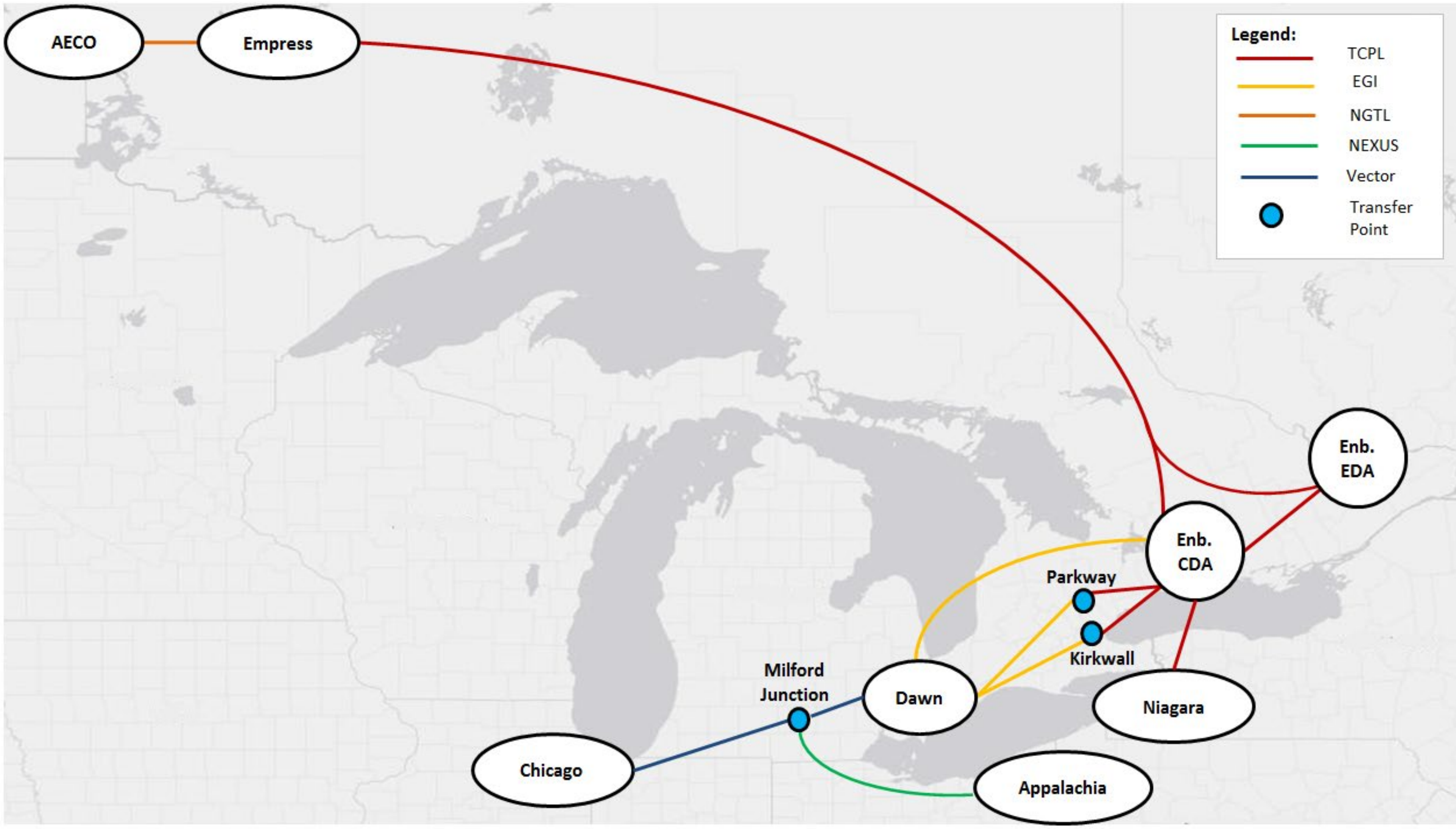
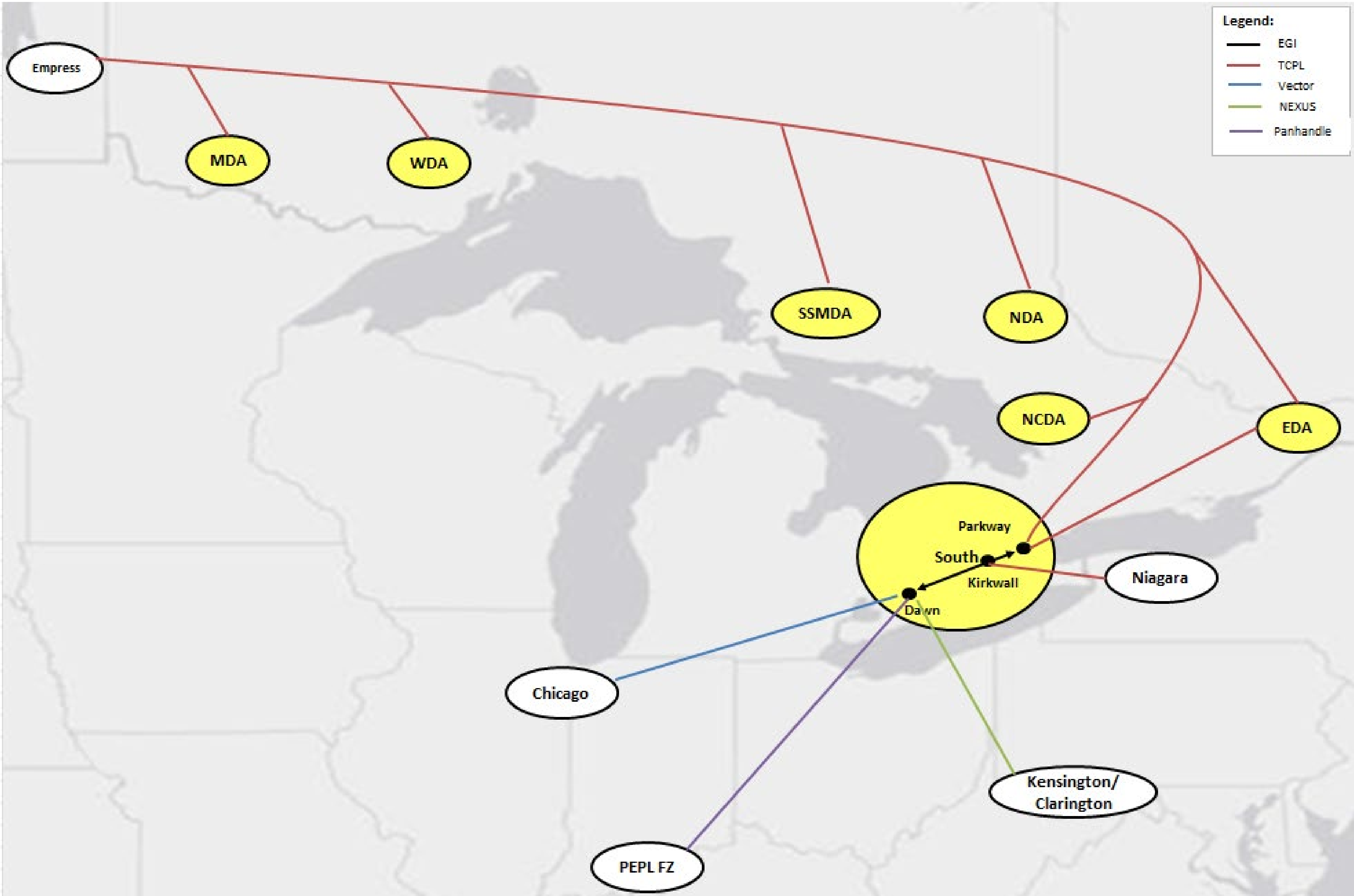


Figure 13
Union Rate Zones Transportation Path Diversity



7.4. Storage Interruption Risk

Enbridge Gas manages risks associated with interruption to storage services in multiple ways. The Company purchases market-based storage from multiple credit-worthy providers with firm injection and withdrawal rights.[89] Enbridge Gas also plans to maintain sufficient inventory throughout the winter, ensuring that maximum withdrawal capabilities are available to meet late-season demand requirements.

The Dawn Hub is an integrated storage facility with multiple pipeline connections which provides flexibility and security. When assessing risk of interruption, it is important to note that a single point of interruption has an extremely low probability. A force majeure, where firm withdrawal services would be reduced, would be very unlikely. The Dawn Hub has not experienced a force majeure and is protected by loss of critical unit compression. However, in the unlikely event of a force majeure storage disruption, Enbridge Gas can purchase incremental supply at the Dawn Hub, purchase upstream transportation or purchase third-party services as an alternative to withdrawals from storage.

8. Gas Supply Plan Execution

Enbridge Gas's Plan is prepared annually for each rate zone and is approved internally by senior management. Once approved, the Gas Supply team prepares a strategy to procure assets and supplies to meet the needs identified in the current Plan. Enbridge Gas's supply procurement strategy uses a layered approach to procure supply regularly throughout the year for various terms from credit-worthy counterparties at multiple purchase points and based on relevant market indexes. Appendix O provides supplier diversity by basin/purchase point including the number of counterparties, and the range of supply provided by each counterparty in the 2023/24 gas year.

While executing the supply procurement strategy Enbridge Gas monitors factors including weather, customer demand, commodity prices, and market conditions to identify when significant variation to forecast or volatility arises.[90] In such situations, the Gas Supply team seeks input from a cross-functional internal team to inform any decision to deviate from the established procurement strategy (i.e., regarding gas supply procurement or transportation utilization). To enable such flexibility to adjust from the supply procurement strategy quickly, Enbridge Gas reserves a portion of the gas

---

[89] Enbridge Gas has also contracted a small number of market-based storage contracts with interruptible withdrawals in April and May and interruptible injections in October and November.
[90] An important input into these decisions is the short and mid-term weather forecast available at the time decisions are made. The weather forecast is used as a means of assessing potential demand impacts and required adjustments to the supply procurement strategy for the upcoming month.

supply identified in the Plan for short-term (e.g., prompt month) contracts whereas the remaining portion is contracted prior to the season via a variety of annual, and seasonal contracts.

8.1. Procurement Process and Policy

Enbridge Gas purchases natural gas supply for system operations and the regulated system gas supply portfolio for all rate zones. To plan these activities, the Gas Supply team develops a monthly procurement plan. Per the *Gas Supply Procurement Policies and Practices,* Enbridge Gas's Director and Manager of Gas Supply approve the monthly procurement plan, authorizing execution of the transactions set out therein. Enbridge Gas's monthly procurement plans layer in annual, seasonal, and monthly purchases as well as certain short-term purchases to provide flexibility to adjust for variation to forecast or market volatility.

Gas supply for all rate zones is purchased using both fixed and indexed price contracts. Enbridge Gas primarily uses an RFP process (written and verbal), and electronic gas trading platforms under both the NAESB contract and a Gas Electronic Data Interchange contract. The Company also infrequently transacts limited straight purchases directly with a counterparty (e.g., variable supply for fuel).

As the system operator, Enbridge Gas also manages many operational factors for all rate zones which may impact its execution of procurement plans, including:

- Actual and forecast consumption relative to planned consumption for its sales service customers;
- Seasonal balancing requirements for sales service customers at key control points;
- Weather variances for all sales customers and outside of checkpoint balancing for bundled DP customers in the Union rate zones;
- Changes in supply and balancing requirements as customers move between sales service and DP;
- Unaccounted for gas and compressor fuel variances; and
- Planned and unplanned supply or pipeline disruptions.

9. Link to Other Applications

Table 22 summarizes how the 5-Year GSP might inform other applications with gas supply related elements, and how those applications may in turn inform the 5-Year GSP through Annual Updates or future iterations of the 5-Year GSP.

Table 22

Links to Other Applications

Related Application[91]	How the 5-Year GSP Informs Related Applications	How Related Applications Inform the 5-Year GSP	Implications for Rates
Rebasing/ Cost of Service Applications	The cost consequences of the Plan will be included in the revenue requirement of the Company's rebasing/cost of service applications.	Methodologies used to prepare the Plan (such as annual and design day demand and storage requirement) are set through a Rebasing/Cost of Service application. Proposals for other Plan impacts may also be made with the application.	The Rebasing/Cost of Service application is the mechanism where the cost consequences of the Plan are reflected in the Company's revenue requirement and certain gas supply costs in base rates are established.
QRAM	Execution of the Plan will result in ongoing changes to pass-through gas supply costs which are largely recovered through QRAM applications.	QRAM applications include data and information which will help to inform Annual Updates and the next iteration of the 5-Year GSP.	QRAM applications are the mechanism through which most gas supply costs are updated in rates and variances are passed through to customers.
Disposition of Deferral and Variance Account Balances	Execution of the Plan will result in ongoing changes to certain gas supply costs that are trued-up through the annual Disposition of Deferral and Variance Account Balances application.	Annual Disposition of Deferral and Variance Account Balance applications include data and information which will help to inform Annual Updates and the next iteration of the 5-Year GSP.	The Disposition of Deferral and Variance Account Balances application is the mechanism through which variances between certain gas supply forecast and actual costs are passed through to customers (market-based storage costs, unabsorbed demand costs). Load balancing costs are also reported in the application.
Leave to Construct Applications	The most recent iteration of the Plan provides the foundation for related Leave to Construct applications which enable sustained or improved execution of the Plan in accordance with the OEB's Guiding Principles.	Upon approval of related Leave to Construct applications, any resulting new assets or gas supply options will be reflected in Annual Updates and the next iteration of the 5-Year GSP.	Capital expenditures resulting from related Leave to Construct applications will be adjudicated in the appropriate proceeding. Any resulting changes to gas supply costs will be reflected in QRAM and/or Annual Rate applications, as appropriate.
Long-Term Contract Applications	The most recent iteration of the Plan provides the foundation for Long-Term Contract applications which enable sustained or improved execution of the Plan in accordance with the OEB's Guiding Principles.	Upon approval of related Long-Term Contract applications, any resulting new assets or gas supply options will be reflected in Annual Updates and the next iteration of the 5-Year GSP.	Any changes to gas supply costs resulting from Long-Term Contract applications will be reflected in QRAM and/or Annual Rate applications, as appropriate.

[91] The Framework includes Rate Applications (Section 5.4) as a related application. Gas costs are included in the 2024 Rebasing Application, effective January 1, 2025, to December 31, 2028 and not updated through Rate Applications. Therefore, Rate Applications have been excluded as a related application in Table 22.

10. Three-Year Historical Review

The following section provides a review of the prior three gas years (November to October), comparing the Plan for each year to the actuals experienced.

10.1. Heating Degree Days

Table 23 provides a comparison of the actual vs. Plan HDD variance for the prior three years with variance explanations.

Table 23
Actual vs. Plan Annual HDDs (1)

Line No.	Particulars	2021/22 Actual	2021/22 Plan	2021/22 Variance (2)	2022/23 Actual	2022/23 Plan	2022/23 Variance (2)	2023/24 Actual	2023/24 Plan	2023/24 Variance (2)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Weather Zone									
1	Central	3,607	3,634	-0.7%	3,265	3,566	-8%	3,055	3,560	-14%
2	East	4,428	4,343	2.0%	3,895	4,299	-9%	3,778	4,338	-13%
3	West	3,408	3,419	-0.3%	3,121	3,398	-8%	2,901	3,398	-15%
4	South	3,744	3,757	-0.3%	3,409	3,704	-8%	3,181	3,781	-16%
5	North	4,988	4,950	0.8%	4,545	4,877	-7%	4,046	4,673	-13%

Notes:
(1) Table 23 represents HDDs based on a base temperature of 18°C. The HDD forecast underpinning this Plan in relation to the annual demand forecast is determined using base temperature of 15°C as filed and explained in EB-2022-0200, Exhibit 3, Tab 2, Schedule 5, Attachment 1.
(2) A negative variance indicates actual HDD were lower than Plan HDD due to warmer than expected temperatures, a positive variance indicates actual HDD were higher than Plan HDD due to colder than expected temperatures. Variance calculated as actual divided by Plan minus 1.

HDD variance explanations:

- 2021/22 – Actual HDDs were relatively close to Plan across the five weather zones: colder than expected in the East and North weather zones; and warmer in the Central, West, and South weather zones.
- 2022/23 – Actual HDDs were lower than Plan in all five weather zones due to warmer than expected temperatures.
- 2023/24 – Actual HDDs were lower than Plan in all five weather zones due to warmer than expected temperatures.

10.2. Annual Demand

Table 24 provides a comparison of the actual vs. Plan annual demand (volume) forecast variance for the prior three years with variance explanations. Actual volumes have not been weather normalized.

Table 24
Actual vs. Plan Annual Demand

Line No.	Particulars (TJ)	2021/22 Actual	2021/22 Plan	2021/22 Variance	2022/23 Actual	2022/23 Plan	2022/23 Variance	2023/24 Actual	2023/24 Plan	2023/24 Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	EGD									
1	General Service	385,135	381,835	3,300	359,231	386,703	(27,472)	343,239	382,674	(39,435)
2	Contract	77,313	70,000	7,313	78,922	73,456	5,466	79,858	73,285	6,573
3	Total EGD	462,448	451,835	10,613	438,153	460,159	(22,006)	423,097	455,959	(32,862)
	Union North West									
4	General Service	14,344	14,579	(235)	13,097	14,133	(1,036)	12,049	14,762	(2,713)
5	Contract	3,376	1,441	1,935	2,500	1,579	921	2,868	1,775	1,093
6	Total Union North West	17,720	16,020	1,700	15,597	15,713	(116)	14,917	16,537	(1,620)
	Union North East									
7	General Service	36,903	39,107	(2,204)	35,007	38,816	(3,809)	33,507	37,664	(4,157)
8	Contract	4,399	3,554	845	4,343	3,911	432	4,654	3,682	972
9	Total Union North East	41,302	42,660	(1,358)	39,350	42,727	(3,377)	38,161	41,346	(3,185)
	Union South									
10	General Service	172,079	173,820	(1,741)	159,526	168,743	(9,217)	154,062	172,047	(17,985)
11	Contract	59,121	55,729	3,392	58,480	58,439	41	57,767	60,024	(2,257)
12	Total Union South	231,200	229,549	1,651	218,006	227,182	(9,176)	211,830	232,071	(20,241)
13	Total	752,670	740,065	12,605	711,106	745,780	(34,674)	688,004	745,912	(57,908)

Annual demand variance explanations:

- 2021/22 – The increase in total actual annual demand compared to forecast (Plan) was driven by new customer attachments and growth from existing customers in applicable rate zones.
- 2022/23 – The decline in total actual annual demand compared to forecast (Plan) was driven by warmer weather experienced in the general service market in all rate zones.
- 2023/24 – The decline in total actual annual demand compared to forecast (Plan) was driven by warmer weather experienced in the general service market in all rate zones.

10.3. Commodity

Table 25 provides a comparison of the actual vs. Plan supply (volume) forecast variance for the prior three years with variance explanations. Positive variances indicate higher volumes of actual supply relative to forecasted supply in the Plan and negative variances indicate lower volumes of actual supply relative to forecasted supply in the Plan.

Table 25
Actual vs. Plan Sources of Supply

Line No.	Particulars (TJ)	2021/22 Actual	2021/22 Plan	2021/22 Variance	2022/23 Actual	2022/23 Plan	2022/23 Variance	2023/24 Actual	2023/24 Plan	2023/24 Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	EGD									
1	Appalachia	41,452	43,151	(1,699)	40,018	43,140	(3,122)	41,954	43,087	(1,133)
2	Chicago	25,742	32,980	(7,238)	21,943	32,963	(11,020)	18,108	33,021	(14,913)
3	Niagara Region	73,070	73,341	(271)	73,095	73,194	(99)	73,195	73,471	(276)
4	Dawn	110,825	86,748	24,077	85,489	92,039	(6,550)	58,307	81,303	(22,996)
5	Peaking/Seasonal	-	23	(23)	-	41	(41)	-	77	(77)
6	WCSB	94,680	92,580	2,100	94,447	95,653	(1,206)	92,960	97,062	(4,102)
7	Total EGD	345,769	328,823	16,946	314,992	337,030	(22,038)	284,524	328,021	(43,497)
	Union North West									
8	WCSB	19,811	11,851	7,960	21,533	11,467	10,066	18,031	16,301	1,730
9	Ontario/Dawn	-	-	-	-	-	-	-	-	-
10	Total North West	19,811	11,851	7,960	21,533	11,467	10,066	18,031	16,301	1,730
	Union North East									
11	Appalachia	18,612	19,254	(642)	19,015	19,255	(240)	18,372	19,308	(936)
12	Dawn	13,374	11,432	1,942	11,577	12,068	(491)	3,015	6,309	(3,294)
13	WCSB	1,590	1,493	97	2,940	2,700	240	2,863	2,708	155
14	Total North East	33,577	32,180	1,397	33,532	34,024	(492)	24,250	28,325	(4,075)
	Union South									
15	Appalachia	33,008	38,510	(5,501)	33,644	38,510	(4,866)	36,842	38,615	(1,773)
16	Chicago	32,747	38,509	(5,763)	30,926	38,509	(7,583)	30,186	38,615	(8,429)
17	Niagara Region	8,873	7,702	1,171	7,702	7,702	0	7,722	7,723	(1)
18	Dawn	36,195	34,799	1,396	28,306	30,991	(2,685)	22,385	39,044	(16,659)
19	U.S. Mid-Continent	21,246	21,950	(704)	17,255	21,950	(4,695)	18,351	22,011	(3,660)
20	WCSB	8,765	8,797	(32)	8,806	8,797	9	8,683	8,821	(138)
21	Total South	140,834	150,267	(9,433)	126,639	146,459	(19,820)	124,169	154,828	(30,660)
22	Total	539,990	523,121	16,870	496,696	528,980	(32,284)	450,975	527,476	(76,501)

Commodity variance explanations:

- 2021/22 – Colder than normal weather increased demand and gas supply deliveries relative to budget, primarily driven by demands in the EGD rate zone.
- 2022/23 – Warmer than normal weather decreased demand and gas supply deliveries relative to budget.
- 2023/24 – Warmer than normal weather decreased demand and gas supply deliveries relative to budget.

10.4. Unutilized Capacity

Table 26 provides a comparison of the actual vs. Plan unutilized capacity (volume) variance for the prior three years with variance explanations.

Table 26
Actual vs. Plan Unutilized Capacity

Line No.	Particulars (PJ)	2021/22 Actual	2021/22 Plan	2021/22 Variance	2022/23 Actual	2022/23 Plan	2022/23 Variance	2023/24 Actual	2023/24 Plan	2023/24 Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	EGD	-	-	-	-	-	-	-	-	-
2	North West	6.0	13.6	(7.7)	4.0	13.9	(9.9)	9.1	10.4	(1.3)
3	North East	1.9	1.8	0.1	4.7	2.4	2.3	12.4	8.3	4.1
4	South	9.5	-	9.5	18.6	-	18.6	28.1	-	28.1
5	Total	17.4	15.5	1.9	27.3	16.3	11.0	49.6	18.7	30.9

Note:
(1) Actual 2023/24 unutilized capacity volume allocations are preliminary as of the date of this filing. Final allocations will be filed in the 2024 Disposition of Deferral and Variance Account Balances proceeding.

Unutilized capacity variance explanations:

- 2021/22 – Total actual unutilized capacity was relatively consistent with total forecasted (Plan) unutilized capacity, except for demand and supply variances for the Union rate zones.
- 2022/23 – Total actual unutilized capacity was higher than total forecasted (Plan) unutilized capacity primarily due to warmer than normal weather.
- 2023/24 – Total actual unutilized capacity was higher than total forecasted (Plan) unutilized capacity primarily due to warmer than normal weather.

11. Performance Measurement

Enbridge Gas's performance metrics reflect the criteria the OEB has established to monitor the effectiveness of the Plan, including how the OEB's Guiding Principles have been achieved. Enbridge Gas's performance metrics are provided at Appendix E and include a three-year average based on the past three years of reported results for each measure. Enbridge Gas will continue to review and modify its approach to performance metrics and will provide updates on these efforts in future gas supply plan filings, as required.

For the current 5-Year GSP, Enbridge Gas has split the performance metrics of "Emissions abated through procurement of RNG" and "Emissions abated through procurement of hydrogen" as requested as part of the stakeholder questions in the 2024 Annual Update proceeding (EB-2024-0067).

In response to OEB Staff recommendations regarding the Company's 2024 Annual Update, Enbridge Gas has considered the appropriateness of adding targets to its performance metrics. Accordingly, Enbridge Gas has attributed a target to certain performance metrics where the outcome of the Plan is expected to achieve a single value goal. Going forward, in cases where the Plan has not met the performance metric target Enbridge Gas will provide an explanation of contributing factors.

Where a single value target was not applicable, Enbridge Gas has attributed a variance range to indicate statistically significant variation. The variance range was calculated as two standard deviations using the five years of historical data available. An additional year of historical data will be added to the calculation of the variance range for each measure annually going forward. Where the Plan results fall outside of the variance range, Enbridge Gas will provide an explanation of contributing factors.

Two performance metrics, "Reference Price" and "Instances when QRAM expected bill impacts exceed +/- 25%", were not attributed a target or variance range. Given the nature of these metrics a target or variance range was considered not appropriate and therefore these have been marked as "N/A". In addition, the metrics "Percentage of RNG in the portfolio", "Emissions abated through procurement of RNG", "Emissions abated through procurement of hydrogen", and "Percentage of certified gas in the portfolio" do not have sufficient historical data to calculate a variance range. These performance metrics are marked as "N/A" until sufficient historical data points are available to support the calculation.

As discussed in Section 5.1, in addition to the performance metrics provided in Appendix E, Enbridge Gas has developed a cost-effectiveness analysis that provides the actual premium/discount paid by transportation path compared to the expected premium/discount assessed as part of the landed cost analysis prepared in prior years at the time of contracting decisions. Enbridge Gas has provided the cost-effectiveness analysis at Appendix I.

2023/24 Performance Metrics Results

The 2023/24 performance metric "Weather Variance" result for "HDD Variance - Union South" of (16%) fell below the calculated variance range of (14%) - 8%. The negative HDD variance for all weather zones, including Union South, is a result of warmer than expected temperatures throughout the gas year, particularly the 2023/24 winter, as discussed at Section 10.1

The 2023/24 performance metric supply basin "Diversity" result for "Ontario/Dawn" of 19% fell below the calculated variance range of 20% - 39%. Ontario/Dawn supply purchases were below the variance range because of a high storage inventory balance following the 2023/24 winter season, consistent with the lower than Plan HDD variance results for all weather zones. As a result, the Company reduced Dawn purchases during the summer of 2024 compared to Plan and thus had a reduced proportion of Ontario/Dawn purchases of total purchases for the same period.

The 2023/24 performance metric "Reliability" result for "Number of days of failed delivery of supply (including force majeure)" of 237 days fell above the calculated variance range of 18 - 178 days. While such instances of failed delivery are outside of Enbridge Gas's control, the Company consistently monitors its Portfolio for such risks to supply reliability and security. Importantly, none of these instances impacted supply deliveries to customers as Enbridge Gas promptly responded to each instance by evaluating market conditions and replacing supplies where necessary. Enbridge Gas will continue to monitor this trend across its Portfolio and may take actions to improve Portfolio reliability and security of supply going forward.

Market Outlook

Background

This appendix summarizes certain publicly available natural gas market information, including natural gas market data and analysis published by the Canada Energy Regulator (CER), and the U.S. Energy Information Administration (EIA),[1] as well as capacity reports posted by upstream pipelines relevant to Enbridge Gas. To understand current market conditions, it is helpful to consider how the market has been influenced by domestic, continental, and global events in recent years.

In late 2021, global energy supplies were disrupted due to conflict in Ukraine (Russian natural gas supplies normally delivered to European markets were curtailed) resulting in a global natural gas price spike. In response, North American LNG exports increased to partially replace Russian supplies into major European markets. As a result, North American natural gas storage inventories reached historically low levels in 2022. Together, sudden global supply uncertainty and low North American inventory levels led to higher North American natural gas prices and greater price volatility throughout 2022. This also resulted in higher commodity reference prices for Enbridge Gas in 2022.

During 2023-2024, while North American suppliers adjusted production levels to compensate for increased LNG exports, North America experienced extremely mild weather during both the winter 2022/23 and winter 2023/24 seasons. As a result, North American natural gas storage inventories reached historically high levels in 2023 that persisted until the fall of 2024. As global markets regained some balance and given persistently high North American inventory levels in 2023 and 2024, North American natural gas prices declined and stabilized leading to lower commodity reference prices for Enbridge Gas in 2023 and 2024.

While North American natural gas storage inventories were full at the outset of the winter 2024/25 season, certain weather forecasts predicted colder than normal temperatures. As a result, forward North American natural gas prices and short-term price volatility increased. Increased price levels and volatility were largely sustained over the course of the winter 2024/25 season due to persistent weather-driven demand and subsequent normal or below normal North American storage inventory levels.

[1] These publicly available forecasts are not created by Enbridge Inc. or any of its affiliates. Inclusion of these forecasts within this evidence does not mean that Enbridge Inc. or its affiliates endorse, agree with or support the accuracy of these forecasts. The publicly available forecasts are provided for informational purposes only in compliance with Framework direction.

These market factors have resulted in higher commodity reference prices for Enbridge Gas as reported in its April 2025 QRAM.[2]

<u>The CER's Energy Future Report</u>

In its 2023 Energy Future (EF2023) report,[3] the CER provides outlooks for Canada's natural gas supply and demand under three energy transition scenarios:

- Current Measures Scenario: The least aggressive scenario with only limited future actions assumed to reduce GHG emissions and no assumed requirement for Canada to achieve net-zero emissions.
- Canada Net-Zero Scenario: Assumes Canada will achieve net-zero by 2050. The EF2023 report does recognize many uncertainties around Canada's pathway to net-zero. This scenario assumes that global GHG reductions are less aggressive than Canada's, impacting Canada's supply/demand balance through the magnitude of forecast supply exports from Canada.
- Global Net-Zero Scenario: Is the most aggressive scenario where Canada reaches net-zero by 2050, and global action is also at a much more rapid pace to reduce GHG emissions.

The CER recognizes the uncertainty inherent in its 2023 Energy Future report, stating:[4]

> The results in EF2023 are not predictions about the future and nor are they policy recommendations. Rather, they are the product of scenarios based on a specific premise and set of assumptions. Relying on just one scenario to understand the energy outlook implies too much certainty about what could happen in the future.

<u>The EIA's Annual Energy Outlook</u>

In its Annual Energy Outlook 2023 (AEO2023), the U.S. EIA provides outlooks for U.S. natural gas supply and demand under a variety of cases that vary technical and economic assumptions, including combination cases that extend the bounds of uncertainty:[5]

---

[2] EB-2025-0078, Enbridge Gas Inc. April 1, 2025, Quarterly Rate Adjustment Mechanism (QRAM) Application.
[3] The EF2023 report is the most recent version released by the CER as of the date of this filing.
[4] Canada's Energy Future 2023, June 20, 2023, p. 4, https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/index.html.
[5] The AEO2023 report is the most recent version released by the EIA as of the date of this filing.

Reference Case:

- 1.9% annual GDP growth
- Brent = $101 per barrel (b) in 2050

Economic Growth:

- Low = 1.4% - 2.3% annual GDP growth
- High = 2.3% annual GDP growth

Oil Price:

- Low = $51/b Brent in 2050
- High = $190/b Brent in 2050

Oil and Gas Supply:

- Low – 50% lower oil and gas resource recovery and 50% higher drilling costs relative to Reference case
- High – 50% higher oil and gas resource recovery and 50% lower drilling costs relative to Reference case

Zero-Carbon Technology Cost:

- Low = About 40% reduction in cost by 2050
- High = No reduction in costs

Combination:

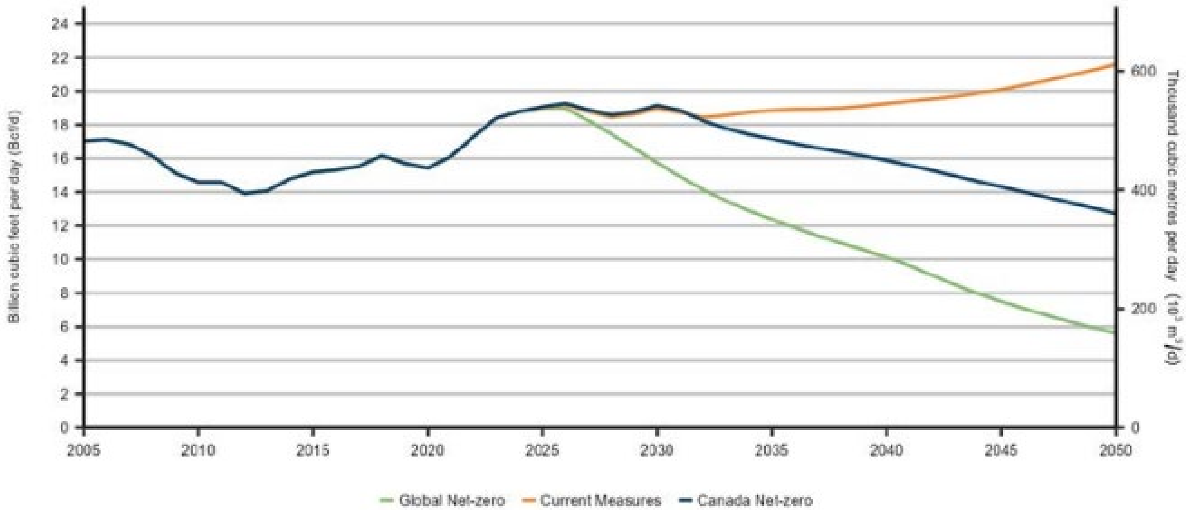
- Combinations of Economic Growth and Zero-Carbon Technology Cost cases

North American Natural Gas Supply

Regarding Canadian natural gas supply (see Figure A-1), in all but the most aggressive of the global GHG emission reduction scenarios (Global Net-Zero Scenario) set out in EF2023, the CER forecasts production of natural gas in Canada to stay relatively constant at approximately 18 Bcf/day for the next decade. Through 2050, the report projects that Canadian natural gas production will range from a 24% increase (to 21.5 Bcf/day) to a 68% decrease (to 5.5 Bcf/day), relative to 2022 levels.

Figure A-1

Canadian Natural Gas Production[6]



Historically and across all scenarios, Canada's natural gas production is dominated by Alberta and British Columbia. All projected growth is expected to come from the Montney formation in northeast British Columbia and this area's percentage share of Canada's production will continue to grow in all three of the CER's energy transition scenarios.

Regarding U.S. natural gas supply (see Figure A-2), the EIA's Reference case forecasts production of natural gas in the U.S. to continue to grow from 2022 to 2050 by 15% to just over 40 Tcf/day. The AEO2023 projects that U.S. natural gas production through 2050 will range from a 20% increase (to 50 Tcf) under its High Oil and Gas Supply case to a 25% decrease (to 30 Tcf) under its Low Oil and Gas Supply case, relative to 2022 levels.[7]

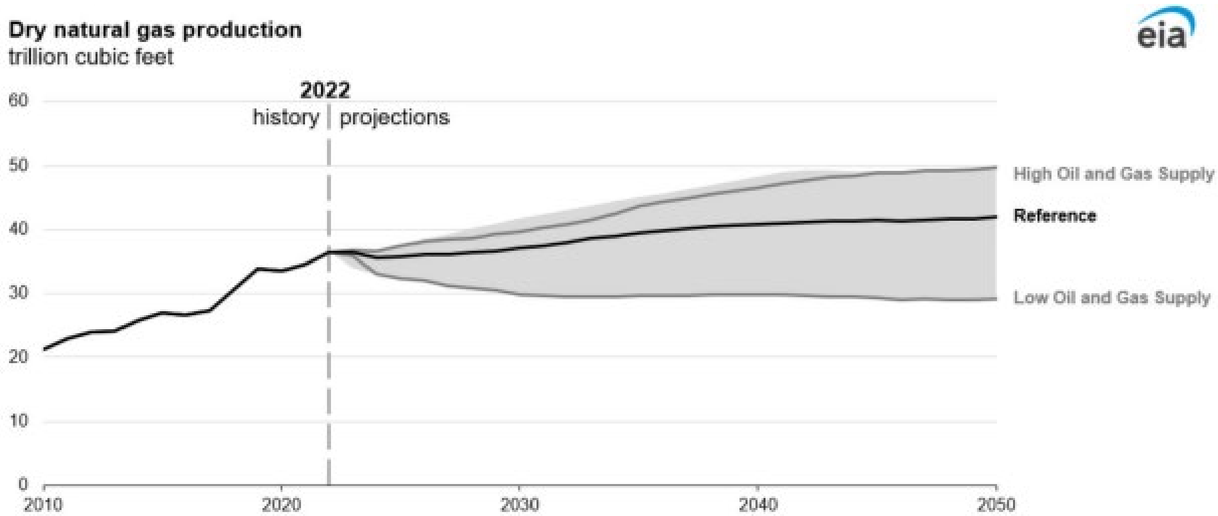
---

[6] Canada's Energy Future 2023, June 20, 2023, p. 14, https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/index.html.

[7] In scenarios where production is projected to exceed domestic consumption, LNG exports are driving additional U.S. production.

Figure A-2

U.S. Natural Gas Production[8]



Shale gas and associated natural gas from oil wells are the primary sources for any projected long-term U.S. natural gas production growth. Increased shale gas production is mainly projected in the Appalachian basin and the Texas-Louisiana salt basin, with an increase in associated natural gas from increased production wells in the Permian basin.

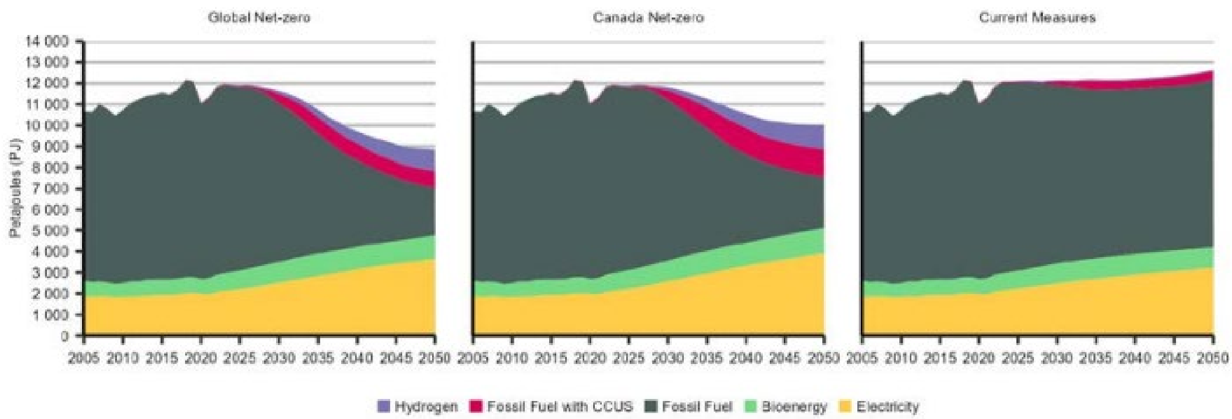
North American Natural Gas Demand

Regarding Canadian natural gas demand (see Figure A-3), the CER forecasts electricity, hydrogen and biofuels to make up a greater share of Canada's energy use in all scenarios set out in EF2023, while the use of fossil fuels decreases. That said, a portion of the decrease in fossil fuel use is replaced by fossil fuels with Carbon Capture and Underground Storage (CCUS) in all scenarios. Further, natural gas-based electricity generation persists through 2050 in all scenarios. Even in the most aggressive of the scenarios (Global Net-Zero), natural gas still plays an important role in Canada's energy mix through 2050.

[8] Annual Energy Outlook 2023, March 16, 2023, p. 23. https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Release_Presentation.pdf.

Figure A-3

Canada's Energy Use[9]



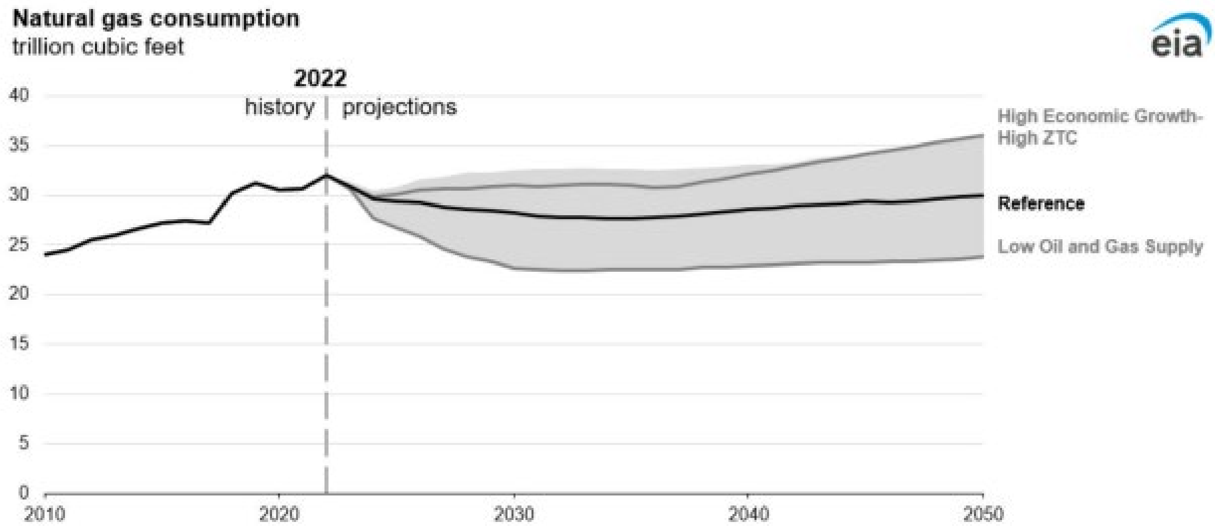
In both Net-Zero scenarios, Canada's end-use energy demand declines in the longer term by 22% through 2050, relative to 2022 levels, due in-part to assumptions around more efficient use of energy, and undefined technological advancements. In the Current Measures scenario, energy use is stable until 2040 and increases from 2040 to 2050.

Regarding U.S. natural gas demand (see Figure A-4), the EIA's Reference case forecasts relatively stable natural gas demand through 2050 at an average of approximately 30 Tcf. The AEO2023 projects that U.S. natural gas demand through 2050 will range from an approximately 18% increase (to 36 Tcf) under its High Economic Growth-High ZTC case to an approximately 14% decrease (to 24 Tcf) under its Low Oil and Gas Supply case, relative to 2022 levels.

[9] Canada's Energy Future 2023, June 20, 2023, p.8, https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/index.html.

Figure A-4

U.S. Natural Gas Consumption[10]



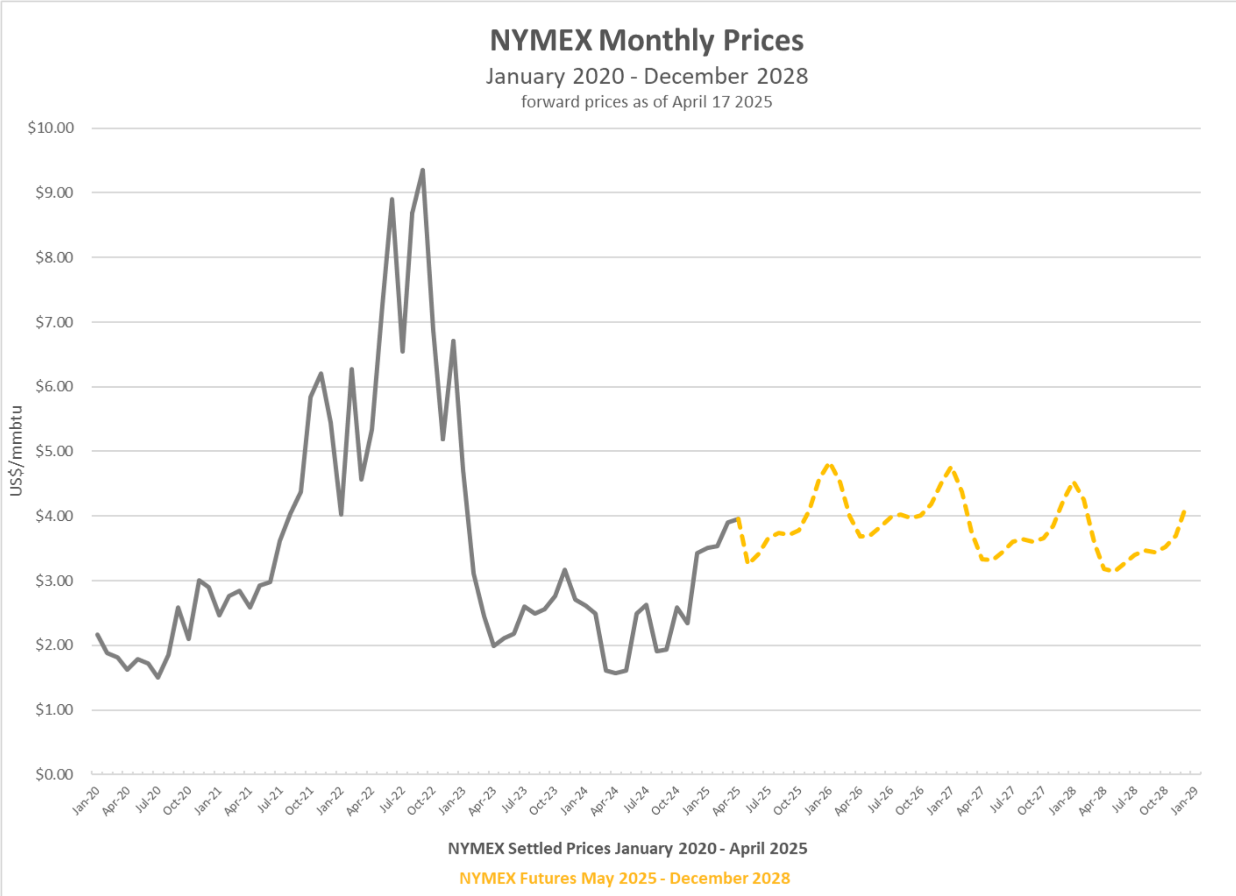
Current North American Natural Gas Price Signals

Natural gas prices that trade on the New York Mercantile Exchange (NYMEX) at Henry Hub are the primary price for the North American natural gas market and are used to calculate locational basis differentials. As of April 17, 2025, the NYMEX forward curve ranges from $3.25 US/MMBtu in the near term to $4.84 US/MMBtu for next winter's peak, with a long-term average price of $3.84 US/MMBtu through 2028 as shown in Figure A-5. However, forward forecast natural gas prices change constantly as they are affected by a variety of market forces, including but not limited to variation from normal temperatures, global geo-political events, and market (supply/demand balance) fundamentals.

[10] Annual Energy Outlook 2023, March 16, 2023, p. 23, https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Release_Presentation.pdf.

Figure A-5

NYMEX Natural Gas Prices[11]

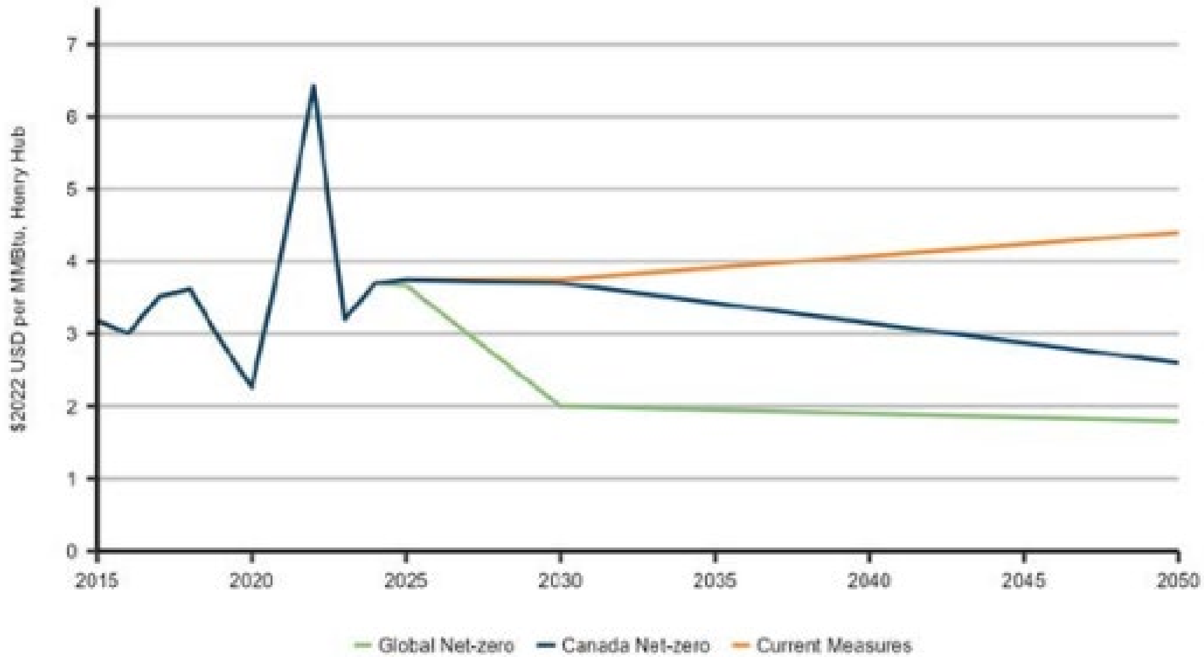


The CER produced long-term natural gas price forecasts under all scenarios set out in EF2023 (see Figure A-6). Under the Current Measures Scenario, average forecast natural gas prices at Henry Hub are comparable to the current forward market prices set out in Figure A-5. Under the Canada Net-Zero Scenario, forecast prices decline steadily after 2030 due to projected lower demands. Under the Global Net-Zero Scenario, forecast prices decline more significantly after 2024 due to projected lower demands. In all scenarios, prices at Henry Hub are expected to be below $5 US/MMBtu through 2050.

[11] NYMEX monthly settled prices and forward curve as of April 17, 2025.

Figure A-6

NYMEX Natural Gas Price Projections[12]



Transportation Market Overview

This section describes market changes relating to North American natural gas transportation which have a direct impact on Enbridge Gas's gas supply planning and related supply option analysis. In general, (as discussed in Section 5 of the current application) existing transportation capacity to Dawn and Enbridge Gas delivery areas has become increasingly scarce since the Company filed its original 5-year Gas Supply Plan in 2017 (EB-2017-0129). This is a concerning trend as it has the potential to constrain Enbridge Gas's ability to ensure adequate supply deliveries to its system to meet the design demands of customers in the future. Contracted upstream capacity to Enbridge Gas's system is also considered in the design of Enbridge Gas's transmission and distribution systems and provides a means to potentially reduce the need to meet customer demands with incremental infrastructure projects. As a result, Enbridge Gas places great value upon its existing transportation capacity to Dawn and Enbridge Gas delivery areas in Ontario.

As is the case with the CER demand forecast scenarios discussed above, Enbridge Gas acknowledges that depending on how the energy transition unfolds, lower annual demands for natural gas could arise in the future. However, the extent and timing of the

[12] Canada's Energy Future 2023, June 20, 2023, p. 36, https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/index.html.

impacts on both annual and design day needs of Enbridge Gas's customers remains uncertain. These impacts will also not likely occur uniformly across the Enbridge Gas franchise area. Currently, Enbridge Gas continues to experience strong demands from its customer base in Ontario, particularly during cold winter conditions like those experienced during the winter of 2024/25. As the supplier of last resort, Enbridge Gas must ensure that its gas supply portfolio is adequate to meet such customer demands. Contracts for upstream transportation capacity to Enbridge Gas's system play a critical role in ensuring the necessary system reliability and flexibility to operate under such conditions.

A combination of energy transition-related factors, including environmental concerns, public opposition, regulatory hurdles, renewable energy growth, and changing energy market dynamics has resulted in reductions to planned expansions of transportation capacity across North America in recent years (e.g., Atlantic Coast Pipeline, Constitution Pipeline, PennEast Pipeline, Mountain Valley Pipeline, Keystone XL Pipeline, Northern Gateway Pipeline). While limited new transmission infrastructure is being constructed, customer demands for natural gas across North America are steady or growing in many regions. These conditions are exacerbating transportation capacity scarcity on many paths upstream of Enbridge Gas's system, increasing the value of existing infrastructure and the negotiating position of transportation capacity providers. As a result, upstream transportation providers are requesting higher tolls and longer-term contracts to secure existing capacity.

While Enbridge Gas has largely managed to contract for upstream transportation capacity at relatively stable prices and contract term lengths, the Company has begun to take a longer-term view in its assessments of existing capacity offered to the market (i.e., securing scarce and high-value capacity when it becomes available). In particular, the Company must be prepared to adjust its strategy to serve areas of its system that have limited alternatives to meet customer demand (i.e., the Union North rate zones).

As discussed below and detailed in Appendix B, Enbridge Gas has significant contracting flexibility on nearly every one of its upstream transportation paths. This flexibility generally allows the Company to secure capacity (either new or renewed) at longer terms, where required, while retaining flexibility to respond to uncertain future demand impacts of the energy transition through reducing or eliminating existing contracted transportation capacity. The following sections describe the current availability of capacity and associated risks pertaining to specific transportation paths that the Company actively contracts.

Vector Pipeline (Vector)

The Vector pipeline has been fully contracted on its eastbound capacity to Dawn for several years and has also experienced increasing demand for westbound capacity to Chicago. In an October 2024 presentation to customers,[13] Vector identified known and potential additional large volume transportation demand growth in Ontario, Michigan, and Indiana (i.e., electric vehicle battery plants, datacenters, and power plants). Vector also identified two potential projects that could increase westbound capacity as early as November 2026 by redeploying an underutilized compressor. Vector expects to execute binding commitments with 1-2 Anchor Shippers to support these projects, then implement an Open Season to gauge market interest for any remaining capacity.

