EB-2020-0091

Integrated Resource Planning Proposal

FRPO Compendium

February 25, 2021

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (“STAFF”)

INTERROGATORY

Reference:

Exhibit B / pp. 12-17, 29 of 46

Preamble:

Enbridge Gas provides an Illustrative Process Plan that appears to be scoped to its infrastructure planning responsibilities. However, on p. 29, Enbridge Gas notes that it will consider long-term natural gas supply IRPAs if they meet the Gas Supply Guiding Principles as outlined in Enbridge Gas’s 5 Year Gas Supply Plan.

Question:

a) Please clarify whether Enbridge Gas’s IRP proposal (and Illustrative Process Plan) is intended to encompass consideration of IRPAs in the planning processes for both infrastructure needs (currently addressed largely through the Asset Management Plan) and gas supply needs (currently addressed largely through the 5 Year Gas Supply Plan), or only infrastructure needs (i.e. any consideration of natural gas supply IRPAs by Enbridge Gas would initially be done in the context of the IRPA’s potential ability to meet an infrastructure need).Please provide the rationale behind Enbridge Gas’s proposed approach.

b) Please describe the key linkages between the infrastructure planning process and the gas supply planning process, with an emphasis on any considerations relevant to the role of IRPAs. For example, if an IRPA was under consideration to address an infrastructure planning need, could and would Enbridge Gas take into account as part of its evaluation the impact (if any) of this IRPA on its gas supply needs and costs?

<u>Response</u>

a) & b)

Enbridge Gas intends for the IRP Proposal to consider IRPA(s), including supply-side alternatives, in order to resolve identified system constraints. Enbridge Gas is not, however, planning to apply its IRP Proposal to evaluate options for incremental gas supply requirements.

The Asset Management Plan considers long-term forecasts for customer demand at a granular, geographically specific level. This level of detail is then used to formulate potential future projects to address identified system constraints. Once a constraint is identified, IRPAs would then be evaluated alongside facility alternatives. IRPAs could include supply-side alternatives, but these would be evaluated as part of the IRPA evaluation and are not associated with the Gas Supply Plan itself as the IRPAs would be addressing a very specific local transmission or distribution need.

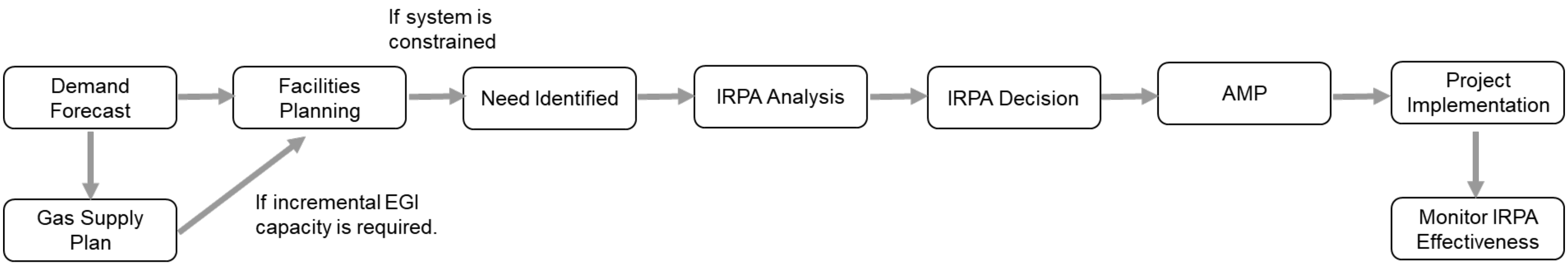
Whereas the Asset Management Plan and the development of specific IRPA(s) or facility alternatives are done at a local facility level, Enbridge Gas's Gas Supply Plan is created at the Delivery Area level (Union South, Union North DDAs, and the Enbridge CDA and EDA) based on forecasted peak day demands for each Delivery Area. The Gas Supply Plan does not look at specific local facilities, and therefore IRPAs would not be developed out of the Gas Supply Plan itself.

Enbridge Gas's Gas Supply Plan considers existing facility capabilities as an input, thus the impact of any IRPAs would be reflected in the Gas Supply Plan. As an example, if an IRPA required firm upstream transportation to deliver gas supply to a specific Delivery Area, this requirement would become an input into the Gas Supply Plan.

Enbridge Gas is in the process of integrating EGD and Union processes and will be developing new processes and procedures as an output of the integration exercise (please see the response at Exhibit I.OSEA.1 c)).

Please see Figure 1 below for a visual representation of the integration of IRP with system planning and gas supply planning processes. As outlined above, the Gas Supply Planning process is upstream of the Asset Management Plan and any IRPA analysis that is performed.

Figure 1


If system is constrained
Demand Forecast
Facilities Planning
Need Identified
IRPA Analysis
IRPA Decision
AMP
Project Implementation
Gas Supply Plan
If incremental EGI capacity is required.
Monitor IRPA Effectiveness

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Additional Public Documents: Enbridge Gas Inc. 5 Year Gas Supply Plan, May 1, 2019 (EB-2019-0137)

Preamble:

Enbridge Gas provides an illustrative process plan explaining how Enbridge Gas will incorporate IRP into its planning processes. OEB staff wish to ensure that it has an understanding of Enbridge Gas's current planning process for the "Generic Planning" stages in this process plan that are not discussed further as part of Enbridge Gas's IRP proposal, specifically demand forecasting and needs identification. Enbridge Gas describes its long-term demand forecast and annual demand forecast, and the key factors that go into these forecasts.

Question:

a) Do the demand forecasting practices described in Enbridge Gas's 5 Year Gas Supply Plan remain accurate descriptions of Enbridge Gas's procedures for forecasting both annual demand and design day demand for the EGD and Union rate zones, and the factors Enbridge Gas considers in these forecasts (e.g., existing firm demand, customer growth, weather, DSM impacts, system design day requirements, customer consumption patterns, economic outlooks, public policy)? If not, please describe any changes to forecasting practices Enbridge Gas has made in these areas.

b) Enbridge Gas notes (Exhibit B, p. 14) that it completes a long-term demand forecast. How long a time period does Enbridge Gas's long-term demand forecast cover and how often is it updated? How, if at all, do the factors and methodology underlying the long-term demand forecast differ from those used for the annual demand and design day demand forecasts that are described in the 5Year Gas Supply Plan?

Response

a) The descriptions of procedures for forecasting both annual demand and design day demand in Enbridge Gas's 5 Year Gas Supply Plan remain accurate. Please see the response at Exhibit I.STAFF.4, for additional discussion of Enbridge Gas' demand forecast.

b) Enbridge Gas's long-term demand forecast covers a 10-year period and is updated annually. The factors and methodology underpinning the long-term demand forecast do not differ from those used for the annual demand and design day demand forecasts that are described in the 5 Year Gas Supply Plan.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / p. 14 of 46; Exhibit A, Tab 13, Page 11 of 24 (load forecast as a screening criterion); Exhibit A, Tab 13, Page 19 of 24 (AMI)

Additional Public Documents: Enbridge Gas Inc. 5 Year Gas Supply Plan, May 1, 2019 (EB-2019-0137); Enbridge Gas Inc. 2021-2025 Utility System Plan and Asset Management Plan (filed October 15, 2020; EB-2020-0181, Exhibit C, Tab 1, Schedule 1 (Utility System Plan), Exhibit C, Tab 2, Schedule 1 (Asset Management Plan)).

Preamble:

Enbridge Gas notes that "when Enbridge Gas determines that its current facilities cannot balance the peak demand forecast with existing system facilities that can deliver the forecasted volumes safely and reliably, a system need is identified."

Question:

a) The demand forecasts in Enbridge Gas's 5 Year Gas Supply Plan are for the EGD, Union North West, Union North East, and Union South rate zones in their entirety. Please describe how these high-level demand forecasts in Enbridge Gas's 5 Year Gas Supply Plan are refined to produce more granular demand forecasts of smaller geographic areas to inform the "Needs Identification" phase of Enbridge Gas's IRP Process Plan. Please clarify how, if at all, the inputs from the 5-Year Gas Supply Plan are supplemented with more detailed local information (metering data, knowledge of customer numbers/energy trends, etc.).
b) Is the Asset Management Planning process that is described in Enbridge Gas's 2021-2025 Asset Management Plan the primary tool that Enbridge Gas will use for the "Needs Identification" phase of the IRP Process Plan? Please list and briefly describe any other tools or processes that play a material role in the "Needs Identification" phase.
c) Does Enbridge Gas believe that most, if not all, system needs where IRPAs could potentially be a solution would be identified and described through the Asset

Management Plan? If not, please identify circumstances where a system need may not be identified and described through the Asset Management Plan

d) Enbridge Gas's 2021-2025 Asset Management Plan (section 5.1.6 for distribution system reinforcement and section 5.1.7 for transmission system reinforcement) describes how Enbridge Gas uses demand forecasts as an input to identify specific needs for system reinforcements. Does this document provide the best overview of how Enbridge Gas identifies needs for system reinforcement, and do the processes described regarding needs identification remain accurate? If not, please describe any changes or additional information regarding Enbridge Gas's process for needs identification.

e) What level of geographic specificity is Enbridge Gas's needs identification process conducted at?

f) Enbridge Gas notes that "the deployment of an AMI system…will allow for the collection of the hourly data that Enbridge Gas requires to…target IRPAs effectively". Does this refer to improving the accuracy of the needs identification phase (better data on peak demand and capabilities of existing infrastructure to meet this demand), improving the ability of Enbridge Gas to identify potential IRPAs (e.g. customer or measure-specific information on possible peak demand reductions) or both? Please describe as needed.

<u>Response</u>

a) The Gas Supply Plan does not require the same level of granularity required by the Asset Management Plan. The Gas Supply Plan focuses on upstream transportation requirements and utility needs on the Dawn-Parkway system. Accordingly, the Plan contains the needs of only a sub-set of Enbridge Gas customers. For example, customers who contract for their own transportation to the Company are not included in the Gas Supply Plan. The Company creates detailed bottom up forecasts for use in the Asset Management Plan and these forecasts are also used to inform the forecasts used for the Gas Supply Plan (please also see the response at Exhibit I.STAFF.2).

   Enbridge Gas uses a robust, bottom up approach to obtain the granularity of demand growth, location and timing required for the detailed reinforcement plans identified in the Asset Management Plan. This information includes economic forecast data, public policy information, municipal planning data, individual customer data, tacit knowledge, and historical growth rates in geographic areas. This information is included in Enbridge Gas's planning processes which then identifies areas of system constraint/need where the timing and scope of potential reinforcement projects will be identified. The plans to serve the need, along with alternatives identified are set out in the Asset Management Plan.

b) Yes. The Asset Management Plan and underlying process are anticipated to be the primary tool that Enbridge Gas will use for “Needs identification”. Enbridge Gas also expects additional needs/constraints will be identified through ongoing dialogue with customers and stakeholders, and Gas Supply Planning.

c) Yes, the Asset Management Plan will identify and describe most anticipated system constraints/needs on Enbridge Gas’s system and the facilities or IRPAs required to resolve those constraints/needs.

d) Yes, this information remains accurate. Similar to all processes, any changes will be reflected in the updates to the Asset Management Plan in the future. Exhibit I.STAFF.4 Attachment 1, provides a system criteria document specifically created for the Dawn Parkway system, however, the planning methodologies laid out therein are generally consistent with those used for all Enbridge Gas pipeline systems.[1]

e) Needs Identification is performed at a robust level of granularity for the distribution system evaluation potentially down to the customer level (i.e for commercial/industrial customers) and is aggregated up to the municipal and or regional level to inform the transmission system evaluation. Ex-franchise customer needs are obtained from Open Season requests for transmission system capacity. These Open Seasons are held every few years to solicit interest.

f) Both. By investing in AMI, Enbridge Gas can vastly improve the granularity of customer consumption data that it gathers, allowing for more precise IRPA design, more accurate forecasts of associated energy savings, and higher quality monitoring and reporting on the effectiveness of IRPAs. This improved information will allow for more informed decisions regarding whether to continue, adjust, increase or cease IRPA activities. AMI is expected to also enable demand response program impacts to be reliably included in system demand forecasts.

[1] Note that Exhibit I.STAFF.4 Attachment 1 is intended to be illustrative and is consistent with the processes used within the AMP.

Dawn Parkway Transmission System

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Review of System Design

21 January 2021

Transmission System Planning Department

ENBRIDGE

1. Purpose of This Document

This document provides detail on the criteria used to review the Enbridge Gas Dawn Parkway transmission system to determine if the existing facilities are adequate from a capacity and reliability standpoint to service forecast Design Day demands of the in-franchise and ex-franchise customers. This report is updated using the available customer growth forecasts, and will be used to properly select the preferred option which best meets the current and forecast system demands. The option may include construction of new facilities or contracting of commercial services.

The system review process is comprised of a number of distinct sections including the following:

- Review of the Physical System
- Forecast of Design Day Demand
- System Operating Criteria
- System Capacity
- Selection of Future Facilities

The creation of this report results in the selection of the best solution for meeting forecast Design Day demands, both in the short and long-term, with a focus on minimizing cost to ratepayers and maximizing system reliability.

