Adam Stiers
Technical Manager
Regulatory Applications
Regulatory Affairs

Tel: (519) 436-4558
Email: astiers@uniongas.com
EGIRegulatoryProceedings@enbridge.com

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

February 2, 2021

BY RESS AND EMAIL

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

Dear Ms. Long:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board File No.: EB-2020-0091
Integrated Resource Planning Proposal
Interrogatory Responses

In accordance with Procedural Order No. 7, enclosed please find interrogatory responses from Enbridge Gas in the above noted proceeding.

Request for Confidential Treatment

In accordance with the OEB's revised Practice Direction on Confidential Filings effective October 28, 2016, all personal information as well as the hourly rates have been redacted from the following exhibit:

- Exhibit I.PP.4_Attachment 1

Enbridge Gas requests confidential treatment of the information which has been redacted for the following reasons:

- Many of the redactions relate to the names and personal information of third-parties and in some instances Enbridge Gas staff. This information should not be disclosed in accordance with the Freedom of Information and Protection of Privacy Act. As well, such information is not relevant for the purposes of this Application. Enbridge Gas notes that pursuant to the Boards Practice Direction on Confidential Filings ("Practice Direction") at section 4.3, such information should not be provided to parties to a proceeding.

- Enbridge Gas has further redacted the unit rates proposed by the consultants in their proposals to the Company. Such information is commercially sensitive and, if disclosed, would be prejudicial to the Company negotiating future contracts with competitors to the consultants as it would give the competitors knowledge about rates which the Company has accepted in the past. Enbridge Gas further submits that such information is not relevant for the purposes of this IRP Framework application.

The above request for confidential treatment is made pursuant to the Board's Rules of Practice and Procedure and the Practice Direction.

An unredacted version of the confidential Attachment will be filed separately with the OEB.

If you have any questions, please contact the undersigned.

Sincerely,

(Original Digitally Signed)

Adam Stiers
Technical Manager, Regulatory Applications

cc.: D. Stevens (Aird & Berlis)
M. Parkes (OEB Staff)
M. Millar (OEB Counsel)
EB-2020-0091 (Intervenors)

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit A, Tab 13 / p. 10 of 24; Exhibit B / p. 18 of 46

Preamble:

Enbridge Gas proposes a goal of IRP in its initial application as "aimed at reviewing and implementing alternatives that reduce natural gas in-franchise peak period demand growth", and in its additional evidence as "a planning strategy underpinned by the Guiding Principles to consider facility and non-facility alternatives in tandem which address long-term system constraints/needs such that an optimized and economic solution is proposed to meet the identified constraint or need."

Question:

a) Does Enbridge Gas's original proposal that consideration of IRPAs would be limited to facility expansion/reinforcement projects and focused on reducing natural gas in-franchise peak period demand growth still apply?

Response

Enbridge Gas expects that, based on its original IRP Proposal, Additional Evidence and Reply Evidence, the nature of the majority of identified system constraints for which IRPA Screening determines that an IRPA may be feasible/viable would be classified as reinforcement projects. In such instances, reduction of natural gas in-franchise peak period demand growth will be most impactful.

Given the nascent nature of natural gas IRP across North America it should not be surprising that Enbridge Gas's definition of natural gas IRP has evolved since it filed its original IRP Proposal in 2019 to reflect: (i) its learnings from IRP processes and strategy in other North American jurisdictions; (ii) the scope of IRP to be considered by the Board as part of this proceeding as established by the Board in its Decision on Issues List and Procedural Order No. 2 (dated July 15, 2020); and (iii) continued development of IRP-related perspectives and processes within the Company. Enbridge Gas reiterates that its proposal to establish an IRP Framework which is informed by the Guiding Principles set out in its Additional Evidence at Exhibit B, Section 2.0, pages 12 to 13, is the best path forward as it would also enable the Company to evaluate and consider IRPAs to resolve identified system constraints more broadly (not solely for those for which comparable facility alternatives would be classified as reinforcement projects).

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.

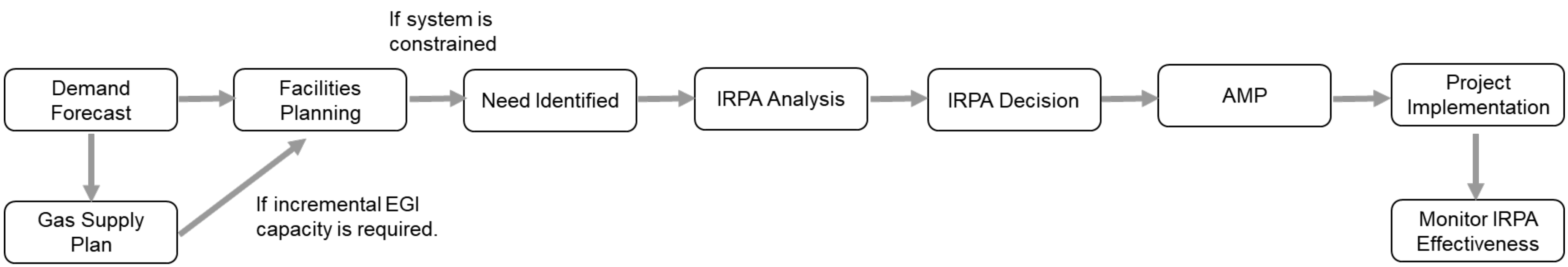
Whereas the Asset Management Plan and the development of specific IRPA(s) or facility alternatives are done at a local facility level, Enbridge Gas's Gas Supply Plan is created at the Delivery Area level (Union South, Union North DDAs, and the Enbridge CDA and EDA) based on forecasted peak day demands 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.

Details of the mainline compressor stations are shown below:

COMPRESSOR STATION	KILOMETER POST	UNIT	ISO RATING (MW)
Lobo	73	A1	16.5
		A2	15.3
		B	26.1
		C	33.2
		D	33.2
		TOTAL	**124.3**
Bright	141	A1	28.0
		A2	28.0
		B	26.1
		C	33.2
		TOTAL	**115.3**
Parkway	229	A1	16.5
		B	32.9
		C	33.2
		D	33.2
		TOTAL	**115.8**

Notes:

- *Kilometer post denotes the distance from Dawn to the specific delivery location in kilometers*
- *ISO (International Standards Organization) rating refers to available power of a unit at specific standard conditions (an intake air temperature of 15 ℃, barometric pressure of 101.325 kPa and no inlet or outlet losses). These ratings are provided by the Original Equipment Manufacturer.*

The compressor stations at Dawn, Lobo, Bright and Parkway have Loss of Critical Unit (LCU) coverage. Please see section 4.3 for additional information.