On September 19, 2024, the FERC initiated a Section 5 review of Vector Pipeline rates.[14] Enbridge Gas is a registered intervenor in the proceeding and is monitoring for potential impacts to its gas supply portfolio and gas supply costs. Enbridge Gas will provide any updates related to the Section 5 proceeding or related FERC initiatives in a future gas supply plan annual update when more information is available.

Enbridge Gas Dawn to Dawn-Vector

In December 2024, Enbridge Gas announced an open season for up to 120,000 GJ/d of new C1 firm transportation capacity beginning April 1, 2025, from Dawn (Facilities) to Dawn-Vector (pipeline). However, no additional westbound Dawn-Vector to Courtright transportation capacity was available on the Vector pipeline at the time. No further public information regarding this open season has been released.

Great Lakes Gas Transmission (GLGT)

The GLGT pipeline remains fully contracted on its eastbound capacity from Emerson to Dawn. In a 2022 presentation to customers, TransCanada U.S. advised that receipts at Emerson continue to grow, and the pipeline continues to experience high rates of utilization. Enbridge Gas is not aware of any expansion plans to increase capacity on the GLGT system to Dawn.

The scarcity of transportation capacity on GLGT is resulting in longer contract terms. As a result, in 2023 when GLGT offered shippers with contract expiration dates of October 31, 2024, the option to extend their contracts by five years at maximum rate without

---

[13] Vector Pipeline, Customer Meeting, October 10, 2024. https://www.vector-pipeline.com/~/media/EepEeqMep/Site-Documents/Vector/News-Releases/Vector-2024-Customer-Meeting.pdf?rev=d2ea88ce78ba4a66a23c2b872efa4abc&hash=101604C4F9FC68DF752C46DBDB13B5F9.
[14] FERC Docket No. RP24-971-000.

having to go through the right of first refusal (ROFR) process, all but one impacted shipper accepted the five-year renewal offer.

Maintenance and integrity work was undertaken on the Emerson Eastbound system throughout 2024. This scheduled maintenance during both summer and winter impacted firm supply. Winter maintenance is continuing into 2025.[15]

TransCanada PipeLine Limited (TCPL)

TCPL (a subsidiary of TC Energy Corporation), remains focused on maintaining existing capacity, completing facility upgrades and maintenance work at points of constraint, and offering services that deliver Western Canadian Sedimentary Basin (WCSB) supply to eastern North American markets. Maintenance and integrity work was undertaken on the Western Mainline (WML) segment of the TCPL Canadian Mainline in 2024.

No new capacity open seasons (NCOS) were conducted in 2024 for services delivering to Enbridge Gas delivery areas. An existing capacity open season (ECOS) was conducted in August 2024 for services delivering to the Enbridge CDA and Union Parkway Belt. As these delivery points are similarly located on the TCPL system in eastern Ontario, bids for both compete for the same capacity on an economic basis. Reported contracts on the Empress to Union Parkway Belt path with a term of 10 years are presumed to have been awarded in the ECOS.[16] Together, the lack of NCOS and ECOS demanding longer contract terms make it increasingly challenging for Enbridge Gas to contract for additional TCPL capacity.

In 2022, the earning sharing mechanism on the WML segment of the TCPL Mainline was triggered based on the balance in the WML Short-Term Adjustment Account (STAA). In 2023, the earning sharing mechanism on the Eastern Triangle (ET) segment of the TCPL Mainline was triggered based on the balance in the ET STAA. TCPL updates the STAA rate riders annually and updates tolls effective January 1, following CER approval. 2025 STAA surcharges were approved on December 12, 2024, by the CER in its Order TG-009-2024 and implemented in the January 1, 2025 QRAM.[17]

In accordance with the terms of the TCPL Mainline Settlement Agreement, STAA balances are recalculated each year to include an additional year's shared earnings to be amortized over the subsequent four-year period. The current Mainline Settlement Agreement ends December 31, 2026, and the treatment of any unamortized STAA balances will be the subject of the next Mainline Settlement Agreement.

---

[15] https://tcplus.com/Great%20Lakes/Notice/PlannedServiceOutage.
[16] TC Energy, Contract Demand Energy (CDE) Report, January 2, 2025. https://www.tccustomerexpress.com/docs/ml_contracts/CDE-Report.pdf.
[17] EB-2024-0326, Exhibit B, Tab 1, Schedule 1, pp. 2-3; Exhibit D, Tab 1, Schedule 1, p. 3.

TCPL Mainline abandonment surcharges were lower in 2025 compared to 2024 due to a lower annual contribution amount and increased billing determinants. TCPL updates abandonment surcharges annually and updates tolls effective January 1, following CER approval. 2025 abandonment surcharges were approved on December 11, 2024, by the CER in its Order TG-008-2024 and implemented in the January 1, 2025 QRAM.[18]

Both the WML and ET segments of the TCPL Mainline are nearly fully contracted due to recent increased demand and maintenance activities. As a result, the Company has had limited opportunities to contract for incremental capacity to serve Enbridge Gas delivery areas. However, Enbridge Gas expects that additional existing capacity may become available over the next five years through ECOS and will continue to monitor capacity availability and analyze opportunities as they arise. The scarcity of Mainline capacity is a significant consideration when Enbridge Gas evaluates transportation alternatives

TCPL Mainline capacity of approximately 1.5 PJ/d is currently contracted by shippers from Empress to the Union Dawn delivery point under TCPL's Dawn Long Term Fixed Price (Dawn LTFP) service. The Dawn LTFP service includes a 10-year contract term, with most contracts expiring in 2027.[19] Dawn LTFP contracts are not renewable but may be converted to FT service at the end of the contract term. As both Empress and Dawn constitute significant sources of natural gas supply for Enbridge Gas, the status of Dawn LTFP shipper demands beyond 2027 could significantly impact the Company's procurement strategies. Enbridge Gas continues to monitor the status of the Dawn LTFP service and related implications at Empress and Dawn (e.g., price, liquidity, reliability of supply).

Panhandle Eastern Pipe Line (PEPL)

Capacity on PEPL to the interconnect with Enbridge Gas's system at Ojibway is currently only available from certain meters beginning after Bourbon (located in Illinois). However, none of these available meters are considered liquid trading points. Further, short-haul transportation contract options from Defiance (ANR Interconnect) and/or Falcon (Rover Interconnect) to Ojibway are also not available from PEPL for an annual term contract.

On January 16, 2019, the FERC initiated a Section 5 review of PEPL rates. On August 30, 2019, PEPL filed a Section 4 application seeking to increase rates and make other tariff changes. On December 16, 2022, the FERC released its Decision on PEPL's

---

18 Ibid.

19 TransCanada Mainline Index of Customers, https://www.tccustomerexpress.com/888.html. Approximately 90% of Dawn LTFP contracts are for the 2017 to 2027 period. Remaining contracts expire in 2028 or 2029.

Section 4 filing.[20] On February 14, 2023, PEPL filed compliance tolls in response to the FERC's Section 4 Decision that became effective October 1, 2023.

On November 30, 2023, PEPL filed a notice with the FERC that it has refunded amounts to shippers for the period March 1, 2020, through September 30, 2023. These amounts totaled over $206 million USD. Enbridge Gas's refund exceeded $20 million CAD and was credited to ratepayers in the Company's January 2024 QRAM application (EB-2023-0330). The interest component of the refund to customers was calculated in accordance with Section 154.501(c) of the Commission's Regulations through November 17, 2023.[21] On November 30, 2023, PEPL filed a Refund Report, which was protested and resulted in a Compliance Order.[22] Pursuant to the Order, PEPL recalculated the refunds and included interest through June 27, 2024. This resulted in an additional credit to Enbridge Gas in the amount of $5.3 million CAD and was credited to ratepayers in the Company's October 2024 QRAM application (EB-2024-0245). PEPL subsequently filed an appeal with the United States Court of Appeals, for a review of the Compliance Order and the additional refund that PEPL was directed to pay to its customers. Enbridge Gas has not received new information on the status of this appeal in the past year. Enbridge Gas will continue to monitor PEPL's appeal process and any revisions to the reimbursement will be reflected in the next applicable QRAM.

[20] FERC Docket No. RP19-78-000.
[21] https://www.ecfr.gov/current/title-18/chapter-I/subchapter-E/part-154/subpart-F/section-154.501.
[22] Docket No. RP19-78-000, *et al.* Refund Amounts to be paid Pursuant to the Commission issued order in Opinion No. 885-A dated September 25, 2023, and May 28, 2024.

Description of Gas Supply and Asset Options

Gas Supply Options

This section outlines viable gas supply sources typically evaluated by Enbridge Gas.

Western Canadian Supplies

Historically, the dominant source of natural gas supply for Enbridge Gas has been the WCSB, which spans most of Alberta as well as parts of British Columbia and Saskatchewan. Enbridge Gas typically refers to WCSB sources as supplies received at Empress, Alberta Energy Company (AECO), NOVA Inventory Transfer (NIT), or Alliance Trading Pool location (ATP).

Empress is a trading point on the TCPL Mainline near the border of Alberta and Saskatchewan. Gas purchased at, or delivered to, Empress can be transported on the TCPL Mainline to every Enbridge Gas delivery area.

AECO/NIT is a trading point on the NOVA Gas Transmission Ltd. (NGTL) system in Alberta. Gas purchased at AECO/NIT can be transported on the NGTL system to Empress, and onwards to every Enbridge Gas delivery area via the TCPL Mainline.

ATP is a trading point on the Alliance Pipeline in Alberta. Gas purchased at ATP can be transported on the Alliance Pipeline system to the Chicago market hub and onward to the Vector pipeline system. Enbridge Gas does not currently procure supplies at ATP or hold any Alliance Pipeline capacity.

Chicago Supplies

The Chicago market hub benefits from access to several major pipeline systems that can source supply from some of the most significant gas production regions in North America. Supply regions connected via pipelines to Chicago include Alberta, Appalachia, the Bakken, the Gulf of Mexico, the U.S. midcontinent, and the U.S Rockies, making it a liquid natural gas hub for Enbridge Gas to access. Gas procured at the Chicago market hub can be transported to Dawn on the Vector pipeline system, where it can be stored and/or transported to Enbridge Gas's distribution systems on transmission pipelines owned and operated by Enbridge Gas and TCPL.

Dawn Supplies

The Dawn Hub is the largest integrated underground storage facility in Canada and is one of North America's most liquid natural gas trading hubs. Dawn's proximity to Ontario customers as well as its direct access to natural gas supply basins and storage via numerous connections (direct and indirect) to upstream transmission pipeline systems (i.e., MichCon/DTE Gas Transmission, Panhandle Eastern Pipeline System, Great Lakes Gas Transmission, NEXUS Gas Transmission, TCPL Mainline, Vector Pipeline, ANR Pipeline, Dominion Gas Transmission, Empire Pipeline, Iroquois Gas Transmission, National Fuel Gas, Portland Natural Gas Transmission System, Tennessee Gas Pipeline, and Bluewater Gas Storage) makes it an integral part of the Plan. Gas procured at Dawn can be transported to Enbridge Gas's distribution systems on transmission pipelines owned and operated by Enbridge Gas and TCPL.

Appalachia Supplies

The Marcellus and Utica basins located in the U.S. Northeast, are some of the largest and most prolific shale deposits in North America. Gas procured in Appalachia from these basins (e.g., at the Clarington or Kensington delivery points) can be transported to Ontario on both the Rover and NEXUS pipelines to Enbridge Gas's distribution, storage, or transmission systems.

Appalachian gas is also procured at the Niagara and Chippawa delivery points located at the U.S./Canada border (along the Niagara River). Gas procured at Niagara and Chippawa can be transported to Enbridge Gas's distribution systems on transmission pipelines owned and operated by Enbridge Gas and TCPL. However, Niagara and Chippawa are less liquid trading points (limited active counterparties and transactions) which necessitates the use of term supply contracts at these points (i.e., seasonal, annual, or monthly).

South Central U.S. Supplies

Several prolific shale plays located in Kansas, Oklahoma, and Texas can be accessed via the Panhandle Eastern Pipe Line (PEPL) system. Gas procured in the Panhandle field zone from these basins can be transported on PEPL to Enbridge Gas's distribution systems.

MichCon Supplies

Enbridge Gas can procure gas supply at a point referred to as "MichCon Generic", which is part of the DTE Energy system in and around Detroit, Michigan. Gas procured at MichCon Generic can be transported to Dawn on the Vector Pipeline where it can be stored and/or transported to Enbridge Gas's distribution systems on transmission pipelines owned and operated by Enbridge Gas and TCPL. Gas procured at MichCon Generic can also be transported to Enbridge Gas's distribution systems (Union Northwest) on the GLGT system and the TCPL Mainline.

Delivered Service

Delivered Services refer to term contracts with third-party providers typically contracted for the winter season to balance increased seasonal demand, diversify purchases, and to avoid incremental transportation capacity. Depending on the arrangement made with the supplier, supplies are delivered to Dawn or directly to Enbridge Gas's distribution system.

Peaking Supplies

Peaking supply arrangements source gas from third-party suppliers for firm delivery directly to Enbridge Gas's distribution system a few days per year (typically a maximum of 10 days) during the winter season, avoiding incremental transportation capacity. Peaking supplies trade at a premium to conventional supply, recognizing the magnitude of daily supply contracted and the likelihood that they are called upon during peak winter conditions (i.e., when market prices are typically highest).

<u>Transportation Asset Options</u>

This section outlines the viable upstream firm transportation options typically evaluated by Enbridge Gas.

TCPL Mainline System

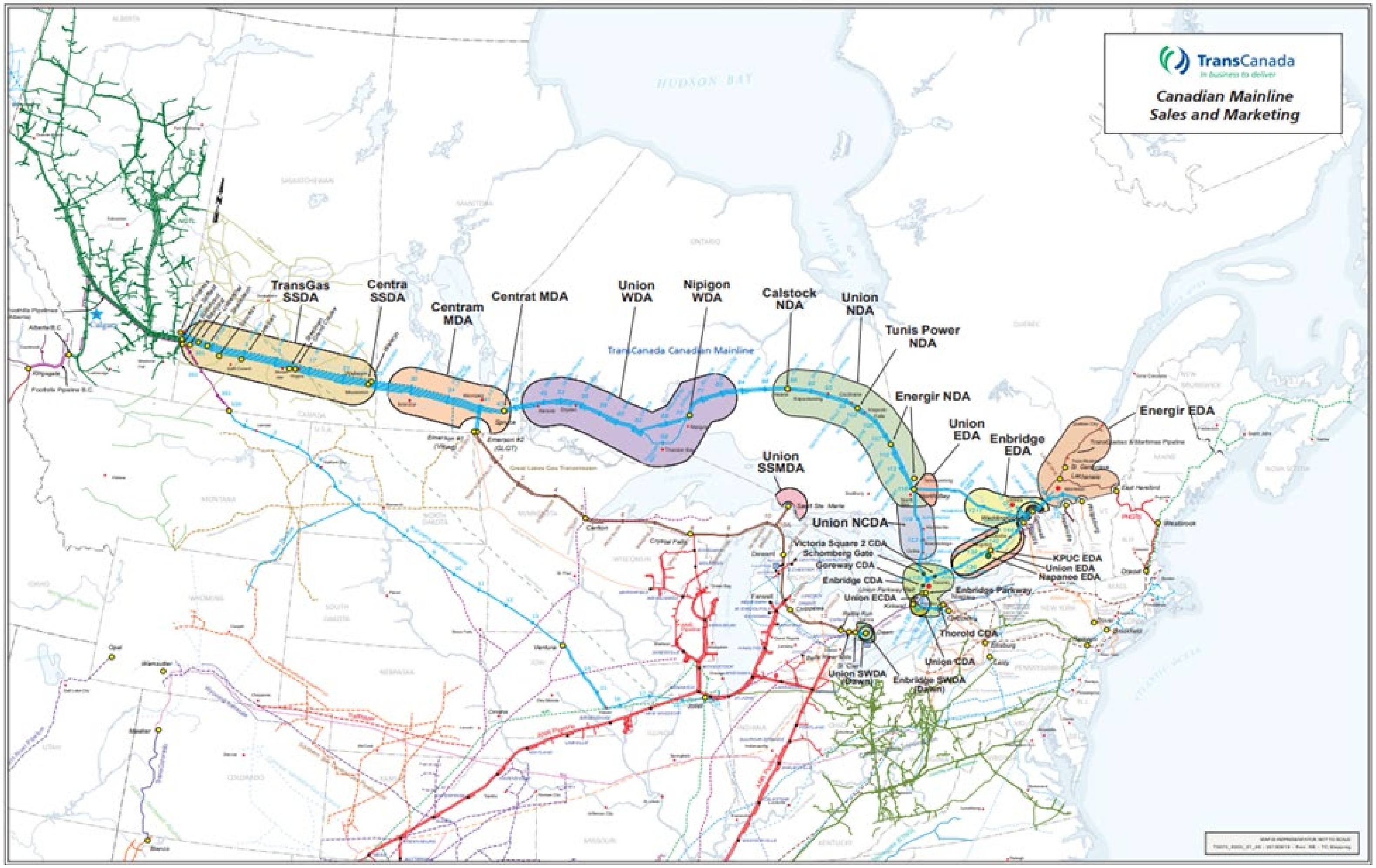
The 14,101 km TCPL Mainline pipeline system transports natural gas from Empress, north of the Great Lakes, and branches off into two lines which form two sides of what is known as the "Eastern Triangle". One branch is directed south towards the Greater Toronto Area, the other branch continues east towards the Ottawa region, the U.S. border at Iroquois, and into Québec. The remaining side of the triangle connects to TCPL Mainline near the Greater Toronto Area in the west and to the Ottawa region in the east. The TCPL Mainline offers firm transportation service and the ability to procure supply from the liquid Empress trading point.

The TCPL Mainline also has two Transmission by Others (TBO) agreements for transportation services on other interconnecting transmission pipeline systems, which enable TCPL to offer services to points beyond the TCPL Mainline. One such TBO agreement is for transportation services on the Great Lakes Gas Transmission (GLGT) System – a pipeline that interconnects with the TCPL Mainline near Emerson, Manitoba in the west and to Dawn, in the east. The other TBO agreement is for transportation services on Enbridge Gas's Dawn Parkway System.

Figure B-1 illustrates the TCPL Mainline (as blue lines), including key points on the system.

Figure B-1

TCPL Mainline Map[1]



[1] https://www.tccustomerexpress.com/docs/ml_system_maps/Canadian%20Mainline%20Tariff%20Map.pdf.

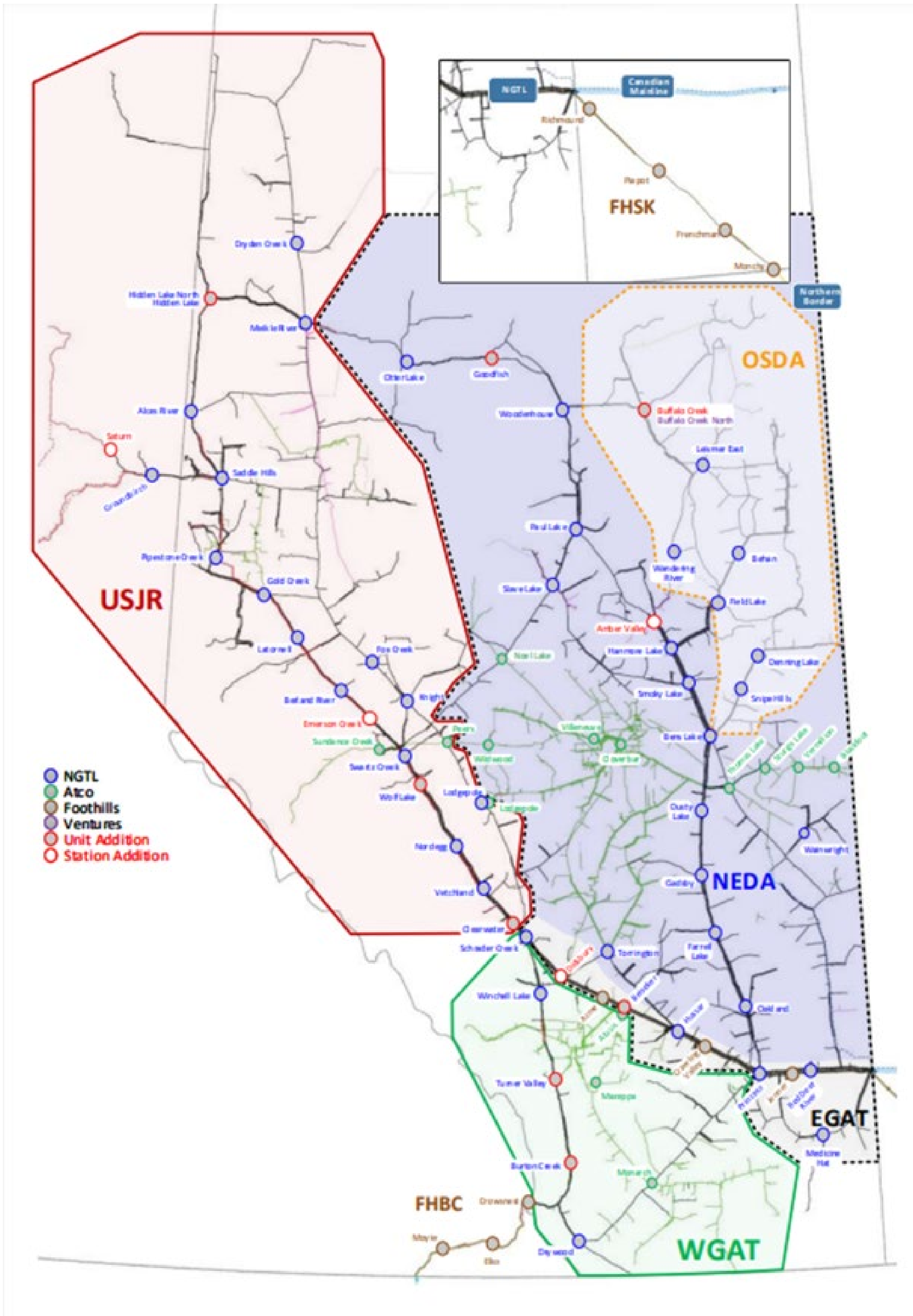
NOVA Gas Transmission Ltd. (NGTL) System

The 24,500 km NGTL pipeline system gathers and transports natural gas in Alberta and northeastern British Columbia. NGTL has over 1,100 receipt points and 300 delivery points. Of those delivery points, East Gate, otherwise known as Empress, is where NGTL interconnects with the TCPL Mainline. Enbridge Gas's main procurement point on the NGTL system is the generic NGTL system point known as AECO/NIT upstream of Empress within the WCSB producing basins. Supply procured at AECO/NIT is transported to Empress via the NGTL system. The NGTL system offers firm transportation service and the ability to procure supply from the liquid AECO/NIT trading point.

Figure B-2 illustrates the NGTL system, including key points on the system.

Figure B-2

NGTL System Map[2]



[2] https://www.tccustomerexpress.com/docs/ab_system_maps/ngtl-system-map-operational-areas.pdf.

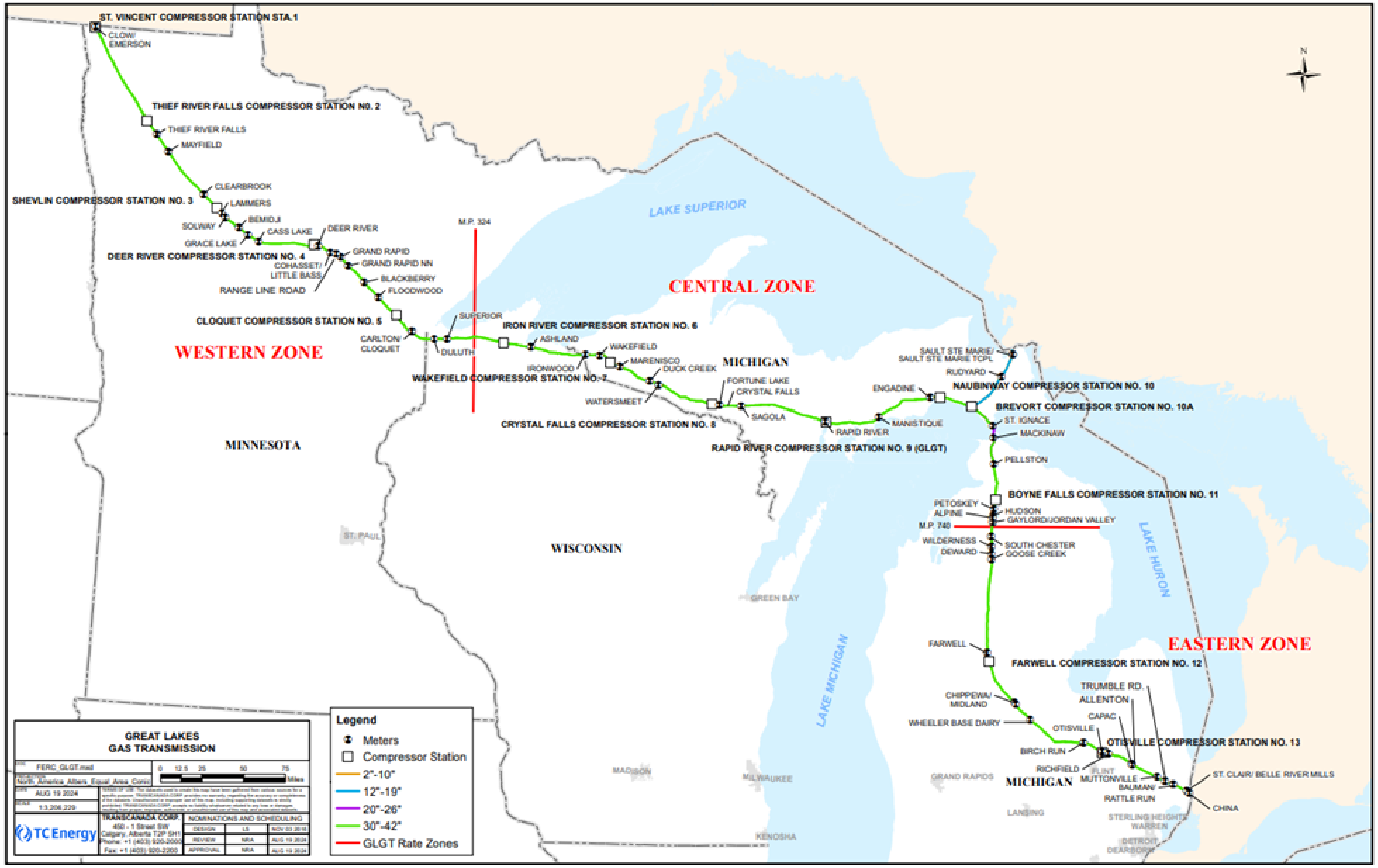
Great Lakes Gas Transmission System

The 3,404 km GLGT pipeline system transports WCSB natural gas from Emerson, south of the great lakes to major markets in the U.S. Midwest and Canada (Dawn). GLGT interconnects with the TCPL Mainline near Emerson, Manitoba in the west and Dawn, in the east (via the Great Lakes Canada Pipeline (GLC). The GLGT system (and GLC) offers firm transportation capacity and provides access to the Emerson and MichCon trading points.

Figure B-3 illustrates the GLGT Pipeline, including key points on the system.

Figure B-3

Great Lakes Gas Transmission System Map[3]



[3]https://tcplus.com/Great%20Lakes/SharedFolder/DisplayFile/4f88ab39d9a76989c1d87b87efe4b4518c4b651e?downloadType=SystemMap.

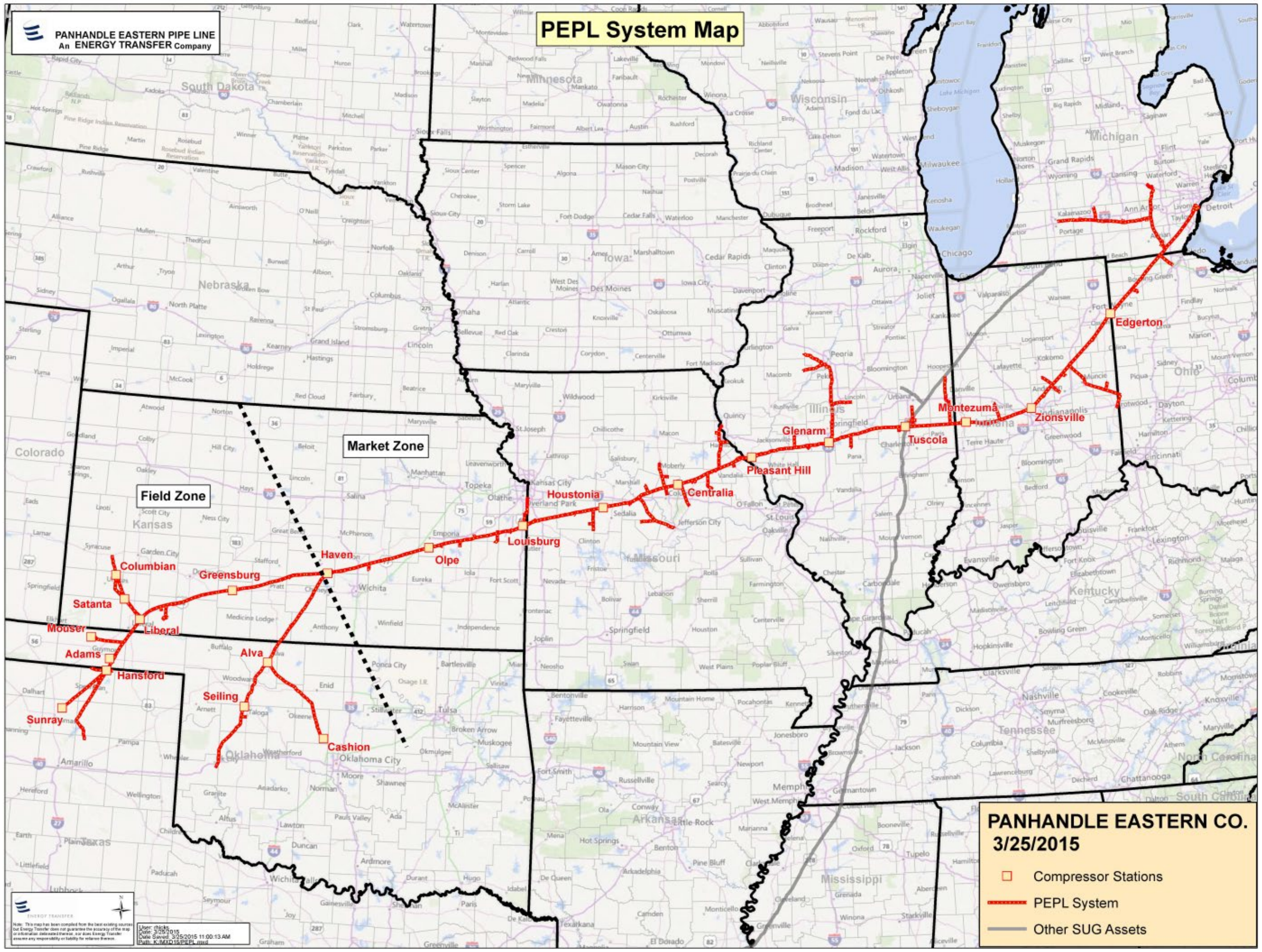
Panhandle Eastern Pipe Line System (PEPL)

The 1,300 mile PEPL system transports natural gas from producing areas in the Anadarko Basin of Texas, Oklahoma, and Kansas through Missouri, Illinois, Indiana, Ohio, and Michigan. PEPL system interconnects with Enbridge Gas's integrated transmission system at the Ojibway point, located near Windsor, Ontario. PEPL system offers firm transportation capacity.

Figure B-4 illustrates the PEPL system, including key points on the network.

Figure B-4

Panhandle Eastern Pipeline System Map[4]



[4] https://peplmessenger.energytransfer.com/ipost/PEPL/maps/system-map.

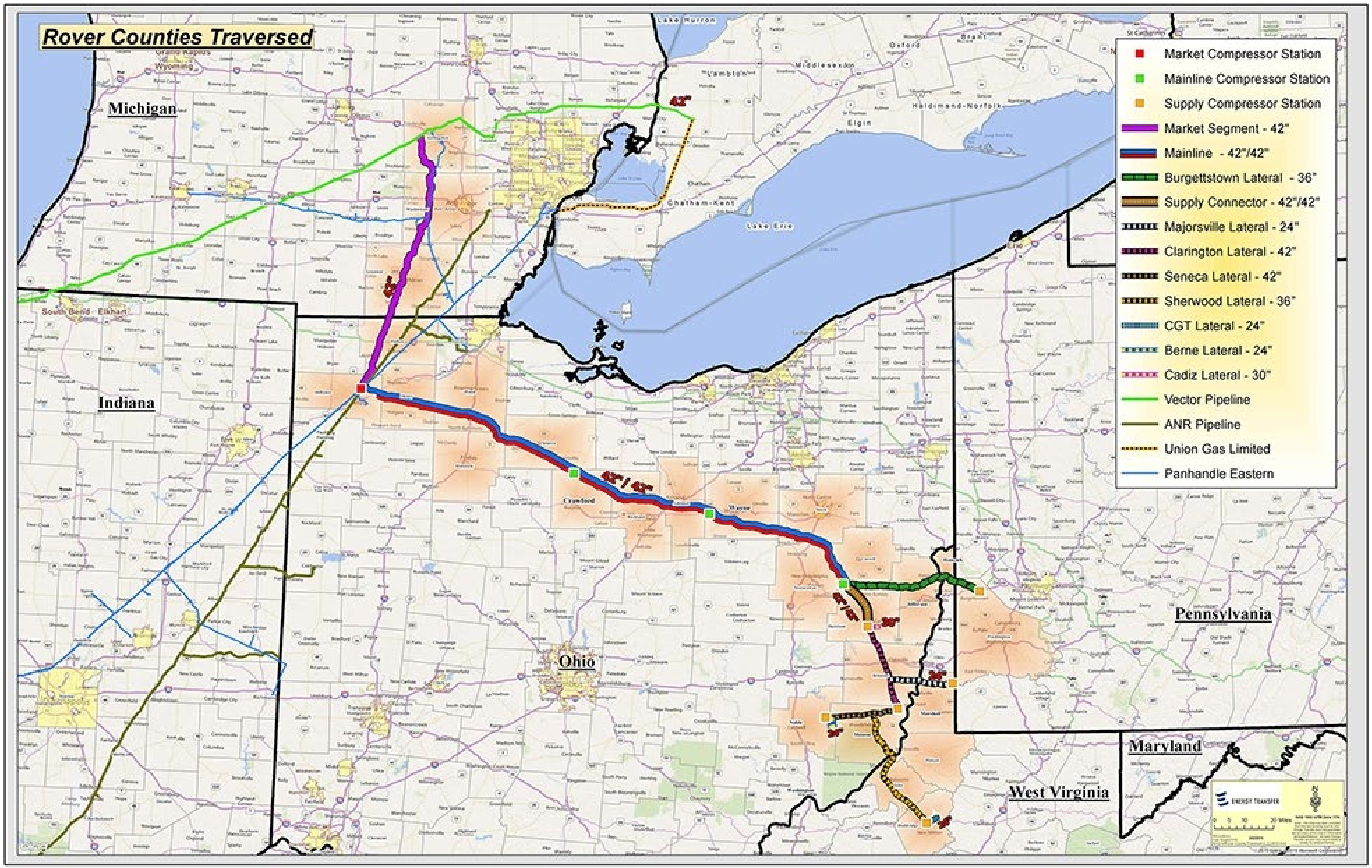
Rover Pipeline System

The 713 mile Rover pipeline system transports natural gas from the Appalachian production basin in West Virginia, Eastern Ohio and Western Pennsylvania to interconnecting pipelines and markets across West Virginia, Ohio, and Michigan. Rover is indirectly connected to Dawn via the Vector pipeline. The Rover pipeline offers firm transportation capacity and the ability to procure supply from multiple trading points within the Appalachian supply basin.

Figure B-5 illustrates the Rover pipeline, including key points on the system.

Figure B-5

Rover Pipeline Sy.stem Map[5]



[5] https://rovermessenger.energytransfer.com/ipost/ROVER/maps/system-map.

Vector Pipeline System

The 348 mile Vector pipeline system links the Chicago and Dawn market hubs, and interconnects with the Alliance Pipeline, Northern Border and Guardian Pipelines in Illinois, and Bluewater Gas Storage, DTE Gas Transportation, NEXUS Gas Transmission, and Rover Pipeline in Michigan.[6] The Vector Pipeline offers firm transportation capacity, access to liquid trading points, and access to gas storage in Michigan (both direct and indirect access), Illinois (indirect access), and Indiana (indirect access).

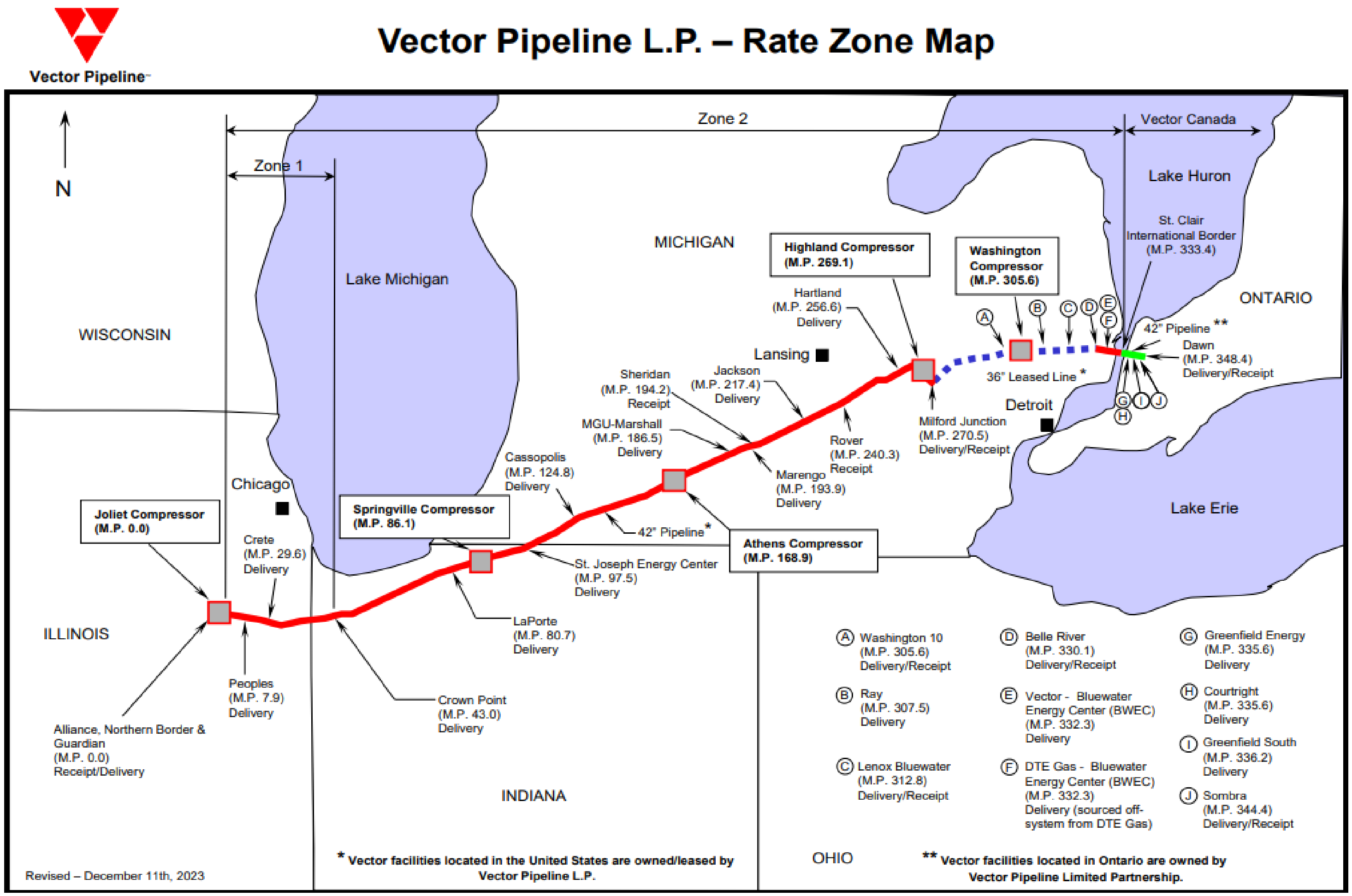
The Chicago market hub has access to supply from diverse production regions across North America. The pipelines directly supplying the Chicago market hub include, but not limited to, Alliance Pipeline, Northern Border Pipeline, Guardian Pipeline and ANR Pipeline. Alliance Pipeline originates in northeastern British Columbia and transports WCSB supply to Chicago. Northern Border Pipeline originates at the Saskatchewan/ Montana border and transports WCSB and Bakken supply to Chicago. Guardian Pipeline extends from Green Bay, Wisconsin to Joliet, Illinois and has access to multiple supply basins through various interconnects. ANR pipeline system is one of the largest interstate pipeline systems in the United States and connects the Chicago market hub to supply and storage areas throughout North America.

Figure B-6 illustrates the Vector Pipeline system, including key points on the system.

[6] Vector, Bluewater Gas Storage, and NEXUS are affiliates of Enbridge Inc.

Figure B-6

Vector Pipeline System Map[7]



[7] https://www.vector-pipeline.com/~/media/EepEeqMep/Site-Documents/Vector/Informational-Postings/Tariff/Map/Rate-Zone-Map.pdf?rev=47e534241fa74419a9cacd57e29263dc&hash=456F8EC0BFF3CCAB3CCCCF99EB352B25.

NEXUS Gas Transmission System

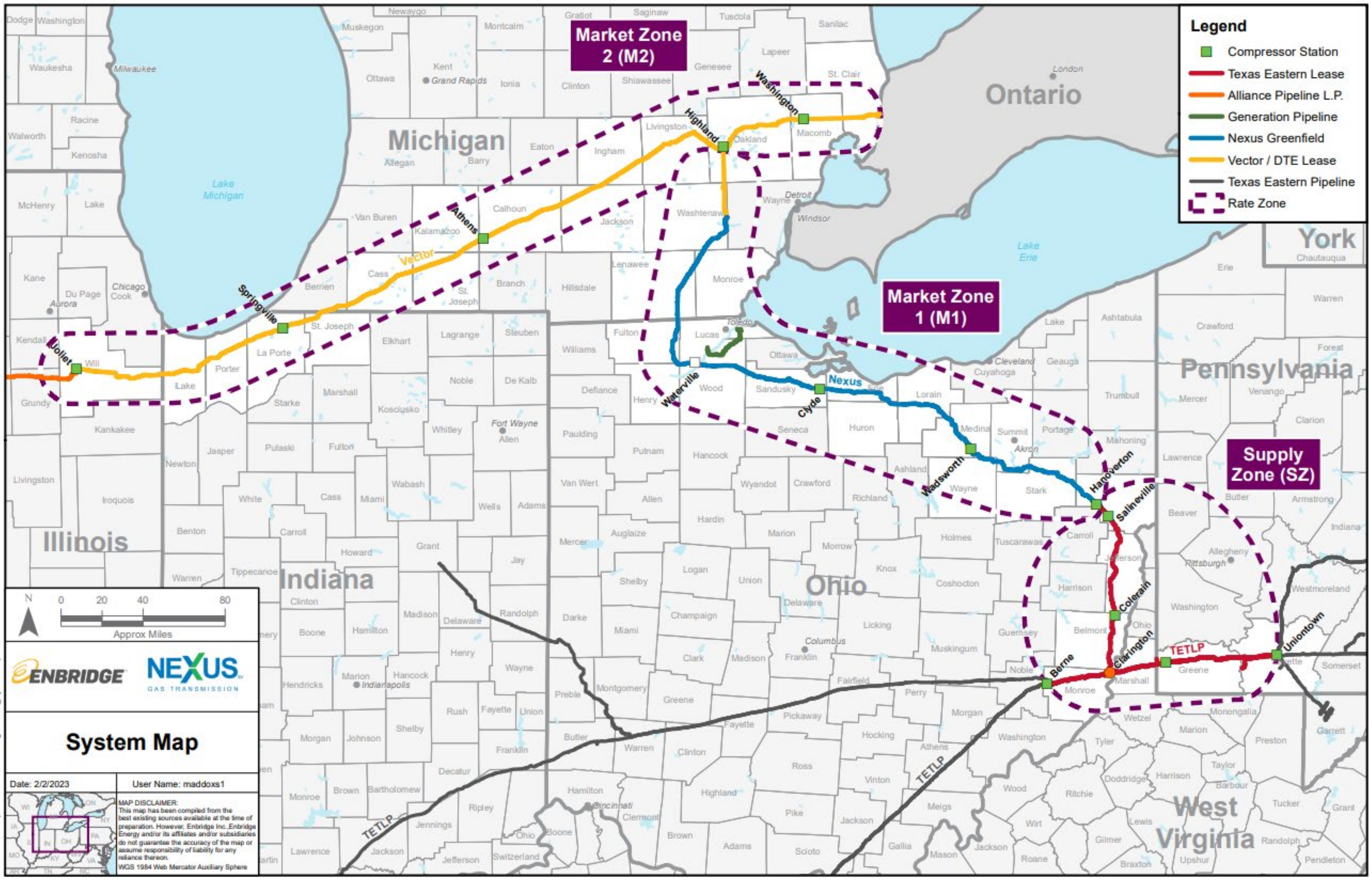
The 256 mile NEXUS Gas Transmission (NEXUS) pipeline system transports natural gas from Kensington, Ohio to markets in the U.S. Midwest and Canada (Dawn). The NEXUS pipeline offers firm transportation capacity and the ability to procure supply from multiple trading points within the Appalachian supply basin including Kensington and Clarington.[8]

Figure B-7 illustrates the NEXUS pipeline, including key points on the system.

[8] Access to Clarington is via TEAL on the Texas Eastern system, as discussed in the following section.

Figure B-7

NEXUS Gas Transmission System Map[9]



---

9 https://linkwc.enbridge.com/SystemMaps/NEXSystemMap.pdf.

Texas Eastern Transmission System

The 9,029 mile Texas Eastern Transmission system (Texas Eastern) transports natural gas from producing areas in Texas and the Gulf Coast to markets in the U.S. northeast. Texas Eastern interconnects with the NEXUS pipeline, Tennessee Natural Gas pipeline, and Algonquin Gas Transmission pipeline. The NEXUS Supply Zone10 is comprised of capacity leased by NEXUS from Texas Eastern. The Texas Eastern pipeline offers firm transportation capacity that when combined with Enbridge Gas's NEXUS pipeline capacity provides the ability to procure supply from multiple trading points within the Appalachian supply basin including Clarington.

Figure B-8 illustrates the Texas Eastern pipeline, including key points on the system.

[10] https://linkwc.enbridge.com/SystemMaps/NEXSystemMap.pdf.

Figure B-8

Texas Eastern Transmission System Map[11]

[11] https://infopost.enbridge.com/infopost/TEHome.asp?Pipe=TE.

Link Pipeline System, St. Clair Pipeline System, and Bluewater Pipeline System

The 6.2 mile (9.9 km) Link Pipeline (Link) transports natural gas from the international border in the St. Clair River into Ontario, where it completes a path from the MichCon system in Michigan (via the ANR pipeline system) to Enbridge Gas's integrated storage (Dawn) and transmission systems in Lambton County, Ontario.

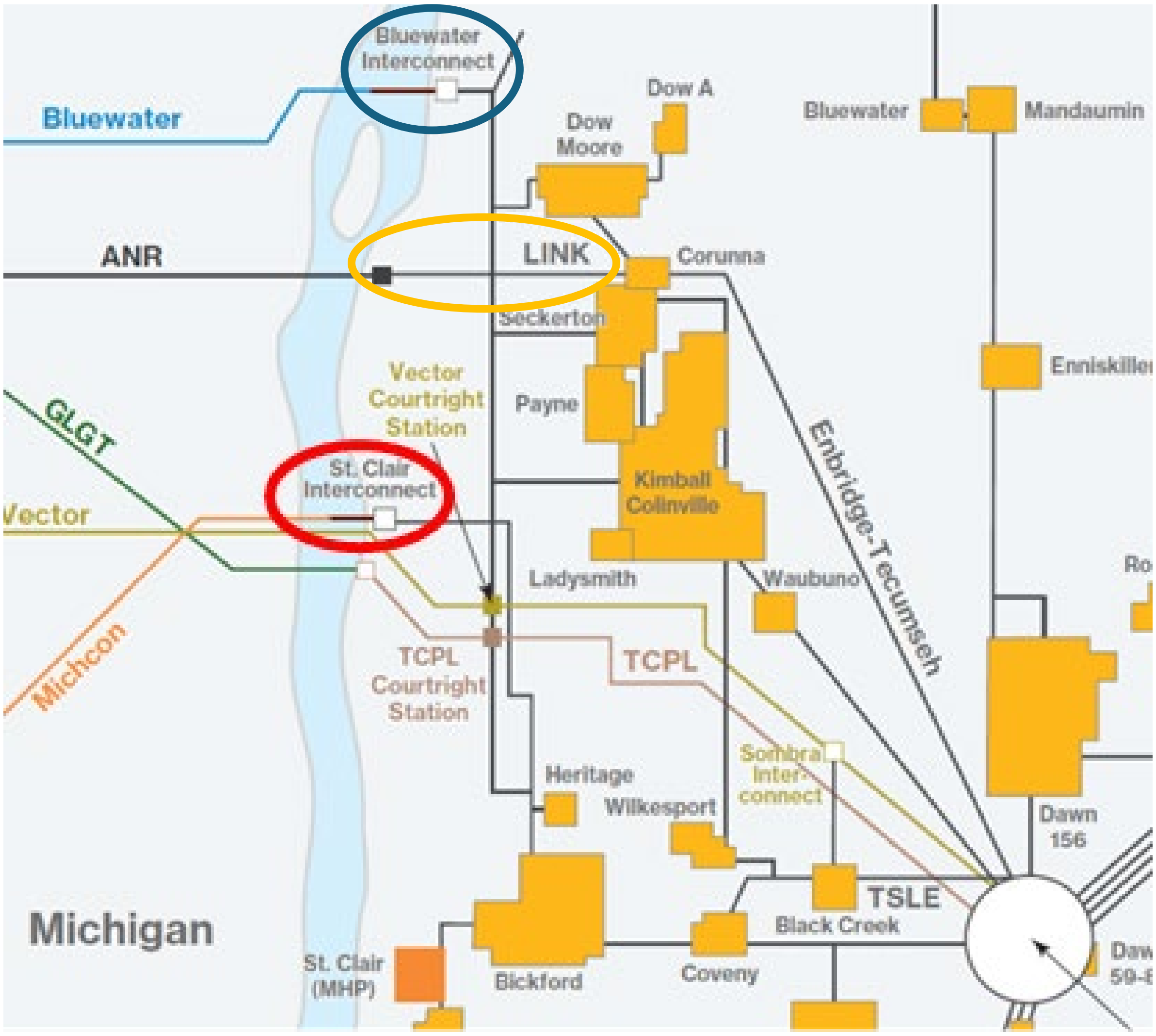
The 0.6 mile (0.9 km) St. Clair pipeline system (St. Clair) transports natural gas from the international border in the St. Clair River into Ontario, where it completes a path from the MichCon system in Michigan (including storage in St. Clair County, Michigan) to Enbridge Gas's integrated storage (Dawn) and transmission systems in Lambton County, Ontario at the St. Clair Interconnect.

The 1.9 mile (3 km) Bluewater Pipeline system (Bluewater) transports natural gas from the international border in the St. Clair River into Ontario, where it completes a path from Bluewater Gas Storage (BGS) in Michigan to Enbridge Gas's integrated storage (Dawn) and transmission systems in Lambton County, Ontario at the Bluewater Interconnect.

Figure B-9 illustrates the Link, St. Clair, and the Bluewater pipelines.