2. Review of the Physical System

The physical system is composed of pipelines, regulation and meter stations and compressor stations. The physical system moves gas to delivery locations along the pipeline to meet the volumetric demands and pressure requirements of Enbridge Gas' customers. The pipeline system forms the foundation for future development as customer's needs grow.

Enbridge Gas has three transmission[1] systems 1) Dawn Parkway, 2) Panhandle and 3) Sarnia Industrial. A map showing the location of the transmission systems is shown in Schedule 1. The remainder of this document will focus exclusively on the Dawn Parkway transmission system.

2.1. DAWN PARKWAY

The Dawn Parkway system is comprised of a series of parallel pipelines, compressor stations and regulation and meter stations. The system starts at the Dawn compressor station near Sarnia and extends to the Parkway compressor station and Lisgar regulation and meter station in Mississauga. For clarity, this section is split into the major physical components; Pipelines, Compressor Stations, Supply and Delivery Locations.

2.2. PIPELINES

The Dawn Parkway system consists of 4 parallel pipelines; 26, 34, 42, and 48-inch diameter. The 26, 34- and 48-inch diameter pipelines run the entire distance between Dawn and Parkway. The 42 inch runs from Dawn to Kirkwall. A second 48 inch has been constructed between Hamilton and Milton.

[1] Other Enbridge Gas departments including Pipeline Engineering and Plant Accounting have different definitions of what is considered a transmission pipeline. In this document the Transmission systems or pipelines refer to the pipelines modelled by the Transmission Optimization & Engineering Department.

The Dawn Parkway system continues downstream of Parkway with a 42 inch diameter pipeline that runs between Parkway and Albion Road Station in Toronto[2]

Details of the existing pipeline sections are shown below.

SECTION	NOMINAL PIPE SIZE (IN)	LENGTH (KM)	OUTSIDE DIAMETER (MM)
Dawn to Lisgar	26	229	660
Dawn to Lisgar	34	229	864
Dawn to Kirkwall	42	189	1067
Dawn to Parkway	48	229	1219
Hamilton to Milton	48	19.5	1219
Parkway to Albion	42	27	1067

The remaining "4th Loop" sections to be constructed in the future are:

SECTION	NOMINAL PIPE SIZE (IN)	LENGTH (KM)	OUTSIDE DIAMETER (MM)
Kirkwall to Hamilton	48	10	1219
Milton to Parkway	48	9	1219

Enbridge Gas will perform a 5th line study to determine options for future pipeline sections to meet increasing system market demands.

The flow of gas on the Dawn Parkway system, on Design Day, is easterly from Dawn towards Parkway.

2.3. COMPRESSOR STATIONS

Compressor stations are integral to the operation of the Dawn Parkway system. The compressor stations are located at specific points on the system to increase the overall transmission system capacity. In addition to the Dawn compressor station, which provides supply to the Dawn Parkway system, there are three mainline compressor stations located at Lobo, Bright, and Parkway.

[2] *Although the GTA Line which connects Albion Road Station is a component of the contiguous Dawn Parkway System, EGI has not yet incorporated this facility into its Dawn Parkway System operations or capacity models. EGI expects that future Dawn Parkway System Leave To Construct applications will include further consideration of these facilities.*

3.2.6. Obligated Deliveries at Parkway

In the Gas Supply Plan, there are obligated deliveries (DCQ) delivered to Enbridge Gas for the Union South Rate Zone system supply and direct purchase customers. A portion of these volumes are required to be delivered at Parkway (Parkway Delivery Obligation or PDO) on the downstream side of the compressors (the other portion is obligated at Dawn (Dawn Obligation). Enbridge Gas considers the PDO in the Design Day analysis of the Dawn-Parkway system to reduce the physical transportation needs from Dawn to Parkway.

The PDO reduction available as a result of Dawn to Kirkwall turn back volume was reduced to zero effective in Winter 2018/2019 consistent with the OEB-approved settlement agreement (EB-2013-0365). There is no additional PDO reduction available as there is no future Dawn to Kirkwall turn back forecast.

3.2.6.1. Parkway Delivery Obligation Benefit to Dawn Parkway System

Historically, the majority of Union South Rate Zone in-franchise and direct purchase customers and Enbridge Gas purchased their gas supply in the Western Canadian Sedimentary basin, with transportation contracted on TC Energy Mainline from Empress to Parkway. At the time the cost to transport gas to Parkway was less expensive than transporting gas to Dawn, so customers were obligated to deliver their supply gas to Parkway and thus had a PDO. Over time customers “West of Dawn” (i.e. Panhandle and Sarnia Industrial customers) were allowed to change their obligation to Dawn however customers that were “East of Dawn” or served by the Dawn Parkway system continued to have a PDO.

As the Dawn Parkway system was expanded, gas delivered to Parkway directly reduced the pipeline facilities required and as a result, the Dawn Parkway system is smaller today than if all the customers’ gas was supplied from Dawn and had to be transported to Parkway.

3.2.6.2. Parkway Delivery Obligation Settlement Agreement

Due to turn back on the Dawn to Kirkwall path, Enbridge Gas used this surplus capacity to allow customers to have a higher proportion of their delivery obligation changed to Dawn. The PDO reduction available as a result of Dawn to Kirkwall turn back volume was reduced to zero effective Winter 2018/2019 consistent with the OEB-approved settlement agreement (EB-2013-0365). There is no additional PDO reduction available as there is no future Dawn to Kirkwall turn back forecast.

3.2.7. Hourly Demand Profile

Enbridge Gas develops hourly demand profiles for the delivery locations on the Dawn Parkway system for Union South Rate Zone customers plus EGD Rate Zone customers served from delivery point Parkway-Uncompressed (Consumers 1 and 2, and Lisgar stations) which reflect the expected pattern of natural gas use during the Design Day. These patterns are mainly a result of temperature sensitive demand throughout the day, with highest usage in the morning around 8 am.

Profiles are developed for heat sensitive customers who do not generally consume natural gas at a constant rate during the day. With these customers, demand varies over the period of the day with higher consumption in the morning hours, lower in the early afternoon and an increase during the early evening. Customers who consume natural gas at a constant rate do not receive a profile.

SCHEDULE 1 – MAP OF DAWN PARKWAY SYSTEM

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit A, Tab 13 / p. 10 of 24

Preamble:

Enbridge Gas proposes a goal of IRP as "aimed at reviewing and implementing alternatives that reduce natural gas in-franchise peak period demand growth".

Question:

a) Is "peak period demand growth" the sole driver of system needs, at least for facility expansion/reinforcement projects? Is the level of volumetric consumption ever a driver of system needs?
b) Enbridge Gas proposes that IRP should be aimed at reducing "in-franchise peak period demand growth". Is ex-franchise demand (peak period or otherwise) a contributor or driver of any system needs identified through the Needs Identification process? Please describe.
c) Is Enbridge Gas' proposal to focus on in-franchise peak period demand growth based on (1) the assumption that ex-franchise demand has minor or no impacts on system needs and infrastructure costs; (2) a perceived greater difficulty of developing IRPAs that could reduce peak period demand for ex-franchise customers, or both? Please describe.

Response

a) Yes, peak period demand growth is the main driver of system constraints/needs. There are instances where changes to the location of gas supply and replacement of infrastructure for integrity reasons could also drive a system constraint/need. If 'volumetric consumption' is taken to mean annual volume consumption, annual demand volumes are not a driver for expansion/reinforcement projects.

b) & c)
Yes, ex-franchise customers contracting for transportation services also contribute to system needs.

Enbridge Gas' IRP proposal focuses on identifying any system constraint and then evaluating whether that constraint can be resolved with an IRPA or if it requires a facility alternative. Enbridge Gas has no ability to influence government or regulatory policy, or conservation/DSM or IRP programming in other jurisdictions where its ex-franchise customers reside.

Ex-franchise demand is contracted on a daily basis. These contracts flow on the in-franchise transmission pipeline systems, such as the Dawn Parkway System, at a constant hourly rate. Only IRPAs which focus on reduction of peak daily demand reduce demand on the transmission systems. IRPAs focusing on peak hour demand reduction will not reduce demand on the transmission pipeline systems, such as the Dawn Parkway System, unless they coincidently also reduce peak day demand.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit C / pp. 6-7 of 26; Exhibit M2.GEC-ED, pp. 16-18 of 55

Additional Public Documents: Enbridge Gas Inc. 2021-2025 Utility System Plan and Asset Management Plan (filed October 15, 2020; EB-2020-0181, Exhibit C, Tab 1, Schedule 1 (Utility System Plan), Exhibit C, Tab 2, Schedule 1 (Asset Management Plan)).

Preamble:

In its expert evidence, Energy Futures Group (EFG) states that a longer-term needs forecast (e.g. ten years) may allow for more consideration of IRPAs, and presents an example (from Green Mountain Power) of a summary of longer-term needs and planning status, that it believes could be a useful model for Ontario. Enbridge Gas states that it generally agrees with EFG that a ten-year time horizon for forecasting in-franchise system needs is appropriate to ensure adequate planning, deployment and adjustments can be undertaken, but notes that there is more uncertainty in forecasts and projection of system needs beyond the 3-5 year time period.

Question:

a) The 2021-2025 Asset Management Plan notes (p. 20) that the scope of the Asset Management Plan had been adjusted from 10 years to five years due to the impact of COVID-19 to resourcing and potential uncertainty surrounding longer term forecasting {previous Asset Management Plans had included a forecast 10-year capital investment plan, including business cases for projects within the 10-year capital investment plan, and a brief description of projects not included in the capital investment plan where solution scopes are still under development}.Does Enbridge Gas intend to adjust the scope of the Asset Management Plan back to 10 years? Why or why not?

b) If Enbridge Gas intends to keep the scope of the Asset Management Plan at 5 years, would it still undertake longer-term demand forecasting and needs identification (e.g. on a 10-year basis), and if so, in what format?

c) Is inclusion within the Asset Management Plan the first stage at which a potential system need (and proposed "baseline" solution) would come to the attention of the OEB and other stakeholders outside of Enbridge Gas? If not, please explain.

d) Does Enbridge Gas have any views on EFG's suggestion regarding providing a public summary of longer-term needs and planning status? If Enbridge Gas supports this idea, does Enbridge Gas believe this information would be best presented as part of its Utility System Plan/Asset Management Plan, its proposed annual IRP monitoring report, or in a separate process?

e) What information does Enbridge Gas propose to provide to the OEB and stakeholders regarding the status of IRPA consideration in response to identified system needs, and when? (e.g. Enbridge Gas's determination based on its binary screening criteria as to whether any form of IRPA should be considered further; Enbridge Gas's plans/actions for further IRPA analysis for system needs that passed the initial screening, etc.)

   Does Enbridge Gas believe this information would be best presented as part of its Utility System Plan/Asset Management Plan, its proposed annual IRP monitoring report, or in a separate process?

f) Does Enbridge Gas believe that its determinations regarding system needs and the potential role of IRPAs should be subject to formal OEB review at any stage prior to Enbridge Gas's application for project-specific approval (IRP Plan/Leave to Construct)? Please explain why or why not.

<u>Response</u>

a) & b)
   Yes, Enbridge Gas intends to increase the scope of the Asset Management Plan ("AMP") back to 10 years in support of longer-term planning initiatives such as IRP.

c) Yes, the first stage at which the OEB and the majority of stakeholders will see identified system constraints/needs and any IRPA(s) and comparable baseline facilities is in the AMP. However, in some instances, Enbridge Gas may work directly with specific stakeholders at an earlier time to review and assess their specific needs on the system and to discuss baseline facility alternatives and potential IRPAs.

d) & e)
Enbridge Gas proposes that the AMP be used to present the long-term needs and IRPA planning status to the Board.

Once the OEB has established an IRP Framework for Enbridge Gas, the Company will begin to reflect IRP details in the AMP, which is filed with the Board to support rate applications. The AMP will identify potential IRPAs within the 10-year time forecast period, including details regarding baseline facility alternatives, IRPAs considered, the rationale for the alternative selected and proposed timing. Enbridge Gas will continue to monitor the underlying constraint/need and update the AMP accordingly if the constraint/need or alternative(s) selected changes until such time that either the baseline facility alternative or IRPA is implemented.

Enbridge Gas will also either file an IRPA application for an IRPA/IRPA portfolio or an application for leave-to-construct ("LTC") facilities which will provide additional details to the OEB and stakeholders as part of the OEB's review of the same

Enbridge Gas also proposes to file an annual IRP Report that documents the progress of any IRPA being planned and implemented.

f) No, Enbridge Gas believes that the only determination required from the Board related to IRP should be for approval of the IRPA applications when filed. As noted in the responses above, details regarding Enbridge Gas's identified system constraints needs, baseline facility alternatives, and potential IRPAs will be filed within the AMP as part of Enbridge Gas's rate setting applications and will be open to discovery and comment by the OEB and intervenors at that time. The OEB and intervenors/stakeholders will also be afforded additional opportunity to further review baseline facility alternatives and potential IRPA(s) at such time that Enbridge Gas files subsequent applications with the Board for approval to invest in IRPA(s)or for LTC facilities and at such time that the Company seeks to recover the costs associated with such investments (the latter being limited to confirming that Enbridge Gas has implemented alternatives in accordance with OEB-approved IRPA/LTC applications prudently). Please see the response at Exhibit I.STAFF.10, for further discussion of the approvals that Enbridge Gas intends to seek from the Board related to future investments in IRPA(s).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

Based on the process described in the EB 2019-0159 materials, it appears that EGI's current system design and planning process calls for the identification, screening, assessment, and presentation of alternatives considered in relation to a proposal to have the OEB approve the construction of incremental pipeline facilities.