2.4. SUPPLY AND DELIVERY LOCATIONS

There are specific delivery locations along the system between Dawn and Lisgar which are connected to downstream Enbridge Gas distribution systems in Union South and EGD Rate Zones[3] or ex-franchise customers' pipeline systems. At these locations gas is delivered to Enbridge Gas's in-franchise and ex-

[3] *Other Enbridge Gas departments including Pipeline Engineering and Plant Accounting have different definitions of what is considered a distribution pipeline. In this document the distribution systems or pipelines refer to the systems planned and modelled by the Network Analysis Department and fed from the Transmission systems as modelled by the Transmission Optimization & Engineering Department.*

franchise (M12) customers. The following table summarizes the delivery locations, distance from Dawn and the in-franchise area or ex-franchise customer supplied for each location.

LATERAL	KILOMETER POST	AREA / SYSTEM SERVED
Forest	44.01	Forest, Thedford, Parkhill
Strathroy	54.93	Strathroy
London West / Byron	73.05	London, St Thomas
Hensall	85.74	London, Lucan, Exeter, Hensall
London North	90.35	London
St Mary's	103.93	St Mary's
Stratford	121.45	Stratford, Mitchell, Wingham, Goderich
Beachville	121.45	Ingersoll, Woodstock, Tillsonburg
Oxford	142.92	Woodstock, Paris
Owen Sound	159.39	Waterloo, Kitchener, Owen Sound
Cambridge	175.14	Cambridge
Brantford	175.14	Brantford
Guelph	183.67	Guelph
Kirkwall	188.67	Niagara (Enbridge CDA), M12 (TC Energy and others)
Kirkwall Dominion	188.67	Caledonia, Hagersville, Nanticoke
Hamilton 3	188.67	Hamilton, Stoney Creek
Hamilton 1 & 2	199.25	Hamilton, Burlington
Milton	218.09	Milton, Burlington
Halton Hills	221.61	Halton Hills, Milton
Burlington Oakville	228.94	Burlington, Oakville
Greenbelt	228.94	Georgetown, Acton, Oakville
Parkway Cons / Lisgar	228.94	Toronto GTA (Enbridge CDA)
Parkway Discharge	228.94	Union North (Union NDA/EDA), GTA West & Niagara and GTA EAST (Enbridge CDA), and M12 (TC Energy & others)
Albion	255.94	Toronto GTA (Enbridge CDA)

Note: Kilometer post denotes the distance from Dawn to the specific delivery location in kilometers.

The Dawn Compressor Station is the main source of supply to the Dawn Parkway system. Supply is also received at Parkway and Kirkwall, which reduces the need for Dawn supply. There is also a small amount of storage and production gas which feeds into the system.

3. Forecast of Design Day Demand

Enbridge Gas has a requirement to provide safe and reliable service to its customers on a very cold day called the Design Day. The Design Day demand is the firm volumetric amount of natural gas that is consumed by the in-franchise and ex-franchise customers on the Design Day.

The majority of the customers, both in-franchise and ex-franchise, served by the transmission systems are heat sensitive and their maximum demands occur during a very cold winter day. Enbridge Gas plans its facilities to meet the demands on this very cold day, defined to be the Design Day.

Calculating the Design Day demand requires customer consumption and weather history.

3.1. WEATHER CONDITION

The Design Day weather condition for the Union South Rate Zone is 43.1 Degree Days (43.1 DD), which represents an average daily temperature of -25.1 degrees centigrade. This temperature is the coldest historical based upon the weather data for the London Airport which consists of recorded temperature and wind speeds from 1953 to current. From this data, Enbridge Gas has found the likelihood of a 43.1 DD occurring over the course of a winter is a reasonable assumption, with the highest probability of occurrence in mid-January to mid-February. Using the 43.1DD ensures Enbridge Gas's Union South Rate Zone customers can continue to be safely and reliably served during the coldest winters.

The Union North and EGD Rate Zones can be reliably served based on the Degree Days selected for those regions. For additional information regarding Degree Day values for Union North and EGD Rate Zones, refer to EB-2019-0137 Enbridge Gas Inc. – 5 Year Gas Supply Plan on pages 34-35 and 74-75.

3.2. DESIGN DAY DEMAND

The Design Day demand is defined as the amount of firm demand that Enbridge Gas is committed to supply through its systems on a Design Day. The total Design Day demands for the transmission systems are the sum of the firm demands of Enbridge Gas's in-franchise customers connected to the transmission systems in the Union South Rate Zone, plus the demands transported to serve the EGD and Union North Rate Zones, as well as any firm easterly ex-franchise Dawn Parkway system customer demands. Interruptible demand is curtailed on Design Day. Ex-franchise demand flowing counter to the flow direction of the transmission systems are not included for Design Day analysis.

3.2.1. In-franchise Demand (Union South) – Transmission System

Union South Rate Zone in-franchise customers are served by laterals connected to and located along the transmission systems.

Enbridge Gas has a process to develop the Design Day demand which provides a reliable, repeatable and predictable way to generate base customer consumption for the transmission system. Once the demand has been determined it is assigned to the customer location. The base demand is calculated once the winter heating season is completed at the end of March. Corporate forecasts are added to the base demands to predict future customer consumption.

The transmission system in-franchise Design Day demand for Union South Rate Zone is the sum of the Design Day general service demand plus the Design Day demand of the firm contract customers. All interruptible in-franchise contract customers are curtailed for the Design Day condition and not included in the Design Day demand.

Schedule 2 outlines the process that Enbridge Gas uses to develop the Transmission Load Forecast for Design Day demand for its Union South Rate Zone in-franchise customers.

3.2.1.1. General Service

Enbridge Gas develops its base year general service Design Day demands from a regression analysis of actual daily measured demands and degree days from the previous winter season. These regression analyses are segmented based on geography and downstream distribution systems.

Based on further analysis of the general service customer's demands, Enbridge Gas has found a gradual downward trend in the Design Day use per general service customer. A regression line has been calculated from this data and the base year Design Day demands are adjusted to fit the line.

