ENBRIDGE

Joel Denomy
Technical Manager
Regulatory Applications

Tel: 416-495-5499
EGIRegulatoryProceedings@enbridge.com

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

VIA RESS and EMAIL

February 1, 2021

Christine Long
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario
M4P 1E4

Dear Ms. Long,

Re: EB-2021-0004 – Enbridge Gas Inc. ("Enbridge Gas")
2021 Annual Update to 5 Year Gas Supply Plan

In accordance with the Ontario Energy Board's ("OEB") Letter dated July 6, 2020 in the EB-2020-0135 proceeding, please find attached Enbridge Gas's 2021 Annual Update to its 5 Year Gas Supply Plan.

This is the second Annual Update to the 5 Year Gas Supply Plan that Enbridge Gas has filed with the OEB pursuant to the Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans (EB-2017-0129) (Gas Supply Framework).

In a June 24, 2020 letter related to the 2020 Annual Update process, Enbridge Gas requested that the OEB allow the Company to file future Annual Updates in January or February of each year, rather than in May of each year as prescribed in the Gas Supply Framework. Enbridge Gas explained that filing of future Annual Updates in the early months of a calendar year, as opposed to mid-year, would better align with internal gas supply planning timelines which, by necessity, cannot be altered. This timing would also make it easier for Enbridge Gas to reflect outcomes from the review of the Annual Update into gas supply planning for the following winter, because the process would conclude earlier.

In a letter dated July 6, 2020, the OEB directed Enbridge Gas to file the 2021 Annual Update by February 1, 2021. The OEB noted that "[w]hether this is a permanent change to the timing of the review of GSPs will be determined at a later date".

In connection with the filing of the 2021 Annual Update, Enbridge Gas is requesting that the OEB require Enbridge Gas to file future Annual Updates by March 1 of each year. Having completed two Annual Updates to date, Enbridge Gas has determined that this timing will better align with internal gas supply planning timelines and allow for the provision of Annual Updates that contain the most up to date information. This timing would still allow for outcomes from the Annual Review process to be reflected in gas supply planning for the following year.

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

Sincerely,

Joel Denomy Digitally signed by Joel Denomy
Date: 2021.02.01 16:08:09 -05'00'

Joel Denomy
Technical Manager, Regulatory Applications

cc:
David Stevens, Aird & Berlis LLP
All Interested Parties EB-2019-0137 (5 Year Gas Supply Review)

2021 Annual Gas Supply Plan Update

EB-2021-0004

Enbridge Gas Inc.
February 1, 2021

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1. Administrative Information

1.1 Introduction

Effective January 1, 2019, Union Gas Limited ("Union") and Enbridge Gas Distribution ("EGD") amalgamated to form Enbridge Gas Inc. ("EGI"). EGI provides natural gas distribution services to over 3.8 million residential, commercial and industrial customers located throughout Ontario and Québec.

On October 25, 2018 the Ontario Energy Board ("Board") issued its Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans ("Framework")[1] which set out a new requirement for all rate-regulated natural gas distributors in the Province of Ontario to file five-year gas supply plans. The Framework also requires distributors to file an Annual Update to the 5-Year Gas Supply Plan.

EGI filed its 5-Year Gas Supply Plan[2] ("5-Year Plan") for all rate zones on May 1, 2019 based on the 2018/19 Gas Supply Plan and one year later filed the 2020 Annual Gas Supply Plan Update ("2020 Annual Update") on May 1, 2020[3]. The 2020 Annual Update was prepared prior to the onset of the COVID-19 pandemic, and as noted within the 2020 Annual Update itself, it did not contemplate any impacts the pandemic may have on Enbridge Gas's gas supply plan[4]. As a result, EGI filed a subsequent letter on June 24, 2020 requesting that EGI's 2021 Gas Supply Plan Update ("2021 Annual Update") be filed in January or February 2021 and to forego consultation with stakeholders until the 2021 Annual Update[5]. In its letter dated July 6, 2020[6], the Board accepted EGI's proposal to expedite the filing of the 2021 GSP Update and consultation such that the OEB and interested parties would receive the information by February 1, 2021 as opposed to the period of May when generally the Annual Gas Supply Plan Update ("Annual Update") is required to be filed as per the Framework.

This document is the second Annual Update to the 5-Year Plan and addresses changes to the market outlook, planning and execution process, and integration updates, inclusive of the historical comparisons of actuals required by the Framework. The 5-Year Plan and Annual Update should be read in conjunction with one another. This update is based on the 2020/21 Gas Supply Plan ("Plan") for November 1, 2020 to October 31, 2025 which received internal senior management approval in Q3 2020.

EGI's Plan covers the EGD rate zone[7] and the Union rate zones (Union North West[8], Union North East[9] and Union South). The objective of EGI's Plan is to identify an efficient combination of upstream

[1] EB-2017-0129
[2] EB-2019-0137
[3] EB-2020-0135 EGI Gas Supply Plan Update
[4] EB-2020-0135 EGI Gas Supply Plan Update - Page 6
[5] EB-2020-0135 Ltr EGI Annual Update Gas Supply Plan – Page 2
[6] EB-2020-0135 Kick off letter – Review of Gas Supply Plans - ENGLP
[7] Enbridge EDA, Enbridge CDA
[8] Union MDA, Union SSMDA, Union WDA
[9] Union EDA, Union NCDA, Union NDA

transportation, supply purchases, and storage assets to serve sales service and bundled ("DP") customers' annual, seasonal and design day natural gas delivery requirements while adhering to the set of gas supply planning guiding principles as outlined in the Framework.

1.2 Significant Changes

This document is the second Annual Update to EGI's 5-Year Plan.

The 5-Year Plan contains in-depth descriptions of methodologies and related gas supply processes. This submission provides an update to the processes and portfolio detailed in the 5-Year Plan.

The Annual Update captures four notable changes:

1. Market changes including COVID-19 impacts;
2. Public Policy initiatives and pilots;
3. Contracting changes; and
4. Changes to existing processes.

Discussion on impacts to EGI's demand forecast including but not limited to the COVID-19 pandemic are included in Section 5. The current forecast was produced in the summer of 2020 and reflects the best information available at the time. This includes actual 2019 consumption data, forecasted growth, and updated demand driver variables.

Overall natural gas market outlooks are provided in Section 4, with Section 4.1 detailing changes as they may affect EGI's supply option alternatives and analysis. The discussion on market changes includes those relevant to the North American natural gas market, natural gas price signals, and Ontario natural gas demand along with changes related to available assets.

During 2020, EGI has received approval on a pilot basis for two low carbon energy initiatives that will see future acquisitions of RNG and Hydrogen supply. These initiatives are detailed in Section 4.2 along with updates to carbon pricing and other public policy initiatives.

EGI continues to work towards harmonizing its two legacy planning processes and to make changes to existing processes including further improvements for transparency, efficiency, and alignment with OEB requirements. Refinements to EGI's Gas Supply organizational structure, gas supply planning processes, and the Blind RFP Process are discussed in Section 2 while progress on the Gas Supply Plan Harmonization Project ("Project") is outlined in Section 3.

2. Continuous Improvement Strategies

EGI continues to enhance its gas supply planning processes and practices. EGI will continue to evaluate and act on opportunities to improve on its gas supply planning process and practices as they arise in accordance with the guiding principles identified in the Framework.

Since filing EGI's 5-Year Plan, the Gas Supply department ("Gas Supply") has analyzed the existing processes, identified the best elements of each legacy process and created new processes which continue to balance reliability, flexibility, and diversity while remaining cost-effective. Several of these improvements were identified in EGI's 2020 Annual Update[10].

EGI has made additional improvements since filing the 2020 Annual Update. These improvements, explained in more detail below, include but are not limited to the following:

- Refinements to the Gas Supply organizational structure
- Blind RFP process enhancement.

Refinements to Gas Supply Organizational Structure

During Q4 of 2020, EGI made a refinement to the organizational structure of the Gas Supply team. This involved moving accountabilities for procurement of storage and transportation assets to the same group accountable for procurement of the gas commodity. This consolidation of the procurement function under one group is anticipated to improve the efficiency of information sharing and knowledge transfer and improve overall procurement decision-making.

Further to the consolidation of the procurement function, accountabilities for EGI's non-OEB regulatory function have also been moved to the Gas Supply team. These accountabilities include the monitoring of regulatory matters impacting upstream transportation assets held by EGI as well as the management of reporting requirements associated with EGI storage and transportation assets regulated by non-OEB parties such as the CER, FERC, and various state and provincial regulators. This change is also anticipated to improve the efficiency and effectiveness of information sharing that is important for the Gas Supply team to carry out their accountabilities.

Blind RFP Process

As discussed in the stakeholder presentation for the 5-Year Plan, EGI purchases storage services on behalf of customers in the EGD rate zone through a competitive blind RFP process. A blind RFP process is used for these purchases because EGI and its affiliates own and operate a significant amount of non-utility storage facilities in Ontario.

In its Final Report on the 5-Year Plan, Board Staff raised concerns that the blind RFP process is not entirely "blind" and therefore, the "process does not effectively ring-fence EGI's gas supply procurement group from its own non-utility storage and that the process does not eliminate concerns of possible bias"[11]. It was also recommended that the process be refined to eliminate follow-up requests with the RFP manager by ensuring that the RFP manager had sufficient natural gas expertise to provide EGI with the winning bids only. It was recommended by stakeholders that EGI should be required to undertake a third-party independent expert assessment of its blind RFP process by someone with natural gas experience.

[10] EB-2020-0135 EGI Annual Gas Supply Plan Update
[11] EB-2019-0137 Final OEB Staff Report – page 32

EGI provided detail on enhancements made during 2019 to the blind RFP process in EGI's 2020 Annual Update[12]. Some of these changes included having the RFP manager convert all bids into common units of measure and currency and including any necessary transportation costs in the overall price of a storage bid.

During the OEB process to review the 5-Year Plan, EGI accepted stakeholder recommendations that the blind RFP process should be reviewed by a third-party independent expert who has natural gas experience. EGI sought proposals from parties to conduct this evaluation in the spring of 2020 and selected ScottMadden Management Consultants ("ScottMadden"). ScottMadden is a general management consulting firm serving the North American energy market with relevant experience in the natural gas industry. CV's of the ScottMadden project team members are included as Appendix A. ScottMadden provided its final report on October 9, 2020 and has been included as Appendix B.

ScottMadden's Key Recommendations include;

- Expanding the criteria and requirements for choosing an external RFP manager
- Defining and documenting the roles and responsibilities of EGI and the external RFP manager
- Revising the RFP letter, bid template and bid instructions to increase clarity and reduce follow up questions from RFP bidders
- Extending the bidding period to allow bidders more time to submit bids
- Having the external RFP manager conduct Round 1 of bid evaluations and provide initial rankings and recommendations to EGI

EGI has incorporated recommendations from ScottMadden Management Consulting's report into its blind RFP process that took place during January 2021.

3. Integration

3.1 Early Successes

The gas supply planning process is an integrated process that begins months in advance of the upcoming gas year with multiple teams executing on numerous internal processes. Gas Supply has placed an emphasis on cross-functional communication and project management best practices to ensure proper education and training and tasks are completed efficiently.

The gas supply planning project management structure has two levels; a large, cross-functional team that is tasked with managing the overall project deliverables as well as smaller sub teams that are responsible for specific deliverables. This structure allows for the efficient communication of timelines, deliverable status, priorities, and provides a forum to identify unplanned challenges and

[12] EB-2020-0135 EGI Annual Gas Supply Plan Update – page 9

solutions. Each sub-team is responsible to maintain its own schedule and to report to the cross-functional team.

Implementing this structure has resulted in improved communication across the utility and increased awareness to each team and how their efforts impact others. This understanding is important because EGI is still adjusting to an amalgamated state. If original expectations change due to unforeseen circumstances, communication of those changes can be carried out in a quick and effective manner and adjustments can be made swiftly.

During the first two years of combining the legacy utility gas supply functions, EGI has accomplished many integration enhancements and efficiencies[13]. Integration-related accomplishments during 2020 include:

- Further refinements to the Gas Supply organizational structure to increase the flow of reporting and to better align with group accountabilities
- Training and transitioning of responsibilities
- Further refinement to the blind RFP process to reflect recommendations in the ScottMadden final report
- Coordination of the timeline for development of the Gas Supply Plan for each rate zone, establishing improved communication and increasing overall efficiency of the planning process
- Combined, consolidated, and aligned the Gas Supply plan input processes and information formatting increasing overall efficiency of the process
- Reduced the number of staff and resources required to generate and review the Gas Supply Plan output information

3.2 Continuing Efforts

Bringing the Gas Supply teams together allowed for processes and practices to be combined and created the opportunity for increased knowledge sharing. As discussed above, the initial steps taken towards integration were fundamental in bringing the two legacy Gas Supply teams together.

Combining the gas supply plans of the legacy utilities is not a straightforward process. EGI is bound by pre-existing regulatory processes, Board approved methodologies, and rate structures. As integration continues, the appropriate time to present changes to Board approved methodologies is at rebasing, as confirmed in the Final Report[14]. EGI intends to use the deferred rebasing period to evaluate and recommend appropriate changes as part of the rebasing process.

Gas Supply Plan Harmonization

Gas Supply plays a major role in planning and execution of the gas supply plan for the utility, with expenditures of more than $2 billion annually. Over the past two years, EGI has worked to integrate

[13] Accomplishments from 2019 can be found at EB-2020-0135 EGI Annual Gas Supply Plan Update – page 11
[14] EB-2019-0137 Final OEB Staff Report, page 27

its two legacy planning processes into one; however, since some methodologies require Board approval, EGI has not been able to fully align across rate zones.

In order to facilitate the review and recommendations of changes, EGI has initiated a project to provide recommendations for harmonizing the complex underlying methodologies used in the Gas Supply planning process.

This project will require collaboration with EGI's Finance, Regulatory, Engineering, and Operations departments.[15] More details regarding the scope of the project including a listing of the planning categories and timeline are discussed below with additional details to be determined in 2021.

EGI's 2020 annual planning process was leveraged in Q1 and Q2 of 2020 to engage departments to review all inputs, outputs, forms and processes completed by Gas Supply to help further identify the work required.

The project focuses on ensuring documentation of the following seven planning categories[16]:

1. Weather Assumptions – Includes annual degree days, monthly distribution, multi-peaks, design day weather
2. Customer Growth Assumptions – Includes annual unlocks/customer growth, monthly distribution of customer growth
3. Demand Assumptions: Average Day – Includes annual demand, monthly distribution, customer types
4. Demand Assumptions: Design Day – Includes design criteria, unlocks assumptions, curtailment assumptions and consideration of interruptible rates policies, customer types
5. Transportation Assumptions – Includes input sources, allocation of capacity, modeling parameters
6. Storage Assumptions – Includes input sources, allocation of space, modeling parameters
7. Supply Assumptions – Includes input sources, supply price assumptions, direct purchase delivery assumptions, modeling parameters

Reviewing the seven categories above will identify which legacy best practices can be improved upon and which items will require Board approval.

As noted above, EGI's Finance, Regulatory, Engineering, and Operations departments will be involved in conducting evaluations and providing recommendations. Significant effort and coordination across EGI will be necessary in order to evaluate each item and recommend changes. It is expected that some items may require engaging expert consultants to provide opinions as well as having recommendations considered and determined by the Board.

[15] See EB-2019-0137, Appendix A for process flows
[16] The review and documentation of these items will be led by Gas Supply. Other departments will be completing specific tasks to evaluate and make recommendations for changes, as discussed in Phase Three.

At this time, the project is scheduled to continue throughout 2021. Timing and resource requirements are anticipated to be outlined in EGI's Annual Update filed in 2022.

Once the requirements are understood and recommendations are accepted, creation of a single integrated model will begin.

IT System Integration

In support of the 2019 amalgamation of the two legacy utilities, one of the key integration requirements impacting Gas Supply is the integration of the IT systems used for contracting, invoice management, and accounting for gas supply related procurement. Currently EGI has two distinct processes and systems for these functions for each of the legacy utilities.

In 2019, a project kicked off with the purpose of integrating all underlying IT systems that support the gas supply purchasing and accounting functions for EGI. The project is currently expected to be complete by the end of 2021.

The mandate of the project is to develop an integrated and automated utility gas purchasing and financial reporting solution. This includes an integrated solution to contract for, purchase, nominate, manage invoicing, manage credit and risk requirements, book gas costs, maintain accounting records and associated deferrals for financial, regulatory reporting and inventory management for all rate zones. Achieving integration synergies for the amalgamated utility depends on a single integrated and automated solution to address this entire stream of processes.

4. Market Overview

4.1 Market Outlook

In 2020 North American energy markets were impacted from the COVID-19 pandemic as well as a steep decline in oil prices. The demand destruction from COVID-19 is mainly affecting the commercial sector, with many schools, offices, restaurants, and retail outlets closed in several states, and the industrial sector, where demand is down mainly from the chemical and refinery sector.[17] EGI has noted similar impacts in Canada and continues to monitor market intelligence from external sources as well as internal sources to stay informed on changing market conditions.

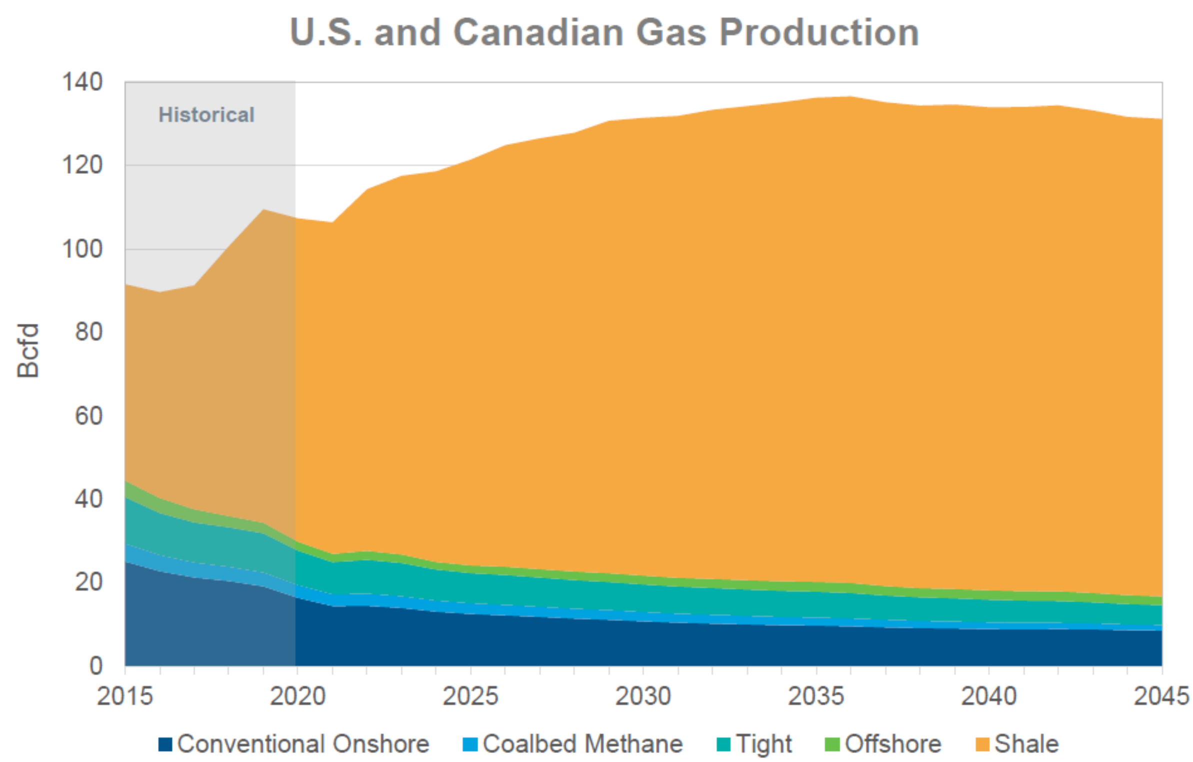
North American Supply

North American natural gas production in the near-term is expected to be lower as many producers cut back production and capital spending due to the low commodity price environment. U.S. dry natural gas production is not expected to return to 2019 levels until 2022. Total Canadian and U.S. gas production is expected to increase by 0.8% per year on average from 2020. Increased production is driven by growth in production of shale gas. By 2025, shale gas production will account for about 71%

[17] ICF Q4 2020 Natural Gas – Strategic

of all U.S. and Canadian gas production. Conventional production is expected to decline by 2.6% annually.[18]

Figure 1 - U.S. and Canadian Natural Gas Production by Type



Source: ICF Q4 2020 Natural Gas – Strategic. Used with permission.

In its 2020 Energy Future ("EF2020"), the Canada Energy Regulator ("CER") projects Western Canadian Sedimentary Basin ("WCSB") natural gas production will remain consistent until 2025 and then grow to 18.4 Bcf/d by 2040. In the longer term, rising prices and the onset of LNG export demand support higher capital expenditures from producers and therefore natural gas production growth.[19]

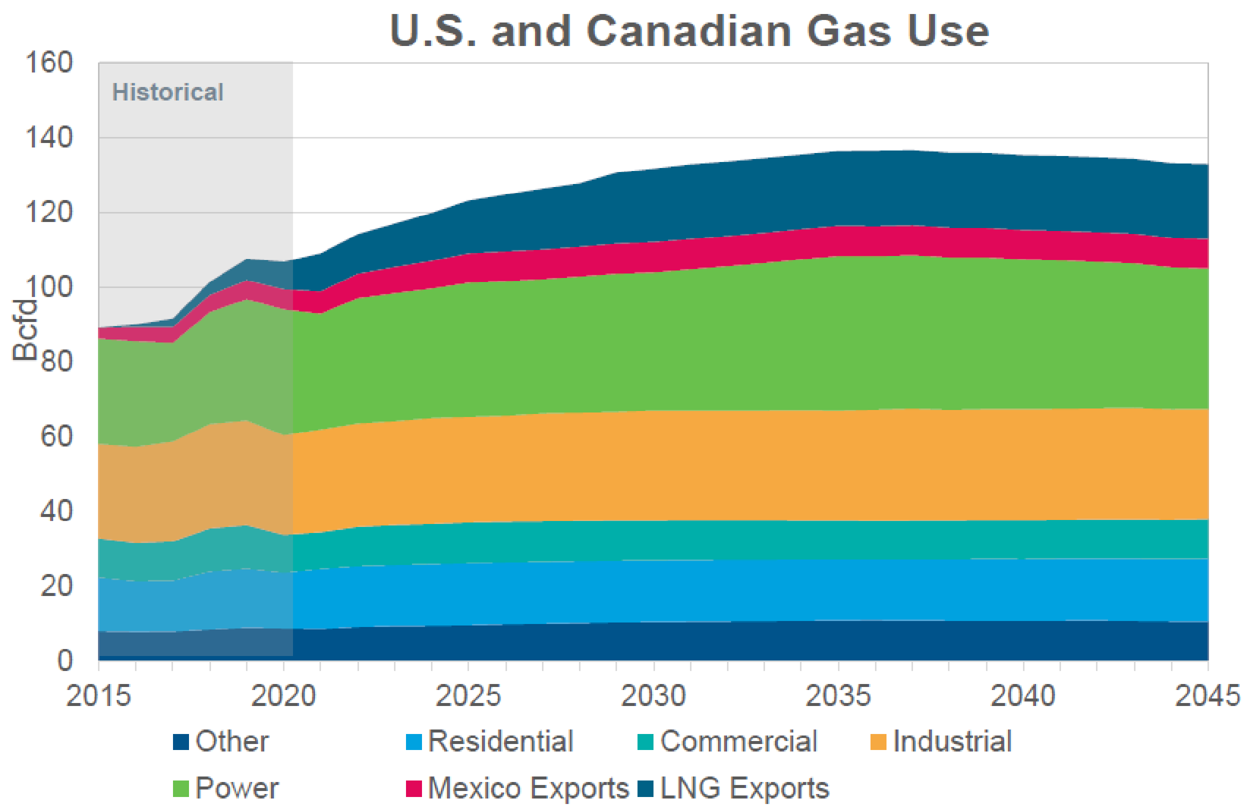
Natural Gas Demand

The impact of restrictions related to COVID-19 on Canadian energy consumption has been significant with the greatest impact to Refined Petroleum Products ("RPP's") used for transportation such as gasoline, diesel, and jet fuel. Consumption of natural gas in Canada fell in early 2020, but not as significantly as RPP consumption.[20] U.S. and Canadian natural gas demand is expected to decline due to the slowdown in economic activity in 2020. Gas demand from the residential sector increases slightly while the commercial demand continues to fall with some recovery starting in 2021. The decline in industrial demand in 2020 included a significant reduction in refinery demand for natural

[18] ICF Q4 2020 Natural Gas Strategic
[19] CER – Canada's Energy Future 2020
[20] CER – Canada's Energy Future 2020

gas as lower demand for transportation fuels and other petroleum products eroded domestic refinery natural gas demand.