At Exhibit B page 13, EGD is proposing an IRP process that takes into account its existing planning and forecasting processes.

Question:

What market solicitations, if any, do the current manual(s) require before identified alternatives are compared and assessed?

Response

As set out in the response at Exhibit I.FRPO.1, Enbridge Gas's withdrawn 2021 Dawn Parkway Expansion Project application and evidence is not currently before the Board in this proceeding.

Regarding consideration of supply-side or market-based alternatives, Enbridge Gas has a long history of considering such alternatives as part of its applications to the OEB for Leave to Construct facilities. As part of the its review of such applications, the Board and intervenors have historically played a role in testing the analyses upon which such conclusions are based and have brought their own alternatives forward for assessment. Please see the responses at Exhibit I.STAFF.2 and at Exhibit I.STAFF.16 for additional discussion of supply side-alternatives. Please also see the response at Exhibit I.OSEA.1 c) for discussion of Enbridge Gas's activities to integrate IRP with existing planning processes.

Please also see the response at Exhibit I.STAFF.4.Attachment 1, for discussion of existing processes related to the Dawn Parkway System where Enbridge Gas states at Section 6:

> “If the existing facilities cannot deliver the forecast demands at the required delivery pressures, Enbridge Gas would consider facility options including pipeline and compressor alternatives, as well as non-facility commercial services such as Winter Peaking services. The available options are reviewed, the best solution is selected, and the Schedule of Facilities is created.”
>
> “In the event that projects identified in the asset plan proceed, Enbridge Gas will complete a Leave to Construct application where a detailed and rigorous examination of both the facility and non-facility alternatives, including detailed costs and economics, can be completed.”

ENBRIDGE GAS INC.

Undertaking Response to FRPO

To provide examples of what's meant by the first sentence in the second paragraph of FRPO 15.

Response:

Enbridge Gas has provided a non-exhaustive list of references in Table 1 below where the Company has evaluated supply side alternatives as part of its internal assessment of facility and non-facility alternatives to resolve identified system constraints and included the results of its assessment as part of subsequent leave to construct proceedings.

Table 1

Line No.	Proceeding No.	Proceeding Name
1	EB-2012-0433	Parkway West
2	EB-2013-0074	2015 Dawn Parkway - Brantford – Kirkwall/Parkway D
3	EB-2014-0182	Burlington Oakville
4	EB-2014-0333	Sarnia Expansion
5	EB-2015-0200	2017 Dawn Parkway - Dawn H, Lobo C, Bright C
6	EB-2016-0186	Panhandle Reinforcement
7	EB-2018-0013	Kingsville Reinforcement
8	EB-2019-0218	Sarnia Industrial Line Reinforcement

As part of these assessments, Enbridge Gas has evaluated both short-term and long-term supply side services, including: peaking supply, delivered supply, exchanges and third-party assignments.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

IRP best practices will likely vary from utility to utility depending upon the attributes of the particular utility system and its interconnection with other systems under consideration and the proposed comparator. Such "best practices" will likely be limited those with a system configuration similar to that of the utility under consideration

For example, the Parkway Delivery Obligation (PDO), that EGI identified in its EB 2019-0159 evidence as a Non-Facility SUPPLY SIDE Alternative to a proposed expansion of its Dawn to Parkway transmission system, is the type of IRP Alternative that is likely to be limited to systems that are similar in their configuration and design to the transmission systems of EGI and its transmission interconnections.

On the other hand, best practices in relation to other IRP measures such as DSM are likely applicable to a broad universe of utilities regardless of their differing locations and system configurations.

The specific delivery/receipt point PDO Alternative, as a means of avoiding transmission system expansion on EGI's transmission system, is an example of a Non-Facility Supply Side Alternative "best practice" because it was introduced and has been adhered to for that purpose for decades.

The PDO is described in Exhibit A, Tab 7, page 13, of EGI's EB 2019-0159 evidence as follows:

> "*Enbridge Gas considers the PDO in the design day analysis of the Dawn Parkway system to reduce physical transportation need s from Dawn to Parkway. Overall, this reduction of Dawn to Parkway transportation has reduced the amount of facilities required. This is achieved because volumes delivered at Parkway, directly offset the need for Dawn to Parkway transportation.*"

An open and transparent IRP Framework is necessary to ensure that cost-effective IRP Alternatives to system expansion will be fairly and reasonably considered by EGI's regulator when considering the how best to respond, in the public interest, to an established need.

FRPO's needs evidence of a concrete example of a Non-Facility Supply Side alternative to a pipeline infrastructure build to support the proposals that it wishes the Board to consider for evaluation of criteria for supply side alternatives and suggestions for the timing to assess these alternatives.

The questions that follow about PDO and features of some of the other identified by EGI in its EB-2019-0159 evidence as Non-Facility Supply Side options are intended to obtain evidence of this nature. The need for these questions is prompted, in part, by the absence of evidence on Non-Facility SUPPLY SIDE Alternatives in EGI's Additional and Reply evidence as described above in paragraphs 4 and 5 of the section entitled "PREFACE AND CONTEXT".

We understand that Direct Purchase customers' obligation to deliver daily quantities of gas at Parkway (now known as the Parkway Delivery Obligation (PDO)) has been in place for many years. We believe that there is an opportunity to enhance this a variant of this mechanism as an IRPA.

Before filing requirements related to the full range of mechanisms that can avoid or defer the construction of incremental infrastructure can be finalized, the Board needs to understand how contracting to transport gas to a particular Delivery Point on the EGI transmission system is a very cost effective IRPA that is well established as a "best practice.

Question:

Please confirm that the PDO existence has been and is currently utilized as a substitute for additional infrastructure (pipe, compression, etc.).

Response

As discussed in Union's 2014 Rates proceeding (EB-2013-0365) as part of the Settlement Framework for Reduction of Parkway Delivery Obligation, subsection A. Context and Guiding Principles, the OEB approved a framework for reducing the PDO based on rectifying an inequity for a number of Direct Purchase customers who were contractually required by Union to deliver their Daily Contract Quantity ("DCQ") of gas to Parkway, at their own expense, for Union to operate its system and whereby the Parties agreed that the PDO should be permanently reduced by awarding excess Dawn Parkway system capacity, through turnback, to said Direct Purchase customers. For the period of time that Direct Purchase customers, who wanted to procure supply at the liquid Dawn Hub, were required to stay obligated at Parkway for Dawn Parkway System requirements, a Parkway Delivery Commitment Incentive payment was provided.

In other words, Direct Purchase customers were compensated to remain obligated at Parkway only until excess system capacity enabled them to permanently obligate at Dawn.

To the extent that the PDO is available, it is used to offset additional Dawn Parkway System infrastructure.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

IRP best practices will likely vary from utility to utility depending upon the attributes of the particular utility system and its interconnection with other systems under consideration and the proposed comparator. Such "best practices" will likely be limited those with a system configuration similar to that of the utility under consideration

For example, the Parkway Delivery Obligation (PDO), that EGI identified in its EB 2019-0159 evidence as a Non-Facility SUPPLY SIDE Alternative to a proposed expansion of its Dawn to Parkway transmission system, is the type of IRP Alternative that is likely to be limited to systems that are similar in their configuration and design to the transmission systems of EGI and its transmission interconnections.

On the other hand, best practices in relation to other IRP measures such as DSM are likely applicable to a broad universe of utilities regardless of their differing locations and system configurations.

The specific delivery/receipt point PDO Alternative, as a means of avoiding transmission system expansion on EGI's transmission system, is an example of a Non-Facility Supply Side Alternative "best practice" because it was introduced and has been adhered to for that purpose for decades.

The PDO is described in Exhibit A, Tab 7, page 13, of EGI's EB 2019-0159 evidence as follows:

> "*Enbridge Gas considers the PDO in the design day analysis of the Dawn Parkway system to reduce physical transportation need s from Dawn to Parkway. Overall, this reduction of Dawn to Parkway transportation has reduced the amount of facilities required. This is achieved because volumes delivered at Parkway, directly offset the need for Dawn to Parkway transportation.*"

An open and transparent IRP Framework is necessary to ensure that cost-effective IRP Alternatives to system expansion will be fairly and reasonably considered by EGI's regulator when considering the how best to respond, in the public interest, to an established need.

FRPO's needs evidence of a concrete example of a Non-Facility Supply Side alternative to a pipeline infrastructure build to support the proposals that it wishes the Board to consider for evaluation of criteria for supply side alternatives and suggestions for the timing to assess these alternatives.

The questions that follow about PDO and features of some of the other identified by EGI in its EB-2019-0159 evidence as Non-Facility Supply Side options are intended to obtain evidence of this nature. The need for these questions is prompted, in part, by the absence of evidence on Non-Facility SUPPLY SIDE Alternatives in EGI's Additional and Reply evidence as described above in paragraphs 4 and 5 of the section entitled "PREFACE AND CONTEXT".

We understand that Direct Purchase customers' obligation to deliver daily quantities of gas at Parkway (now known as the Parkway Delivery Obligation (PDO)) has been in place for many years. We believe that there is an opportunity to enhance this a variant of this mechanism as an IRPA.

Before filing requirements related to the full range of mechanisms that can avoid or defer the construction of incremental infrastructure can be finalized, the Board needs to understand how contracting to transport gas to a particular Delivery Point on the EGI transmission system is a very cost effective IRPA that is well established as a "best practice.

Question:

When did the Board first approve the required commitment of DP customers to deliver at Parkway as part of obligation in providing DP supply?

i. When was the first financial incentive provided and what was the value?
ii. How was that value determined?
iii. Has the valuation process changed over time? If so, how?
iv. Please provide the incentive available ($/GJ) to the parties who delivered provided committed deliveries at Parkway for each of the last 10 years.

Response

OEB approval of direct purchase services first resulted in obligated deliveries at Parkway beginning 1986.

i. From 1990 until 2002, direct purchase in-franchise customers were paid a Delivery Commitment Credit (“DCC”) for obligated Parkway deliveries. The DCC had an approximate cost of $27 million in 2002.

ii. The DCC unit rate was initially calculated as the difference between the Ontario buy/sell price and Union’s weighted average cost of gas (“WACOG”). In 1999, the DCC unit rate was changed to be calculated using the existing M12 storage and transmission rates to recognize the avoided Dawn Parkway System transmission costs as a result of direct purchase customers delivering gas at Parkway. Based on the methodology at the time the DCC unit rate was $4.25/10^3m^3 (approximately $0.108/GJ[1]) in 2002.

iii. The DCC was eliminated in 2003 and until October 31, 2016, direct purchase customers did not receive payment for obligated deliveries at Parkway. Effective November 1, 2016, the Company began payment of the Parkway Delivery Commitment Incentive (“PDCI”) to Union South direct purchase customers with obligated deliveries at Parkway in accordance with the Settlement Framework for Reduction of Parkway Delivery Obligation.[2]

The PDCI is set at the Board approved M12 Dawn to Parkway toll at 100% load factor including fuel based on the fuel cost included in Union’s October 1, QRAM each year. Effective January 1, 2017, the Company included the Cap-and-Trade facility unit rate in the calculation of the PDCI unit rate until the end of Ontario’s Cap-and-Trade program in 2018. Effective April 1, 2019, the Company included the Facility Carbon Charge unit rate in the calculation of the PDCI unit rate.

iv. Table 1 provides the PDCI unit rate for the last 10 years as set with the annual rates application and for 2019 and 2020 includes the Facility Carbon Charge effective April 1 of each year.[3] The PDCI may change throughout the year based on changes in the underlying components of the rate.

[1] Conversion to GJs based on the current heat value of 39.28 GJ/10^3m^3.
[2] EB-2013-0365, Decision and Order on Parkway Delivery Obligation, June 3, 2014, Appendix B.
[3] The 2017 and 2018 PDCI unit rates reflect the applicable Cap-and-Trade facility unit rate.

Table 1
10-Year History of the PDCI Unit Rate

Line No.	Particulars ($/GJ/d)	PDCI Unit Rate
		(a)
1	2012	-
2	2013	-
3	2014	-
4	2015	-
5	2016 (1)	0.134
6	2017	0.158
7	2018	0.156
8	2019 (2)	0.147
9	2020	0.144
10	2021 (3)	0.147

Notes:
(1) Effective November 1, 2016.
(2) The 2019 PDCI unit rate was effective April 1, 2019.
(3) The 2021 PDCI unit rate currently reflects the 2020 Facility Carbon Charge.