Growth rates for the general service customers are developed by the Distribution Optimization & Engineering department to account for the forecast addition of new customers, as part of their Facilities Business Plans. General Service volumes are analyzed by operating region over a 20-year period, identifying when and where system load is increasing. The growth rates are applied to the base year Design Day demands for each lateral.

3.2.1.2. Contract Rate

Enbridge Gas develops its base year contract rate Design Day demands from a regression analysis of actual daily measured demands and degree days from the previous season and daily contracted demand. These regression analyses are segmented based on rate class, heat sensitivity, geography and downstream distribution systems. Contract rate customer contracted demands (CD) are used to guide the selection of appropriate design volumes for these customers.

Growth rates for the contract rate customers are developed by the Utility Revenue department to account for the addition of new customers and changes to the requirements of existing customers. The growth rates are customer specific and assigned to specific customer locations on the transmission systems.

3.2.2. In-franchise Demand (Union North)

Enbridge's Gas Supply Plan determines the Design Day transportation requirement on the Dawn Parkway system for Union North Rate Zone in-franchise customers. The design day demands are calculated using a similar process to the Union South Rate Zone and is described in EB-2019-0137 Enbridge Gas Inc. – 5 Year Gas Supply Plan.

3.2.3. In-franchise Demand (EGD)

Enbridge's Gas Supply Plan determines the Design Day transportation requirement on the Dawn Parkway system for EGD Rate Zone in-franchise customers. Legacy Enbridge contracted for Dawn Parkway system transportation through M12 contracting services and the volume equivalent of these contracts is being transported for EGD Rate Zone customers on Design Day. The design day demands for EGD rate zone is described in EB-2019-0137 Enbridge Gas Inc. – 5 Year Gas Supply Plan.

3.2.4. Ex-franchise Design Day Demand

The ex-franchise customers also have a Design Day demand. This group of customers has made a conscious decision to contract for a specific level of transportation service on Enbridge Gas's Dawn-Parkway system. Enbridge Gas has the contractual commitment and the customer has the contractual right to full contract demand on any day, including the Design Day. As a result, Enbridge Gas considers the Design Day demands for these customers to be equivalent to their full contact demand. Only easterly flowing contracts are considered for Design Day purposes as counter-flow (westerly) contracts are not guaranteed to flow on Design Day.

Enbridge Gas may require facilities to accommodate customer required counter-flow contracts to deliver their supply from the receipt point to Dawn during all times of the year.

Growth forecasts for ex-franchise customers are provided by the Business Development Department and are customer and path specific (for example: Dawn to Kirkwall, Dawn to Parkway and Kirkwall to Parkway).

3.2.5. System Supply

The main source of supply to all of Enbridge Gas's in-franchise and ex-franchise customer demand is Dawn Hub ("Dawn"). Dawn is a world class natural gas trading hub and the largest underground storage facility in Canada with 281 Bcfd of high deliverability storage. Multiple pipelines converge at Dawn from all the major gas producing regions in North America.

At Dawn, near Sarnia, the Dawn Parkway System connects to a number of pipelines, including: Vector, Panhandle Eastern via the Enbridge Gas Panhandle system, the TC Energy Great Lakes Gas Transmission Pipeline ("GLGT"), DTE (formerly Michigan Consolidated), Bluewater Gas Storage and ANR via Niagara Gas Transmission (Niagara Link).

Enbridge Gas can also receive gas into the Dawn to Parkway system from third party pipeline systems at Kirkwall, Parkway, Enbridge Gas Inc. (EGI") storage facilities directly connected to its transmission systems, and local producers.

At Kirkwall, Near Hamilton, the Dawn Parkway System connects to the TC Energy Canadian Mainline ("TC Energy Mainline") at Enbridge Gas's Kirkwall Custody Transfer Station ("Kirkwall"). This portion of the TC Energy Mainline, known as the Niagara Export Line, connects to the import/export points at Niagara and Chippewa at the Ontario/New York border.

At Parkway, the Dawn Parkway System connects to the TC Energy Mainline, at the Parkway compressor site at a delivery point referred to as Parkway (TCPL).[4]

Location of these supplies in relation to the transmission system and customers can increase the system capacity.

Enbridge Gas's system supply is described in EB-2019-0137 Enbridge Gas Inc. – 5 Year Gas Supply Plan.

[4] The TC Energy Domestic Line runs between Niagara interconnect point at Parkway (TC Energy). This pipeline can also be used to supply gas into the EGD and Union South Rate Zones.

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.

The hourly demand profiles are developed from historical gate station data. The transient or Unsteady State modeling technique used by Enbridge Gas allows simulate the ability of the pipeline system to serve the average daily demand at the critical morning uplift period which peaks around 8 am and other critical time periods as required. Transient modelling typically reduces transmission pipeline facility requirements. A sample hourly demand profile is shown in Schedule 3.

4. System Operating Criteria

The transmission systems have several operating criteria which ensures the system can operate within its constraints. The primary requirements are that the system:

- Cannot operate above its maximum operating pressure
- Must operate above minimum contractual delivery pressures
- Must operate above minimum suction pressure at the compressor stations
- Must operate within flow and pressure constraints at meter and regulating stations
- The required supply and pressure is available from Dawn and other supply sources

4.1. MAXIMUM OPERATING PRESSURE

The Maximum Operating Pressure (MOP) of the Dawn-Parkway system is 6160 kPag between Dawn and Parkway. The MOP of the NPS 42 GTA pipeline between Parkway and Albion is 6450 kPag.

4.2. MINIMUM SYSTEM PRESSURES

During analysis, it is necessary to ensure that inlet pressures to regulation and meter stations and delivery pressures to in-franchise and ex-franchise customers remain at or above the contractual guaranteed minimum pressure. Pressure must also be maintained above the minimum suction pressures at Enbridge Gas's compressor stations.

- The contractual minimum delivery pressure at Kirkwall is 4,480 kPag
- The contractual minimum delivery pressure at Parkway-Compressed (TC Energy) and Parkway-Compressed (EGT) is 6,450 kPag
- The minimum operating pressure on the Dawn Parkway system is 3450 kPag to EGD Rate Zone at Parkway-Uncompressed (Consumers 1, Consumers 2, and Lisgar stations)
- The minimum suction pressure for Dawn Parkway System compressor units is 3,450 kPag
- The required outlet pressure to Albion is maintained

4.3. LOSS OF CRITICAL UNIT (LCU) COVERAGE

Loss of critical unit coverage is included in the Design Day analysis to ensure all firm Design Day demands are served in the event of an unplanned compressor outage of the critical compressor unit at either the Lobo or Bright compressor stations. There is full LCU coverage for the Parkway and Dawn compressor stations.