Figure B-9

Link/St. Clair/Bluewater Pipelines System Map



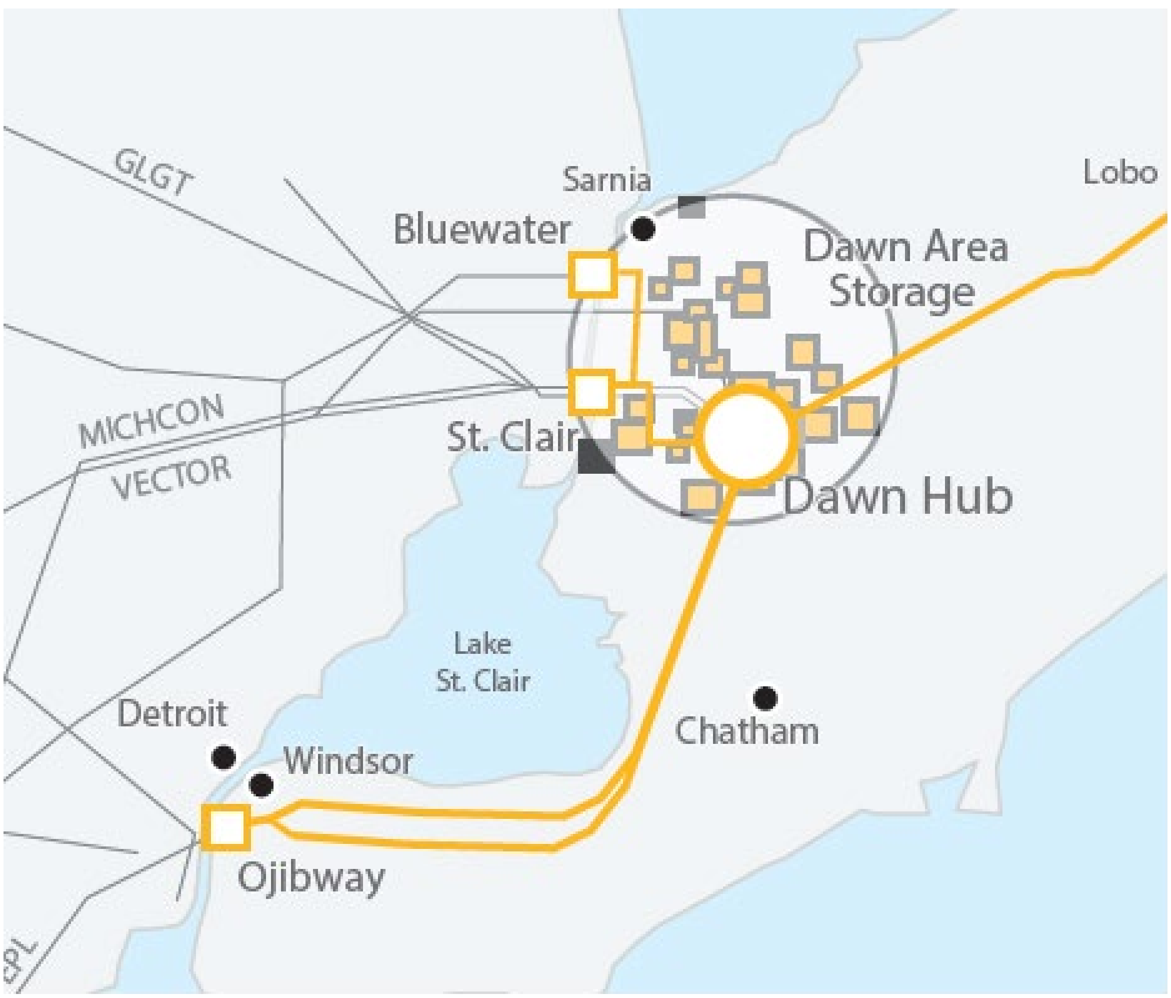
Panhandle Transmission System

The 118 km Panhandle Transmission System, is a bi-directional pipeline system that transports natural gas between its interconnect with PEPL (nearby the Ojibway valve site) and Dawn, serving Enbridge Gas's residential, commercial and industrial in-franchise markets along the path. Depending on the time of year and the level of customer demand, gas may either be received at Dawn on low market days or delivered from Dawn on high market days. The import capability of the Panhandle Transmission System is limited by the Windsor market area demand and capacity of the nearby Sandwich Compressor station.

Figure B-10 illustrates the Panhandle Transmission System.

Figure B-10

Panhandle Transmission System Map



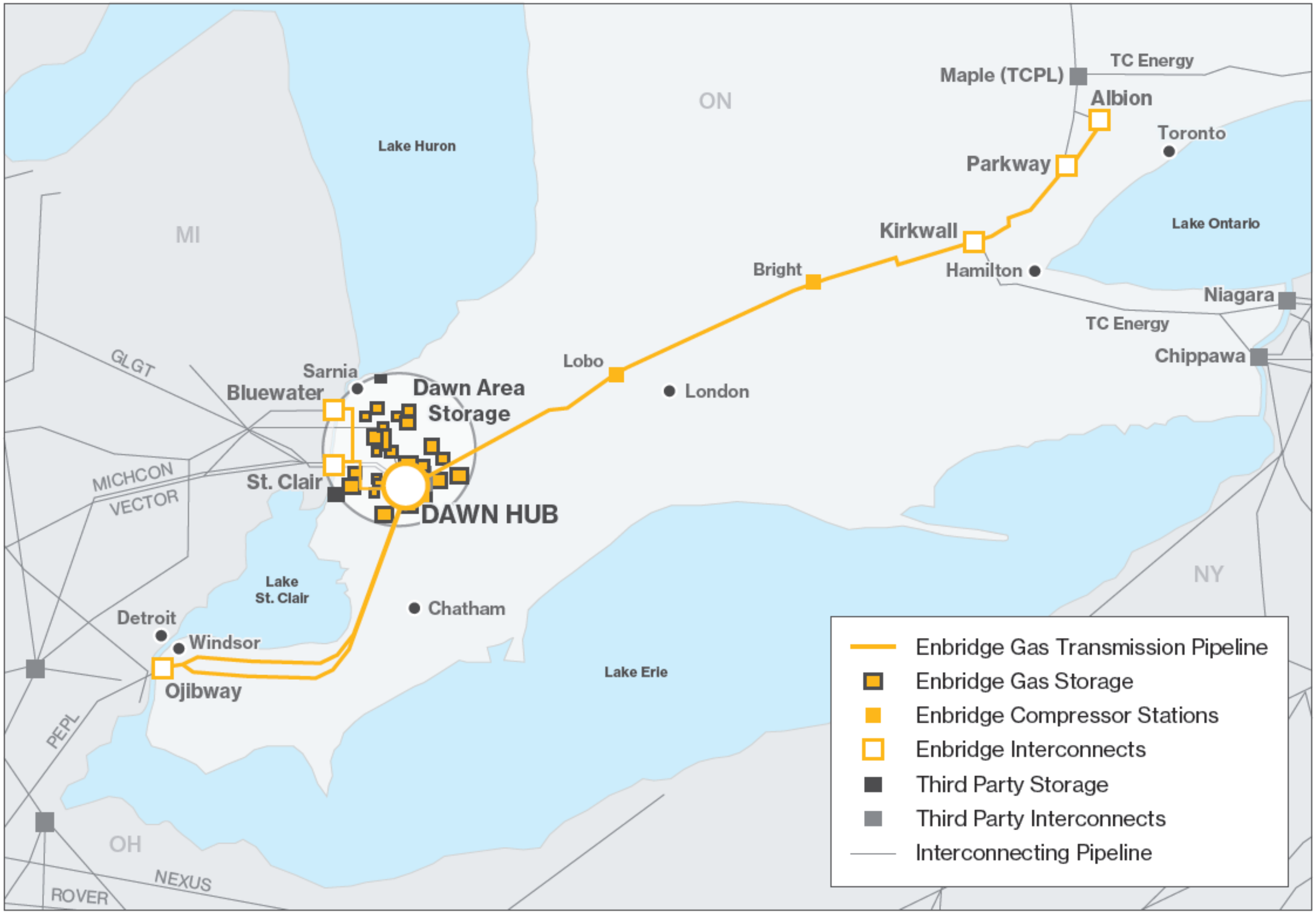
Dawn Parkway Transmission System / Albion Pipeline

The 229 km Dawn Parkway Transmission System (Dawn Parkway System) is a bi-directional pipeline system that transports natural gas between Dawn, Parkway, and Kirkwall. The Dawn Parkway System also interconnects with the Albion Pipeline which transports natural gas from Parkway to the TCPL Mainline at Kings North. The Dawn Parkway System and the Albion Pipeline each interconnect with Enbridge Gas's distribution systems in the Enbridge CDA at Parkway and Lisgar, and at the Albion Gate Station, respectively. The Dawn Parkway System and Albion Pipeline system offer firm transportation capacity and provide diversity of supply via Dawn.

Figure B-11 illustrates the Dawn Parkway System and Albion Pipeline, including key points on the system.

Figure B-11

Dawn Parkway Transmission System / Albion Pipeline Map



Storage Asset Options

This section outlines physical storage options at Dawn and others located in close proximity to Enbridge Gas's integrated storage facility.

Enbridge Gas Storage Pools in Ontario

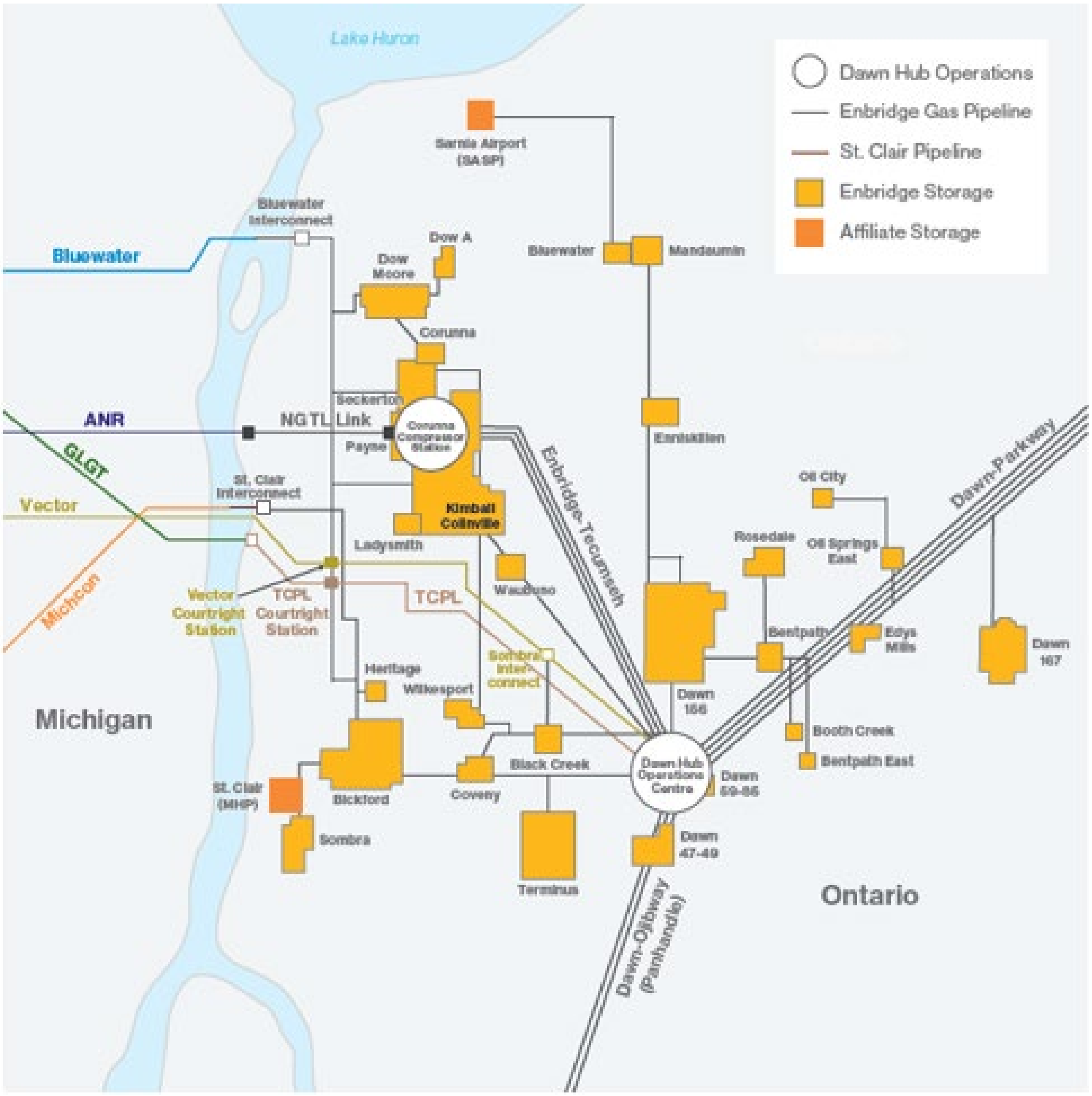
Enbridge Gas owns and operates 35 storage reservoirs which collectively have 288 Bcf (319 PJ) of working capacity (180 Bcf/199 PJ for regulated business and 108 Bcf/120 PJ for unregulated business). More than 100 counterparties actively do business at Dawn, including many of North America's largest natural gas marketers. Further, as of April 1, 2025, about 40 marketers held Peak Storage (LTP) contracts at Dawn.[12] The depth of liquidity at Dawn together with the primary (physical/high-flexibility) and secondary (synthetic/low-flexibility) storage service market enables counterparties to routinely offer/procure a variety of services.

Figure B-12 provides a map of storage pools that connect to Dawn, including key points on the surrounding systems.

[12] https://www.enbridgegas.com/-/media/Extranet-Pages/Storage-and-transportation/operational-information/Index-of-customers/Storage_Report.xlsx?rev=9987404d7d3f4e7b9209be75a6d6e1c7&hash=E8CD0A99D038B97316DC6AFE333A3A3D.

Figure B-12

Enbridge Gas Storage Map



Michigan Storage Pools

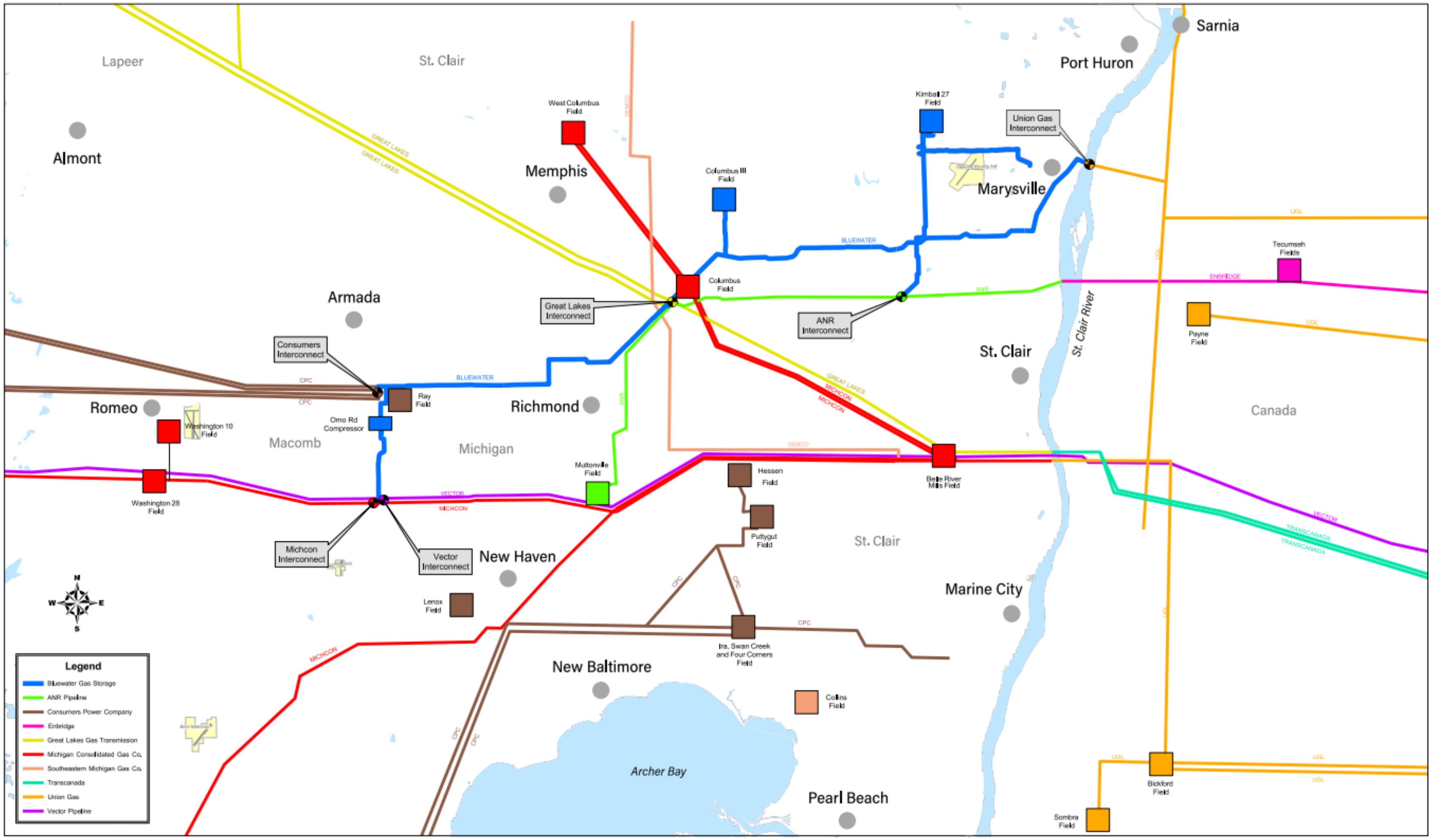
Michigan has 52 storage reservoirs which collectively have approximately 671 Bcf[13] of working capacity, including Washington 10 and Belle River Mills. Michigan storage pools interconnect to Enbridge Gas's integrated storage and transmission systems via the GLGT/GLC, ANR, Vector, Link, St. Clair, and Bluewater pipelines previously discussed.

Figure B-13 provides a map of Michigan storage pools located nearby Enbridge Gas's integrated storage and transmission systems, including key points on the surrounding systems.

[13] Michigan Natural Gas Active Storage Field Summary, https://www.michigan.gov/mpsc/regulatory/natural-gas/transportation-storage/michigan-natural-gas-active-storage-field-summary.

Figure B-13

South Michigan Storage[14]



14 https://www.bluewatergasstorage.com/about/bluewater-system-map.pdf.

<u>2024/25 Enbridge CDA Shortfall – Holistic Analysis</u>

This Appendix provides the holistic analysis prepared by Enbridge Gas to evaluate options for meeting the 2024/25 Enbridge CDA design day shortfall. Enbridge Gas considers the analysis “holistic” because the commercial alternatives available to meet the shortfall were compared based on total Pan cost impact (commodity, transportation and storage costs) and to impacts such as portfolio flexibility, storage utilization, supply diversity, and scarcity of supply. Enbridge Gas will consider assessing alternatives using this holistic approach in future contracting analysis, where applicable.

Following the holistic analysis of alternatives, Enbridge Gas decided to bid for 40,000 GJ/d in the TCPL ECOS and to contract with a third-party for assignment of TCPL capacity for the remaining Enbridge CDA shortfall (TCPL Assignment). Enbridge Gas was awarded 34,457 GJ/d of new TCPL capacity in the TCPL ECOS and adjusted the amount of TCPL assignment capacity contracted with the third-party to eliminate the remaining 2024/25 Enbridge CDA shortfall.

Appendix C, Page 3 provides the design day position of the Enbridge CDA for the forecast period (2024/25 to 2029/30). The design day shortfall increases from the 2024/25 current year shortfall of 252.9 TJ/d to a peak of 310.9 TJ/d in 2027/28; an increase of 58 TJ/d from the current shortfall. In no year of the forecast period does the design day shortfall decrease below the current year shortfall. Therefore, a solution to meet the current year design day shortfall is forecast to be required in all years of the 5-Year GSP period.

Appendix C, Page 4 provides a summary of the options analysis to meet the design day shortfall for the Enbridge CDA. The available options were evaluated except for “Third-Party TCPL Assignment - Empress to Enbridge CDA” which was determined to be less cost-effective relative to the 2024 TCPL ECOS and was not pursued past the options analysis stage.

Appendix C, Page 5 provides a summary of the alternatives Enbridge Gas assessed to meet the design day shortfall. The options of the 2024 TCPL ECOS and the Third-Party TCPL Assignment (and various scenarios) were evaluated individually as well as in combination (in various differing proportions). In total, Enbridge Gas considered and compared six alternatives through an assessment of their respective total costs. The 2024 TCPL ECOS had 84,457 GJ/d of available Empress to Enbridge CDA capacity. For this reason, the holistic analysis (i.e., Page 4 – Alternative Overview) was completed using a common total of 84,457 GJ/d of capacity under all alternatives; to equitably compare the alternatives based on a standard capacity (volume).

Appendix C, Page 6 provides a cost summary of the six alternatives assessed. The total cost of each alternative was determined by updating the transportation portfolio for the alternative in the gas supply plan optimization model for the EGD rate zone. The alternative gas supply plan cost was then compared against the cost without the alternative (base case). The 2024 TCPL ECOS was the lowest cost alternative and Scenario 1 of the Third-Party TCPL Assignment was the lowest cost of the three scenarios provided by the third-party. For this reason, Enbridge Gas used the Third-Party TCPL Assignment Scenario 1 in further alternatives in combination with the 2024 TCPL ECOS. Scenarios 2 and 3 of the Third-Party TCPL Assignment were not evaluated past the cost stage.

Appendix C, Page 7 provides additional gas supply impact considerations that Enbridge Gas used in the evaluation of the alternatives. As a result of the cost summary results of the six alternatives, Enbridge Gas assessed Alternatives 1, 2, 5, and 6 through the evaluation of additional considerations. Enbridge Gas considered the impact to the gas supply plan for the EGD rate zone flexibility by reviewing the total annual supply quantity and impact to summer Dawn purchases. These factors are important because the supply commitment at Empress or Niagara would reduce the Dawn supply position that Enbridge Gas uses for flexibility in the Plan (e.g., to enable supply mitigation). Evaluation of the summer Dawn purchases is important in years with warm winters and associated high inventory balances coming out of the winter such as the most recent 2023/24 gas year where storage inventory levels entering the summer season were significantly higher than planned requiring commensurate summer supply mitigation (more than 20 PJ for the EGD rate zone). Enbridge Gas also considered the impact to storage utilization by reviewing the incremental end of winter balance in storage because of the additional supply purchases. Other considerations in the evaluation of alternatives were supplier diversity, as the third-party TCPL assignment alternative represented an opportunity to add a new supplier to Enbridge Gas's portfolio, and scarcity of supply considerations, since the 2024 TCPL ECOS provided an increasingly rare opportunity to secure FT capacity.

Following the holistic analysis, Enbridge Gas pursued contracting for Alternative 6 of 40,000 TJ/d 2024 TCPL ECOS and the remaining Enbridge CDA shortfall through Third-Party TCPL Assignment. As a result of being awarded 34,457 TJ/d through the 2024 TCPL ECOS, Enbridge Gas increased the Third-Party TCPL Assignment by the difference. Enbridge Gas selected Alternative 6 because the small incremental cost ($0.6 million) relative to the lowest cost option of the 2024 TCPL ECOS (as detailed in Appendix C, Page 5) provided a better balance of flexibility (through reduced annual supply commitment and higher summer Dawn purchases), improved utilization of storage, and improved supply diversity.

Enbridge CDA - Design Day Position

Line No.	Particulars (TJ/d)	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
		(a)	(b)	(c)	(d)	(e)	(f)
	Demand						
1	Design Day Demand	3,578.3	3,594.1	3,622.3	3,624.1	3,622.6	3,619.2
	Supply						
2	Great Lakes	-	-	-	-	-	-
3	In-franchise Supply (1)	2,249.3	2,237.1	2,237.1	2,237.1	2,237.1	2,237.1
4	NEXUS	-	-	-	-	-	-
5	Panhandle	-	-	-	-	-	-
6	TCPL Long-haul	5.0	5.0	5.0	5.0	5.0	5.0
7	TCPL Short-haul	787.2	787.2	787.2	787.2	787.2	787.2
8	TCPL STS	283.9	283.9	283.9	283.9	283.9	283.9
9	Vector	-	-	-	-	-	-
10	Total Supply	3,325.4	3,313.2	3,313.2	3,313.2	3,313.2	3,313.2
11	Supply Excess / (Shortfall)	(252.9)	(281.0)	(309.1)	(310.9)	(309.5)	(306.0)

Note:
(1) Includes supply arriving directly into the franchise area (i.e. Dawn, storage, DP deliveries, Crowland, Hagar, delivered supply, etc.).

Enbridge CDA - Options Analysis

Line No.	Particulars (TJ/d)	Availability	Capacity Available
		(a)	(b)
	Long-haul		
1	2024 TCPL ECOS - Empress to Enbridge CDA	Yes	Up to 84,457 GJ/d
2	Third-Party TCPL Assignment - Empress to Enbridge CDA (1)	Yes	Up to 84,457 GJ/d
	Short-haul		
3	Third-Party TCPL Assignment - Niagara to Enbridge CDA (2)	Yes	Up to 255,618 GJ/d
4	Dawn to Parkway + TCPL Parkway to Enbridge CDA	No	
5	Dawn to Enbridge CDA	No	
6	TCPL Niagara to Enbridge CDA	No	

Notes:

(1) The availability of this capacity was dependant on the third-party securing capacity through the 2024 TCPL ECOS. Enbridge Gas conducted preliminary analysis of this offering by a third-party and determined it was not competitive from a cost-effectiveness perspective. Therefore, this alternative was not pursued further.

(2) This alternative includes the assignment of pipeline capacity under three different commercial scenarios made available by the same counterparty. This alternative requires the purchase of gas commodity from the third-party at Niagara at a fixed premium to the Dawn daily index price (as published by S&P Global Platts).

Enbridge CDA - Alternative Overview

Line No.	Alternative Number	Particulars (TJ/d)	Capacity	Capacity Availability
			(a)	(b)
		Long-haul		
1	1	2024 TCPL ECOS - Empress to Enbridge CDA	84,457 GJ/d	January to December (year-round)
		Third-Party TCPL Assignment Scenarios		
2	2	Third-Party TCPL Assignment - Niagara to Enbridge CDA (Scenario 1) (1)	84,457 GJ/d	December to March
3	3	Third-Party TCPL Assignment - Niagara to Enbridge CDA (Scenario 2)	84,457 GJ/d	January to March
4	4	Third-Party TCPL Assignment - Niagara to Enbridge CDA (Scenario 3)	84,457 GJ/d	January and February
		Combination of Long-haul and Third-Party Assignment		
5	5	2024 TCPL ECOS - Empress to Enbridge CDA, plus	20,000 GJ/d	January to December (year-round)
6		Third-Party TCPL Assignment - Niagara to Enbridge CDA (Scenario 1) (1)	64,457 GJ/d	December to March
7	6	2024 TCPL ECOS - Empress to Enbridge CDA, plus	40,000 GJ/d	January to December (year-round)
8		Third-Party TCPL Assignment - Niagara to Enbridge CDA (Scenario 1) (1)	44,457 GJ/d	December to March

Note:
(1) Third-Party TCPL Assignment Scenario 1 was selected for further evaluation in Alternatives 5 and 6 as it was the most cost-competitive of the three scenarios provided by the third-party.

Enbridge CDA - Alternative Cost Summary

Line No.	Alternative Number	Particulars ($million)	Alternative Cost Variance to Base Case	Alternative Cost Variance to Lowest Cost Alternative (Alt 1)
			(a)	(b)
1	-	Base Case	-	N/A
	Long-haul			
2	1	2024 TCPL ECOS - Empress to Enbridge CDA	23.7	-
	Third-Party TCPL Assignment Scenarios			
3	2	Third-Party TCPL Assignment - Niagara to Enbridge CDA (Scenario 1) (1)	31.4	7.7
4	3	Third-Party TCPL Assignment - Niagara to Enbridge CDA (Scenario 2)	37.3	13.6
5	4	Third-Party TCPL Assignment - Niagara to Enbridge CDA (Scenario 3)	39.5	15.8
	Combination of Long-haul and Third-Party Assignment			
6	5	20,000 GJ/d 2024 TCPL ECOS - Empress to Enbridge CDA, plus	27.1	3.4
7		64,457 GJ/d Third-Party TCPL Assignment - Niagara to Enbridge CDA (Scenario 1) (1)		
8	6	40,000 GJ/d 2024 TCPL ECOS - Empress to Enbridge CDA, plus	24.3	0.6
9		44,457 GJ/d Third-Party TCPL Assignment - Niagara to Enbridge CDA (Scenario 1) (1)		

Note:

(1) Third-Party TCPL Assignment Scenario 1 was selected for further evaluation in Alternatives 5 and 6 as it was the most cost-competitive of the three scenarios provided by the third-party.

Enbridge CDA - Alternative Considerations

Line No.	Particulars (TJ/d)	Alternative Number 1 TCPL Empress to Enbridge CDA	2 Third-Party Assignment Niagara to Enbridge CDA (Scenario 1)	5 20,000 GJ/d TCPL / 64,457 GJ/d Third-Party Assignment	6 40,000 GJ/d TCPL / 44,457 GJ/d Third-Party Assignment
		(a)	(b)	(c)	(d)
	Portfolio flexibility				
1	Total annual supply quantity	30.9 PJ	10.3 PJ	15.2 PJ	20.0 PJ
2	Total summer Dawn purchases	2.6 PJ (reduction of 20.5 PJ)	20.6 PJ (reduction of 2.5 PJ)	16.3 PJ (reduction of 6.8 PJ)	12.1 PJ (reduction of 11.0 PJ)
	Storage utilization				
3	Incremental end of winter balance /				
4	Reduction in annual inventory cycled	4.9 PJ	2.4 PJ	3.0 PJ	3.6 PJ
5	Supply diversity (1)	WCSB increases by 10% to 39% Dawn decreases by 10% to 15%	Niagara increases by 3% to 25% Dawn decreases by 3% to 22%	WCSB increases by 3% to 32% Niagara increases by 3% to 25% Dawn decreases by 6% to 19%	WCSB increases by 5% to 34% Niagara increases by 2% to 24% Dawn decreases by 6% to 19%
6	Scarcity of supply	Preference to secure FT capacity when available	Third-party holds 255,618 GJ/d Niagara to Enbridge CDA		

Note:

(1) Percentages provided are relative to the base percentages of the total supply portfolio for the EGD rate zone: 29% of WCSB, 25% of Dawn, 22% of Niagara, 13% Appalachian, and 10% Chicago.

Chicago Natural Gas Price Analysis

PREPARED FOR:
Enbridge Gas

PREPARED BY:
Andrew Griffith and Neha Jain
ICF Resources

October 14, 2024

1. Executive Summary

1.1 Purpose

Prior to 2021, Chicago natural gas prices were consistently lower than prices at Dawn, and the natural gas forward prices were consistent with the day-ahead prices. However, since early 2021, the Chicago natural gas price forward prices have diverged from the ensuing Chicago day-ahead prices, with the forward strip remaining consistently higher than the day-ahead prices. This shift in market behavior has resulted in a shift in the price relationship between Chicago and Dawn from a Chicago discount to a Chicago premium relative to Dawn in the futures market even though the Chicago day-ahead prices have on average continued to trade at a discount.

In August 2023, Enbridge Gas asked ICF to analyze the causes for the divergence between the Chicago natural gas forward prices and the Chicago day-ahead prices in order to identify the causes of this change in market pricing behavior and to assess the outlook for this shift in market pricing. In August 2024, Enbridge Gas asked ICF to provide an updated assessment of Chicago natural gas price forwards, day-ahead prices, and markets fundamentals conducted last year. This report provides a refreshed analysis using the most recent year of actual price information and ICF's most recent Q3 2024 forecast.

Enbridge Gas contracts for capacity on the Vector pipeline from Chicago to Dawn, which provides it with access to Chicago natural gas supply. ICF's assessment is expected to be used by Enbridge Gas to help evaluate the future value of Vector pipeline capacity as part of the Enbridge Gas supply portfolio. Given the lack of available pipeline capacity between the Chicago and Ontario markets, Enbridge Gas likely would be unable to re-contract for capacity on Vector or other pipelines in the Chicago to Dawn corridor without paying a significant premium if the existing capacity is allowed to expire given the scarcity of pipeline capacity. According to the Vector Pipeline's index of customer data, firm transportation delivery contracts on Vector increased to 3.3 Bcfd in Q4 2024 from 2.9 Bcfd in Q4 2019.

Based on the ICF review, financial markets are currently building a significant risk premium into the forward curve at Chicago in response to recent price volatility and extreme price events in the region. In the absence of similar extreme price events, ICF expects this risk premium to decline over time. While the Chicago price hub has experienced recent price volatility contributing to the futures market premium at that location, future events could lead to similar increases in forward pricing at other price locations. If that occurs, the supply portfolio diversity provided by sourcing gas at Chicago will become increasingly valuable. This report discusses why ICF's expectations that the increase in Chicago forward pricing relative to Dawn is likely to be a short-term trend and why the diversity of supply provided by access to the Chicago market is important for Enbridge Gas.

1.2 Context

During Winter Storm Uri in February 2021, the day-ahead Chicago natural gas price spiked to $136.68/MMBtu while other price hubs in the region, including Dawn, remained relatively stable. Day-ahead prices in the Dawn market reached $9.18/MMBtu. In response to that price spike, and other temporary price increases like the ones seen in December 2022 during Winter Storm Elliott and in January 2024 during Winter Storm Heather, when the Chicago and Dawn prices reached $16.90/MMBtu and $27.22/MMBtu respectively, the futures market has diverged from the market fundamentals observed in the day-ahead prices and ICF's fundamentals-based forecasts that are used by Enbridge Gas. On average, since Winter Storm Uri, between March 2021 and August 2024, the day-ahead natural gas prices at Chicago have traded at a discount to price hubs such as Dawn, where Chicago averaged $3.69/MMBtu and Dawn averaged $3.64/MMBtu. ICF's forecasts also include a discount for Chicago's natural gas prices relative to Michcon and Dawn similar to the day-ahead market. However, the forward curve has at times included a premium of more than $1/MMBtu for Chicago's winter prices in comparison with Dawn.

Some of the price volatility observed in the context above has been driven by fundamental changes in North American natural gas markets that are transforming the natural gas price relationships between different natural gas market centers. The shale gas revolution changed the quantity of available natural gas supply across North America. While there are shale gas plays in a variety of regions (including Western Canada, the Gulf Coast, and the Midcontinent), most of the natural gas production growth since 2015 has occurred in the Marcellus and Utica shale plays in the Northeastern U.S. and growth there is expected to continue, albeit at a slower pace than during the past seven years. As a result, the utilization and significance of pipeline infrastructure to bring low-cost gas from the producing regions to demand centers has increased. Largely in response to the increased availability of supply, demand growth has been driven by the increase in natural gas demand for heating, power generation, industrial use, liquefied natural gas (LNG) exports, and pipeline exports to Mexico. Since 2021, on days with extremely high natural gas demand, the increased utilization and sometimes insufficient capacity of infrastructure led to increased prices at Chicago and increased price spreads between Chicago and Dawn due to its reliance on pipeline deliveries. Dawn, which has better access to natural gas storage and pipelines, has not experienced similar price spikes recently.

Key Natural Gas Market Terminology

- ***Basis*** *refers to the difference in price between Henry Hub and another natural gas price hub (although it could be between any two locations).*
- ***Bid-week prices*** *represent the price of gas that will flow every calendar day during the forthcoming calendar month. These are based on trading conducted in the fifth, fourth and third business days before the start of the contract month.*
- ***Day-ahead prices*** *for a particular day are determined on the preceding day by traders using localized supply and demand conditions. On the last day before a weekend, public holiday or other industry-agreed non-trading days, day-ahead indexes also include the weekend, public holiday and/or other industry-agreed nontrading days.*
- ***Futures market****: A trade center for quoting prices on contracts for the delivery of a specified quantity of a commodity at a specified time and place in the future. Trades in the futures market determine the forward price.*
- ***Forward price****: The predetermined delivery price for the delivery of a specified quantity of natural gas at a specified time and place in the future. The* ***forward curve*** *shows the forward price for numerous dates (often months) in the future.*
- ***Prompt month*** *(front month) prices refer to the forward prices from a trade date for the immediate next month. For example, prompt-month contracts traded in August are typically for delivery in September.*
- ***Trade date*** *refers to the date on which the trading is being done. On a particular trade date, the prices are set for the forward (future)* ***contract date****.*

1.3 Summary of Findings

Since early 2021, the Chicago and Dawn forward curves and bid-week prices, which are financial products that result from the buying and selling of future natural gas supply, have projected that natural gas prices at Chicago will trade at a significant premium to Dawn. Winter Storm Uri in 2021 and Winter Storm Elliott in 2022 were the main drivers that led to this shift in the forward market dynamics. This year between January 13th and 16th, 2024 the Winter Storm Heather impacted the entire United States and caused price spikes across the entire country. Because of the storm, Chicago prices during January 2024 averaged a $2.25/MMBtu premium to Dawn. The December 2023 bid week price spread between Chicago and Dawn was just $0.47/MMBtu for January 2024. Excluding the three winter storms listed above, the Chicago day-ahead price has traded at an average $0.03/MMBtu discount to Dawn between January 2021 and August 2024. From 2019 through 2023, the Chicago day-ahead price averaged a $0.01/MMBtu discount to Dawn between May to August however, in 2024, Chicago averaged a $0.07/MMBtu premium to Dawn from May to August. This premium is $0.04/MMBtu higher than the bid week prices for the May-August 2024 period assessed in April-July 2024. Two primary factors have led to this price dynamic. First, high summer gas demand in the power sector in the Midcontinent region. Second, low Midcontinent gas production due to the prevailing low gas price environment as well as aging wells, reduced drilling activity, and operational challenges has exerted an upward pressure at regional price points thus impacting Chicago prices as well. Hence, there is an increase in the summer spread between Chicago and Dawn.

ICF forecasts, however, which are calculated using ICF's Gas Market Model (GMM) and are based on the market fundamentals such as the cost of production, the forecasted demand, and the cost of transportation, projected the premium to be much lower during the same period. Historically, ICF's fundamentals-based forecasts largely have been supported in the day-ahead market. This is mainly because Chicago has access to the Western Canada, Midcontinent, Haynesville, Bakken, and Rockies production basins. Dawn gets most of its gas from the Marcellus/Utica basins and Western Canada sedimentary basins. ICF, in its Q3 2024 base case projections, expects demand at both Chicago and Dawn to remain stable over the long term. ICF also forecasts that as gas prices recover and production efficiency increases, the Midcontinent gas production will increase and continue to serve the upper Midwest market areas as it has done historically. As a result, ICF forecasts that the day-ahead natural gas prices at Chicago will trade at a discount to Dawn throughout most of the year and only peak during extreme cold-weather events in which the demand spikes are seen upstream of Chicago and not at Dawn. Given the interconnected pipeline network between the Midcontinent and Chicago, if the Midcontinent production continues to experience the same trend as noted during the summer of 2024, this might change the regional market dynamics, and the historical price spread relationship between Chicago and Dawn.

ICF analyzed the index of customers for the Vector Pipeline to assess the change in contracting over time. According to the data, firm transportation capacity delivery contracts on Vector increased to 3.3 Bcfd in Q4 2024 from 2.9 Bcfd in Q4 2019. This is the total daily delivery capacity that can be available to the Vector customers.

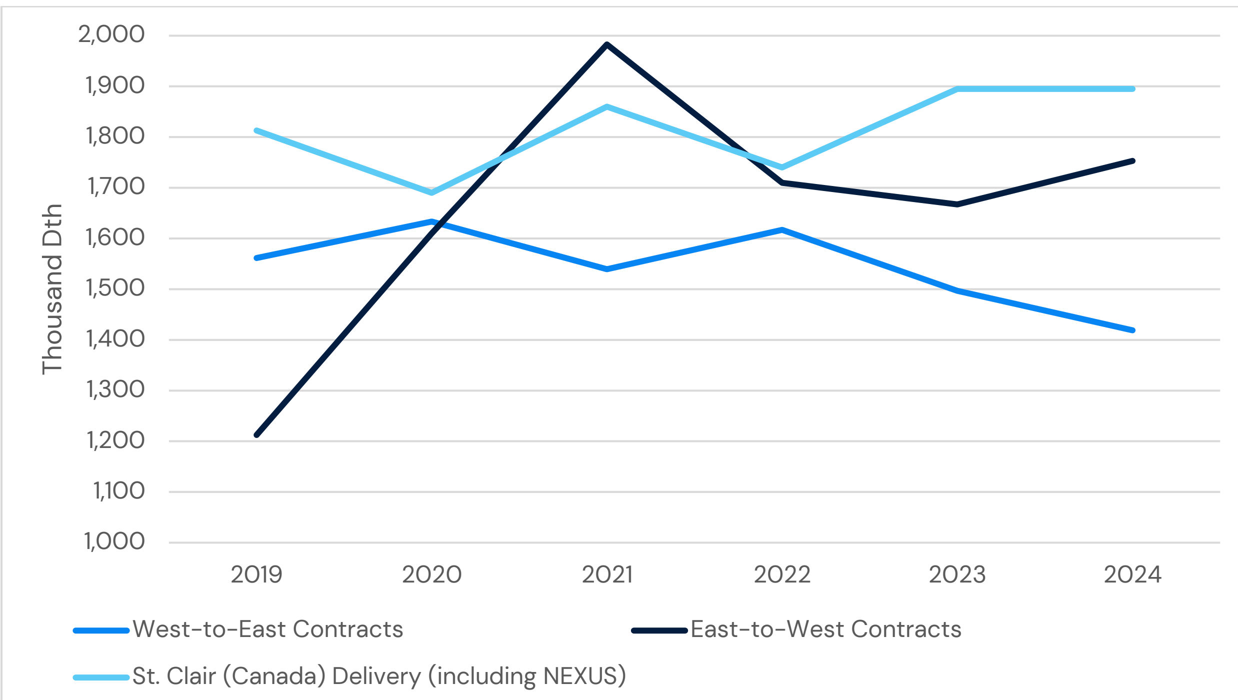
The growth in the firm transportation contracts between Q4 2019 and Q4 2024 includes an additional 533 MMcfd of new contracts. This increase is due to new contracts with Castleton Commodities Merchant Trading LP, Chevron USA Inc, Connexus Energy, Constellation Energy Commodities Group, Direct Energy Business LLC, DTE Electric Co, DTE Energy Trading Inc, EDF Trading North America LLC, Uniper Global Commodities North America LLC, and Just Energy New York LLC.

BPX Energy Co, DTE Gas Co, Equinor Natural Gas LLC, Michigan Gas Utilities Corp, Northern Indiana Public Service Co LLC, SEMCO Energy Gas Co, and Tenaska Marketing Ventures, reduced their contracted capacity on the pipeline. These customers reduced capacity held on the pipeline by 178 MMcfd from 2019 to 2024. Additionally, Gulfport Energy Corp, J Aron & Co, and Morgan Stanley Capital Group Inc, which held a total of 123 MMcfd of capacity, did not renew their contracts on Vector.

On balance, the total pipeline capacity under contract increased by 398 MMcfd. The net increase in contracting capacity is indicative that customers value the firm transportation capacity on the pipeline.

Additionally, the index of customer data for the Vector pipeline over the past few years indicates that the pipeline is fully contracted, with customers consistently retaining and renewing their capacity contracts due to the pipeline's critical role in supplying gas to and from Chicago. The data from Q4 2024 confirms that the pipeline remains fully contracted. Exhibit 1-1 below shows the Q4 firm transportation contracts on the Vector pipeline categorized by the direction that they entitle customers to flow gas based on the receipt and delivery points. The west-to-east contracts provide firm transportation in the forward haul direction of Chicago towards St. Clair and the east-to-west contracts go in the backhaul direction. There has been a small decline of 143 MMcfd of west-to-east firm transportation contracts on Vector since 2019. However, when the NEXUS contracts on the leased Vector capacity are included, the St. Clair delivery capacity remains fully contracted at nearly 1.9 Bcfd. This suggests a slight shift towards sourcing gas from NEXUS (Marcellus/Utica) instead of Chicago, yet it still indicates that the west-to-east direction on Vector is fully contracted.

Exhibit 1-1 : Q4 Capacity Contracts on Vector Pipeline (Thousand Dth)



Source: Hitachi Energy

Table 1-1 shows all the contracts on Vector Pipeline in the west-to-east direction from Q4 2024. While Enbridge Gas is a significant holder, there are many other customers with capacity on this route. There are 15 unique west-to-east firm transportation customers holding 23 contracts and over 1.4 Bcfd of delivery capacity. These contracts underscore the continued value of holding contracts on the Vector pipeline in the west-to-east direction. There is not a trend in Vector pipeline contracting towards releasing the forward haul capacity and this suggests it would be difficult for a customer that releases the capacity to recontract.

Table 1-1 : Vector Q4 2024 West-to-East Firm Transportation Contracts

Customer	Receipt Area	Delivery Area	Dth
Andersons Albion Ehtanol LLC	Chicago	Michigan	12,000
BPX Energy Co	Chicago	St. Clair (Canada)	45,000
Constellation Energy Commodities Group	Michigan	Michigan	20,000
Constellation Energy Commodities Group	Chicago	Michigan	1,500
DTE Gas Co	Chicago	Michigan	2,500
Enbridge Gas Distribution Inc	Chicago	St. Clair (Canada)	20,000
Enbridge Gas Distribution Inc	Chicago	St. Clair (Canada)	65,000
Enbridge Gas Distribution Inc	Michigan	St. Clair (Canada)	110,000
Just Energy New York LLC	Chicago	Indiana	5,000
Michigan Gas Utilities Corp	Chicago	Michigan	10,000
Northern Indiana Public Service Co LLC	Chicago	Indiana	1,000
Peoples Gas Light & Coke Co	Chicago	Michigan	19,000
Peoples Gas Light & Coke Co	Chicago	Michigan	10,000
Rover Pipeline LLC	Michigan	St. Clair (Canada)	950,000
SEMCO Energy Gas Co	Chicago	Michigan	6,000
Sequent Energy Management LP	Michigan	Michigan	300
Union Gas Limited	Chicago	St. Clair (Canada)	20,000
Union Gas Limited	Chicago	St. Clair (Canada)	80,000
Wisconsin Electric Power Co	Chicago	Michigan	4,550
Wisconsin Gas LLC (DBA We Energies)	Chicago	Michigan	5,200
Wisconsin Gas LLC (DBA We Energies)	Chicago	Michigan	28,572
Wisconsin Public Service Corp	Chicago	Michigan	3,250
Total			**1,418,872**

Source: Hitachi Energy

This makes re-contracting on the pipeline challenging if any of the contracts expire. Hence, ICF recommends that Enbridge Gas continue to base their long-term re-contracting decisions on the market fundamentals represented by the day-ahead prices as well as the supply diversity and reliability benefits associated with access to an additional market center, rather than the near-term futures market trends.

In ICF's opinion, there is a long-term benefit to Enbridge Gas in continuing to hold its capacity and supply agreements on Vector based on the fundamental market assessment, despite the potential risk owing to the increasing instances when Chicago traded at a premium to Dawn such as those seen during the summer of 2024 and during winter storm events like Uri, Elliott, and Heather.

Market Fundamentals – ICF's Approach

*The **Gas Market Model** (GMM) simulates regional natural gas markets in the United States and Canada by solving for gas production, transmission/pipelines flows, storage injections & withdrawals, gas consumption, and gas prices. Forecasts are generated for each month between now and December 2045 for 121 regional market centers (nodes). The model uses a sequential non-linear optimization, representing the anticipated market outcomes for future months.*

The objective function in the model optimizes total net economic benefit, that is, consumers' and producers' surplus minus costs. Model optimization has several constraints, equations representing physical limits of production, storage and transmission capacity and a series of "balance equations" that ensure that supply and demand are equal at each node.

*Natural gas prices in GMM are determined by the marginal (or incremental) value of natural gas at 121 nodes. Gas prices are evaluated based on **the balance of supply and demand in a regional marketplace**. These prices are indicative of ICF's view of the national market and reflect our most current base case data and modeling assumptions at the time of derivation.*

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. Prices are also influenced by "pipeline discount curves", which reflect the change in basis or the marginal value of gas transmission into and out of each node as a function of load factor. The pipeline discount curves are calibrated to actual observed flows and basis between market areas. On the demand-side of the equation, prices are represented by a curve that captures the 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.

*The **fundamental based price forecast is driven by the supply demand dynamics** and is different from a **forward/futures pricing** as the latter **is driven by market sentiments**. Extreme weather forecasts or concerns on gas supply volumes or natural gas storage inventories or any speculation around changing regulations or any uncertainty in the natural gas markets gets captured in the futures price, creating an unnecessary premium/discount over the fundamental view.*

2. Historical Price Spreads

Historically, Chicago has been a significant supply hub for natural gas delivered into Ontario through Dawn. In 2019 and 2020, after the NEXUS, Rover and Vector pipeline expansions came online, the day-ahead prices at Dawn traded near parity to Chicago, with Chicago averaging $0.02/MMBtu more than Dawn. The slightly positive spread between the two market hubs was mostly driven by weather, when the daily prices at Chicago rose above the prices at Dawn. There were 10 days in which the Chicago price was more than $0.25/MMBtu above the Dawn price in 2019 and 2020 and, if those are removed, the Chicago price averages at $0.01/MMBtu discount to the Dawn price during that period.

The 2020 average natural gas day-ahead prices at Chicago hit a historic low of $1.88/MMBtu with Dawn trading at $1.87/MMBtu, marking the lowest annual average in over 7 years. The year commenced with relatively low prices, influenced by a mild winter and the economic repercussions of the COVID-19 pandemic which curtailed both natural gas production and consumption. As March 2020 arrived, spring weather and pandemic-related responses caused a decline in gas demand, thereby intensifying the price reduction. Notably, June 2020 saw the Chicago and Dawn prices dip to $1.55/MMBtu and $1.57/MMBtu, respectively, the lowest average monthly value in over 7 years. Subsequently, the latter half of 2020 witnessed price increases due to diminished natural gas production and a surge in LNG exports. This culminated in December's average of $2.44/MMBtu in Chicago and $2.41/MMBtu at Dawn.

In 2021, the natural gas day-ahead prices at Chicago experienced a huge price spike in the month of February due to Winter Storm Uri, leading to an annual average price of $5.13/MMBtu, about 42% more than Dawn’s annual average price. Day-ahead prices at Chicago reached $136.68/MMBtu whereas prices at Dawn only reached $9.18/MMBtu during the storm period. Winter Storm Uri, which occurred from February 13th to February 17th, 2021, led to increased demand from Texas to the Midwest U.S. while also causing a significant, temporary loss of production due to freeze-offs and pipeline force majeures. Natural gas deliveries from Texas into the Midwest declined as Texas used the natural gas available within the region to meet its own demand during the storm. U.S. dry natural gas production in February 2021, was 67.9 Bcf per day, down by 8%, compared to January 2021 as reported by the U.S. Energy Information Administration (EIA). The substantial winter heating and power demand for natural gas, coupled with reduced production, triggered the significant price hikes.

Winter Storm Uri had a significant adverse financial impact on multiple energy companies and utilities. For example:

- Vistra Energy estimated a $1.6 billion loss, primarily driven by unmet gas contracts with third parties, leading to high replacement gas costs, and reduced power generation capacity due to insufficient gas supply and pipeline issues.[1]

[1] “Vistra says Texas February freeze cost about $1.6 billion”. Reuters. April 26, 2021. https://www.reuters.com/business/energy/vistra-says-texas-february-freeze-cost-about-16-billion-2021-04-26/

- Black Hill Corp incurred $2.1 million in incremental fuel costs, which were not recoverable through its fuel cost recovery mechanisms, resulting in a $4.7 million decrease in its gas utilities operating income.[2]
- Exelon Corp faced a loss of net income of between $560 million and $710 million.[3]
- Xcel Energy lost nearly $1 billion due to high fuel costs, with the bulk of the $965 million in net costs stemming from gas distribution and generation portions of its subsidiaries.[4]

The billions of dollars in losses by natural gas buyers during Winter Storm Uri were the catalyst for the change in the forward curve at Chicago, as the demand for financial hedges against such events in the future drove up the price of the bid-week contracts and the forward curve.

The day-ahead prices at Chicago averaged $1.51/MMBtu more than Dawn in 2021. However, if the two-week period from February 6th to February 19th are removed from the year, the Chicago price averaged a $0.01/MMBtu discount to Dawn. This two-week period included the only days in 2021 in which the Chicago price was $0.25/MMBtu more than Dawn. In fact, in December 2021, the Chicago price averaged an $0.18/MMBtu discount to Dawn and Chicago traded at an average discount of $0.04/MMBtu to Dawn in the winter of 2021/22.