Figure 2 - U.S. and Canadian Gas Use



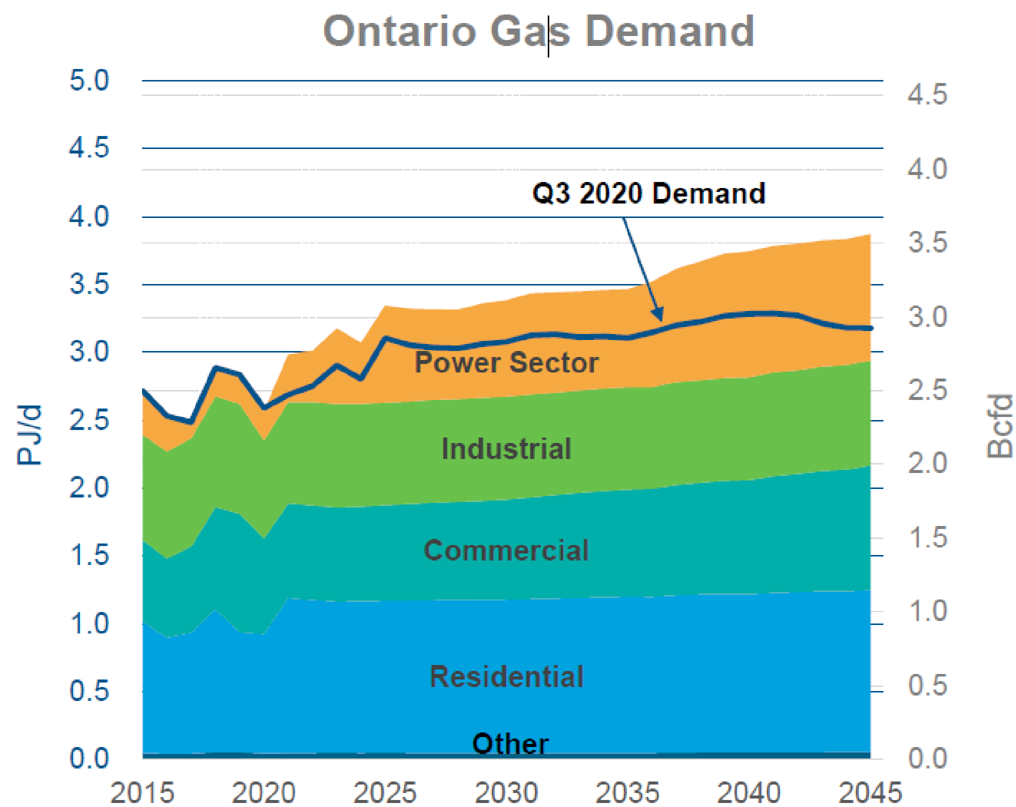
Source: ICF Q4 2020 Natural Gas – Strategic. Used with permission.

In Ontario, COVID-19's effect on natural gas demand has been as much as a 7% to 12% reduction since the pandemic began with the most significant impacts seen in April and May 2020. Consumption was down in all sectors except for power generation with the largest declines seen in the commercial and industrial sectors.

ICF forecasts overall Ontario demand in 2021 to exceed pre-COVID 2019 levels. Residential, commercial, and industrial sector natural gas demand in Ontario has recovered more quickly than expected. In the longer term, ICF forecasts average demand in Ontario to grow by 1.59% until 2045. Demand growth is greatest in the power sector and is primarily due to nuclear retirements and refurbishments.[21]

[21] ICF Q4 2020 Natural Gas – Strategic

Figure 3 - Ontario Natural Gas Demand



Source: ICF Q4 2020 Natural Gas – Strategic. Used with permission.

Natural Gas Price Signals

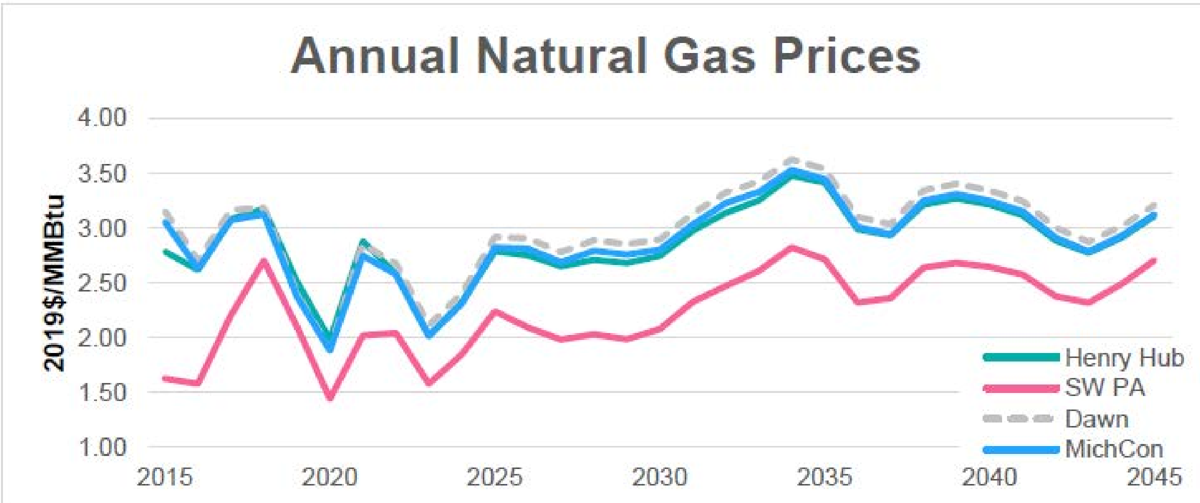
Throughout the winter of 2019/20, natural gas prices were historically low. This was driven by warmer than normal winter temperatures which kept demand for natural gas low, while continued supply from Marcellus, Utica, Permian, and Haynesville production basins kept supply buoyant. North American storage levels were consistently above the five-year average, providing downside pressure on prices. According to the U.S. Energy Information Administration ("EIA")[22] October 2020 storage levels across North America were more than 5% higher than the five-year average. However, EIA forecasts that declines in U.S. natural gas production this winter compared with last winter will more than offset the declines in natural gas consumption, which will contribute to inventory withdrawals outpacing the five-year average during the remainder of the winter season that ends in March 2021. Forecast natural gas inventories are expected to end March 2021 at 1.6 Tcf, 12% lower than the 2016-20 average. This is expected to place upward pressure on near-term natural gas prices. Despite these near-term forecasted price increases, natural gas prices remain low relative to historic averages.

Natural gas prices set at Henry Hub are generally seen to be the primary price for the North American natural gas market with locational basis differentials based off the New York Mercantile

[22] EIA January 2020 Short-term Energy Outlook: https://www.eia.gov/outlooks/steo/report/natgas.php

Exchange ("NYMEX"). ICF forecasts that Henry Hub prices will remain between $1.88 and $3.35 USD/MMBtu in the longer-term as shown in Figure 4.

Figure 4 - Comparative Long-Term Natural Gas Prices



Source: ICF Q4 2020 Natural Gas – Strategic. Used with permission.

Transportation Market Overview

This section describes market changes relating to transportation which have a direct impact to EGI's Gas Supply Plan and related supply option analysis.

TransCanada PipeLines Limited ("TCPL")

TCPL continues to focus on filling its existing capacity and creating services that help the WCSB supply Eastern markets.

Post-2020 Mainline Tolls & Abandonment Surcharges

On December 20, 2019, TCPL filed the 2021-2026 Mainline Settlement Application (the "Settlement")[23] with the CER. The Settlement and associated tolling framework were approved on April 17, 2020[24]. The then-current tolling framework of the Mainline expired on December 31, 2020. The Settlement addresses tolling and certain service matters on the TCPL Canadian Mainline ("Mainline") for the six-year period effective January 1, 2021.

On October 30, 2020 in compliance with CER Order TG-003-2020 and the settlement[25], TCPL filed an application for a one-time adjustment to the revenue requirement associated with the Long Term

[23] The Settlement Application is comprised of CER Filings C03833-1 and C03833-2
[24] CER Order TG-003-2020
[25] CER Filing C03833-2 Attachment 1 Unanimous TTF Resoluition 02.2019 – Section 9.1

Adjustment Account ("LTAA")[26] to be used in the determination of final tolls. Following review, the CER approved the adjustment and final tolls as filed on December 14, 2020[27] to be effective January 1, 2021.

As approved, the forecast LTAA balance included in the Settlement's revenue requirement and allocation of the balance were amended as follows[28]:

- The LTAA balance included in calculation of the revenue requirement was updated from approximately $200 million CAD to approximately $223 million
- The allocation of the LTAA balance in following the methodology approved in the Supplemental Agreement to the Mainline Settlement Agreement[29] was updated from 50% Western Mainline/50% Eastern Triangle to approximately 42% Western Mainline/58% Eastern Triangle

The above amendments to the LTAA balance and allocation resulted in impacts to final 2021-2026 Tolls[30]:

- A decrease of approximately 1.2% to Eastern Triangle tolls compared to the Settlement 2021-2026 Tolls
- An increase of approximately 0.6% to Western Mainline tolls compared to the Settlement 2021-2026 Tolls

In addition to updating the forecast LTAA balance and final tolls, TCPL also filed an application for the Mainline's abandonment surcharges on October 30, 2020.[31] On review, the CER approved the abandonment surcharges as filed on December 11, 2020 to be effective January 1, 2021 to December 31, 2021.[32]

Existing TCPL Mainline Capacity & Constraints

EGI reported in its last annual update that long-haul Firm Transportation ("FT") capacity has not been consistently available on the TCPL Canadian Mainline due to an increase in FT contracting. EGI expects that this long-haul capacity may be available at various times over the next five years through existing capacity open seasons as a result of de-contracting, line maintenance, and integrity work. Long-haul capacity is currently available. This change of capacity availability is a consideration when EGI

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[26] CER Filing A2C6O0 Application for Business and Services Restructuring Proposal and 2012 and 2013 Mainline Final Tolls (RH-003-2011) Section 07 Toll Design – subsection 7.7.1 Long Term Adjustment Account
[27] CER Filing C10387 CER Order TG-014-2020
[28] CER Filing C09248-1 TCPL 2021-2026 Mainline Settlement_One Time LTAA Adjustment_Final Tolls – Pg. 2 – Updated Forecast of the LTAA Balance and Allocation to Segments
[29] CER RH-001-2018 Application for the 2018-2020 Mainline Tolls
[30] CER Filing C09248-1 TCPL 2021-2026 Mainline Settlement_One Time LTAA Adjustment_Final Tolls – Pg. 3 – Impact to Final 2021-2026 Tolls
[31] CER Filing C09246-1 TCPL_Application for approval of 2021 Abandonment Surcharges
[32] CER Filing C10358 CER Letter and Order TG-013-2020

evaluates transportation alternatives, and EGI will continue to monitor what becomes available in the market.

New Service Offerings

In 2020, there were existing capacity open seasons offering capacity made available as a result of maintenance on the prairies section of TCPL's Canadian Mainline as well an offering for Dawn LTFP 2.

Included as part of the Post-2020 settlement agreement is a new, complaint-based Market Driven Service ("MDS"). MDS will be offered by TCPL through the use of existing capacity or capacity that can be made available in the future if maintenance is undertaken. In either case, a minimum quantity of FT service will also be offered during an MDS Open Season, as detailed in Section 6.1 of TCPL's Transportation Access Procedure. TCPL is required to provide an analysis of the net benefit to the Mainline system as a result of each MDS offering. In response to the net benefit analysis, should any shipper feel the service is not in the best interest of the mainline, they may file a complaint directly with the CER. The MDS can only proceed once any and all complaints received by the CER are resolved or dismissed.

MDS service provides TCPL with a means of discounting and marketing uncontracted capacity on their system and could have an impact on transportation alternatives available to EGI.

Key elements of the MDS are as follows:

- Maximum of 400 TJ/d can be offered in an MDS open season;
- Primary and secondary delivery points only eligible on the Western Mainline and to Union SWDA, Enbridge SWDA, and Dawn Export;
- Diversions and alternate receipt points are not available; and
- Minimum and maximum terms apply.

Panhandle

On August 30, 2019, Panhandle Pipelines filed a Section 4 application[33] with the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act. Panhandle Pipelines proposed rate changes for existing services and changes to certain terms and conditions of service. These rates became effective March 1, 2020 on an interim basis pending FERC approval. The proposed rates have been reflected beginning with EGI's April 1, 2020 QRAM application[34] and will increase the annual bill for a typical residential customer on system gas in Union South by <1%. EGI estimates that FERC will render its decision on the Panhandle Pipelines rates application in 2021.

[33] RP19-1523-000
[34] EB-2020-0077

New Sources of Supply to Ontario

New projects that will increase deliveries of supply to Ontario include two projects being developed by National Fuel Gas Company ("National Fuel") in the U.S. Northeast which will deliver an incremental 660 MMcf/d (719 TJ/d) of supply to the Chippawa receipt point. This incremental capacity could increase market depth at Chippawa and may result in increased deliveries of gas to Dawn via TCPL's Canadian Mainline and EGI's Dawn Parkway System facilities.

The first of these two projects is the Northern Access project which will add 490 MMcf/d (535 TJ/d) of capacity to the Chippawa receipt point. The project has been forced to revise its in-service date multiple times and is not expected to be in service until at least 2022.

National Fuel's second project is the Empire North Project. which went into service in 2020 and provides an incremental 170 MMcf/d of delivery to the Chippawa receipt point.

4.2 Public Policy Updates

EGI will continue to be responsive to public policy. EGI will speak to the aspects of public policy that impact the gas supply plan, including in the execution of the gas supply function in accordance with the guiding principles set forth by the OEB in the Framework. The following sections demonstrate EGI's commitment to remain responsive to public policy.

Renewable Natural Gas ("RNG")

The Ontario government released the Made-in-Ontario Environment Plan ("MOEP") on November 29, 2018, which outlines a requirement for natural gas utilities to implement a voluntary RNG option for customers. The Ontario government will also consult on the appropriateness of clean content requirements[35]. EGI recognizes the importance of emissions reduction in Ontario, as well as the important role that EGI plays in supporting the achievement of GHG emission reduction targets.

An application for EGI's proposed Voluntary RNG program was filed with the OEB on March 5, 2020[36] proposing to offer system gas general service customers the option to pay a fixed $2 monthly charge to fund the incremental cost of procuring RNG as part of the overall system gas supply. The amount of RNG procured will depend on the number of participants in the Voluntary RNG Program, the availability of RNG, as well as the cost difference between RNG and traditional natural gas at any given time. On September 25, 2020, the OEB granted EGI approval of the program on a pilot basis until the OEB issues a further decision on the program.

EGI will launch the program in 2021 and begin procuring RNG thereafter. EGI forecasts total RNG procurement for the voluntary program to reach approximately 35,000 GJ by the third year of the program.

[35] Ontario Ministry of the Environment, Conservation and Parks, "Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan", page 33, https://www.ontario.ca/page/made-in-ontario-environment-plan
[36] EB-2020-0066

Low Carbon Energy Project

EGI submitted a Leave to Construct application for the Low Carbon Energy Project ("LCEP") with the OEB on March 31, 2020[37]. As proposed, the pilot project will supply natural gas blended with up to 2% renewable hydrogen by volume to around 3,600 customers in Markham, Ontario. EGI will report findings as per Schedule B of the OEB's Decision and Order following the first five years of blending operations.

Blended gas, due to its hydrogen content, will emit less greenhouse gas emissions than traditional natural gas. The experience gained through implementation of the LCEP will help EGI determine whether to expand hydrogen blending to other parts of the distribution system. The LCEP pilot project, and future projects of the same type, will expand EGI's ability to support current and future government policies and objectives aimed at reducing greenhouse gas emissions.

Community Expansion

EGI has several community expansion projects underway, made possible through funding provided by Phase One of the Province of Ontario's Natural Gas Expansion Support Program. These projects include bringing natural gas to the communities of Chippewas of the Thames First Nation, North Bay-Northshore and Peninsula Roads, Saugeen First Nation, Scugog Island, and Chatham Kent Rural. EGI also brought natural gas to Fenelon Falls and Moraviantown First Nation, made possible with funding provided by the Ontario Government's previous Natural Gas Grant Program.

EGI is committed to building on success to date by working with all levels of government to bring affordable, reliable natural gas to more rural, northern and Indigenous communities across Ontario. In December 2019, the Government of Ontario announced its intention to continue to expand access to natural gas with the Phase Two of the Natural Gas Expansion Support Program, allocating approximately $130 million to support new natural gas expansion projects. EGI submitted project proposals to the OEB for review and consideration. The OEB was mandated to provide recommendations to the Ministry of Energy, Northern Development and Mines by October 31st, 2020 to assist in selecting the future expansion projects that will receive funding. It is expected that EGI and other project proponents will be advised early in 2021 as to which projects will receive funding.

Federal Carbon Charge

EGI filed an application[38] on September 30, 2020, seeking Board approval for rates effective April 1, 2021 to recover costs associated with meeting its obligations under the federal *Greenhouse Gas Pollution Pricing Act* ("GGPPA").

As of April 1, 2021, the Federal Carbon Charge that EGI must remit to the Government of Canada under the GGPPA for eligible volumes of natural gas will increase from $30 per tonne of carbon dioxide equivalent ("tCO_2e") to $40 per tCO_2e.

[37] EB-2019-0294
[38] EB-2019-0247

The demand forecast underpinning the 2021 Annual Update includes this federal carbon charge in the price-related demand driver variables used in its regression equations. EGI assumes $40 per tCO_2e in 2021, increasing by $10 per tCO_2e annually until it reaches $50 per tCO_2e in 2022.

Federal Clean Fuel Standard

The federal government is developing a Clean Fuel Standard ("CFS"), which will require fossil fuel producers, importers and distributors to reduce the carbon intensity of the fuels used in Canada. In December 2020, the federal government announced that the proposed CFS will not impose a compliance obligation on gaseous or solid fuels. The CFS will only impose a compliance obligation on the liquid fuels sector.However gaseous fuel producers, importers and distributors may have the ability to participate in CFS by generating credits for production/import of low carbon fuels, such as RNG and hydrogen. As a result, EGI anticipates that any RNG or hydrogen procured as part of the Company's supply portfolio may generate CFS credits, effectively lowering the cost of these fuels. As the CFS regulation has not been finalized, impacts of the CFS have not been considered in the 2021 Annual Update.

Integrated Resource Plan ("IRP")

In Procedural Order No. 1 in the Dawn-Parkway Expansion proceeding, issued January 30, 2020, the OEB found that the IRP Proposal raised issues of broad applicability that would be best dealt with outside of a project-specific Leave to Construct proceeding, also determining that Enbridge Gas' IRP Proposal would be heard separately from the Leave to Construct application. On April 28,2020 the OEB issued a Notice of Hearing for the Enbridge Gas Integrated Resource Planning Proposal, (EB-2020-0091) initiating this proceeding to determine an IRP Framework for Enbridge Gas. This proceeding is now underway with an oral hearing scheduled for March 2021. Enbridge Gas recognizes that the IRP Framework will set out a role for non-pipeline solutions to meet customer needs in the future, and that outcomes of the IRP Framework may need to be addressed in future Annual Updates.

5. Demand Forecast Analysis

EGI's in-franchise customers are divided into two customer segments: the general service market and the contract market. General service customers in the EGD rate zone are billed on Rate 1 or Rate 6, and Rate M1, Rate M2, Rate 01 or Rate 10 for the Union rate zones. EGI's general service customers are mostly residential and small commercial customers who primarily use natural gas for space heating. As such, their consumption follows a seasonal consumption profile based on temperature throughout the year. The remaining rate classes make up the contract market. These customers are mostly large industrial firms, and their consumption tends to follow a steadier baseload pattern over the year.

EGI provides distribution services to all in-franchise customers, however customers have the option to purchase their supply from EGI as a sales service customer or arrange their own supply through a DP arrangement.

EGI's proportion of general service and contract customers volume is outlined in Figure 5. This is further split by sales service and DP customer types.

Figure 5 - EGI Service Types

5.1 Annual Demand

The 2021 Annual Update is based on the demand forecast for the general service market and contract market rate classes as prepared by EGI's Demand Forecasting & Analysis department. The annual demand forecasts are prepared separately for the EGD rate zone and the Union rate zones, using Board approved methodologies[39]. As mentioned in Section 3.2, EGI is currently evaluating its annual demand forecast methodologies and will provide the results and any proposed changes as part of its rebasing application.

The current forecast was produced in the summer of 2020 and reflects the best information available at the time. This includes actual 2019 consumption data, forecasted growth, and updated demand driver variables. At the time of filing this document, EGI does not expect any additional variance from what was included in the forecast related to the COVID-19 pandemic. Overall, the pandemic is expected to reduce total annual demand in EGI's forecast in the contract market in 2020, with volumes beginning to return to pre-pandemic levels in 2021. EGI expects the pandemic to have a very modest impact to general service volumes resulting from lower forecasted housing starts and delayed growth from attachments.

Table 1 below illustrates the annual demand forecast for each rate zone[40]. Overall, the current forecast is showing higher demand compared to the 2020 Annual Update as a result of updated driver variables, recent actual consumption trends, and known and forecasted customer and contracted demand growth. Compared to the previous forecast, general service demands are about 2.8% higher on average, driven by updated average use, partially offset by a lower customer forecast. The contract market overall is an average 4.2% higher than the previous plan as a result of updated sales information, higher firm contract demand in some markets and planned growth. EGI's total annual demand is expected to be almost flat, increasing by an average of 0.3% over the forecast period.

Year over year, increasing demand from customer growth is slightly outpacing decreases related to DSM savings and other efficiencies. Energy efficiency advances and the expectation of higher gas prices, mainly driven by the federal carbon charge[41], continue to play a role in reducing both general service and contract market demand growth.

[39] RP-2000-0040, EB-2014-0276 for EGD, and EB-2011-0210 for Union

[40] Annual demands include general service and contract market. Other volumes (i.e. Gazifere, unaccounted for gas, company use) are excluded.

[41] The forecast assumes \$30 per tCO_2e for 2020, increasing by \$10 per tCO_2e annually until it reaches \$50 per tCO_2e in 2022. A 2% per year increase is forecasted thereafter.

Table 1 - Annual Demand Forecast

Line No.	Particulars (TJ)	2020/21	2021/22	2022/23	2023/24	2024/25
	EGD					
1	General Service	388,193	390,299	392,361	395,340	396,176
2	Contract	70,625	70,148	69,784	69,513	68,861
3	Total EGD	458,819	460,448	462,145	464,853	465,037
	Union North West					
4	General Service	14,335	14,470	14,484	14,601	14,579
5	Contract	1,636	1,683	3,767	4,803	4,798
6	Total Union North West	15,971	16,153	18,252	19,404	19,377
	Union North East					
7	General Service	38,290	38,646	38,671	38,961	38,892
8	Contract	3,763	3,878	3,884	3,871	3,858
9	Total Union North East	42,053	42,524	42,555	42,832	42,750
	Union South					
10	General Service	175,431	175,430	175,133	175,944	175,170
11	Contract	54,127	56,738	57,587	55,609	54,407
12	Total Union South	229,558	232,168	232,720	231,553	229,577
13	Total Demand Forecast	746,401	751,292	755,671	758,642	756,741

5.2 Design Day Demand

EGD rate zone design day demand weather conditions are based on a 1 in 5 recurrence interval[42] using a lognormal distribution. The Union rate zones design day demand weather conditions are based on the coldest observed degree day.[43] Table 2 below illustrates the design day demand forecast for each rate zone. As the customer base continues to increase EGI's design day demand is expected to increase relative to annual demand primarily because DSM and efficiency gains are typically targeted at reducing annual demand as opposed to specifically reducing design day demand.

[42] A recurrence interval is defined as the average frequency, in years, in which an actual weather event or HDD level is expected to exceed that of the design level one time. For example a 1 in 10 recurrence interval would mean that the HDD level assumed on peak day is expected to be exceeded once every ten years. Another way to express this statement is that there is a 10% probability that the specified peak day HDD value would be exceeded in any given year.

[43] In the coldest day method, the design day HDD value is selected by choosing the coldest day on record and utilizing this HDD value to derive the design day demand that is used to establish the gas supply and transportation portfolio.

Table 2 - Design Day Demand Forecast

Line No.	Particulars (TJ/d)	2020/21	2021/22	2022/23	2023/24	2024/25
1	EGD	4,022	4,040	4,057	4,074	4,090
2	Union North West	128	128	128	128	127
3	Union North East	398	404	406	410	409
4	Union South	3,137	3,175	3,275	3,450	3,486

6. Current Portfolios

6.1 Commodity Portfolio

EGI procures supply on behalf of its system sales service customers. The commodity portfolio reflects many years of planning which leverages much of the North American natural gas supply landscape, including supply from sources such as: the WCSB, Dawn, Chicago, Niagara, US Midcontinent, and the Appalachian Basin in the U.S. Northeast. These supply sources, along with EGI's transportation contracts which move the supply to both the distribution system and storage assets, has resulted in a commodity portfolio which is diverse, flexible, reliable, and cost-effective.

To serve Union North West, EGI holds firm transportation contracts connecting to supplies in Western Canada via the TCPL Mainline; the only pipeline available to directly supply these areas of EGI's franchise.

For Union North East, EGI holds firm transportation contracts on multiple upstream pipelines providing access to supplies in Western Canada, Appalachia and Dawn. In addition, the Union North East rate zone can receive supply from third-party services, such as peaking services or delivered supply arrangements.

In order to serve the EGD rate zone, EGI holds firm transportation contracts on multiple upstream pipelines providing access to supplies in Western Canada, Chicago, Niagara, Dawn and Appalachia. In addition, the EGD rate zone can receive supply from third-party services, such as peaking services or delivered supply arrangements.

Similarly, EGI holds firm transportation contracts on multiple upstream pipelines to serve Union South, providing access to supplies in Western Canada, Chicago, Niagara, the U.S. Mid-Continent and Appalachia. Dawn purchases are also included as part of the Union South supply portfolio.