The critical compressor unit is defined as the compressor unit that creates the greatest loss of system capability if it fails.

Long term compressor unit outages are evaluated to establish the critical unit outage. A Long-Term Outage (LTO) analysis considers the largest compressor unit at either Lobo or Bright is not available for the entire day. This type of outage would occur if the unit had failed and was the unable to be repaired prior to the Design Day occurrence. Additional information regarding LCU is provided in Schedule 4.

Compressor stations without LCU coverage cannot be used to provide firm level of service to in-franchise customers.

5. System Capacity

With the demands, supplies and operating criteria set, system modeling takes place to determine if the existing facilities have enough capacity to serve the demands on Design Day.

The simulation function is preformed after the forecast Design Day demands and hourly profiles have been developed and are loaded into the model simulation software. Updates to supply, compressor behavior and new facilities are included in the analysis. System flow and pressures are assessed to ensure that all guaranteed minimum delivery pressures to customers can be maintained and all stations are operating within their design parameters. Locations that are approaching minimum system pressures are identified and reinforcement plans are created. Additional information on the simulation software is found in Schedule 5.

On a regular basis the pressure and flow information are compared to actual field data recordings and the model is adjusted to match field conditions. This verified model becomes the piping system of record that is used for all subsequent piping system analysis.

6. Selection of Future Facilities

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.

The selection of future facilities is completed by reviewing the current and forecasted future state of the system. Options are then considered for facility or non-facility growth which will meet both the short-term and long-term requirements of the system at the lowest cost. Consideration of new facilities will include system reliability and security of supply concerns. If the system review is being performed for expansion purposes, the options are considered based on lowest “cost per throughput”.

For the first year in the Schedule of Facilities, only facility alternatives that can be constructed to meet the required in service date are examined. The capacity provided by each alternative along with the capital costs are used to complete an initial ranking based on 'cost per unit of throughput'. Next, an economic evaluation is prepared for the viable facility alternatives. This economic evaluation is extended to include the available non-facility alternatives, such as Winter Peaking Service. The alternative having the highest economic benefit is selected.

Facilities needs for subsequent years are determined in a chronological sequence. For each year the facility alternatives remaining are reviewed and ranked based on 'cost per unit throughput'. The highest-ranking alternative will be the proposed facility addition for that year.

In a situation where more than one viable alternative ties for the highest rank, multiple facilities schedules will be developed, using each of the alternatives as a base. In this case, the multi-year schedule of facilities will be ranked, with the multi-year alternative with the lowest overall cost per unit throughput chosen as the proposed facility schedule.

The asset management plan provides a magnitude level estimate of future pipeline or compression facilities and does not include any non-facility alternatives or detailed economics for alternative comparisons. In the event the 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.

6.1. SCHEDULE/FACILITY CHANGES

The schedule of facilities may change over time due to the uncertainty in the timing, volume and delivery location of the forecasted demands and supplies. As these parameters change over time, they may a change the schedule of facilities.

Specific examples of factors that may change the schedule of facilities are:

- Changes in Design Day demand
    - Decreased demand - a customer may choose not to renew their contracted demand. This could also occur during Reverse Open Seasons.
    - Increased demand – an unexpected increase in customer demand may occur.
    - Location of demand - a customer may decide to change the location of their demand. For example, an ex-franchise customer may want their demand delivered to Parkway instead of Kirkwall.
    - Introduction of new services – The creation of services that allow for multiple receipt and delivery points (i.e. M12X) or different paths (Kirkwall to Parkway) may affect the capacity of the system.
    - Timing of demand - a customer may decide to delay or accelerate the addition of demand. For instance, the conversion of power generation facilities to natural gas is dependent on government approvals.
- Changes in Supply
    - Obligated Delivery at Parkway may decrease if direct purchase customers change their firm supply level to reflect their current plant operations.
    - Enbridge's Gas Supply Plan may change volume and delivery location depending on gas price, transportation costs and new sources of supply.

The changes above cause shifts in the total system capacity with various facility alternatives. These shifts can change the relative cost effectiveness of an individual facility alternative and may change the ranking of that alternative. This could result in a change in the Schedule of Facilities.

7. Glossary

Compressor Station
A facility which adds energy into the natural gas stream to increase the system capacity by increasing the system pressure.

Contract Demand
A level of demand Union agrees to supply to a customer based on the customer's requirement.

Contract Rate
The high volume in-franchise commercial and industrial customers served under Union's contract rate schedules.

Cost per Unit Throughput
An analysis to determining the relative value of a facility addition. It is calculated by dividing the capital cost of the facility by the amount of capacity it provides.

Daily Demand Profile
The pattern of customer gas usage during a day.

Design Day
The degree day and demand conditions under which the capacity of the system is determined.

Design Day Demand
The volume of natural gas the customers (in-franchise and M12) are forecast to use on the Design Day.

Design Day Operating Criteria
The set of boundary conditions which must operate within to provide required volume at contractual pressure to customers.

Degree Day
The temperature defined as the design weather condition.

Facility
A physical piece of equipment which increases the capacity of the system. This can include pipelines, compressor stations or metering / regulating stations.

General Service
The residential, small commercial and small industrial customer served under Union's general service schedules.

Growth Factors
The ratio of the forecast winter season divided by the base year winter season volume. Multiplying the base year general service Design Day demand by this ratio gives the future year Design Day demand.

M12 Rate
A rate class used to serve ex-franchise customers wanting firm service on the Dawn Parkway system.

Metering and Regulating Facilities
The facilities used to control pressures on a system and measure the amount of natural gas moving from one system to another.

Non-Facility
A commercial service contracted as a means of providing capacity alternatives without the addition of facilities.

Parkway Obligated Deliveries
The volume of natural gas which is to be supplied to Union at Parkway on behalf of direct purchase and system supply customers.

Pipeline
A number of pipe sections joined together for the purpose of carrying natural gas from one location to another.

Schedule of Facilities
A schedule of additional pipelines or compressor stations required to serve forecast demand.