Enbridge Gas has also recently agreed to file evidence detailing infrastructure and market-based alternatives in order to inform the Board whether it is cost-effective to eliminate or reduce the PDO and/or PDCI for 2022 and future years.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

IRP best practices will likely vary from utility to utility depending upon the attributes of the particular utility system and its interconnection with other systems under consideration and the proposed comparator. Such "best practices" will likely be limited those with a system configuration similar to that of the utility under consideration

For example, the Parkway Delivery Obligation (PDO), that EGI identified in its EB 2019-0159 evidence as a Non-Facility SUPPLY SIDE Alternative to a proposed expansion of its Dawn to Parkway transmission system, is the type of IRP Alternative that is likely to be limited to systems that are similar in their configuration and design to the transmission systems of EGI and its transmission interconnections.

On the other hand, best practices in relation to other IRP measures such as DSM are likely applicable to a broad universe of utilities regardless of their differing locations and system configurations.

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FRPO's needs evidence of a concrete example of a Non-Facility Supply Side alternative to a pipeline infrastructure build to support the proposals that it wishes the Board to consider for evaluation of criteria for supply side alternatives and suggestions for the timing to assess these alternatives.

The questions that follow about PDO and features of some of the other identified by EGI in its EB-2019-0159 evidence as Non-Facility Supply Side options are intended to obtain evidence of this nature. The need for these questions is prompted, in part, by the absence of evidence on Non-Facility SUPPLY SIDE Alternatives in EGI's Additional and Reply evidence as described above in paragraphs 4 and 5 of the section entitled "PREFACE AND CONTEXT".

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Question:

When did the Board first approve a design of the Dawn-Parkway system that included committed deliveries as part of the design criteria of Union Gas?

Response

The obligation to deliver, approved by the Ontario Energy Board in April 1989,[1] has allowed Union to rely on these volumes in order to manage its deliveries efficiently and to meet Dawn Parkway System design and security criteria since that date.

[1] E.B.R.O. 456-4, Decision with Reasons, April 14, 1989.

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Question:

What was the level of PDO in GJ/day and percentage of the daily design day demand of the Dawn-Parkway system in each of 2000, 2013 and 2020?

Response

Enbridge Gas is unable to provide the level of PDO on the Dawn Parkway System in 2000 as the earliest available information is for the Winter of 2006/2007.

PDO levels represented as GJ/day and percentage of design day requirements on the Dawn Parkway System for 2006/2007, 2013/2014 and 2020/2021 were as follows:

Winter 2006/2007 - 660 TJ/d; Percentage of Design Day Demand: 10.9%
Winter 2013/2014 - 672 TJ/d; Percentage of Design Day Demand: 9.8%
Winter 2020/2021 - 228 TJ/d; Percentage of Design Day Demand: 2.9%

ENBRIDGE GAS INC.

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Federation of Rental-housing Providers of Ontario ("FRPO")

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Question:

Please confirm that the Parkway Delivery Obligation (PDO) is not part of the Gas Supply Plan for utility gas procurement as the PDO is provided by suppliers to Direct Purchase Customers. If not confirmed, then please explain.

Response

Confirmed.

ENBRIDGE GAS INC.

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Federation of Rental-housing Providers of Ontario ("FRPO")

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Question:

If confirmed, please confirm that PDO is, in fact, a contracted mechanism to reduce facilities or said differently, a non-facility, supply-side solution.

Response

Please see the responses at Exhibit I.FRPO.26 and at Exhibit I.FRPO.27, for discussion confirming that, to the extent the PDO is available, it is being used to offset additional Dawn Parkway System infrastructure.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

The market circumstances related to a PDO have materially changed with the availability of 365 days of Empress to Dawn transportation under the auspices of Long-Term Fixed Price ("LTFP"); in conjunction with the capacity available on the Northern Ontario line and the actual use of that line to carry some of the Empress to Dawn volumes under this service.

The extremely cost effective PDO Alternative, in conjunction with companion displacement transaction (that for years have been facilitated by market operators) could operate to avoid or defer future expansions of the Dawn Parkway system well into the future.

At a high level, the Parkway Delivery Commitment Incentive (PDCI) can be used as a ballpark surrogate for the amount to be paid to commit to deliver volumes at Parkway. TCPL's charges for making case specific commitment to use the Northern Line for a fixed level of demand should be nominal (related to incremental fuel gas and associated carbon taxes).

Like other utilities TCPL has an obligation to support the cost-effective use of all interconnected transmission facilities in a manner that serves the public interest. The actual costs that it incurs to make use the Northern line to support a transaction of this nature will be negligible.

Timely market solicitations by EGI in relation to market-based Non Facility Supply Side alternatives to an infrastructure build are essential to a fair and reasonable comparison of those alternative to the incremental facilities option and to other IRPAs. This is particularly so when conducting an evaluation of market based PDO alternatives and peaking services options.

The provisions of the IRP Framework that the OEB is considering should require EGI to conduct timely market solicitations in cases where these types of market- based alternatives are relevant.

By way of example, the provisions of the Framework should oblige EGI solicit PDO related solutions from the market in cases where the determination of need gives rise to a consideration of alternatives to an expansion of EGI's Dawn Parkway system.

FRPO's position is that, having regard to the existence of long-term commitments by Dawn LTFP shippers for a large volume of gas to be transported on TCPL facilities between Empress and Dawn under the auspices of the 365 day fixed price LTFP service, there is an opportunity for EGI to acquire a very cost competitive type of PDO service from a market constituency consisting of TCPL and the Dawn LTFP shippers.

The timely market solicitations that EGI should be required to make in relation to PDO related options to a Dawn Parkway system expansion should reflect the changes in market circumstances that have taken place as a consequence of the extent to which shippers have made long term commitments for Dawn LTFP service.

FRPO has drafted, for discussion purposes, a concept outline pertaining to the content of a market solicitation such as an "Expression of Interest" in these types of cases. This is the type of solicitation that EGI should be required to present to TCE and the Dawn LTFP shippers for a PDO type of arrangement that is far more cost effective than an expansion of the Dawn Parkway transmission system. The elements of this draft Concept Outline are presented below.

To be clear, this obligation does not constitute a purchase of gas by EGI only a commitment by the successful bidders to ensure that they either provide firm delivery to Parkway daily in the winter or, for Dawn LTFP shippers, that they provide firm delivery to Empress coupled with TCPL's cooperation in committing these quantities through Parkway. It would be the cooperation of EGI and TCPL to move the gas through the Northern Ontario Line and through displacement, meet the needs at Parkway.

PARKWAY OBLIGATED DELIVERIES - CONCEPT APPROACH

<u>RFP</u>

- EGI performs RFP for winter-only obligated deliveries to Parkway (or Empress)
    - Open to all Shippers holding firm capacity to Parkway
    - Existing delivery commitments currently receiving the Parkway Delivery Commitment Incentive do not qualify as those obligations are already contractually committed
    - Preference given to those holding firm capacity to Parkway or Dawn using Dawn LTFP service (commitment is to nominate daily at Empress)
    - Term 5 years
    - Start Nov. 1, 2021 (or date dictated by need)
    - EGI to offer annual extensions beyond the initial term starting in a notice period in the fall three years in advance of the expiry of the contract.
    - Up to 200 TJ (minimum 20 TJ) depending upon need of EGI

<u>Dawn LTFP Contracts</u>

- Shipper enters into contract with EGI to nominate their commitment quantity at Empress each day of the winter

  - Financial Assurances – EGI standard
  - Non-Performance – EGI General Terms & Conditions
  - Duty to Mitigate – Contract Law
- EGI enters contract with TCE to commit to provide any firm, obligated Empress receipts via the Northern Ontario Line and through Union Parkway (contractually not physically)

Mechanism for Funding

- Shipper paid accepted bid price for service
- EGI recovers cost from ratepayers in same methodology as PDCI is currently recovered

Question:

Please provide EGI's comments on FRPO's concept outline described above and its supporting rationale.

Response

Please see the response at Exhibit I.FRPO.1. Enbridge Gas is not seeking OEB approval to implement specific IRPAs or to recover the costs associated with investment in specific IRPAs and Enbridge Gas has no intention of seeking any such IRPA-specific approval from the Board as part of this proceeding. Natural gas market fundamentals are dynamic, a snapshot of information and data on the natural gas market and flow dynamics, including FRPO's concepts described above, at a particular point in time are more relevant in the context of future applications to address specific identified system constraints than in the development of an IRP Policy Framework for Enbridge Gas. Enbridge Gas does not agree with many of the assertions made by FRPO in its Preamble and finds its supporting rationale erroneous and misplaced.

In its response at Exhibit I.STAFF.2, Enbridge Gas has provided additional explanation of how it proposes to integrate IRP with system planning and gas supply planning processes.

In addition, Enbridge Gas has addressed supply-side/market-based (commercial) alternatives, including: peaking services, delivered supply, exchanges, and third-party assignments in its response at Exhibit I.STAFF.16. Exchange services were further discussed in the response at Exhibit I.FRPO.57.

Enbridge Gas provided detailed discussion regarding the Parkway Delivery Obligation ("PDO") in its responses beginning at Exhibit I.FRPO.26 through to the response at Exhibit I.FRPO.35.

Enbridge Gas has also provided further information regarding the TCPL Dawn LTFP service in its responses beginning at Exhibit I.FRPO. 52 through to the response at Exhibit I.FRPO.54 as well as in the responses at Exhibit I.FRPO. 65 through to the response at Exhibit I.FRPO.68. Enbridge Gas also provided related information with respect to system operations in its responses at Exhibit I.FRPO.55 and at Exhibit I.FRPO.56.

Enbridge Gas has no evidence to support FRPO's claim that TCPL has any obligation to support the cost-effective use of all interconnected transmission facilities in a manner that serves the public interest nor with regard to how any such obligation extends to coordinating the operation of the TCPL Mainline with other interconnecting pipelines, including Enbridge Gas's system.

Enbridge Gas cannot support either of FRPO's concept outlines or its supporting rationale at this time, given:

(i) Enbridge Gas is not seeking OEB approval to implement specific IRPAs as part of this proceeding;

(ii) The premise of the proposed criteria is based on FRPO's selective and limited interpretation of historic market fundamentals and services;

(iii) Natural gas market fundamentals are dynamic and as such, the Board should not seek to establish criteria for assessment of market-based services today for future IRPA(s) applications as doing so might inadvertently restrict consideration of such IRPA(s) in the future;

(iv) Enbridge Gas has already provided extensive clarifications, as cited above and wherever appropriate, regarding the services and issues of interest to FRPO through its responses to interrogatories; and

(v) As discussed in the response at Exhibit.I.FRPO.15, it is more appropriate that Enbridge Gas solicit the market for feasible market-based solutions without restriction at the time a system constraint is identified and bring forward the results of that solicitation along with assessment of other facility and non-facility alternatives as part of a future IRPA application for the Board's and parties' review.[1]

[1] It is more appropriate that FRPO bring forward market-based IRPA(s) for the Board's consideration as part of the review of such future IRPA applications with the benefit of timely market data at that time.

4) Bluewater Gas Storage, LLC ("BGS")/Bluewater Pipeline (St. Clair Pipelines L.P.).

1) GLGT/GLC

26. The Dawn Extension Pipeline owned by TC Energy affiliate GLC directly connects to the SIL system at Courtright and also directly connects to the Dawn Hub further east. At the international border under the St. Clair River the Dawn Extension Pipeline connects to another TC Energy affiliate pipeline, GLGT, at a point called St. Clair, which is the southern terminus of the GLGT system. The Dawn Extension Pipeline is wholly located in Ontario. The combination of the Canadian Mainline, GLGT and GLC provide eastern markets access to natural gas supply from the Western Canadian Sedimentary Basin ("WCSB") via the GLGT connection to the TC Energy Mainline at Emerson, Manitoba.

27. Enbridge Gas has the ability to direct up to 0.4 PJ/d of supply from the GLC system into the SIL system at Great Lakes Courtright.[17] The SIL system was constructed north from this point and prior to 1989 was reliant on this pipeline as the sole supply from Michigan into the Sarnia market as it was the only pipeline flowing past the area.

28. Enbridge Gas contracts for firm transportation (21 TJ/d starting November 1, 2019) on the GLGT/GLC system to deliver natural gas to the Union South West Delivery Area (SWDA) which includes the SIL system at Great Lakes Courtright. While there are times when larger volumes of gas are flowing past Great Lakes Courtright, Enbridge Gas has no direct control over these volumes. At times, the GLGT/GLC system has experienced reverse flow conditions under which Enbridge

[17] Enbridge Gas directs flow into the SIL system at Courtright and to complete TC Energy's deliveries to Dawn on the Emerson to Dawn path, Enbridge Gas provides TC Energy the same amount of natural gas at Dawn as is directed into the SIL system (displacement).

Ontario Energy
Board

Commission de l'énergie
de l'Ontario

Ontario

EB-2013-0365

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

AND IN THE MATTER OF an Application by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2014.