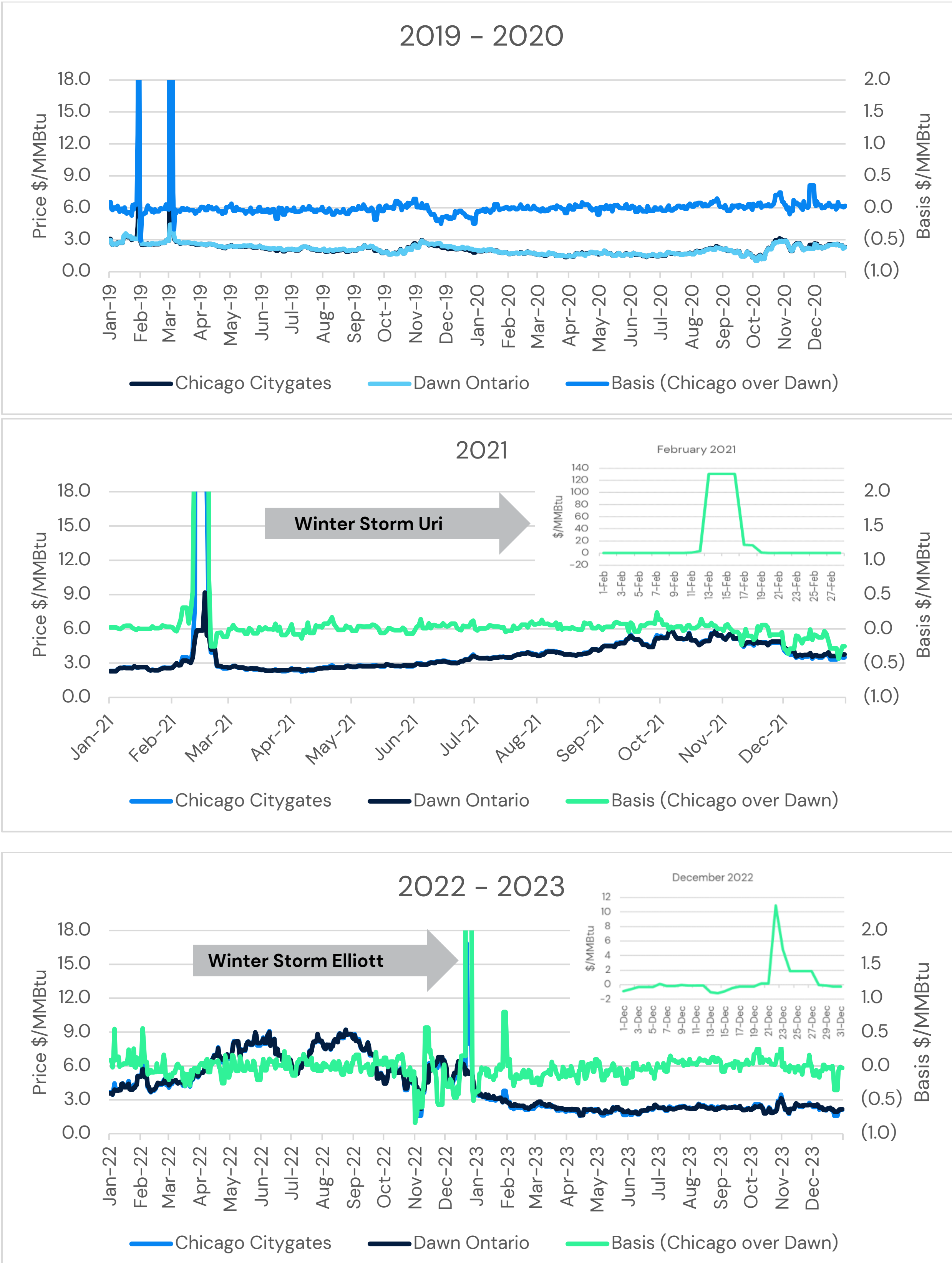
---

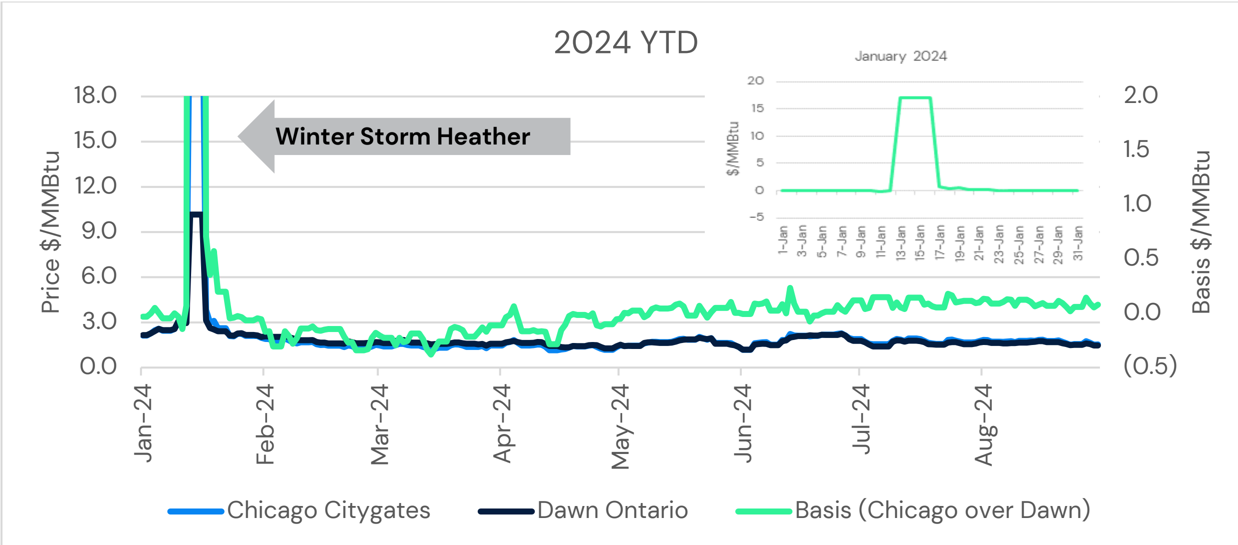
[2] Black Hills Corporation. (2022). Form 10-K. https://www.sec.gov/Archives/edgar/data/1130464/000095017023002759/bkh-20221231.htm.

[3] "Exelon Reports Higher Negative Impact From Texas Winter Weather Event, In Reporting Q1 Earnings". May 5, 2021. Energychoicematters.com. http://www.energychoicematters.com/stories/20210505cd.html.

[4] "Xcel takes nearly $1B fuel cost hit from February storms but still sees Q1 profit rise". April 30, 2021. Catherine Morehouse. Utility Dive. https://www.utilitydive.com/news/xcel-takes-nearly-1b-fuel-cost-hit-from-february-storms-but-still-sees-q1/599330/.

Exhibit 2-1 : Historical Day-Ahead Prices at Chicago and Dawn ($/MMBtu)





Source: Argus Day-Ahead Prices

In 2022, the annual average natural gas day-ahead price at Chicago surged to $6.10/MMBtu, the highest annual average price in decades. The price oscillated widely between $1.60/MMBtu and $16.90/MMBtu, underscoring significant day-to-day volatility. The first quarter of 2022 saw a pronounced increase owing to a confluence of factors. Production freeze-offs in January and February curtailed U.S. natural gas production, while robust net withdrawals from storage fueled the price surge. By August, the Chicago natural gas day-ahead price soared to $8.30/MMBtu, marking the highest summer month price since 2013. A decline followed in October, with average prices at $5.08/MMBtu, propelled by a period of robust dry natural gas production and several consecutive weeks of relatively large injections into natural gas storage. However, on December 21st, 2022, the Chicago natural gas day-ahead prices spiked to $16.90/MMBtu as a result of Winter Storm Elliott, the highest price levels since Winter Storm Uri in February 2021. The winter months also contributed to price elevation, driven by the seasonal demand for space heating and amplified demand for LNG exports, especially in the Northern Hemisphere. Increased demand at LNG export facilities, notably the resumption of operations at the Freeport LNG terminal in November, further contributed to the price surge. Primarily as a result of the price spike at Chicago during Winter Storm Elliott, the Chicago natural gas price averaged $0.73/MMBtu more than Dawn in December 2022. The day-ahead prices at Chicago averaged a $0.04/MMBtu premium to Dawn in 2022. However, if the Winter storm Elliott period from December 21st, 2022 to December 26th, 2022 is removed from the year, the Chicago price averaged a $0.03/MMBtu discount to Dawn.

In January and February 2023, prices at Chicago were again below Dawn – $0.08/MMBtu below on average – as above-average temperatures in the Midwest and Northeast U.S. lowered the heating demand. The interplay of relatively mild temperatures, robust production, and higher-than-average inventories pushed natural gas prices downwards. Notably, May 2023 recorded the lowest average monthly price since June 2020, as the natural gas day-ahead price at Chicago averaged $1.94/MMBtu. The day-ahead prices at Chicago averaged $0.03/MMBtu discount to Dawn in 2023.

In January 2024, the monthly average natural gas day-ahead price in Chicago surged to $5.68/MMBtu due to Winter Storm Heather, which caused a significant spike in day-ahead prices between January 13th and January 16th, 2024. During this period, day-ahead prices in Chicago traded at $27.2/MMBtu. Production freeze-offs, along with robust net withdrawals from storage facilities, fueled the price surge not only in Chicago but also at Dawn. The monthly average natural gas day-ahead price at Dawn reached $3.43/MMBtu in January 2024, peaking at $10.2/MMBtu during the winter storm. For the winter of 2023/24 (December 2023-February 2024), Chicago traded at an average $0.66/MMBtu premium to Dawn. Excluding the days of winter storm Heather (January 13th to January 16th), Chicago traded at a discount of $0.09/MMBtu to Dawn for the winter of 2023/24.

In August 2024, natural gas day-ahead prices in Chicago averaged $1.71/MMBtu, which is 27% lower than the corresponding price in 2023 but a $0.09/MMBtu premium relative to Dawn. In 2024, Chicago has maintained a premium over Dawn for 106 out of 182 days, or 58% of all trading days between March and August. The high oil price environment and low natural gas price environment across North America have shaped the natural gas supply portfolio of the region, pushing prices in Chicago to a premium over Dawn this summer.

Non-associated natural gas production in the Appalachia and Niobrara regions, which is tied to the drilling of natural gas wells, fell by 2.6% and 3.2%, respectively, in the summer of 2024 compared to 2023[5]. Conversely, associated natural gas production in the Western Canada Sedimentary Basin, which is tied to the drilling of oil wells, grew by 4.4% in Q2 2024 compared to the previous year[6]. These changes in upstream operational dynamics in the current oil and gas price climate have directly impacted pipeline deliveries into Ontario via the TC Energy Mainline and Vector/Rover pipelines.

Flows on the TC Energy Mainline, an inter-provincial pipeline in Canada that transports natural gas from Alberta to Ontario, were 350 MMcfd higher between May and July 2024 compared to the same period last year. On the other hand, flows on the Vector, Rover, and NEXUS pipelines, interstate pipelines in the U.S. that transport natural gas from Michigan to Ontario via Chicago, were 350 MMcfd lower between May and July 2024 compared to the same period last year. This fundamental shift in the sources of natural gas deliveries in Ontario has suppressed natural gas prices at Dawn relative to Chicago in the summer of 2024.

Exhibit 2-2 depicts the 5-year (2019-2023) average monthly prices at Chicago and Dawn, without February 2021, when Winter Storm Uri occurred, and the same 5-year period with all the months included. Due to the high prices at Chicago in February 2021, the 5-year monthly average at February changes from $2.81/MMBtu to $6.94/MMBtu and Dawn changes from

[5] EIA – STEO (Published in August 2024) (https://www.eia.gov/outlooks/steo/)

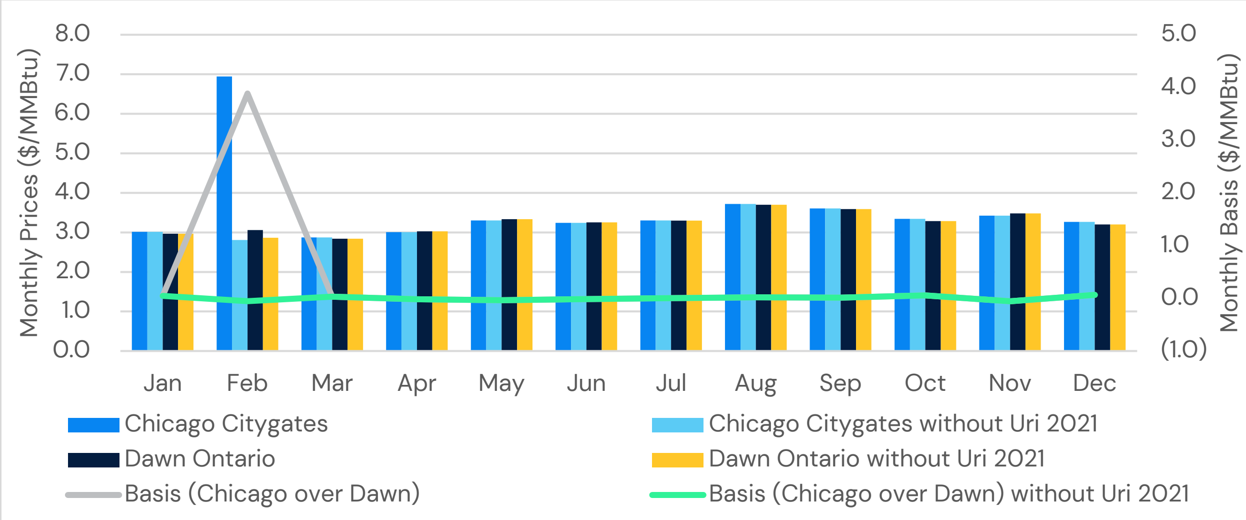
[6] CER – Marketable Natural Gas Production in Canada (https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/natural-gas/statistics/marketable-natural-gas-production-in-canada.html)

$2.86/MMBtu to $3.06/MMBtu. The February 5-year average basis was much higher given the sharp increase in prices seen at Chicago during February 2021. The December 5-year average prices were more stable even with Winter Storm Elliott included. This is because the impact of Winter Storm Elliott in December 2022 was much smaller as it lasted for a shorter period compared to Uri, the natural gas storage inventories were much larger compared to February 2021, and the resulting day-ahead price at Chicago were only $16.90/MMBtu instead of $136.68/MMBtu. Since February 2021 when Winter Storm Uri occurred, the Chicago price and the Chicago to Dawn price spread has behaved the same way it did before the storm. The Chicago price averaged a $0.01/MMBtu discount between March 2021 and August 2023 and was more than $0.25/MMBtu greater than Dawn on only 14 days.

Even during December 2022, when Winter Storm Elliott occurred, the day-ahead monthly average price was $8.10/MMBtu at Chicago and $7.71/MMBtu at Dawn, a $0.39/MMBtu price spread. This is still lower than the forward curve for December 2023 dated August 8th, 2023, which includes a Chicago to Dawn spread of $0.58/MMBtu.

In January 2024, when Winter Storm Heather occurred, the day-ahead monthly average price was $5.68/MMBtu at Chicago and $3.43/MMBtu at Dawn, a $2.25/MMBtu price spread. If the price spike from Winter Storm Heather is not included within this analysis, the day-ahead monthly average price decreases to $2.49/MMBtu at Chicago and $2.42/MMBtu at Dawn, a $0.06/MMBtu price spread. This implies that the forward curve for the upcoming 2024/25 winter not only includes the risk of larger, longer-lasting price spread that occurred during Winter Storm Elliott & Winter Storm Heather, but also factors in the near-term fundamental shift in supply sources, at Chicago and Dawn, due to the current oil & gas price environment.

Exhibit 2-2 : Average 5-Year (2019-2023) Monthly Day-Ahead Price and Basis at Chicago vs Dawn ($/MMBtu)[7]



Source: Argus Day-Ahead Prices

The price relationship between the Chicago Hub and the Dawn Hub has seen notable changes over time as discussed above, with Chicago trading at a discount to Dawn for most of the historical period. However, the market also witnessed a flipping relationship between the two owing to extreme weather events and changes in the supply and demand dynamics in the region, as well as the interconnected markets.

2.1.1 Midcontinent Prices' Effect on Chicago Prices

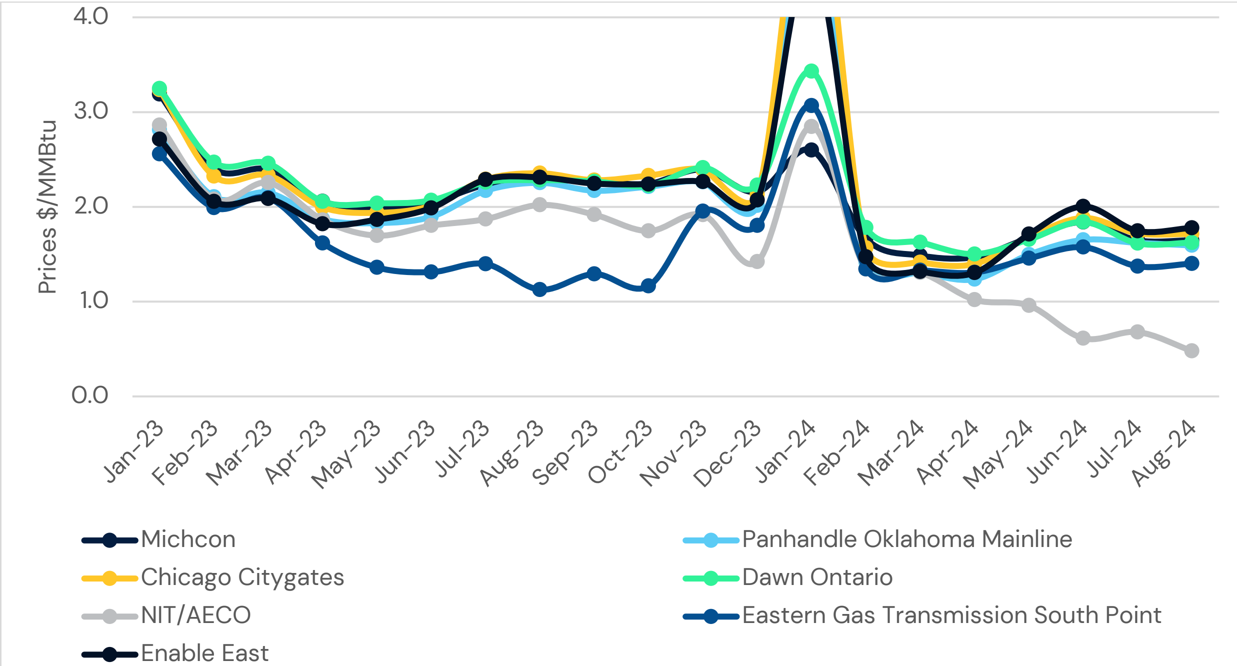
Natural gas prices in Chicago have been sensitive to the Midcontinent market dynamics. This close correlation is primarily due to the interconnected pipeline infrastructure and the shared market conditions between these regions. When there is a price change in the Midcontinent, it often reflects shifts in supply and demand, weather conditions, or other market factors that also affect Chicago. For instance, any supply disruption in the Midcontinent region due to severe weather can lead to a spike in prices there, which in turn impacts Chicago prices due to the reliance on the same supply sources. Prices at Chicago often mirror the trend seen in the Midcontinent because of the significant volume of gas flowing through shared pipelines like the Natural Gas Pipeline Company of America (NGPL) and the ANR Pipeline. These pipelines transport natural gas from production areas in the Midcontinent to various demand centers, including Chicago, and ensure that any fluctuations in the Midcontinent market are quickly transmitted to Chicago.

Prices at Chicago were found to be better correlated with the prices at Enable East and Michcon when compared to other gas hubs at which Chicago sources its natural gas supplies.

[7] The prices "without Uri 2021" exclude high prices between February 6th, 2021, to February 19th, 2021, triggered by Winter Storm Uri.

Exhibit 2-3 compares the monthly average day-ahead prices at the gas price hubs supplying Chicago and Dawn.

Exhibit 2-3 : Monthly average day-ahead prices at hubs the supply sources for Chicago and Dawn



Source: Argus Day-Ahead Prices

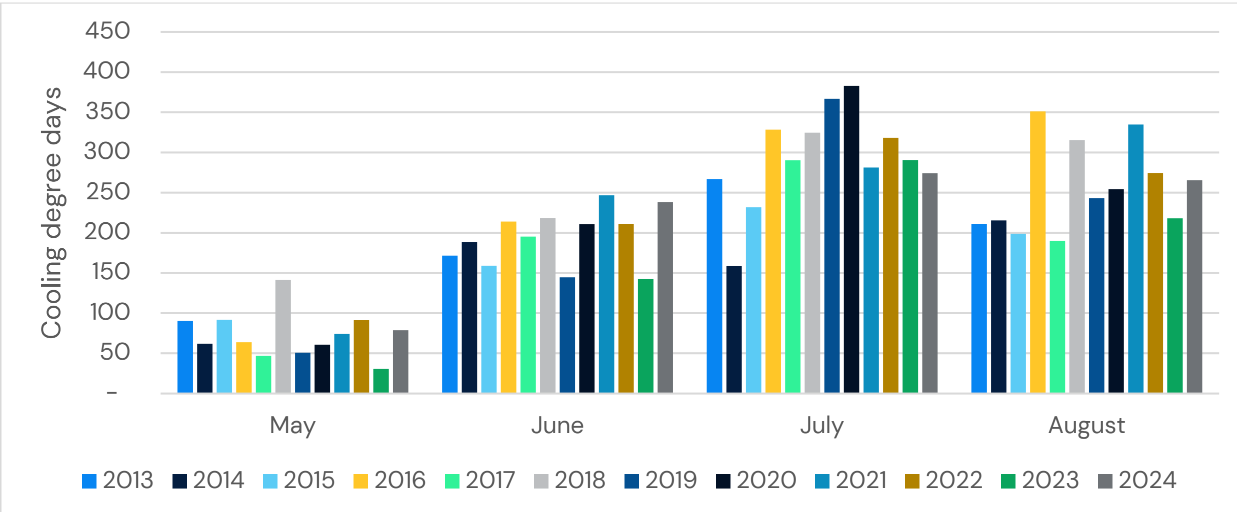
Enable East is a key gas pricing hub in the Midcontinent which includes deliveries into the north and neutral pooling areas of the Enable Gas Transmission (EGT) system. The North Pooling Area includes all points in Arkansas along the EGT system that are north of the Malvern Compressor Station; the small lateral in Arkansas that runs south of Malvern in Arkansas and Desha counties; and all points west of the Dunn Compressor Station up to but not including the beginning of the Neutral Pooling Area in Oklahoma. The Neutral Pool Area includes all points along EGT in Haskell, Latimer, Pittsburg and Pushmataha counties in Oklahoma.

Prices at Enable East generally trade at a discount to Chicago given the access of Enable East to the Midcontinent production. From May 2023 through August 2023, day-ahead prices at Enable East traded below Chicago with the basis ranging between $0.00/MMBtu to $0.07/MMBtu. However, for the summer of 2024, i.e. between May 2024 to August 2024, the day-ahead prices at Enable East traded higher than Chicago with the basis ranging between $0.03/MMBtu to $0.12/MMBtu.

The increasing gas consumption in the Midcontinent this summer, owing to the greater usage of gas in the power sector, has added an upward pressure on the Midcontinent prices. The population weighted cooling degree days for the Midcontinent Independent System Operator (MISO) region from May 2024 to August 2024 were 60% higher than May 2023 to

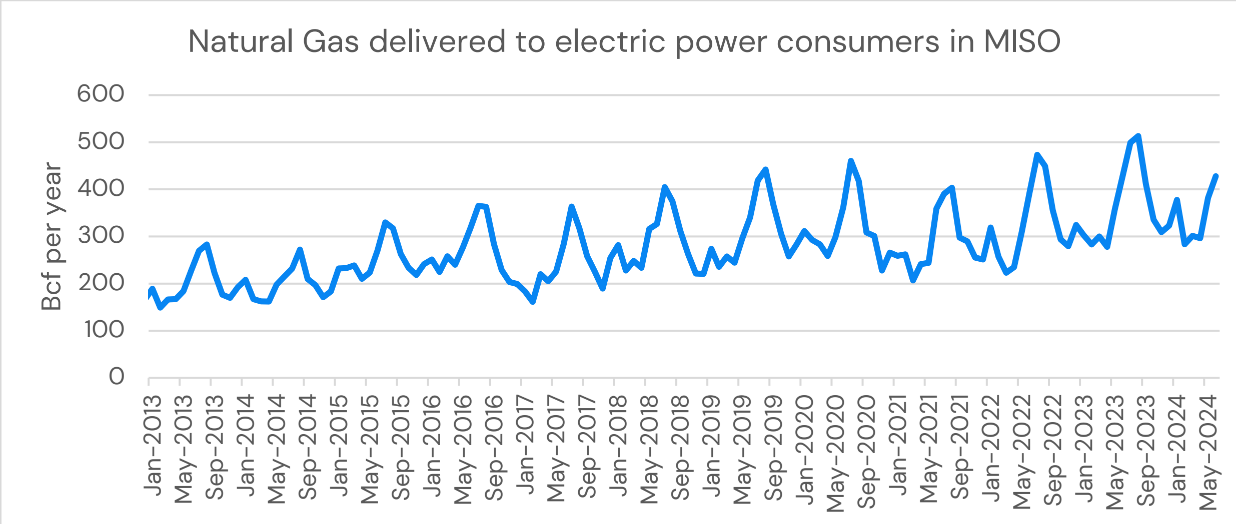
August 2023 on average. May and June of 2024 were considerably warm for the region and had over 126% more cooling degree days than the 5-year average for these months from 2019 to 2023. The exhibits below (Exhibit 2-4 and Exhibit 2-5) showcase the increasing cooling degree days in the MISO region since 2013 and an increasing electric power sector demand for natural gas in the states of Midcontinent.

Exhibit 2-4 : Population Weighted Cooling Degree days in MISO (Summer of 2013-2024)



Source: Hitachi Energy

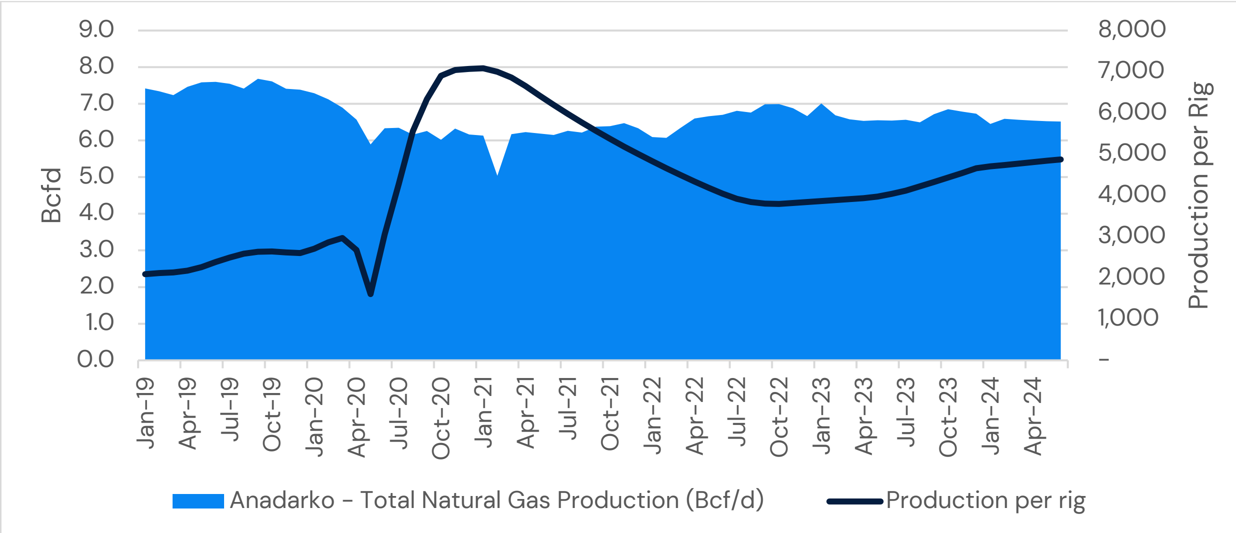
Exhibit 2-5 : Natural Gas Delivered to Electric Power Consumers in MISO (Jan 2013-Jun 2024)



Source: EIA

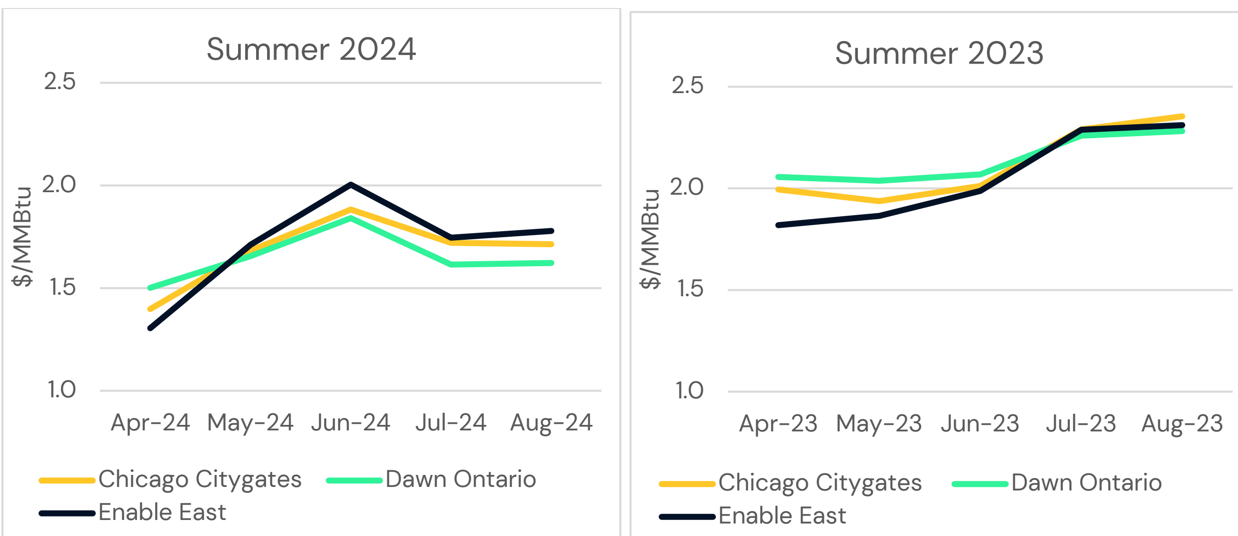
Additionally, production from the Midcontinent region is declining due to aging wells, reduced drilling activity, and operational challenges. As per the latest Drilling Productivity Report from the EIA, production at Anadarko basin, which is a representative of production around Enable East, has been declining. Exhibit 2-6 below shows the total natural gas production at Anadarko basin decreasing to 6.5 Bcfd in June 2024, which is 3% lower to the levels in December 2023 and 0.4% lower than the levels in June 2023 during a period in which production has been increasing in other basins in North America. The production per rig has increased indicating the exploration & production (E&P) companies are focusing more on drilling efficiency rather than drilling new wells. The production trend in the Anadarko from January 2019 to May 2024 can be seen in Exhibit 2-6. This declining production further adds an upward pressure on the prices relative to other production areas.

Exhibit 2-6 : Anadarko – Natural Gas Production vs Production per Rig



Source: EIA

Exhibit 2-7 : Gas Prices for the Summer of 2023 and 2024



Source: Argus Day-ahead Prices

Between 2019 and 2024 when the day-ahead prices at Enable East traded at a premium to Dawn, Chicago traded at a premium to Dawn. This dynamic was witnessed during the summer months of August 2020, July-August 2023 and May-August 2024. During August 2020, Enable East traded at a $0.07/MMBtu premium to Dawn and Chicago traded at a $0.06/MMBtu premium to Dawn.

In 2023, prices at Enable East increased owing to the increased gas consumption in the electric power sector during the peak summer months. July and August 2023 were warmer than normal, driving the need for additional power generation gas demand. In July 2023, prices at Enable East as well as Chicago averaged $2.29/MMBtu while Dawn averaged

$2.26/MMBtu. For the month of August 2023, prices at Enable East averaged $2.31/MMBtu, Chicago averaged $2.35/MMBtu, and Dawn averaged $2.28/MMBtu. For the months of July and August 2023, Enable East traded at an average $0.03/MMBtu premium to Dawn and Chicago traded at a $0.05/MMBtu premium to Dawn.

In 2024, prices at Enable East were lower than 2023, but they still applied upward pressure on the Chicago price. Due to lower gas prices at Enable East, gas production was not incentivized, which impacted the markets interconnected to the Midcontinent. In May 2024, prices at Enable East averaged $1.71/MMBtu, Chicago averaged $1.68/MMBtu, and Dawn averaged $1.66/MMBtu. In August 2024, prices at Enable East averaged $1.78/MMBtu, Chicago averaged $1.71/MMBtu, and Dawn averaged $1.62/MMBtu. In July and August of 2024, Enable East again traded at a premium of $0.14/MMBtu to Dawn and Chicago traded at a $0.10/MMBtu premium to Dawn. Exhibit 2-7 shows the monthly gas price movements at Chicago, Dawn, and Enable East.

Thus, it is evident that prices in the Midcontinent (Enable East) in particular were low enough to influence the region's production but also high enough to influence prices at Chicago thus leading it to trade at a premium to Dawn.

3. Natural Gas Forward Prices in Chicago vs Dawn

Since Winter Storm Uri in February 2021, the financial markets and the resulting forward curves have included a large premium for Chicago over Dawn, which has only been justified during a handful of days of cold weather in the Midwest U.S. The historical basis between Chicago and Dawn for the winter of 2021/22 traded at a discount of $0.05/MMBtu and winter of 2022/23 traded at a premium of $0.05/MMBtu. The premium in 2022/23 was due to the higher prices seen at Chicago in December 2022 during Winter Storm Elliott. This past 2023/24 winter basis between Chicago and Dawn traded at a premium of $0.34/MMBtu mainly influenced by the Winter Storm Heather which caused Chicago prices to go as high as $27.22/MMBtu while Dawn prices reached $10.16/MMBtu during the Martin Luther King (MLK) weekend in January 2024.

Exhibit 3-1 below showcases the volatility in the forward price curves which are still responding to Winter Storm Uri, Winter Storm Elliott, Winter Storm Heather and the increased price volatility experienced across North America in 2022 and 2024. The day-ahead prices are frequently much lower than the forward price, suggesting that the buyers pay the higher prices as a hedge against price volatility and potential price increases. Especially during colder-than-average winter periods, it has been observed that the forward curve projections and bid-week price spreads have significantly differed from the actual day-ahead price spread.

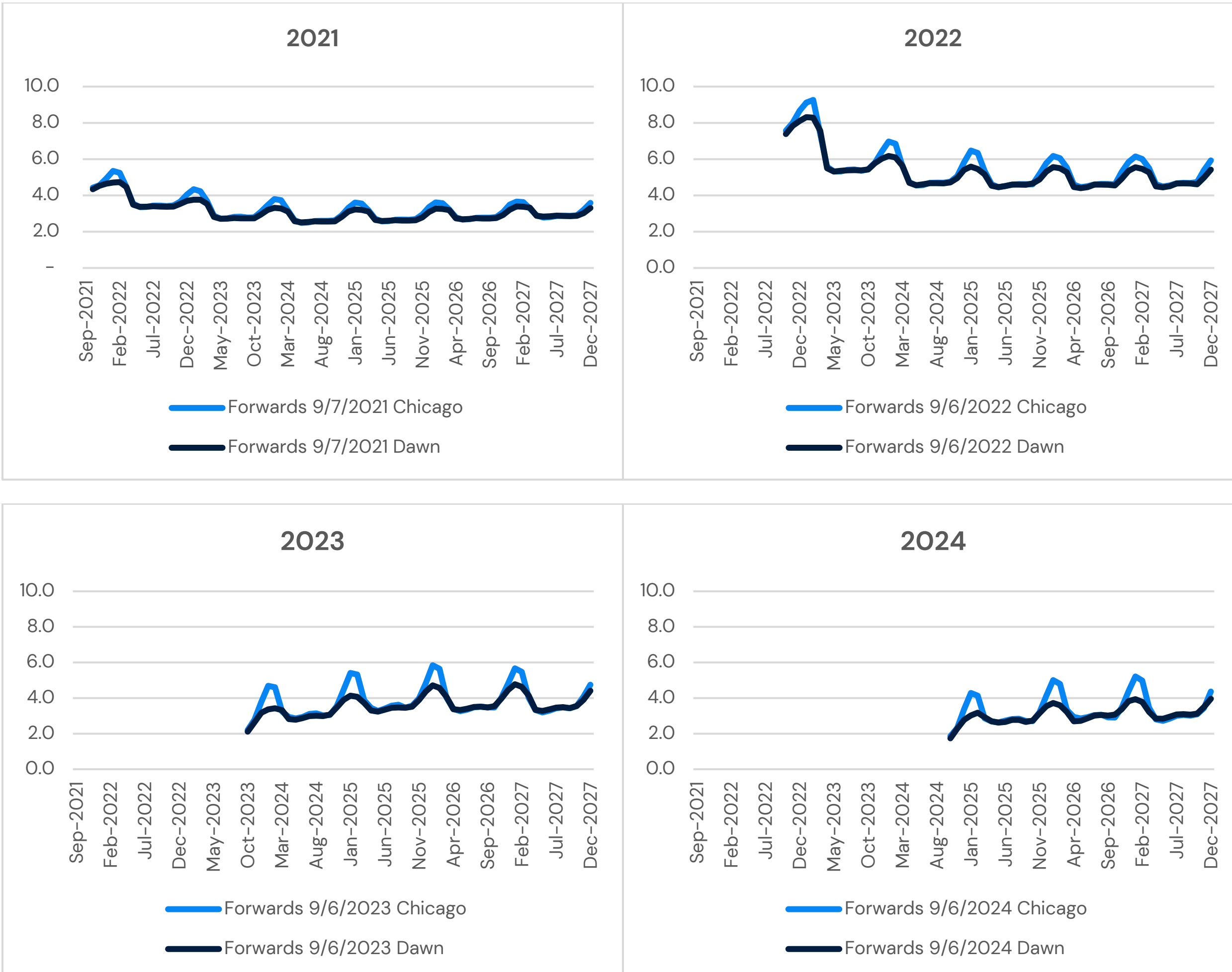
From September 2021 to September 2023, the forward curves included an increasing positive price spread between Chicago and Dawn. For the years of 2024 to 2026, the forward curves dated September 7, 2021, projected an average annual premium for Chicago relative to Dawn of $0.12/MMBtu. This spread increased to $0.21/MMBtu in the September 2022 forward curves, and $0.23/MMBtu in the September 2023 and 2024 forward curves. The forward price spread has been widening on the expectation of recurring winter storms and high price volatility as seen during past three Winter Storms in United States.

As per the forward curve dated September 6th, 2023, for the period of November 2023 to March 2024, the price spread between Chicago and Dawn averaged $0.63/MMBtu. The bid-week price spread for the same timeframe averaged $0.30/MMBtu. However, these forward prices were very different than the ensuing average day-ahead price spread which was a premium of just $0.34/MMBtu.

For January to August 2024, the forward curves dated September 6th, 2023, projected a $0.21/MMBtu premium for Chicago over Dawn, with bid-week prices averaging a $0.16/MMBtu premium. However, the actual day-ahead price spread averaged a $0.24/MMBtu premium, highlighting a trend of higher-than-expected premiums in the day-ahead prices. ICF's Q3 2023 base case, under weather normal assumptions, which was finalized in September 2023, projected Chicago to be at a discount of $0.13/MMBtu relative to Dawn. The day-ahead price spread turned out to be higher mainly due to Winter Storm Heather which occurred during January 2024. Excluding January 2024, the forward curves dated September 6th, 2023, projected Chicago to be at $0.07/MMBtu premium with respect to Dawn and the bid-week price averaged at a premium of $0.11/MMBtu for the months of February 2024 to August 2024. The day-ahead price spread, however, averaged a $0.05/MMBtu discount close to the ICF's Q3 2023 base case projection in which Chicago was at a discount of $0.13/MMBtu relative to Dawn.

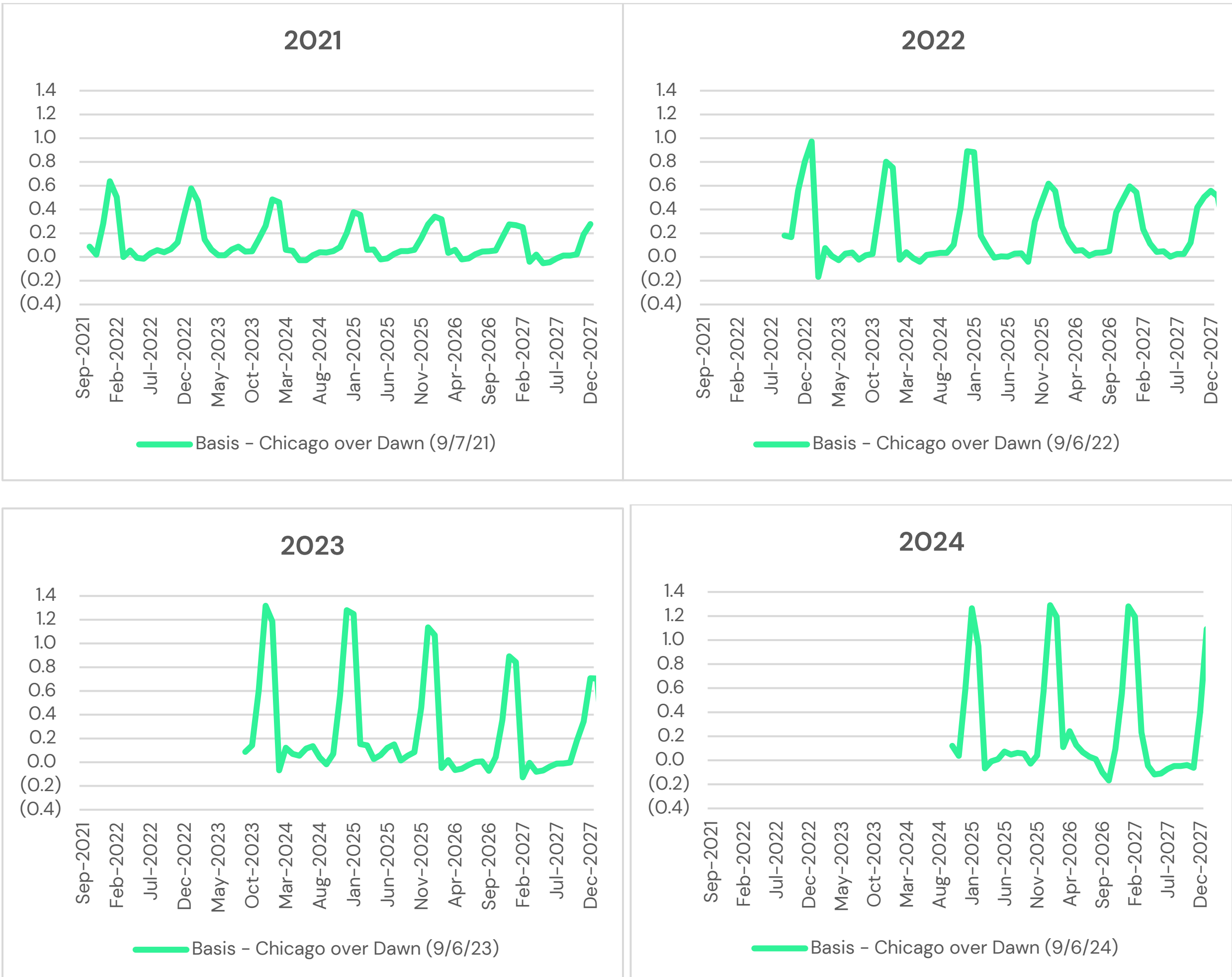
ICF's Q3 2024 (released August 2024) natural gas price forecast projected the price spread to be at a discount of $0.06/MMBtu to Dawn for the upcoming winter period (November 2024 to March 2025), assuming weather normal conditions.

Exhibit 3-1 : Chicago and Dawn Forward Curves in $/MMBtu (2021-2024)



Source: Argus Forward Prices

Exhibit 3-2 : Forward Price Spread Between Chicago and Dawn in $/MMBtu (2021-2024)

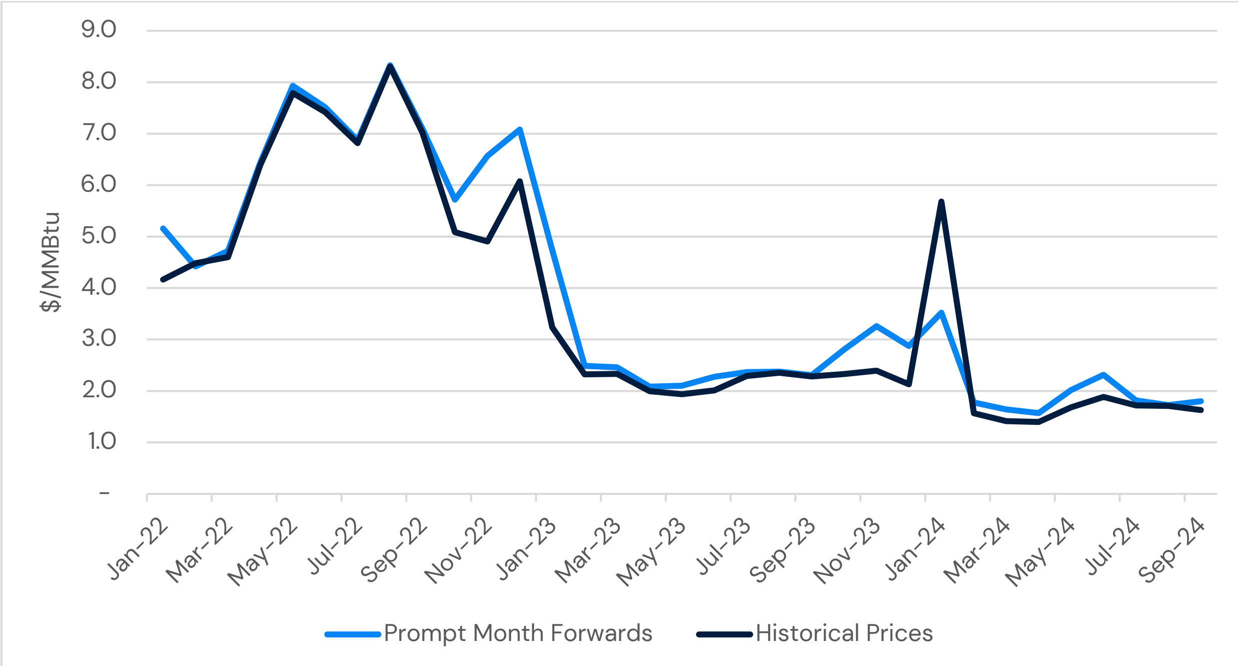


Source: Argus Forward Prices

Chicago's day-ahead prices averaged a $0.19/MMBtu premium to Dawn during the past two winters mainly due to the impact of Winter Storms Elliott and Heather which caused price spikes at Chicago compared to Dawn. However, the forward curve dated September 6th, 2024, still projects a $0.56/MMBtu premium for the 2024/25 winter (Nov 2023 - Mar 2024).

Exhibit 3-3 shows the volatility of the Chicago prompt month forward prices that has been seen since the beginning of 2022. The prompt month forward prices from December 2022 (for prices in January 2023) were $7.08/MMBtu, however the day-ahead price in January 2023 averaged $3.23/MMBtu. The exhibit emphasizes the premium built in by the forward prices for the winter period. The prompt month forward prices from December 2023 (for prices in January 2024) were at $2.87/MMBtu, however the day-ahead price in January 2024 averaged $5.68/MMBtu mainly influenced by the Winter Storm Heather which caused huge price spike at Chicago Citygate during the MLK weekend. Except for January 2024 spike due to Winter Storm Heather prompt month forward prices have been high compared to the day-ahead prices and the premium built in the forwards curve is to hedge against the risk.

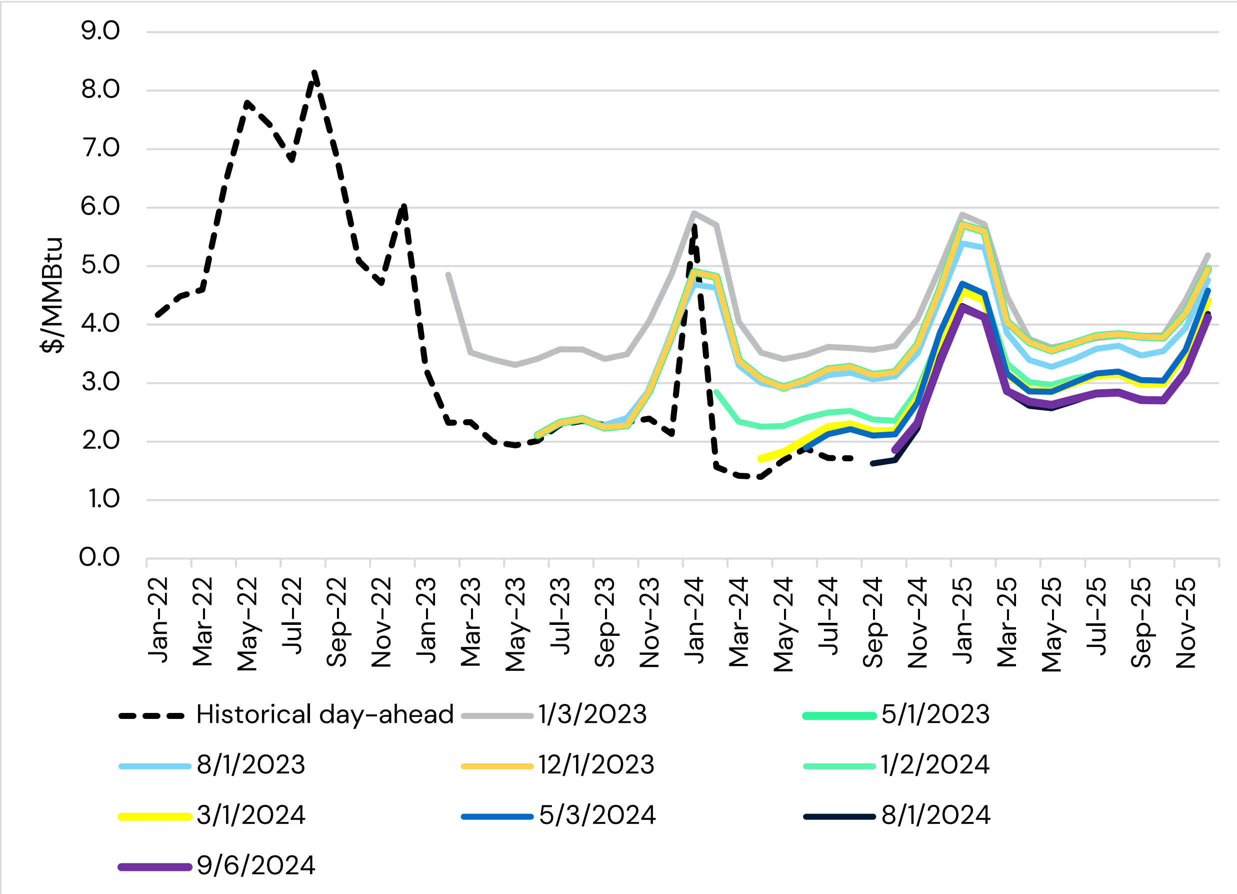
Exhibit 3-3 : Chicago Prompt Month Forward Prices from January 2022 to September 2024 ($/MMBtu)



Source: Argus Day-Ahead and Forward Prices

Exhibit 3-4 shows the change in forward price strip on different trade dates in the past years for Chicago and compares the same to the historical day-ahead prices. On January 3rd, 2023, the forward price strip for January 2024 to August 2024, averaged $4.16/MMBtu. This decreased to $3.48/MMBtu on August 1st 2023 and further decreased to $2.81/MMBtu on December 1st, 2023, when day-ahead prices were low, storage levels were above the five-year average, and gas production was high due to increased associated production due to high oil prices. Also, the ensuing day-ahead prices for January 2024 to August 2024 averaged $2.13/MMBtu. The movement of the forward prices was mostly driven by price volatility and concerns about winter-weather driven supply shortages and not based on fundamental market drivers.

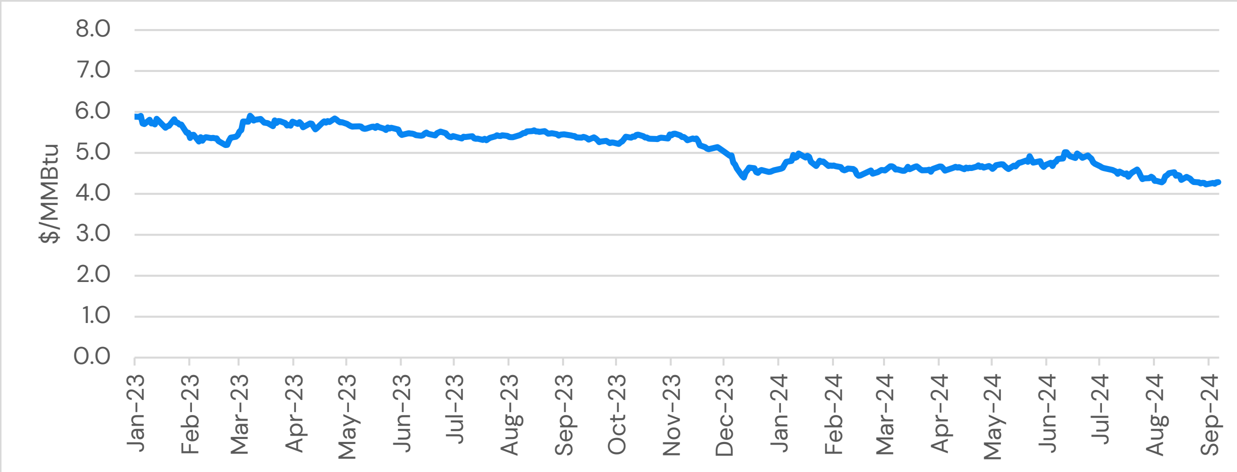
Exhibit 3-4 : Forward Pricing at Chicago Between January 2023 and September 2024 vs Day-Ahead Prices ($/MMBtu)



Source: Argus Day-Ahead and Forward Prices

Exhibit 3-5 shows the daily change in the forward prices for the month of January 2025 over the past two years. As can be seen, the January 2025 prompt month prices have been declining steadily since January 2023, dropping to at $4.23/MMBtu as per the futures strip from August 30th, 2024, from a high of $5.91/MMBtu. as per the futures strip from March 7th, 2023.

Exhibit 3-5 : Daily Fluctuation in January 2025 Forward Prices at Chicago



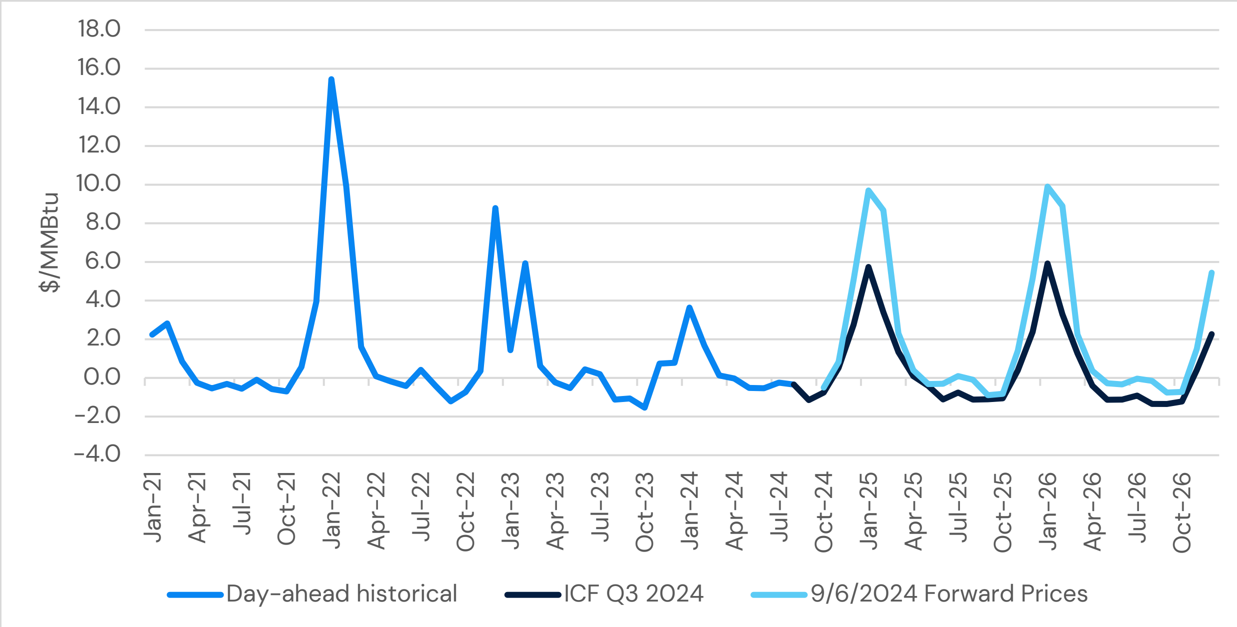
Source: Argus Forward Prices

3.1 The Influence of Market Sentiment on Natural Gas Forward Prices in Other Markets

The Chicago hub is not the only natural gas price hub that has seen an increase in the financial premium in its forward curve over the past few years. Natural gas forward prices are crucial for the risk management and hedging strategies of market participants. These prices are often influenced by near-term market developments and trader sentiments, which can sometimes cause deviations from the underlying market fundamentals. For instance, recent extreme weather events and forecasts drive traders to assess the intrinsic value of natural gas during winter months based on anticipated daily peak demand. The stronger the weather outlook for the upcoming winter, the higher the expected daily peak demand, and consequently, the higher the intrinsic value of natural gas for those months. In essence, market participants are willing to pay a futures market premium to hedge against extreme price increases.