System
The transmission system including the pipelines, compressor stations and the metering and regulating facilities

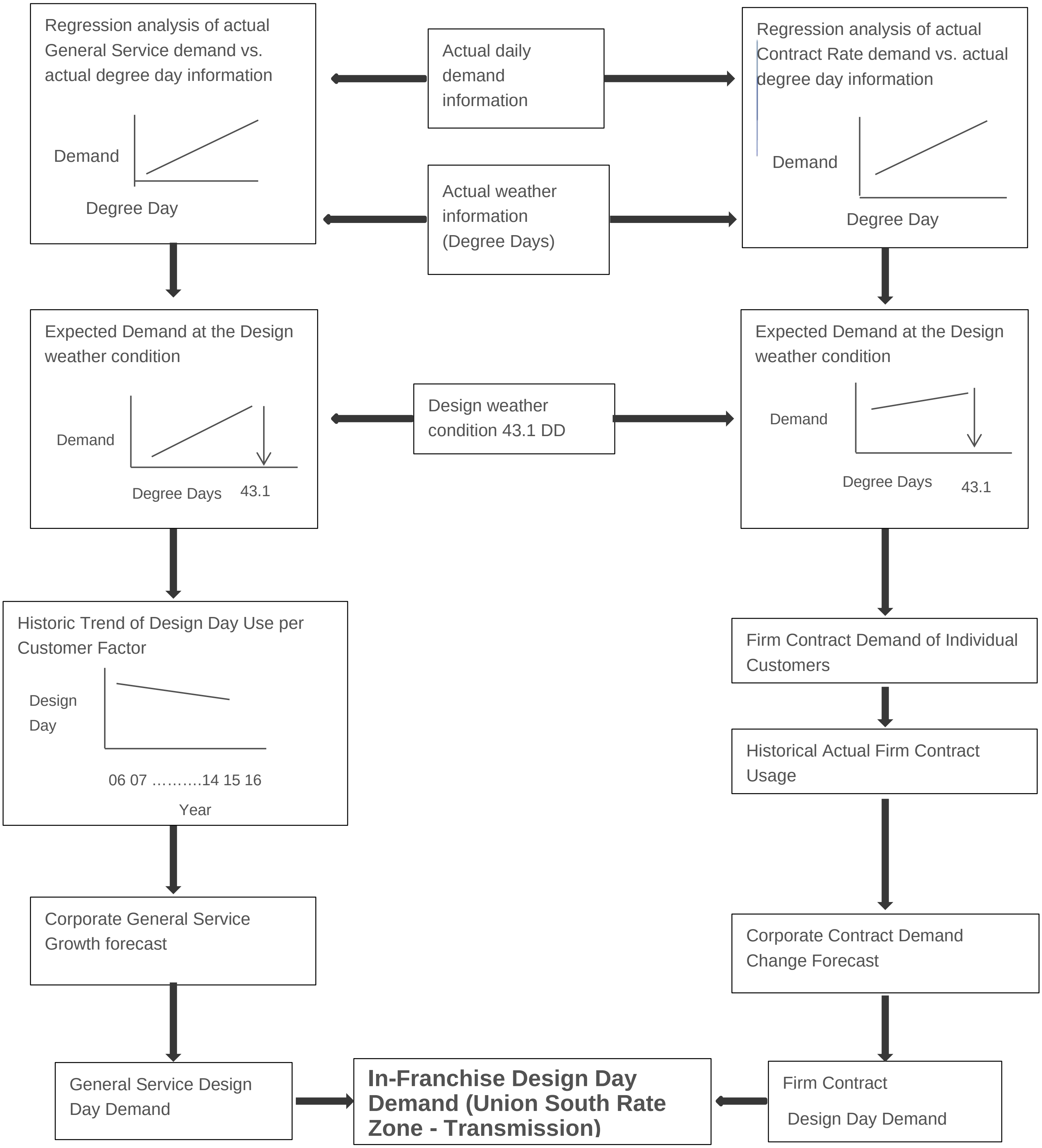
Winter Peaking Service
A non-facility alternative service which delivers a specified amount of gas to Parkway for a specified number of days.

8. Appendix

Schedule 1	Map of Dawn-Parkway System
Schedule 2	Union South Rate Zone In-franchise Design Day Demand Development
Schedule 3	Sample Design Day Demand Profile
Schedule 4	Loss of Critical Unit Coverage
Schedule 5	Simulation Information