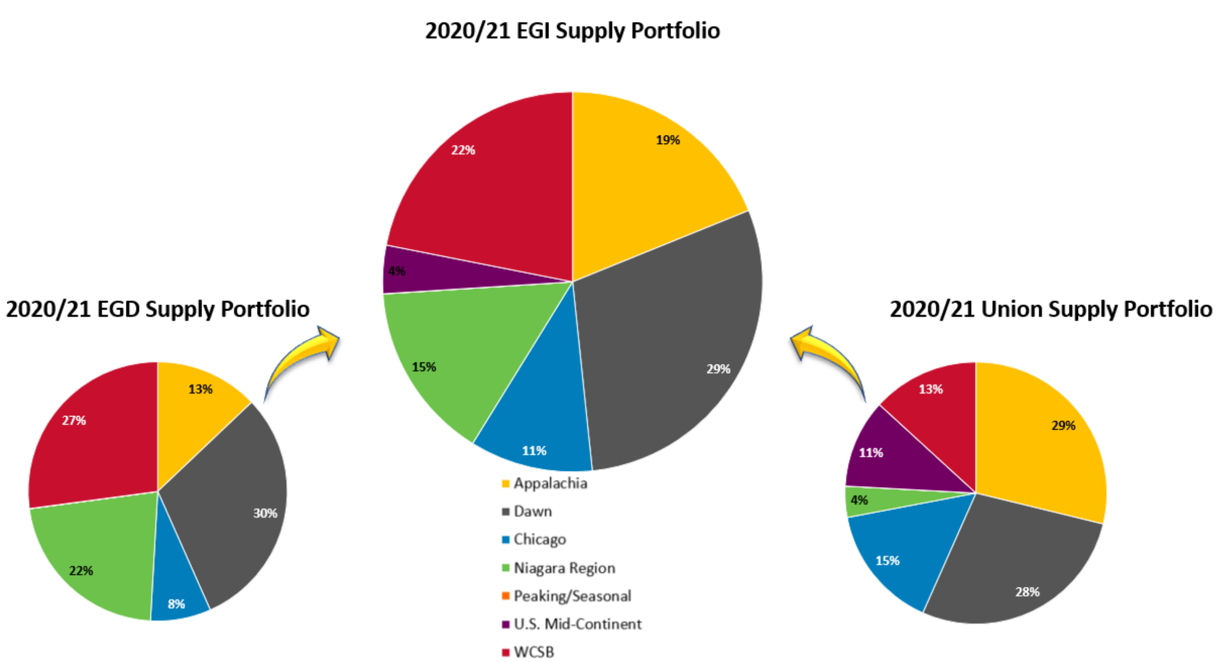
Table 3 provides the sources of supply assumed in EGI's Plan for sales service customers with an illustration in Figure 6.

Table 3 - Sources of Supply

Line No.	Particulars (TJ)	2020/21	2021/22	2022/23	2023/24	2024/25
	Supply Forecast					
	EGD					
1	Appalachia	43,117	43,117	43,117	43,235	43,117
2	Chicago	25,194	25,194	25,194	25,263	25,194
3	Niagara Region	73,355	73,355	73,355	73,556	73,355
4	Dawn	101,670	103,295	104,449	105,214	104,982
5	Peaking/Seasonal	82	18	31	48	64
6	WCSB	90,562	90,596	90,622	90,884	90,597
7	Total EGD	333,980	335,576	336,768	338,200	337,309
	Union North West					
7	WCSB	16,314	17,914	17,596	18,812	20,393
	Union North East					
8	Appalachia	19,255	19,255	19,255	19,308	19,255
9	Dawn	11,867	11,233	13,335	10,757	8,770
10	WCSB	1,364	1,493	1,493	1,359	1,355
11	Total North East	32,486	31,981	34,084	31,423	29,380
	Union South					
12	Appalachia	38,510	38,510	38,509	38,615	38,510
13	Chicago	30,807	30,807	30,807	30,892	30,807
14	Niagara Region	7,702	7,702	7,702	7,723	7,702
15	Dawn	43,992	46,382	46,504	45,200	44,682
16	U.S. Mid-Continent	21,950	21,950	21,950	22,011	21,950
17	WCSB	8,797	8,797	8,797	8,821	8,797
18	Total South	151,758	154,148	154,270	153,261	152,448
19	Total Supply Forecast	534,538	539,620	542,718	541,697	539,530

*Ontario Production is included as part of Dawn number in Union South Total

Figure 6 - EGI Sources of Supply



6.2 RNG Portfolio

RNG is an alternative to conventional gas supply and can be stored, transmitted and distributed when connected to existing natural gas infrastructure. RNG is produced by capturing methane that results from the decay of organic matter. Some examples of RNG sources include landfills and wastewater treatment plants.

On March 5, 2020, EGI filed an application with the OEB seeking approval to implement a Voluntary RNG Program.[44] EGI received approval for this program on a pilot basis on September 24, 2020.

EGI plans to procure RNG on short-term contracts from RNG suppliers beginning shortly after the launch of the Voluntary RNG Program in 2021. The amount of RNG procured will depend on customer participation in the program as well as RNG supply pricing and availability. EGI has forecasted total RNG procurement for the voluntary program to reach approximately 35,000 GJ by the third year after program launch. RNG is not currently reflected in EGI's Gas Supply Plan due to the relatively low volumes forecasted for RNG in relation to EGI's total gas supply portfolio, the uncertainty surrounding actual program participation and the timing of RNG purchases. As EGI develops more experience with RNG procurement it will look to include RNG purchases as part of the Voluntary RNG Program within the Gas Supply Plan.

6.3 Sustainable Natural Gas

While not explicitly included within emerging public policy, EGI has been closely monitoring the development of new certifications which measure a natural gas producer's conformance to a number of standards. These standards measure the impacts to environmental, social, and governance ("ESG") attributes including air and water quality, carbon emissions, and relations with Indigenous communities. The certifications are issued to producers of natural gas and give their customers assurance that their product is responsibly sourced. Natural gas that is certified by these standards is referred to as Sustainable Natural Gas ("SNG").

One example of an emerging SNG certification is Equitable Origins EO100™ Certification. The EO100™ Certification process evaluates producers based on their impacts to water, air, wildlife, indigenous relations, and working conditions for employees. Equitable Origin provides a framework for responsible energy development based on census from industry, affected communities, governmental agencies, and incentivizing excellence in social and environmental performance.[45] Certification is granted after third-party verification of compliance with all parameters of the EO100™ Standard at a specific energy development site (e.g. an oil or gas drilling pad, a hydroelectric dam, or a wind farm). These parameters include:

- Corporate governance, accountability & ethics
- Human rights, social impacts and community development

[44] EB-2020-0066
[45] https://www.equitableorigin.org/eo100-for-responsible-energy/overview/

- Fair labour and working conditions
- Indigenous peoples' rights
- Climate change, biodiversity and environment
- Project life cycle management

In early 2020, Énergir, Québec's largest natural gas utility, entered into the first SNG supply agreement governed by the EO100™ framework. In the accompanying media release, Énergir announced a target of 20 percent of their gas supply portfolio dedicated to SNG by the end of 2020.[46] Progress against this target will be monitored by EGI in 2021.

Procurement of SNG aligns very well with EGI's Gas Supply guiding principles. SNG meets the spirit of many public policy initiatives surrounding ESG. While SNG is not a "net zero" fuel alternative such as RNG or hydrogen, it has been certified as gas that is produced using industry-leading best practices including regard for the impact on the environment.

SNG is a very cost-effective solution to improving ESG within the natural gas sector. While the exact pricing of commercial arrangements has not been communicated to the market, EGI understands the premiums to be in the $0.05/GJ to $0.15/GJ range. Sourcing SNG as a portion of EGI's system gas supply portfolio would therefore have negligible price impact compared to conventional natural gas.[47]

EGI is investigating SNG frameworks and exploring opportunities for the potential inclusion of SNG within its system supply portfolio as early as November 1, 2021. It is important to note that SNG is a new and emerging trend in the North American natural gas industry. For this reason, current SNG supply options are limited. In accordance with existing natural gas procurement practices, EGI's assessment of SNG opportunities will consider factors such as supply diversity, liquidity, reliability and counterparty credit risk.

6.4 Transportation Portfolio

To manage risk, EGI holds a diverse portfolio of transportation contracts to meet the design day needs of each delivery area. The transportation portfolio of firm services provides direct and secure access to a diverse group of supply basins and market hubs across North America.

Figure 7 is a visual representation of the combined transportation contracts that EGI holds to serve its delivery areas. Figures 8-11 provide a visual representation of all contracted transportation services for the EGD and Union rate zones. Figures 8, 10, and 11 are as of November 1, 2020. Figure 9 illustrates the EGD rate zone portfolio after the North Bay Junction LTFP service is effective January 1, 2021. A

[46] https://www.energir.com/en/about/media/news/developpement-etapprovisionement-energetique-responsables-et-transparents/

[47] EGI estimates that sourcing 5% of its system gas portfolio as SNG would result in incremental costs to ratepayers of less than 0.01%.

complete listing of the transportation capacity currently contracted for EGD, Union North, and Union South rate zones is provided in Appendix C.

Figure 7 - Transportation Portfolio by Delivery Area

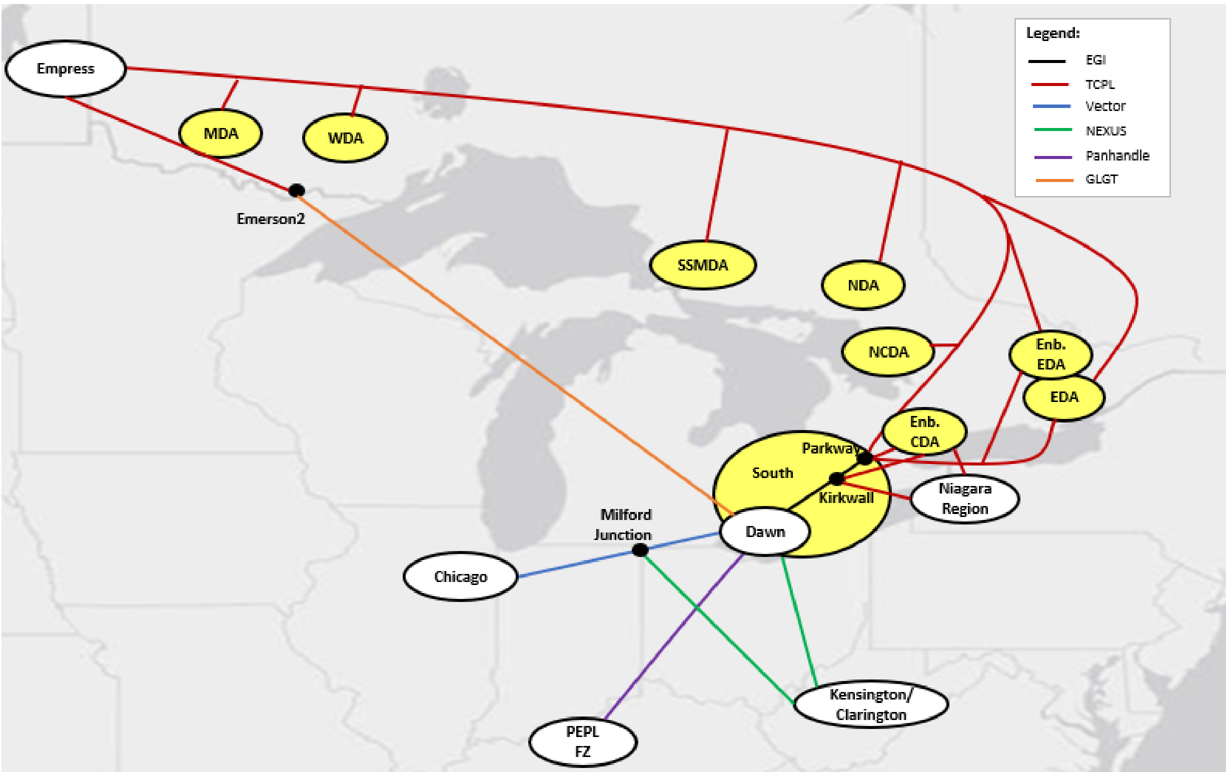
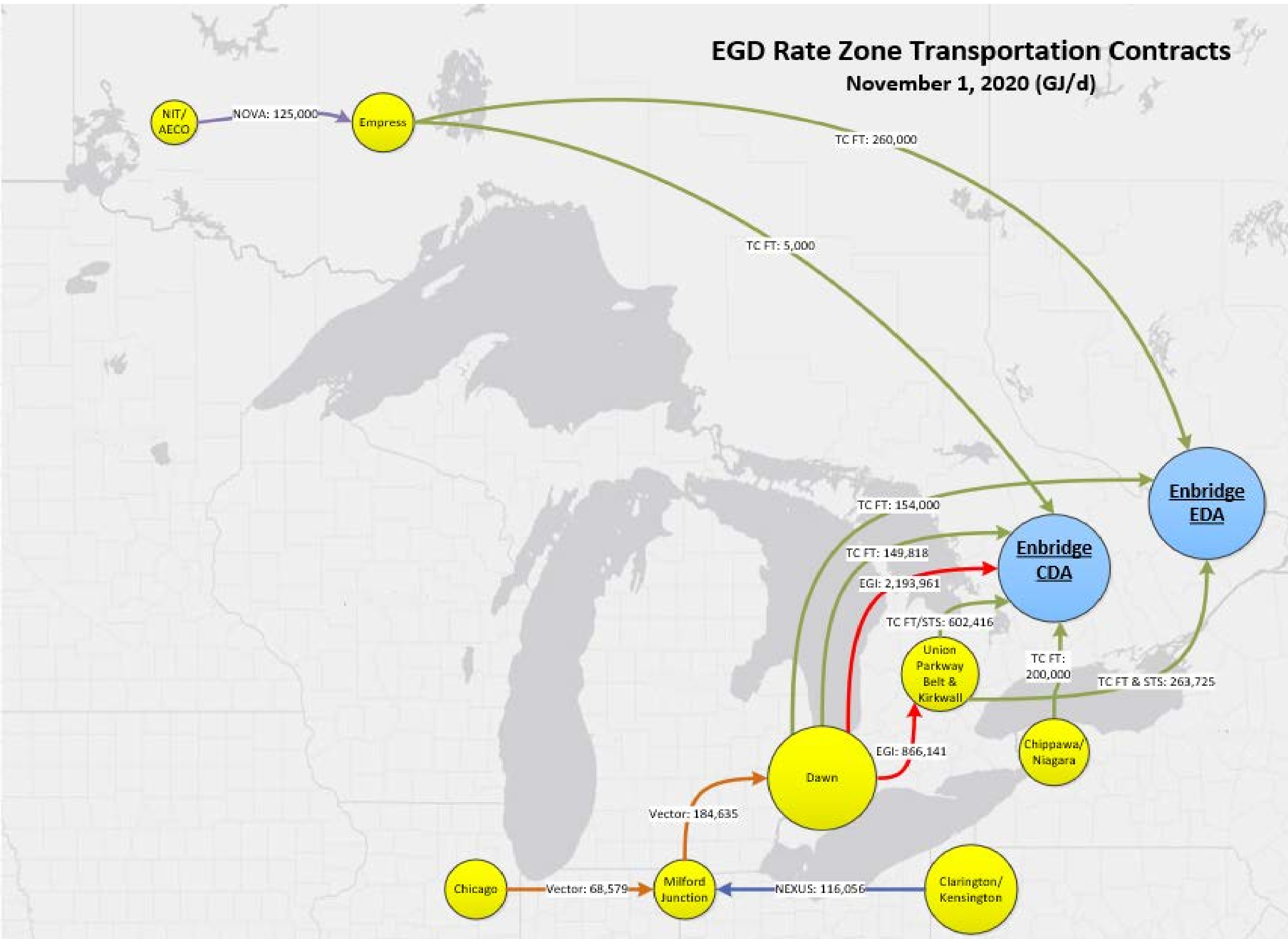
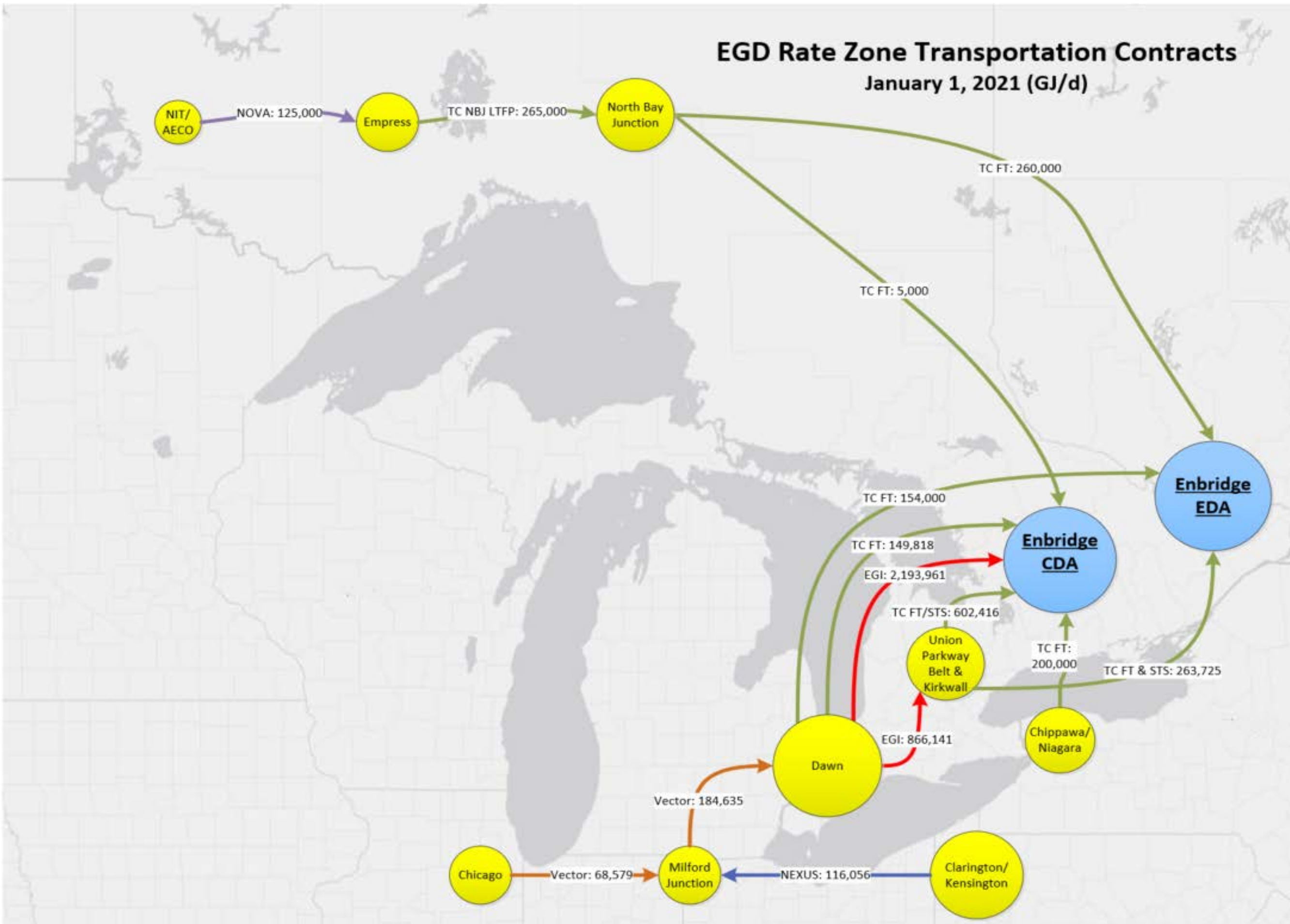


Figure 8 - EGD Transportation Portfolio (November 1, 2020)[48]



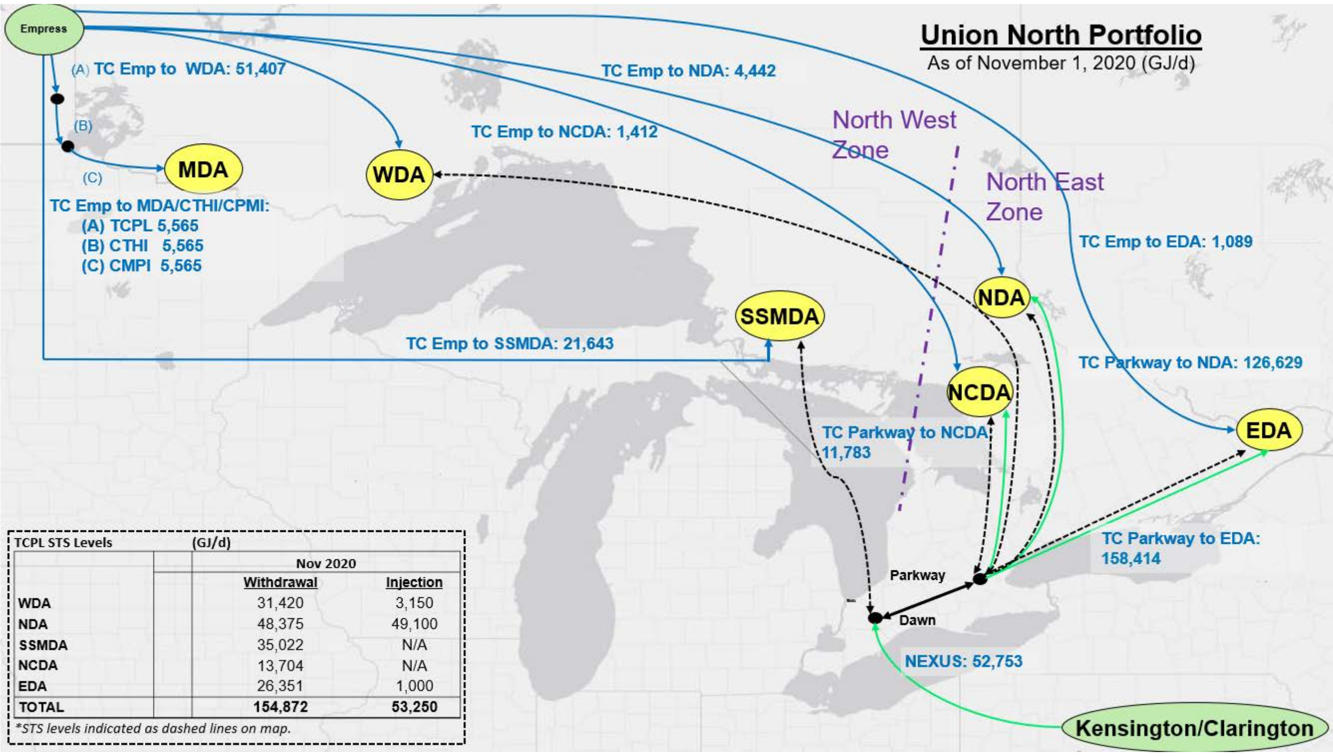
[48] A full summary of EGI's transportation contracts can be found in Appendix C

Figure 9 - EGD Transportation Portfolio (January 1, 2021)[49]



[49] A full summary of EGI's transportation contracts can be found in Appendix C

Figure 10 - Union North Transportation Portfolio (November 1, 2020)[50]



TCPL STS Levels	(GJ/d)	
	Nov 2020	
	Withdrawal	Injection
WDA	31,420	3,150
NDA	48,375	49,100
SSMDA	35,022	N/A
NCDA	13,704	N/A
EDA	26,351	1,000
TOTAL	154,872	53,250

**STS levels indicated as dashed lines on map.*

[50] A full summary of EGI's transportation contracts can be found in Appendix C

Figure 11 - Union South Transportation Portfolio (November 1, 2020)[51]

6.5 Transportation Portfolio Changes

EGI continuously monitors market conditions and service offerings and will enter into contracts throughout the planning period as required for the ongoing execution of the gas supply plan.

The following section addresses transportation portfolio changes since the time the 2020 Annual Update was developed. The format of this section is consistent with the Transportation Contracting Analysis filing requirements as outlined in EB-2005-0520.

Transportation Contracting Analysis

For the period of November 1, 2020 to March 31, 2022 Union South rate zone has the following portfolio changes:

1. NEXUS Pipeline
   a. Effective November 1, 2020, 26,376 GJ/d capacity from Clarington to Kensington

A comparison of landed costs for NEXUS Pipeline capacity relative to the viable alternatives can be found in Appendix D.

[51] A full summary of EGI's transportation contracts can be found in Appendix C

Rationale for NEXUS Pipeline Capacity

During the summer of 2020, EGI acquired 25,000 Dth/d of NEXUS Pipeline capacity for the term November 1, 2020 to March 31, 2022 (17 months) with a receipt point of Clarington and a delivery point of Kensington. This capacity does not change the volume of NEXUS deliveries to EGI but rather increases EGI's access to the Clarington supply point, which is located in the NEXUS Supply Zone. Clarington, located at the junction of NEXUS and Texas Eastern Pipelines, and which has been a liquid and economic supply point for EGI. The costs of this transportation are expected to be largely offset by lower commodity prices at Clarington and offer EGI additional benefits including:

i. Supports the acquisition of supply from upstream markets, maintaining diversity of contract terms and supply basins;
ii. Provides flexibility to access other supply points along the path;
iii. Provides EGI with receipt flexibility within the path;
iv. Provides flexibility as the capacity can be segmented; and
v. Landed cost of gas flowing to EGI along this route is competitively priced.

6.6 Storage Portfolio

In accordance with the Natural Gas Electricity Interface Review ("NGEIR") Decision[52] and confirmed in the Board's Decision and Order regarding the amalgamation of EGD and Union and the associated rate-setting mechanism ("MAADs decision")[53], the amount of cost-based storage reserved for EGD rate zone customers is 99.4 PJ and 100 PJ is reserved for Union rate zone customers.

The allocation of storage to natural gas distribution customers is based upon methodologies approved by the Board as part of the Natural Gas Storage Allocation Policies Decision[54] and the quantity was confirmed in the MAADs decision.

Table 4 illustrates the in-franchise storage requirement for each rate zone. Union in-franchise storage requirement has increased as a result of the increasing demand forecast discussed in Section 5.1.