Although this is not true for all regional natural gas commodity markets, the intrinsic value of natural gas changes significantly for winter months in the Northwest U.S. For example, at Algonquin city-gates, as shown in Exhibit 3-6, the forward curve shows a significant premium in the basis at Algonquin for the winter of 2024/25 compared to ICF's Q3 2024 base case. This is despite the fact that, as of September 6th, 2024, working gas levels in the East region 6% above the five-year average. ICF forecasts that basis at Algonquin and other gas hubs in the Northeast U.S. will be elevated this winter but at significantly lower levels than the forward curve. ICF projects the Algonquin winter basis will stay below $5.74/MMBtu. Basis at Algonquin reached the heights projected by the current forward curve in February 2015, January 2018, and January 2022, suggesting that the forward curve is including a premium for the entire upcoming winter that was only seen in the a few individual winter months during the past decade.

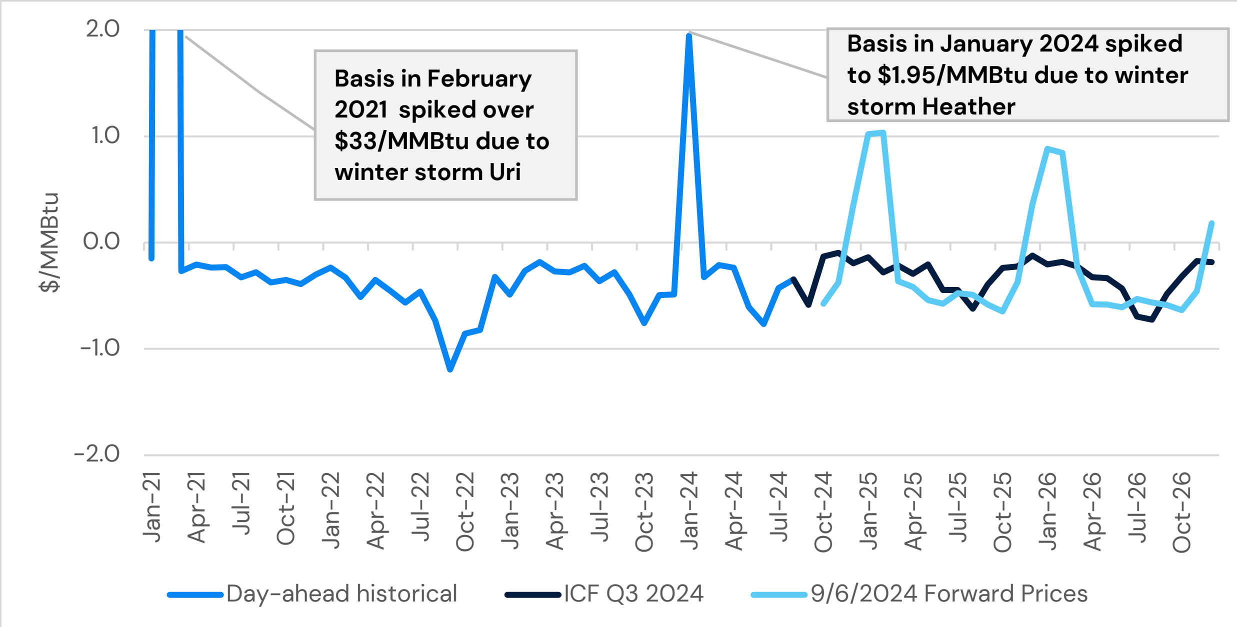
Exhibit 3-6 : Basis Between Algonquin city-gates and Henry Hub (Nominal $/MMBtu)



Source: Argus Day-Ahead and Forward Prices; ICF Q3 2024

Another example of markets which experience higher natural gas price forward prices as against the fundamentals view is the Panhandle Eastern Pipeline Limited (PEPL). In Exhibit 3-7 the forward curve shows a significant premium in the basis at PEPL for the winter of 2024/25 compared to ICF's Q3 2024 base case. This price hub includes gas deliveries into Panhandle Eastern Pipeline on two laterals running from Texas and Oklahoma, southwestern Kansas, upstream of the compressor station in Haven, Kansas, into Montana. ICF's fundamental analysis of the region concludes that there is likely to be modest growth in gas-fired generation as a result of coal plant and nuclear retirements but also that this region has significant access to low-cost Marcellus and Utica gas. Therefore, the area's prices are projected to be close to Henry Hub as per ICF's Q3 2024 forecast. The forward prices are based on the risk that the Marcellus and Texas/Oklahoma supply will be rerouted to other demand centers for long periods of time during the upcoming winters (the Northeast U.S. and Ontario in case of Marcellus supplies and Texas along with rest of Midcontinent in case of gas supplies from Texas and Oklahoma). According to the forward curve dated September 6th, 2024, the basis at PEPL for the upcoming 2024/25 winter (December 2024 to February 2025) is expected to average $0.80/MMBtu. This is significantly higher than the basis observed in recent winters. For the 2023/24 winter (December 2023 to February 2024), the average day-ahead price was $0.38/MMBtu above Henry Hub, influenced by Winter Storm Heather in January 2024. In contrast, the basis at PEPL for the winters of 2021/22 and 2022/23 averaged at a discount of $0.32/MMBtu to Henry Hub. The forward market is incorporating substantial premiums that are driven by the day-ahead prices this past winter.

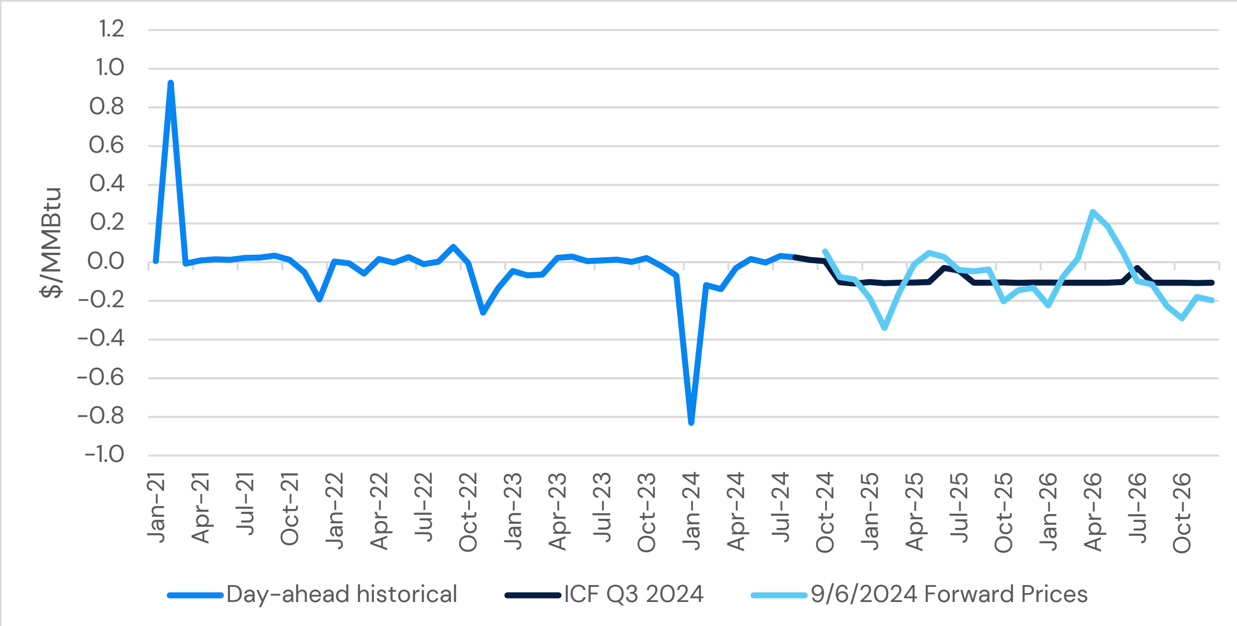
Exhibit 3-7 : Basis Between Panhandle and Henry Hub (Nominal $/MMBtu)



Source: Argus Day-Ahead and Forward Prices; ICF Q3 2024

Below is an example of a gas market that is not currently showing higher natural gas price forward prices compared to the day-ahead prices and ICF's fundamentals view: Michcon Citygates. In Exhibit 3-8, the forward curve shows minimum to no premium in the prices at Michcon Citygates for the winter of 2024/25 compared to ICF's Q3 2024 base case. This gas price hub includes gas deliveries into the citygates of Michigan Consolidated Gas, which serves the Detroit and Grand Rapids areas and much of north and northeast Michigan. Michcon Citygates are geographically located at interconnects with ANR Pipeline at Willow Run and Wolk-fork, MI, Panhandle Eastern Pipeline at River Rouge, Great Lakes Gas Transmission at Belle River, Union Gas at St. Clair Pipeline and Consumers Energy at Northville. Michcon Citygates is located geographically between Chicago and Dawn and has a similar diversity in its supply from multiple production basins like the Mid-continent, Western Canada, and Marcellus & Utica. Michcon Citygates is closer than Chicago and Dawn to natural gas supplies from Marcellus/Utica via the Rover, Nexus, and Vector pipeline corridor but its price spread to Dawn behaved differently during Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022. Michcon Citygates spiked $0.10/MMBtu above Dawn in February 2021 but was $0.14/MMBtu below Dawn in December 2022. The forward curve dated September 6th, 2024, is projecting the price for the upcoming winter (December 2024–February 2025) will be at a discount of $0.21/MMBtu at Michcon Citygates relative to Dawn. The market and traders are placing greater weight on the most recent winter and Winter Storm Elliott instead of February 2021 and Winter Storm Uri, even though that winter included a much larger price spike and basis blowout. This suggests that the forward curve spread between Chicago and Dawn could revert to trading closer to parity for upcoming winters if we experience a winter in which the price spread stays low during a cold-weather event. The market can adjust its expectations and trading behavior quickly.

Exhibit 3-8 : Basis between Michcon Citygates and Dawn ($/MMBtu)



Source: Argus Day-Ahead and Forward Prices; ICF Q3 2024

These examples above reinforce the fact that futures markets are influenced by market sentiments or the varying weather predictions, which is most of the times different from the actual day-ahead prices observed in the past and also captured through the fundamental drivers of gas prices in ICF's Q3 2024 base case.

4. ICF's Forecast for Chicago and Dawn

4.1 Natural Gas Consumption in Chicago and Ontario & Quebec

The price spread between Chicago and Dawn is driven largely by the downstream natural gas demand not just in Chicago or Ontario & Quebec but also by the surrounding regions.

As discussed below, ICF's Q3 2024 base case projects the natural gas demand at both Chicago and Ontario & Quebec to grow modestly, however, the corresponding price forecasts in ICF's Q3 2024 base case for Chicago or Dawn do not show the price spikes built in by the futures market.

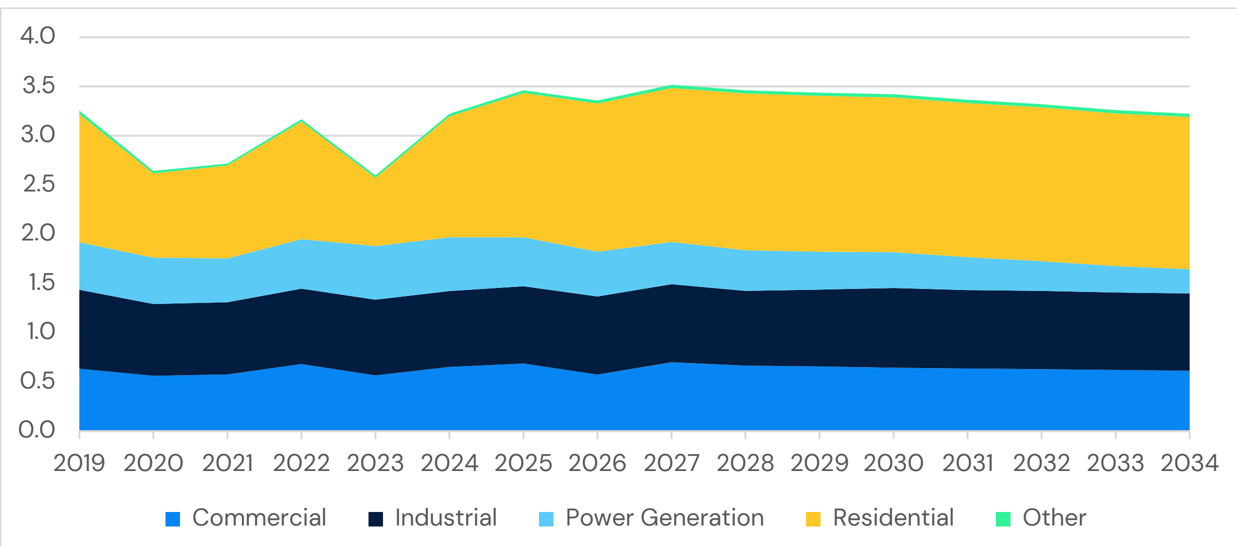
4.1.1 Natural Gas Consumption in Chicago

Natural gas consumption in Chicago is primarily driven by the residential and commercial sectors. Natural gas demand from the residential and commercial sectors in Chicago accounted for 55% of total natural gas consumption between 2019 and 2023. Monthly natural gas consumption from the residential and commercial sectors in Chicago during January 2019 to January 2023 varied from 2.5 billion cubic feet per day (Bcfd) to almost 4.1 Bcfd, primarily dependent on prevailing temperatures. Natural gas demand from the electric power sector has grown significantly over the past five years. For example, electric power sector's natural gas consumption was 13% higher in 2023 compared to 2019, with an y-o-y average growth rate of 3%. As coal power plants have retired and space-heating technologies have developed and the use of electric heat pumps has grown, natural gas consumed to generate electricity for space heating has increased along with already established direct end-use consumption for space heating.

Natural gas demand from the end use sectors in 2023 in Chicago averaged 2.6 Bcfd, 18% lower than the previous year mainly due to less demand from the residential and commercial sector due to mild weather. The residential and commercial sector gas use declined, however the power sector gas used increased by 8% compared to the previous year. In January 2023, the residential and commercial sectors in Chicago combined saw a 19% decrease in natural gas consumption compared to January 2022. However, during July and August 2023, the power demand averaged 0.8 Bcfd, 14% higher compared to the five-year average, driven by the low natural gas prices making natural gas more competitive to use.

Natural gas demand from the end use sectors in 2024 in Chicago for the first half of the year was 3% higher compared to the 2019-2023 five-year average levels. Much of that increase occurred in the residential sector demand during the month of January when winter storm Heather hit the United States.

Exhibit 4-1 : Natural Gas Consumption in Chicago (Bcfd)

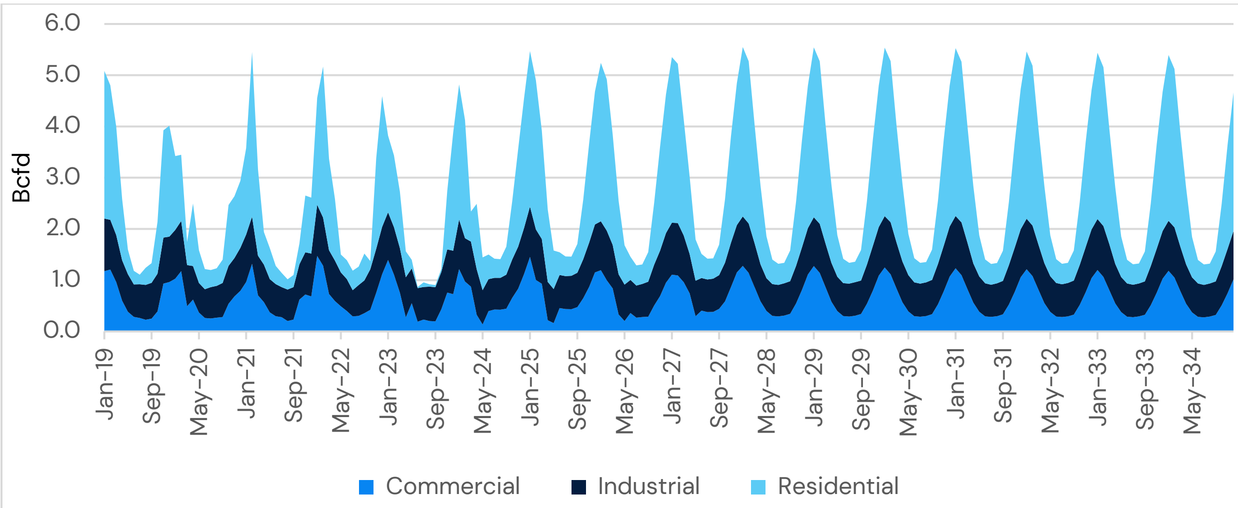


Source: ICF Q3 2024

Per ICF's Q3 2024 forecast, the residential sector is forecasted to account for 45% of the total demand on average between 2024-2034. ICF projects the natural gas demand from the residential, commercial and industrial sector to grow from 2.7 Bcfd in 2024 to 3.1 Bcfd in 2027, a 15% increase. More than 80% of the demand increase is coming from the residential sector while rest is coming from the commercial and industrial sector. Between 2028 to 2034, assuming weather normal conditions, the gas use in the residential, commercial and industrial sector is projected to decline by 2% reaching 2.9 Bcfd in 2034 mainly due to drop in the commercial sector gas use.

The natural gas consumption from residential, commercial, and industrial sectors in Chicago is winter peaking as shown in Exhibit 4-2 below.

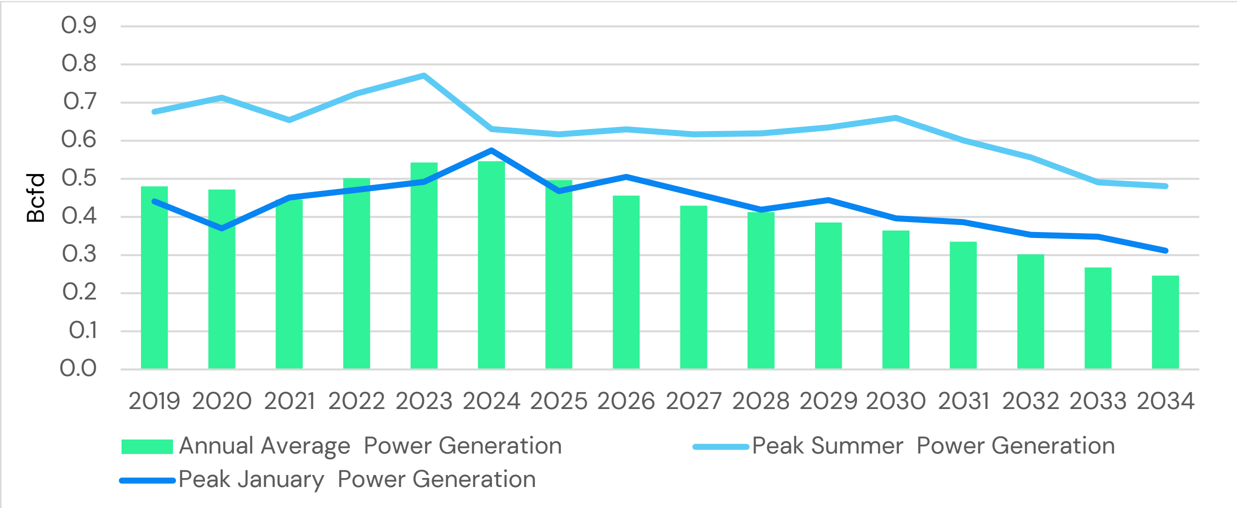
Exhibit 4-2 : Monthly Residential, Commercial, and Industrial Natural Gas Consumption (Bcfd)



Source: ICF Q3 2024

Power sector gas use peaks in the summer months (July to August) in Chicago. Demand in these months has gone as high as 0.8 Bcfd in the past 5 years (2019-2023). ICF projects a modest growth in gas-fired generation due to coal and nuclear plant retirements and electric load growth. As per ICF's Q3 2024 forecast, the power sector gas use is expected to peak in 2024 reaching above 0.5 Bcfd, 1% higher than 2023 levels. Beyond 2024, the power sector demand is projected to decline steadily and reach 0.2 Bcfd by 2034. The monthly power sector demand, however, is projected to reach 0.7 Bcfd in the month of July 2030. Exhibit 4-3 below shows a comparison of the annual power generation demand vs the monthly power generation demand from January and peak summer months of July and August as projected by ICF.

Exhibit 4-3 : Annual vs Monthly Power Generation Demand in Chicago (Bcfd)



Source: ICF Q3 2024

Therefore, as discussed above, ICF's Q3 2024 base case projects the RCI demand to peak in the winter months and hence, the total demand at Chicago is forecasted to increase. This does add an upward pressure on the prices at Chicago, but ICF's forecasts still do not project price increases of the same magnitude as the forward curve as there is enough supply and pipeline capacity to prevent the price spread relationship between Chicago and Dawn to change under normal weather conditions.

4.1.2 Natural Gas Consumption in Ontario & Quebec

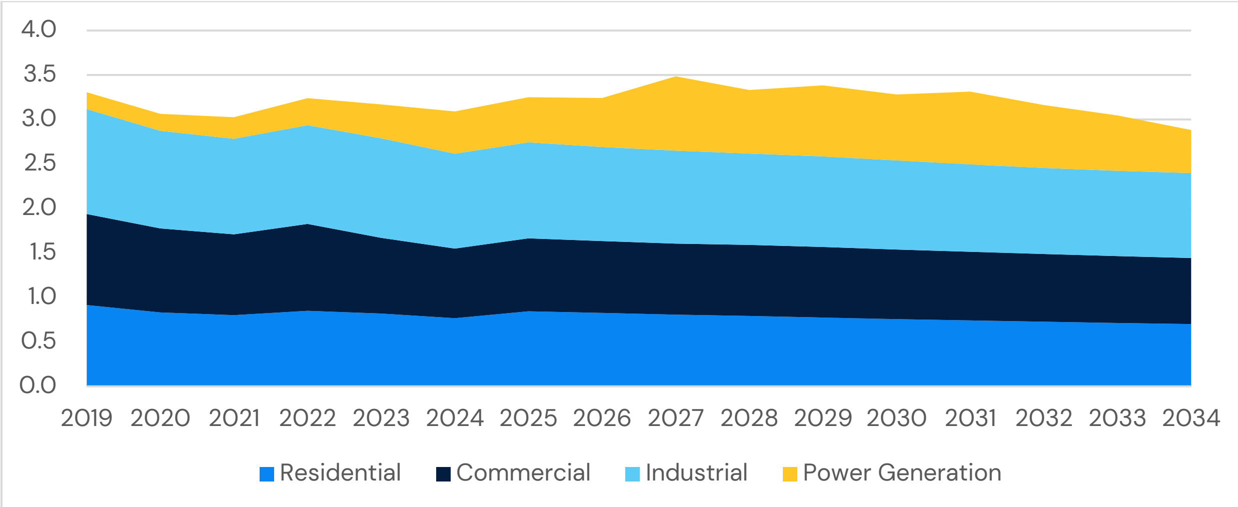
Demand in Ontario & Quebec is expected to increase in the near term driven by the demand from the power sector as Pickering retires and load continues to grow. The power generation gas demand remains steady and fluctuates with electric demand growth, renewables and storage coming online and ongoing refurbishments. In the long term, the gas demand declines in the residential, commercial, industrial and power (RCIP) sectors. The long term decline in power sector comes as Pickering returns to service in mid-2030s thus reducing the gas forecast.

Per ICF's Q3 2024 case, demand from the RCI sectors in Ontario & Quebec is expected to decline between 2024 to 2034 at an annual average rate of 1.3%. In 2025, the demand from the RCI sectors is expected to average 2.7 Bcfd, a 4.8% increase from the 2024 levels of 2.6 Bcfd. Beyond 2025, the demand is expected to decline gradually reaching 2.4 Bcfd in 2034.

The demand from the power sector, however, grows at 4% on an annual average basis between 2024 to 2034. The power demand grows from 0.5 Bcfd in 2024 and peaks in 2027 reaching 0.8 Bcfd. Between 2028-2031, it averages 0.8 Bcfd and declines to 0.5 Bcfd by 2034.

Even with these changes in the natural gas use in Ontario & Quebec, ICF doesn't expect any large price changes at Dawn hub relative to other nearby price hubs.

Exhibit 4-4 : Natural Gas Demand by Sector in Ontario & Quebec (Bcfd)



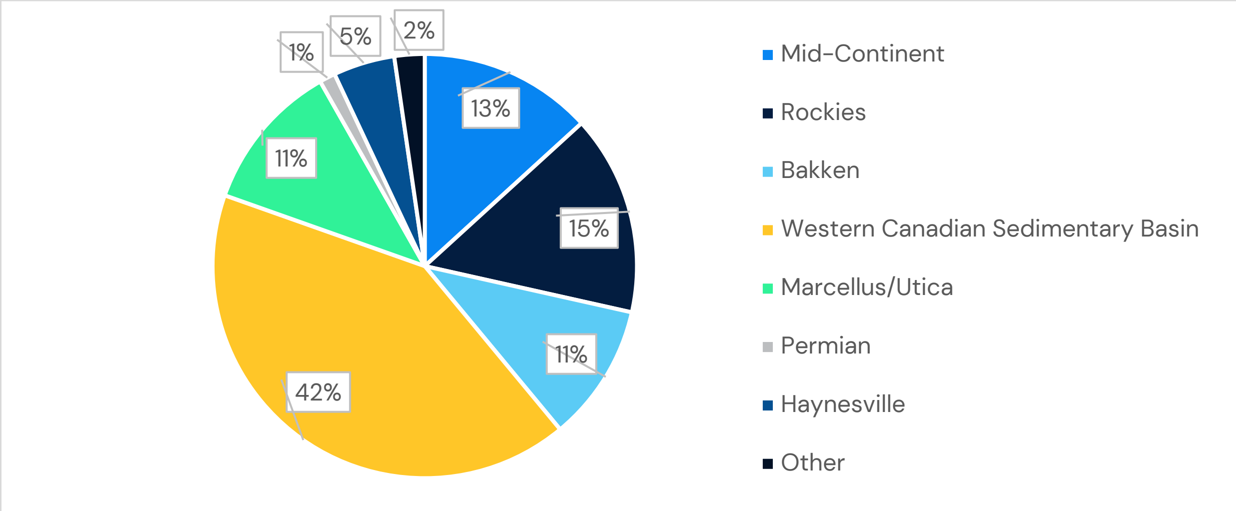
Source: ICF Q3 2024

4.2 Gas Production Outlook Around Chicago and Ontario & Quebec

4.2.1 Gas Supply Outlook at Chicago

The Rockies, Bakken, Western Canadian Sedimentary Basin, and Midcontinent are the natural gas production regions that Chicago has direct pipeline access to. Natural gas produced from these basins is transported to Illinois via major interstate pipelines such as the Natural Gas Pipeline Company of America, Alliance Pipeline, Northern Border Pipeline, Northern Natural Gas, ANR Pipeline, Rockies Express Pipeline, and Texas Gas Transmission. Exhibit 4-5 shows that Chicago is centrally located and has the capability to access gas supply across these gas production hubs across North America. Between 2024 to 2034, ICF expects that over 55% of gas supply to Chicago will be sourced from Rockies and Western Canada. The Midcontinent, Bakken, and Marcellus/Utica basins also play a pivotal role in supplying gas to Chicago, particularly during peak winter months.

Exhibit 4-5 : Chicago Supply (2024-2034 Percent Contribution by Supply Basin)



Source: ICF Q3 2024

Over the past five years, the Rockies basin has continued to be a significant player as a major natural gas supply basin. This region encompasses Colorado, Wyoming, Utah, New Mexico, and Montana. Natural gas production in the Rockies has been steady in the last half-decade, due to advancements in drilling and extraction techniques, such as hydraulic fracturing (fracking) and horizontal drilling. These innovations have enabled supply growth in Niobrara region that offsets decline in San Juan and Western Rockies plays. ICF expects gas production from the Rockies to grow by 6.1% on average between 2024 and 2027. Production growth is expected to continue till 2030, averaging around 3.9% between 2028-2030. Beyond 2030, production in the Rockies is expected to decline by 2.6% on average between 2031 and 2034.

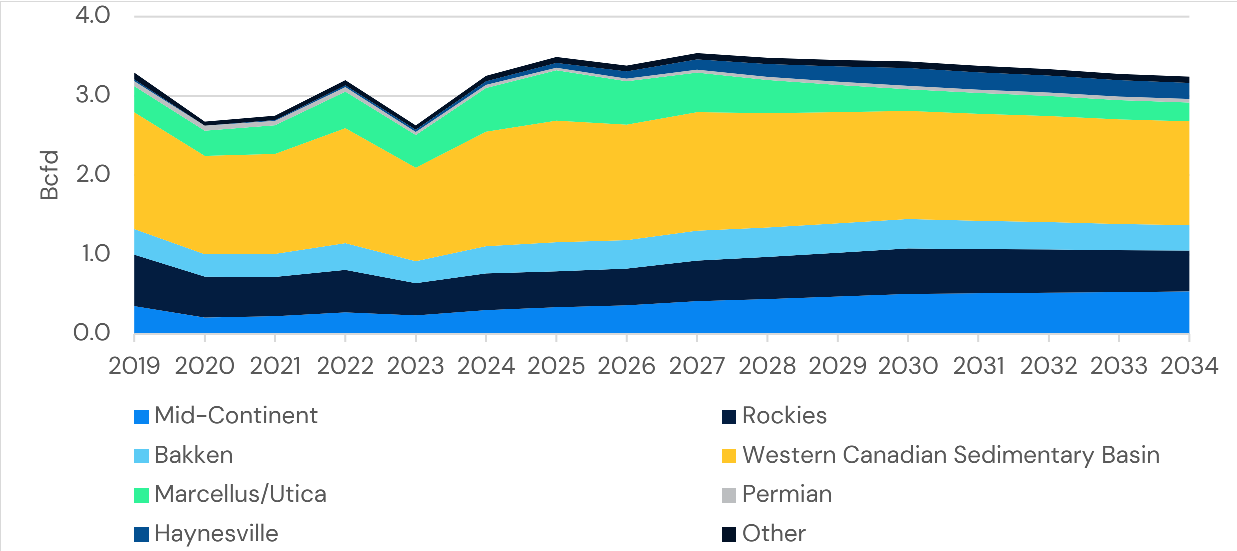
Bakken Gas Production, centered primarily in North Dakota, has emerged as a significant contributor to natural gas supply to Chicago. While renowned for its abundant shale oil resources, the Bakken Formation also holds substantial reserves of associated natural gas, and the basin is becoming increasingly gassier as more and more shale oil resources are produced. In other words, the proportion of associated natural gas is increasing from the oil & gas mixture extracted from this basin. Therefore, ICF expects that natural gas production at Bakken to steadily grow by 8% on average between 2024 and 2027. In the long run, Bakken production is expected to decline by 2.3% on average between 2028 and 2034.

Midcontinent Gas Production, located in South Central US, is a major supply basin that contains several small fields that produce Oil & Gas. The basin spans across Oklahoma, the Texas Panhandle, Arkansas, and Kansas. The major gas plays within this supply basin include Fayetteville, Granite Wash, Mississippian and SCOOP/STACK. Among these gas plays, SCOOP/STACK is considered to be the most economical with comparatively lower gas production costs by acreage and with higher potential to grow over the next decade. SCOOP is an acronym for South Central Oklahoma Oil Province,and is spread over Carter, Garvin, Grady, McClain, Stephens, Jefferson, Love, Caddo, and Murray counties in Oklahoma. STACK stands for Sooner Trend in Anadarko basin, Canadian and Kingfisher (counties). Most of the play is located across Canadian and Kingfisher counties, together with Blaine, Dewey, Major, and Garfield counties. The SCOOP refers to geological location while the STACK refers to geographical location of the basin. ICF expects gas production from the Midcontinent to grow by 16% on average between 2024 and 2027. In the long run, production in the Midcontinent is expected to grow by 3.8% on average between 2028 and 2034.

Across the border in Western Canada, gas production is anchored by the Western Canadian Sedimentary Basin, encompassing Alberta, Saskatchewan, and parts of British Columbia and Manitoba. This basin is known for its vast oil sands, conventional oil, and natural gas reserves. ICF expects that gas production in Western Canadian Sedimentary Basin to steadily grow by 6.6% on average between 2024 and 2027. Longer-term production growth of this basin is tied to development of the Montney basin and high oil price environment. ICF expects natural gas production out of Western Canada to decline by 1.9% on average between 2028 and 2034.

Exhibit 4-6 below shows natural gas deliveries into Chicago by supply basin. ICF expects that gas deliveries into Chicago from Midcontinent, Western Canada, and Haynesville to increase between 2024 and 2034. These three major supply centers allow the gas consumers at Chicago to diversify their portfolio, making them not reliant on a single source of supply. Furthermore, it should be noted that the major natural gas pipelines responsible for transporting natural gas to Chicago also transport gas to surrounding major demand centers like Northeastern U.S., New England, and Ontario & Quebec. However, due to the geographic vicinity of these supply basins to Chicago, and the path of natural gas pipelines, this region has a competitive advantage. As a result, the fundamentals forecast does not build a significant premium at Chicago.

Exhibit 4-6 : Net Gas Flows into Chicago by Supply Basin (Bcfd)



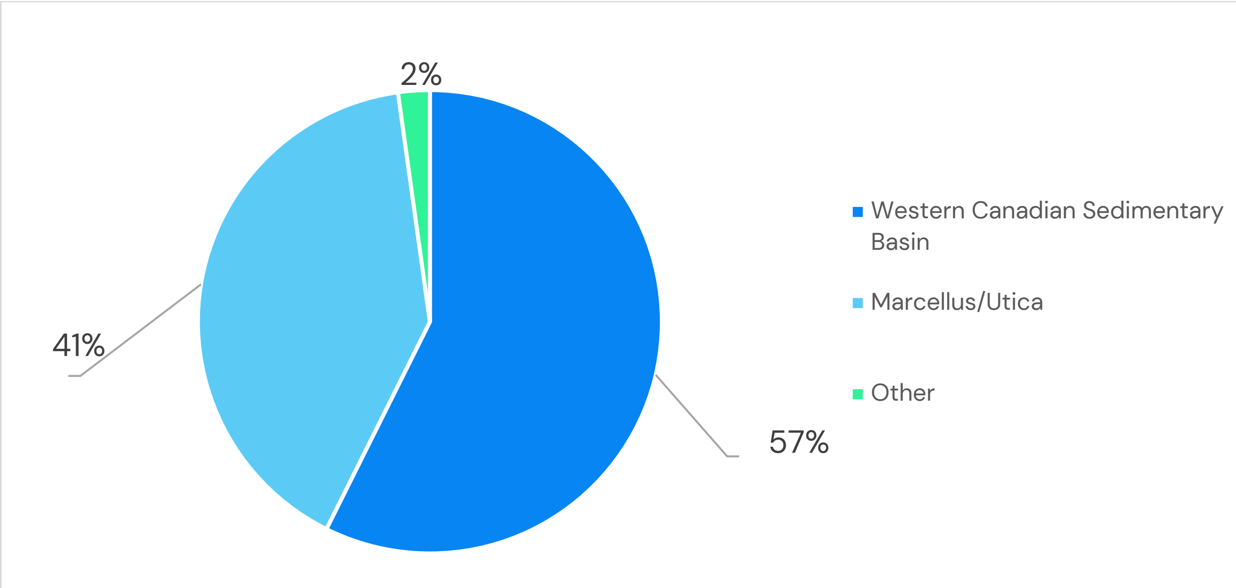
Source: ICF Q3 2024

4.2.2 Gas Supply Outlook at Ontario & Quebec

The Western Canadian Sedimentary Basin and Marcellus/Utica basins are the two major natural gas production regions that Ontario & Quebec have direct pipeline access to. Natural gas produced in the Western Canadian Sedimentary Basin is transported to Ontario & Quebec via major inter-provincial pipelines like the TC Energy Mainline and the Great Lakes Pipeline. Natural gas produced in Marcellus/Utica basins primarily is transported to Ontario via the Rover, Nexus, Vector, National Fuel, and Empire pipelines. ANR pipeline and Panhandle eastern also have interconnects with the Enbridge Gas pipeline network and TC Energy pipelines in Ontario. They bring gas supply into Ontario from the Midcontinent and Rockies.

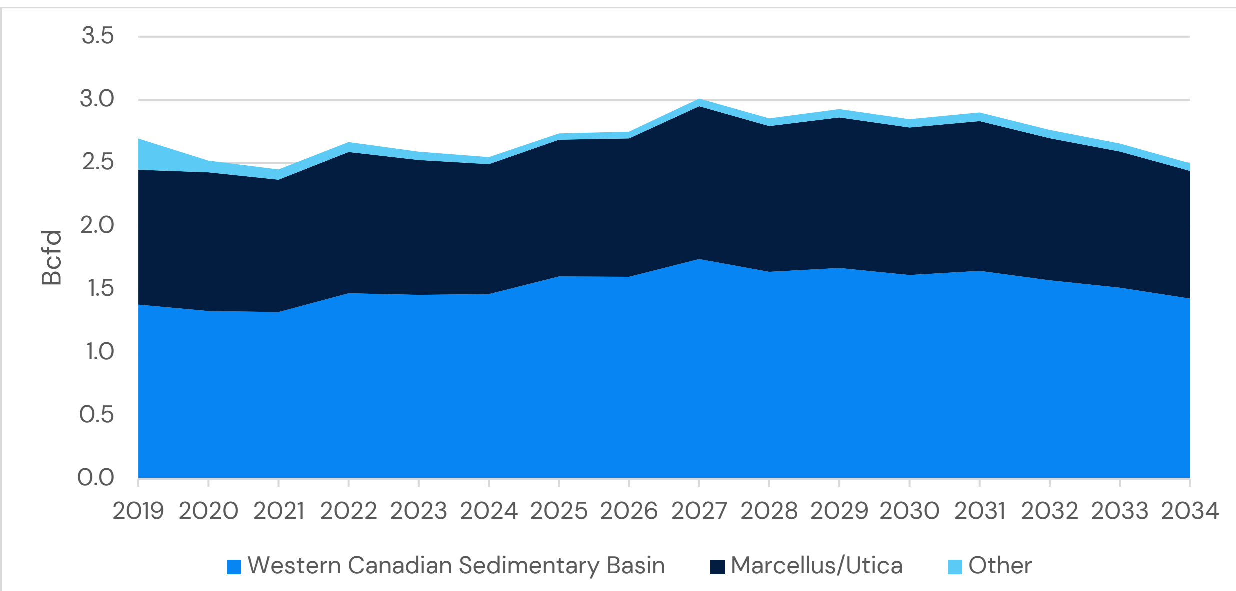
Exhibit 4-7 and Exhibit 4-8 show that Ontario & Quebec are dependent on natural gas originating from the Marcellus/Utica basins and Western Canada. Geographically, Ontario & Quebec do not have a significant amount of indigenous natural gas production and therefore are reliant on pipelines to bring gas from the U.S. and Western Canada.

Exhibit 4-7 : Ontario & Quebec Supply (2024-2034 Percent Contribution by Supply Basin)



Source: ICF Q3 2024

Exhibit 4-8 : Net Gas Flows into Ontario & Quebec by Supply Basin (Bcfd)



Source: ICF Q3 2024

4.3 Gas Pipeline Infrastructure into and Around Chicago

Gas pipeline infrastructure in North Illinois and Chicago plays a critical role in supplying natural gas to end users across the demand region. Chicago is strategically positioned due to its proximity to multiple interstate gas pipelines in North Central US. Illinois is a key crossroads point for inter-state pipelines like the Natural Gas Pipeline of America (NGPL), Northern Natural Gas, Northern Border Pipeline, ANR Pipeline, Alliance Pipeline, Texas Gas Transmission, Rockies Express, Panhandle Eastern, and Midwestern Gas Transmission. These pipelines together form a network of gas pipeline infrastructure that form a grid around Chicago enabling it to access gas supply for major supply hubs like the Marcellus/Utica, Rockies, Bakken, Western Canadian Sedimentary Basin, and Midcontinent. Table 4-1 below gives a summary of major gas pipelines around Chicago, their pipeline route, and where these pipelines source their natural gas.

Table 4-1 : Interstate Pipelines that Supply Natural Gas to Chicago

Gas Pipeline Name	Pipeline Route	Pipeline Capacity into North Illinois/Chicago (MMcfd)	Gas Supply Source Description
Alliance Pipeline	From Alliance Border Crossing in North Dakota to North Illinois/Chicago	1,750	Western Canadian Sedimentary Basin and Bakken
ANR Pipeline	From Kansas to North Illinois/Chicago	700	Midcontinent
ANR Pipeline	From Southern Ohio to Indiana	950	Marcellus and Utica
Midwestern Gas Transmission	From Indiana to North Illinois/Chicago	650	Gas is sourced from pipeline interconnects within Indiana with Texas Gas Transmission, Rockies Express, ANR Pipeline and Panhandle Eastern
Natural Gas Pipeline of America (NGPL)	From South Illinois to North Illinois/Chicago	1,894	Permian and Haynesville
Natural Gas Pipeline of America (NGPL)	From Iowa to North Illinois/Chicago	1,775	Rockies
Northern Border Pipeline	From Iowa to North Illinois/Chicago	1,000	Western Canadian Sedimentary Basin and Bakken
Northern Natural Gas	From Iowa to North Illinois/Chicago	575	Rockies
Texas Gas Transmission	From Southern Ohio to Indiana	425	Marcellus and Utica
Panhandle Eastern	From Southern Ohio to Indiana	150	Marcellus and Utica
Rockies Express Pipeline	From Southern Ohio to Indiana	2,000	Marcellus and Utica
Vector Pipeline	From Dawn to Chicago	1,300	Marcellus and Utica

4.4 Gas Pipeline Infrastructure Into and Around Ontario & Quebec

Gas pipeline infrastructure into and around Ontario & Quebec brings gas from the Western Canadian Sedimentary Basin as well as the Marcellus/Utica basins into Dawn. There is a small amount of local natural gas production at Dawn, Ontario but the region relies primarily on natural gas imports from nearby supply sources along with the storage facilities within the region. Table 4-2 below lists down the pipelines that supply natural gas into Ontario & Quebec. These pipeline deliveries into Ontario & Quebec along with the storage facilities at Dawn help keep the prices at Dawn below other price hubs in the region, especially during high demand periods, preventing them from spiking during winter months when there is need for additional heating demand.

Table 4-2 : Interstate Pipelines that supply natural gas to Ontario & Quebec

Gas Pipeline Name	Pipeline Route	Pipeline Capacity into Ontario & Quebec (MMcfd)	Gas Supply Source Description
ANR Pipeline Co	From the Midcontinent and Gulf Coast through Michigan to Dawn	256	Midcontinent, Gulf Coast, Marcellus & Utica
Bluewater Pipeline Co	From Michigan to Dawn	250	Underground gas storage
Great Lakes Gas Transmission	From the TC Energy Mainline at the Manitoba/Minnesota border through Michigan to Dawn	2,026	Marcellus & Utica
Iroquois Gas Transmission System	Bidirectional flows between Ontario and New York	2,050	Western Canadian Sedimentary Basin and Marcellus & Utica
Panhandle Eastern	From Texas and Oklahoma through Michigan to Dawn	100	Midcontinent and Permian
TC Energy Mainline	From Alberta to Ontario & Quebec	3,500	Western Canadian Sedimentary Basin
Enbridge Gas	From Parkway to Dawn	3,000	Western Canadian Sedimentary Basin and Marcellus & Utica
Vector Pipeline	From Illinois through Michigan to Dawn	1,290	Midcontinent, Gulf Coast, Marcellus and Utica
St. Clair/DTE Michcon	From Michigan to Dawn	225	Underground gas storage and Marcellus & Utica

4.5 Storage Capacity at Ontario & Quebec and Illinois

Underground storage is an important component of natural gas pipelines and becomes critical in regions with large winter heating requirements. Ontario & Quebec and Illinois both have access to strategically located natural gas storage facilities, which play a pivotal role in ensuring stable and reliable natural gas supply particularly during the challenging peak winter months. According to EIA's underground natural gas storage data by state, as of June 2024, Illinois state has a total storage capacity of 1,019.2 Bcf across 28 underground storage fields. Dawn, on the other hand, has a total storage capacity of 291.6 Bcf[8] across 36 underground storage fields. Ontario also has access to an additional 1,076.1 Bcf of underground storage capacity at Michigan through interstate natural gas pipelines that run

[8] Storage at Dawn, St. Clair and Sarnia combined
https://www.enbridge.com/about-us/natural-gas-transmission-midstream-and-lng/natural-gas-storage

from Michigan into Ontario. On the demand side, Chicago has an average 5-months winter demand of 4.1 Bcfd whereas Ontario has an average 5-month winter demand of 3.5 Bcfd.

With greater direct access to natural gas storage, Dawn is better positioned to manage variation on seasonal load patterns, balancing winter daily load and rapidly cycling volatile gas loads as compared to Chicago. Hence, during the 2021 winter storm Uri and Heather, day-ahead prices at Chicago saw a much greater premium as compared to Dawn.

4.6 Outlook for the Natural Gas Price Basis between Chicago and Dawn

Per ICF's Q3 2024 natural gas price forecast based on normal weather, the annual average prices at Chicago are projected to range between $2.15/MMBtu to $3.90/MMBtu (in real 2023$) between 2024 to 2034, while the monthly prices go as high as $4.78/MMBtu (in January 2032). Annual average prices at Dawn are projected to range between $2.00/MMBtu to $4.02/MMBtu (in real 2023$) between 2024 to 2034, while the monthly prices go as high as $4.82/MMBtu (in January 2032).

Prices at Chicago are projected to trade at an average discount of $0.02/MMBtu (in real 2023$) to Dawn for the upcoming winter (December 2024 to February 2025). Also, for the next two winters (December 2025 to February 2026 and December 2026 to February 2027), ICF continues to project Chicago to trade at a discount of $0.04/MMBtu on average under normal weather assumptions. The forward curve as of September 6th, 2024, has, however, built in a premium on the Chicago basis with respect to Dawn. Exhibit 4-9 compares ICF's view on the basis with the forward prices. The basis at Chicago over Dawn as per the forward prices is close to $0.93/MMBtu on average for the next two winters, with basis going over $1/MMBtu in the months of January and February suggesting that the buyers pay the higher prices as a hedge against price volatility and potential price increases.

The day-ahead prices at Chicago can trade at a premium to Dawn during the peak summer months (July and August) driven by increased power sector gas demand across the US Midcontinent region. Historically between 2019-2023, Chicago traded at a $0.01/MMBtu premium to Dawn during peak summer months. However, during July and August 2024 Chicago traded at a $0.10/MMBtu premium to Dawn, the highest premium witnessed so far. Additionally, Chicago on average traded at a $0.03/MMBtu premium to Dawn during May and June 2024, the highest premium so far which is 1 cent above than the average $0.02/MMBtu premium during May and June 2021 and 5 cents higher than the 5-year (2019-2023) May-June average. The number of days Chicago traded at premium to Dawn during the months of May and June is highest in 2024. On an average 24 days during 2024 compared to 20 days in 2021. Natural gas production at Anadarko basin experienced a 3% decline between December 2023 and June 2024. Declining Midcontinent production coupled with high gas demand for power generation required for air conditioning has put an upward pressure on the gas hubs like Enable East which in turn has influenced prices in Chicago this summer. However, the average prices, as shown by the 2024 year-to-date

(January to August 2024) day-ahead prices, excluding the winter storm Heather days, still show Chicago trading at a discount of $0.03/MMBtu to Dawn, which is in-line with ICF's fundamental view on the price basis.

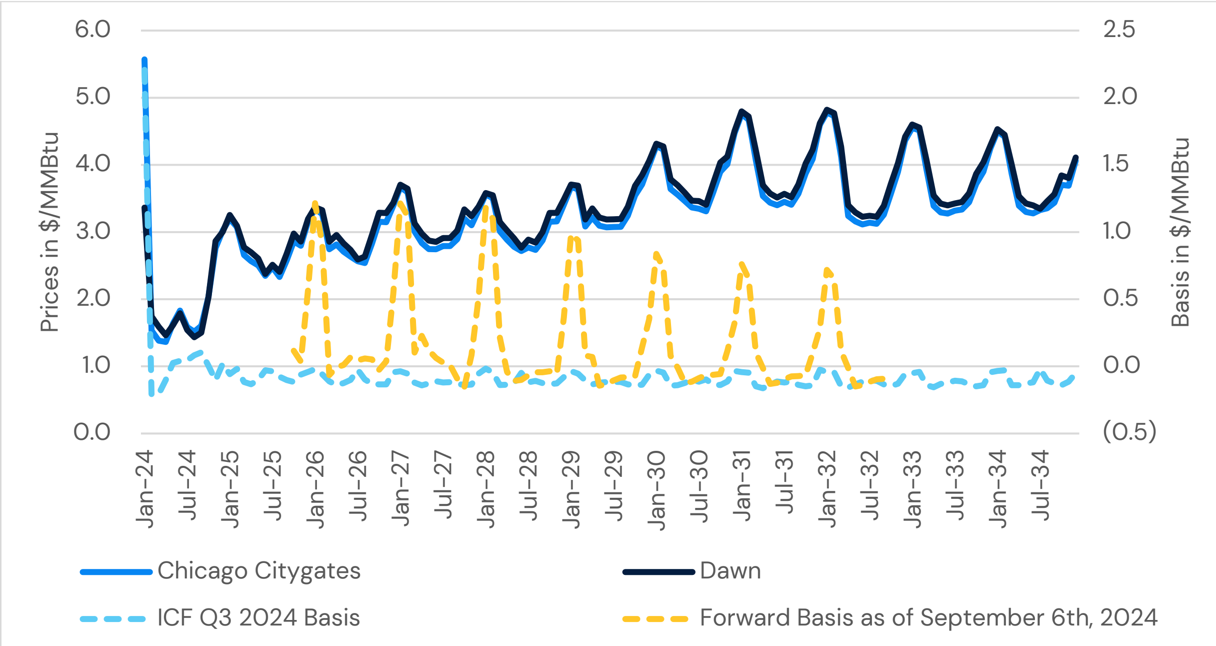
The forward curve as of September 6th, 2024, has also built in a premium on the Chicago basis with respect to Dawn for the upcoming May-August period for the year 2025 and 2026 and it averages about $0.05/MMBtu. Beyond 2026, however, the forwards market project May-August period to be at discount. ICF in its forecast however continues to project Chicago to trade at a discount to Dawn during summer months.

ICF's Q3 2024 forecast projects the monthly price at Chicago will trade between a $0.10/MMBtu premium and a $0.16/MMBtu discount to Dawn between August 2024 to December 2034. The basis is mostly negative with Chicago trading at a discount to Dawn. This is still much lower than the futures market projections for the winter months. The annual average basis between 2024 to 2034 is projected by ICF to be a discount of $0.08/MMBtu.

ICF in its base case assumes gas production from SCOOP/STACK – one of the major gas plays in Midcontinent region – will grow over the next decade. It is considered to be the most economic gas plays in North America with significant associated and non-associated gas production. ICF forecasts gas production from the Midcontinent to grow by 6% between 2025 and 2034 and there will be sufficient supply to keep Chicago pricing at a discount to Dawn. While ICF projects small growth in demand at Chicago, this growth on its own is not enough to change the price relationship between Chicago and Dawn in the near-term or to the degree suggested by the forward curve. On the supply side, Chicago is well positioned to access natural gas from multiple regions, which limits price spikes at Chicago under normal weather conditions and ensures they do not last for extended periods of time when they do happen. However, based on the recent decline in Midcontinent production, its upward pressure on price hubs like Enable East and Chicago, and its resulting impact on the Chicago market, there is a possibility of potential price related risk in the future.

If extreme winter events occur in the coming yeras and the supply from the Midcontinent basin continues declining as it has in 2024, this could lead the premium at Chicago over Dawn to continue until traders have evidence that the market has returned to its pre-2021 state. There is uncertainty about whether this price flip will persist in the long term or if it will be a short-term event.

Exhibit 4-9 : ICF's Fundamental Forecast vs Forward Prices – Chicago and Dawn (2023$/MMBtu)



Source: Argus Forward Prices; ICF Q3 2024

5. Conclusion

Since early 2021, forward curves and bid-week prices have included a significant Chicago price premium relative to Dawn. This began after Winter Storm Uri in 2021 and then was exacerbated by Winter Storm Elliott in 2022. More recently, Winter Storm Heather, which impacted the entire U.S. in January 2024, caused significant a significant price spike at Chicago relative to Dawn. As a result, Chicago day-ahead prices in January 2024 averaged a $2.25/MMBtu premium over Dawn, compared to a $0.47/MMBtu spread in the December 2023 forwards for January 2024. Excluding these three storms, the Chicago day-ahead price traded at an average $0.03/MMBtu discount to Dawn from January 2021 to August 2024. From 2019 to 2023, the Chicago day-ahead price averaged a $0.01/MMBtu discount to Dawn between May and August, suggesting the market fundamentals in weather-normal conditions still favored a Chicago discount to Dawn.