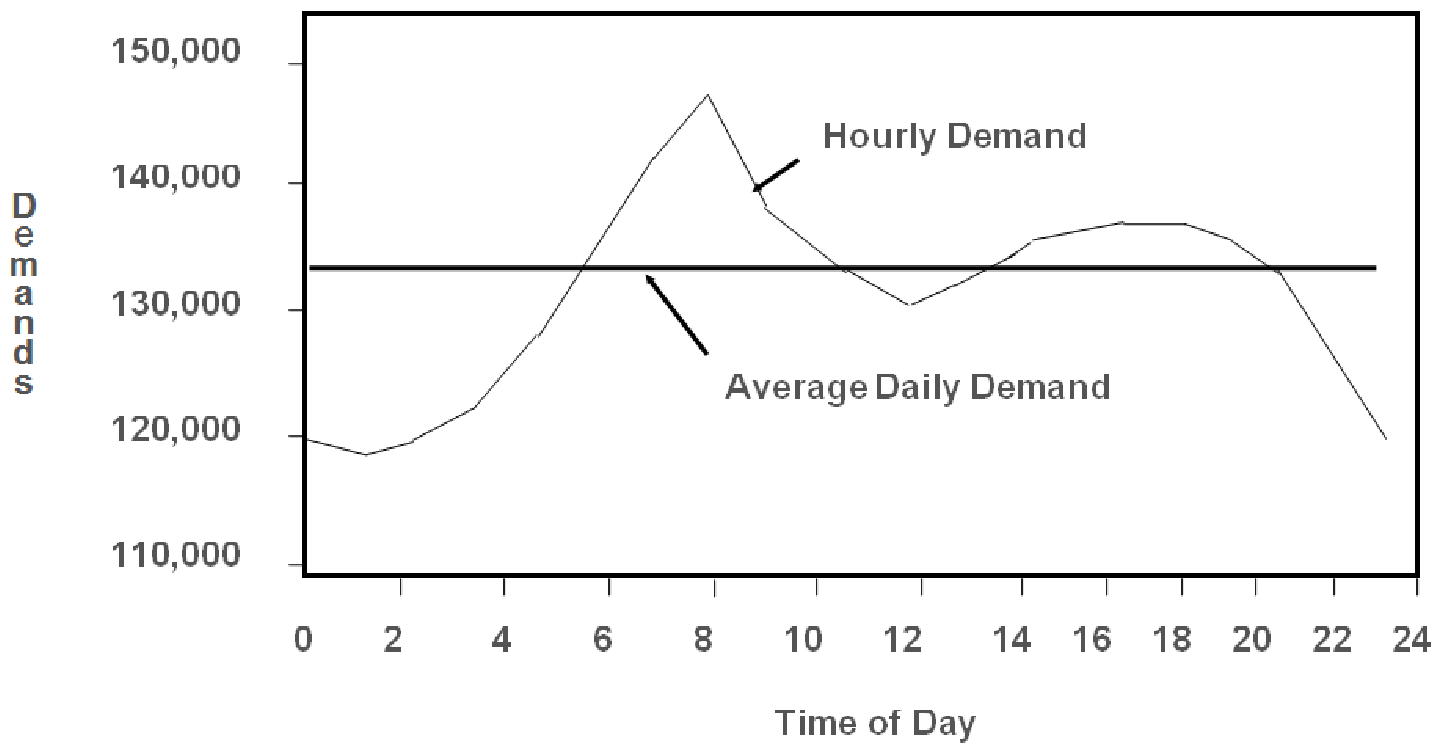
SCHEDULE 1 – MAP OF DAWN PARKWAY SYSTEM

SCHEDULE 2 – UNION SOUTH RATE ZONE IN-FRANCHISE DESIGN DAY DEMAND DEVELOPMENT



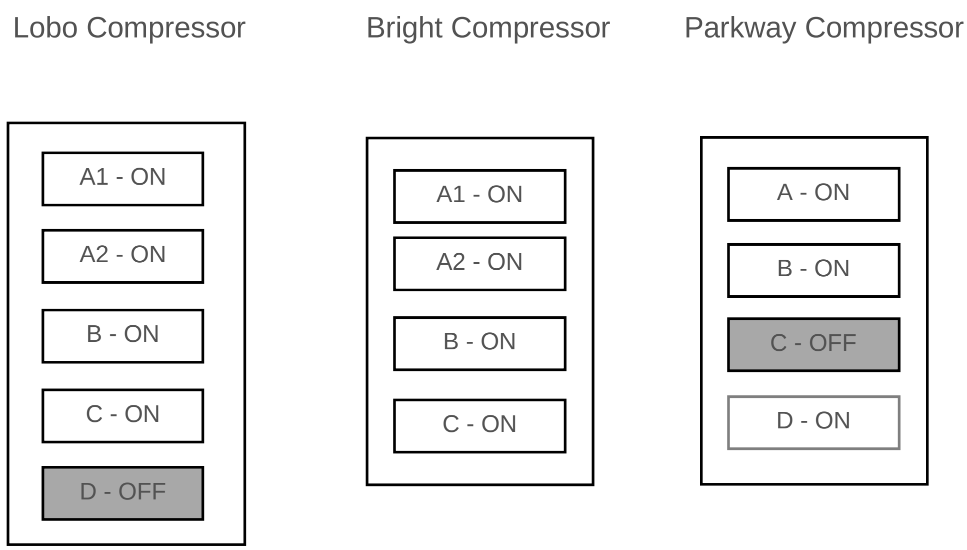
Note: Forecasts provided by Demand Forecasting Department

SCHEDULE 3 – SAMPLE DESIGN DAY DEMAND PROFILE (HOURLY PROFILE)



SCHEDULE 4 LOSS OF CRITICAL UNIT COVERAGE

Long Term Outage – The Critical compressor unit unavailable for entire day.



SCHEDULE 5 –SIMULATION INFORMATION

Union uses a proprietary software package (Synergi) by DNV-GL to complete hydraulic simulation of the transmission systems for Design Day conditions. This model incorporates all of the physical components of the system, Design Day demands and hourly demand profiles.

The Synergi software uses the following engineering fluid flow equations to model the system:

Pipeline Flow Equation:

Flow calculations are based on the fundamental flow equation described below:

$$Q = 77.54\frac{T_b}{P_b}\cdot D^{2.5}E\cdot\left[\frac{P_1^2-P_2^2-\dfrac{0.0375G(h_2-h_1)P_a^2}{ZT_a}}{G\cdot T_a\cdot L\cdot Z\cdot f}\right]^{\frac{1}{2}}$$

fined.

Where:

Q	= flow rate at standard conditions (standard cubic feet/day)
T_b	= base temperature at standard gas state (°R)
P_b	= base pressure of the standard gas state (Psia)
D	= internal pipeline diameter (inches)
E	= pipeline efficiency (dimensionless)
P_1	= upstream pressure (psig)
P_2	= downstream pressure (psig)
G	= gas specific gravity (dimensionless)
L	= pipe length (miles)
Z	= gas compressibility factor (dimensionless)
f	= pipeline friction factor (dimensionless)
h_1	= upstream node elevation (feet)
h_2	= downstream node elevation (feet)
P_a	= average pipeline pressure (psig)
T_a	= average gas flowing temperature (°R)

Compressor Equation:

$$HP = 3.0303 \frac{Q Z_s P_b T_s}{E_c T_b} \frac{k}{k-1} \left[\left(\frac{P_d}{P_s} \right)^{\frac{k-1}{k}} - 1 \right]$$

Error! Bookmark not defined. Where:

Q	= flow rate at standard conditions (standard cubic feet/day)
HP	= horsepower
T_b	= base temperature at standard gas state (°R)
P_b	= base pressure of the standard gas state (Psia)
T_s	= gas suction temperature (°R)
P_s	= suction pressure (Psia)
P_d	= discharge pressure (Psia)
Z_s	= gas compressibility factor at suction conditions (dimensionless)
k	= gas coefficient (dimensionless)
E_c	= compression efficiency (dimensionless)

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.

Response

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
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit A, Tab 13 / p. 10 of 24

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:

Enbridge Gas proposes a goal of IRP as "aimed at reviewing and implementing alternatives that reduce natural gas in-franchise peak period demand growth to defer or avoid future transmission and distribution system facility expansion/reinforcement projects". OEB staff wishes to better understand the definition of facility expansion/reinforcement projects, how this maps to Enbridge Gas's categorization of capital investments in its Utility System Plan and Asset Management Plan, and why Enbridge Gas is proposing limiting IRP to facility expansion/reinforcement projects.