DECISION AND ORDER ON PARKWAY DELIVERY OBLIGATION

June 16, 2014

Union Gas Limited ("Union") filed an Incentive Rate Mechanism ("IRM") application along with a Settlement Agreement on July 31, 2013 with the Ontario Energy Board (the "Board") seeking approval of a multi-year IRM framework for the period 2014-18. The Board approved the Settlement Agreement filed by Union that established a framework to set rates for a five year term.

Based on the approved framework, Union filed this application on October 31, 2013 with the Board pursuant to section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Schedule B, for an order or orders approving rates for the distribution, transmission and storage of natural gas, effective January 1, 2014. The Board assigned the application, file number EB-2013-0365.

The Board issued a Notice of Application and Hearing on November 22, 2013.
Union filed a Settlement Agreement and Draft Rate Order on April 24, 2014 for rates effective January 1, 2014. This Settlement covered all issues with the exception of three issues:

1. Parkway Delivery Obligation;

2. Allocation of Kirkwall Metering Costs; and
3. Leamington Line Project.

The Board accepted the Settlement Agreement by way of Decision, Rate Order and Procedural Order No. 3 issued on May 12, 2014.

On June 3, 2014 Union filed an update to the Settlement Agreement (“Updated Settlement Agreement”) which included a settlement on the Parkway Delivery Obligation issue (entitled “Settlement Framework for Reduction of Parkway Delivery Obligation”). At an oral hearing on June 5, Union presented the Parkway Delivery Obligation settlement and responded to questions by the Board. Counsel for Union, Board staff and intervenors also participated in the hearing. The Updated Settlement Agreement dated June 3, 2014 is attached as Appendix A and includes the Settlement Framework for Reduction of Parkway Delivery Obligation in Appendix B to this Decision.

The Board accepts the Updated Settlement Agreement and the Settlement Framework for Reduction of Parkway Delivery Obligation, and commends Union and the participating stakeholders for their efforts in coming to an agreement that the Board considers to be in the public interest.

THE BOARD ORDERS THAT:

1. Union shall establish the Parkway Obligation Rate Variance Deferral Account (179-138) as noted in the Settlement Framework for Reduction of Parkway Delivery Obligation and as set forth in Appendix “C”. Union shall record simple interest on the monthly opening balances, calculated at the Board-approved rate.

DATED at Toronto June 16, 2014

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX B

TO

DECISION AND ORDER

UNION GAS LIMITED

BOARD FILE NO. EB-2013-0365

DATED: JUNE 16, 2014

SETTLEMENT FRAMEWORK FOR REDUCTION OF PARKWAY DELIVERY OBLIGATION

SETTLEMENT FRAMEWORK
FOR REDUCTION OF PARKWAY DELIVERY OBLIGATION

A. CONTEXT AND GUIDING PRINCIPLES

1. There is currently an inequity in the manner in which the delivery of gas volumes required by Union at Parkway is achieved. A number of Direct Purchase ("DP") customers are contractually required by Union to deliver their Daily Contract Quantity ("DCQ") of gas to Parkway, at their own expense, in order for Union to operate its system. As a consequence, DP customers with a Parkway Delivery Obligation ("PDO") are conferring a benefit on all users of the Dawn-Parkway transmission system because its size and capacity are less than would otherwise be required.

2. To rectify this inequity, the Parties agree that the PDO should be permanently reduced primarily in the manner Union has proposed and as reflected in its evidence, but with certain modifications and an end-state as outlined below. Conceptually, the modified proposal is for Union to use excess Dawn-Parkway transmission capacity and other resources to provide the PDO relief it proposes, but with a defined end-state which includes the payment of a Parkway Delivery Commitment Incentive ("PDCI") for any continuing obligated DCQ deliveries at Parkway.

3. The ultimate objective of the modified proposal is to remedy an inequity. The guiding principle is to keep Union whole rather than to enhance or reduce its earnings during the operation of the Incentive Regulation Mechanism ("IRM") to December 31, 2018.

4. Union identifies TransCanada Power, a Division of TransCanada Energy Ltd. ("TCE"), as a M12 DP customer having a PDO eligible for reduction by turnback of M12 capacity. (See Exhibit B1.5) TCE holds M12 service for 132,000 GJ/day pursuant to an arrangement made with Union under the auspices of sub-paragraph (b) in the "Delivery Obligations" portion of section 1.3 of the EB-2005-0551 Settlement Agreement dated June 13, 2006 (the "NGEIR Settlement"). Under the provisions of subparagraph (b)(ii) of the NGEIR Settlement, this M12 service arrangement allows TCE's Halton Hills Generating Station ("HHGS") to purchase and deliver all of its DP gas supply to Union at Dawn on a non-obligated basis. Union then transports and delivers those non-obligated volumes from Dawn to HHGS, located near Parkway.

5. These delivery services are provided by Union to TCE for HHGS under the auspices of a M12 Dawn to Parkway contract for 132,000 GJ/day which TCE has assigned to Union and a Rate T2 contract for distribution services at a Billing Contract Demand ("BCD") of approximately 52,000 GJ/day. This is the minimum quantity that causes the Rate T2 demand charges paid by HHGS to fully recover the capital costs of the HHGS lateral under the economic test that is used for leave to construct applications.

6. This PDO Reduction proposal includes within its ambit the 132,000 GJ/day of capacity which TCE holds pursuant to its M12 contract which it has assigned to Union. TCE's M12 contract expires on October 31, 2018.

7. Ratepayer representatives and Union acknowledge that M12 turnback opportunities should be made available to TCE in the same proportions as those opportunities are made available to DP customers with PDOs in excess of 100 GJ/day so that TCE can transition to full Rate T2 service by increasing its BCD above its current level of 52,000 GJ/day. The parties acknowledge that TCE should increase the level of its BCD to the extent necessary to produce an amount of incremental T2 demand revenue which equates to the loss of M12 demand revenue related to TCE's M12 turn back provided that TCE's obligation to increase its Rate T2 BCD ends when it reaches 132,000 GJ/day.

8. The equitable end-state which Union's ratepayers seek is one which either eliminates in its entirety the PDO or, where it is more cost-effective to do so, calls for all ratepayers to compensate DP customers upon whom a PDO is imposed and who deliver PDO volumes at Parkway and sales service customers on whose behalf Union delivers volumes at Parkway for the benefit conferred on Union's integrated system.

9. The PDO Reduction Proposal which follows is based on the foregoing concepts and principles.

B. TERMS OF PDO REDUCTION PROPOSAL (EXCLUDING TCE)

(i) <u>Phase 1 (April 1, 2014)</u>

1. Effective April 1, 2014, the PDO will be permanently reduced by 146 TJ/day using temporarily available M12 Dawn to Parkway capacity. Upon Board approval of the PDO Reduction proposal, Union will facilitate a 36.1% reduction of the M12 capacity held by the DP customers identified by Union in Exhibit B1.5, excluding TCE, who elect to change their obligated delivery point from Parkway to Dawn effective April 1, 2014. A proportionate share of the aggregate PDO reduction available will be allocated to all Parkway delivery obligated direct purchase ("PDO DP") customers as follows:

   (a) PDO DP customers with PDOs of 100 GJ/day or less, who elect to change their obligated delivery point from Parkway to Dawn, will have their entire PDO transferred to Dawn;

   (b) PDO DP customers with PDOs above 100 GJ/day, excluding TCE, who elect to change their obligated delivery point from Parkway to Dawn, will have 36.1% of their PDO transferred to Dawn;

   (c) PDO DP customers, excluding TCE, holding M12 Dawn to Parkway capacity to satisfy their PDO may elect to turn back up to 36.1% of that capacity. The total potential M12 turn back by such PDO customers is about 18 TJ/day;

   (d) The annual demand costs of the currently unutilized capacity between Dawn and Parkway to be used to provide 146 TJ/day of PDO relief and the additional 18 TJ/day of capacity to be realized by the turn back of M12 capacity held by PDO DP customers, excluding TCE, will be determined by applying the 2014 proposed M12 rate for Dawn to Parkway transportation at 100% load factor excluding fuel, being a unit rate of $0.080/GJ, for total annual demand costs of about $4.763

million, of which $4.240 million is for the 146 TJ/day and $0.523 million is for the 18 TJ/day, for a total of $4.763 million;

(e) Consistent with Union's evidence, the annual demand costs of $4.763 million will be recovered through a deferral account (see Attachment 1 for the accounting order) for the period April 1, 2014 – December 31, 2014 and thereafter in the delivery rates of in-franchise customers served under the auspices of Rates M1, M2, M4, M5 Firm, M7 Firm, M9, M10, T1, T2 Firm and T3, and will be allocated to those rate classes using the 2013 Board approved Dawn-Parkway Design Day Demands reflected in the In-franchise Peak Day Demand allocation factor updated for the EB-2011-0210 Decision, all as shown in Schedule 1;

(f) Union will include in rates the incremental fuel, per Schedule 2, to transmit, to points east of Dawn, for new obligated deliveries at Dawn described in paragraphs B.1(a), (b) and (c) above and Section C below which fuel volumes are incremental to the fuel volumes already embedded in the rates of Union's in-franchise customers. Union will manage any volume variances associated with actual fuel used to transport in-franchise gas east of Dawn;

(g) Incremental delivery volumes, will continue to be allocated a PDO per Union's existing DCQ policies, if Union, acting reasonably and in a non-discriminatory manner, determines a PDO to be necessary, and will be eligible for the PDCI described in paragraph B.4.

(ii) <u>Phase 2 (April 1, 2014 through October 31, 2018)</u>

2. Between April 1, 2014 and October 31, 2018, there will be a temporary shortfall in the Dawn to Parkway capacity needed to support the PDO reduction proposed by Union in its pre-filed evidence. Based on Union's forecast, the portion of Dawn to Parkway capacity needed to support PDO reduction which will be temporarily unavailable will be as follows:

- Between April 1, 2014 and October 31, 2015 – no Parkway delivery shortfall;
- Between November 1, 2015 and October 31, 2016 – Parkway delivery shortfall of 146 TJ/day;
- Between November 1, 2016 and October 31, 2017 – Parkway delivery shortfall of 118 TJ/day; and
- Between November 1, 2017 and October 31, 2018 – no Parkway delivery shortfall.

The actual Dawn to Parkway capacity which will be temporarily unavailable will vary.

Union intends to manage its Parkway delivery requirement as proposed in its pre-filed evidence and interrogatory responses as follows:

i. 146 TJ/day of temporarily available M12 Dawn to Parkway capacity will be used to reduce the PDO from April 1, 2014 to October 31, 2015.

ii. Effective November 1, 2015, the temporarily available Dawn to Parkway capacity will be used for other purposes leaving Parkway in a delivery shortfall position. The demand costs associated with the temporarily unavailable capacity as described above will nevertheless remain in delivery rates to be used by Union to manage the Parkway delivery shortfall through the acquisition of incremental resources, the costs of which are not already covered by base rates, Y factors and/or deferral and variance accounts and subject to the reporting and risk allocation measures described in paragraph B.10 (c) below.

iii. Any Dawn to Kirkwall M12 capacity turned back to Union by ex-franchise shippers will be used to first, reduce the Parkway shortfall and secondly, to further reduce the PDO. All incremental costs associated with the incremental PDO reduction, including demand charges and fuel, will be recovered by Union either through the deferral account due to timing differences or included in rates per paragraphsB.1 (d), B.1 (e), B.1(f) and B.3.

iv. The 98 TJ/day currently being delivered to Parkway by Union on behalf of sales service gas customers will transition to Dawn by November 1, 2016, as described at Exhibit B1.9.

3. The demand costs associated with the Dawn to Parkway capacity, the Parkway shortfall and M12 turn back used to support the PDO reduction will be calculated using the Board-approved M12 Dawn to Parkway toll at 100% load factor excluding fuel.

4. From and after November 1, 2016, all PDO volumes (DP and sales service gas) will attract a PDCI. The PDCI will be set at the Board approved M12 Dawn to Parkway toll at 100% load factor including fuel based on the fuel cost included in Union's October 1 QRAM each year.

5. The PDCI will be paid on the Parkway deliveries Union requires from DP customers, for which they commit to deliver their DCQ volumes at Parkway, and requires from its sales service customers. For greater clarity, volumes voluntarily delivered to Parkway, rather than delivered pursuant to a PDO required by Union, will not attract the PDCI.

6. The payment of the PDCI to sales service customers will be made by way of a credit to the Union South gas supply transportation rate. The payment of the PDCI to DP customers will be by way of a credit on the bill to the Bundled Transportation contract holder.

7. The costs of the PDCI will be allocated to rate classes and recovered in rates in the same manner as the PDO reduction costs are allocated to rate classes and recovered in rates as described in paragraphs B.1(e) and B.1(g) above. Schedule 1 includes illustrations of the manner in which the PDCI will be allocated and recovered from in-franchise rate classes, the manner in which the credit for sales service customers will be

applied and the manner in which the PDCI will be credited on the bills to Bundled transportation contract holders for ratepayers who acquire their gas under the auspices of DP arrangements.