[52] EB-2005-0551, Decision with Reasons, November 7, 2006
[53] EB-2017-0306/0307, Decision and Order, August 30, 2018
[54] EB-2007-0724/0725, Decision with Reasons, April 29, 2008

Table 4 - Storage Requirement Forecast

Line No.	Particulars (PJ)	2020/21	2021/22	2022/23	2023/24	2024/25
	EGD					
1	Infranchise Storage Requirement					
2	Infranchise Customer Requirement	125.8	125.8	125.8	125.8	125.8
3	Cost-Based Storage					
4	Tecumseh	99.0	99.0	99.0	99.0	99.0
5	Welland	0.3	0.3	0.3	0.3	0.3
6	Market Based Storage	26.5	26.5	26.5	26.5	26.5
7	Space Allocated for Infranchise Use	125.8	125.8	125.8	125.8	125.8
	Union					
8	Infranchise Storage Requirement					
9	Contingency	9.5	9.5	9.5	9.5	9.5
10	Infranchise Customer Requirement	88.1	87.8	87.1	88.3	88.5
		97.6	97.3	96.7	97.8	98.0
11	Cost-Based Storage					
12	Dawn	100.0	100.0	100.0	100.0	100.0
13	Excess Utility Space Available	2.4	2.7	3.3	2.2	2.0

In addition to the cost-based storage available to customers in the EGD rate zone, EGI holds 11 service agreements equaling 26.4 PJ of storage capacity at market-based rates. The size and term of each service agreement varies. Every year EGI conducts analysis to determine its storage requirements. Based on the results of the analysis, a blind RFP process is undertaken to replace expiring storage service agreements or add incremental storage capacity.

The inclusion of storage assets in the Gas Supply Plan provides a cost-effective, reliable and secure alternative to purchasing commodity when required by customers, which is consistent with the Board's guiding principles. Storage provides further operational flexibility and aligns with the planning target to fill storage at November 1, maintain sufficient inventory at February 28 to meet the design day storage withdrawal requirement, and at March 31 to meet planning requirements.

6.7 Unutilized Capacity

EGI does not plan for any unutilized EGD rate zone capacity of its TCPL long-haul transportation, which will be converted to a combination of NBJ LTFP and Short-Haul FT on January 1, 2021, given the persistently low prices of supply procured in Alberta and the ability to utilize in-path diversions on long-haul transportation at no or limited incremental cost.

In the Union North rate zones, the upstream transportation portfolio is sized to meet design day demand. Logically, the amount of supply transported to meet average annual demand is less than the capacity needed to meet requirements on design day. As a result, a portion of EGI's contracted capacity is planned to be unutilized during the year. The difference between the total contracted capacity and total demand for both Union North sales service and bundled DP customers equals the planned unutilized capacity. If weather is colder than normal and/or annual consumption is greater than forecast, EGI will use this capacity to meet incremental supply requirements.

For the Union South rate zone, EGI plans for upstream pipeline capacity to flow at 100% utilization each day of the year. During times when usage is less than upstream supply, the excess supply is injected into storage at Dawn. When demands are greater than upstream supply, gas is withdrawn from storage and transported to Union South in-franchise customers. Consequently, there is no planned unutilized capacity in Union South.

Table 5 illustrates the total planned UDC by rate zone.

Table 5 - Planned UDC

Line No.	Particulars (PJ)	2020/21	2021/22	2022/23	2023/24	2024/25
1	EGD	-	-	-	-	-
2	North West	9.7	8.5	8.6	9.7	8.3
3	North East	5.9	6.3	4.4	5.2	6.7
4	South	-	-	-	-	-
5	Total Planned UDC	15.6	14.8	13.0	14.9	15.0

7. Supply Option Analysis

EGI's gas supply, storage, and transportation portfolios have been developed over time and guided by its approved gas supply planning principles and North American natural gas market conditions. EGI's strategy is continuously evolving and contemplates both the North American market in its entirety and the impact that changes across the continent can have on the Ontario market, including Dawn as outlined above in Section 4.1. Several other factors such as contract terms, renewal rights, operational requirements and supply source constraints are also significant factors influencing EGI's supply option analyses and decisions. Each individual gas supply, storage, and transportation evaluation cannot be considered independently and needs to be considered as part of the overall portfolio and strategy.

When evaluating alternatives for portfolio decisions, EGI balances its supply planning principles of reliability, flexibility, diversity and cost-effectiveness. Balancing these factors in evaluating gas supply options allows EGI to meet the Board's guiding principles for assessment of the Plan. EGI's gas supply portfolio decisions are made based on market conditions at the time.

Evaluating the reliability and flexibility of a potential supply option includes the assessment of several qualitative and quantitative features.

Some of the features of a supply option's reliability that EGI may consider in its evaluation include:

- Supply liquidity, nomination performance, delivery performance, distance of haul, firmness of option, gate station connectivity; and,
- The level of third-party services (e.g. peaking and delivered services) held within the portfolio. EGI aims to limit the level of third-party services because in the event that third-party services failed to deliver, the utility expects to manage the supply shortfall within the parameters of its existing firm transportation contracts[55].

Some elements of flexibility that EGI may consider in its evaluation may include; contracting lead time, transportation contract term, supply contract term, availability of third-party services, number of nomination windows, and renewal rights.

Assessing a supply option's ability to be reliable and flexible supports the Board's guiding principle of reliability and security of supply.

When evaluating a supply option's impact on diversity, EGI assesses the ability to provide transportation capacity through multiple paths and the impact on overall supply diversity. Transportation path diversity and supply diversity are evaluated on a quantitative basis but also take qualitative factors into consideration.

EGI's consideration of diversity of transportation path and supply supports the Board's guiding principles of reliability and security of supply and cost-effectiveness.

Finally, EGI's evaluation of the costs of a potential supply option is mainly a quantitative exercise. If the option is intended to satisfy average day needs, EGI will evaluate 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.

EGI's consideration of costs supports the Board's guiding principle of cost-effectiveness.

EGI's consideration of alternatives and whether infrastructure may be required is one way EGI supports the Board's guiding principles of public policy. EGI has added an "available capacity" column to the evaluation matrices reflecting the market information known at the time the analysis is completed. This is not a new concept for EGI but was added to the tables based on feedback through the Final Report. Available capacity changes over time and is influenced by many factors, including contracting levels on upstream capacity and pipeline integrity work.

When EGI considers a new supply basin, new upstream transportation capacity, new storage assets, or renewals of existing transportation, multiple alternatives are considered. The supply option analysis provides a list of viable alternatives evaluated and the associated qualitative and quantitative considerations for incremental assets required for design day or average day.

[55] EGI's existing firm transportation contracts allow for discretionary overrun of up to 2% before incurring penalties

In the event there are no viable alternatives to serve a delivery area, or if disclosing sensitive information will impact the market, EGI will not publicly file the analysis.

Once a decision has been made, the decision analysis will be filed in the Transportation Contracting Analysis section of the Transportation Portfolio within the next annual update or 5-Year Plan.

7.1 Design Day Analysis

Each year, EGI conducts a design day position analysis for each delivery area in each rate zone in which projected design day demand is compared against existing contracted assets for that rate zone's delivery areas. A design day shortfall occurs when there is more demand than capacity through existing assets to meet design day demand. Forecast shortfalls are monitored throughout the length of the Plan and analyzed on an annual basis. EGI evaluates the requirements over the entire forecast period.

EGI considers the availability of assets into the 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. Contracting for one year, or less, gives EGI the flexibility to adjust contracted capacity, as requirements and market conditions are subject to change over time. If the delivery area is constrained, EGI 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 EGI bidding into an open season with a minimum commitment term (e.g. 15 years).

The Plan does not include any excess assets; only those necessary to meet firm customer requirements.

EGD Rate Zone

The EGD rate zone demand and supply balance which identifies EGI's design day position is outlined in Table 6. The forecast shows a shortfall in nearly every year resulting from growth in the Enbridge CDA.

Table 6 - EGD Rate Zone Design Day Position

		EGD CDA					EGD EDA				
Line No.	Particulars (TJ/d)	2020/21	2021/22	2022/23	2023/24	2024/25	2020/21	2021/22	2022/23	2023/24	2024/25
	Demand										
1	Gross Demand	3,400	3,412	3,425	3,437	3,448	719	724	729	734	738
2	Curtailment	(71)	(71)	(71)	(71)	(71)	(26)	(26)	(26)	(26)	(26)
3	Net Demand	3,329	3,341	3,354	3,366	3,377	693	698	703	708	713
	Supply Asset										
4	TCPL Long-haul	5	5	5	5	5	260	260	260	260	260
5	TCPL Short-haul	668	773	768	768	768	337	358	362	362	362
6	TCPL STS	284	284	284	284	284	81	81	81	81	81
7	EGI D-P	2,194	2,194	2,194	2,194	2,194	-	-	-	-	-
8	In-Franchise Supply	72	72	72	72	72	0	0	0	0	0
9	Third-Party Services	40	-	-	-	-	-	-	-	-	-
10	Total Supply	3,263	3,328	3,323	3,323	3,323	678	698	703	703	703
11	Excess(Shortfall)	(66)	(14)	(31)	(42)	(54)	(16)	-	(1)	(5)	(10)
12	*Shortfall % of Net Demand*	*2.0%*	*0.4%*	*0.9%*	*1.3%*	*1.6%*	*2.2%*	*0.0%*	*0.1%*	*0.7%*	*1.4%*

Enbridge CDA

Supply Options

Table 7 below provides a list of options which are expected to be available to EGI[56,57] at various times over the next five years to meet the shortfalls identified in Table 6. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 12 provides a representative map of the paths described in the options.

Table 7 - Enbridge CDA Supply Options

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

Figure 12 - Enbridge CDA Supply Options Map

56 The list of options in Table 7 is not an exhaustive list of all options. The list of options is a short-list of options that do not disclose commercially sensitive information and offers the reliability and flexibility required to manage a design day event, which is short-term and a temporary phenomenon.

57 Third-Party considers both peaking service and delivered service. Delivered services have limited participants so disclosing costs could impact the market. Therefore, when considering costs, peaking service is the option being considered as there are more counterparties and disclosing pricing will not impact the market.

Evaluation Matrix

Each of the options outlined in Table 7 above were evaluated for their reliability, flexibility, diversity and annual costs, as described at the beginning of Section 7. Table 8 summarizes the analysis.

Table 8 - Enbridge CDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($Millions/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	↑	→	↑	23.78	<1%	Yes
Short-haul: D-P	↑	→	→	4.71	<1%	No
Short-haul: Dawn	↑	→	→	2.78	<1%	No
Short-haul: Niagara	→	→	→	3.36	<1%	No
Third-Party	→	↓	↑	1.80	<1%	Unknown[58]

For reference, the symbols in Table 8 describe whether a particular option has a: positive ↑, neutral →, or negative ↓ impact on the ability of the option to satisfy a design day shortfall as compared to EGI's current portfolio.

Preferred Planning Strategy

Since the 5-Year Plan was filed, there have been no change in options to serve and no material differences in the evaluation matrix, therefore the preferred strategy is still to procure a third-party service. EGI will continue to monitor any shortfall positions and make decisions using the best available information at that time.

Enbridge EDA

Supply Options

Table 9 below provides a list of options which are expected to be available to EGI[59] at various times over the next five years to meet the shortfalls identified in Table 6. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 13 provides a representative map of the paths described in the options.

[58] EGI believes that third-party services are likely to be available but are subject to discussion with market participants at the time of evaluation

[59] The list of options in Table 9 is not an exhaustive list of all options. The list of options is a short-list of options that do not disclose commercially sensitive information and offers the reliability and flexibility required to manage a design day event, which is short-term and a temporary phenomenon.

Table 9 - Enbridge EDA Supply Options

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

Figure 13 - Enbridge EDA Supply Options Map

Evaluation Matrix

Each of the options outlined in Table 9 above were evaluated for their reliability, flexibility, diversity and annual costs, as described at the beginning of Section 7. Table 10 summarizes the analysis.

Table 10 - Enbridge EDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($Millions/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	↑	↑	→	3.69	<1%	Yes
Short-haul: D-P	↑	→	→	1.17	<1%	No
Short-haul: Niagara	→	→	↑	1.07	<1%	No
Short-haul: Iroquois	→	→	↑	0.55	<1%	No
Third-Party	→	↓	↑	0.28	<1%	Unknown[60]

[60] EGI believes that third-party services are likely to be available but are subject to discussion with market participants at the time of evaluation

For reference, the symbols in Table 10 describe whether a particular option has a: positive , neutral , or negative impact on the ability of the option to satisfy a design day shortfall as compared to the current portfolio.

Preferred Planning Strategy

Since the 5-Year Plan was filed, there has been no change in options to serve and no material differences in the evaluation matrix, therefore the preferred strategy is still to procure a third-party service. EGI will continue to monitor any shortfall positions and make decisions using the best available information at that time.

Union North Rate Zones

The Union North rate zone demand and supply balance which identifies EGI's design day position is outlined in Table 11. The North East (Union EDA) forecast shows a 2 TJ/d shortfall starting in 2023/24 which grows to 3 TJ/d by 2024/25. This small shortfall will be monitored by EGI and may result in the procurement of a transportation service in the future.

Table 11 - Union North Rate Zone Design Day Position

Line No.	Particulars (TJ/d)	North West					North East				
		2020/21	2021/22	2022/23	2023/24	2024/25	2020/21	2021/22	2022/23	2023/24	2024/25
	Demand										
1	Union North	128	128	128	128	127	398	404	406	410	409
	Supply Asset										
2	TCPL Long-Haul	78	78	78	78	78	4	4	4	4	4
3	TCPL Short-Haul	-	-	-	-	-	120	120	120	120	120
4	North Dawn T-Service	-	-	-	-	-	33	33	33	33	33
5	LNG	-	-	-	-	-	0	0	0	2	0
6	Redelivery from Storage										
7	*From Parkway*										
8	STS Withdrawals	30	30	30	29	29	84	87	88	88	88
9	STS Pooled Withdrawals	-	-	-	-	-	13	16	16	16	16
10	Short-haul Firm	-	-	-	-	-	119	119	119	119	119
11	Enhanced Market Balancing	-	-	-	-	-	25	25	25	25	25
12	*From Dawn*										
13	STS Withdrawals	20	20	20	20	20	-	-	-	-	-
14	Total Supply	128	128	128	127	127	398	404	406	408	406
15	Excess(Shortfall)	0	0	0	0	0	0	0	0	-2	-3
16	*Shortfall % of Demand*	*0.1%*	*0.1%*	*0.1%*	*0.2%*	*0.2%*	*0.0%*	*0.0%*	*0.0%*	*0.4%*	*0.7%*

* includes Sales Service, Bundled DP, North Dawn T-Service

Union EDA

Supply Options

Table 12 below provides a list of options which are expected to be available to EGI[61] at various times over the next five years to meet the shortfall identified in Table 11. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 14 provides a representative map for the paths of the supply options.

Table 12 - Union EDA Supply 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

Figure 14 - Union EDA Supply Options Map

Evaluation Matrix

Each of the options outlined in Table 12 above were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 7. Table 13 summarizes the analysis.

[61] The list of options in Table 12 is not an exhaustive list of all options. The list of options is a short-list of options that do not disclose commercially sensitive information and offers the reliability and flexibility required to manage a design day event, which is short-term and a temporary phenomenon.

Table 13 - Union EDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($Millions/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	↑	↑	↑	0.53	<1%	Yes
Short-haul: D-P	↑	→	→	0.15	<1%	No
Short-haul: Niagara	→	→	↑	0.15	<1%	No
Short-haul: Iroquois	→	→	↑	0.08	<1%	No
Third-Party	→	↓	↑	0.04	<1%	Unknown[62]

For reference, the symbols in Table 13 describe whether a particular option has a: positive ↑, neutral →, or negative ↓ impact on the ability of the option to satisfy design day shortfall as compared to the current portfolio.

Preferred Planning Strategy

EGI will monitor the requirement for incremental transportation services to the Union North East rate zone. As stated in EGI's 2020 update to the 5-year Gas Supply Plan, 3rd party services will be considered as an option to meet a shortfall[63].

Union South Rate Zone

EGI's Union South rate zone design day demand to supply position is outlined below in Table 14. EGI currently forecasts no excess or shortfall in the Union South rate zone over the term of the Plan.

Table 14 - Union South Rate Zone Design Day Position

Line No.	Particulars (TJ/d)	2020/21	2021/22	2022/23	2023/24	2024/25
	Demand					
1	Union South	3,137	3,175	3,275	3,450	3,486
	Supply Asset					
2	Great Lakes	106	106	106	106	106
3	Nexus	251	251	251	251	270
4	Non-obligated (e.g. Power Plants)	1,811	1,851	1,953	2,107	2,124
5	Ontario Dawn	60	60	60	60	60
6	Ontario Parkway	238	234	232	232	231
7	Panhandle	3	3	3	3	3
8	Storage	84	84	84	84	84
9	TCPL Long-Haul	542	543	544	565	566
10	TCPL Niagara	21	21	21	21	21
11	Vector	21	21	21	21	21
12	Total Supply	3,137	3,175	3,275	3,450	3,486
13	Excess(Shortfall)	-	-	-	-	-

* includes Sales Service, Bundled DP, T-Service

[62] EGI believes that third-party services are likely to be available but are subject to discussion with market participants at the time of evaluation
[63] EB-2020-0135

7.2 Average Day Requirement

Beyond forecasting design day demand, it is also important for EGI to understand the average day demand requirements within each rate zone, as this can help to inform EGI's approach for procuring supply throughout the year. EGI has the opportunity to purchase supply at Dawn or upstream of Dawn and transport it into each rate zone. The average day analysis places a greater emphasis on determining if a need exists for transportation capacity from particular supply basins and hubs (e.g. WCSB, Appalachia, Chicago, Dawn).

Consistent with the annual demand forecast developed by EGI found in Section 5.1, Table 15 shows both the annual and marginal average day demand growth expected over the five-year period of the Plan for system sales service customers.

Table 15 - Average Day Demand Analysis for System Sales Service Customers

Line No.	Particulars (TJ)	2020/21	2021/22	2022/23	2023/24	2024/25	Growth 2020 → 2024
	EGD						
1	Annual Demand	312,819	314,448	316,145	318,453	319,037	6,218
2	Daily Demand	857	862	866	870	874	17
	Union						
3	Annual Demand	190,216	191,669	191,904	193,315	192,626	2,409
4	Daily Demand	521	525	526	528	528	7

As Table 15 shows, the average annual demand for the EGD rate zone is expected to increase by roughly 6,218 TJ over the five years, or roughly 17 TJ/d of average day demand and Union rate zone is expected to increase by 2,409 TJ over the five years or roughly 7 TJ/d. As a result, EGI does not plan to procure additional gas supply assets to serve annual demand changes for any rate zone. However, a supply option analysis for average day requirements is presented to determine if additional transportation assets upstream of Dawn may provide additional reliability, flexibility, diversity and cost effectiveness.

Supply Options

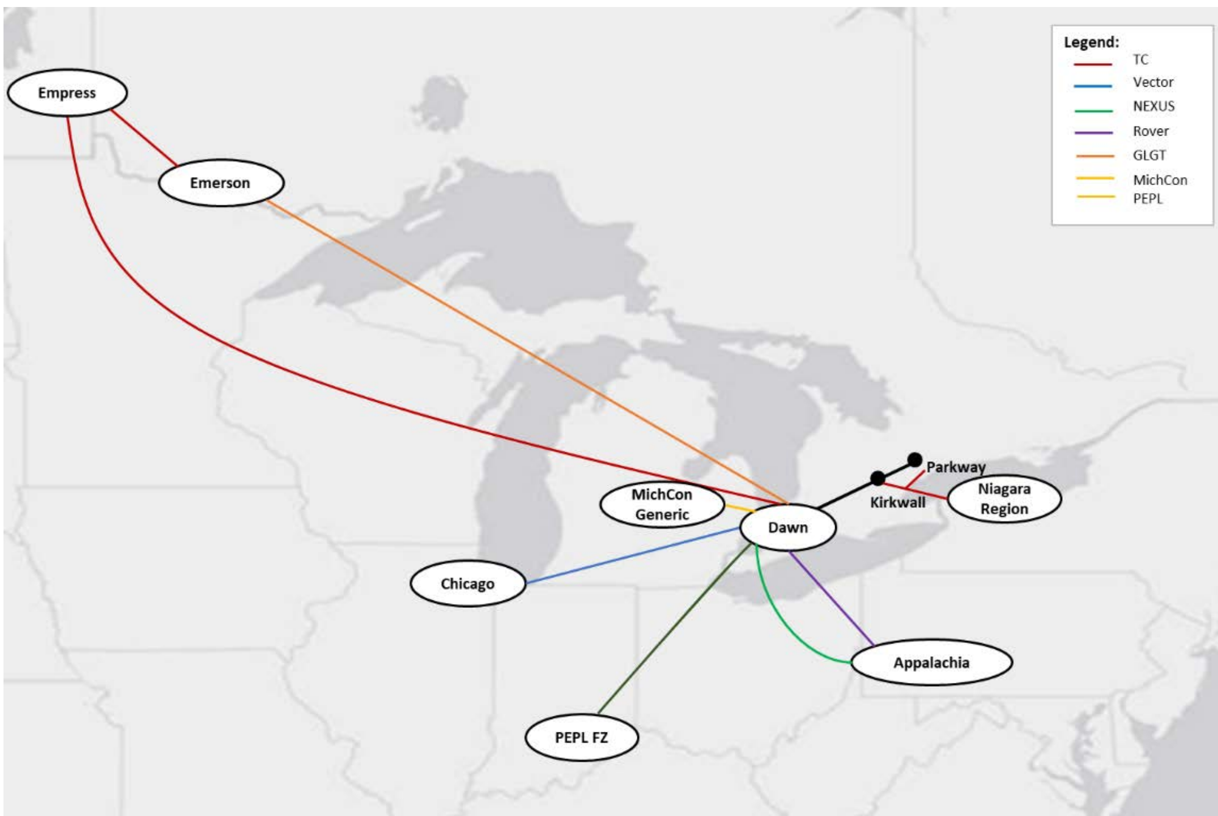
Table 16 below provides a list of options which are expected to be available to EGI[64], at various times over the five-year period. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 15 provides a representative map for the paths of the supply options.

[64] The list of options in Table 16 is not an exhaustive list of all options. The list of options is a short-list of options that do not disclose commercially sensitive information and offers the reliability and flexibility required to manage average day demand growth.

Table 16 - Average Day Growth Supply Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Dawn	-	-	Dawn	-	Dawn
Dawn LTFP[65]	TCPL	LTFP	Empress	-	Union SWDA
Great Lakes	TCPL + GLGT	FT-LH + FT	Empress	Emerson	Dawn
MichCon	DTE	FT	MichCon	St. Clair	Dawn
Vector	Vector	FT-1	Chicago	-	Dawn
Panhandle	PEPL+EGI	FT	Panhandle FZ	Ojibway	Dawn
NEXUS	NEXUS	FT	Dominion	-	Dawn
Rover	Rover	FT	Dominion	-	Dawn
Niagara	TCPL + EGI	FT	Niagara	Kirkwall	Dawn

Figure 15 - Average Day Growth Supply Options Map



[65] TCPL held an Open Season for LTFP 2 service from March 10 until April 3, 2020. The toll for this offering was $0.02 lower than the original Dawn LTFP offering.

Evaluation Matrix

Each of the options outlined in Table 16 above were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 7. Table 17 summarizes the analysis.

Table 17 - Average Day Growth Evaluation Matrix

Option	Relative to Status Quo			Costs ($/GJ)	Average Cost/Customer Impact - Relative to Status Quo	Available Capacity
	Reliability	Flexibility	Diversity			
Dawn	-	-	-	4.28	-	Yes
Dawn LTFP	➲	➲	➲	4.24	<1%	Yes[66]
Great Lakes	➲	➲	➲	4.31	<1%	No
MichCon	➲	➲	⬆	4.40	<1%	No[67]
Vector	➲	➲	➲	4.36	<1%	No
Panhandle	➲	➲	➲	5.04	<1%	Yes[68]
NEXUS	➲	➲	➲	4.36	<1%	Yes
Rover	➲	➲	⬆	4.48	<1%	Yes
Niagara	➲	➲	➲	4.30	<1%	No

For reference, the symbols in Table 17 describe whether a particular option has a: positive ⬆, neutral ➲, or negative ⬇ impact on the ability of the option to satisfy average day growth as compared to the current portfolio.

Preferred Planning Strategy

Since the 5-year Plan was filed, there has been no material change in demand growth and no change in options to serve or material differences in the evaluation matrix. Therefore, the preferred strategy is to continue to manage changes in average day demand through purchases at Dawn. EGI will continue to monitor any market offerings and its position at Dawn and make decisions using the best available information at that time.

7.3 Transportation Contracts Renewals

EGI evaluates its expiring contracts within the term of the Plan and determines whether these contracts should be renewed. There are 31 contracts requiring renewal analysis and these have been organized into two categories below.

[66] TCPL has held an Open Season for Dawn LTFP 2 earlier in 2020 and EGI believes TCPL would offer the service again if requested.
[67] St. Clair to Dawn path currently has limited winter capacity available
[68] Ojibway to Dawn Path

Design Day Renewals

Each of the contracts in Table 18 are included within the design day analyses previously presented for each rate zone, and have been required to serve each rate zone on a design day for many years.

Table 18 - Design Day Contract Expiries

Summary of Contracts Expiring within the 5 Year Gas Supply Plan
As of November 1, 2020

Category	Rate Zone	Path	Pipeline	Contract Quantity		Expiry Date
Design Day	EGD(1)	Empress to Iroquois	TCPL	26,956	GJ	31-Dec-20
Design Day	EGD(1)	Empress to Enbridge CDA	TCPL	5,000	GJ	31-Oct-21
Design Day	EGD(1)	Empress to Enbridge EDA	TCPL	70,000	GJ	31-Oct-21
Design Day	EGD(1)	Empress to Enbridge EDA	TCPL	163,044	GJ	31-Oct-22
Design Day	Union North East	Empress to Union NCDA	TCPL	1,412	GJ	31-Oct-22
Design Day	Union North East	Empress to Union NDA	TCPL	4,442	GJ	31-Oct-22
Design Day	Union North East	Empress to Union EDA	TCPL	1,089	GJ	31-Oct-22
Design Day	Union North West	Spruce to Union MDA	Centra Transmission Holdings	149.6	103m3	31-Oct-21
Design Day	Union North West	Sprague to Baudette	Centra Pipelines Minnesota Inc.	5,281	MCF	31-Oct-21
Design Day	Union North West	Empress to Centrat MDA	TCPL	4,522	GJ	31-Oct-22
Design Day	Union North West	Empress to Centrat MDA	TCPL	1,043	GJ	31-Oct-22
Design Day	Union North West	Empress to Union SSMDA	TCPL	2,700	GJ	31-Oct-22
Design Day	Union North West	Empress to Union SSMDA	TCPL	6,143	GJ	31-Oct-22
Design Day	Union North West	Empress to Union SSMDA	TCPL	12,800	GJ	31-Oct-22
Design Day	Union North West	Empress to Union WDA	TCPL	39,880	GJ	31-Oct-22
Design Day	Union North West	Empress to Union WDA	TCPL	11,527	GJ	31-Oct-22
Design Day	Union South	(Union) Dawn to Union ECDA	TCPL	8,000	GJ	31-Oct-22
Design Day	Union South	Empress to Union ECDA	TCPL	3,000	GJ	31-Oct-22

Note:
(1) Implied end date of Dec 31, 2020. To be replaced by NBJ LTFP effective Jan 1, 2021.