Question:

a) Please provide Enbridge Gas's definition of facility expansion/reinforcement projects.
b) Of the four investment categories outlined in Enbridge Gas's Utility System Plan ("system access", "system renewal", "system service", "general plant"), which category/categories do facility expansion/reinforcement projects fit into?
c) Is Enbridge Gas's definition of "facility expansion/reinforcement projects" in the IRP proposal intended to be identical to the "Growth" asset class in Enbridge Gas's Asset Management Plan (section 5.1), which the Asset Management Plan defines as "the addition of new customers based on new housing or business starts, customers converting to natural gas from another fuel source as well as equipment and service upgrades to accommodate existing customer load growth"? Does it include the Asset sub-class "Customer Connections" or only the "Distribution System Reinforcement" and "Transmission System Reinforcement" categories?

d) Section 5.1 of the Asset Management Plan (p. 72) notes that “capital costs related to transmission system reinforcements are included in the expenditure summary for the Transmission Pipe and Underground Storage asset class” .Please clarify which types of infrastructure projects described in the “storage and transmission operations” asset class would be considered “facility expansion/reinforcement” and therefore subject to consideration of IRPAs.
e) Please provide the rationale as to why Enbridge Gas is not proposing consideration of IRPAs for the other asset classes described in chapter 5 of Enbridge Gas’s Asset Management Plan. Does Enbridge Gas believe that viable IRPAs (e.g. downsizing pipe infrastructure on replacement due to implementation of IRPAs) do not exist for any of these classes? Please describe

Response

a) Facility expansion/reinforcements refer to projects that are designed to meet the needs of customers, whether these projects result from the addition of new customers to the system or from the increasing load/demands of existing customers. Facility expansion/reinforcements refer to projects that support the transmission and distribution of natural gas at the system level as opposed to those projects that are required to connect a specific customer to the system (Exhibit B, paragraph 38 (iv)) and projects that result from programs explicitly designed to deliver natural gas to communities to help bring heating costs down (Exhibit B, paragraph 38 (v)).

b) These projects would typically be found in the Asset Class Programs (EB-2020-0181 Exhibit C, Tab 2, Schedule 1) noted in Table 1 below and mapped as shown to the USP categories.

Table 1

USP Category	Asset Class	Asset Class Program	AMP Reference
System Service	Transmission Pipe & Underground Storage	TPS-Growth	Page 72
System Service	Growth	GTH-System Reinforcement	Page 72
System Access	Compression Stations	CS-Growth	Page 191
System Renewal	Distribution Stations	DS-Gate, Feeder & A Stations	Page 126

c) Enbridge Gas's definition of facility expansion/reinforcement is not identical to the Growth Asset Class. The Asset Programs currently defined in the AMP that would align with Enbridge Gas's definition of facility expansion/reinforcement are defined in Table 1 above. These Asset Programs are aligned with multiple Asset Classes. Furthermore, the definition of facility expansion/reinforcement set out in the response at part a) specifically excludes Customer Connections and programs such as Community Expansion.

d) In the AMP at Section 5.1.7, page 87 (Growth), some of the significant Transmission System Reinforcements investments are described and the resultant capital investment is shown in the Transmission Pipe and Underground Storage asset class (Section 5.5.8, page 209). All of these could be subject to IRPA consideration unless precluded by their timing or the fact that they are required to meet the needs of one or a small number of industrial customers.

e) For investments that are driven by the condition of existing assets there is often too short a lead time to identify and verify the effectiveness of IRPA's. In instances in the future where Enbridge Gas has sufficient lead time to identify and verify the effectiveness of IRPA(s) it is possible that investment in IRPA(s) could reduce the size of replacement facilities required. However, as existing pipelines serve customers that are readily consuming natural gas it is unlikely that investments in IRPA(s) could be relied upon to completely eliminate the need for such facilities.

   Most of the other investments identified within the AMP relate to the ongoing replacement of assets that have already failed (Exhibit B, paragraph 38 (i)), are required to meet regulatory requirements (replacement of meters, upgrading of buildings), meet the needs of municipal and other stakeholders (Exhibit B, paragraph 38 (iii)), or make capital investments to maintain the safety and reliability of the system (Integrity). Enbridge Gas proposes that the nature of these investments eliminates them for the purposes of considering IRP/IRPA(s).

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit A, Tab 13 / p. 11 of 24; Exhibit B / pp. 19-20 of 46; OEB staff evidence (Guidehouse report) / pp. 29-31 of 77

Additional Public Documents: Enbridge Gas Inc. 2021-2025 Asset Management Plan (filed October 15, 2020; EB-2020-0181), Exhibit C, Tab 2, Schedule 1, Tables 6.1-3, 6.1-4, pp. 257-259); Consolidated Edison Company of New York, Inc, Proposal for use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure / p. 5 of 33.

Preamble:

Enbridge Gas proposes criteria for a binary screening that would be used to determine which system needs would require consideration of IRPAs. Guidehouse provides a discussion of Consolidated Edison Company of New York's (Con Ed's) Non-Pipeline Alternatives Framework Proposal as to which types of projects could likely be considered for IRP solutions, which can be compared with Enbridge Gas's proposed criteria.

Question:

a) Has Enbridge Gas reviewed Con Ed's proposed screening criteria? Does Enbridge Gas believe that there are any differences between Enbridge Gas and Con Ed's circumstances that have led to differences in proposed screening criteria? If so, please describe.
b) Enbridge Gas's original IRP proposal included a proposed screening criterion that IRPAs would only be considered in areas with a maximum annual forecasted load growth of 1.4%. Please confirm that Enbridge Gas is no longer proposing that load growth be an element of the binary screening for the relevance of IRPAs, and if so, why Enbridge Gas has proposed removing this criterion.
c) Please provide more clarity as to Enbridge Gas's proposed exemption criterion for safety. Does Enbridge Gas intend this criterion to apply only to projects that need to be addressed immediately, or also to projects where Enbridge Gas intends to

address safety/integrity issues over a longer period of time? For comparison, Con Ed proposes a similar criterion which is limited to “emergent safety risks” that must be resolved as quickly as practicable. Con Ed gives the examples of “replacement of leaking services; replacement of gas mains with active leaks; replacement of main segments due to water intrusion or contractor damage; and replacement of cast iron main due to encroachment activity.”