(iii) <u>Phase 3 (November 1, 2016 and beyond)</u>

8. Effective November 1, 2016, or such earlier date upon which, as described in Exhibit B1.9, Union transitions to Dawn delivery volumes currently being delivered to Parkway by Union on behalf of sales service customers, any remaining PDO for all DP customers and sales service customers will be eliminated provided that it can be eliminated in a manner which is more cost-effective for all of Union's ratepayers than the terms and conditions described in paragraphs B.4 through B.7.

9. Should DP customers renew their M12 Dawn to Parkway contract and Union subsequently offers a reduction to the direct purchase PDO, then notwithstanding these renewals, such customers will be allowed to reduce their M12 contracts by an amount equivalent to that PDO reduction.

(iv) <u>Annual Reporting</u>

10. Union will include in its annual rate case filings a report on:

(a) Capacity that could become available, or could be made available, in the 2 years commencing with the test year, and could be used to further reduce the PDO in place at the time of the rate case filing on a more cost effective (i.e. lower revenue requirement) basis than the cost of the PDCI. Parties in the rate review process may explore any such options and advocate for further physical displacement of remaining PDOs to Dawn or other delivery points less costly to deliver to than Parkway.

(b) Forecast PDO volumes for the two years commencing with the test year. This information will facilitate consideration, at the time of rebasing, of the status of the PDO and associated PDCI provided for in this agreement.

(c) The measures that Union used and the costs incurred to manage the Parkway delivery shortfall (described in paragraph B.2) to acquire incremental resources, the costs of which are not already recovered in base rates, Y factors and/or existing deferral and variance accounts.

If the costs incurred to manage the Parkway delivery shortfall component of the PDO reduction in any year are less than the annual demand costs related to the shortfall in that year and actual fuel costs in that year for capacity equal to the shortfall capacity, then the entire amount of such cost savings will accrue to Union. Conversely, if the actual costs in any year to manage the Parkway Delivery shortfall in that year exceed annual demand costs and actual fuel costs in that year for capacity equal to the shortfall amount, then Union will be entirely responsible for those excess costs.[1] Parties further agree that ratepayers will be entitled to recover from Union that portion of the costs incurred by Union to manage the Parkway Delivery shortfall to the extent that the cost of the measures used by Union to manage the shortfall are already covered in base rates, Y factors and/or existing deferral or variance accounts.

(d) The total actual transmission compressor fuel used on the Dawn to Parkway system in the prior year.

C. TCE PDO Reduction Proposal

1. Immediately following the Board's approval of the PDO Reduction settlement, Halton Hills Generating Station ("HHGS"), through TCE, will be entitled to elect to turn back up to 36.1% of its 132,000 GJ/day of M12 capacity effective April 1, 2014, being a turn back amount of up to 47,652 GJ/day, provided that there is a one-time increase in the HHGS Rate T2 Billing Contract Demand ("BCD") to the extent necessary to make the increase in Rate T2 demand payments, taking into account the demand rate adjustments resulting from B.1(e), equal to the reduction in M12 demand payments associated with the turn back volumes, and HHGS will continue to have non-obligated delivery at Dawn for its full Contract Demand.

   Example

   If HHGS elects the full M12 reduction of 47,652 GJ/day, the M12 demand costs would be reduced by $115,318 per month at current rates [47,652 x $2.420 = $115,318]. To keep the total demand payments the same, HHGS would need to increase its BCD by 1,071,600 m^3/day (approximately 40,250 GJ/day) [1,071,600 x $0.107608 = $115,318] from 1,374,000 m^3/day (approximately 52,000 GJ/day) to 2,445,600 m^3/day (approximately 92,550 GJ/day).

2. The increase in Rate T2 demand payments will accrue entirely to the benefit of ratepayers exposed to the PDO Reduction costs associated with the HHGS M12 turn back so that their exposure to such costs will be eliminated.

   Example

   The incremental T2 revenue of $115,318/month described above would accrue entirely to the benefit of ratepayers exposed to PDO Reduction costs associated with the M12 turn back and effectively eliminate ratepayer responsibility for PDO Reduction costs associated with TCE's M12 turn back of 47,652 GJ/day.

[1] Based on Union's forecasts, of the total of $4.763 million per annum of demand costs plus actual fuel costs to be paid by ratepayers to Union for PDO Reduction, the amount of $4.240 million plus actual fuel costs related to the shortfall amount of 146 TJ/day will be available for use by Union to manage Parkway shortfall between October 1, 2015 and October 31, 2016. Between November 1, 2016 and October 31, 2017,the portion of the total of $4.763 million of demand costs plus actual fuel costs which will be available for use to manage Parkway shortfall will be $3.446M of demand costs plus actual fuel costs related to the shortfall amount of 118 TJ/day.

3. HHGS will have the right to turn back additional M12 capacity as and when that turn back option is made available to DP customers with a PDO obligation greater than 100 GJ/day, as described in B.8 above, provided that HHGS, through TCE, further increases its BCD in the manner described in C.1 above, up to but not exceeding its Rate T2 Contract Demand ("CD") of 132,000 GJ/day.

4. T2 demand revenues associated with increases in BCD from 92,250 GJ/day to 132,000 GJ/day will be applied as described in C.2 above.

5. The application of the demand revenues in the manner described in C.2 and C.4 above will prevail until the end of Union's Incentive Regulation Mechanism ("IRM") term on December 31, 2018 or when the BCD of HHGS, through TCE, has reached 132,000 GJ/day and TCE has turned back all of its M12 capacity, whichever last occurs.

6. On or after November 1, 2018, HHGS will have the option to turn back all or any portion of its remaining M12 capacity and convert an equal amount of the PDO to non-obligated deliveries at Dawn, subject to the BCD modification described in C.1 and C.3 above, <u>or</u> HHGS may convert to standard Rate T2 service, with non-obligated deliveries at Dawn for 100% of the Rate T2 Contract Demand. Under the full conversion option, HHGS will turn back, or allow the term to expire, any remaining Rate M12 capacity and pay Rate T2 demand charges on 100% of the Rate T2 Contract Demand.

7. This proposal is in no way intended to degrade or lessen the quality of the firm services HHGS contracted with Union under the terms and conditions of the existing tariff structure.

8. Once the HHGS Rate T2 BCD equals the Contract Demand of 3,480,000 m^3/d (about 132,000 GJ/day), HHGS will have the option to shorten the T2 contract term to end one year from the date of full Contract Demand conversion as per 3 or 6 above, with one year renewal, provided, however that HHGS will contract for at least 1,374,000 m^3/d (about 52,000 GJ/day) of firm Rate T2 service through July 31, 2029.

9. HHGS, through TCE, will not become entitled to the PDCI with respect to any of its M12 capacity which it refrains from turning back.

Gas Cost Savings for Sales Service Customers
Associated with the 98 TJ/day Reduction for Sales Service PDCI

Line No.	Rate Class	2013 Board Approved Volume (10^3m^3)	Gas Cost Savings ($000's)		Unit Rate ($/m^3$)
		(a)	(b)		(c) = (b/a)
1	Rate M1	2,271,443	3,745		0.001649
2	Rate M2	378,137	623		0.001649
3	Rate M4	16,855	28		0.001649
4	Rate M5	14,132	23		0.001649
5	Rate M10	48	0		0.001649
6	Total	2,680,616	4,420	(1)	0.001649

Notes:
(1) Page 2, Line 15, Column (e)
(2) The payment of the PDCI to sales service customers will be made by way of a credit to the Union South gas supply transportation rate.

Gas Cost Savings for Direct Purchase Customers
Associated with the 268 TJ per Day for the Direct Purchase PDCI

Line No.	Rate Class	Direct Purchase Allocation (GJ)	Gas Cost Savings for DP ($000's)	
		(a)	(b)	
1	Rate M1	19,532	883	
2	Rate M2	17,466	789	
3	Rate M4	22,309	1,008	
4	Rate M5A	26,300	1,189	
5	Rate M7	8,299	375	
6	Rate M9	3,845	174	
7	Rate T1	27,978	1,264	
8	Rate T2	121,230	5,479	
9	Rate T3	20,498	926	
10	Total	267,457	12,087	(1)

Notes:
(1) Page 3, Line 15, Column (e)

UNION GAS LIMITED
Summary of Estimated Delivery Impacts and PDCI to Union South In-Franchise Customers

Line No.	Rate Class ($000's)	Delivery: Allocation of Demand Costs (1)	Delivery: Allocation of Fuel & UFG Costs (2)	Delivery: Total Costs	Sales PDCI (3)	DP PDCI (4)	Net Amount
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f) = (c + d + e)
1	Rate M1	7,808	2,087	9,896	(3,745)	(883)	5,268
2	Rate M2	2,623	739	3,362	(623)	(789)	1,949
3	Rate M4	763	337	1,099	(28)	(1,008)	63
4	Rate M5 Firm	7	9	16	-	-	16
5	Rate M5 Interruptible	-	233	233	(23)	(1,189)	(978)
6	Rate M7 Firm	352	135	487	-	(375)	112
7	Rate M7 Interruptible	-	-	-	-	-	-
8	Rate M9	126	70	195	-	(174)	22
9	Rate M10	4	0	4	(0)	-	4
10	Rate T1 Firm	377	307	684	-	(1,264)	(581)
11	Rate T1 Interruptible	-	33	33	-	-	33
12	Rate T2 Firm	2,445	1,580	4,025	-	(5,479)	(1,454)
13	Rate T2 Interruptible	-	37	37	-	-	37
14	Rate T3	886	312	1,198	-	(926)	272
15	Total	15,391	5,878	21,269	(4,420)	(12,087)	4,763

Notes:
(1) Calculated as the sum of Page 1, Column (f), Page 2, Column (b) and Page 3, Column (b).
(2) Calculated as the sum of Page 2, Column (d) and Page 3, Column (d).
(3) Page 4, Line 6, Column (b).
(4) Page 5, Line 10, Column (b).

Ontario

Ontario Energy Board
Commission de l’énergie de l’Ontario

DECISION AND ORDER

EB-2015-0200

UNION GAS LIMITED

2017 Dawn-Parkway Expansion Project

BEFORE: Emad Elsayed
Presiding Member

Christine Long
Panel Member

Paul Pastirik
Panel Member

December 22, 2015

3 OEB DECISION

The OEB approves the Settlement Proposal based on the following key findings:

- The need for the Project has been demonstrated by Union on the basis of replacing aging infrastructure and meeting the growing demand from shippers on the system.
- The Project meets the OEB's economic tests as outlined in the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications, dated February 21, 2013 and the E.B.O. 134 Report on System Expansion, as applied to Union.
- The resulting short-term and long-term economic impacts on customers are reasonable.
- The Project meets the capital pass-through mechanism criteria established in the EB-2013-0202 proceeding for pre-approval to recover the cost consequences of the Project.

The OEB commends the parties for their efforts in coming to an agreement that the OEB considers to be in the public interest.

Parties have suggested that the OEB consider reviewing the feasibility parameters in the E.B.O. 134 guidelines and the impact on existing ratepayers. The hearing panel in this proceeding notes that this Application considered Union's 2017 Dawn Parkway Expansion Project and the review of the E.B.O. 134 guidelines is outside the scope of this proceeding. The OEB will therefore not make any determination on this request.

The OEB will not approve the 2017 Dawn Parkway System Expansion Deferral Account (179-144) in this proceeding. The accounting order will be reviewed and approved in Union's 2016 IRM Rates proceeding (EB-2015-0116) currently before the OEB.

SCHEDULE B

SETTLEMENT PROPOSAL – NOVEMBER 13, 2015

UNION GAS LIMITED

EB-2015-0200

DECEMBER 22, 2015

The following parties agree with the settlement of this issue:APPrO, BOMA, CME, Energy Probe, FRPO, IESO, IGUA, LPMA, SEC, VECC

The following parties take no position: ANE, Gaz Métro, TransCanada

Evidence References:

1. A/T6 (Updated), A/T10 (Updated)
2. B.APPrO.4, B.SEC.9, B.TCPL.3, B.Energy Probe.5, B.Energy Probe.9, B.BOMA.17

4. **Do the proposed facilities meet the Board's economic tests as outlined in the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications, dated February 21, 2013, as applicable. (E.B.O. 134 and Treatment of Dawn Plant B replacement)**

(Complete Settlement)

Based on the evidence provided by Union, for the purposes of settlement the parties accept that the proposed facilities meet the Board's economic tests as outlined in the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications, dated February 21, 2013, as applied by Union.

As filed at A/T9/p. 2 (Updated), Union employs a three-stage analysis to assess the economic feasibility of projects in accordance with OEB recommendations from the E.B.O. 134 Report on System Expansion. This methodology is consistent with the methodology used in Union's past Dawn Parkway System facilities applications.