In 2023, the day-ahead Chicago prices traded at a $0.05/MMBtu premium to Dawn in July and August. In 2024, the day-ahead Chicago prices traded at a $0.07/MMBtu premium to Dawn between May and August. This was the first time in at least a decade that the day-ahead prices at Chicago averaged a premium to Dawn during those primarily summer months. The 2024 summer bid-week prices (assessed in April-July 2024) even traded with a smaller ($0.03/MMBtu) Chicago premium over Dawn than ensuing the day-ahead price average.

ICF's assessment of natural gas markets in and around Chicago and Dawn documented in this report indicates that the divergence of the futures prices from the day-ahead price still likely reflects short-term market dynamics and a risk premium that is currently much greater in the Chicago market than in the Dawn market.

During events like Winter Storm Uri, Elliott and Heather, prices at Dawn did not experience the same extreme price spikes witnessed at Chicago. Prices at Dawn are not immune to these types of price spikes; the day-ahead prices at Dawn reached $44.42/MMBtu in March 2014 due to extremely cold weather in the first three months of 2014. However, Dawn has not seen any major price spikes since the NEXUS and Rover pipelines were completed, the corresponding expansions on the Vector pipeline were completed in 2017 and 2018, and the TC Energy Dawn Long-Term Fixed Price contracts were introduced. As a result, the risk premium in the forward market at Dawn has been much lower than in the Chicago market.

Despite the risk premium factored into recent futures market pricing in Chicago, the long-term average day-ahead natural gas prices there trade at a discount to Dawn. This trend only reversed during extreme cold-weather events, where demand spikes occurred upstream of Chicago rather than at Dawn, and during the summer of 2024, which was caused by higher prices the Midcontinent region. The Chicago day-ahead prices have traded at a premium to Dawn during the peak summer months in the past two years for the months of July and August.

ICF's Q3 2024 base case projects Chicago to be at a discount to Dawn, diverging from futures and recent day-ahead prices for the summer of 2024. The summer price spread between Chicago and Dawn has been influenced by the Midcontinent region. Increasing summer gas consumption in the Midcontinent is putting upward pressure on regional gas prices, impacting Chicago prices. Additionally, declining Midcontinent gas production due to the low gas price environment, aging wells, reduced drilling activity, and operational challenges has further exerted upward pressure on regional prices, affecting Chicago. Consequently, the summer spread between Chicago and Dawn day-ahead prices has increased. However, ICF's Q3 2024 base case forecasts an increasing gas production in the Midcontinent, which keeps Chicago prices at a discount to Dawn.

The risk premiums in the forward markets are driven by the need of gas buyers at Chicago to hedge against price spikes caused by weather, price volatility, and other market events such as production freeze-offs and pipeline force majeures. These events are challenging to project and to assess. As a result, the market tends to assess the impact of these events based on recent observed history, and the market assessment of the impacts of these events will change over time as different events impact gas markets in different ways. The market perception of risk at Chicago and the demand for Chicago forwards to hedge against that risk is likely to be different in the long term than it is in the short term.

ICF projects only modest changes in demand over the next decade at both Chicago and Dawn. However, the shifts in market fundamentals at either location do not justify the changes in Chicago's forward curve observed since 2021. Additionally, the current day-ahead prices at Chicago, which are trading at a premium to Dawn, are not reflected in ICF's base case. This discrepancy arises because our base case assumes increasing production in the Midcontinent. Given the interconnected pipeline network between the Midcontinent and Chicago, if the Midcontinent production continues to experience a declining trend as it did during the summer of 2024, this might change the regional market dynamics, and the historical price spread relationship between Chicago and Dawn.

As observed in other markets, ICF expects the risk premium in the Chicago and Dawn futures prices to move toward the market fundamentals in the long term, resulting in a declining premium between Chicago and Dawn as evidenced by shifts seen in the forward curve at Michcon.

In addition, ICF expects the supply diversity provided by the ability to source gas for the Ontario market through Chicago to remain valuable. Recent trading at the PEPL hub shows that other potential supply points can also start trading at premiums to Dawn, suggesting the continuing value of supply portfolio diversity.

The index of customers data for the Vector pipeline over the past few years shows it is fully contracted, with customers consistently retaining and renewing firm transportation contracts due to its critical role in supplying gas to and from Chicago. As of Q4 2024, the Vector capacity to deliver to St. Clair is fully contracted, contracting in the forward haul (west-to-east) direction has remained consistent; there are 14 customers other than Enbridge gas who hold contracts on Vector to move gas west-to-east. This would make re-contracting challenging or impossible if Enbridge releases its current Vector capacity. Therefore, ICF advises Enbridge Gas to base its long-term re-contracting decisions on market fundamentals, such as day-ahead prices, and the benefits of supply diversity and reliability, rather than short-term futures market trends.

While the link between the market fundamentals and the financial markets has changed at Chicago since 2021, it is most likely to revert toward the supply and demand fundamentals in the long term. In the meantime, other Enbridge Gas supply hubs could experience disruptions or price volatility that lead to increased prices or forward premiums, making Chicago prices more attractive even if the risk premium built into the Chicago forwards fails to subside or subsides more slowly than expected.

Given the lack of incremental pipeline capacity, any change in pipeline capacity holdings in these markets will have long-term implications, and decisions regarding pipeline capacity should reflect a long-term perspective on costs and benefits. Hence, ICF recommends that Enbridge Gas base their pipeline re-contracting decisions on the long-term market fundamentals as well as the supply diversity and reliability benefits associated with access to an additional market center, rather than the near-term futures market trends.

In ICF's opinion, there is a long-term benefit to Enbridge Gas in continuing to hold its capacity and supply agreements on Vector based on the fundamental market assessment, but there is a potential risk owing to the increasing instances when Chicago traded at a premium to

Dawn such as those seen during the summer of 2024 and during winter storm events like Uri, Elliott, and Heather.

ICF's analysis highlights the complex dynamics influencing natural gas prices between Chicago and Dawn. While recent extreme weather events have caused significant price fluctuations, the long-term market fundamentals suggest a different trend. Despite the current premiums observed in Chicago, it is still uncertain that this flip in the price basis between Chicago and Dawn will continue over the long term. ICF projects that increasing gas production in the Midcontinent will eventually lead to Chicago prices trading at a discount to Dawn.

ICF advises Enbridge Gas to focus on long-term market fundamentals, supply diversity, and reliability when making re-contracting decisions for pipeline capacity. The interconnected pipeline network and the critical role of the Vector pipeline underscore the importance of maintaining capacity agreements. Although short-term market trends and risk premiums may cause temporary deviations, the long-term perspective should guide strategic decisions to ensure stability and cost-effectiveness in gas supply.

twitter.com/ICF

linkedin.com/company/icf-international

facebook.com/ThisIsICF

#thisisicf

icf.com

About ICF

ICF (NASDAQ:ICFI) is a global consulting and digital services company with over 7,000 full- and part-time employees, but we are not your typical consultants. At ICF, business analysts and policy specialists work together with digital strategists, data scientists and creatives. We combine unmatched industry expertise with cutting-edge engagement capabilities to help organizations solve their most complex challenges. Since 1969, public and private sector clients have worked with ICF to navigate change and shape the future. Learn more at icf.com.

2023/24 PERFORMANCE METRICS

OEB Guiding Principle	Performance Category	Intent of Measure	Measure	Target/ Variance Range	2023/24 Results	2022/23 Results	2021/22 Results	3-Year Average (1)
COST EFFECTIVENESS								
The gas supply plans will be cost-effective. Cost-effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner.	Policies and Procedures	Demonstrates EGI's consideration of timely pricing information and the utility's ability to transact according to internal policies for managing counterparty risk	Procurement plan reviewed and approved as outlined in the policy	C	C	C	C	N/A
			Transacting counterparties have met appropriate credit requirements	C	C	C	C	N/A
	Weather Variance (2)	Illustrates weather risk in EGI's Plan correlated with price variances (e.g. positive HDD variances tend to lead to higher prices)	HDD Variance - EGD CDA	(16%) - 11%	(14%)	(8%)	(1%)	(8%)
			HDD Variance - EGD EDA	(17%) - 15%	(13%)	(9%)	2%	(7%)
			HDD Variance - EGD Niagara	(15%) - 11%	(15%)	(8%)	0%	(8%)
			HDD Variance - Union North	(15%) - 12%	(13%)	(7%)	1%	(6%)
			HDD Variance - Union South	(14%) - 8%	(16%)	(8%)	0%	(8%)
	Price Effectiveness	Demonstrates the diversity of supply terms within EGI's procurement plan through a layered approach to contracting	Distribution of procurement supply terms:					
			Less than one month	0% - 15%	2%	1%	5%	3%
			Monthly	17% - 32%	21%	25%	18%	21%
			Seasonal	15% - 64%	46%	41%	59%	49%
			Annual or longer	16% - 46%	31%	33%	18%	27%
		Illustrates price stability and consistency in EGI's Plan	Reference Price (3)	N/A	Please see page 3.	Please see page 3.	Please see page 3.	N/A
RELIABILITY AND SECURITY OF SUPPLY								
The gas supply plans will ensure the reliable and secure supply of gas. Reliability and security of supply is achieved by ensuring gas supply to various receipt points to meet planned peak day and seasonal gas delivery requirements.	Design Day	Demonstrates the extent to which EGI is able to procure assets required to meet design day demand, indicating the reliability of the Plan	Acquired assets to meet design day requirements, as identified by the Plan	100%	100%	100%	100%	100%
	Storage	Demonstrates EGI's execution of its storage inventory strategy	Percentage of actual storage target at November 1 compared to the Plan	94% - 100%	99%	96%	100%	98%
			Percentage of actual storage target at February 28 compared to the Plan	100%	100%	100%	100%	100%
			Percentage of actual storage target at March 31 compared to the Plan	100%	100%	100%	100%	100%
	Communication	Ensure ongoing communication and understanding between planning and operations teams	Meet once a month at a minimum to discuss inventory position relative to targets and what action is required	C	C	C	C	C
			Instances when QRAM expected bill impacts exceed +/- 25%	N/A	0	1	3	1
			Communicated to ratepayers when bill impacts exceed +25%	C	C	C	C	C
	Diversity	Illustrates EGI's diversity of basin, contract term, counterparties and supply procurement in the Plan	Supply basin diversity					
			Ontario/Dawn	20% - 39%	19%	25%	26%	23%
			WCSB	17% - 29%	27%	26%	21%	25%
			Appalachia	14% - 22%	21%	19%	20%	20%
			Niagara Region	13% - 19%	18%	16%	18%	17%
			Chicago	8% - 11%	11%	11%	10%	11%
			U.S. Mid-Continent	2% - 5%	4%	4%	3%	4%
			Percentage of contracts with remaining terms of:					
			1-5 years	3% - 69%	52%	43%	56%	50%
			6-10 years	21% - 57%	44%	52%	33%	43%
			> 10 years	0% - 59%	4%	5%	12%	7%
			Total number of unique counterparties	54 - 58	55	55	55	55
			Total number of firm receipt points	20 - 31	24	25	25	25
	Reliability	Reports EGI's experience with pipeline and supply disruptions demonstrating the reliability of the portfolio	Number of days of force majeure on upstream pipelines that reduced capacity	0 - 22	0	15	14	10
			Number of days of force majeure on upstream pipelines impacting customers' security of supply	0	0	0	0	0
			Number of days of failed delivery of supply (including force majeure)	18 - 178	237	161	113	170
			Number of days of failed delivery of supply impacting customers security of supply	0	0	0	0	0
			Number of days of force majeure on storage assets	0	0	0	0	0

2023/24 PERFORMANCE METRICS

OEB Guiding Principle	Performance Category	Intent of Measure	Measure	Target/ Variance Range	2023/24 Results	2022/23 Results	2021/22 Results	3-Year Average (1)
PUBLIC POLICY								
The gas supply plan will be developed to ensure that it supports and is aligned with public policy where appropriate.	Supporting Policy	Reports public policy considered in EGI's Plan	Community expansion addressed in the Plan	C	C	C	C	N/A
			DSM savings addressed in the Plan	C	C	C	C	N/A
			Federal Carbon Pricing Program addressed in the Plan	C	C	C	C	N/A
			Percentage of RNG in the portfolio	N/A	0%	0%	0%	0%
			Emissions abated through procurement of RNG (tCO2) (4)	N/A	113	113	49	92
			Emissions abated through procurement of hydrogen (tCO2e) (5)	N/A	60	82	68	70
			Percentage of certified gas in the portfolio	N/A	4.5%	5.8%	0.4%	3.6%
			OEB-approved supply-side IRP alternatives implemented in the Plan	C	C	C	C	N/A

Notes:

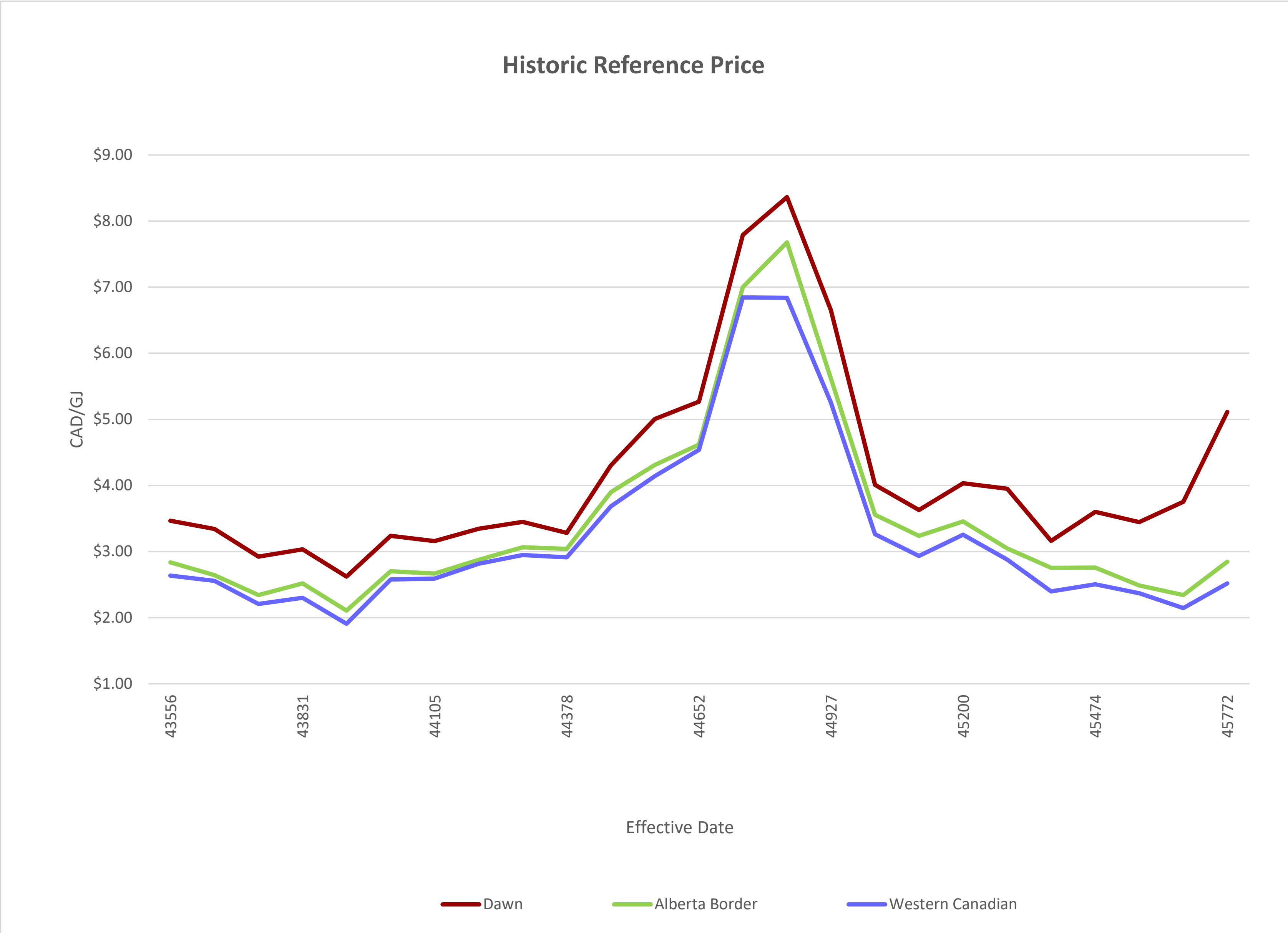
(1) 3-year historical rolling average, including the reporting year. C = Compliant, N/A = Not Applicable

(2) Positive variance indicates colder than planned weather. Negative variance indicates warmer than planned weather.

(3) As filed in the relevant QRAM proceedings.

(4) For 2021/22 & 2022/23 per Environment and Climate Change Change Canada. (2022, April 14). 2022 National Inventory Report 1990-2020: Greenhouse Gas Sources and Sinks in Canada. Part 2. Table A6.1-1. https://unfccc.int/documents/461919; For 2023/24: Environment and Climate Change Change Canada. (2024, April). 2024 National Inventory Report 1990-2022: Greenhouse Gas Sources and Sinks in Canada. Part 2. Table A6.1-1. https://publications.gc.ca/collections/collection_2024/eccc/En81-4-2022-2-eng.pdf.
The combustion of RNG results in a small amount of methane and nitrous oxide emissions being produced. The emissions abated only considers the CO2 emissions abated through procurement of RNG. 2021/22 and 2022/23 have been updated to reflect this.

(5) For 2021/22 & 2022/23 per Environment and Climate Change Change Canada. (2022, April 14). 2022 National Inventory Report 1990-2020: Greenhouse Gas Sources and Sinks in Canada. Part 2. Table A6.1-1 and Table A6.1-3. https://unfccc.int/documents/461919; 2023/2024: Environment and Climate Change Change Canada. (2024, April). 2024 National Inventory Report 1990-2022: Greenhouse Gas Sources and Sinks in Canada. Part 2. Table A6.1-1 and Table A6.1-3. https://publications.gc.ca/collections/collection_2024/eccc/En81-4-2022-2-eng.pdf.


Historic Reference Price
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
CAD/GJ
43556
43831
44105
44378
44652
44927
45200
45474
45772
Effective Date
Dawn
Alberta Border
Western Canadian

Directive and Commitment Response Summary

The following summarizes the status of outstanding directives and commitments addressed in this submission and provides an evidentiary reference where the information is provided .

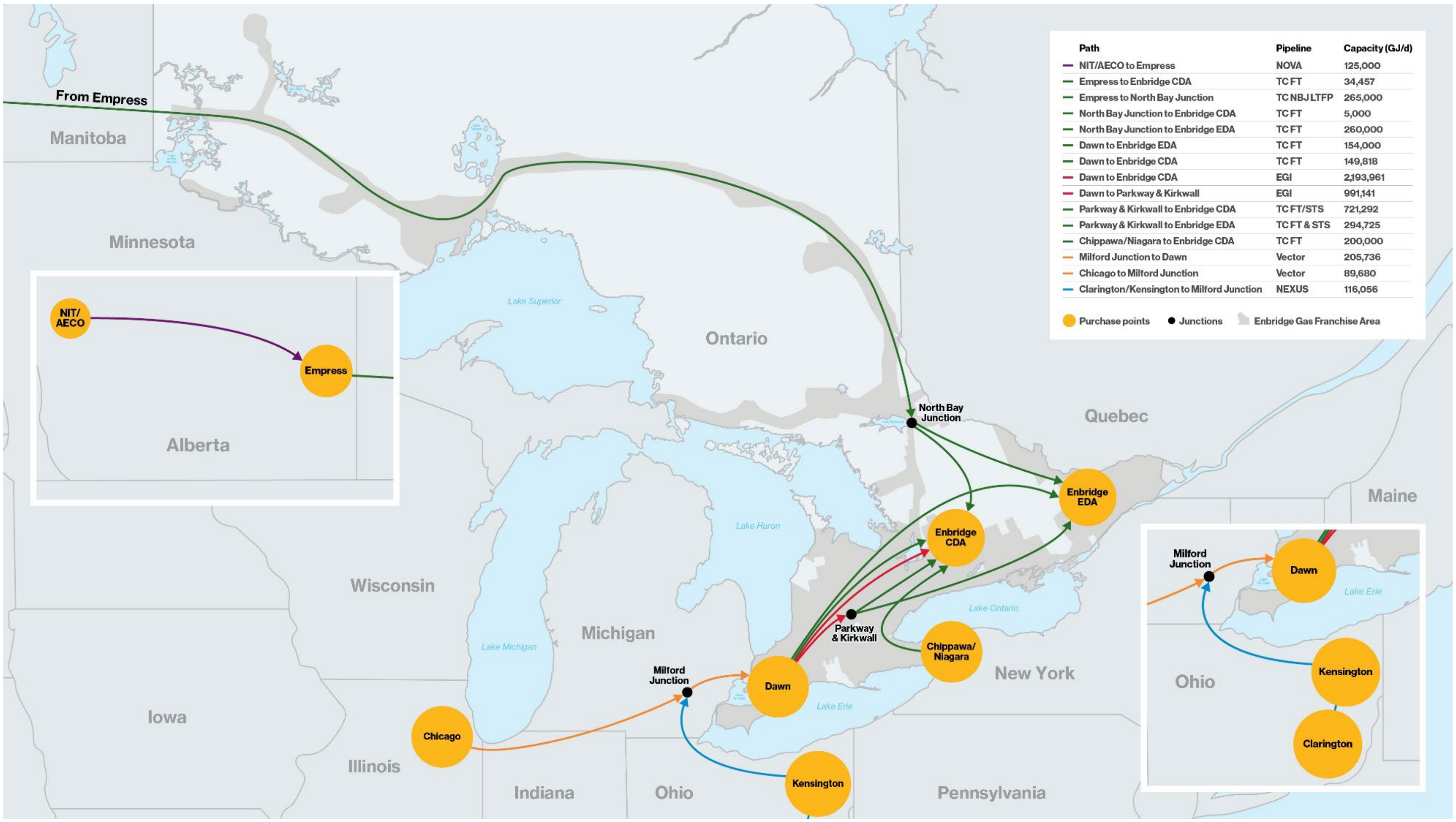
Line No.	OEB File No.	Directive/Commitment	Response
	(a)	(b)	(c)
	EB-2024-0067 - Review of 2024 Annual Update to Enbridge Gas Inc. Natural Gas Supply Plan		
1		Enbridge Gas is to provide actual gas cost for Chicago supply premiums as compared to	Appendix I - Cost-Effectiveness Analysis
2		Enbridge Gas is to provide market forward pricing information at Chicago and Dawn.	Appendix D - ICF Chicago Pricing Report
3		Enbridge Gas is to provide further evidence quantifying avoided facilities costs in the Sarnia area.	Section 6.2
4		Enbridge Gas to provide, where applicable, discussion and descriptions of potential facilities benefits that could result from gas supply contracting.	Section 6.2
5		Enbridge Gas to adapt to changing demand due to energy transition factors and file any additional information on how energy transition is impacting gas supply.	Section 4.2
6		Enbridge Gas should provide additional analysis in the GSP on global policy development and energy transition impacts to Ontario.	Section 6.1
7		Phase 2 rebasing decisions relating to RNG are to be appropriately reflected in the next five-year GSP.	At the time of the 5-Year GSP submission, Phase 2 Rebasing decision related to RNG has not been received.
8		Enbridge Gas should provide a more holistic cost impact analysis, including facilities that are avoided, incremental load balancing considerations for supply option analysis.	Note (1) Appendix C - 2024/25 Enbridge CDA Shortfall - Holistic Analysis
9		Enbridge Gas should consider providing additional detail, such as bill impact for typical customer, on a best-efforts basis for supply option analysis.	Note (1) Section 5.7 provides customer impact % based on supply options
10		Enbridge Gas should establish targets for some of the performance metrics.	Section 11; Appendix E - 2023/24 Performance Metrics
11		Enbridge Gas committed to report emission abatement from RNG and Hydrogen purchases	Appendix E - 2023/24 Performance Metrics
	EB-2023-0326 - 2021 Vector Contracting Decision		
		Evidence in support of gas supply contracting decisions should include:	
12		Relevant, dated and comprehensive documentation of the analysis supporting the contracting decision that is completed prior to entering into any new contracts or extending any existing contracts.	Appendix J - Transportation Recommendation Documentation
13		A quantitative comparison of the net premium forecast in each year over the term of the new or renewed contract, comparing the landed cost of gas from the pipeline receipt point to delivery point, relative to sourcing gas at the same delivery point.	Appendix L - Forecasted Premium Discount Resulting From Transportation Purchases
14		The actual cost of any premium paid for the contract compared to the expected premium over the term of the contract. This hindsight information will provide the materiality of the contracting decision, but is not expected to be used in the determination of prudence.	Appendix I - Cost-Effectiveness Analysis

Note:

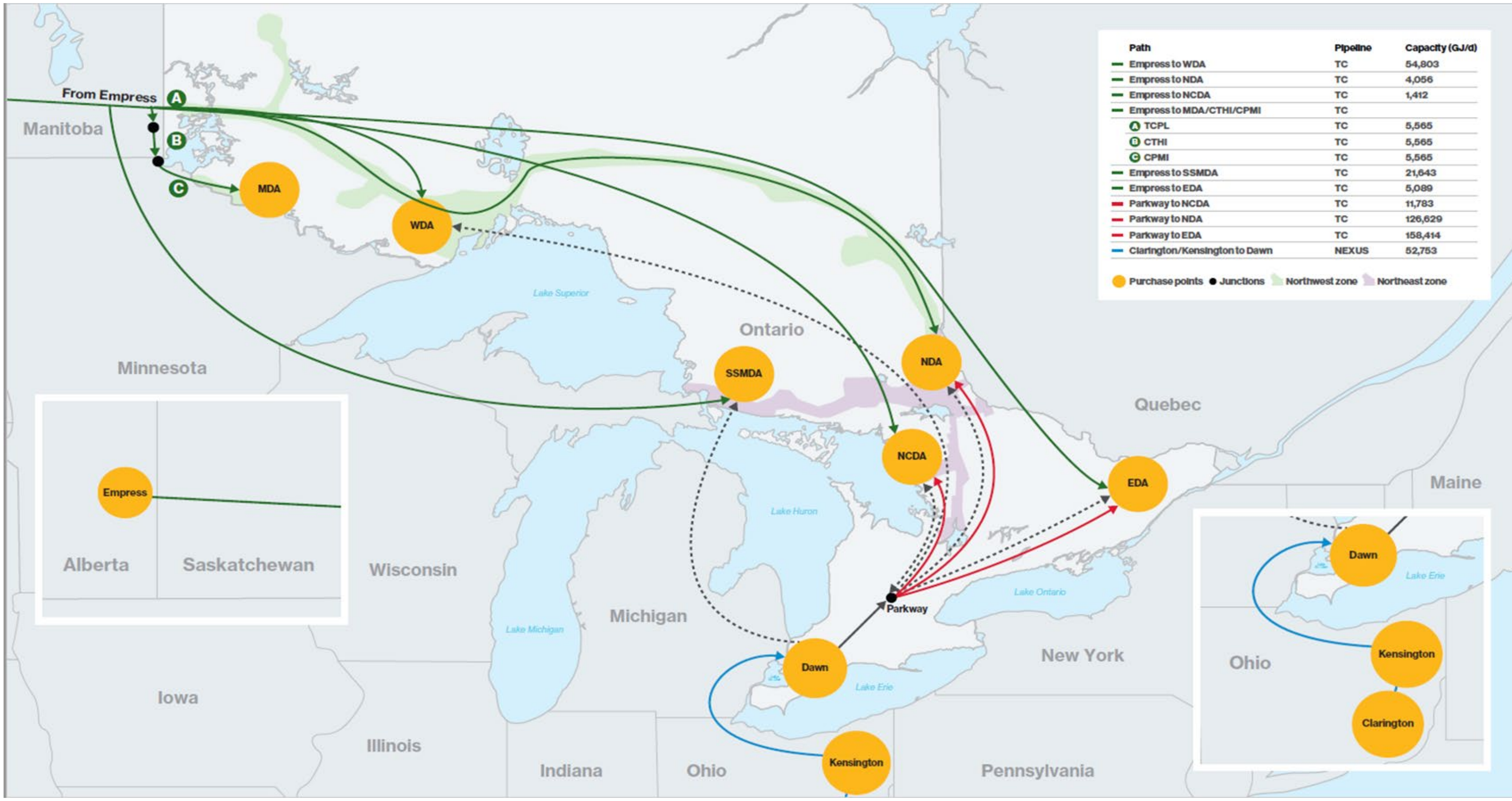
(1) Enbridge Gas notes it received OEB Staff's Report on the 2024 Annual Update on January 15, 2025, subsequent to the supply options analysis completed for contracting decisions for November 1, 2024. For purposes of this 2025 Annual Update, Enbridge Gas has provided responses to the recommendations with the analysis it completed prior to contracting decisions for November 1, 2024. Enbridge Gas will further consider the OEB Staff recommendations on supply options analysis for contracting decisions in the future.

Transportation Portfolio Maps

EGD Rate Zone Transportation Map

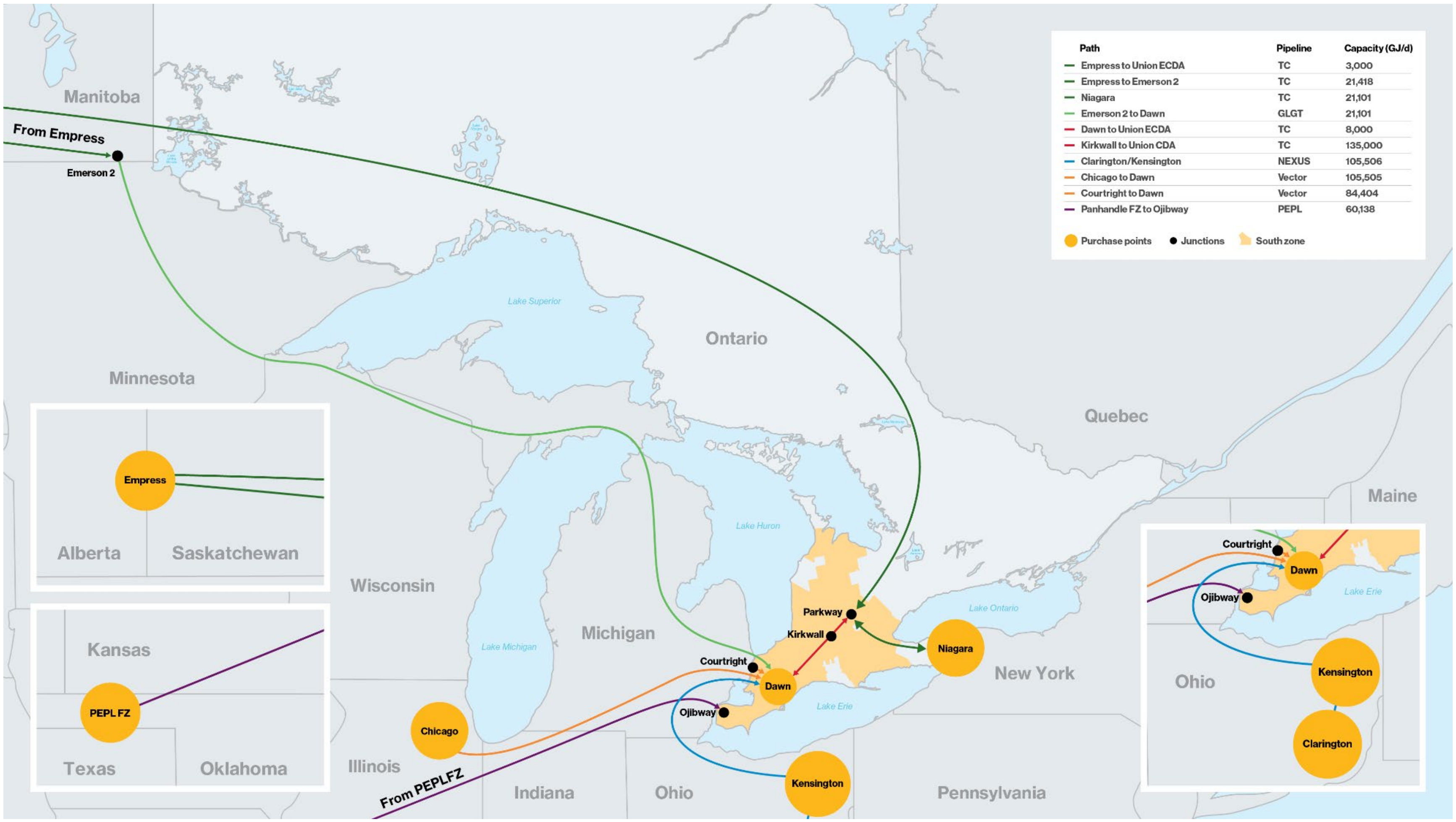


<u>Union North Rate Zones Transportation Map</u>



Path	Pipeline	Capacity (GJ/d)
Empress to WDA	TC	54,803
Empress to NDA	TC	4,056
Empress to NCDA	TC	1,412
Empress to MDA/CTHI/CPMI	TC	
A TCPL	TC	5,565
B CTHI	TC	5,565
C CPMI	TC	5,565
Empress to SSMDA	TC	21,643
Empress to EDA	TC	5,089
Parkway to NCDA	TC	11,783
Parkway to NDA	TC	126,629
Parkway to EDA	TC	158,414
Clarington/Kensington to Dawn	NEXUS	52,753

Union South Rate Zone Transportation Map



2024/25 Design Day Position

Line No.	Particulars (TJ/d)	Enbridge CDA	Enbridge EDA	Union MDA	Union SSMDA	Union WDA	Union EDA	Union NCDA	Union NDA	Union South	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Demand										
1	Design Day Demand	3,578.3	723.0	5.6	42.0	84.8	191.7	50.6	179.3	3,433.2	8,288.4
	Supply										
2	Great Lakes	-	-	-	-	-	-	-	-	21.1	21.1
3	In-franchise Supply (1)	2,249.3	-	-	-	-	-	-	-	3,116.9	5,366.2
4	NEXUS	-	-	-	-	-	-	-	-	105.5	105.5
5	Panhandle	-	-	-	-	-	-	-	-	60.1	60.1
6	TCPL Long-haul	5.0	260.0	5.6	20.9	54.8	5.0	1.0	2.1	3.0	357.4
7	TCPL Short-haul	787.2	368.1	-	-	-	158.4	11.8	126.6	21.1	1,473.3
8	TCPL STS	283.9	80.6	-	21.0	30.0	26.4	37.8	39.7	-	519.4
9	Vector	-	-	-	-	-	-	-	-	105.5	105.5
10	Total Supply	3,325.4	708.7	5.6	42.0	84.8	189.8	50.6	168.4	3,433.2	8,008.5
11	Supply Excess / (Shortfall)	(252.9)	(14.3)	-	-	-	(1.9)	-	(10.8)	-	(279.9)

Note:
(1) Includes supply arriving directly into the franchise area (i.e. Dawn, storage, DP deliveries, Crowland, Hagar, delivered supply, etc.).

2025/26 Design Day Position

Line No.	Particulars (TJ/d)	Enbridge CDA	Enbridge EDA	Union MDA	Union SSMDA	Union WDA	Union EDA	Union NCDA	Union NDA	Union South	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Demand										
1	Design Day Demand	3,594.1	725.5	5.6	42.0	84.7	192.1	50.7	179.1	3,505.8	8,379.6
	Supply										
2	Great Lakes	-	-	-	-	-	-	-	-	21.1	21.1
3	In-franchise Supply (1)	2,237.1	-	-	-	-	-	-	-	3,189.4	5,426.5
4	NEXUS	-	-	-	-	-	-	-	-	105.5	105.5
5	Panhandle	-	-	-	-	-	-	-	-	60.1	60.1
6	TCPL Long-haul	5.0	260.0	5.6	20.9	54.8	5.0	1.0	2.1	3.0	357.4
7	TCPL Short-haul	787.2	368.1	-	-	-	158.4	11.8	126.6	21.1	1,473.3
8	TCPL STS	283.9	80.6	-	21.1	29.9	26.4	37.9	39.6	-	519.4
9	Vector	-	-	-	-	-	-	-	-	105.5	105.5
10	Total Supply	3,313.2	708.7	5.6	42.0	84.7	189.8	50.7	168.3	3,505.8	8,068.7
11	Supply Excess / (Shortfall)	(281.0)	(16.8)	-	-	-	(2.3)	-	(10.8)	-	(310.9)

Note:
(1) Includes supply arriving directly into the franchise area (i.e. Dawn, storage, DP deliveries, Crowland, Hagar, delivered supply, etc.).

2026/27 Design Day Position

Line No.	Particulars (TJ/d)	Enbridge CDA	Enbridge EDA	Union MDA	Union SSMDA	Union WDA	Union EDA	Union NCDA	Union NDA	Union South	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Demand										
1	Design Day Demand	3,622.3	727.5	5.6	42.0	84.6	192.4	50.8	178.9	3,521.2	8,425.3
	Supply										
2	Great Lakes	-	-	-	-	-	-	-	-	21.1	21.1
3	In-franchise Supply (1)	2,237.1	-	-	-	-	-	-	-	3,204.9	5,441.9
4	NEXUS	-	-	-	-	-	-	-	-	105.5	105.5
5	Panhandle	-	-	-	-	-	-	-	-	60.1	60.1
6	TCPL Long-haul	5.0	260.0	5.6	20.9	54.8	5.0	1.0	2.1	3.0	357.4
7	TCPL Short-haul	787.2	368.1	-	-	-	158.4	11.8	126.6	21.1	1,473.3
8	TCPL STS	283.9	80.6	-	21.1	29.8	26.4	38.0	39.6	-	519.4
9	Vector	-	-	-	-	-	-	-	-	105.5	105.5
10	Total Supply	3,313.2	708.7	5.6	42.0	84.6	189.8	50.8	168.4	3,521.2	8,084.2
11	Supply Excess / (Shortfall)	(309.1)	(18.8)	-	-	-	(2.7)	-	(10.5)	-	(341.1)

Note:
(1) Includes supply arriving directly into the franchise area (i.e. Dawn, storage, DP deliveries, Crowland, Hagar, delivered supply, etc.).

2027/28 Design Day Position

Line No.	Particulars (TJ/d)	Enbridge CDA	Enbridge EDA	Union MDA	Union SSMDA	Union WDA	Union EDA	Union NCDA	Union NDA	Union South	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Demand										
1	Design Day Demand	3,624.1	729.1	5.6	42.0	84.4	192.6	50.8	178.6	3,538.0	8,445.2
	Supply										
2	Great Lakes	-	-	-	-	-	-	-	-	21.1	21.1
3	In-franchise Supply (1)	2,237.1	-	-	-	-	-	-	-	3,221.6	5,458.7
4	NEXUS	-	-	-	-	-	-	-	-	105.5	105.5
5	Panhandle	-	-	-	-	-	-	-	-	60.1	60.1
6	TCPL Long-haul	5.0	260.0	5.6	20.9	54.8	5.0	1.0	2.1	3.0	357.4
7	TCPL Short-haul	787.2	368.1	-	-	-	158.4	11.8	126.6	21.1	1,473.3
8	TCPL STS	283.9	80.6	-	21.1	29.6	26.4	38.0	39.8	-	519.4
9	Vector	-	-	-	-	-	-	-	-	105.5	105.5
10	Total Supply	3,313.2	708.7	5.6	42.0	84.4	189.8	50.8	168.5	3,538.0	8,101.0
11	Supply Excess / (Shortfall)	(310.9)	(20.3)	-	-	-	(2.9)	-	(10.1)	-	(344.2)

Note:
(1) Includes supply arriving directly into the franchise area (i.e. Dawn, storage, DP deliveries, Crowland, Hagar, delivered supply, etc.).

2028/29 Design Day Position

Line No.	Particulars (TJ/d)	Enbridge CDA	Enbridge EDA	Union MDA	Union SSMDA	Union WDA	Union EDA	Union NCDA	Union NDA	Union South	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Demand										
1	Design Day Demand	3,622.6	730.2	5.6	42.0	84.3	192.7	50.8	178.2	3,672.5	8,578.8
	Supply										
2	Great Lakes	-	-	-	-	-	-	-	-	21.1	21.1
3	In-franchise Supply (1)	2,237.1	-	-	-	-	-	-	-	3,356.2	5,593.2
4	NEXUS	-	-	-	-	-	-	-	-	105.5	105.5
5	Panhandle	-	-	-	-	-	-	-	-	60.1	60.1
6	TCPL Long-haul	5.0	260.0	5.6	20.9	54.8	5.0	1.0	2.1	3.0	357.4
7	TCPL Short-haul	787.2	368.1	-	-	-	158.4	11.8	126.6	21.1	1,473.3
8	TCPL STS	283.9	80.6	-	21.1	29.5	26.4	38.0	40.0	-	519.4
9	Vector	-	-	-	-	-	-	-	-	105.5	105.5
10	Total Supply	3,313.2	708.7	5.6	42.0	84.3	189.8	50.8	168.7	3,672.5	8,235.5
11	Supply Excess / (Shortfall)	(309.5)	(21.4)	-	-	-	(3.0)	-	(9.5)	-	(343.3)

Note:
(1) Includes supply arriving directly into the franchise area (i.e. Dawn, storage, DP deliveries, Crowland, Hagar, delivered supply, etc.).

2029/30 Design Day Position

Line No.	Particulars (TJ/d)	Enbridge CDA	Enbridge EDA	Union MDA	Union SSMDA	Union WDA	Union EDA	Union NCDA	Union NDA	Union South	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Demand										
1	Design Day Demand	3,619.2	730.8	5.6	41.9	84.0	192.7	50.8	177.7	3,686.8	8,589.5
	Supply										
2	Great Lakes	-	-	-	-	-	-	-	-	21.1	21.1
3	In-franchise Supply (1)	2,237.1	-	-	-	-	-	-	-	3,370.4	5,607.5
4	NEXUS	-	-	-	-	-	-	-	-	105.5	105.5
5	Panhandle	-	-	-	-	-	-	-	-	60.1	60.1
6	TCPL Long-haul	5.0	260.0	5.6	20.9	54.8	5.0	1.0	2.1	3.0	357.4
7	TCPL Short-haul	787.2	368.1	-	-	-	158.4	11.8	126.6	21.1	1,473.3
8	TCPL STS	283.9	80.6	-	21.0	29.2	26.4	38.0	40.3	-	519.4
9	Vector	-	-	-	-	-	-	-	-	105.5	105.5
10	Total Supply	3,313.2	708.7	5.6	41.9	84.0	189.8	50.8	169.0	3,686.8	8,249.7
11	Supply Excess / (Shortfall)	(306.0)	(22.1)	-	-	-	(3.0)	-	(8.7)	-	(339.7)

Note:
(1) Includes supply arriving directly into the franchise area (i.e. Dawn, storage, DP deliveries, Crowland, Hagar, delivered supply, etc.).

Cost Effectiveness: Actual Premium/(Discount) Compared to Landed Cost Forecast

Line No.	Particulars ($CAD/GJ)	Gas Year 2021/22	2022/23	2023/24
		(a)	(b)	(c)
	NYMEX			
1	Actual	8.01	4.16	2.93
	Landed Cost Analysis (1)			
2	2019	N/A	N/A	N/A
3	2020	3.68	3.68	3.68
4	2021	3.68	3.70	3.70
5	2022	N/A	3.78	3.78
6	2023	N/A	N/A	N/A
	AECO Premium/(Discount) to Empress			
7	Actual	0.01	(0.48)	0.03
	Landed Cost Analysis (1)			
8	2019	N/A	N/A	N/A
9	2020	(0.02)	(0.02)	(0.02)
10	2021	N/A	N/A	N/A
11	2022	N/A	N/A	N/A
12	2023	N/A	N/A	N/A
	GLGT Premium/(Discount) to Dawn			
13	Actual	(0.52)	0.14	(0.42)
	Landed Cost Analysis (1)			
14	2019	0.13	0.13	0.13
15	2020	0.18	0.18	0.18
16	2021	0.47	0.48	0.48
17	2022	N/A	N/A	N/A
18	2023	N/A	N/A	N/A
	Niagara Premium/(Discount) to Dawn			
19	Actual	0.50	(1.32)	(0.62)
	Landed Cost Analysis (1)			
20	2019	N/A	N/A	N/A
21	2020	0.04	0.04	0.04
22	2021	0.03	0.04	0.04
23	2022	N/A	N/A	N/A
24	2023	N/A	N/A	N/A
	Vector Premium/(Discount) to Dawn			
25	Actual	0.80	(0.25)	(0.04)
	Landed Cost Analysis (1)			
26	2019	N/A	N/A	N/A
27	2020	0.10	0.10	0.10
28	2021	0.09	0.10	0.10
29	2022	N/A	N/A	N/A
30	2023	N/A	N/A	N/A
	Clarington Premium/(Discount) to Kensington			
31	Actual	(0.93)	(0.05)	(0.38)
	Landed Cost Analysis (1)			
32	2019	N/A	N/A	N/A
33	2020	0.02	N/A	N/A
34	2021	N/A	N/A	N/A
35	2022	N/A	(0.05)	(0.05)
36	2023	N/A	N/A	(0.18)

Note:

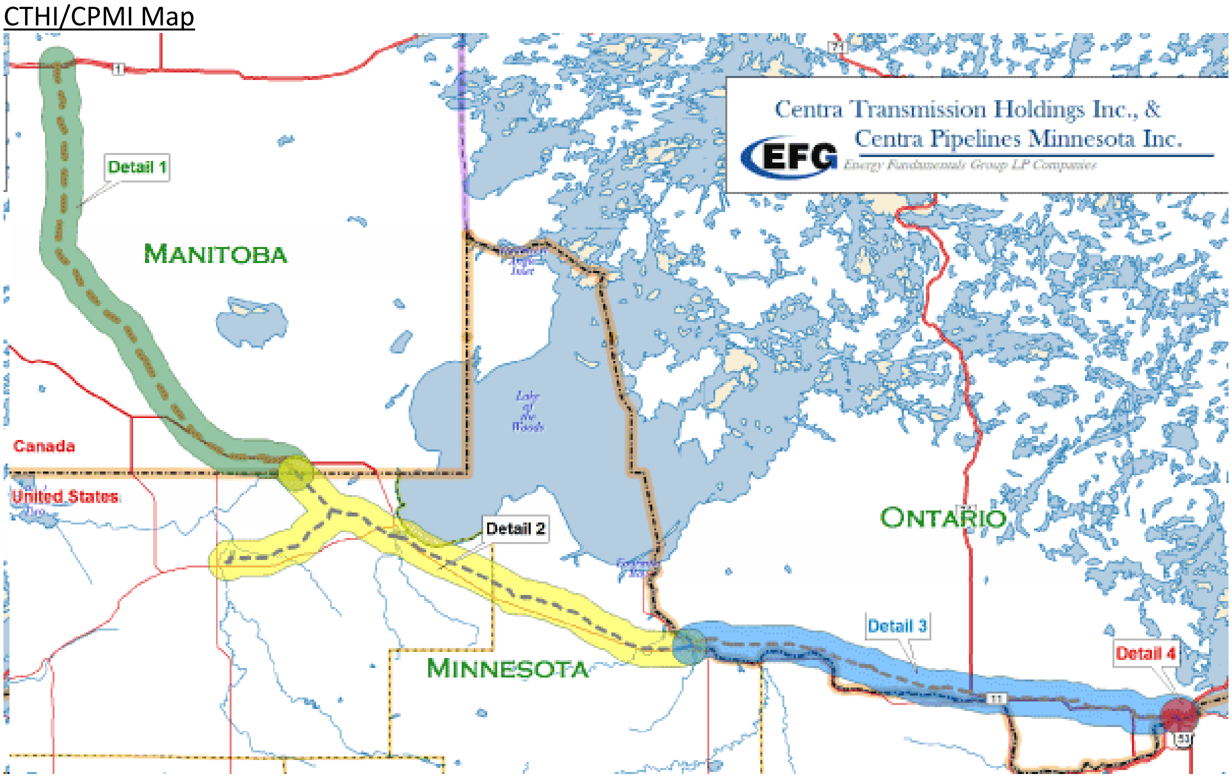
(1) Where a landed cost analysis was prepared in a year, the premium/(discount) is shown in the table. If no landed cost analysis was prepared in a year, N/A is provided. The landed cost analysis prepared annually was used in support of the subsequent year's Gas Supply Plan filing.

CTHI/CPMI 2024 Capacity Renewal

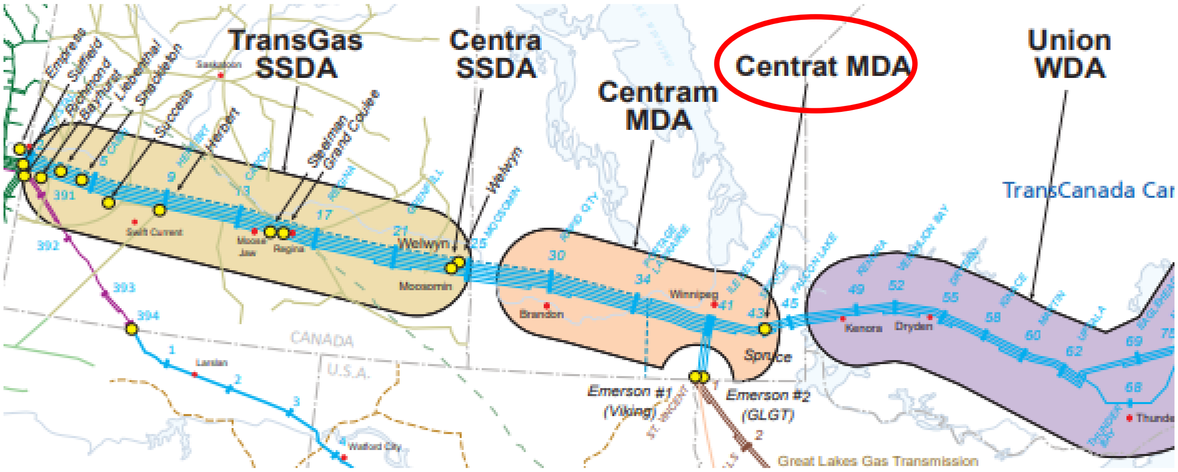
Rate Zone	Company	Path	Current Capacity
Union North-West MDA	CTHI/CPMI	Centrat MDA to Union MDA	CPMI- 5,473 mcf/d , CTHI- 155.0 10^3M^3 /d (5,771 GJ/d)
Current Contract Expiry	**Renewal Notice Due Date**	**Recommended Renewal Length**	**Current Annual Contract Valuation**
October 31, 2024	April 30, 2024	1 years	~ $1.75 Million

Introduction
Centra Transmission Holdings Inc. (CTHI)/Centra Pipelines Minnesota Inc. (CPMI) is the only pipeline that provides capacity into the Union MDA. Historically, the contracted capacity on CTHI/CPMI is approximately aligned with TransCanada FT capacity from Empress to the Centrat MDA of (currently contracted for 5,565 GJ/day).

CTHI/CPMI Map



<u>TCPL Map</u>



Annually, Enbridge Gas must provide 6 months' notice to CTHI/CPMI by April 30 to extend the contract by an additional year, effective on November 1.

Last year, Enbridge Gas increased CTHI/CPMI capacity by 206 GJ/d from 5,565 GJ/d to 5,771 GJ/d starting November 1, 2023 to align with the forecasted growth in design day demand from the 2023/2024 Gas Supply Plan. Enbridge Gas contracted for peaking service for the 2023/2024 winter to the Centrat MDA to supply the incremental 206 GJ/d on CTHI/CPMI.

The OEB-approved Settlement Agreement in EB-2022-0200 included a change to the Design Day methodology used for gas supply planning purposes. The settlement methodology will came into effect in the 2024-2034 Gas Supply Plan. Applying the settlement methodology to the 2023-2033 Gas Supply Plan data results in a forecast 2024/2025 Design Day demand of 5,549 GJ in the Union MDA.

Winter 2024-25 Northern Firm Demand on Peak Day in GJ/Day (2024-34 Plan)

	MDA				
	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029
Firm Demand					
Bundled Firm Contract Demand	-	-	-	-	-
Regular Rate Design Day Demand	5,549	5,545	5,539	5,531	5,519
T-Service Storage Redelivery Demand					
North Dawn T-Service Demand					
Peak Day Demand for the Region	**5,549**	**5,545**	**5,539**	**5,531**	**5,519**
Firm Supply					
TCPL FT from Empress	5,565	5,565	5,565	5,565	5,565
TCPL SH from Parkway					
North Dawn T-Service					
STS Firm Withdrawals from Parkway					
STS Firm Pooling Withdrawls from Parkway					
STS Firm Withdrawals from Dawn					
LNG					
Parkway to NDA/EDA/NCDA FT (Redelivery)					
Parkway to EDA EMB					
Peak Day Supply to the Region	**5,565**	**5,565**	**5,565**	**5,565**	**5,565**
Excess(Shortfall) by delivery area	16	20	26	34	46

*Supply numbers are as of Sept 2024 when the 2024/25 Plan was approved

Analysis	
Alternatives Identified	**N/A** -There are no alternatives to CTHI/CPMI to serve the MDA. CTHI/CPMI capacity is the only pipeline that can serve Union MDA demands. Due to limited counterparties holding firm capacity into the Union MDA, peaking service is not available to be contracted at the Union MDA.
Evaluation of Alternatives	**N/A -** No evaluation Matrix has been prepared as there are no alterntives to serve the MDA other than this capcity.
Public Policy Considerations	**N/A –** No public policy considerations are applicable as there are no alternatives to serve the MDA other than this capcity.
Rationale	<u>CTHI/CPMI</u> The 2023-2033 Gas Supply Plan supports the ongoing need for CTHI/CPMI capacity to meet design day requirements. The CTHI/CPMI pipeline system has only 4 shippers. It currently has available capacity that can be contracted for 1-year increments. Existing shippers can obtain available capacity by executing an amending agreement at any time. Current Annual Cost (5,771 GJ/d)*:

Pipeline	Monthly Invoice	Currency	Annual Cost	Annual Cost (CAD)
CPMI	$18,057	USD	$216,681	$298,240
CTHI	$121,358	CAD	$1,456,299	$1,456,299
				$1,754,538

Annual cost including reduction of 206 GJ/d of capacity to match existing TCPL Capacity (5,565 GJ/d)*:

Pipeline	Monthly Invoice	Currency	Annual Cost	Annual Cost (CAD)
CPMI	$17,412	USD	$208,946	$287,594
CTHI	$117,026	CAD	$1,404,315	$1,404,315
				$1,691,909
	Cost Reduction			($62,629)

Annual cost including reduction of 294 GJ/d of capacity to align to forecasted design day demand (5,549 GJ/d)*:

Pipeline	Monthly Invoice	Currency	Annual Cost	Annual Cost (CAD)
CPMI	$17,362	USD	$208,346	$286,767
CTHI	$116,690	CAD	$1,400,277	$1,400,277
				$1,687,044
	Cost Reduction			($67,494)

*CPMI is regulated by the CER and CTHI by the FERC. Tolls paid by EGI are per the Tariff and are subject the regulatory approval.