As of today, the viable alternatives available to replace the expiring contracts listed above are restricted to the firm transportation options found in Table 7, Table 9, Table 12, and Table 16.

Preferred Planning Strategy

Each of the firm contracts identified above are key components in ensuring the reliability of EGI's plan. Further, when coupled with an increasing need for assets on design day, EGI's preferred planning strategy is to continue to renew each contract on an annual basis. This approach supports the Board's guiding principles by ensuring security of supply, flexibility and the reliability of the Plan. EGI will retain significant flexibility to respond to changing design day demand requirements and, should a need arise to reduce the amount of firm transportation capacity to the distribution system, diversity of path and service will remain intact and the portfolio costs will not be impacted. EGI will continue to monitor market conditions and make renewal decisions using the best available information at that time.

Average Day Renewals

The average day contracts due for renewal over the term of the Plan listed in Table 19 are assets held upstream of Dawn or provide diversity of supply.

Table 19 - Average Day Contract Expiries

Category	Rate Zone	Path	Pipeline	Contract Quantity		Expiry Date
Average Day	EGD	AECO to Empress	NOVA Transmission	50,000	GJ	31-Oct-24
Average Day	EGD	AECO to Empress	NOVA Transmission	75,000	GJ	31-Oct-25
Average Day	EGD	Chicago to US/Cdn Border	Vector Pipeline	65,000	DTH	31-Oct-24
Average Day	EGD	US/Cdn Border to Dawn	Vector Pipeline	68,579	GJ	31-Oct-24
Average Day	Union South	Empress to Emerson 2	TCPL	21,418	GJ	31-Oct-22
Average Day	Union South(1)	Clarington to St. Clair (Union)	NEXUS	75,000	DTH	31-Oct-22
Average Day	Union South	Clarington to Kensington	NEXUS	25,000	DTH	31-Mar-22
Average Day	Union South	Niagara to Kirkwall	TCPL	21,101	GJ	31-Oct-22
Average Day	Union South	Emerson 2 to St. Clair (Union)	Great Lakes Transmission	20,000	DTH	31-Oct-24
Average Day	Union South	St. Clair (Union) to Dawn	Great Lakes Canada	21,101	GJ	31-Oct-24
Average Day	Union South	Field Zone to Ojibway	Panhandle	35,000	DTH	31-Oct-25
Average Day	Union South	Chicago to US/Cdn Border	Vector Pipeline	80,000	DTH	31-Oct-22
Average Day	Union South	US/Cdn Border to Dawn	Vector Pipeline	84,404	GJ	31-Oct-22
Average Day	Union South	Bluewater/Intl Border to Bluewater/Intl Border	St. Clair Pipelines L.P. (Bluewater Pipeline)	127,000	GJ	31-Oct-23
Average Day	Union South	St. Clair/Intl Border to St. Clair/Intl Border	St. Clair Pipelines L.P. (St.Clair Pipeline)	214,000	GJ	31-Oct-23

Note:
(1) EGI has allocated the capacity as 2/3 to Union South and 1/3 to Union North East. Clarington to St. Clair expires and converts back to Kensington to St. Clair.

Great Lakes, NEXUS, TCPL, NOVA and Vector transportation capacities all provide increased diversity through multiple supply basins, transportation paths, counterparties, receipt and delivery points, and flexible contract terms for EGI to de-contract should requirements change. This approach appropriately balances the Board's guiding principles, ensuring cost-effective, reliable and secure supply for customers.

Preferred Planning Strategy

As noted in Section 7.2, the options to serve average day have not changed and there are no material differences in the evaluation matrix, therefore the preferred strategy is to continue to renew the contracts on an annual basis. EGI will continue to monitor market conditions and will make renewal decisions using the best available information at that time.

EGD Average Day Contract Renewals

1. Vector Pipeline
    a. Effective November 1, 2021, EGI has renewed a contract for 65,000 Dth/d capacity from Chicago to the US/Canadian border and associated 68,578 GJ/d contract from the US/Canadian border to Dawn for a period of 3-years

A comparison of landed costs for Vector Pipeline capacity relative to the viable alternatives can be found in Appendix E.

Rationale for Vector Pipeline Renewal

Vector provides a competitively priced, reliable and flexible transportation option that offers supply diversity at Chicago as well as along the Vector pipeline route. All other available options would reduce EGI's diversity by reducing Chicago purchases and increasing either Empress or Appalachia purchases.

The benefits of this capacity include:

i. Contract supports EGI's objective of structuring a portfolio with a diversity of contract terms and supply basins;
ii. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost;
iii. Landed cost of gas flowing from Chicago along this route is competitively priced and has an end date that aligns with the gas year;
iv. Provides a fixed-rate toll which provides toll certainty on a portion of EGI's upstream transportation portfolio;
v. Supports the acquisition of supply from upstream markets, maintaining diversity of contract terms and supply basins;
vi. Provides flexibility to access multiple supply sources at Joilet and other points along the path;
vii. Provides EGI with delivery point flexibility within the path including Michigan storage and Sarnia; and,
viii. Provides flexibility as the capacity can be segmented and used bi-directionally.

2. NOVA Gas Transmission Renewals
   a. Effective November 1, 2021 EGI has renewed its 50,000 GJ/d NGTL contract for 3 years.

A landed cost analysis for NGTL renewal options can be found in Appendix F.

Rationale for NOVA Gas Transmission Renewals

EGI has a 10-year commitment to flow 260,000 GJ/d on TCPL Mainline from Empress. Rather than purchasing all supply at Empress, NGTL capacity provides EGI with the ability to diversify its gas purchases between Empress and AECO. Landed cost analysis indicates that rate payers will benefit by contracting for 3-year term which facilitates longer-term liquids extraction deals with more favorable pricing and also reduces the transportation toll by 5%. By renewing one of EGI's NGTL contracts for a term of 3 years and 10 months aligns the contract expirations date with the end of the gas year.

The benefits of this capacity include:

a. Contract supports EGI's objective of structuring a portfolio with a diversity of contract terms and supply basins;

b. Firm Transportation capacity provides diversity to meet the firm requirements 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. Term of 3 years results in a 5% discounted toll;
e. Facilitates longer-term liquids extraction deals with better pricing; and,
f. Landed cost of gas flowing to Empress along this route is competitively priced and has an end date that aligns with the gas year.

7.4 Storage Capacity Renewals

EGI holds 26.5 PJ of market storage capacity for use in the EGD rate zone. This storage capacity is held across 11 different non-renewable service agreements of varying terms and volumes. This diversity in term and volume allows EGI the flexibility to issue its annual RFP without needing to approach the market for all required storage capacity in any one year.

Storage is an integral upstream asset for the EGI portfolio. Storage is located close to the EGD rate zone increasing reliability and security of supply. Storage assets are a cost-effective means to manage the purchase of supply, as it allows for the purchase of the commodity in the summer, when prices tend to be lower, and withdrawal in the winter when prices tend to be higher. Further, storage service agreements provide a reliable asset that the utility can typically nominate within the day to help balance demand requirements.

Preferred Planning Strategy

EGI's preferred planning strategy for storage expiries is to continue to issue blind RFPs to the market each year to replace any capacity that is expiring as discussed in section 2.

7.5 Summary of Supply Option Analysis

EGI's approach to diversifying its portfolio is analogous to a prudent investment portfolio where diversity of assets, supply, risk and term are critical to a successful portfolio, and where market conditions are continuously evolving. The portfolio contemplates the North American market as a whole as well as the resulting impacts on the Ontario market. To serve each rate zone, EGI uses capacity on multiple upstream pipelines to access several supply basins and market hubs. These pipelines provide access to supplies in Western Canada, Chicago, Dawn, U.S. Mid-continent, Niagara and Appalachia.

As part of its ongoing process, EGI will continue to evaluate each rate zone's portfolio to ensure it meets the needs identified in the Plan, balancing the guiding principles set forth by the Board in the Framework. This ongoing work will include monitoring the impacts of in-service delays for new transportation projects and evaluating potential transportation alternatives.

A summary of EGI's preferred planning strategies to manage changes include:

- Design day
  - Enbridge CDA – acquire third-party services to manage design day shortfalls
  - Enbridge EDA – acquire third-party services to manage design day shortfalls
  - Union EDA – acquire third-party services to manage design day shortfalls
  - Remaining delivery areas[69] – no action required
- Average day
  - Purchase supply at Dawn to manage average day growth
- Transportation contracts renewals
  - Renew existing transportation contracts on an annual basis
- Storage capacity renewals
  - EGD rate zone – Replace existing level of storage service agreements on an annual basis for varying terms

8. Gas Supply Plan Execution

EGI's Plan is updated annually for each rate zone and is approved internally by senior management. Once approved, the Gas Supply procurement team prepares a strategy to procure the necessary assets identified in the Plan. EGI executes the Plan balancing reliability, diversity and flexibility, while achieving a cost-effective solution for ratepayers, in accordance with the Board's guiding principles.

Within each season, EGI frequently monitors customers' demand, commodity prices, and market conditions. Decisions related to the continued execution of the Plan are made during operational planning meetings, held throughout the year. The frequency of these meetings changes based on the season, weather and market or operational conditions. A diverse, cross-functional team operates with oversight from the Director of Gas Supply to make purchasing decisions related to the execution of the Plan through gas supply procurement and transportation capacity utilization decisions.

To manage risk, EGI procures supply regularly throughout the year from creditworthy counterparties at multiple trading points using a layered approach with consideration to diversity of delivery term and supplier. Appendix G provides supplier diversity by basin for 2019/20 by highlighting the number of counterparties and the range of supply provided by each counterparty. This appendix highlights the diversity of supplier available at the most liquid trading points and the locations with less diversity of supplier.

Long-term, annual and seasonal supply arrangements are contracted prior to entering a season. These are contracted to a level that still allows for flexibility through prompt month and shorter-term purchases to manage changes in demand due to weather, usage patterns or other factors.

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

[69] Includes Union SSMDA, Union MDA, Union WDA, Union NCDA, Union NDA, and Union South

impacts and required adjustments to the supply plan for the upcoming month. The use of medium-term weather forecasts provides EGI with the ability to adjust planned month-ahead supplies earlier, allowing EGI more flexibility in purchase terms. Conversely, in a warmer than normal year, the medium-term forecast gives EGI the opportunity to reduce planned purchases earlier.

Contracting for supply in this manner allows EGI to provide a stable, cost-effective solution for ratepayers while still maintaining the flexibility required to manage to seasonal storage inventory targets. This flexibility is also valuable when demand uncertainties present themselves, such as the current uncertainty presented by the COVID-19 pandemic.

8.1 Procurement Process and Policy

EGI purchases natural gas for system operations and the regulated system gas supply portfolio for all rate zones. On October 2, 2019, the *Gas Supply Procurement Policies and Practices* document was updated to represent a combined group of policies and practices for both legacy utility's rate zones. The objectives of the Policy remain consistent with past versions from both legacy utilities to provide cost effective, reliable and diversified supply within appropriate controls and credit requirements. This updated document was sent to the Board in December 2019. This update to policy has allowed for synergies in execution of combined RFPs and transactions, however the methodology for execution of the Plan is consistent for all rate zones.

The Gas Supply department continues to develop the monthly procurement plan. Per the *Gas Supply Procurement Policies and Practices,* EGI's Director and Manager of Gas Supply sign the monthly procurement plan authorizing the execution of the transactions in the procurement plan. EGI's procurement plan layers in annual, seasonal and monthly purchases each month leaving flexibility should requirements change. Gas supply for all rate zones continues to be purchased using both fixed and indexed price contracts. EGI is authorized to use an RFP process (written and verbal), electronic gas trading platforms or a brokerage house, and straight purchases directly with a counterparty under both the North American Energy Standards Board ("NAESB") contract or a Gas Electronic Data Interchange ("gas EDI") contract.

As system operator, EGI also manages many operational factors for all rate zones including:

- Actual and forecast consumption relative to planned consumption for its sales service customers (92% of all 3.8 million 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

In the second half of 2020, EGI received Board approval of two applications that will result in EGI purchasing RNG to support the Voluntary RNG Program[70] and hydrogen to support the Low Carbon Energy Project[71]. EGI will begin contracting for and procuring these supplies on behalf of sales service customers in 2021. In January 2021, the *Gas Supply Procurement Policies and Practices* were updated to allow for the purchase of hydrogen. See section 4.2 for further details on the inclusion of hydrogen in the system supply portfolio.

9. Three-Year Historical Review

The following section provides a review of the prior three gas years, comparing the Plan for each year to the actuals experienced[72].

9.1 Heating Degree Days

The purpose of this section is to provide a brief review of the prior three years, comparing the forecasted HDD underlying each gas supply plan to the actual HDD experienced. The forecasted HDD are prepared according to the Board Approved methodologies for each region.

Table 20 - Actual vs Plan Annual HDDs

		2017/18			2018/19			2019/20		
Line No.	Particulars (HDD)	Actual	Plan	Variance	Actual	Plan	Variance	Actual	Plan	Variance
1	EGD Central	3,818	3,642	5%	3,841	3,640	6%	3,648	3,621	1%
2	EGD Eastern	4,521	4,331	4%	4,707	4,325	9%	4,418	4,336	2%
3	EGD Niagara	3,604	3,421	5%	3,637	3,417	6%	3,424	3,417	0%
4	Union North West	5,479	4,918	11%	5,460	4,948	10%	5,173	4,941	5%
5	Union North East	5,064	4,918	3%	5,100	4,948	3%	4,864	4,941	-2%
6	Union South	3,921	3,779	4%	3,909	3,782	3%	3,726	3,763	-1%

As shown in Table 20:

- 2017/18 – HDDs were higher than budget across all weather zones due to colder than expected temperatures
- 2018/19 – HDDs were higher than budget across all weather zones due to colder than expected temperatures
- 2019/20 – HDDs were relatively close to budget across most weather zones: colder than expected in EGD Central, Eastern, Niagara, and Union North West; and warmer in Union North East and Union South

[70] EB-2020-0066
[71] EB-2019-0294
[72] Tables presented on gas year for all rate zones

9.2 Annual Demand

The purpose of this section is to provide a brief review of the prior three years, comparing the demand forecast underlying each gas supply plan to the actual throughput volume. Actual volumes have not been normalized for weather variances.

Table 21 - Actual vs Plan Annual Demand

Line No.	Particulars (TJ)	2017/18 Actual	2017/18 Plan	2017/18 Variance	2018/19 Actual	2018/19 Plan	2018/19 Variance	2019/20 Actual	2019/20 Plan	2019/20 Variance
	EGD									
1	General Service	394,777	368,461	26,317	413,685	379,759	33,926	381,268	378,189	3,079
2	Contract	68,241	66,898	1,343	67,770	67,245	525	64,216	66,821	(2,606)
3	Total EGD	463,018	435,358	27,660	481,456	447,004	34,451	445,484	445,010	474
	Union North West									
4	General Service	14,765	13,420	1,345	14,994	14,008	986	14,176	14,375	(198)
5	Contract	2,861	2,022	839	2,172	1,347	825	1,879	1,418	461
6	Total Union North West	17,626	15,442	2,184	17,165	15,355	1,811	16,055	15,793	262
	Union North East									
7	General Service	38,849	36,834	2,015	40,199	36,329	3,871	38,477	38,248	230
8	Contract	4,019	3,879	140	4,003	3,663	340	4,004	4,227	(223)
9	Total Union North East	42,868	40,713	2,155	44,203	39,992	4,211	42,481	42,474	7
	Union South									
10	General Service	176,087	161,379	14,708	180,218	164,995	15,223	169,670	173,530	(3,860)
11	Contract	51,808	49,350	2,458	53,593	50,015	3,578	53,990	51,814	2,176
12	Total Union South	227,895	210,729	17,166	233,811	215,010	18,801	223,660	225,344	(1,684)
13	Total Demand Forecast	751,407	702,242	49,165	776,634	717,361	59,274	727,680	728,622	(941)

As shown in Table 21:

- 2017/18 – Colder than normal weather increased demand above budget
- 2018/19 – Colder than normal weather increased demand above budget
- 2019/20 – Actual demand was relatively close to budget overall

9.3 Commodity Portfolio

The purpose of this section is to provide a brief review of the prior three years, comparing the supply forecast underlying each gas supply plan to the actual supply procured.

Table 22 - Actual vs Plan Commodity Purchases

Supply Actual vs Plan

Line		2017/18			2018/19			2019/20		
No.	Particulars (TJ)	Actual	Plan	Variance	Actual	Plan	Variance	Actual	Plan	Variance
	EGD									
1	Appalachia	-	43,466	(43,466)	42,152	43,466	(1,314)	38,500	43,585	(5,085)
2	Chicago	67,537	25,258	42,279	24,418	25,233	(815)	20,866	25,192	(4,325)
3	Niagara Region	72,462	72,988	(526)	72,483	73,085	(603)	72,319	73,303	(984)
4	Dawn	130,891	101,518	29,372	124,929	98,601	26,327	105,287	89,687	15,599
5	Peaking/Seasonal	216	135	81	1,013	166	847	-	96	(96)
6	WCSB	65,670	69,287	(3,617)	86,322	82,303	4,018	87,922	89,903	(1,981)
7	Total EGD	336,776	312,653	24,122	351,316	322,855	28,461	324,893	321,766	3,127
	Union North West									
8	WCSB	15,487	11,343	4,144	19,242	11,541	7,701	19,327	16,975	2,352
9	Ontario/Dawn	3,293		3,293	4,602		4,602	359		359
10	Total North West	18,780	11,343	7,437	23,844	11,541	12,303	19,685	16,975	2,710
	Union North East									
11	Appalachia	-	3,218	(3,218)	19,228	19,255	(27)	18,750	19,308	(558)
12	Chicago	8,016	16,037	(8,021)		-	-	-		-
13	Dawn	20,936	7,326	13,610	15,039	10,783	4,255	9,419	7,206	2,214
14	WCSB	4,545	4,781	(236)	1,491	1,364	127	1,495	1,368	127
15	Total North East	33,497	31,362	2,135	35,758	31,403	4,355	29,664	27,882	1,782
	Union South									
16	Appalachia	-	6,436	(6,436)	38,275	38,510	(234)	37,546	38,615	(1,069)
17	Chicago	32,365	24,329	8,036	30,332	30,807	(476)	27,412	30,892	(3,479)
18	Great Lakes			-			-	-	7,723	(7,723)
19	Niagara Region	7,553	7,702	(149)	6,879	7,702	(823)	7,722	7,723	(1)
20	Ojibway	7,702	7,702	0	7,702	7,702	0		-	-
21	Dawn	48,777	47,535	1,242	54,963	44,158	10,806	33,411	42,287	(8,876)
22	U.S. Mid-Continent	48,030	42,345	5,685	13,470	13,478	(8)	18,232	22,011	(3,779)
23	WCSB	1,095	1,095	-	1,095	1,095	(0)	8,821	1,098	7,723
24	Total South	145,522	137,144	8,378	152,716	143,452	9,264	133,144	150,348	(17,205)
25	Total Supply Forecast	534,575	492,503	42,072	563,634	509,251	54,384	507,387	516,971	(9,585)

**Ontario Production is included as part of the Dawn number in the Union South total*

As shown in Table 23:

- 2017/18 – Colder than normal weather increased demand and gas supply deliveries above budget.
- 2018/19 – Colder than normal weather increased demand and gas supply deliveries above budget.
- 2019/20 – Warmer than normal weather decreased demand and gas supply deliveries above

9.4 Unutilized Capacity

The purpose of this section is to provide a brief review of the prior three years, comparing the UDC underlying each gas supply plan to the actual UDC incurred.

Table 23 - Actual vs Plan UDC

Planned UDC

Line No.	Particulars (PJ)	2017/18 Actual	2017/18 Plan	2017/18 Variance	2018/19 Actual	2018/19 Plan	2018/19 Variance	2019/20 Actual[1]	2019/20 Plan	2019/20 Variance
1	EGD	-	-	-	-	-	-	-	-	-
2	North West	6.7	14.3	(7.6)	1.4	14.4	(13.0)	8.0	8.4	(0.4)
3	North East	0.6	2.7	(2.1)	0.9	4.3	(3.4)	8.4	7.1	1.3
4	South	-	-	-	-	-	-	11.6	-	11.6
5	Total UDC	7.3	17.0	(9.7)	2.3	18.6	(16.3)	28.0	15.6	12.4

[1] *Actual 2019/2020 UDC volume allocations are preliminary. Final allocations will be filed in the 2020 Non-Commodities Deferral proceeding.*

As shown in Table 23:

- 2017/18 – The actual UDC incurred was 9.7 PJ lower than planned due to colder than normal weather
- 2018/19 – The actual UDC incurred was 16.3 PJ lower than planned due to colder than normal weather
- 2019/20 – The actual UDC incurred was 12.4 PJ higher than planned primarily due to warmer than normal weather

10. Performance Measurement

EGI has developed performance metrics that reflect the criteria the Board has established to monitor effectiveness of the Plan and how the guiding principles have been achieved, and to drive continuous improvements. EGI's performance metrics for 2019/20 can be found in Appendix H with a brief explanation of each measure's intent.

scottmadden
MANAGEMENT CONSULTANTS

Resume & Testimony Listing of:
James M. Stephens
Partner

Summary

Mr. Stephens has 30 years of experience in the energy industry and has held senior management positions at economic consulting firms, a retail energy marketer, and local distribution companies prior to joining ScottMadden. Mr. Stephens has assisted numerous clients in the United States and Canada with natural gas supply analysis, portfolio assessment and optimization, demand forecasting and risk management, energy infrastructure evaluation, and regulatory strategy development and implementation. He has also provided expert testimony in numerous proceedings at various jurisdictions, including federal, state, and provincial regulatory agencies.

In addition, Mr. Stephens has commercial experience through his leadership positions at a retail energy marketing company, where he was responsible for all aspects of business unit management, including front, mid and back-office functions. He was also responsible for gas supply procurement and portfolio optimization for a local distribution company. Mr. Stephens holds a Bachelor of Science degree in management and a Masters in Business Administration with a concentration in operations management from Bentley College.

REPRESENTATIVE PROJECT EXPERIENCE

Energy Market Assessment

Retained by numerous companies to develop regional energy market assessments which included: market impacts associated with new energy infrastructure, assessment of the implications associated with natural gas infrastructure, market structure and regulatory situational analysis, and assessment of competitive position. Market assessment engagements typically have been used as required elements of business unit or asset-specific strategic plans or valuation analyses. In addition, certain market assessments have been submitted to various federal, state, and provincial regulatory agencies.

Representative engagements have included:

- Submitted expert testimony on behalf of Eversource to the Massachusetts Department of Public Utilities and the New Hampshire Public Utility Commission regarding pipeline capacity and LNG service precedent agreements on the Access Northeast project.
- Submitted an expert report on behalf of Union Gas and Enbridge Gas Distribution to the Ontario Energy Board with respect to pipeline precedent agreements on the NEXUS Pipeline project.
- For two Canadian LDCs, developed a review of certain mid-Atlantic natural gas supply basins.
- For the State of Maine Public Utility Commission, prepared a report that summarized the Northeast and Atlantic Canada natural gas and power markets; and analyzed the potential benefits and costs associated with natural gas pipeline expansions. The independent report was filed at the Maine Public Utility Commission.
- On behalf of Spectra Corporation, developed a market assessment evaluating the impact of new pipeline infrastructure into the New York City, New Jersey and New England markets. The independent reports were filed at the Federal Energy Regulatory Commission and/or presented to state public utility commissions.
- For a Canadian utility developed a detailed review of the U.S. Northeast energy market and presented findings to their senior management.
- For an international energy company, prepared an assessment of the market potential for distributed LNG, with a particular focus on the commercial and industrial sectors.
- For a project developer, prepared a natural gas demand analysis of the Southeast U.S. The independent report, which was filed at the Federal Energy Regulatory Commission, addressed the demand for natural gas in both the electric generation and traditional LDC markets.
- For an international energy company, prepared an analysis regarding LNG peaking facilities.
- Conducted due diligence for commercial banks regarding investments in natural gas pipelines, natural gas storage projects, and LNG facilities.
- For a project developer, assisted with the evaluation of the market opportunity for an LNG importation terminal in the northeastern United States.

- For numerous clients, provided regional natural gas demand assessments to assist with the evaluation of energy infrastructure.
- For a natural gas producer, reviewed energy contracting practices and pricing mechanisms to support a contract arbitration process.

Business Strategy and Operations

Retained by numerous North American energy companies to support the development of strategic plans and planning processes for both regulated and non-regulated entities. Specific services provided include: developing market entry strategies for the retail and wholesale energy sectors; review of management practices and procedures; and business process redesign initiatives.