The Board's Guidelines note "*These requirements apply to all Ontario Energy Board regulated gas utilities requesting approval to construct new transmission facilities. For purposes of these Guidelines transmission pipelines are defined as any planned or proposed pipeline project that* *would provide transportation services to move natural gas on behalf of other shippers within Ontario. Distribution system expansion pipelines that are subject to the filing guidelines set in EBO 188 would not be subject to the proposed filing requirement."*

As filed at A/T9/p. 3 (Updated), the result of the Stage 1 economics for the proposed facilities at a total estimate capital cost of $622.5 million indicate a cumulative net present value ("NPV") of ($343.1) million and a profitability index ("PI") of 0.43. The E.B.O. 134 recommendations state that this Stage 1 Discounted Cash Flow ("DCF") analysis "*provides a superior measure of the subsidy required from the existing customers for a particular project*" and that Union's three-stage test has considerable merit to aid in determining public interest. A Stage 1 PI of less than 1.0 does not mean the project is not in the public interest. As per Issue 1 above, this project is underpinned by long-term signed contracts. Bill impacts and impacts on rates for in-franchise and ex-franchise customers are addressed under Issue 5. Rate impacts for in-franchise customers are generally decreases while rate impacts for ex-franchise customers are increases.

As filed at A/T9/p. 5 (Updated), a Stage 2 analysis may be undertaken when the Stage 1 NPV is less than zero. Union's Stage 2 analysis considers the estimated energy cost savings that accrue directly to Union's in-franchise general service rate customers as a result of using natural gas instead of another fuel to meet their energy requirements. A Stage 2 analysis was not quantified in this case because the in-franchise use of the 2017 Dawn Parkway Project is based on the New Firm North Transportation Service rather than incremental growth in energy demand using gas instead of alternative energy sources.

Energy cost savings are also available to customers in Ontario that will be served as a result of additional transportation services on Union's Dawn Parkway System. Although these savings are likely to be substantial, they are not estimated for purposes of the Stage 2 analysis, which Union applies only to capture savings from use of gas instead of alternative energy sources. These customers select transportation services on Union's Dawn Parkway System based on their own assessment of the most economical way to meet increases in energy requirements.

Union's Stage 3 analysis considers other quantifiable benefits and costs related to the construction of the Project that are not included in the Stage 2 analysis, along with other non-quantifiable public interest considerations.

As filed at A/T9/Table 9-1/p. 10 (Updated), the result of Union's three-stage economic analysis for the Project is a positive NPV of $123.0 million.

Based on the evidence, and for the purposes of this agreement (but without prejudice to future positions on these issues), the parties accept Union's application of the Board's policy on economic feasibility tests for new gas pipeline transmission projects as first enunciated in the E.B.O. 134 Report and later reiterated by the Board in its Filing Guidelines on the Economic Tests for Transmission Pipeline Applications ("Feasibility Guidelines").

Considering;

i) the passage of time since E.B.O. 134;

ii) the fact that the Feasibility Guidelines clarified filing requirements but did not review, reconsider or clarify the E.B.O. 134 principles or tests themselves;

iii) the rapid evolution of both the market and gas infrastructure; and

iv) the recent context of projects a principal purpose of which is to allow ex-franchise shippers to shift gas supply to eastern North American resources,

a number of the parties believe that a different approach to addressing feasibility and impact on existing ratepayers may be appropriate in future, and that review and clarification by the Board of "feasibility" parameters for future similar expansion projects would be timely. A number of parties further believe that given the accelerating pace of change in the market, future expansion applications should include evidence reflecting consideration and evaluation, including through consultation with the market, open season or by way of RFP, as, when and if appropriate, of the risks and benefits of permanent or interim non-facility alternatives to facility investment. These parties further suggest that, to start with, the topic could be usefully included in the Board's next Energy Sector Forum (as contemplated in the Board's March 31, 2015 Letter to interested parties at the conclusion of the EB-2014-0289 Natural Gas Market Review).

The following parties agree with the settlement of this issue: APPrO, BOMA, CME, Energy Probe, FRPO, IESO, IGUA, LPMA, SEC, VECC

The following parties take no position: ANE, Gaz Métro, TransCanada

Evidence References:

1. A/T9 (Updated)
2. B.Staff.5, B.ANE.3, B.ANE.4, B.ANE.5, B.ANE.6, B.BOMA.14, B.BOMA.15, B.Energy Probe.11, B.Energy Probe.12, B.Energy Probe.13, B.Energy Probe.14, B.LPMA.12, B.LPMA.13, B.VECC.9, B.VECC.10, B.VECC.11

★ IMPORTANT NOTICE: Enbridge Gas Distribution and Union Gas have merged into one company, Enbridge Gas Inc., and we are working to serve our customers better by combining our websites. If you are unsure which website you need, use our postal code lookup tool to get to the right information.

M12 Firm Transportation Open Season

Invitation to Bid

Enbridge Gas Inc. Binding Open Season – Dawn to Parkway M12 Firm Transportation - CLOSED

Enbridge Gas Inc.("**Enbridge Gas**") is holding an open season for firm M12 transportation service ("**Open Season**") for up to 100,000 GJ/day of capacity beginning in 2023 and up to 250,000 GJ/day of capacity beginning in 2024 along the following transportation paths:

(a) Dawn to Parkway;
(b) Dawn to Kirkwall; and
(c) Kirkwall to Parkway.

Dawn to Parkway / Dawn to Kirkwall / Kirkwall to Parkway M12 Firm Transportation Service
Total Capacity Available: up to 100,000 GJ/d starting in 2023 and up to 250,000 GJ/d starting in 2024*
Start Date(s): November 1, 2023 and/or November 1, 2024
Term: Minimum of 15 Years
Receipt Point(s): Dawn or Kirkwall
Delivery Point: Kirkwall or Parkway
Rate: Service in accordance with the OEB - approved Enbridge Gas **M12 Rate Schedule**
Fuel: In accordance with the OEB - approved Enbridge Gas **M12 Rate Schedule**
• **Standard Contract** • **M12 Rate Schedule**

**Total capacity available for M12 firm transportation service combined is up to 100,000 GJ/d in 2023 and up to 250,000 GJ/d in 2024.*

For more information, please download the following:

- M12 Firm Transportation Open Season Package

- M12 Firm Transportation Open Season Bid Form

All bids are due on or before 2 p.m. ET / 1 p.m. CT, on Jan. 15, 2021. Enbridge Gas expects to award capacity on or before 2 p.m. ET / 1 p.m. CT, on Jan. 18, 2021.

Source: https://www.uniongas.com/storage-and-transportation/newsroom/open-seasons/2020/nov-24-2020

From: Liberty, Erin
Sent: May-26-16 12:12 PM
To: Liberty, Erin
Cc: McClacherty, Shawn
Subject: Union Gas Request for Proposals for Firm Ojibway Transportation Capacity

Union Gas Limited ("Union") is inviting your company, along with other suppliers, to submit proposals to provide Union with Long Term Firm Transportation capacity to the Panhandle Pipeline interconnection with Union Gas (Union Ojibway point) starting as early as November 1, 2016. Later start dates and combined Supply and Transportation purchases will also be considered.

Union will entertain capacity offers facilitated via capacity on the Panhandle Pipeline system as well as capacity from customers holding capacity on Union's Ojibway to Dawn transmission system. Bids involving both a Panhandle Pipeline and Union Gas concurrent release will also be entertained.

Please provide details capacity offered including path, quantity, start/end date, receipt and delivery points, secondary points and price. If capacity is contingent upon release of a secondary contract please specify in proposal.

If capacity is to be provided to Union Gas via capacity release the releasing party must provide a copy of the underlying contract to Union Gas prior to Union's acceptance of the proposal. Upon acceptance, the successful bidder will post the pre-arranged biddable release subject to FERC's capacity release posting rules.

Please submit your proposal by responding to this email.

Proposals to be received no later than 1:00 pm Eastern Time May 31st, 2016. Union will confirm receipt of proposal via email. If you do not receive confirmation of receipt from Union Gas prior to the submission please notify Union via contact info below.

The company with the successful proposal will be contacted as soon as possible. The lowest bid price or any proposal will not necessarily be accepted, at Union's sole discretion.

Any questions should be directed to the undersigned.

Sincerely,
UNION GAS LIMITED

Erin Liberty, CPA, CGA
Manager, Transportation Acquisitions
Union Gas Limited | A Spectra Energy Company
50 Keil Drive North | Chatham, ON N7M 5M1
Tel: (519) 436-5314
Email: eliberty@uniongas.com| www.uniongas.com

ENBRIDGE GAS INC.
Answer to Interrogatory from
OEB Staff (STAFF)

Reference:

Exh B/Tab 1/Sch 3

Question(s):

Enbridge Gas assessed the proposed Project to eight other facility alternatives (i.e., additional pipeline/station infrastructure) and two non-facility alternatives (commercial third-party and integrated resource planning options).

a) For each alternative, please provide, as applicable, total estimated pipeline capital costs, total estimated station capital costs; and/or total estimated contract for transportation of supply costs.

b) Please provide the Discounted Cash Flow and Profitability Index for the alternatives that have not been selected.

Response:

a) Total estimated pipeline and station costs for acceptable facility alternatives considered by Enbridge Gas are set out in Table 1.

Table 1
Estimated Capital Cost of Facility Alternatives

Facility Alternative	Facility Detail	Pipeline Cost ($ millions)	Station Cost ($ millions)
Bluewater Interconnect to Churchill Road Station and Sarnia Industrial Station[1]	6 km of NPS 24 with 6620 kPag MOP	60.7	7.3
Great Lakes Courtright to Courtright Line	4.5 km of NPS 24 with 6620 kPag MOP	19.4	23.3
Dawn Hub to Payne Pool Station	21 km of NPS 20 with 6895 kPag MOP	124.6	10.2

[1] At Exhibit B, Tab 1, Schedule 3, p. 6, Enbridge Gas mistakenly described this alternative as involving construction of 24 km of 6620 kPag MOP pipeline. This alternative would involve construction of approximately 6 km of 6620 kPag MOP pipeline. Accordingly, the estimated cost for this alternative set out in Table 1 reflects construction of 6 km of 6620 kPag MOP pipeline.

In its application and pre-filed evidence, at Exhibit B, Tab 1, Schedule 3, pp. 7-8, Enbridge Gas explains that replacing existing pipelines between the Bluewater Interconnect and Churchill Road Station (with 3.5 km of 6620 kPag NPS 24 pipeline) and between the Bluewater Interconnect and the Sarnia Industrial Station (with 2.5 km of 6620 kPag NPS 24 pipeline) are not acceptable facility alternatives to the proposed Project. Both of these existing pipelines run on easement directly through the Aamjiwnaang First Nation Reserve lands and Enbridge Gas would require a new easement and temporary land use to construct a new pipeline. Enbridge Gas initiated discussions with Aamjiwnaang First Nation and respects their decision to not provide Enbridge Gas a new easement through their lands. As a result,and considering that both alternatives would also require construction of a larger diameter pipeline at more than double the distance compared to the proposed Project, Enbridge Gas eliminated these alternatives early in its assessment and did not complete formal cost estimates.

Similarly, construction of a new Compressor Plant, new Liquified Natural Gas Plant and new Compressed Natural Gas facilities were all eliminated by Enbridge Gas early in its assessment of facility alternatives due to unacceptable technical and operational conditions these alternatives produce. For additional acceptability thoroughness, desktop estimates were completed for these alternatives.[2] Further, as explained at Exhibit B, Tab 1, Schedule 3, pp. 9-10, Enbridge Gas noted the following attributes of each alternative that justified their respective elimination:

New Compressor Plant

- Would strand volumes of gas supply flowing on DTE and BGS during the winter operating season due to pressure differentials.
- Could not be constructed in time for November 2021 in-service.
- Would require Loss of Critical Unit (“LCU”) coverage through spare compression capacity to ensure reliability to serve firm customer demands in the event of an unplanned compressor outage.

New Liquefied Natural Gas Plant

- Due to the process-oriented nature of Sarnia market demand, as detailed at Exhibit B, Tab 1, Schedule 2, Enbridge Gas anticipates it would be problematic to fill an LNG facility and serve customers at the same time. LNG tanks have a finite storage capacity and are typically sized to serve a very limited number of days per year, due in-part to their required operational cycle of fill-empty-refill.

[2] Conceptual estimating was used for tie-in costs (i.e. no site drawings) and the estimates would not include the costs of unforeseen site conditions (e.g. hazardous waste, major archeological, abandonment).

Typically, LNG facilities are filled during the summer months when demand is low. This situation does not exist in the Sarnia market as the process-oriented customer demand is continuous throughout the year. Therefore, an LNG facility cannot be relied upon to provide continuous and reliable supply of natural gas on a firm daily basis every day as required.
- Could not be constructed in time for November 2021 in-service.
- As set out at Exhibit B, Tab 1, Schedule 3, p. 9, based on previous high-level cost estimates, Enbridge Gas anticipates that the capital cost to construct an LNG facility to serve NOVA demand would be more than the cost of the proposed Project and annual operating costs for such a facility would be greater than the incremental operating costs of the proposed Project.

New Compressed Natural Gas Facilities
- Due to the process-oriented nature of Sarnia market demand, as detailed at Exhibit B, Tab 1, Schedule 2, Enbridge Gas anticipates it would be problematic to rely upon CNG facilities due to their traditional function of serving winter peaking demands for a very limited number of days per year, as opposed to NOVA's requirement of continuous and reliable supply of natural gas on a firm daily basis.
- May not be possible to construct in time for November 2021 in-service.
- As set out at Exhibit B, Tab 1, Schedule 3, p. 10, based on previous high-level cost estimates, Enbridge Gas anticipates that the capital cost to construct a CNG facility and to acquire necessary trucks and trailers to serve NOVA demand would be more than the cost of the proposed Project and annual operating costs associated with such a facility would be greater than the incremental operating costs of the proposed Project.