Given the availability of CTHI/CPMI pipeline capacity and cost savings outlined in the scenarios above, the recommendation is to renew 5,565 GJ/d and turn back the previously increased 206 GJ of capacity. This amount of capacity will match the Empress to Centrat MDA capacity total and will closely align to forecasted design day requirements.

<u>TCPL</u>

Reducing CTHI/CPMI capacity by 206 GJ/d to 5,565 GJ/d will result in Enbridge Gas having 16 GJ/d of excess Empress to Centrat MDA capacity between November 1, 2024 and October 31, 2025, based on the 2023-2033 Gas Supply Plan design day forecast of the Union MDA. Capacity on the TCPL Mainline is very scarce, and it is likely that any capacity turned back will be difficult to obtain if required in future years. At this time Enbridge Gas will wait until the 2025-2036 Gas Supply Plan is available and will assess a decision on Empress to Centrat MDA capacity turnback upon review of the updated Union MDA design day demand. If applicable, Enbridge Gas will take action to mitigate the cost of any excess capacity (i.e. temporary or permanent assignments, etc).

Current Annual Cost (5,565 GJ/d):

Pipeline	Monthly Invoice	Currency	Annual Cost (CAD)
TCPL	$6,808	CAD	$81,696

Annual cost savings if a reduction of 16 GJ/d of capacity was contracted (5,550 GJ/d):

Pipeline	Monthly Invoice	Currency	Annual Cost (CAD)
TCPL	$6,790	CAD	$81,475
	Cost Reduction		($221)

Benefits of CTHI/CPMI Capacity

a. Firm transportation purchase provides access to secure and reliable gas supply at a reasonable cost; b. Provides a regulated toll which provides toll certainty on a portion of Enbridge Gas's upstream transportation portfolio; c. Transportation capacity from the Centrat MDA to Union MDA is a flexible option because it can be purchased for a term of 1-year and has renewal rights	
Recommendation Summary	
Reduce CTHI/CPMI contracted capacity by 206 GJ/d and renew 5,565 GJ/d for a term of 1-year to October 31, 2025. Enbridge Gas will re-assess TCPL and CTHI/CPMI needs again before next CTHI/CMPI renewal notice of April 1, 2025.	
Approvals*	
Recommended by:	Christina Haskell, Sr. Advisor, Gas Supply
Approved by:	Amy Mikhaila, Director, Gas Supply
Date of Approval:	Sept 20th, 2024

*Approvals must be in accordance with Delegated Authorities Limits and the Gas Supply Procurement Policies and Practices.

2025 NOVA Gas Transmission Ltd. (NGTL) Transportation Renewal

Rate Zone	Company	Path	Current Capacity
EGD	NOVA Gas Transmission Ltd. (NGTL)	AECO (NIT) to Empress	75,000 GJ/d
Current Contract Expiry	**Renewal Notice Due Date**	**Recommended Renewal Length**	**Recommended Contract Valuation**
October 31, 2025	October 31, 2024	3 Years	~$18 million CAD

Introduction

The purpose of this document is to evaluate and recommend a course of action related to the pipeline contract renewal for NOVA Gas Transmission Ltd (NGTL) for the EGD rate zone.

NGTL has notified Enbridge Gas Ontario that the 1-year renewal notice is coming due on October 31, 2024, for the NGTL firm transportation (FT) contract of 75,000 GJ/d from AECO (NIT) to Empress expiring on October 31, 2025. Renewals are for a minimum of 1 year, however, discounted tolls are offered to shippers who choose to contract for 3 to 4-year terms (95% of toll) and for terms of 5 years or more (90% of toll).

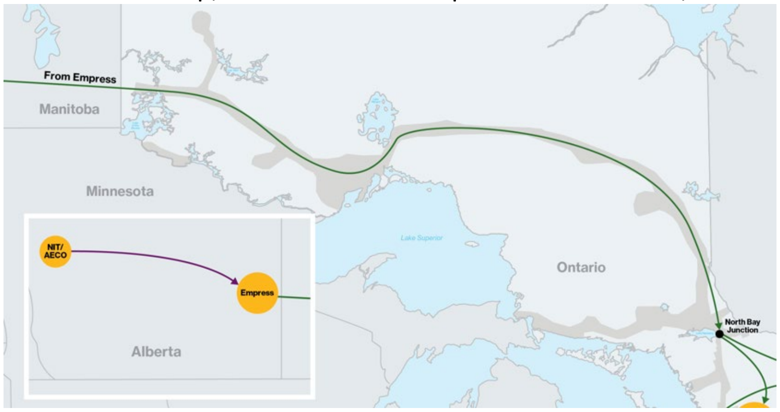
Enbridge Gas Ontario currently holds two contracts on NGTL totaling 125,000 GJ/d:

1) 75,000 GJ/d Expiring Oct 31, 2025
2) 50,000 GJ/d Expiring Oct 31, 2027

Enbridge Gas Ontario has contracts to flow up to 265,000 GJ/d on the TCPL Mainline from Empress for the EGD rate zone until December 31, 2030. Rather than purchasing all supply at Empress, NGTL capacity provides Enbridge Gas with the ability to diversify its gas purchases between Empress and AECO (NIT).

NOVA Gas Transmission Ltd. owns the NGTL system, a natural gas gathering and transportation system in Alberta and northeastern British Columbia. One of NGTL's major delivery points includes Empress/McNeill border where NGTL connects with TransCanada's Canadian Mainline. Enbridge Gas Ontario uses the NGTL system to purchase supply at AECO (NIT) and deliver to the Empress border to then flow onto our existing TCPL Mainline capacity.

In the below map, TCPL Mainline is represented in Green, NGTL is represented in Purple:



Nova Inventory Transfer (NIT) is a natural gas trading hub located in Alberta and is the commercial mechanism that overlays the Nova Gas Transmission Ltd. (NGTL) pipeline network. It is connected to several export markets via interconnected pipelines and connects to multiple storage facilities in Alberta. AECO or AECO-C is often used interchangeably with NIT and is the pricing point used for natural gas sourced from the Western Canadian Sedimentary Basin (WCSB).

NGTL capacity is currently sold out and if Enbridge Gas were to reduce its contract levels on NGTL it would be unlikely to be able to recontract in the foreseeable future.

Analysis

Alternatives Identified

Alternatives identified are to renew the NGTL capacity at 1, 3 or 5 years or not renew the NGTL capacity (shifting our gas purchasing back to Empress).

Evaluation of Alternatives

Table 1: Identified Alternatives

	Option Details					
Option	**Provider(s)**	**Service**	**Pricing**	**Reciept Point**	**Transfer Point**	**Delivery Point**
No Renewal	N/A	N/A				Empress Border
1 or 2 Year Renewal	NGTL	Firm Transport	100% NGTL Toll	AECO (NIT)		Empress Border
3 or 4 Year Renewal	NGTL	Firm Transport	95% NGTL Toll	AECO (NIT)		Empress Border
5+ Year Renewal	NGTL	Firm Transport	90% NGTL Toll	AECO (NIT)		Empress Border

Table 2: Landed Cost Analysis for gas landing at Empress versus AECO (NIT) for 1, 3, and 5-year terms

2025-2030 Transportation Analysis

Route	Point of Supply	Basis Differential $US/mmBtu	Supply Cost $US/mmBtu	Unitized Demand Charge $US/mmBtu	Commodity Charge $US/mmBtu	Fuel Charge $US/mmBtu	100% LF Transportation Inclusive of Fuel $US/mmBtu	Landed Cost $US/mmBtu	Landed Cost $Cdn/GJ	Point of Delivery
(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	(K)	(L)
AECO to Empress 1-year	AECO	-1.302	1.999	0.174	0.00	0.0000	0.174	$2.173	**$2.766**	Empress
Empress 1-year	Empress	-1.119	2.181	0.000	0.00	0.0000	0.000	$2.181	**$2.791**	Empress
AECO to Empress 3-year	AECO	-1.105	2.303	0.167	0.00	0.0000	0.167	$2.470	**$3.146**	Empress
Empress 3-year	Empress	-0.934	2.473	0.000	0.00	0.0000	0.000	$2.473	**$3.166**	Empress
AECO to Empress 5-year	AECO	-1.058	2.647	0.157	0.00	0.0000	0.157	$2.804	**$3.574**	Empress
Empress 5-year	Empress	-0.893	2.812	0.000	0.00	0.0000	0.000	$2.812	**$3.599**	Empress

*$0.015 Per GJ has been deducted off the AECO to Empress Landed Cost $Cdn/GJ column to reflect the value of liquids extraction.

	Table 3: Analysis of Term Length Options | Term Legnth | AECO Landed Cost $Cdn/GJ | Empress Landed Cost $Cdn/GJ | Landed Cost Savings $Cdn/GJ | Savings Per Year for Renewal $Cdn | | 1-year | $2.766 | $2.791 | -$0.025 | -$688,481 | | 3-year | $3.146 | $3.166 | -$0.020 | -$548,794 | | 5-year | $3.574 | $3.599 | -$0.024 | -$666,494 | In all cases of term, there is a small landed cost savings associated with purchases at AECO (NIT) over Empress. As seen in the table above, the renewal term lengths have immaterial saving differences since the projected gas pricing over 3 or 5 years offsets the toll discount associated with 3 or 5-year terms. Therefore, the decision on term will be made based on other factors than the landed cost savings. Table 4: Total Transportation Costs of Alternatives | Term | END DATE | RENEWABLE CD (GJ/D) | Monthly Toll | Monthly Abandonment | Toll Paid with Discount | Total Montly Cost $/GJ | Total Cost (Million CAD) | | 1 Year | 2026-Oct-31 | 75,000 | 6.62000 | 0.17000 | 100% | $6.7900 | $7 | | 3 Year | 2028-Oct-31 | 75,000 | 6.62000 | 0.17000 | 95% | $6.4590 | $18 | | 5 Year | 2030-Oct-31 | 75,000 | 6.62000 | 0.17000 | 90% | $6.1280 | $28 |
Public Policy Considerations	Purchasing transportation with a 3 to 5-year term would not negatively impact EGI's ablitity to comply with public policy.
Rationale	NGTL capacity has provided good value to Enbridge Gas Ontario when purchasing commodity from the Western Canadian Sedimentary Basin over the last few years. From time-to-time the NGTL system experiences planned and unplanned outages between AECO (NIT) and Empress causing the cost of commodity to vary significantly. Being able to procure gas upstream of Empress limits the risk of Alberta purchases being exposed to temporary price disparities within Alberta. RNG is located near AECO (NIT) and NGTL capacity could facilitate procurement of RNG by Enbridge Gas Ontario subject to RNG purchase approval by the OEB. Enbridge Gas Ontario has a commitment to deliver 265,000 GJ/d on TCPL Mainline via North Bay Junction until December 31, 2030; procuring 75,000 GJ/d of AECO (NIT) represents ~28% of this commitment. NGTL system expansions have reduced the forecasted economic value of holding NGTL capacity over the years. The savings in gas costs at AECO (NIT) are roughly equal to the cost of the transportation between AECO and Empress over the next five years, however, the service would continue to provide access to increased number of counterparties and supply point diversity. Landed cost analysis indicates that NGTL capacity provides a small economic benefit and portfolio diversity to ratepayers when the toll reduction and liquids extraction savings are considered. In all cases of term, there is a small landed cost savings associated with purchases at AECO (NIT) over Empress. The renewal term lengths have an immaterial difference in savings. Therefore, the decision on term will be made

	based on other factors. <u>Term Rationale</u> Traditionally this agreement has been renewed at a 3-year term, allowing a balance between toll discounts and contracting flexibility. A 5-year term would better align with the 2030 Empress Capacity renewal. If the NGTL capacity is renewed for 3 years there would be only 2 years remaining for the next renewal to align with the 2030 date. At that time, Enbridge Gas Ontario would have to choose between aligning to this 2030 date and a discount to toll option. Since all the renewal term length options have an immaterial difference in savings, this is not a strong enough benefit to lose contract flexibility.

Benefits of Capacity

a. Contract supports Enbridge Gas Ontario's objective of structuring a portfolio with a diversity of contract terms and supply basins
b. Firm transportation capacity allows for diversity of supply opportunity as an alternative to purchases at Empress
c. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost
d. Landed cost of gas flowing to Empress along this route is competitively priced and has an end date that aligns with the gas year
e. 3-year contract term balances Enbridge Gas Ontario's contract flexibility and administrative burden of annual renewals

Recommendation Summary

Based on the above analysis, Enbridge Gas Ontario's recommendation is to renew the 75,000 GJ/d contract for 3 years. Enbridge Gas Ontario is committed to Empress until at least 2030 and will benefit from having the delivery point and counterparty diversity at AECO that this contract provides. By committing to a longer term, Enbridge Gas Ontario is able to benefit from a lower toll.

The total value of the 3-year renewal is ~$18 million CAD and is within Amy Mikhaila's ATL.

Approvals*

Recommended by:	Christina Haskell, Sr. Advisor, Gas Supply
Approved by:	Amy Mikhaila, Director, Gas Supply
Date of Approval:	October 24, 2024

*Approvals must be in accordance with Delegated Authorities Limits and the Gas Supply Procurement Policies and Practices.

Enbridge CDA Shortfall Recommendation

2024/25 Gas Supply Plan

Introduction

The purpose of this document is to evaluate and recommend a course of action related to a forecasted design day shortfall in the Enbridge CDA, beginning in the 2024/25 gas year.

The 2024/25 Gas Supply Plan is the first plan that incorporates the new design day forecasting methodology approved by the OEB in Phase 1 of the 2024 Rebasing proceeding (EB-2022-0200). A shortfall was identified in the 2024/25 Gas Supply Plan for the Enbridge CDA of approximately 253 TJ/d. This significant shortfall warranted a detailed review of Enbridge Gas' preferred planning approaches to satisfying design day shortfalls.

To date, Enbridge Gas' preferred planning approach is to procure third-party services (peaking services) for up to 2% of design day needs and to evaluate transportation/supply options as they become available to manage future design day growth. Enbridge Gas uses 2% as a guideline for the amount of peaking services held within the portfolio of any delivery area to limit risk in the event that peaking services fail to deliver. In the event of a failure, Enbridge Gas expects to be able to manage the supply shortfall within the parameters of its firm transportation contracts, which accommodates up to 2% consumption above deliveries in a delivery area on a discretionary basis before incurring penalties.

Given that the 2024/25 gas year is the first year in which the new design day forecasting methodology is applied to Gas Supply Plan, and that this resulted in a significant increase to the design day shortfall for the Enbridge CDA, Enbridge Gas re-evaluated its risk tolerance for peaking services in the Enbridge CDA for a temporary term until more experience is gained with the year-to-year design day forecast results under the new methodology. For the 2024/25 gas year, Enbridge Gas will replace its 2% tolerance for peaking services to an amount equivalent to the statistical variation within the design day model. Enbridge Gas used statistical validation analysis of the design day model to determine the deviation between actual and forecasted design day demand. The statistical analysis resulted in a 2.7% variation, which Enbridge Gas will use as the basis for increasing reliance on peaking services to approximately 2.7% of total demand in the Enbridge CDA. The increase in risk tolerance for peaking services reduces the amount that would otherwise be contracted as higher reliability, longer-term services that often come at higher fixed costs. It is important to note that while peaking services have low fixed costs, they are typically extremely expensive in the event supply is called upon and may not result in a lower total cost.

The 2024/25 Design Day Demand Forecast and Supply Shortfall is outlined below:

Summary of Enbridge CDA 2025 to 2029 Budget Design Day Report (GJ)

		Jan-25	Jan-26	Jan-27	Jan-28	Jan-29
Peak Day Demand		3,578,330	3,594,139	3,622,265	3,624,069	3,622,620
TCPL						
	Long-Haul	5,000	5,000	5,000	5,000	5,000
	Niagara Supply	200,000	200,000	200,000	200,000	200,000
	Short-Haul	587,218	587,218	587,218	587,218	587,218
	STS	283,892	283,892	283,892	283,892	283,892
Total TCPL		1,076,110	1,076,110	1,076,110	1,076,110	1,076,110
Dawn Parkway		2,193,961	2,193,961	2,193,961	2,193,961	2,193,961
Other Supply		30,209	30,209	30,209	30,209	30,209
OTS Deliveries		25,162	12,884	12,884	12,884	12,884
	Total Supply	3,325,442	3,313,164	3,313,164	3,313,164	3,313,164
	CDA Shortfall	252,888	280,975	309,101	310,905	309,456
	CDA Shortfall (% of demand)	7.07%	7.82%	8.53%	8.58%	8.54%
Proposed Solution:						
Peaking Supply		97,289	TBD	TBD	TBD	TBD
Firm transportation capacity required		155,599	TBD	TBD	TBD	TBD
Total Incremental Supply		**252,888**				
Peaking Supply - % of Demand		2.7%				

Enbridge Gas plans to meet the 2024/25 Gas Supply Plan Enbridge CDA shortfall as follows:

- Peaking services of ~97,000 GJ/d
- Firm Transportation services (including third-party assignments) of 155,599 GJ/d

The peaking services will be obtained through Enbridge Gas' regular annual peaking service RFP process. The below Analysis and Recommendation relates to the 155,599 GJ/d of transportation services required to meet design day demands for the Enbridge CDA.

Enbridge Gas will assess a proposed solution for the Enbridge CDA shortfall for Jan-26 and later years following the completion of the annual gas supply planning process in future years.

Analysis	
Alternatives Identified	Enbridge Gas reviewed and evaluated several alternatives for meeting the design day shortfall: <u>Long-Haul Alternatives</u> 1) TCPL Empress to Enbridge CDA FT capacity made available through a July 5 – August 8, 2024, existing capacity open season (ECOS). • Volume offered by TCPL is limited to 84,457 GJ/d. Therefore, this alternative must be combined with other alternatives to meet the forecasted design day shortfall. • While the ECOS did not specify a minimum term for this alternative, Enbridge Gas will need to compete with other bidders for capacity along the TCPL Mainline. A bid term of 6 years is expected to be competitive against other in-demand paths available in the open season. • FT capacity contains renewal rights and therefore secures Enbridge Gas' access to this capacity into the future as required. • This alternative is evaluated further throughout this recommendation document and included in the cost-effectiveness analysis at Attachment 1. • Details of the TCPL ECOS are included at Attachment 2. 2) Third-party assignment of TCPL Empress to Enbridge CDA FT capacity for various winter terms. • Volume offered is limited to 84,457 GJ/d. Therefore, this alternative must be combined other alternatives to meet the forecasted design day shortfall. The capacity offered by the third-party is the same capacity offered in Alternative #1, and therefore cannot be combined with that Alternative to meet the entire requirement. • This alternative results in an annual temporary assignment of FT capacity for various winter terms in exchange for a demand charge payable to the assignor. • This alternative contains renewal rights and therefore secures Enbridge Gas' access to this capacity into the future as required. • This alternative is evaluated further throughout this recommendation document and details of this third-party assignment are included in the cost-effectiveness analysis at Attachment 1.

	<u>Short-Haul Alternatives</u> 3) Enbridge Gas Dawn to Parkway capacity coupled with TCPL Parkway to Enbridge CDA FT capacity • No Dawn Parkway System capacity is available. Therefore, this alternative has not been evaluated further. 4) Enbridge Gas Dawn to Enbridge CDA capacity • No Dawn Parkway System capacity is available. Therefore, this alternative has not been evaluated further. 5) TCPL Niagara to Enbridge CDA capacity • No TCPL Niagara to Enbridge CDA system capacity is available. Therefore, this alternative has not been evaluated further. 6) Third-party assignment of TCPL Niagara to Enbridge CDA FT capacity for various winter terms, coupled with a firm commodity purchase at Niagara. • This alternative results in an annual temporary assignment of FT capacity for various winter terms at no cost to Enbridge Gas. Enbridge Gas must purchase gas commodity from the third-party at Niagara at a fixed premium to the Dawn daily index price as published by S&P Global Platts. • This alternative allows for annual volume increases over a 5-year term up to a maximum of 255,618 GJ/d. • This alternative contains renewal rights and therefore secures Enbridge Gas' access to this capacity into the future as required. Renewals after the 5-year term are subject to a 10% price escalation applied to the supply price premium over Dawn. • This alternative is evaluated further throughout this recommendation document and details of this third-party assignment and gas purchase are included in the cost-effectiveness analysis at Attachment 1. <u>Hybrid Alternatives</u> Several of the alternatives, as noted above, must be combined with other alternatives to meet the total shortfall amount. Furthermore, certain alternatives have operational impacts that significantly limit the flexibility of Enbridge Gas' overall Gas Supply Plan if deployed at their maximum potential volume. Enbridge Gas has therefore evaluated multiple hybrid alternatives, consisting of various combinations of the most cost-effective alternatives identified above. 7) A combination of 20,000 GJ/d of TCPL Empress to Enbridge CDA FT capacity (identified in Alternative #1 above) and 135,599 GJ/d of third-party assignment of TCPL Niagara to Enbridge CDA FT capacity for December to March, coupled with a firm commodity purchase at Niagara (identified in Alternative #6 above). 8) A combination of 40,000 GJ/d of TCPL Empress to Enbridge CDA FT capacity (identified in Alternative #1 above) and 115,599 GJ/d of third-party assignment

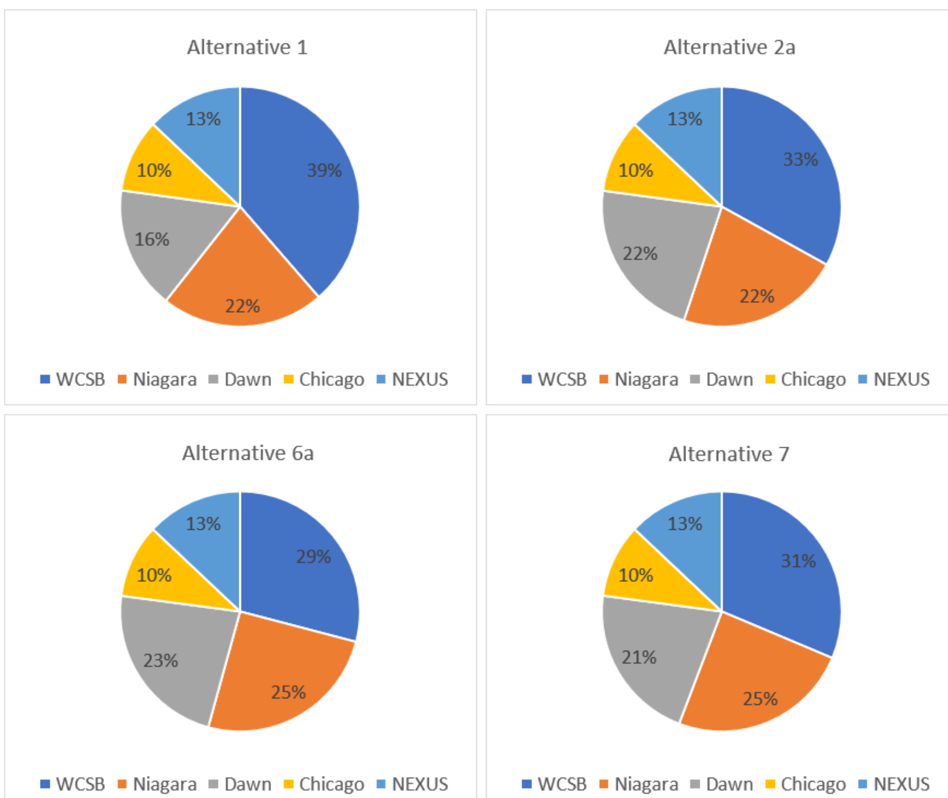
	of TCPL Niagara to Enbridge CDA FT capacity for December to March, coupled with a firm commodity purchase at Niagara (identified in Alternative #6 above). The hybrid alternatives are included in the cost-effectiveness analysis at Attachment 1.
Evaluation of Alternatives	Enbridge Gas performed a detailed evaluation of each available alternative, as summarized below: **Cost-Effectiveness:** • The cost of each available alternative was evaluated by creating various scenarios of the 2024/25 Gas Supply Plan which included each of the alternatives and compared the resulting total cost of the plan to a base case whereby peaking service is used to fill the entire shortfall. Details of the cost-effectiveness comparison can be found at Attachment 1 to this recommendation. • Based on the outcome of this analysis, the most cost-effective Alternative is #1 (TCPL Empress to Enbridge CDA FT capacity). The next most cost-effective non-hybrid alternative is #6a (Third-party assignment of TCPL Niagara to Enbridge CDA FT capacity for December to March, coupled with a firm commodity purchase at Niagara). • The most cost-effective hybrid alternative is Alternative #8. This hybrid alternative contains a modest cost increase relative to Alternative #1 but does not reduce the overall Gas Supply Plan's flexibility below acceptable levels. • The cost-effectiveness of all alternatives with long-haul components (#1, #2, #7, #8) are heavily reliant on the Dawn-Empress basis spread. Reduction of this spread can materially increase the cost of long-haul alternatives such that it would no longer be the lowest cost alternative. Additionally, long-haul capacity is subject to future TCPL toll changes. • Alternative #6 contains a very high level of cost certainty as the commodity premium is fixed over a 5-year term. **Reliability & Security of Supply:** • Each of the alternatives have been assessed as having a high degree of reliability and security of supply. This has a neutral impact on Enbridge Gas' portfolio, which includes highly reliable services to meet design day needs. • Alternative #1 and #2 provide firm capacity from a liquid supply point (Empress) to the Enbridge CDA. Enbridge Gas has many years of experience purchasing supply at Empress and has no concerns with being able to fill this capacity as needed. • Alternative #6 provides firm capacity from a sufficiently liquid supply point (Niagara) to the Enbridge CDA. While Niagara is not as liquid as Empress, this alternative is packaged with a firm purchase of gas supply for the full term and capacity of the assignment. In the event of default or failure to deliver of this supply by the third-party, Enbridge Gas has many years of experience purchasing supply at Niagara and has no significant concerns with being able to fill this capacity if required.

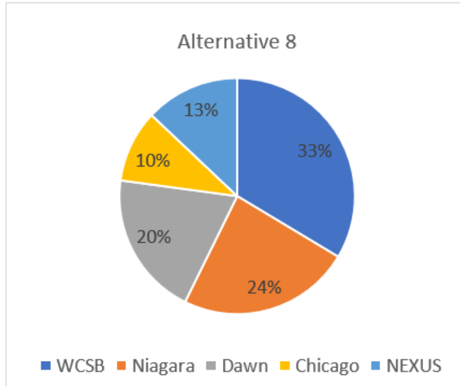
- Both hybrid alternatives (#7 and #8) result in a mix of highly reliable services discussed above.

Supply Diversity:

- Alternatives #1, #2, #7, and #8 result in additional supply diversity to the Enbridge CDA by increasing Empress supply. At the portfolio level, Alternatives #7 and #8 are preferrable as they result in a lower increase to Empress supply, which already makes up a large portion of Enbridge Gas' overall gas supply commodity portfolio.
- Alternatives #6, #7, and #8 result in a reduction of supply diversity to the Enbridge CDA, as it increases an already significant source of supply (Niagara) to this area. At the portfolio level, Alternatives #7 and #8 are preferrable as they result in a lower increase to Niagara supply, which already makes up a large portion of Enbridge Gas' overall gas supply commodity portfolio.
- Alternatives #6, #7, and #8 result in a significant portion of the incremental supply coming from a single supplier. However, this supplier does not currently make up a material portion of Enbridge Gas' pre-existing commodity purchase portfolio and therefore these alternatives do not materially impact supplier diversity.

Figure 1: Supply Diversity Across Available Alternatives





Note: Information in Figure 1 assesses supply diversity impacts on 84,457 GJ/d contracting requirement. See Attachment 1 for further discussion.

Flexibility:

- While Alternative #1 does not have a minimum term, Enbridge Gas will compete in the ECOS for this capacity with other bidders who are seeking capacity anywhere between Empress and the Enbridge CDA. Several shippers on TCPL have capacity from North Bay Junction to export points on the TCPL Mainline and may wish to obtain capacity from Empress to North Bay Junction to connect their capacity to a more liquid supply point. Furthermore, marketers have shown strong demand for TCPL Mainline capacity to the SSDA in previous open seasons, bidding for significant terms. In order to provide a competitive bid for capacity, Enbridge Gas expects a bid of at least 6 years will provide a reasonable chance of success against other bidders. Once obtained, this capacity contains renewal rights, but no ability to increase or decrease capacity from year to year.
- Alternative #2 and #6 have initial terms of 5 years with renewal rights. Alternative #2 does not contain rights to increase or decrease volume contracted. Alternative #6 contains rights to increase volume contracted year to year up to 255,618 GJ/d provided adequate notice is provided to the counterparty.
- Alternative #1 is only economically efficient if filled with lower cost Empress supply every day of the year. Contracting this alternative for significant volumes reduces Enbridge Gas' flexibility to reduce planned summer supplies in response to warmer than normal winters and the resulting high inventory position. This is because reducing summer purchases at Empress will forgo the significant commodity cost benefit that makes this alternative cost-effective relative to other options. In warmer than normal years, Enbridge Gas requires purchasing flexibility in planned summer supplies (at Dawn or on upstream pipelines that aren't required to be run at a 100% load factor (i.e. Vector)) to have the required flexibility to mitigate projected supply length. Over the past ~5 years, Enbridge Gas has required up to 33 PJ of summer supplies to mitigate inventory length for the EGD rate zone. To maintain this summer flexibility, Enbridge Gas recommends Alternative #1 be limited to 40,000 GJ/d. Contracting for amounts above this level could result in higher cost, since lower cost Empress supply may not be acquired in summer

months which would reduce the impact of the higher FT demand charges relative to other options. Therefore, the hybrid Alternatives #7 and #8 are preferrable to Alternative #1.

- Both hybrid alternatives allow for sufficient flexibility in Enbridge Gas' gas supply plan.

Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Cost	Available Capacity
Alternative 1: Long-haul	→	↓	↑	See Attachment 1	Yes
Alternative 2: Third Party (Long Haul Assignment)	→	→	↑	See Attachment 1	Yes
Alternative 6: Third Party (Niagara Assignment)	→	↑	↓	See Attachment 1	Yes
Alternative 7: Hybrid (20 TJ LH, 136 TJ Niagara Assignment)	→	↑	↓	See Attachment 1	Yes
Alternative 8: Hybrid (40 TJ LH, 116 TJ Niagara Assignment)	→	↑	↓	See Attachment 1	Yes

Note: Ratings for Reliability, Flexibility, and Diversity assess each option's impact compared to the existing design day portfolio for the Enbridge CDA (i.e. status quo)

Public Policy Consideration

- No alternative results in a need to expand natural gas infrastructure.
- Alternatives containing long-haul capacity involve transportation along a longer path and therefore have marginally higher fuel requirements (i.e marginally higher emissions associated with transportation fuel).

Recommendation
Based on the evaluation outlined above, Alternative #8 (a combination of 40,000 GJ/d of TCPL Empress to Enbridge CDA FT capacity and 115,599 GJ/d of third-party assignment of TCPL Niagara to Enbridge CDA FT capacity for December to March, coupled with a firm commodity purchase at Niagara) is the recommended alternative to meet the design day shortfall in the Enbridge CDA. The recommended approach is a cost-effective alternative, provides for a high degree of reliability and security of supply, provides renewal rights to ensure capacity availability into the future, provides annual flexibility with regard to volume contracted and can therefore be leveraged to meet future design day growth in the Enbridge CDA, and allows for sufficient summer purchasing flexibility such that Enbridge Gas can manage supply length that may result from warmer than normal winters. The remaining shortfall of ~97 TJ/d will be contracted as peaking supply. The approval for peaking supply will be obtained as part of Enbridge Gas' general peaking RFP at a later date. The recommendation results in the following required purchases: 1) 40,000 GJ/d of TCPL Empress to Enbridge CDA FT capacity, bid into the ECOS for a term of 6 years. The total forecast contract value is ~$110 million CAD. 2) 115,599 GJ/d of third-party assignment of TCPL Niagara to Enbridge CDA FT capacity for December to March for a 5-year term, coupled with a firm commodity purchase at Niagara. The total forecast contract value is ~$263 million USD.

Approvals*	
Recommended by:	Christina Haskell, Senior Advisor, Gas Supply Dave Janisse, Manager, Gas Supply Acquisition Amy Mikhaila, Director, Gas Supply
Approved by:	Jim Redford, VP Energy Services
Approval date:	August 7, 2024

*Contracts must be executed in accordance with Delegated Authorities Limits and the Gas Supply Procurement Policies and Practices.

Attachment 1

Cost-Effectiveness Analysis

Enbridge Gas evaluated the cost-effectiveness of each alternative using 84,457 GJ/d, the maximum capacity available from the TCPL ECOS. This approach provided for a comparison of the TCPL ECOS against available alternatives. Enbridge Gas used the 2024/25 Gas Supply Plan to calculate changes in forecasted 5-year portfolio costs. Table 1 is a summary of the cost-effectiveness of 84,457 GJ/d for each alternative:

Table 1 – Summary of 2024/25 Gas Supply Plan 5-Year Forecast Portfolio Costs Impacts

Alt #	Description	Capacity available?	5-Year Forecasted Portfolio Cost Increase ($ million)
Long-haul			
1	TCPL Empress to Enbridge CDA FT capacity	Yes	23.7
2	Third-party assignment of TCPL Empress to Enbridge CDA FT capacity	Yes	
2a	November to March; 88% of TCPL annual toll		76.5
2b	December to March; 83% of TCPL annual toll		87.6
2c	January to March; 76% of TCPL annual toll		90.1
2d	December to February; 75% of TCPL annual toll		83.0
2e	January to February; 68% of TCPL annual toll		84.5
Short-haul			
3	Enbridge Gas Dawn to Parkway capacity coupled with TCPL Parkway to Enbridge CDA FT capacity	No	
4	Enbridge Gas Dawn to Enbridge CDA capacity	No	
5	TCPL Niagara to Enbridge CDA capacity	No	
6	Third-party assignment of TCPL Niagara to Enbridge CDA FT capacity	Yes	
6a	December to March; Dawn commodity price + $0.50 USD/GJ		31.4
6b	January to March; Dawn commodity price + $0.75 USD/GJ		37.3
6c	January to February; Dawn commodity price + $1.30 USD/GJ		39.5
7	A combination of 20,000 GJ/d of TCPL Empress to Enbridge CDA FT capacity (identified in Alternative #1) and 64,457 GJ/d of third-party assignment of Niagara to Enbridge CDA FT capacity for December to March, coupled with a firm commodity purchase at Niagara (identified in Alternative #6)	Yes	27.1
8	A combination of 40,000 GJ/d of TCPL Empress to Enbridge CDA FT capacity (identified in Alternative #1 above) and 44,457 GJ/d of third-party assignment of Niagara to Enbridge CDA FT capacity for December to March, coupled with a firm commodity purchase at Niagara (identified in Alternative #6 above)	Yes	24.3

The only available cost-effective alternative to meet the incremental Enbridge CDA shortfall of 71,142 GJ/d (155,599 GJ/d firm capacity requirement less 84,457 GJ/d assessed in Table 1) is Alternative #6. Therefore, the portfolio cost increase associated with the incremental shortfall of 71,142 GJ/d does not impact the outcome of the cost-effectiveness analysis. For each alternative, an incremental portfolio cost of approximately $29.4 million over 5 years associated with contracting for the incremental 71,142

GJ/d under Alternative #6 can be added to each alternative identified in Table 1 to arrive at the total portfolio cost associated with contracting for the firm capacity requirement.

Attachment 2

TCPL ECOS

Canadian Mainline Existing Capacity Open Season

ECOS July 5, 2024 – August 8, 2024

TransCanada PipeLines Limited's ("**TCPL**") Canadian Mainline pipeline system ("**Mainline**") is posting an Existing Capacity Open Season ("**ECOS**") for Firm Transportation ("**FT**") and Non-Renewable Firm Transportation ("**FT-NR**") capacity as determined by a recent operational reassessment and as per section 4.2 of the Transportation Access Procedures ("**TAPs**"). The available capacity may vary for future start dates. Capacity may be re-evaluated and is subject to change. Further capacity analysis is ongoing and any potential increase to capacity would be offered in a future ECOS. Please contact your Marketing Representative for details. Capitalized terms not defined within this posting have the meaning ascribed to them under the TCPL Mainline Transportation Tariff ("**Tariff**").

The System Segments offered in this ECOS share a common system capacity. A successful bid on one System Segment may also reduce the capacity on another System Segment in this ECOS.

TCPL is accepting bids for FT and FT-NR service to the delivery points up to the capacities specified in Tables 1 and 2. Segments not listed in Tables 1 and 2 may have capacity analysis ongoing, please contact your Marketing Representative.

Table 1: Available Capacity(1) (2)

Posted System Segments(3) (4)	FT Capacity (GJ/d)	FT-NR(5) Capacity (GJ/d)
	Starting November 1, 2024	Starting November 1, 2025
Empress to Domestic		
South Saskatchewan Delivery Area (SSDA)	315,000	29,617
Manitoba Delivery Area (MDA)	315,000	29,617
Western Delivery Area (WDA)	87,688	0
Northern Delivery Area (NDA)	87,688	0
Enbridge CDA	84,457	0
Union NCDA, Union ECDA, and Union Parkway Belt	84,457	0
Eastern Delivery Area (EDA)(6)	0	0
Empress to Export		
Emerson 1	315,000	29,617
Emerson 2	315,000	29,617
Cornwall	0	0
Iroquois	0	0
Napierville	0	0
Phillipsburg	0	0
East Hereford	0	0

Table 2: Available Capacity(1) (2)

Canadian Mainline Existing Capacity Open Season

Posted System Segments[3]	FT Capacity (GJ/d) Starting November 1, 2024
Niagara to	
Kirkwall[8]	1,000
Chippawa to	
Kirkwall[8]	1,300
Iroquois to	
Other points, subject to downstream capacity	26,952 [7]

1) The paths above contain shared capacity, and as such, the capacity available for one path may be impacted by bids to another path sharing the same capacity.

2) Customers and prospective customers are responsible for ensuring sufficient upstream and downstream capacity is available.

3) TCPL does not accept bids for firm service from export points unless otherwise listed in the tables above.

4) Bayhurst 1, Herbert, Richmound, Shackleton, Success, Suffield 2, and Welwyn are also valid receipt points for the delivery points listed in Table 1, subject to metering capacity.

5) As a result of contract sales that start in the future, the Canadian Mainline is offering existing capacity as Non-Renewable Firm Transportation ("FT-NR"). Customers can contract for FT-NR for a minimum term of one year, or with annual increments, or in the case of FT-NR up to the FT-NR service termination date, as per Section 4.2 of the TAPs. FT-NR service is available for up to 29,617 GJ/d from November 1, 2025 with a termination date of March 31, 2027, or up to 15,000 GJ/d from November 1, 2025 with a termination date of March 31, 2028, or up to 5,000 GJ/d from November 1, 2025 with a termination date of March 31, 2029 for the system segments to Empress to SSDA, MDA, and Emerson 1 and Emerson 2. These FT-NR available capacities are not additive however, The FT-NR available capacity is incremental to the FT available capacity offered.

6) EDA Capacity applies to Enbridge EDA, Union EDA, KPUC EDA, and Energir EDA.

7) This is the available capacity at the Iroquois Receipt meter station. Capacities available to downstream points are subject to downstream segment capacities.

8) Niagara to Kirkwall and Chippawa to Kirkwall capacities are not additive.

Open Season & Bidding Procedure Highlights

- Bids must be received by TCPL no later than 8:00 a.m. MDT (Calgary time) on August 8, 2024.
- The Mainline Rate Rider is not applicable for allocating capacity to the ECOS but will be applied to customer billing in accordance with Mainline Tariffs.
- TCPL will assess all bids in accordance with Section 4.4 of the TAPs.
- System Segment Capacity:
  - Some posted segments share a common capacity within the ECOS. A successful bid on one System Segment may reduce the capacity of another System Segment. Any bids that pertain to common capacity will be evaluated together for allocation purposes.

- Each capacity segment requested must be on an individual bid form.
- Bids can be conditioned on another bid in the ECOS:
  - If an ECOS bid is conditional on another ECOS bid, and if either ECOS bid requires a reduction to the maximum daily quantity, the maximum daily quantity for the other ECOS bid will be reduced by the same percentage. Please submit each set of conditional bids in a separate bid, to provide clarity on which bids are related.
- Minimum Acceptable Quantity: May be specified by the bidder if prorating capacity is necessary.
- Please refer to the TAPs for information on bid deposit requirements.
- TCPL will notify successful Service Applicants in accordance with s. 4.5 of TAPs. All bids received will be evaluated together for allocation purposes, and contracts will then be issued to successful Service Applicants who will then have 3 Banking Days to return the signed contract to TCPL.
- TCPL requires acceptable financial assurances. Please refer to Section XXIII Financial Assurances of the General Terms and Conditions of the Tariff.

How to Bid

Service applicants must submit a binding bid via the Paper Version or Electronic Version to TCPL's Mainline Contracting Department by email at mainline_contracting@tcenergy.com or by fax at 1.403.920.2309 and must be received by 8:00 a.m. MDT (Calgary time) (10 a.m. EST) on August 8, 2024. All bids received will be evaluated together for allocation purposes and contracts will then be issued to successful Service Applicants who will then have three Banking Days to return the signed contract to TCPL.

Questions

If you have any questions, please contact your Marketing Representative.

Toronto

Amelia Cheung
Phone: 1.416.869.2115
Email: amelia_cheung@tcenergy.com

Tim Stringer
Phone: 1.416.869.2177
Email: tim_stringer@tcenergy.com

Rory Black
Phone: 1.437.518.2648
Email: rory_black@tcenergy.com

Chelsea Medcalfe
Phone: 1.416.869.2103
Email: chelsea_medcalfe@tcenergy.com

Calgary

Tyler Cook
Phone: 1.403.920.6021
Email: tyler_cook@tcenergy.com

Kelsey Johannson
Phone: 1.403.920.5956
Email: kelsey_johannson@tcenergy.com

Vanessa Swick
Phone: 1.587.432.8051
Email: vanessa_swick@tcenergy.com

Kevin D'Souza
Phone: 1.403.920.7915
Email: kevin_dsouza@tcenergy.com

Goran Miljevic
Phone: 1.403.920.5569
Email: goran_miljevic@tcenergy.com

Holly Waldorf
Phone: 1.403.920.8086
Email: holly_waldorf@tcenergy.com

Jim Tran
Phone: 1.403.920.5181
Email: jim_tran@tcenergy.com

Appendix

LINKS to Additional Information:

- Existing Capacity Open Season Paper Bid Form
- Existing Capacity Open Season Electronic Bid Form
- Mainline Tariffs: Toll Schedules & Pro Forma Contracts
- TAPs: Transportation Access Procedure
- Index of Customers: showing recent contracts and renewals
- Mainline Tolls and Abandonment Surcharges - Effective January 1, 2024
- Other TCPL Information: http://www.tccustomerexpress.com/index.html

GST Procedures

TCPL is required to charge the Goods and Services Tax (GST) or Harmonized Sales Tax (HST), whichever is applicable, on transportation of gas that is consumed in Canada. Shippers may zero-rate GST or HST on contracts intended to serve an export market by making a Declaration on the nomination line in Gas Customer Transactional System (GCTS). Shippers may also provide a declaration for any Unutilized Demand Charges (UDC). For more information, please see GST/HST Procedures.

2025 Panhandle Eastern Pipe Line Renewal

Rate Zone	Company	Path	Current Capacity
Union South	Panhandle Eastern Pipe Line Company, LP	Markwest to Ojibway	35,000 Dth/d
Current Contract Expiry	**Renewal Notice Due Date**	**Recommended Renewal Length**	**Recommended Contract Valuation**
October 31, 2025	October 31, 2024	2 Years	~$12 million USD

Introduction

The purpose of this document is to evaluate and recommend a course of action related to the pipeline contract renewal for Panhandle Eastern Pipe Line (PEPL).

Energy Transfer has notified Enbridge Gas Ontario that the 1-year renewal notice is coming due on October 31, 2024, for the firm transportation (FT) contract expiring on October 31, 2025.

Enbridge Gas Ontario's Panhandle System interconnects with the Energy Transfer's PEPL system at Ojibway. Long-haul PEPL shippers can source gas from the Panhandle Field Zone located in Texas, Oklahoma, and Kansas. Other PEPL supply locations include interconnects with the Rockies Express ("REX"), NEXUS and ROVER pipelines. Ojibway is the final delivery point along the PEPL system.

Enbridge Gas Ontario holds two contracts for a total of up to 57,000 Dth/d (60 TJ/d) for sales service customers on PEPL:

1) 35,000 GJ/d Expiring Oct 31, 2025
2) 22,000 GJ/d Expiring Oct 31, 2027

These volumes are required to arrive on Design Day to meet the firm demands of Enbridge Gas Ontario's Panhandle System and Gas Supply Plan.

The following addresses the renewal option under Right of First Refusal ("ROFR") for one of the two contracts in the amount of 35,000 Dth/d.

The firm demand for natural gas from new and existing general service and contract rate customers has continued to grow on Enbridge Gas Ontario's Panhandle System over the past decade. Approximately 9% or 60 TJ/d of the demand on the Panhandle System is served through Enbridge Gas Ontario sales service deliveries at Ojibway on Design Day. Ojibway is not a liquid trading point, but rather a trans-shipment point between two pipeline systems. In order to deliver supply to Ojibway, market participants must contract for transportation on the PEPL system to access more liquid upstream natural gas markets.

Ojibway enables access to natural gas supplies shipped on the Panhandle system and contributes to the security and diversity of Enbridge Gas Ontario's natural gas supply portfolio and supply to the Dawn Hub.

Analysis

Alternatives Identified

There are no other alternatives identified as the 57,000 Dth/d (60 TJ/d) is required at Ojibway to meet Design Day requirements and there is no other pipeline interconnect at Ojibway.

Evaluation of Alternatives

A landed cost analysis has not been prepared as the capacity is required operationally and there are no upstream transportation alternatives. Shorter paths on PEPL such as Defiance are currently sold out.

Table 1: Total Transportation Cost of Recommendation

Contract Number	Shipper	Portfolio	Start Date	End Date	Service Type	Reciept Point	Delivery Point	Renewable Capacity (MMBtu/Day)	Current Transportation Rate (USD/MMBtu)	Annual Cost (USD)	2 Year Renewal (Million USD)
19605	Enbridge Gas Inc.	UGL	2025-Nov-01	2027-Oct-31	FT	Markwest	Ojibway	35,000	0.46390	$5,926,323	$12

Public Policy Considerations

N/A – No public policy considerations are applicable

Rationale

Per the Panhandle Regional Expansion Project (PREP, EB-2022-0157), the 60 TJ/d of capacity contracted by Enbridge Gas Ontario for delivery to Ojibway from the PEPL system is fundamentally an IRPA that is being utilized today.

Enbridge Gas Ontario defines commercial alternatives as any supply-side service provided by a third-party. Commercial alternatives include, but are not limited to, upstream transportation services to enable the delivery of supply to a point on Enbridge Gas Ontario's system, peaking supply transactions, delivered supply transactions, exchanges, and third-party assignments of transportation capacity. The suitability of commercial alternatives to meet transmission system needs is dependent on the contractual terms of the agreement and therefore is assessed on a case-by-case basis.

Enbridge Gas Ontario relies on firm sales service deliveries from the Gas Supply Plan to reduce the need for physical transportation from the Dawn Hub, and therefore to reduce the need for pipeline facilities. Ojibway enables access to natural gas supplies shipped on the Panhandle Eastern system and contributes to the security and diversity of Enbridge Gas Ontario's natural gas supply portfolio and supply to the Dawn Hub.

Table 2: Ojibway Import Capability to Enbridge Gas Panhandle System

Capacity	Long-Term (Annual) [TJ/d]	Short-Term (Winter-Only) [TJ/d]
Total Ojibway Import Capability	108	126
Gas Supply (Included in Design Day)	60	60
Ojibway to Dawn C1 Service[10]	37	37
Available Import Capacity	11	29

The PEPL volumes are required to arrive on Design Day to meet the firm demands of Enbridge Gas Ontario's Panhandle System and Gas Supply Plan. Therefore, renewal of this 35,000 Dth/d is required. PEPL is regulated by the FERC. Tolls paid by Enbridge Gas Ontario are per the Tariff and are subject to regulatory approval.

	Typically, renewal term agreed to by PEPL would be 3-5 years. However, in April 2025 Enbridge Gas Ontario will be inspecting the river crossing associated with this contract. Enbridge and Panhandle mutually agreed a 2-year renewal is beneficial. A 2-year renewal will provide additional contracting flexibility at a time when the health of the assets are being investigated. Also, with a renewal end date of Oct 31, 2027, this contract will now align with Enbridge Gas Ontario's 22,000 Dth/d contract. At next renewal the entire PEPL capacity be evaluated at once.

Benefits of Capacity

a. Contract supports Enbridge Gas Ontario's objective of structuring a portfolio with a diversity of contract terms, supplier and supply basins
b. Firm transportation capacity allows for diversity of supply purchase location to the Gas Supply Plan as well as diversity of suppliers to meet the firm requirements for delivery to Ojibway
c. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost
d. 2-year contract term maintains Enbridge Gas Ontario's contract flexibility
e. Provides a fixed-rate toll which provides toll certainty on a portion of EGI's upstream transportation portfolio

Recommendation Summary

Based on the above analysis, Enbridge Gas Ontario's recommendation is to renew the 35,000 Dth/d contract for 2 years. The PEPL capacity is required as Enbridge Gas Ontario requires this quantity of gas arrive at Ojibway for Design Day operational requirements.

The total value of the 2-year renewal is ~$12 million USD (provided in Table 1) and is within Christina Haskell's ASL.

Approvals*

Recommended by:	Christina Haskell, Sr. Advisor, Gas Supply
Approved by:	Amy Mikhaila, Director, Gas Supply
Date of Approval:	October 24, 2024

*Approvals must be in accordance with Delegated Authorities Limits and the Gas Supply Procurement Policies and Practices.

2025 Vector Pipeline Renewal

Rate Zone	Company	Path	Current Capacity
Union South	Vector Pipeline L.P.	Chicago to Dawn	80,000 Dth/d
Current Contract Expiry	**Renewal Notice Due Date**	**Recommended Renewal Length**	**Recommended Contract Valuation**
October 31, 2025	October 31, 2024	3 Years	~$15 million USD

Introduction

The purpose of this document is to evaluate and recommend a course of action related to the pipeline contract renewal for Vector pipeline.

Vector Pipelines (Vector) has notified Enbridge Gas Ontario that the 1-year renewal notice is coming due on October 31, 2024, for the firm transportation (FT) contract of 80,000 Dth/d from Chicago to Dawn expiring on October 31, 2025.

Enbridge Gas Ontario currently holds four contracts on the Vector pipeline from Chicago to Dawn (through St. Clair) totaling 185,000 MMBtu/d:

1) 80,000 MMBtu/d expiring Oct 31, 2025 (Union South)
2) 20,000 MMBtu/d expiring Oct 31, 2026 (Union South)
3) 20,000 MMBtu/d expiring Oct 31, 2026 (EGD)
4) 65,000 MMBtu/d expiring Oct 31, 2027 (EGD)

The expiring contract includes renewal rights whereby Enbridge Gas Ontario has the option to renew the capacity for an additional three years at the existing negotiated toll of $0.165 US/Dth by providing notice to Vector no later than 12 months prior to the contract expiration.

As outlined in the Sarnia Expansion Pipeline Project[1], 5-Year Gas Supply Plan[2], Sarnia Industrial Line (SIL) Reinforcement[3], 2023 Annual Gas Supply Plan Update[4], 2023 Annual Gas Supply Plan Update[5] and OEB Vector Contracting Decision[6] capacity on the Vector pipeline to Dawn provides a competitively priced, reliable and flexible transportation option that offers supply diversity at Chicago as well as along the Vector pipeline route, and also provides an important secondary benefit of maintaining Enbridge Gas's ability to serve the SIL, which is used to support gas deliveries to both general service and contract customers across the Sarnia region.

One of the important strategic considerations for the Gas Supply Plan, is to evaluate transportation alternatives. EGI evaluates alternatives for design day capacity shortfalls and average day demand changes using its planning principles of: reliability, flexibility, diversity, and cost.

[1] EB-2014-0333, p.4-11.
[2] EB-2019-0137, p.91-94.
[3] EB-2019-0218, p.9-15.
[4] EB-2023-0072, Appendix F.
[5] EB-2024-0067, p. 38-41
[6] EB-2023-0326.