Representative engagements have included:

- For Columbia Gas of Massachusetts, developed expert testimony analyzing a contract for natural gas pipeline capacity. The testimony was submitted to the Massachusetts Department of Public Utilities.
- For Union Gas, developed expert testimony regarding the gas supply planning process and associated activities. The testimony was submitted to the Ontario Energy Board.
- For Gaz Métro, developed expert testimony regarding the utilization of natural gas storage. The testimony was submitted to the Régie de l'énergie.
- For an LDC, reviewed its current retail choice program, certain proposed changes, and the potential impacts on the gas supply portfolio.
- For an LDC, reviewed the cost and benefits of expanding into new service territories.
- Reviewed natural gas supply alternatives (i.e., supply basin cost, transport basis and regulatory issues) for an integrated energy company.
- Developed regional market assessments and associated market entry strategies for a wholesale energy marketing company.
- Reviewed certain risk management practices and procedures for a wholesale energy marketing company.
- For a retail energy marketer, conducted due diligence including a review of risk management policies and procedures.
- Prepared a competitive position analysis (i.e., SWOT analysis) for an interstate gas pipeline.
- On behalf of a wholesale energy marketing company, reviewed federal and state requirements associated with entering certain natural gas markets.
- For an LDC, assessed the economic viability of gas distribution utility service expansion.
- Developed new service offerings, including firm transportation and stand-by service, for a mid-Atlantic utility.
- Managed the re-engineering of a large Midwest LDC's gas supply procurement process.
- Managed the re-engineering of a mid-Atlantic wholesale energy marketing company's gas operations including certain risk management areas.
- On behalf of an interstate pipeline, conducted a customer outreach/survey program.

Regulatory Analysis and Support

On behalf of energy market participants, supported the development of regulatory and ratemaking strategies, energy supply obligations, stranded cost assessment and recovery, rate design, and management procedures and decisions. Specific projects include: design and implementation of pipeline capacity open season processes; review utility contracting approaches with respect to gas supplies; assess compliance requirements of the FERC standard of conduct regarding affiliate transactions; analysis of provider of last resort obligations in both electric and gas markets; review the process to procure and hedge default service supplies; and develop new service offerings.

Representative engagements have included:

- Retained by EPCOR Energy Alberta to review procurement and pricing of energy for their supplier of last resort obligation, including identifying and quantifying economic risks of providing the service. Expert report and testimony were submitted to the Alberta Utilities Commission.
- Retained by a utility for regulatory support with respect to energy storage and electric vehicle infrastructure.
- On behalf of an LDC, developed an integrated resource plan including demand forecasting and gas supply portfolios analysis. The final work product was submitted to the state utility commission.
- Retained by the Alaska Gasline Development Corporation to assist with a market review and assessment; open season process development, implementation, and third party contracting; and associated activities (e.g., tariff and service development).
- Retained by various LDCs and electricity utilities to evaluate interstate pipeline capacity and storage open seasons including an analysis of the quantitative and qualitative aspects of the various projects.
- Retained by an LDC to develop regulatory strategy associated with the funding of distribution expansion.
- Retained by a Midwest U.S. interstate gas pipeline to assist with an open season including drafting of tariffs and precedent agreements.
- Retained by a Northeast energy company to review the FERC reporting requirements and standards of conduct for an interstate pipeline business unit.
- Provided regulatory and litigation support to a natural gas pipeline regarding rate impacts of new infrastructure development.
- Provided litigation support to a mid-west utility regarding proposed gas purchase disallowances for storage utilization, hedging activity, and pipeline capacity decisions.
- On behalf of a Midwest utility, developed and implemented a third party transportation program.
- Developed a demand forecast to support the AES Sparrows Point LNG FERC application.
- Provided support to a Canadian LNG supplier regarding their NEB export license application.

Energy Procurement

Directed and participated in the review of various energy procurement projects including demand modeling, portfolio review/optimization, risk management, procurement strategies and associated cost structures.

Representative experience has included:

- Retained by a utility to review the financial concepts of risk and risk aversion with respect to the provision of regulated energy service and the associated compensation for the service obligation.
- Retained by New Brunswick Power to document and assess fuel procurement and associated processes. Expert report was submitted to New Brunswick Energy and Utilities Board.
- For a municipal utility, evaluated its current gas supply portfolio and associated purchasing strategies.
- For a municipal utility, evaluated the benefits and costs associated with quick-start generation.
- Retained by a utility to review the value achieved under an asset management agreement, including the use of storage.
- Provided a market participant with a review of natural gas supply and storage options, associated prices, and risk mitigation opportunities.
- On behalf of a natural gas distribution company, evaluated the benefit associated with asset management opportunities.
- On behalf of a regional combination utility, reviewed the appropriate jurisdiction for a natural gas pipeline asset.
- On behalf of a natural gas utility, conducted a detailed audit of the gas supply, marketing, risk management, and accounting functions.
- On behalf of several gas utilities, developed demand forecasts and supported those forecasts in regulatory proceedings.
- For a multi-state utility, reviewed the demand forecast planning process and procedures and recommended certain process changes.

- On behalf of a financial institution, reviewed the competitiveness of a storage project investment and quantified the impact of various new projects on the storage project financial performance.
- As President of a retail energy marketing firm directed all aspects of the business unit and was responsible for marketing, origination, operations, accounting, and billing. In addition, was responsible for the physical and financial commodity books; developed and implemented risk management strategy and objectives; implemented risk management policies and procedures; negotiated counterparty contracts; and reviewed and reported on financial performance to the Board of Directors.

Financial and Economic Advisory Services

Involved in the sale or evaluation of several regulated and non-regulated energy companies including wholesale and retail energy marketing companies, on-line energy brokers, and energy services' companies. Assisted clients with market strategy and the identification of partnership opportunities. Specific services provided include: business unit evaluation, development of marketing and sale materials, marketing of transaction, bid evaluation and negotiation support.

Representative engagements have included:

- For an energy broker, developed and executed an acquisition strategy.
- For Eversource, assisted with the sale of its retail services business unit.
- For an international integrated utility, supported its due diligence team with respect to an evaluation of a multi-state utility.
- For a private equity firm, evaluated natural gas procurement and energy sales in support of an investment in generation.
- For a utility, supported its due diligence with respect to a potential acquisition of a natural gas distribution company.
- For a municipal utility, evaluated and negotiated an asset management agreement.
- Assisted an LDC with gas supply due diligence regarding a potential asset acquisition.
- For a third-party investor, performed an independent review of a retail energy marketer including existing physical and financial books, risk management protocols and exposures, and growth strategy.
- Supported the sale of Niagara Mohawk Power Corporation's non-regulated energy marketing affiliate.
- Directed the sale of a non-regulated marketing affiliate.
- Performed an independent valuation of an on-line energy broker on behalf of an investor.

Professional History

ScottMadden, Inc. (2016 – Present [acquired Sussex Economic Advisors, LLC])
Partner

Sussex Economic Advisors, LLC (2012 – 2016)
Partner

Concentric Energy Advisors, Inc. (2002 – 2012)
Executive Advisor
Senior Vice President
Vice President

Navigant Consulting, Inc. (2000 – 2001)
Director, Energy Market Assessment Practice Area

Providence Energy Services (1997 – 2000)
President (1998 – 2000)
President, Providence-Southern (1997 – 1998)

REED Consulting Group (1994 – 1997)
Assistant Vice President

Colonial Gas Company (1991 – 1994)
Director, Gas Supply Planning and Acquisition (1993 – 1994)
Manager, Gas Supply (1991 – 1993)

Boston Gas Company (1987 – 1991)
Senior Gas Supply Analyst (1990 – 1991)
Transportation and Exchange Analyst (1988 – 1990)
Business Analyst (1987 – 1988)

Education

Masters in Business Administration with a concentration in Operations Management, Bentley College, 1991
Bachelor of Science in Management, Bentley College, 1987

Designations and Professional Affiliations

Member of the American Gas Association
Member of the New England Gas Association
Member of the Society of Gas Lighting
Member of the New England-Canada Business Council
Member of the Northeast Energy and Commerce Association
Member of the Guild of Gas Managers

scottmadden MANAGEMENT CONSULTANTS

Resume & Testimony Listing of:
James M. Stephens
Partner

Recent Expert Witness Appearances of James M. Stephens

SPONSOR	DATE	JURISDICTION	DOCKET NO.	SUBJECT
Union Gas Limited	April, 2013	Ontario	Docket No. 2013-0109	Gas Supply Planning
Columbia Gas of Massachusetts	September, 2013	Massachusetts	Docket No. 13-158	Pre-Approval of a Long-Term Capacity Contract
Columbia Gas of Massachusetts	September, 2013	Massachusetts	Docket No. 13-161	Integrated Resource Plan
Gaz Métro	October, 2013	Québec	Cause tarifaire 2014, R-3837-2013	Storage Utilization
Maine Public Utility Commission	February, 2014	Maine	Docket No. 2014-00071	Pipeline Open Season
Gaz Métro	January, 2015	Québec	Cause tarifaire 2015, R-3879-2014	Storage Utilization
UIL Holdings Corporation d/b/a Total Peaking Services, LLC	September, 2015	Federal Energy Regulatory Commission	Docket No. CP15-557-000	Market Power Study
Union Gas Limited	May, 2015	Ontario	Docket No. EB-2015-0166	Pre-Approval of a Long-Term Pipeline Capacity Contract
Enbridge Gas Distribution	June, 2015	Ontario	Docket No. EB-2015-0175	Pre-Approval of a Long-Term Pipeline Capacity Contract
Northern Utilities, Inc.	November, 2015	Maine	Docket No. 2014-00132	Retail Choice Transportation Program
Eversource Energy	December, 2015	Massachusetts	Docket No. 15-181	Pre-Approval of Long-Term Pipeline Capacity Contract
Eversource Energy	February, 2016	New Hampshire	Docket No. DE 16-241	Pre-Approval of Long-Term Pipeline Capacity Contract
New Brunswick Power	October, 2016	New Brunswick	Matter No. 336	Commodity Procurement / Risk Management
EPCOR Energy Alberta	January, 2017	Alberta	Proceeding ID 22357	Energy Procurement and Risk Assessment
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	December, 2017	New Hampshire	Docket No. DG 17-198	Approval of Natural Gas Supply Strategy

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Resume & Testimony Listing of:
James M. Stephens
Partner

Heritage Gas Limited	January, 2018	Nova Scotia	Matter No. M08473	Approval of Long-Term Natural Gas Transportation Contract; Cost Recovery Mechanism; and Capacity Assignment Principles
ENSTAR Natural Gas Company	June, 2018	Alaska	Docket No. U-18-004	Reply Testimony in Support of ENSTAR's Design Day and Gas Supply Contracting Practices
Southwestern Public Service Company	June, 2019	Texas	Docket No. 48973	Direct and Reply Testimony in Support of two Solar PPA's and Associated Cost Recovery in a Fuel Reconciliation Proceeding
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a/ Liberty Utilities	October, 2019	New Hampshire	Docket Number DG 17-152	Approval of Integrated Resource Plan

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Resume of:
Kim N. Dao
Director

Summary

Ms. Dao has 15 years of experience in the energy and utility industries. She has contributed to engagements involving regulatory strategy and market analyses, including the evaluation of open seasons, regional energy market demand/supply dynamics, energy pricing and basis implications, and the associated drivers for new natural gas infrastructure; the development and evaluation of natural gas demand forecasts; and natural gas supply portfolio evaluation and optimization. Ms. Dao has also provided analytical support for expert witness testimony on a variety of issues, including gas supply planning, demand forecasting, cost of capital and capital structure, cost of service and rate design, marginal costs studies, and expense and operating performance benchmarking. She has extensive experience in data analysis, development of customized spreadsheet models (e.g., dispatch, storage optimization, gas pricing, landed costs), Monte Carlo simulation models, database development, researching regulatory and energy market issues, risk identification/assessment, performing statistical analysis, and financial analysis and modeling. Ms. Dao holds a B.A. in economics from Clark University, where she graduated summa cum laude and was a member of the Omicron Delta Epsilon Society.

Areas of Specialization

- Utilities
- Market assessment
- Regulatory strategy and rate case support
- Natural gas
- Demand forecast and supply portfolio evaluation
- Strategic and business planning

Recent Assignments

- Retained by an integrated utility company to support their analysis of new energy infrastructure and upstream pipeline capacity contracts; used @Risk software to develop a Monte Carlo simulation model of daily natural gas pricing estimates that were used in a portfolio optimization software; supported the levelized cost modeling of the utility's proposed infrastructure development projects; developed a qualitative assessment of the proposed projects relative to alternatives; supported the development of expert testimony and sponsored data requests regarding the utility's natural gas supply strategy
- Supported expert testimony filed before and subsequently approved by the Nova Scotia Utility and Review Board regarding a pipeline capacity contract, which included a review of natural gas market dynamics, and the development of several analytical models (e.g., landed cost and resource dispatch models) to review the need for and costs associated with the pipeline capacity contract under various weather and market conditions
- Assisted several New England LDCs with the development of integrated resource plans, including demand forecast model development using various statistical and econometric approaches and supply portfolio analysis and evaluation
- Provided analyses to support expert testimony filed before and subsequently approved by the Massachusetts DPU regarding the utility's capacity decisions associated with the Algonquin Incremental Market open season
- Developed several regression models to estimate peak day demand in support of a potential capacity decision as part of an evaluation of the Tennessee Gas Pipeline Northeast Expansion open season
- Conducted an assessment of the responses to a request for proposal and supported expert testimony that was submitted to the Massachusetts Department of Public Utilities (DPU), which included an overview of current energy market conditions, a summary of natural gas supply options submitted in response to the RFP, and a quantitative and qualitative evaluation of the submissions
- Provided research and analytical support for expert testimony submitted to the Maine Public Utility Commission regarding the retail choice program and the benefits of program changes to the LDC planning function
- Provided support for expert testimony submitted to the Régie de l'énergie regarding the utilization of natural gas storage, which included the development of a natural gas storage dispatch and optimization model
- Supported expert testimony submitted to the Ontario Energy Board, which included an overview of existing market conditions and a quantitative and qualitative assessment of a natural gas transmission project
- For the Maine Public Utility Commission, prepared a report that summarized the Northeast and Atlantic Canada natural gas and power markets, reviewed the current open seasons for incremental pipeline capacity, and analyzed the potential benefits and costs associated with incremental natural gas deliverability
- Supported the evaluation of natural gas storage for an electric utility, which included a review of the open season documentation and offers, the development of a model to evaluate various levels of storage service, and benchmarking analysis of the parameters of the proposed natural gas storage contract to similar services offered by other storage providers
- Supported expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies for electric and natural gas utilities through state and company-specific research and analysis, financial analysis and modeling, and testimony development

Natural Gas Storage Blind RFP Process

Prepared for Enbridge Gas, Inc.

October 9, 2020

1. INTRODUCTION

ScottMadden, Inc. (“ScottMadden”) was retained by Enbridge Gas Inc. (“EGI” or the “Company”) to review and provide recommendations regarding the annual blind bid process used by the Company to conduct, and evaluate responses to, a request for proposal (“RFP”) for natural gas storage capacity (the “Blind RFP Process”). ScottMadden understands that the Ontario Energy Board Staff (“OEB Staff”) in its Final OEB Staff Report to the Ontario Energy Board (“OEB”), dated March 26, 2020, in Case No. EB-2019-0137 (“OEB Staff Final Report”) stated the following regarding the Company’s Blind RFP Process:

- “The process is not entirely “blind” and therefore, the process does not effectively ring fence Enbridge gas supply procurement group (who are making the decision to purchase market-based storage) from its own non-utility storage in the Union South rate zone and its affiliates in Ontario.
- The process as currently designed does not eliminate concerns of possible bias.”[1]

As a result of these observations, OEB Staff recommended that the Company retain an independent expert with natural gas experience to review and assess the current Blind RFP Process; specifically, OEB Staff stated:

> “As per the draft OEB Staff Report, OEB staff supports Enbridge undertaking a third-party independent expert assessment of its blind RFP process, by a party that has natural gas experience. However, regardless of the outcome of a third-party assessment, OEB staff recommends that Enbridge refine its process so that follow-up requests with the RFP Manager are eliminated. One way to do this is to retain an RFP Manager that has natural gas expertise and the RFP Manager provides Enbridge with the winning storage proposal only. This will eliminate any concerns of bias. OEB staff recommends that Enbridge, in its 2020 Annual Update, report on its progress to refine the current blind RFP process.”[2]

Based on a review of the concerns and directives identified in the OEB Staff Final Report, ScottMadden has evaluated and documented the current process used by EGI to administer the Company’s Blind RFP Process, and has detailed recommendations regarding the planning and execution of the EGI Blind RFP Process in the sections that follow. To undertake our review and analysis, ScottMadden used the following approach:

- <u>Document the Current Process</u> – as a first step, ScottMadden conducted a review of various documents used in the current Blind RFP Process, including the bidder documents and the spreadsheet used to compare and evaluate the bids. In addition, ScottMadden discussed the process with certain EGI personnel involved in the Blind RFP Process.
- <u>Review and Assess Bid Evaluation</u> – in this second step, ScottMadden reviewed the quantitative approach used to evaluate the bids.
- <u>Narrative Report</u> – in the third and last step, ScottMadden developed this narrative report, which summarizes our understanding of the EGI Blind RFP Process and provides recommendations that support an improved process and address the OEB Staff observations regarding the current process.

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1 Final OEB Staff Report to the Ontario Energy Board – Consultation to Review Natural Gas Supply Plans – EB-2019-0137, dated March 26, 2020, at 32.

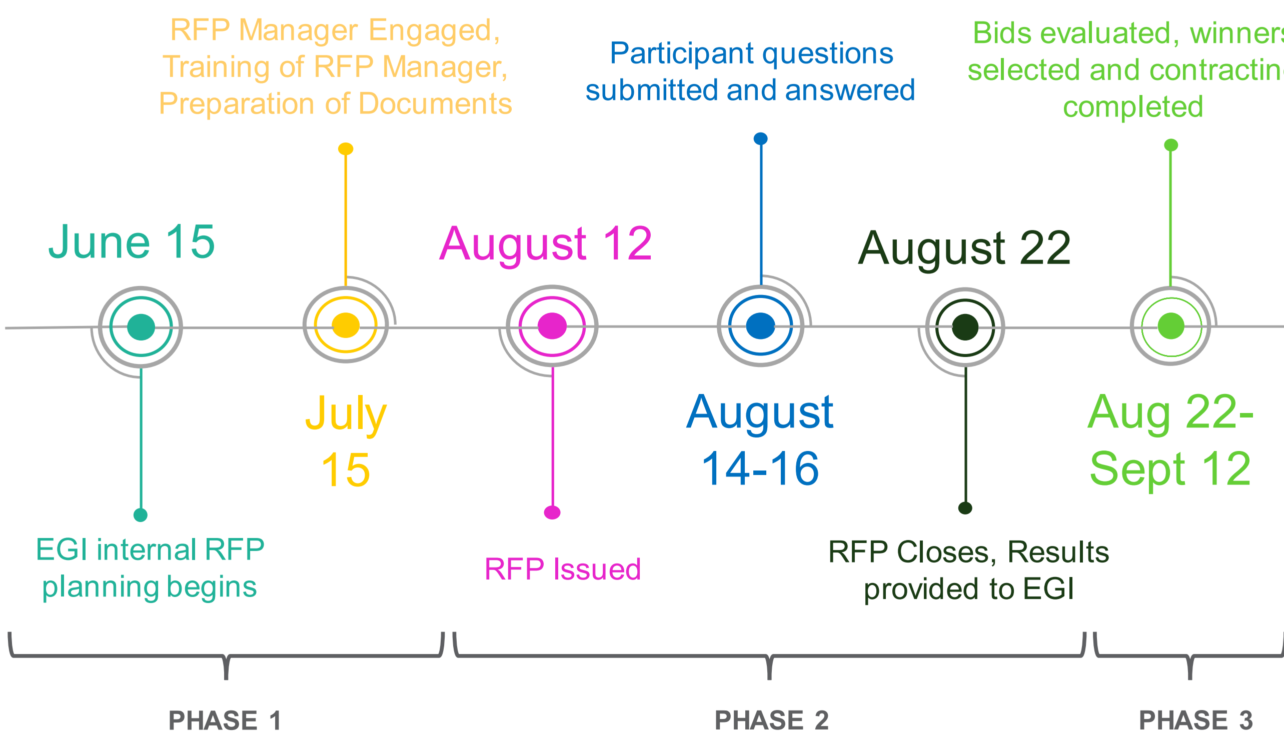
2 *Ibid.*, at 33.

2. OVERVIEW OF CURRENT EGI BLIND RFP PROCESS

EGI, given the level of non-utility natural gas storage it owns and operates,[3] conducts an annual Blind RFP Process with respect to contracting for natural gas storage capacity. To administer this process, and to maintain anonymity of bidders and limit potential bias, the Company contracts with an independent third-party manager (the "External RFP Manager") to help conduct and manage the Company's Blind RFP Process.

To provide the appropriate context and summarize the overall Blind RFP Process, the timeline of activity associated with the Company's 2019 Blind RFP Process is provided below as Figure 1.

Figure 1: EGI 2019 Blind RFP Timeline[4]



Based on ScottMadden's review of the 2019 Blind RFP Process, the timeline of activities spanned approximately 13 weeks. As shown at the bottom of Figure 1, ScottMadden has categorized the activities associated with the Blind RFP Process into three distinct phases, specifically:

- Phase 1 (i.e., planning stage) included activities leading up to the issuance of the RFP and covered the period from June 15 to August 12, 2019 (i.e., approximately 8 weeks);
- Phase 2 (i.e., implementation stage) consisted of approximately 2 weeks of activities from the issuance of the RFP on August 12, 2019, the bidders' question and answer stage, and the

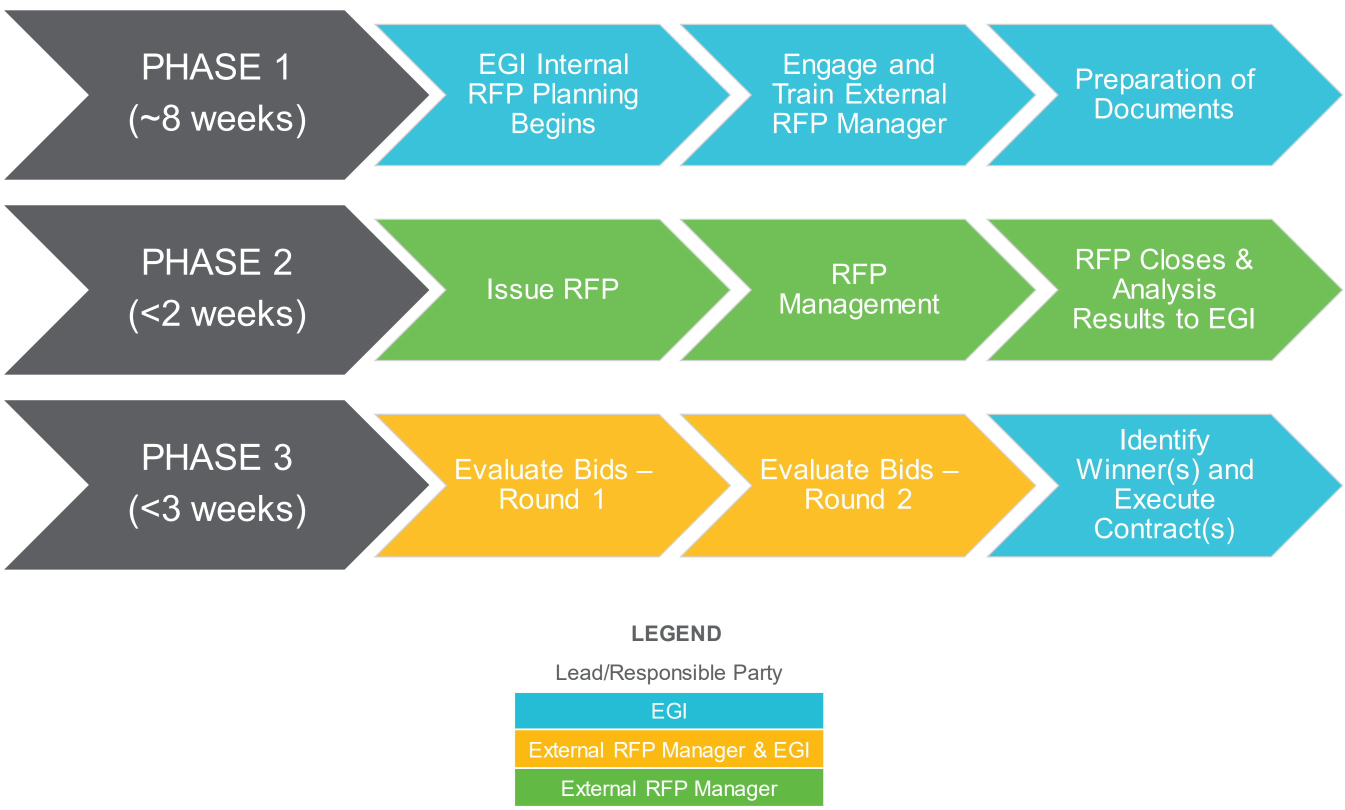
3 *Ibid.*, at 14.
4 Source: Company provided.

closing of the RFP; and concluded with certain information for all bids provided to EGI, on August 22, 2019; and

- Phase 3 (i.e., assessment stage) involved the evaluation of bids, selection of winner(s), and execution of associated natural gas storage contract(s), which occurred from August 22 through September 12, 2019 (i.e., approximately 3 weeks).

In Figure 2 below, ScottMadden has documented, at a high level, the major activities within each phase of the current Blind RFP Process and identified the lead, or responsible party, for those activities, recognizing that certain activities were conducted by both EGI and the External RFP Manager.

Figure 2: Current EGI Blind RFP Process Flow Chart and Roles



As illustrated in Figure 2 above, for the most recent Blind RFP Process, activities shaded in blue were managed by EGI; activities shaded in green were led by the External RFP Manager; and activities that were conducted by both EGI and the External RFP Manager are shown in yellow. Based on our review of the Blind RFP Process conducted in 2019, and given the concerns and directives associated with the bid process outlined in the OEB Staff Final Report (discussed in Section 1 above), ScottMadden has documented the specific tasks associated with the various major activities within each phase and has specific recommendations regarding the planning, implementation, and assessment stages of the EGI Blind RFP Process as discussed in Section 3 below.