Enbridge Gas eliminated IRP/DSM alternatives early in its assessment of alternatives. Please see the response at Exhibit I.STAFF.4, for explanation of Enbridge Gas's assessment of the potential for IRP/DSM alternatives to reduce SIL system demand sufficiently to defer the need for the proposed Project by the projected November 2021 in-service date.

Finally, as explained in its application and pre-filed evidence at Exhibit B, Tab 1, Schedule 3, p. 10, Enbridge Gas eliminated gas supply delivered at the Bluewater Interconnect early in its assessment of alternatives as BGS does not offer a firm transportation service to the Sarnia market from interconnected pipelines. Enbridge Gas cannot rely upon an interruptible transportation (wheeling) service to provide continuous and reliable supply of natural gas on a firm daily basis to the SIL system.

b) Discounted Cash Flow ("DCF") and Profitability Index ("PI") for acceptable facility alternatives considered by Enbridge Gas are set out in Table 2.

Table 2
DCF and PI of Facility Alternatives

Facility Alternative	**Discounted Cash Flow ($ millions)**	**Profitability Index**
Bluewater Interconnect to Churchill Road Station and Sarnia Industrial Station	(24.2)	0.6
Great Lakes Courtright to Courtright Line	(3.9)	0.9
Dawn Hub to Payne Pool Station	(70.5)	0.4

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

We are also interested in EGI's use of peaking service as a Non-Facility, Supply-Side solution. We define a peaking service as a utility contracts with a counter-party for a certain quantity of gas to be delivered to a specific location up to a certain number of days in a certain period by paying a demand charge upfront for the right to call on that gas to be delivered with a specific amount of due notice.

Question:

Was an RFP performed for peaking service in any of the prior 5 years?

Response

Enbridge Gas has not performed an RFP for peaking services to support transmission system capacity in the last 5 years. Please see the response at Exhibit.I.STAFF.16 for further discussion of commercial alternatives.

Table 8 – Enbridge CDA Design Day Supply/Demand Balance

Line No.	Particulars (TJ)	2020	2021	2022	2023	2024
	Design Day Demand					
1	Gross Design Day Demand	3,414	3,426	3,439	3,451	3,463
2	Curtaliment	(79)	(79)	(79)	(79)	(79)
3	Net CDA Design Day Demand	3,335	3,347	3,360	3,372	3,384
	CDA Design Day Supply Assets					
4	In-Franchise Supply	88	88	88	88	88
5	Third-Party Services	40	-	-	-	-
6	TCPL Long Haul	5	5	5	5	5
7	TCPL Short Haul	668	668	768	768	768
8	TCPL STS	284	284	284	284	284
9	EGI D-P	2,194	2,194	2,194	2,194	2,194
10	CDA Design Day Supply Assets	3,279	3,239	3,339	3,339	3,339
11	**CDA Design Day Supply Assets Surplus/(Shortfall)**	**(56)**	**(108)**	**(21)**	**(33)**	**(45)**
12	*Shortfall % of Net Design Day Demand*	*2.9%*	*3.2%*	*0.6%*	*1.0%*	*1.3%*

Supply Options

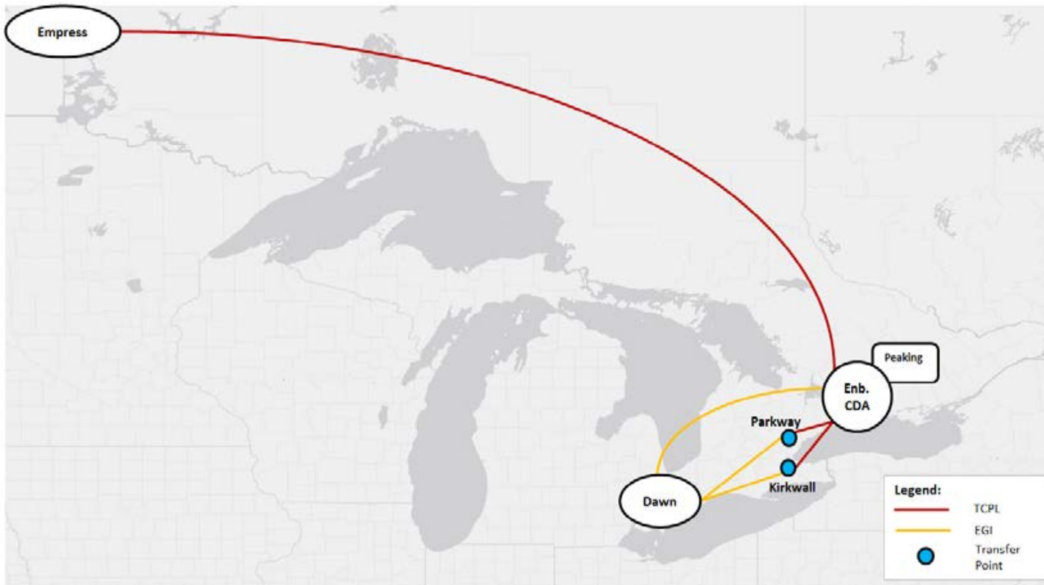
Table 9 below lists service and asset options which are expected to be available to EGI[25], at various times during the five years, to meet the Enbridge CDA design day gas supply asset shortfalls projected. Figure 22 provides a representative map of the paths described in the options.

Table 9 – Enbridge CDA Design Day Asset Shortfall Supply Options

Option	Option Details				
	Provider(s)	**Service**	**Receipt Point**	**Transfer Point**	**Delivery Point**
Peaking	Market Participants	Peaking	Enb. CDA	-	Enb. CDA
Long Haul	TCPL	FT-LH	Empress	-	Enb. CDA
Dawn Parkway	EGI	D-P	Dawn	-	Enb. CDA
Short Haul-Parkway	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	Enb. CDA
Short Haul-Kirkwall	EGI + TCPL	D-P + FT-SH	Dawn	Kirkwall	Enb. CDA

[25] 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 temporary phenomenon. One example of an option not listed is FT from Niagara. This option is not included in the analysis because a design day event is short-term and temporary and Niagara supply is procured with a minimum term of one month (i.e. poor flexibility). In the future should FT from Niagara become more flexible then it will be included.

Figure 22 - Enbridge CDA Design Day Asset Shortfall 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 6. Table 10 below summarizes the analysis.

Table 10 – Enbridge CDA Design Day Asset Shortfall Options: Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($M/yr)	Average Cost/Customer Impact[26]
Peaking	→	↓	↑	1.7	< 1%
Long Haul	↑	↑	→	34.5	1-2%
Dawn Parkway	↑	→	→	2.8	< 1%
Short Haul-Parkway	↑	→	→	6.0	< 1%
Short Haul-Kirkwall	↑	→	→	6.0	< 1%

For reference, the symbols in Table 10 describe whether or not 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.

[26]Average cost per customer impact is for typical residential sales service customers consuming 2,400 m^3 annually. Estimated costs are derived based on sales service volumes for the EGD rate zone for the respective period. The impact for T-Service customers varies from sales service customers as they procure their own supply.

Preferred Planning Strategy

EGI's preferred planning strategy to eliminate the design day asset shortfall is to procure a peaking service for each year over the five year period.

In terms of costs, peaking is the lowest cost option at a total expected average annual cost of $1.7M, which is $1.1M/year less than the next lowest cost option. As such selection of peaking supports the Board's guiding principle of cost-effectiveness.

Peaking is a somewhat reliable option, albeit not the most reliable available. However, EGI's RFP process for procuring peaking stipulates the need to demonstrate that the service is underpinned by firm transportation, which limits reliability risks. Furthermore, there is no recent history of contracted peaking supplies failing to be delivered to the distribution system. Should peaking supply fail to be delivered, EGI's risk mitigation strategy is to utilize the parameters of its existing firm transportation contracts; namely limited balancing agreement. This approach, inclusive of a risk mitigation strategy, is consistent with the Board's guiding principle of ensuring reliability and security of supply.

In considering the flexibility of peaking supply there are positives and negatives. On the one hand, peaking supply is readily available in the market, does not require construction of new facilities, can be called on with short notice and can be adjusted on a daily basis. On the other hand, peaking supply does not have discretionary service attributes (e.g. interruptible diversion rights). This restraint is of limited concern in this instance given the peaking supply is only being procured for use in the Enbridge CDA during a design day. Peaking supply also only has one nomination window, meaning that it cannot be used to balance intra-day demand changes. However this too is of limited concern since EGI holds sufficient transportation assets to balance daily fluctuations. Finally, the peaking supply lacks renewal rights. Having renewal rights is desirable since it guarantees the utility the option to re-contract for an asset.

The use of peaking supply has marginal implications for the Plan's diversity and can provide additional diversity in terms of counterparties, term of the service, and pricing.

Overall, peaking supply is the lowest cost option, has limited reliability concerns for the design day plan, is readily available in the market on short notice, and has some marginal benefits to overall portfolio diversity. EGI's preferred planning strategy to eliminate design day asset shortfall will be to procure peaking supply in the Enbridge CDA for each year of the five year period. This approach appropriately balances the Board's guiding principles, ensuring cost-effective, reliable and secure supply for EGD rate zone customers.

Enbridge EDA

As it does for the Enbridge CDA, each year EGI conducts a design day supply/demand balance analysis for the Enbridge EDA (Table 11) where projected design day demand is compared against contracted assets serving the Enbridge EDA.

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

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Enbridge Gas Inc. for an order or orders granting leave to construct a natural gas pipeline and ancillary facilities in the Township of North Dumfries.

APPLICATION

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

2. Enbridge Gas is seeking approval of the Ontario Energy Board ("Board") to relocate approximately 2 kilometers of NPS 26 hydrocarbon natural gas pipeline in the Township of North Dumfries within the Regional Municipality of Waterloo ("Project"). This relocation is required in order for Enbridge Gas to comply with the class designation requirements of Canadian Standards Association Code Z662 ("CSA Z662") because surrounding land use has changed the pipe's class location designation from 1 to 3.

3. The Project is a like-for-like replacement and although additional lands will be required for the Project, the landowners granting such additional lands by way of private easement are the same landowners that granted the current private easements for the existing hydrocarbon pipeline being removed and relocated. As a result, no new landowners will be directly affected by the Project or this application.

4. Attached to this application is a map showing the general location of the Project and the municipalities, and roads through, under, over, upon or across which the proposed pipeline will pass.

5. This application is also supported by written evidence. This evidence is pre-filed and will be amended from time to time as required by the Board, or as circumstances may require.

6. Enbridge Gas hereby applies to the Board pursuant to the *Ontario Energy Board Act* ("Act") for an order or orders granting:

<u>Timing</u>

11. The proposed construction schedule will span one construction season. If the Project is approved, Enbridge Gas would install the new pipeline between April and November 2021, with an in-service date of November 2021.

<u>Alternatives</u>

12. Enbridge Gas considered two other alternatives (1) increasing the size of this section of pipe, and (2) leaving the pipeline in the existing easement. The first option was not selected as increasing the size on such a relatively short length of pipe would not provide an increase in capacity. Also, launcher and receiver facilities for pigging this section of pipe would be required to complete integrity inspections. The second option was not selected because it would leave the pipeline in close proximity to future development. Enbridge did not consider any other route as North of the existing pipeline is a residential area. Based upon this analysis as well as the views of the affected landowners, Enbridge has proposed the design as detailed in this application.

ENBRIDGE GAS INC.

Undertaking Response to FRPO

To provide details of the steps or the activities within the four-year timeline that it will take Enbridge to design, plan, seek OEB approval for, and construct an LTC facilities project.

Response:

In its response to interrogatories at Exhibit I. FRPO.17, the Company stated

> "…based on Enbridge Gas' current estimates of scheduling, the Company would require a minimum term of approximately 4 years to design, plan, seek OEB approval for and to construct."

This approximate timeline can vary, depending on the nature of specific projects and upon a variety of external factors at the time (e.g. environmental, regulatory etc…).

If a facility alternative is determined to be the preferred solution, the timelines associated with the activities set out in Table 1 will determine the amount of time required to design, plan, seek OEB approval for and to construct the project.

Table 1

Activity	**Approximate Duration**
Detailed design and engineering	3-6 months
Environmental assessment and archaeological studies	9-12 months
Regulatory leave to construct process	9-12 months
Stakeholder consultation and land acquisition (including expropriation)	Ongoing from EA 9-12 months *(expropriation)*
Permit application process	Ongoing from LTC filing
Prime contractor bid process and award contract	Ongoing throughout
Long lead time material order and procurement process	Ongoing throughout
Construction	6-9 months
Commissioning	1-2 months

While certain of these activities can partially overlap (occur in parallel to an extent), each activity is somewhat unique for each project and the completion of these activities has historically taken approximately 4 years to complete.