Analysis	
Alternatives Identified	The Vector capacity that is up for renewal meets average day requirements and is also relied upon to meet demands on the SIL. Vector capacity has been evaluated against other options that are able to serve the SIL, which include GLGT, NEXUS, Rover and St. Clair to Dawn.
Evaluation of Alternatives	A landed cost analysis was prepared for Union South using the Q3 2024 fundamentals-based market pricing forecast provided by ICF. ICF fundamentals-based market pricing forecast is used instead of forward market pricing for contracting decisions with terms of one year or more, because the forward market pricing data is not sufficiently robust or reliable. This is explained in detail in EB-2023-0072 Appendix F, where Enbridge Gas Ontario notes that forward market data is highly unreliable for longer terms, and represents transaction prices rather than forecasts of future prices. Table 1 provides upstream transportation alternatives for delivery to the Union South rate zone. As the expiring contract provides delivery at Dawn through St. Clair, any alternative will also be required to provide delivery through St. Clair to serve the Sarnia Market requirements. The Vector pipeline is the lowest landed-cost option available that can deliver to St. Clair to serve the Sarnia Market.

Table 1: Union South Average Day Landed Cost Analysis

2025-2028 Transportation Analysis

Route (A)	Point of Supply (B)	Basis Differential $US/mmBtu (C)	Supply Cost $US/mmBtu (D) = Nymex + C	Unitized Demand Charge $US/mmBtu (E)	Commodity Charge $US/mmBtu (F)	Fuel Charge $US/mmBtu (G)	100% LF Transportation Inclusive of Fuel $US/mmBtu (I) = E + F + G	Landed Cost $US/mmBtu (J) = D + I	Landed Cost $Cdn/G (K)	Point of Delivery (L)
Dawn	Dawn	-0.0310	3.3767				0.0000	$3.38	**$4.32**	Dawn
TC: Great Lakes to Dawn	Empress	-0.9342	2.4735	0.58	0.01	0.0955	0.6879	$3.16	**$4.05**	Dawn
TC: Niagara to Dawn	Niagara	-0.4311	2.9766	0.17	0.00	0.0137	0.1854	$3.16	**$4.05**	Dawn
MichCon: MichCon to Dawn	SE Michigan	-0.1328	3.2748	0.15	0.00	0.0412	0.1943	$3.47	**$4.44**	Dawn
Vector: Chicago to Dawn	Chicago	-0.1375	3.2702	0.16	0.00	0.1024	0.2641	$3.53	**$4.52**	Dawn
Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	-0.2759	3.1318	0.57	0.05	0.0543	0.6681	$3.80	**$4.86**	Dawn
NEXUS-Clar2Dawn	Dominion South Point	-0.8653	2.5423	1.17	0.00	0.0702	1.2439	$3.79	**$4.85**	Dawn
Rover to Dawn	Dominion South Point	-0.8653	2.5423	0.98	0.05	0.0648	1.0943	$3.64	**$4.65**	Dawn

In the past, Bluewater Storage has been raised as an alternative to the Vector pipeline. As stated in the 2021 Vector contracting decision, the goal of Vector capacity is aimed at maintaining or increasing the diversity, reliability and flexibility of the Company's gas supply plan. Contracting with Bluewater would not accomplish those goals, because Bluewater is not a liquid or transparent source of gas supply. Due to this, it is also challenging to provide landed cost analysis for this alternative, so it has been excluded from the landed cost analysis which is consistent with prior years.

Table 2: Total Transportation Costs

Contract Number	Portfolio	End Date	Renewable Capacity (MMBtu/Day)	Renewal Option	Negotiated Transportation Rate (USD/MMBtu)	Annual Cost (USD)	Renewal Cost (Million USD)
FT1-UGL-5577	UGL	2028-Oct-31	80,000	3 Years	0.165	$4,818,000	$15
FT1-UGL-5577	UGL	2031-Oct-31	80,000	6 Years	0.160	$4,672,000	$28

Public Policy Considerations	Purchasing transporation with a 3 to 5-year term would not negatively impact Enbridge Gas Ontario's ablitity to comply with public policy.
Rationale	Enbridge Gas Ontario has historically relied upon deliveries of gas supply from its contracted capacity on Vector, GLGT, and St. Clair (NEXUS) as well as non-obligated third-party deliveries at St. Clair or Bluewater to meet peak design requirements on the Sarnia Industrial Line (SIL). Enbridge Gas Ontario has stopped relying on non-obligated third-party deliveries to meet peak design requirements as a result of the changing market fundamentals experienced between Chicago and Dawn in recent years. As a result, Enbridge Gas Ontario relies on the gas supply deliveries on Vector, GLGT and NEXUS as well as the Vector backhaul transportation contract to meet peak design requirements on the SIL. As a result, any changes in gas supply deliveries on Vector, GLGT or NEXUS would need to be evaluated from the perspective of peak design requirements on the SIL and possible facility alternatives that would be required without the gas supply deliveries. These contracts delay the need for system re-enforcement. Vector capacity to Dawn is sold out, and if Enbridge Gas reduced its contract levels on Vector, it would be unlikely to be able to recontract in the foreseeable future or may be asked to underpin new facilities requiring long term contracts to re-contract. All other available alternatives would reduce Enbridge Gas Ontario's diversity by reducing Chicago purchases and increasing Appalachia or Dawn purchases. In the Landed Cost Analysis at Table 1, Vector is showing as a 20 cent/GJ increase over Dawn. As discussed in 2022, 2023 and 2024 Annual Updates, the natural gas market at Chicago has experienced volatility over the past few years and this has resulted in increases to forward settlement prices during winter months at Chicago. While Enbridge Gas Ontario uses ICF fundamentals-based market pricing forecast and not forward market settlement data to inform long-term contracting decisions, the divergence between long-term forecast pricing at Chicago and forward settlement pricing was a significant topic of interest with certain stakeholders in previous Annual Updates. Prior to assessing the Vector contract, Enbridge Gas Ontario engaged ICF to conduct an analysis of Chicago and Dawn pricing. Please refer to "Chicago Natural Gas Price Analysis" by ICF attached. ICF's analysis states that, while recent extreme weather events have caused significant price fluctuations, the long-term market fundamentals suggest a different trend. There are risk premiums in the forward markets which are driven by the need of gas buyers at Chicago to hedge against price spikes caused by weather, price volatility, and other market events such as production freeze-offs and pipeline force majeures. While the link between the market fundamentals and the financial markets has changed at Chicago since 2021, it is most likely to revert toward the supply and demand fundamentals in the long term. ICF projects that increasing gas production in the Midcontinent will eventually lead to Chicago prices trading at a discount to Dawn as evidenced by shifts seen in the forward curve at Michcon.

	In addition, ICF expects the supply diversity provided by the ability to source gas for the Ontario market through Chicago to remain valuable. Recent trading at the PEPL hub shows that other potential supply points can also start trading at premiums to Dawn, suggesting the continuing value of supply portfolio diversity. The index of customer data on the Vector website suggests re-contracting would be challenging or impossible if Enbridge releases its current Vector capacity. Given the lack of incremental pipeline capacity, any change in pipeline capacity holdings in these markets will have long-term implications, and decisions regarding pipeline capacity should reflect a long-term perspective on costs and benefits. ICF advises Enbridge Gas to focus on long-term market fundamentals, supply diversity, and reliability when making re-contracting decisions for pipeline capacity. The interconnected pipeline network and the critical role of the Vector pipeline underscore the importance of maintaining capacity agreements. Although short-term market trends and risk premiums may cause temporary deviations, the long-term perspective should guide strategic decisions to ensure stability and cost-effectiveness in gas supply. Enbridge Gas Ontario recognizes that Vector pipeline offers long-term flexibility to access supply from the ACE Hub or directly from any of the three pipelines that interconnect with it at Joilett. As well, Vector provides access to supply in the Michigan area which includes NEXUS and Rover supply, DTE, Washington 10 and Bluewater storage. Enbridge Gas Ontario has renewal rights on this contract to renew for 3 years for the current toll of $0.165. Through negotiations with Vector, they were willing to decrease the toll paid to $0.160 but would require Enbridge Gas Ontario to contract for a 6-year term. The toll savings represents a discount of 3% (or ~$146,000 a year or ~$440,000 over the entire 3 year term). A discount of 3% does not justify the flexibility of having the shorter term contract in the current scenario where the market pricing fundamentals are changing and not stable.

Benefits of Capacity
a. Contract supports Enbridge Gas Ontario's objective of structuring a portfolio with a diversity of contract terms and supply basins b. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost c. Landed cost of gas flowing from Chicago and Dawn along this route is competitively priced and has an end date that aligns with the gas year d. 3-year contract term maintains Enbridge Gas Ontario's contract flexibility e. A fixed-rate toll provides toll certainty on a portion of Enbridge Gas's upstream transportation portfolio f. Supports the acquisition of supply from upstream markets, maintaining diversity of contract terms and supply basins g. Provides flexibility to access multiple supply sources at Joliet and other points along the path h. Provides Enbridge Gas with delivery point flexibility within the path including Michigan storage and Sarnia i. Provides flexibility as the capacity can be segmented and used bi-directionally
Recommendation Summary
The evaluation considers impacts to gas supply portfolio costs, reliability, diversity, flexibility and to Enbridge Gas' ability to meet design day demand requirements on the Sarnia Industrial Line (SIL). Based on this evaluation, the recommendation is for Enbridge Gas to extend the contract for 80,000 Dth/d for a term of 3 years at a rate of $0.165. The total value of the 3-year renewal is ~$15 million USD. This falls withing the ASL of Christina Haskell, however since it is close to the upper limit of $15 million, Amy Mikhaila's ASL will be used.

Approvals*	
Recommended by:	Christina Haskell, Sr. Advisor, Gas Supply
Approved by:	Amy Mikhaila
Date of Approval:	October 31, 2024

*Approvals must be in accordance with Delegated Authorities Limits and the Gas Supply Procurement Policies and Practices.

2024 St. Clair Pipeline Renewals

Rate Zone	Company	Path	Current Capacity
Union South	St. Clair Pipelines Limited	DTE St. Clair to Union St. Clair Bluewater Gas Storage transfer point to St. Clair/Union interconnect	St. Clair 214,000 GJ/d Bluewater 127,000 GJ/d
Current Contract Expiry	**Renewal Notice Due Date**	**Recommended Renewal Length**	**Recommended Contract Valuation**
October 31, 2024	October 31, 2024	1 Year	~ $1.2 million USD

Introduction
The purpose of this document is to evaluate and recommend a course of action related to the pipeline contract renewals for St. Clair Pipelines Limited. The St. Clair River Crossing and the Bluewater River Crossing are pipelines owned by St. Clair Pipelines Limited (an affiliate of Enbridge Gas Ontario) and regulated by the CER. Both pipelines provide an important link between storage and pipeline systems in Michigan and Ontario and provide benefits to ratepayers. Enbridge Gas Ontario (Enbridge) contracts on these pipelines expire October 31, 2024. This document evaluates Enbridge's right to extend its agreements by 1-year and makes a recommendation. The St. Clair River crossing connects the Michcon/DTE system in Michigan to the Enbridge Gas Ontario system. Enbridge Gas Ontario contracts for 214,000 GJ/d of capacity on this path with the majority (~158,000 GJ/d) being relied upon to transport Enbridge Gas Ontario's legacy Union Gas NEXUS supply to Ontario. It also provides access to the Michcon/DTE system, providing access to MichCon supply and storage and increasing competition for storage services in the Great Lakes region. Volumes transported into Canada via the St. Clair River Crossing can be directed to the Sarnia Industrial Line at Courtright and benefit the Sarnia market. St. Clair River Crossing capacity is the only direct link between the DTE/Michcon system and Enbridge's system. Not renewing this capacity would strand NEXUS deliveries in Michigan and would eliminate several potential sources of supply. The Bluewater River crossing connects the Bluewater Gas Storage system in Michigan with the Enbridge Gas Ontario system in Ontario. Enbridge Gas Ontario contracts for 127,000 GJ/d of capacity to this system. The Bluewater River Crossing capacity has an annual cost of approximately $1.0 million and provides access to Michigan storage provider, Bluewater Gas Storage, increasing competition for storage services in the Great Lakes region, and provides security of supply for Enbridge Gas Ontario customers. Bluewater Gas Storage is not a liquid trading location but does provide interruptible wheeling services to move gas to different points on their system and firm storage services that could deliver to the Bluewater River Crossing on a firm basis. Volumes transported into Canada via the

<table>
<tr><td colspan="2">Bluewater River Crossing can benefit the Sarnia market by providing supply that can be directed to the Sarnia Industrial Line (SIL). It is important to note that Enbridge Gas is not able to rely upon the interruptible service to provide supply to the SIL on a design day and the Company does not currently have a contract for firm storage service with Bluewater Gas Storage. Therefore, the Bluewater River Crossing contract enables an important back-up supply option for the Sarnia market but is not relied upon in the design of the SIL.

St. Clair Pipelines Limited contracts automatically extend for 1 year every November unless Enbridge Gas Ontario provides notice of termination.</td></tr>
<tr><th colspan="2">Analysis</th></tr>
<tr><td>Alternatives Identified</td><td>There are no viable alterntives to capacity on either of these pipelines.</td></tr>
<tr><td>Evaluation of Alternatives</td><td>A landed cost was not prepared as there are no viable alternatives to capacity on either of these pipelines.</td></tr>
<tr><td>Public Policy Considerations</td><td>Enbridge Gas Ontario’s renewal of this capacity is in compliance with the ARC.</td></tr>
<tr><td>Rationale</td><td>This capacity is important to Enbridge Gas Ontario as it provides numerous benefits (enhances competition, bargaining power, purchasing options, flexibility, security of supply). Supply from these pipelines can be utilized to support the Sarnia Industrial Line. Enbridge Gas Ontario also provides firm transportation service under Rate C1 and interruptible transportation service under a hub contract between Dawn and the St. Clair and Bluewater River Crossings that require these pipelines.

<u>St. Clair River Crossing Ratepayer Benefits</u>
Facilitates 150,000 Dth/d (158,258GJ/d) NEXUS capacity to Ontario
Access to Michcon supply via crossing, increases competition at Dawn
Provides additional options for gas supply purchases at Michcon
St. Clair deliveries support Sarnia Market
Allows access to Michcon storage, increasing competition and optionality
<u>Bluewater River Crossing Ratepayer Benefits</u>
Access to Bluewater Gas Storage, increasing competition and optionality
3rd Party Bluewater deliveries can benefit Sarnia Market
Allows access to Bluewater storage, increasing competition and optionality
St. Clair Pipelines is an affiliate of Enbridge Gas Ontario. Tolls for 2025 have been based on a cost-of-service calculation. This results in payments to St. Clair Pipelines being at or below their current cost-of-service. As a result, Enbridge Gas Ontario’s renewal of this capacity is in compliance with the ARC. There are toll changes associated with this renewal.</td></tr>
</table>

Table 1 & 2: Toll Changes for Renewal

St. Clair Pipelines Renewal Valuation - 2023

Pipeline	Quantitiy (GJ/Day)	Demand Charge (CAD/GJ/ Month)	Montly Demand Fee (CAD/Month)	Abandonment Costs (CAD/Month)	Total Monthly Cost (CAD/Month)	Term (months)	Value (CAD)
St. Clair River Crossing	214,000	0.11	23,540.00	416.19	23,956.19	12	$287,474.28
Bluewater Crossing	127,000	0.63	80,010.00	3,171.31	83,181.31	12	$998,175.72
						Total	**$1,285,650.00**

St. Clair Pipelines Renewal Valuation - 2024

Pipeline	Quantitiy (GJ/Day)	Demand Charge (CAD/GJ/ Month)	Montly Demand Fee (CAD/Month)	Abandonment Costs (CAD/Month)	Total Monthly Cost (CAD/Month)	Term (months)	Value (CAD)	Increase/ Decrease from Prior Year (CAD)
St. Clair River Crossing	214,000	0.15	32,100.00	416.19	32,516.19	2	$387,212	$99,737
				117.92	32,217.92	10		
Bluewater Crossing	127,000	0.54	68,580.00	3,171.31	71,751.31	2	$833,484	($164,691)
				418.17	68,998.17	10		
						Total	**$1,220,695.90**	

Demand fees will increase for St. Clair River Crossing and will decrease for Bluewater River Crossing effective November 1, 2024. Prior to November 2024 the demand rates have not been updated since 2015. Demand rates are calculated based a cost-of-service approach for 2025. A cost-of-service approach estimates what the O&M and capital costs will be for 2025 and ensures the revenue can cover the costs. This calculation uses a rate of return 3% debt and 8.93% equity, tax rate of 26.5% and 2% inflation for LRP years. The cost of capital factors are lower than what is currently approved for Enbridge Gas Ontario and the tax rate and inflation rate are similar to Enbridge Gas Ontario.

In addition, the CER finalized their 5-year review of the Abandonment Costs and the new Annual Cost of Abandonment (ACA) has reduced from $43,050 to $6,434. This results in savings for both pipelines. Note: This reduced toll will not take effect until January 2025 as seen in the Table 2 calculation.

The St. Clair River Crossing is required to facilitate the 150,000 Dth/d (158,258 GJ/d) NEXUS capacity the Enbridge Gas holds to Ontario. Even though there is an increase to charges, the contract will need to be renewed.

The Bluewater River Crossing has a toll decrease over 2023 resulting in a savings to this renewal.

Benefits of Capacity

a. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost
b. Provides fixed-rate tolls which provides toll certainty on a portion of Enbridge's upstream transportation portfolio
c. Transportation capacity from St. Clair pipelines are flexible options because they are purchased for a term of 1-year and have renewal rights
d. Transportation capacity on these paths provide access to Michigan pipeline and storage systems, increasing competition and optionality

Recommendation Summary	
Recommend renewing both transportation contracts with St. Clair pipelines for a term of 1-year. The total value of the 1-year renewals is ~$1.2 million USD (provided in Table 2) and is within Christina Haskell's ASL.	
Approvals*	
Recommended by:	Christina Haskell, Sr. Advisor, Gas Supply
Approved by:	Amy Mikhaila, Director, Gas Supply
Date of Approval:	October 31, 2024

*Approvals must be in accordance with Delegated Authorities Limits and the Gas Supply Procurement Policies and Practices.

NGTL Contract Renewal
2025-2030 Transportation Analysis

Route (A)	Point of Supply (B)	Basis Differential $US/mmBtu (C)	Supply Cost $US/mmBtu (D) = Nymex + C	Unitized Demand Charge $US/mmBtu (E)	Commodity Charge $US/mmBtu (F)	Fuel Charge $US/mmBtu (G)	100% LF Transportation Inclusive of Fuel $US/mmBtu (I) = E + F + G	Landed Cost $US/mmBtu (J) = D + I	Landed Cost $Cdn/GJ (K)	Point of Delivery (L)	Comments
AECO to Empress 1-year	AECO	-1.302	1.999	0.174	0.00	0.0000	0.174	$2.173	**$2.766**	Empress	$0.015 Cad Subtracted from total for extraction
Empress 1-year	Empress	-1.119	2.181	0.000	0.00	0.0000	0.000	$2.181	**$2.791**	Empress	
AECO to Empress 3-year	AECO	-1.105	2.303	0.167	0.00	0.0000	0.167	$2.470	**$3.146**	Empress	$0.015 Cad Subtracted from total for extraction
Empress 3-year	Empress	-0.934	2.473	0.000	0.00	0.0000	0.000	$2.473	**$3.166**	Empress	
AECO to Empress 5-year	AECO	-1.058	2.647	0.157	0.00	0.0000	0.157	$2.804	**$3.574**	Empress	$0.015 Cad Subtracted from total for extraction
Empress 5-year	Empress	-0.893	2.812	0.000	0.00	0.0000	0.000	$2.812	**$3.599**	Empress	

Supply Assumptions used in Developing Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2025 - Oct 2026	Nov 2026 - Oct 2027	Nov 2027 - Oct 2028	Nov 2028 - Oct 2029	Nov 2029 - Oct 2030	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
AECO to Empress 1-year	AECO	$ 2.00					**$ 2.00**	0.00%
Empress 1-year	Empress	$ 2.18					**$ 2.18**	0.00%
AECO to Empress 3-year	AECO	$ 2.00	$ 2.42	$ 2.49			**$ 2.30**	0.00%
Empress 3-year	Empress	$ 2.18	$ 2.59	$ 2.65			**$ 2.47**	0.00%
AECO to Empress 5-year	AECO	$ 2.00	$ 2.42	$ 2.49	$ 2.94	$ 3.39	**$ 2.65**	0.00%
Empress 5-year	Empress	$ 2.18	$ 2.59	$ 2.65	$ 3.09	$ 3.55	**$ 2.81**	0.00%

Sources for Assumptions:

Gas Supply Prices (Col D): ICF Q3 2024

Fuel Ratios (Col G): Average ratio over the previous 12 months or Pipeline Forecast

Transportation Tolls (Cols E & F) Tolls in effect on Alternative Routes at the time of Union's Analysis

Foreign Exchange (Col K) $1 US = $1.350 CDN From Bank of Canada Closing Rate October 1, 2024

Energy Conversions (Col K) 1 dth = 1 mmB 1.055056

EGI's Analysis Completed: Oct-24

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

Forecasted Premium/Discount Resulting From Transportation Purchases

Line No.	Particulars	Gas Year 2025/26 (a)	Gas Year 2026/27 (b)	Gas Year 2027/28 (c)
	NGTL Renewal (1)			
1	Landed Cost at Empress	$ 2.772	$ 3.314	$ 3.397
2	Empress Supply	$ 2.791	$ 3.316	$ 3.390
3	Premium/(Discount) (CAD/GJ)	$ (0.02)	$ (0.00)	$ 0.01
4	Capacity (GJ/d)	75,000	75,000	75,000
5	Forecasted Premium/(Discount) ($000s)	$ (540.8)	$ (53.1)	$ 179.4
	Vector Renewal (1)			
6	Landed Cost at Dawn	$ 4.28	$ 4.62	$ 4.67
7	Dawn Supply	$ 4.06	$ 4.43	$ 4.47
8	Premium/(Discount) (CAD/GJ)	$ 0.22	$ 0.19	$ 0.20
9	Capacity (GJ/d)	84,404	84,404	84,404
10	Forecasted Premium/(Discount) ($000s)	$ 6,729.5	$ 5,843.5	$ 6,070.3

Note:

(1) Assumptions used within the analysis completed in October, 2024:
Gas supply prices taken from ICF Q3 2024
Foreign Exchange of $1 USD to $1.35 CAD using the Bank of Canada closing rate for October 1, 2024

Sarnia Market
2025-2028 Transportation Analysis

Route (A)	Point of Supply (B)	Basis Differential $US/mmBtu (C)	Supply Cost $US/mmBtu (D) = Nymex + C	Unitized Demand Charge $US/mmBtu (E)	Commodity Charge $US/mmBtu (F)	Fuel Charge $US/mmBtu (G)	100% LF Transportation Inclusive of Fuel $US/mmBtu (I) = E + F + G	Landed Cost $US/mmBtu (J) = D + I	Landed Cost $Cdn/G (K)	Point of Delivery (L)	Comments
Dawn	Dawn	-0.0310	3.3767				0.0000	$3.38	**$4.32**	Dawn	
TC: Great Lakes to Dawn	Empress	-0.9342	2.4735	0.58	0.01	0.0955	0.6879	$3.16	**$4.05**	Dawn	
TC: Niagara to Dawn	Niagara	-0.4311	2.9766	0.17	0.00	0.0137	0.1854	$3.16	**$4.05**	Dawn	
MichCon: MichCon to Dawn	SE Michigan	-0.1328	3.2748	0.15	0.00	0.0412	0.1943	$3.47	**$4.44**	Dawn	
Vector: Chicago to Dawn	Chicago	-0.1375	3.2702	0.16	0.00	0.1024	0.2641	$3.53	**$4.52**	Dawn	
Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	-0.2759	3.1318	0.57	0.05	0.0543	0.6681	$3.80	**$4.86**	Dawn	
NEXUS-Clar2Dawn	Dominion South Point	-0.8653	2.5423	1.17	0.00	0.0702	1.2439	$3.79	**$4.85**	Dawn	
Rover to Dawn	Dominion South Point	-0.8653	2.5423	0.98	0.05	0.0648	1.0943	$3.64	**$4.65**	Dawn	

Supply Assumptions used in Developing Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2025 - Oct 2026	Nov 2026 - Oct 2027	Nov 2027 - Oct 2028	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
Henry Hub	**Henry Hub**	**$ 3.30**	**$ 3.44**	**$ 3.48**	**$ 3.41**	
Dawn	Dawn	$ 3.17	$ 3.46	$ 3.49	**$ 3.38**	
TC: Great Lakes to Dawn	Empress	$ 2.18	$ 2.59	$ 2.65	**$ 2.47**	3.86%
TC: Niagara to Dawn	Niagara	$ 2.67	$ 3.08	$ 3.18	**$ 2.98**	0.46%
MichCon: MichCon to Dawn	SE Michigan	$ 3.07	$ 3.36	$ 3.39	**$ 3.27**	1.26%
Vector: Chicago to Dawn	Chicago	$ 3.08	$ 3.35	$ 3.38	**$ 3.27**	3.13%
Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	$ 2.96	$ 3.20	$ 3.23	**$ 3.13**	1.73%
NEXUS-Clar2Dawn	Dominion South Point	$ 2.13	$ 2.67	$ 2.83	**$ 2.54**	2.76%
Rover to Dawn	Dominion South Point	$ 2.13	$ 2.67	$ 2.83	**$ 2.54**	2.55%

Sources for Assumptions:

Gas Supply Prices (Col D): ICF Q3 2024

Fuel Ratios (Col G): Average ratio over the previous 12 months or Pipeline Forecast

Transportation Tolls (Cols E & F): Tolls in effect on Alternative Routes at the time of Union's Analysis

Foreign Exchange (Col K): $1 US = $1.350 CDN From Bank of Canada Closing Rate October 1, 2024

Energy Conversions (Col K): 1 dth = 1 mmBtu = 1.055056

$1.28

EGI's Analysis Completed: Oct-24

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

Summary of November 1, 2024 Upstream Transportation Contracts

EGD Rate Zone

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units (1)	Contract Termination Date
	(a)	(b)	(c)	(d)	(e)	(f)
	TransCanada Pipeline					
1	Chippawa to CDA	Chippawa	Enbridge Parkway CDA	123,441	GJ	31-Oct-2030 *
2	Dawn to CDA FT	Union Dawn	Enbridge CDA	4,818	GJ	31-Oct-2026 *
3	Dawn to CDA FT	Union Dawn	Enbridge CDA	145,000	GJ	31-Oct-2026 *
4	Dawn to EDA FT	Union Dawn	Enbridge EDA	114,000	GJ	31-Oct-2026 *
5	Dawn to Iroquois FT	Union Dawn	Iroquois	40,000	GJ	31-Oct-2026 *
6	Empress to Enbridge CDA	Empress	Enbridge CDA	34,457	GJ	31-Oct-2030 **
7	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	163,044	GJ	31-Dec-2030 **
8	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	70,000	GJ	31-Dec-2030 **
9	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	5,000	GJ	31-Dec-2030 **
10	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	26,956	GJ	31-Dec-2030 **
11	NBJ to Enbridge CDA	North Bay Junction	Enbridge CDA	5,000	GJ	31-Dec-2030 **
12	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	163,044	GJ	31-Dec-2030 **
13	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	70,000	GJ	31-Dec-2030 **
14	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	26,956	GJ	31-Dec-2030 **
15	Niagara Falls to CDA	Niagara Falls	Enbridge Parkway CDA	76,559	GJ	31-Oct-2030 **
16	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	572	GJ	31-Oct-2026 *
17	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	40,093	GJ	31-Oct-2032
18	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	75,000	GJ	31-Oct-2034
19	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	70,000	GJ	31-Oct-2032
20	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	15,000	GJ	31-Oct-2032
21	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	8,375	GJ	31-Oct-2032
22	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	24,484	GJ	31-Oct-2032
23	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	100,000	GJ	31-Oct-2036
24	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	18,876	GJ	31-Oct-2027 *
25	Parkway to CDA FT-SN	Union Parkway Belt	Victoria Square #2 CDA	85,000	GJ	31-Oct-2026 *
26	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	6,000	GJ	31-Oct-2032
27	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	170,000	GJ	31-Oct-2031
28	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	13,114	GJ	31-Oct-2032
29	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	25,000	GJ	31-Oct-2036
30	TCPL FT - Total			1,719,789	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
31	CDA	Parkway	Enbridge CDA	153,700	GJ	31-Oct-2026 *
32	CDA	Parkway	Enbridge CDA	92,822	GJ	31-Oct-2026 *
33	CDA	Parkway	Enbridge CDA	37,370	GJ	31-Oct-2026 *
34	EDA	Parkway/Kirkwall	Enbridge EDA	35,089	GJ	31-Oct-2026 *
35	EDA	Parkway	Enbridge EDA	35,806	GJ	31-Oct-2026 *
36	EDA	Parkway	Enbridge EDA	9,716	GJ	31-Oct-2026 *
37	TCPL Firm STS Withdrawal - Total			364,503	GJ	
	TransCanada Storage Transportation Service Firm Injection					
38	CDA	Parkway	Enbridge CDA	153,700	GJ	31-Oct-2026 *
39	CDA	Parkway	Enbridge CDA	92,822	GJ	31-Oct-2026 *
40	CDA	Parkway	Enbridge CDA	37,370	GJ	31-Oct-2026 *
41	EDA	Parkway/Kirkwall	Enbridge EDA	35,089	GJ	31-Oct-2026 *
42	EDA	Parkway	Enbridge EDA	35,806	GJ	31-Oct-2026 *
43	EDA	Parkway	Enbridge EDA	9,716	GJ	31-Oct-2026 *
44	TCPL Firm STS Injection - Total			364,503	GJ	
	NOVA Transmission					
45	NIT to Empress	NIT	Empress	50,000	GJ	31-Oct-2027 **
46	NIT to Empress	NIT	Empress	75,000	GJ	31-Oct-2028 **
47	Nova Transmission - Total			125,000	GJ	
	Vector Pipeline					
48	Vector US FT1	Milford Junction	St. Clair	110,000	DTH	31-Oct-2033
49	Vector Canada FT1	St. Clair	Dawn	116,056	GJ	31-Oct-2033
50	Vector US FT1	Alliance	St. Clair	65,000	DTH	31-Oct-2027 **
51	Vector Canada FT1	St. Clair	Dawn	68,579	GJ	31-Oct-2027 **
52	Vector US FT1	Chicago	Cdn/US Interconnect	20,000	DTH	31-Oct-2026 **
53	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	21,101	GJ	31-Oct-2026 **
54	Vector - Total			205,736	GJ	
	NEXUS					
55	NEXUS - FT	Kensington	Milford Junction	55,000	DTH	31-Oct-33
56	NEXUS - FT	Clarington	Milford Junction	55,000	DTH	31-Oct-33
57	NEXUS - Total			116,056	GJ	

Note:

(1) Conversion factor of DTH to GJ of 1.055056.

* Upcoming design day contract expiries

** Upcoming average day contract expiries

Summary of November 1, 2024 Upstream Transportation Contracts

Union North Rate Zone (1)

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units (2)	Contract Termination Date
	(a)	(b)	(c)	(d)	(e)	(f)
	TransCanada Pipeline					
1	Empress to Union EDA FT	Empress	Union EDA	1,089	GJ	31-Oct-2026 *
2	Empress to Union EDA FT	Empress	Union EDA	4,000	GJ	31-Oct-2027 *
3	Empress to Centrat MDA FT	Empress	Centrat MDA	4,522	GJ	31-Oct-2026 *
4	Empress to Centrat MDA FT	Empress	Centrat MDA	1,043	GJ	31-Oct-2026 *
5	Empress to Union NCDA FT	Empress	Union NCDA	1,412	GJ	31-Oct-2026 *
6	Empress to Union NDA FT	Empress	Union NDA	4,056	GJ	31-Oct-2026 *
7	Empress to Union SSMDA FT	Empress	Union SSMDA	2,700	GJ	31-Oct-2026 *
8	Empress to Union SSMDA FT	Empress	Union SSMDA	12,800	GJ	31-Oct-2026 *
9	Empress to Union SSMDA FT	Empress	Union SSMDA	6,143	GJ	31-Oct-2026 *
10	Empress to Union WDA FT	Empress	Union WDA	39,880	GJ	31-Oct-2026 *
11	Empress to Union WDA FT	Empress	Union WDA	11,527	GJ	31-Oct-2026 *
12	Empress to Union WDA FT	Empress	Union WDA	3,396	GJ	31-Oct-2027 *
13	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	31-Oct-2026 *
14	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	31-Oct-2026 *
15	Parkway to Union EDA FT	Parkway	Union EDA	75,000	GJ	31-Oct-2031
16	Parkway to Union EDA FT	Parkway	Union EDA	181	GJ	31-Oct-2031
17	Parkway to Union EDA FT	Parkway	Union EDA	9,105	GJ	31-Oct-2031
18	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	31-Oct-2032
19	Parkway to Union EDA FT	Parkway	Union EDA	9,128	GJ	31-Oct-2033
20	Parkway to Union EDA FT (EMB)	Parkway	Union EDA	25,000	GJ	31-Oct-2031
21	Parkway to Union NCDA FT	Parkway	Union NCDA	661	GJ	31-Oct-2031
22	Parkway to Union NCDA FT	Parkway	Union NCDA	439	GJ	31-Oct-2031
23	Parkway to Union NCDA FT	Parkway	Union NCDA	887	GJ	31-Oct-2032
24	Parkway to Union NCDA FT	Parkway	Union NCDA	2,000	GJ	31-Oct-2032
25	Parkway to Union NCDA FT	Parkway	Union NCDA	6,912	GJ	31-Oct-2033
26	Parkway to Union NCDA FT	Parkway	Union NCDA	884	GJ	31-Oct-2033
27	Parkway to Union NDA FT	Parkway	Union NDA	10,000	GJ	31-Oct-2031
28	Parkway to Union NDA FT	Parkway	Union NDA	67,000	GJ	31-Oct-2031
29	Parkway to Union NDA FT	Parkway	Union NDA	24,000	GJ	31-Oct-2031
30	Parkway to Union NDA FT	Parkway	Union NDA	9,000	GJ	31-Oct-2031
31	Parkway to Union NDA FT	Parkway	Union NDA	10,401	GJ	31-Oct-2031
32	Parkway to Union NDA FT	Parkway	Union NDA	6,228	GJ	31-Oct-2031
33	TCPL FT - Total			389,394	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
34	EDA	Parkway	Union EDA	26,351	GJ	31-Oct-2026 *
35	NCDA	Parkway	Union NCDA	13,704	GJ	31-Oct-2026 *
36	NDA	Parkway	Union NDA	48,375	GJ	31-Oct-2026 *
37	SSMDA	Dawn	Union SSMDA	35,022	GJ	31-Oct-2026 *
38	WDA	Parkway	Union WDA	31,420	GJ	31-Oct-2026 *
39	TCPL Firm STS Withdrawal - Total			154,872	GJ	
	TransCanada Storage Transportation Service Firm Injection					
40	EDA	Union EDA	Parkway	5,000	GJ	31-Oct-2026 *
41	NDA	Union NDA	Parkway	49,100	GJ	31-Oct-2026 *
42	WDA	Union WDA	Parkway	3,150	GJ	31-Oct-2026 *
43	TCPL Firm STS Injection - Total			57,250	GJ	
	Centra Transmission Holdings Inc.					
44	Centra Transmission Holdings Inc.	Spruce	Union MDA	147	10^3m^3	31-Oct-2025 *
45	Centra Pipelines Minnesota Inc.	Sprague	Baudette	5,197	MCF	31-Oct-2025 *
46	CTHI FT - Total			5,712	GJ	

Notes:

(1) Excludes NEXUS capacity allocated from the South portfolio.

(2) Conversion factor from DTH to GJ of 1.055056; Conversion to GJ based on heat content of 38.86 GJ / 10^3m^3.

* Upcoming design day contract expiries

** Upcoming average day contract expiries

Summary of November 1, 2024 Upstream Transportation Contracts

Union South Rate Zone

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units (2)	Contract Termination Date
	(a)	(b)	(c)	(d)	(e)	(f)
	TransCanada Pipeline Ltd.					
1	Dawn to Union CDA FT	Dawn	Union ECDA	8,000	GJ	31-Oct-2026 **
2	Empress to Emerson 2 FT	Empress	Emerson 2	21,418	GJ	31-Oct-2026 **
3	Empress to Union ECDA FT	Empress	Union ECDA	3,000	GJ	31-Oct-2026 **
4	Kirkwall to Union CDA FT	Kirkwall	Union CDA	135,000	GJ	31-Oct-2032
5	Niagara to Kirkwall FT	Niagara	Kirkwall	21,101	GJ	31-Oct-2026 **
6	TCPL FT - Total			188,519	GJ	
	Panhandle Eastern Pipe Line Company L.P.					
7	PEPL FT	Panhandle Field Zone	Ojibway (Union)	35,000	DTH	31-Oct-2027 **
8	PEPL FT	Panhandle Field Zone	Ojibway (Union)	22,000	DTH	31-Oct-2027 **
9	PEPL - Total			60,138	GJ	
	Vector Pipelines L.P.					
10	Vector US FT1	Chicago	Cdn/US Interconnect	80,000	DTH	31-Oct-2028 **
11	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,404	GJ	31-Oct-2028 **
12	Vector US FT1	Chicago	Cdn/US Interconnect	20,000	DTH	31-Oct-2026 **
13	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	21,101	GJ	31-Oct-2026 **
14	Vector Canada FT1	Dawn-Vector	Courtright	84,404	GJ	31-Oct-2027 **
15	Vector - Total			189,909	GJ	
	NEXUS Gas Transmission, LLC					
16	NEXUS - FT (1)	Kensington	St. Clair (Union)	150,000	DTH	31-Oct-2033
17				158,258	GJ	
	Great Lakes Gas Transmission					
18	GLGT	Emerson	St. Clair	20,000	DTH	31-Oct-2029 **
19				21,101	GJ	
	Great Lakes Pipeline Canada Ltd.					
20	Great Lakes Pipeline Canada Ltd.	St. Clair	Union SWDA	21,101	GJ	31-Oct-2029 **
	Other					
21	St. Clair Pipelines L.P. (St. Clair Pipeline)	St. Clair/Intl Border	St. Clair/Intl Border	214,000	GJ	31-Oct-2025 **
22	St. Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Intl Border	Bluewater/Intl Border	127,000	GJ	31-Oct-2025 **

Notes:

(1) EGI has contracted for 150,000 DTH/day and allocates 50,000 DTH/day to the Union North portfolio.

(2) Conversion factor of DTH to GJ of 1.055056.

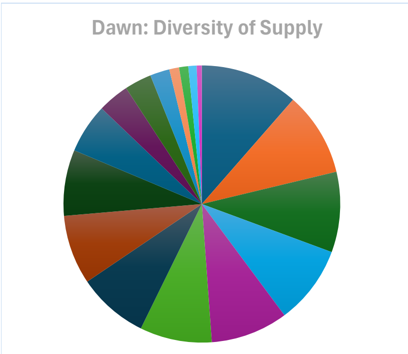
* Upcoming design day contract expiries

** Upcoming average day contract expiries

2023/24 Supplier Diversity By Basin/Purchase Point

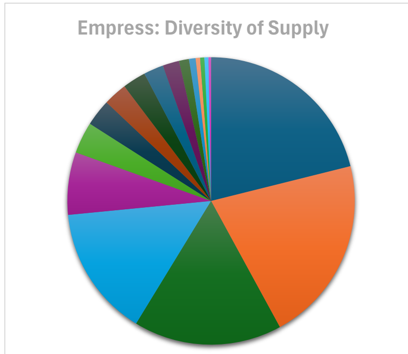
Dawn

Annual Supply Provided	Number of Suppliers
0-2 PJ	7
2-5 PJ	3
5+ PJ	9



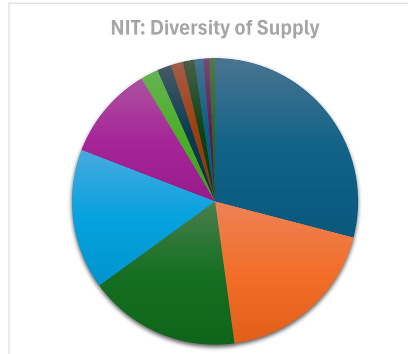
Empress

Annual Supply Provided	Number of Suppliers
0-2 PJ	8
2-5 PJ	4
5+ PJ	5



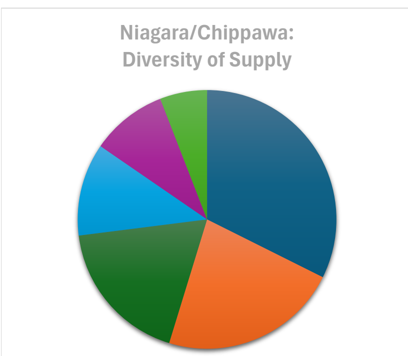
NIT

Annual Supply Provided	Number of Suppliers
0-2 PJ	7
2-5 PJ	1
5+ PJ	4



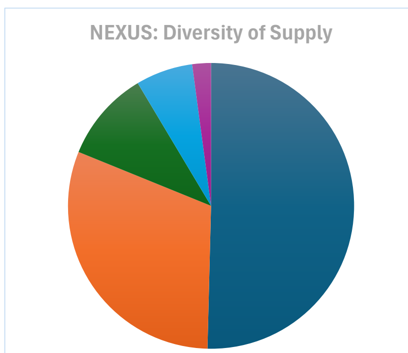
Niagara/Chippawa

Annual Supply Provided	Number of Suppliers
0-2 PJ	0
2-5 PJ	0
5+ PJ	6



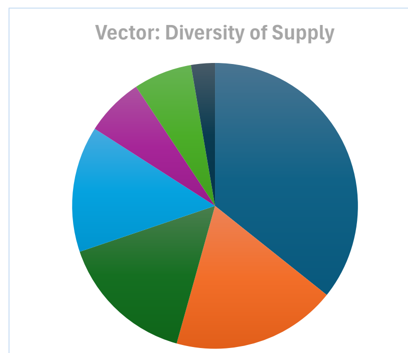
NEXUS

Annual Supply Provided	Number of Suppliers
0-2 PJ	0
2-5 PJ	1
5+ PJ	4



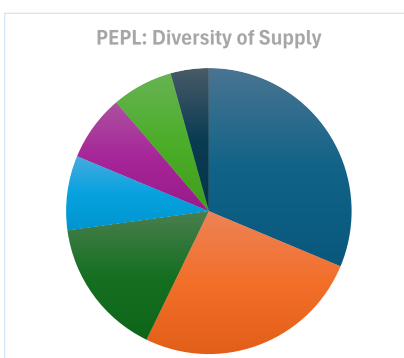
Vector

Annual Supply Provided	Number of Suppliers
0-2 PJ	1
2-5 PJ	2
5+ PJ	4



PEPL

Annual Supply Provided	Number of Suppliers
0-2 PJ	4
2-5 PJ	1
5+ PJ	2



Lesley M Austin Digitally signed by Lesley M Austin Date: 2025.06.04 10:05:46 -04'00' Exhibit C

From:	Bonnie Adams
To:	ablair@elenchus.ca; ajg@londoneconomics.com; albin_antony@tcenergy.com; alex.greco@cme-mec.ca; amanda@elsonadvocacy.ca; amit@londoneconomics.com; bettyboop07@execulink.com; cao@marathon.ca; cboyle@blg.com; chandyd@electrocables.com; chief@caldwellfirstnation.ca; claire.burum1@kochind.com; Cli@enerlife.com; cneme@energyfuturesgroup.com; colin.anderson@appro.org; daniel@resilientllp.com; drichardson@scugogfirstnation.com; DR Quinn; eblanchard@blg.com; Elpe@equinor.com; flora.ho@enercare.ca; ghenderson@enerlife.com; ghenderson@enerlife.com; hlpca52@gmail.com; hovde@pacificeconomicsgroup.com; ian.mondrow@gowlingwlg.com; Ian.richler@oeb.ca; Ijarvis@enerlife.com; info@marshallgarnick.com; jack@cleanairalliance.org; jack@cleanairalliance.org; jane_scott@rogers.com; jay@shepherdrubenstein.com; jaya.chatterjee@kitchener.ca; jgirvan@uniserve.com; jgreen@biogasassociation.ca; jlawford@piac.ca; john.wingate@kochps.com; jonathan@resilientllp.com; jonathan@resilientllp.com; kai@millyard.ca; kbruce@enerlife.com; kent@elsonadvocacy.ca; Khaled.abu-eseifan@kitchener.ca
Subject:	EB-2025-0065 Enbridge Gas Inc. - 5-Year Gas Supply Plan - OEB Notice of Hearing
Date:	Thursday, May 29, 2025 2:54:00 PM
Attachments:	Notice_EGI GSP_20250526.pdf EGI_5-Year Gas Supply Plan_20250501.pdf

To: All intervenors in EB-2024-0067, EB-2022-0200, EB-2019-0137 and EB-2017-0129

On May 1, 2025, Enbridge Gas Inc. (Enbridge Gas) filed the 5-Year Gas Supply plan with the Ontario Energy Board (OEB).

On May 26, 2025, the OEB issued a Notice of Hearing (Notice) and a Letter of Direction for this proceeding. Enbridge Gas has been directed to serve the Notice, along with its 5-Year Gas Supply Plan, to intervenors from previous proceedings.

The Notice outlines how interested parties can stay informed and participate in the process. Those wishing to apply for intervenor status must submit their application to the OEB by June 5, 2025.

The documents can also be accessed online on Enbridge Gas's website under Other Regulatory Proceedings: Regulatory Information | Enbridge Gas

Please contact me if you have any questions.

Sincerely,

Bonnie Jean Adams
Regulatory Coordinator

Enbridge Gas Inc.
T: 416-495-5751
500 Consumers Road I North York Ontario I M2J 1P8

enbridgegas.com
Safety. Integrity. Respect. Inclusion. High Performance.

My working day may differ from your working day. Please do not feel obliged to reply to this email outside of your normal working hours.

From: Bonnie Adams
To: thesselink@epcor.com; docallaghan@epcor.com; mxu@epcor.com; elpe@equinor.com
Subject: EB-2025-0065 Enbridge Gas Inc. - 5-Year Gas Supply Plan - OEB Notice of Hearing
Date: Thursday, May 29, 2025 3:02:00 PM
Attachments: Notice_EGI GSP_20250526.pdf
EGI_5-Year Gas Supply Plan_20250501.pdf

To: All Rate-Regulated Natural Gas Utilities

On May 1, 2025, Enbridge Gas Inc. (Enbridge Gas) filed the 5-Year Gas Supply plan with the Ontario Energy Board (OEB).

On May 26, 2025, the OEB issued a Notice of Hearing (Notice) and a Letter of Direction for this proceeding. Enbridge Gas has been directed to serve the Notice, along with its 5-Year Gas Supply Plan, all Rate-Regulated Natural Gas Utilities.

The Notice outlines how interested parties can stay informed and participate in the process. Those wishing to apply for intervenor status must submit their application to the OEB by June 5, 2025.

The documents can also be accessed online on Enbridge Gas's website under Other Regulatory Proceedings: Regulatory Information | Enbridge Gas

Please contact me if you have any questions.

Sincerely,

Bonnie Jean Adams
Regulatory Coordinator

Enbridge Gas Inc.
T: 416-495-5751
500 Consumers Road I North York Ontario I M2J 1P8

enbridgegas.com
Safety. Integrity. Respect. Inclusion. High Performance.

My working day may differ from your working day. Please do not feel obliged to reply to this email outside of your normal working hours.

Exhibit C

From: Bonnie Adams
To: michael.stedman@activeenergy.ca; mvieira@agenergy.coop; aberrios@amerexenergy.com; awan.waja@gmail.com; m.justice@canadianenergyprotection.com; legal@dneresources.com; shaunpandit@earlybirdpower.com; dcocchetto@ecng.com; ashans@edgecom.ai; khakimjee@energycontractsontario.com; amason@goenergy.ca; regulatory_mgmnt@justenergy.com; regulatory_mgmnt@justenergy.com; greg.carey@owenergy.com; mike.parkes@trioadvisory.com; danq@silverbirchpower.com; tsinson@summittenergy.ca; regulatory@kingstonhydro.com; regulatory@kitchener.ca; michael.harris@unifiedenergy.com; regulatory_mgmnt@justenergy.com; barbara.farmer@nrg.com
Subject: EB-2025-0065 Enbridge Gas Inc. - 5-Year Gas Supply Plan - OEB Notice of Hearing
Date: Thursday, May 29, 2025 3:08:00 PM
Attachments: Notice_EGI_GSP_20250526.pdf
EGI_5-Year Gas Supply Plan_20250501.pdf

To: All Licensed Gas Marketers

On May 1, 2025, Enbridge Gas Inc. (Enbridge Gas) filed the 5-Year Gas Supply plan with the Ontario Energy Board (OEB).

On May 26, 2025, the OEB issued a Notice of Hearing (Notice) and a Letter of Direction for this proceeding. Enbridge Gas has been directed to serve the Notice, along with its 5-Year Gas Supply Plan, all Licensed Gas Marketers.

The Notice outlines how interested parties can stay informed and participate in the process. Those wishing to apply for intervenor status must submit their application to the OEB by June 5, 2025.

The documents can also be accessed online on Enbridge Gas's website under Other Regulatory Proceedings: Regulatory Information | Enbridge Gas

Please contact me if you have any questions.

Sincerely,

Bonnie Jean Adams
Regulatory Coordinator

Enbridge Gas Inc.
T: 416-495-5751
500 Consumers Road I North York Ontario I M2J 1P8

enbridgegas.com
Safety. Integrity. Respect. Inclusion. High Performance.

My working day may differ from your working day. Please do not feel obliged to reply to this email outside of your normal working hours.

From: Bonnie Adams
To: contactus@cityofkingston.ca
Subject: FEB-2025-0065 Enbridge Gas Inc. - 5-Year Gas Supply Plan - OEB Notice of Hearing
Date: Thursday, May 29, 2025 3:11:00 PM
Attachments: Notice_EGI GSP_20250526.pdf
EGI_5-Year Gas Supply Plan_20250501.pdf

To: City of Kingston

On May 1, 2025, Enbridge Gas Inc. (Enbridge Gas) filed the 5-Year Gas Supply plan with the Ontario Energy Board (OEB).

On May 26, 2025, the OEB issued a Notice of Hearing (Notice) and a Letter of Direction for this proceeding. Enbridge Gas has been directed to serve the Notice, along with its 5-Year Gas Supply Plan, to the City of Kingston.

The Notice outlines how interested parties can stay informed and participate in the process. Those wishing to apply for intervenor status must submit their application to the OEB by June 5, 2025.

The documents can also be accessed online on Enbridge Gas's website under Other Regulatory Proceedings: Regulatory Information | Enbridge Gas

Please contact me if you have any questions.

Sincerely,

Bonnie Jean Adams
Regulatory Coordinator

Enbridge Gas Inc.
T: 416-495-5751
500 Consumers Road I North York Ontario I M2J 1P8

enbridgegas.com
Safety. Integrity. Respect. Inclusion. High Performance.

My working day may differ from your working day. Please do not feel obliged to reply to this email outside of your normal working hours.

Lesley M Austin Digitally signed by Lesley M Austin Date: 2025.06.04 10:06:18 -04'00'

Exhibit D

https://www.enbridgegas.com/about-enbridge-gas/regulatory

Regulatory Information

Enbridge Gas is a regulated company through the Ontario Energy Board and Canada Energy Regulator. You can view all of our rate case information and evidence – as well as the evidence we filed in other regulatory proceedings. Please note that we have not posted any evidence that was confidential or that required a non-disclosure agreement.

FRANCHISES | OTHER REGULATORY PROCEEDINGS | RATE CASES AND QRAM

- EB-2025-0065 5-Year Gas Supply Plan
  - Gas-supply-plan
  - Notice of Hearing
- EB-2024-0251 2025 Federal Carbon
- EB-2024-0198 - 2026-2030 DSM Plan
- EB-2024-0193 - 2022 DSM Deferrals Application
- EB-2024-0125 - 2023 Deferrals Application
- EB-2023-0194 - 2024 Federal Carbon Pricing Program
- EB-2023-0092 - 2022 Utility Earnings and Disposition of Deferral and Variance Account Balances
- EB-2023-0062 - 2021 DSM Deferral and Variance Account Disposition Application
- EB-2022-0335 - Integrated Resource Planning - IRP - Pilot Projects
- EB-2021-0002 – Multi Year DSM Plan 2022-2027
- EB-2020-0091 – Integrated Resource Planning Proposal IRP

Lesley M Austin
Digitally signed by Lesley M Austin
Date: 2025.06.04 10:06:49 -04'00'

Exhibit E

LinkedIn: https://www.linkedin.com/feed/update/urn:li:activity:7333914736721338369

Enbridge Gas
49,803 followers
now • Edited •

The Ontario Energy Board (OEB) is holding a hearing to review Enbridge Gas Inc.'s five-year gas supply plan. Learn more. Have your say. https://lnkd.in/eayuuagi

Like Comment Repost

Facebook: https://www.facebook.com/share/p/1DdtzeM9tt/

Enbridge Gas
Published by Brian Kemp
· Just now ·

The Ontario Energy Board (OEB) is holding a hearing to review Enbridge Gas Inc.'s five-year gas supply plan. Learn more. Have your say. https://www.enbridgegas.com/-/me... **See more**

See insights and ads Boost post

Like Comment Send Share

Comment as Enbridge Gas

X: https://x.com/enbridgegas/status/1928150474730951027


Enbridge Gas @enbridgegas · 1s

Promote

The Ontario Energy Board (OEB) is holding a hearing to review Enbridge Gas Inc.'s five-year gas supply plan. Learn more. Have your say.
enbridgegas.com/-/media/Extran...