3. SCOTTMADDEN'S BLIND RFP PROCESS RECOMMENDATIONS

A. Phase 1 Activities

The Blind RFP Process Phase 1 activities (i.e., planning stage) are conducted prior to the issuance of the RFP and are all led and managed by EGI. Specifically, as shown in Figures 3A and 3B below, the major activities in Phase 1 are currently: (i) the Company's internal RFP planning, (ii) the Company's process of engaging and training the External RFP Manager, and (iii) the preparation of supporting bid documents for the Blind RFP Process.

Figure 3A: EGI Blind RFP Process – Current Phase 1 Activities

EGI Internal RFP Planning Begins

1. Outline requirements for External RFP Manager
2. Identify potential External RFP Managers
3. Assess third-party vendors and contract with External RFP Manager

Engage and Train External RFP Manager

1. Training provided to External RFP Manager by EGI
   – Training may include approaches to identifying and including certain unique cost attributes of natural gas storage costs (e.g., incorporating transportation costs in the total price of the storage service for bid evaluation)
2. Explanatory documents provided to External RFP Manager
   – RFP process and requirements
   – Bid Template (in Excel) and bid evaluation spreadsheet
   – Distribution list of potential bidders/recipients

Figure 3B: EGI Blind RFP Process – Current Phase 1 Activities

Preparation of Documents

1. Identify bidder/recipient list
2. Outline bid objectives
   – Location of service - at the Dawn Hub; transport from the storage facility that underpins the bid to the Dawn Hub must be included in bid price
   – Storage volume
   – Daily deliverability
   – Term diversity
3. Develop screening criteria
   – Lowest cost storage offering at Dawn
   – Flexible injection and withdrawal parameters
   – Term offered compliments existing contract expiry profile
   – Unit cost
   – Flexibility in service
4. Develop supporting bid documents
   – RFP announcement
   – RFP letter with bid instructions
   – Bid Template (in Excel) and bid evaluation spreadsheet

Based on a detailed review of the first two activities in Phase 1 (shown in Figure 3A above), ScottMadden has the following process recommendations for the Blind RFP Process:

- Expand the criteria and requirements for choosing the External RFP Manager, which may include:
  - Knowledge of and/or expertise in natural gas markets;
  - Experience in natural gas storage rate, cost, and service analysis;
  - Familiarity with regulatory requirements and associated processes;
  - Understanding of the need for, and intent of, a "blind" bid process to preserve the anonymity of bidders and limit potential bias; and
  - Ability to manage a bidder process (e.g., management of bidders' questions and answers).
- Outline a detailed process schedule from training of the External RFP Manager to issuance of the RFP to the evaluation of bids and final recommendation(s); and
- Define and document the role and responsibilities of EGI and the External RFP Manager:
  - Meet with the External RFP Manager to confirm and document the Blind RFP Process objectives, overall timeline and schedule, and project team responsibilities; and
  - Develop communication protocols for (i) external communications to the market; (ii) internal communications among the project team; and (iii) project management responsibilities.

In addition, as part of Phase 1, ScottMadden has the following recommendations regarding the preparation of supporting documents associated with the Blind RFP Process (shown in Figure 3B above):

- With respect to the bidder/recipient list:
  - Identify primary and secondary contacts for each bidder/recipient on the list; and
  - Eliminate duplication of bidders.
- Provide a timeline/schedule in the RFP announcement and RFP letter that summarizes the RFP milestones and deadlines;
- Provide a common set of assumptions or requirements (e.g., all bids must be submitted in Canadian dollars per gigajoule (CAD/GJ)) for bidders in the Bid Template (in Excel);
- Request additional information to support bid evaluation (e.g., a total annual cost metric for each bid submitted)[5] in the Bid Template (in Excel); and
- As part of the RFP supporting bid documents, revise the RFP letter and bid instructions to:
  - Include a requirement that bidders must provide one conforming bid; and
    - If conforming bid is submitted, alternative structures may also be submitted;

5 As discussed further below, the total annual cost metric provided by bidders will be compared to the total annual cost calculated by the External RFP Manager to confirm costs are appropriately modeled and understood.

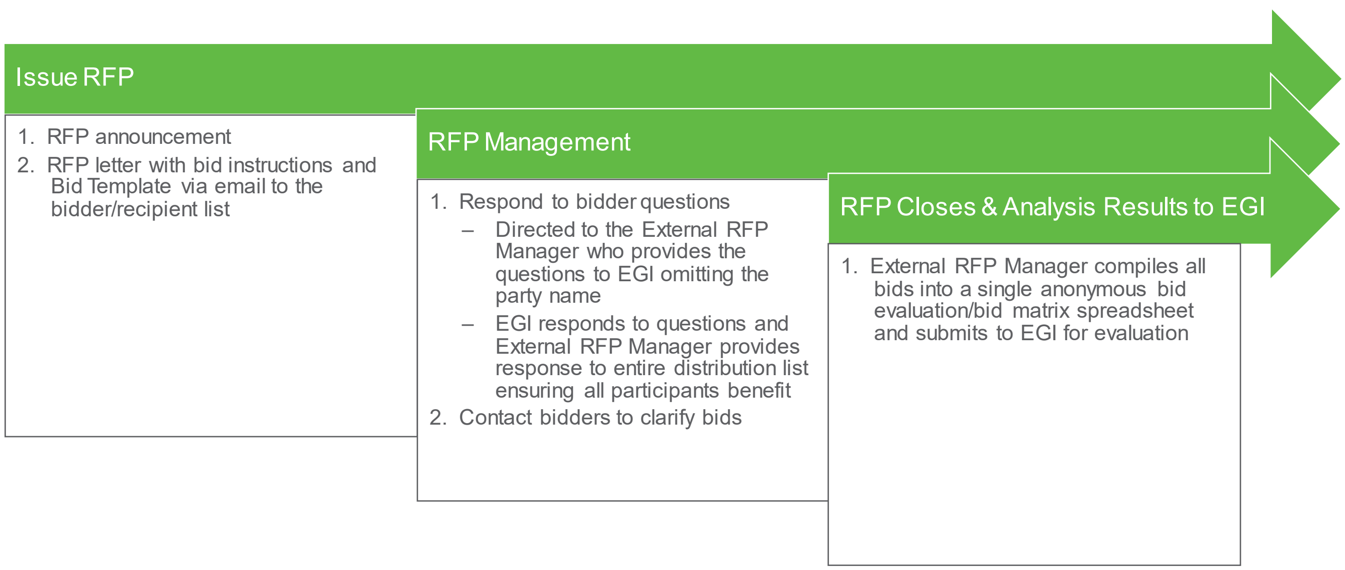
- Request sample monthly invoices from bidders as part of bid submissions – one for an injection month and one for a withdrawal month for each bid submitted.[6]

Please note, a more detailed review of the Bid Template and other supporting bid documents is provided in Sections 3.C. and 3.D, which summarize the ScottMadden recommendations regarding the current process used to evaluate bids.

B. Phase 2 Activities

As shown in Figure 4 below, the current Phase 2 major activities (i.e., implementation stage) of the EGI Blind RFP Process, which are conducted and managed by the External RFP Manager, include: (i) issuance of the RFP; (ii) RFP management and coordination of bidder questions and associated Company responses; and (iii) closing of the RFP and compilation of certain bid information to EGI for evaluation.

Figure 4: EGI Blind RFP Process – Current Phase 2 Activities



Based on ScottMadden's review of the current Phase 2 activities in Figure 4, there are certain modifications that may be implemented by the Company to improve the overall approach and process of the Blind RFP Process. Specifically:

- Conduct a workshop with potential bidders prior to the issuance of the RFP to communicate the objectives of the RFP and describe the RFP process and requirements, which may include a review of the Bid Template and an outline of the timeline/schedule;

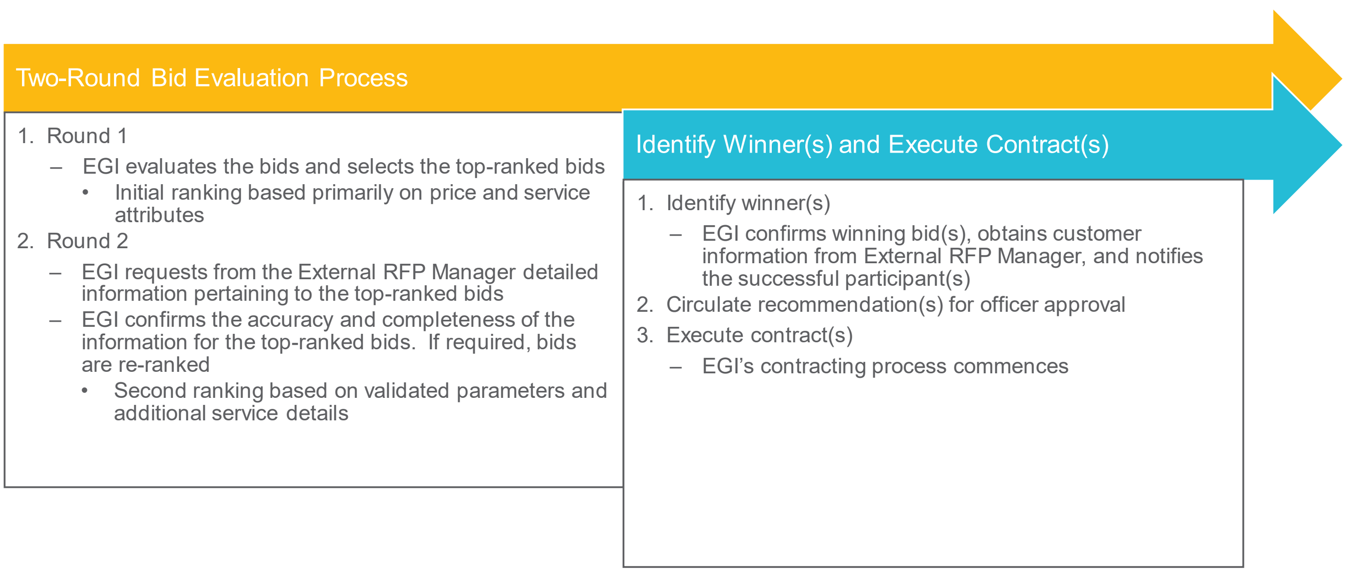
6 As discussed further below, the sample monthly invoice provided by bidders will be compared to the sample monthly invoice values calculated by the External RFP Manager to confirm costs are appropriately modeled and understood.

- Use the EGI website to publicize the RFP, which may need to be supplemented with emails to potential bidders;
- For communication purposes, include a generic EGI email address for bidder submittals (e.g., RFP responses and bidder questions) in addition to the email address of the External RFP Manager, with the generic EGI email automatically forwarded to the External RFP Manager to maintain anonymity of bidders;
- Extend this aspect of the timeline/schedule, which is currently 2 weeks, to allow bidders more time to submit bids; and
- Modify the evaluation process, Bid Template, and other supporting bid documents, which are further described in Sections 3.C and 3.D below.

C. Phase 3 Activities

The major activities in the current Phase 3 (i.e., assessment stage) of the Blind RFP Process include two rounds of bid evaluations, which are coordinated between the Company and the External RFP Manager, as well as the selection of winner(s) and execution of associated natural gas storage contract(s), which are led by EGI.

Figure 5: EGI Blind RFP Process – Current Phase 3 Activities



To address the concerns outlined in the OEB Staff Final Report, ScottMadden has the following recommendations regarding the current two-round bid evaluation process shown in Figure 5. Specifically:

- Revise the Bid Template and other supporting bid documents (further discussed in Section 3.D), which will allow the External RFP Manager to conduct Round 1 of the bid evaluations and provide initial rankings and recommendation(s) to EGI;[7]
- After the Round 1 analysis by the External RFP Manager, the Company can review the initial rankings and recommendation(s) and confirm the accuracy and completeness of the top-ranked bids; and
- Conduct Round 2 analysis, if necessary, to obtain additional bid clarification or request refreshed bid submissions for the short-listed bids.

In addition, with respect to the final activity in Phase 3 of the Blind RFP Process illustrated in Figure 5 (i.e., execute contract(s)), ScottMadden recommends that, after the execution of contract(s), the Company may provide feedback to bidders/participants that were not chosen to maintain and manage the commercial relationships between EGI and bidders.

D. Bid Template and Supporting Bid Documents

The Company's current Bid Template, which is completed by bidders and used by the External RFP Manager to populate the bid evaluation/bid matrix spreadsheet, is illustrated in Figure 6 below.

7 Please note, given the major activities in Phase 2, the External RFP Manager has access to all the information submitted by the bidders, which will facilitate their review and evaluation of bids.

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Figure 6: EGI Blind RFP Process – Current Bid Template

Round				
		EGI Storage RFP		
		EGI defined terms:		
		**Up to 5 years of service commencing April 1, 2020*		
		**Firm Injection Schedule: at a minimum, must include the months of May through September*		
		**Firm Withdrawal Schedule: at a minimum, must include the months of December through March*		
		**Firm Injection Curve rights: at least 0.7% of MSB per day*		
		**Firm Withdrawal Curve rights: 1.2% - 1.5% of MSB per day*		
ROUND 1	*1*	*Counterparty*		
ROUND 1	*2*	*offer descriptor (i.e. 1 of 3)*		
ROUND 1	*3*	*TERM (years)*		
ROUND 1	*4*	*Start date*		
ROUND 1	*5*	*MSB (max annual storage balance) units: GJ or MMbtu*		
ROUND 1	*6*	*Demand Charge per unit*		
ROUND 1	*7*	*Commodity Charge per unit*		
ROUND 1	*8*	*Fuel Charge per unit*		
ROUND 1	*9*	*Maximum Firm Injection %*		
ROUND 1	*10*	*Maximum Firm Withdrawal %*		
ROUND 2	*11*	*Inject/Withdrawal Location*		
ROUND 2	*12*	*Transportation Charge per unit*		
ROUND 2	*13*	*Injection Curve parameters/ratchets*		
ROUND 2	*14*	*Injection period (firm/interruptible)*		
ROUND 2	*15*	*Additional/Enhanced terms*		
ROUND 2	*16*	*Withdrawal Curve parameters/ratchets*		
ROUND 2	*17*	*Withdrawal period (firm/interruptible)*		
ROUND 2	*18*	*Cycling terms (i.e. unlimited)*		
ROUND 2	*19*	*Nomination Windows*		
ROUND 2	*20*	*Additional/Enhanced terms*		
ROUND 2	*21*	*General Terms and Conditions*		
ROUND 2	*22*	*Additional Comments*		
		* If any above line item is not applicable, please insert N/A		

The first 10 data fields of the current Bid Template, shown in Figure 6 above, are generally used to evaluate bids in Round 1 of the current bid evaluation process; and the data fields in rows 11 through 22 are part of the Round 2 evaluation of bids.

Based on ScottMadden's review of the current Bid Template and bid evaluation process, the following recommendations may improve the anonymity associated with bids, increase the role and contribution of the External RFP Manager, as well as improve the overall process of the Blind RFP Process.

- Revise the Bid Template (in Excel) to require additional data elements and to provide to the bidders a common set of assumptions or requirements, which may include:
  - All bids must be submitted in Canadian dollars (with a requirement that monetary values are rounded to three decimal places);

  - All bids must be submitted in GJ (with a requirement that volumes are rounded to the nearest whole number);
  - All pricing must be equivalent to a price landed at the Dawn Hub (i.e., any firm transport required to deliver to the Dawn Hub must be included in bid); and
  - Add a total annual cost metric (assuming one injection and withdrawal cycle of the storage capacity)[8] as an additional data field to be provided by bidders, which may provide transparency regarding the rate structure of bids (i.e., by requesting a total annual cost metric for each bid, the External RFP Manager would be able to compare its calculated total annual cost to the value(s) provided by the bidder).
- Revise the RFP letter and bid instructions to:
  - Include a requirement that bidders must provide one conforming bid with a note that alternative structures may be submitted; and
  - Request sample monthly invoices as additional documentation from bidders as part of bids (one for an injection month and one for a withdrawal month), which will allow the External RFP Manager to compare its calculated sample monthly invoice to the value(s) provided by the bidder.
- Revise certain activities associated with the bid evaluation process, including:
  - By providing a common set of assumptions or requirements that are consistent for all bidders and requiring more information as part of the initial bid submission, the External RFP Manager is better positioned to conduct Round 1 of the bid evaluations, and provide initial rankings and recommendation(s) to EGI;
  - As part of the Round 1 bid review by the External RFP Manager, expand the evaluation to include additional elements, such as lines 11, 12, 13, 14, 16, and 17, of the current Bid Template (i.e., from Figure 6) and use these additional elements to assess and screen bids (see ScottMadden's recommendations associated with the Bid Template in Figure 7 below); and
  - Use Round 2, if necessary, for limited data requests for certain short-listed bids or alternative bid structures.

8 This allows bids that provide flexibility with respect to injection/withdrawal capabilities (e.g., multiple cycles) to be reviewed on a qualitative basis as an additional data element.

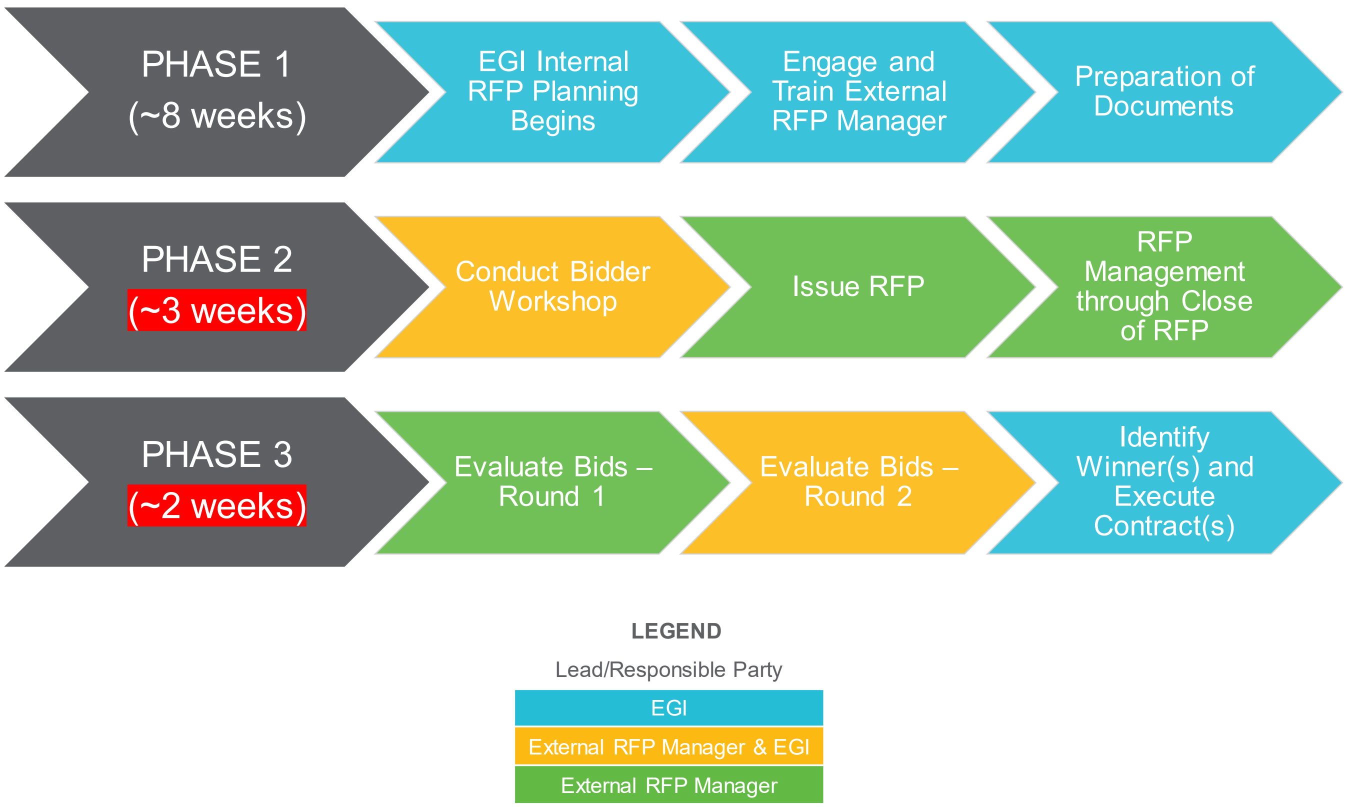
Figure 7: EGI Blind RFP Process – Recommendations for Bid Template

		EGI Storage RFP		
		EGI defined terms:		
		**Up to 5 years of service commencing April 1, 2021*		
		**Firm Injection Schedule: at a minimum, must include the months of May through September*		
		**Firm Withdrawal Schedule: at a minimum, must include the months of December through March*		
		**Firm Injection Curve rights: at least 0.7% of MSB per day*		
		**Firm Withdrawal Curve rights: 1.2% - 1.5% of MSB per day*		
ROUND 1	1	*Counterparty*		
		Primary Contact Name		
		Primary Contact Email Address		
		Primary Contact Phone Number		
	2	*Offer Descriptor (i.e., 1 of 3)*		
	3	*Term (years)*		
	4	*Start Date*		
	5	*Maximum Annual Storage Balance (MSB) (GJ)*		
		Total Annual Cost (assuming one injection and withdrawal cycle of the storage capacity) (CAD/GJ)		
	6	*Daily Demand Charge per unit of Maximum Storage Quantity (CAD/GJ)*		
	7	*Variable Injection Charge per unit (CAD/GJ)*		
		Variable Withdrawal Charge per unit (CAD/GJ)		
	8	*Fuel Charge per unit (CAD/GJ)*		
	9	*Daily Maximum Firm Injection %*		
	10	*Daily Maximum Firm Withdrawal %*		
	11	*Inject/Withdrawal Location (pipeline receipt or delivery meter name and point identifier)*		
	12	*Daily Transportation Charge per unit (include pipeline transport charges incurred to deliver to Dawn Hub) (CAD/GJ)*		
	13	*Injection Curve parameters/ratchets*		
	14	*Injection Period (firm/interruptible)*		
	16	*Withdrawal Curve parameters/ratchets*		
	17	*Withdrawal Period (firm/interruptible)*		
ROUND 2	18	*Cycling Terms (i.e. unlimited)*		
	19	*Nomination Windows*		
	20	*Additional/Enhanced Terms*		
	21	*General Terms and Conditions*		
	22	*Additional Comments*		
		* If any above line item is not applicable, please insert N/A		

4. SUMMARY AND CONCLUSION

Based on the detailed review and analysis of the current bid process, and considering the directives outlined in the OEB Staff Final Report, ScottMadden has identified several process recommendations associated with each phase of the Blind RFP Process (discussed in Section 3). As a result, Figure 8 below recasts the EGI Blind RFP Process with the inclusion of the ScottMadden recommendations for each phase.

Figure 8: Recommendations for EGI Blind RFP Process Flow Chart and Roles



While ScottMadden does not have changes to the major activities and Enbridge Gas responsibilities associated with Phase 1 (i.e., planning stage), ScottMadden recommends: (i) establishing communication protocols; (ii) expanding the criteria and requirements for selecting and contracting with an External RFP Manager; and (iii) revising certain RFP bid documents in order to facilitate the recommended changes to Phases 2 and 3 of the Blind RFP Process.

With respect to Phase 2 (i.e., implementation stage), ScottMadden's recommendations include extending the timeline/schedule to approximately 3 weeks and conducting a bidder workshop prior to the issuance of the RFP as shown in Figure 8. Please note that the bidder workshop would be a joint activity (i.e., External RFP Manager and EGI) and provides an opportunity to communicate to the bidders the RFP process and associated changes to the process, roles and responsibilities of the External RFP Manager and EGI, and milestones and deadlines. In addition, ScottMadden recommends using the EGI website to publicize the RFP and establishing a generic EGI email address for bidder communications.

Finally, ScottMadden's process recommendations associated with Phase 3 (i.e., assessment stage) will likely shorten the timeline/schedule for this phase to approximately 2 weeks as illustrated in Figure 8 above. Most notably, ScottMadden recommends revising the Bid Template, which will allow the External RFP Manager to lead the Round 1 evaluation of bids and provide initial rankings and recommendation(s) to the Company. This process recommendation will allow Round 2 to be used, if necessary, to obtain additional bid clarification or request refreshed bid submissions for short-listed bids. Finally, ScottMadden's proposed modifications to the RFP bid documents and bid evaluation process may maintain anonymity of bidders, while allowing EGI to confirm the winning bid(s) and maintain commercial relationships with bidders.

Summary of November 1, 2020 Upstream Transportation Contracts(1)

Union North Rate Zone

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	1,412	GJ	31-Oct-2022
2	Empress to Union EDA FT	Empress	Union EDA	1,089	GJ	31-Oct-2022
3	Empress to Union NDA FT	Empress	Union NDA	4,442	GJ	31-Oct-2022
4	Empress to Union WDA FT	Empress	Union WDA	39,880	GJ	31-Oct-2022
5	Empress to Union WDA FT	Empress	Union WDA	11,527	GJ	31-Oct-2022
6	Empress to Union SSMDA FT	Empress	Union SSMDA	2,700	GJ	31-Oct-2022
7	Empress to Union SSMDA FT	Empress	Union SSMDA	12,800	GJ	31-Oct-2022
8	Empress to Union SSMDA FT	Empress	Union SSMDA	6,143	GJ	31-Oct-2022
9	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	31-Oct-2022
10	Empress to Union MDA FT	Empress	Union MDA	1,043	GJ	31-Oct-2022
11	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	31-Oct-2026
12	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	31-Oct-2026
13	Parkway to Union EDA FT	Parkway	Union EDA	75,000	GJ	31-Oct-2031
14	Parkway to Union EDA FT (EMB)	Parkway	Union EDA	25,000	GJ	31-Oct-2031
15	Parkway to Union EDA FT	Parkway	Union EDA	181	GJ	31-Oct-2031
16	Parkway to Union EDA FT	Parkway	Union EDA	9,105	GJ	31-Oct-2031
17	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	31-Oct-2032
18	Parkway to Union EDA FT	Parkway	Union EDA	9,128	GJ	31-Oct-2033
19	Parkway to Union NCDA FT	Parkway	Union NCDA	661	GJ	31-Oct-2031
20	Parkway to Union NCDA FT	Parkway	Union NCDA	439	GJ	31-Oct-2031
21	Parkway to Union NCDA FT	Parkway	Union NCDA	887	GJ	31-Oct-2032
22	Parkway to Union NCDA FT	Parkway	Union NCDA	2,000	GJ	31-Oct-2032
23	Parkway to Union NCDA FT	Parkway	Union NCDA	6,912	GJ	31-Oct-2033
24	Parkway to Union NCDA FT	Parkway	Union NCDA	884	GJ	31-Oct-2033
25	Parkway to Union NDA FT	Parkway	Union NDA	10,000	GJ	31-Oct-2031
26	Parkway to Union NDA FT	Parkway	Union NDA	67,000	GJ	31-Oct-2031
27	Parkway to Union NDA FT	Parkway	Union NDA	24,000	GJ	31-Oct-2031
28	Parkway to Union NDA FT	Parkway	Union NDA	9,000	GJ	31-Oct-2031
29	Parkway to Union NDA FT	Parkway	Union NDA	10,401	GJ	31-Oct-2031
30	Parkway to Union NDA FT	Parkway	Union NDA	6,228	GJ	31-Oct-2031
31	TCPL FT - Total			382,384	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
32	NCDA	Parkway	Union NCDA	13,704	GJ	31-Oct-2026
33	WDA	Parkway	Union WDA	31,420	GJ	31-Oct-2026
34	SSMDA	Dawn	Union SSMDA	35,022	GJ	31-Oct-2026
35	NDA	Parkway	Union NDA	48,375	GJ	31-Oct-2026
36	EDA	Parkway	Union EDA	26,351	GJ	31-Oct-2026
37	TCPL Firm STS Withdrawal - Total			154,872	GJ	
	TransCanada Storage Transportation Service Firm Injection					
38	WDA	Union WDA	Parkway	3,150	GJ	31-Oct-2026
39	EDA	Union EDA	Parkway	1,000	GJ	31-Oct-2026
40	NDA	Union NDA	Parkway	49,100	GJ	31-Oct-2026
41	TCPL Firm STS Injection - Total			53,250	GJ	
	Centra Transmission Holdings Inc.					
42	Centra Transmission Holdings Inc.	Spruce	Union MDA	149.6	10^3m^3	31-Oct-2021
43	Centra Pipelines Minnesota Inc.	Sprague	Baudette	5,281	MCF	31-Oct-2021
44	CTHI FT - Total			5,767	GJ	

Conversion Factor	1.055056
Heat Content (as of April 1/20)	38.55

Note:
(1) Excludes NEXUS capacity allocated from the South portfolio.

Summary of November 1, 2020 Upstream Transportation Contracts

Union South Rate Zone

Line	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract	Contract	Contract
	TransCanada Pipeline Ltd.					
1	Empress to Union ECDA FT	Empress	Union ECDA	3,000	GJ	31-Oct-2022
2	Dawn to Union CDA FT	Dawn	Union ECDA	8,000	GJ	31-Oct-2022
3	Niagara to Kirkwall FT	Niagara	Kirkwall	21,101	GJ	31-Oct-2022
4	Kirkwall to Union CDA FT	Kirkwall	Union CDA (Amended)	135,000	GJ	31-Oct-2032
5	Empress to Emerson 2 FT	Empress	Emerson 2	21,418	GJ	31-Oct-2022
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-2025
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-2022
11	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,404	GJ	31-Oct-2022
12	Vector - Total			84,404	GJ	
	NEXUS Gas Transmission, LLC					
13	NEXUS - FT(1)(2)	Kensington	St. Clair (Union)	150,000	DTH	31-Oct-2033
14	NEXUS - FT	Clarington	Kensington	25,000	DTH	31-Mar-2022
				184,635	GJ	
	Great Lakes Gas Transmission					
15	GLGT	Emerson	St. Clair	20,000	DTH	31-Oct-2024
				21,101	GJ	
	Great Lakes Pipeline Canada Ltd.					
16	Great Lakes Pipeline Canada Ltd.	St. Clair	Union SWDA	21,101	GJ	31-Oct-2024
	Other:					
17	St. Clair Pipelines L.P. (St. Clair Pipeline)	St. Clair/Intl Border	St. Clair/Intl Border	214,000	GJ	31-Oct-2023
18	St. Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Intl Border	Bluewater/Intl Border	127,000	GJ	31-Oct-2023

Conversion Factor 1.055056

Note:
(1) EGI has contracted for 150,000 DTH/day and allocates 50,000 DTH/day to the Union North portfolio.
(2) Effective November 1, 2018, Union has obtained a 4 year contract for primary receipt at Clarington for up to 75,000 dth/day with a cost of $0.15US/dth.

Summary of January 1, 2021 Upstream Transportation Contracts

EGD Rate Zone

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
	TransCanada Pipeline					
1	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	163,044	GJ	31-Dec-2030
2	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	70,000	GJ	31-Dec-2030
3	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	5,000	GJ	31-Dec-2030
4	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	26,956	GJ	31-Dec-2030
5	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	163,044	GJ	31-Dec-2030
6	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	70,000	GJ	31-Dec-2030
7	NBJ to Enbridge CDA	North Bay Junction	Enbridge CDA	5,000	GJ	31-Dec-2030
8	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	26,956	GJ	31-Dec-2030
9	Dawn to CDA FT	Union Dawn	Enbridge CDA	4,818	GJ	31-Oct-2026
10	Dawn to CDA FT	Union Dawn	Enbridge CDA	145,000	GJ	31-Oct-2026
11	Dawn to EDA FT	Union Dawn	Enbridge EDA	114,000	GJ	31-Oct-2026
12	Dawn to Iroquois FT	Union Dawn	Iroquois	40,000	GJ	31-Oct-2026
13	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	572	GJ	31-Oct-2026
14	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	40,093	GJ	31-Oct-2032
15	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	75,000	GJ	31-Oct-2034
16	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	70,000	GJ	31-Oct-2032
17	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	15,000	GJ	31-Oct-2032
18	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	8,375	GJ	31-Oct-2032
19	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	24,484	GJ	31-Oct-2032
20	Parkway to CDA FT-SN	Union Parkway Belt	Victoria Square #2 CDA	85,000	GJ	31-Oct-2026
21	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	170,000	GJ	31-Oct-2031
22	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	13,114	GJ	31-Oct-2032
23	Niagara Falls to CDA	Niagara Falls	Enbridge Parkway CDA	76,559	GJ	31-Oct-2030
24	Chippawa to CDA	Chippawa	Enbridge Parkway CDA	123,441	GJ	31-Oct-2030
25	TCPL FT - Total			1,535,456	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
26	CDA	Parkway	Enbridge CDA	153,700	GJ	31-Oct-2026
27	CDA	Parkway	Enbridge CDA	92,822	GJ	31-Oct-2026
28	CDA	Parkway	Enbridge CDA	37,370	GJ	31-Oct-2026
29	EDA	Parkway/Kirkwall	Enbridge EDA	35,089	GJ	31-Oct-2026
30	EDA	Parkway	Enbridge EDA	35,806	GJ	31-Oct-2026
31	EDA	Parkway	Enbridge EDA	9,716	GJ	31-Oct-2026
32	TCPL Firm STS Withdrawal - Total			364,503	GJ	
	TransCanada Storage Transportation Service Firm Injection					
33	CDA	Parkway	Enbridge CDA	153,700	GJ	31-Oct-2026
34	CDA	Parkway	Enbridge CDA	92,822	GJ	31-Oct-2026
35	CDA	Parkway	Enbridge CDA	37,370	GJ	31-Oct-2026
36	EDA	Parkway/Kirkwall	Enbridge EDA	35,089	GJ	31-Oct-2026
37	EDA	Parkway	Enbridge EDA	35,806	GJ	31-Oct-2026
38	EDA	Parkway	Enbridge EDA	9,716	GJ	31-Oct-2026
39	TCPL Firm STS Injection - Total			364,503	GJ	
	NOVA Transmission					
40	NIT to Empress	NIT	Empress	50,000	GJ	31-Oct-2024
41	NIT to Empress	NIT	Empress	75,000	GJ	31-Oct-2025
42	Nova Transmission - Total			125,000	GJ	
	Vector Pipeline					
43	Vector US FT1	Milford Junction	St. Clair	110,000	DTH	31-Oct-2033
44	Vector Canada FT1	St. Clair	Dawn	116,056	GJ	31-Oct-2033
45	Vector US FT1	Alliance	St. Clair	20,000	DTH	31-Oct-2024
46	Vector US FT1	Northern Border	St. Clair	45,000	DTH	31-Oct-2024
47	Vector Canada FT1	St. Clair	Dawn	68,579	GJ	31-Oct-2024
48	Vector - Total			184,635	GJ	
	NEXUS					
49	NEXUS - FT	Kensington	Milford Junction	55,000	DTH	31-Oct-33
50	NEXUS - FT	Clarington	Milford Junction	55,000	DTH	31-Oct-33
51	NEXUS - Total			116,056	GJ	

Conversion Factor 1.055056

Summary of November 1, 2020 Upstream Transportation Contracts

EGD Rate Zone

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
	TransCanada Pipeline					
1	Empress to CDA FT(1)	Empress	Enbridge CDA	5,000	GJ	31-Dec-2020
2	Empress to EDA FT(1)	Empress	Enbridge EDA	163,044	GJ	31-Dec-2020
3	Empress to EDA FT(1)	Empress	Enbridge EDA	70,000	GJ	31-Dec-2020
4	Dawn to CDA FT	Union Dawn	Enbridge CDA	4,818	GJ	31-Oct-2026
5	Dawn to CDA FT	Union Dawn	Enbridge CDA	145,000	GJ	31-Oct-2026
6	Empress to Iroquois FT(1)	Empress	Iroquois	26,956	GJ	31-Dec-2020
7	Dawn to EDA FT	Union Dawn	Enbridge EDA	114,000	GJ	31-Oct-2026
8	Dawn to Iroquois FT	Union Dawn	Iroquois	40,000	GJ	31-Oct-2026
9	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	572	GJ	31-Oct-2026
10	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	40,093	GJ	31-Oct-2032
11	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	75,000	GJ	31-Oct-2034
12	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	70,000	GJ	31-Oct-2032
13	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	15,000	GJ	31-Oct-2032
14	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	8,375	GJ	31-Oct-2032
15	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	24,484	GJ	31-Oct-2032
16	Parkway to CDA FT-SN	Union Parkway Belt	Victoria Square #2 CDA	85,000	GJ	31-Oct-2026
17	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	170,000	GJ	31-Oct-2031
18	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	13,114	GJ	31-Oct-2032
19	Niagara Falls to CDA	Niagara Falls	Enbridge Parkway CDA	76,559	GJ	31-Oct-2030
20	Chippawa to CDA	Chippawa	Enbridge Parkway CDA	123,441	GJ	31-Oct-2030
21	TCPL FT - Total			1,270,456	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
22	CDA	Parkway	Enbridge CDA	153,700	GJ	31-Oct-2026
23	CDA	Parkway	Enbridge CDA	92,822	GJ	31-Oct-2026
24	CDA	Parkway	Enbridge CDA	37,370	GJ	31-Oct-2026
25	EDA	Parkway/Kirkwall	Enbridge EDA	35,089	GJ	31-Oct-2026
26	EDA	Parkway	Enbridge EDA	35,806	GJ	31-Oct-2026
27	EDA	Parkway	Enbridge EDA	9,716	GJ	31-Oct-2026
28	TCPL Firm STS Withdrawal - Total			364,503	GJ	
	TransCanada Storage Transportation Service Firm Injection					
29	CDA	Parkway	Enbridge CDA	153,700	GJ	31-Oct-2026
30	CDA	Parkway	Enbridge CDA	92,822	GJ	31-Oct-2026
31	CDA	Parkway	Enbridge CDA	37,370	GJ	31-Oct-2026
32	EDA	Parkway/Kirkwall	Enbridge EDA	35,089	GJ	31-Oct-2026
33	EDA	Parkway	Enbridge EDA	35,806	GJ	31-Oct-2026
34	EDA	Parkway	Enbridge EDA	9,716	GJ	31-Oct-2026
35	TCPL Firm STS Injection - Total			364,503	GJ	
	NOVA Transmission					
36	NIT to Empress	NIT	Empress	50,000	GJ	31-Oct-2024
37	NIT to Empress	NIT	Empress	75,000	GJ	31-Oct-2025
38	Nova Transmission - Total			125,000	GJ	
	Vector Pipeline					
39	Vector US FT1	Milford Junction	St. Clair	110,000	DTH	31-Oct-2033
40	Vector Canada FT1	St. Clair	Dawn	116,056	GJ	31-Oct-2033
41	Vector US FT1	Alliance	St. Clair	20,000	DTH	31-Oct-2024
42	Vector US FT1	Northern Border	St. Clair	45,000	DTH	31-Oct-2024
43	Vector Canada FT1	St. Clair	Dawn	68,579	GJ	31-Oct-2024
44	Vector - Total			184,635	GJ	
	NEXUS					
45	NEXUS - FT	Kensington	Milford Junction	55,000	DTH	31-Oct-33
46	NEXUS - FT	Clarington	Milford Junction	55,000	DTH	31-Oct-33
47	NEXUS - Total			116,056	GJ	

Conversion Factor 1.055056

November 2020 to March 2022 Transportation Contracting 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
NYMEX											
NEXUS via St. Clair: Kensington to Dawn	Dominion South Point	-0.1471	2.5083	0.93	0.00	0.0640	1.0002	$3.51	**$4.533**	Dawn	
NEXUS via St. Clair: Clarington to Dawn	Dominion South Point	-0.3871	2.2683	1.18	0.00	0.0712	1.2533	$3.52	**$4.549**	Dawn	

Supply Assumptions used in Developing Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
Henry Hub	**Henry Hub**	**$ 2.37**	**$ 2.82**	**$ 2.96**	**$ 2.93**	**$ 2.81**	**$ 2.52**	**$ 2.49**	**$ 2.53**	**$ 2.57**	**$ 2.58**	**$ 2.56**	**$ 2.57**	**$ 2.62**	**$ 2.75**	**$ 2.86**	**$ 2.82**	**$ 2.67**	**$ 2.66**	
NEXUS via St. Clair: Kensington to Dawn	Dominion South Point	$ 1.91	$ 2.38	$ 2.54	$ 2.51	$ 2.38	$ 2.07	$ 2.02	$ 2.02	$ 2.05	$ 2.04	$ 1.95	$ 1.97	$ 2.20	$ 2.35	$ 2.47	$ 2.42	$ 2.28	$ 2.21	2.55%
NEXUS via St. Clair: Clarington to Dawn	Dominion South Point	$ 1.91	$ 2.38	$ 2.54	$ 2.51	$ 2.38	$ 2.07	$ 2.02	$ 2.02	$ 2.05	$ 2.04	$ 1.95	$ 1.97	$ 2.20	$ 2.35	$ 2.47	$ 2.42	$ 2.28	$ 2.21	3.14%

Sources for Assumptions:

Gas Supply Prices (Col D):	June 2 Kiodex DSP Futures		
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 =	$1.363 CDN	From Bank of Canada Closing Rate June 1, 2020
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
EGI's Analysis Completed:	Jun-20		

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

2021-2024 Transportation Contracting 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	0.0478	2.9683				0.0000	$2.97	**$3.74**	Dawn	
	TC: Dawn LTFP	Empress	-0.5589	2.3616	0.61	0.00	0.0826	0.6937	$3.06	**$3.85**	Union SWDA	
	TC: Great Lakes to Dawn	Empress	-0.5589	2.3616	0.66	0.01	0.0826	0.7526	$3.11	**$3.92**	Dawn	
	TC: Niagara to Dawn	Niagara	-0.0881	2.8323	0.15	0.00	0.0165	0.1707	$3.00	**$3.78**	Dawn	
	MichCon: MichCon to Dawn	SE Michigan	-0.0539	2.8665	0.16	0.00	0.0356	0.1964	$3.06	**$3.86**	Dawn	
	Vector: Chicago to Dawn	Chicago	-0.0681	2.8523	0.18	0.00	0.0119	0.1946	$3.05	**$3.84**	Dawn	
	Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	-0.2639	2.6566	0.75	0.06	0.1362	0.9433	$3.60	**$4.54**	Dawn	
	NEXUS via St. Clair: Clarington to Dawn	Dominion South Point	-0.6191	2.3014	1.09	0.00	0.0718	1.1601	$3.46	**$4.36**	Dawn	
	Rover: Rover SZ to Dawn	Dominion South Point	-0.6191	2.3014	0.98	0.05	0.0718	1.1013	$3.40	**$4.29**	Dawn	

Supply Assumptions used in Developing Transportation Contracting Analysis:

	Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2021 - Oct 2022	Nov 2022 - Oct 2023	Nov 2023 - Oct 2024	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
	Henry Hub	**Henry Hub**	**$ 3.01**	**$ 2.60**	**$ 3.15**	**$ 2.92**	
	Dawn	Dawn	$ 3.07	$ 2.61	$ 3.22	$ 2.97	
	TC: Dawn LTFP	Empress	$ 2.44	$ 2.01	$ 2.64	$ 2.36	3.50%
	TC: Great Lakes to Dawn	Empress	$ 2.44	$ 2.01	$ 2.64	$ 2.36	2.93%
	TC: Niagara to Dawn	Niagara	$ 2.95	$ 2.49	$ 3.06	$ 2.83	0.58%
	MichCon: MichCon to Dawn	SE Michigan	$ 2.97	$ 2.52	$ 3.12	$ 2.87	1.24%
	Vector: Chicago to Dawn	Chicago	$ 2.95	$ 2.51	$ 3.10	$ 2.85	0.42%
	Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	$ 2.74	$ 2.33	$ 2.90	$ 2.66	5.13%
	NEXUS via St. Clair: Clarington to Dawn	Dominion South Point	$ 2.47	$ 1.99	$ 2.45	$ 2.30	3.12%
	Rover: Rover SZ to Dawn	Dominion South Point	$ 2.47	$ 1.99	$ 2.45	$ 2.30	0.61%

1

Sources for Assumptions:

Gas Supply Prices (Col D):	ICF Q3 2020 Base Case		
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 =	$1.329 CDN	From Bank of Canada Closing Rate September 21, 2020
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
EGI's Analysis Completed:	Sep-20		

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

2021-2026 Transportation Contracting 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)	Extraction $Cdn/G	Net Landed Cost $Cdn/G	Point of Delivery (L)	Comments
Empress	Empress	-0.5428	2.4804				0.0000	$2.48	**$3.1251**	$0.0000	**$3.1251**	Empress	
NOVA-AECO2Emp (Z)	AECO	-0.6621	2.3611	0.1284	0.00	0.0000	0.1284	$2.49	**$3.1366**	$0.0150	**$3.1216**	Empress	1-year
NOVA-AECO2Emp (Y)	AECO	-0.6621	2.3611	0.1222	0.00	0.0000	0.1222	$2.48	**$3.1288**	$0.0250	**$3.1038**	Empress	3-year
NOVA-AECO2Emp (X)	AECO	-0.6621	2.3611	0.1161	0.00	0.0000	0.1161	$2.48	**$3.1211**	$0.0250	**$3.0961**	Empress	5-year or more

Supply Assumptions used in Developing Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2021 - Oct 2022	Nov 2022 - Oct 2023	Nov 2023 - Oct 2024	Nov 2024 - Oct 2025	Nov 2025 - Oct 2026	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
Henry Hub	**Henry Hub**	**$ 3.01**	**$ 2.60**	**$ 3.15**	**$ 3.33**	**$ 3.24**	**$ 3.02**	
Empress	Empress	$ 2.44	$ 2.01	$ 2.64	$ 2.84	$ 2.71	$ 2.48	
NOVA-AECO2Emp (Z)	AECO	$ 2.32	$ 1.89	$ 2.52	$ 2.71	$ 2.59	$ 2.36	0.00%
NOVA-AECO2Emp (Y)	AECO	$ 2.32	$ 1.89	$ 2.52	$ 2.71	$ 2.59	$ 2.36	0.00%
NOVA-AECO2Emp (X)	AECO	$ 2.32	$ 1.89	$ 2.52	$ 2.71	$ 2.59	$ 2.36	0.00%

Sources for Assumptions:

Gas Supply Prices (Col D): ICF Q3 2020 Base Case

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 = $1.329 CDN From Bank of Canada Closing Rate September 21, 2020

Energy Conversions (Col K) 1 dth = 1 mmBtu = 1.055056

EGI's Analysis Completed: Oct-20

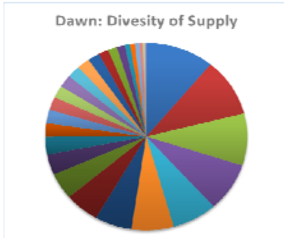
Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

Enbridge Gas Inc.

Suppplier Diversity by Basin

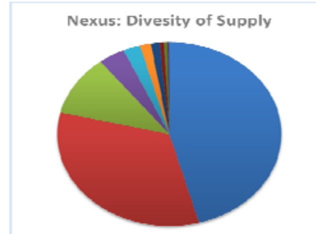
Dawn

Supply Provided	Number of Suppliers
0-2 PJs	0
2-5PJs	1
5 + Pjs	27



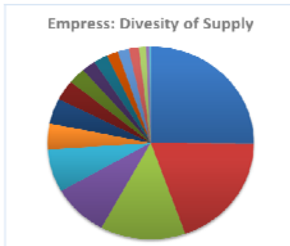
Nexus

Supply Provided	Number of Suppliers
0-2 PJs	3
2-5PJs	1
5 + Pjs	7



Empress

Supply Provided	Number of Suppliers
0-2 PJs	9
2-5PJs	4
5 + Pjs	5

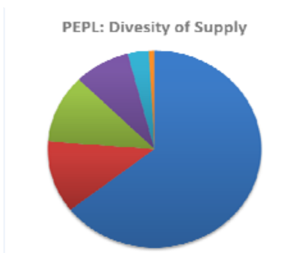


Niagara/ Chipewa

Supply Provided	Number of Suppliers
0-2 PJs	0
2-5PJs	4
5 + Pjs	4

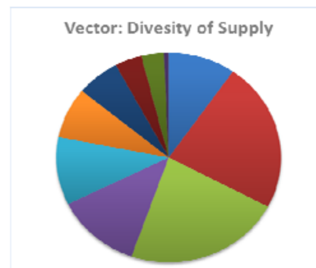
PEPL

Supply Provided	Number of Suppliers
0-2 PJs	5
2-5PJs	0
5 + Pjs	1



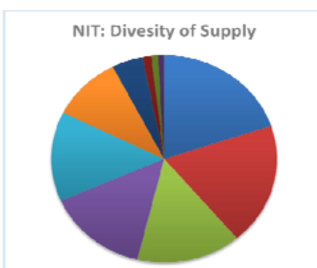
Vector

Supply Provided	Number of Suppliers
0-2 PJs	3
2-5PJs	4
5 + Pjs	3

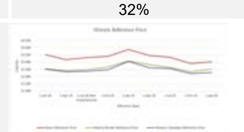
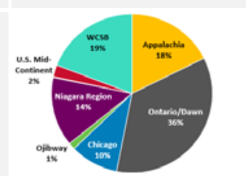


NIT

Supply Provided	Number of Suppliers
0-2 PJs	4
2-5PJs	2
5 + Pjs	4



2019/20 PERFORMANCE METRICS Enbridge Gas Inc.

OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	2018/19 Results
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
			Transacting counterparties have met appropriate credit requirements	C
	Weather Variance[1]	Illustrates weather risk in EGI's Plan correlated with price variances (e.g. Positive HDD variances tends to lead to higher prices)	HDD Variance - EGD CDA	6%
			HDD Variance - EGD EDA	9%
			HDD Variance - EGD Niagara	6%
			HDD Variance - Union North West	10%
			HDD Variance - Union North East	3%
			HDD Variance - Union South	3%
	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	14%
			Monthly	28%
			Seasonal	25%
			Annual or longer	32%
		Illustrates price stability and consistency in EGI's Plan	Reference Price[2]	
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%
	Storage	Demonstrates EGI's execution of its storage inventory strategy	Percentage of actual storage target at November 1 compared to the plan	98%
			Percentage of actual storage target at February 28 compared to the plan	100%
			Percentage of actual storage target at March 31 compared to the plan	95%
	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
			Instances when QRAM expected bill impacts exceed +/- 25%	0
			Communicated to ratepayers when bill impacts exceed +25%	C
	Diversity	Illustrates EGI's diversity of basin, contract term, counterparties and supply procurement in the plan	Supply basin diversity[3]	
			Percentage of contracts with remaining terms of:	
			1-5 years	23%
			6-10 years	33%
			> 10 years	44%
			Total number of unique counterparties	56

2019/20 PERFORMANCE METRICS Enbridge Gas Inc.

OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	2018/19 Results
			Total number of receipt points	27
	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
			Number of days of force majeure on upstream pipelines impacting customers' security of supply	0
			Number of days of failed delivery of supply	61
			Number of days of failed delivery of supply impacting customers security of supply	0
			Number of days of forced majeures on storage assets	0
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
			DSM savings addressed in the plan	C
			Federal Carbon Pricing Program addressed in the plan	C
			Percentage of RNG portfolio	0%

Footnotes:

C - Compliant, NI - Needs Improvement

1 - Positive variance indicates colder than planned weather. Negative variance indicates warmer than planned weather.

2 - As filed in QRAM proceeding

3 - For data see Section 9.3