d) Enbridge Gas proposes that projects where system needs must be met in under 3 years would be exempt from IRP consideration. Based on Enbridge Gas’s historical experience and its needs identification process, how often do facility expansion/reinforcement system needs arise that would not have been identified more than 3 years in advance? Please describe.

e) Is Enbridge Gas’s proposed exemption criterion for “Customer-specific builds” limited to projects that would not impose additional supply or infrastructure costs on Enbridge Gas ratepayers other than the specific customers the projects are intended to connect?

f) Is Enbridge Gas’s proposed exemption criterion for “Community expansion &economic development” driven by policy and related funding limited to specific named projects that have been listed as being eligible for rate reduction (e.g. those currently listed in in O. Reg. 24/19 (“Expansion of Natural Gas Distribution Systems”)? If additional funding was made available to Enbridge Gas to support community expansion projects, but was not allocated to specific projects, would Enbridge Gas propose that the community expansion projects it chose to pursue with this funding would also be exempt from IRPA consideration? Please clarify what (if any) other factors would exempt a project from IRPA consideration under this criterion.

g) Taking into account both Enbridge Gas’s proposal to limit IRP to facility expansion/reinforcement projects, and the additional exemption criteria proposed by Enbridge Gas, please indicate which of the ICM-eligible projects shown in Tables 6.1-3 and 6.1-4 of Enbridge Gas’s 2021-2025 Asset Management Plan(pp. 257-259) would have likely been determined to be suitable for further consideration of IRPAs, had these criteria been in place. For projects determined not to be suitable, please indicate which criterion/criteria would have disqualified them from further consideration of IRPAs.

<u>Response</u>

a) – c)

Enbridge Gas evolved its thinking on binary screening related to IRP assessment in the period between filing its original 2019 IRP Policy Proposal and the October 15, 2020 Additional Evidence. Enbridge Gas considered in more depth what factors should constitute a more definitive screening and which items, although insightful, might not absolutely preclude the possible viability of a IRPA such as load growth rate, or project cost, especially when the Company broadened its thinking beyond incremental traditional DSM programming, as had been explored in the May 2018 ICF IRP Study.

Enbridge Gas has reviewed Con Ed's NPA Framework and the screening criteria. Enbridge Gas feels its screening criteria are similar to Con Ed's and remain appropriate. Con Ed in discussing its screening criteria show two things:

i. They outline by way of specific example projects that are a fit for NPA (IRP) are gas distribution infrastructure projects associated with load growth. Indeed, Enbridge Gas sees projects driven by load growth to be the projects best suited to IRP analysis as well especially as the Company is developing practical experience with IRP.
ii. That Con Ed articulates emergent safety risks, which includes gas leaks, being out of scope. This is in line with Enbridge Gas's proposal. Con Ed indicates in their NPA Framework on page 5, that they are looking at reviewing all other safety and resiliency projects for NPA recognizing that it is nascent learning.

> "Instead, under this Framework, the Company [Con Ed] proposes to evaluate planned safety- and reliability-related infrastructure projects (e.g., planned future work under its Main Replacement Program) for replacement using an NPA and attempts to shed light on the many unanswered questions in this uncharted territory."

Enbridge Gas notes that Con Ed is a joint gas and electric utility which may provide it some inherent ability to benefit from a transition to electricity solutions.
Although Enbridge Gas believes that year over year forecasted load growth is an important factor within a Stage 1 analysis on IRPAs, the Company is no longer proposing a specific threshold for load growth after which an IRPA should not be considered. Enbridge Gas feels that the 1.4% was a finding out of ICF's May 2018 IRP Study which may be appropriate for geotargeted DSM as an IRPA but may or may not be appropriate for other IRPA solutions or portfolios of solutions.

At the outset, as Enbridge Gas is gaining comfort with IRPAs and how to effectively plan around them, it is proposing that all safety or integrity related projects are screened out. Enbridge Gas notes that in addition to 'emergent safety risks', Con Ed has also scoped out regulatory requirements that include main replacements for methane reduction. Between the categories under emergent safety and the regulatory requirements, Enbridge Gas believes there may be little difference between what it has proposed with a broader safety screen and what Con Ed has proposed.

d) Most significant investments (those requiring Leave to Construct approval of the OEB) would be identified with more than three years' notice through Enbridge Gas's long-range planning processes. This process identifies projects up to ten years in advance.

The projects that are required more urgently are typically smaller in scope and cost.

Please see the response at Exhibit. I.STAFF.4 a), for discussion of forecasting and need identification processes. In addition to this, Enbridge Gas monitors the gas distribution network for emergent areas of low pressure or capacity constraints. These would typically require immediate remedy.

Projects identified through the long-range planning process would typically be suitable for IRP consideration, if required more than three years in the future. Those identified through the emergent process would not.

e) Yes, the exemption criterion for 'Customer-specific builds' would be limited to projects where no other customers were connecting or deriving value.

f) Yes, Enbridge Gas's proposed exemption criterion for 'Community expansion and economic development' are driven by policy and funding related to projects specific to O. Reg. 24/19 (Expansion of Natural Gas Distribution Systems). If additional funding was made available to Enbridge Gas to support community expansion projects, but was not allocated to specific projects, Enbridge Gas would include consideration of IRPAs.

g) Tables 6.1-3 and 6.1-4 from Enbridge Gas's 2021-2025 Asset Management Plan tables are replicated below for reference.

Table 6.1-3 ICM-Eligible Capital Projects – EGD Rate Zone

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total In-Service Capital ($M)	Driver	IRP Eligibility
Distribution Growth	Rideau Reinforcement	2025	52.7	53.5	Mandatory: Reinforcement Specified per Network Analysis	These Distribution Growth Projects would be suitable for IRPA consideration, providing there is sufficient lead time.
	York Region Reinforcement	2026	23.8	65.8	Mandatory: Reinforcement Specified per Network Analysis	
	Amaranth System Reinforcement	2024	10.3	10.3	Mandatory: Reinforcement Specified per Network Analysis	
	Thornton Reinforcement	2023	10.9	10.9	Mandatory: Reinforcement Specified per Network Analysis	
Distribution Pipe	NPS 20 Lake Shore Replacement (Cherry to Bathurst) (2019+)	2022	103.4	104.7	Condition	These Distribution Pipe Projects would be excluded as a result of Enbridge Gas' Safety criterion (EB-2020-0091, Exhibit B, Paragraph 38 i).
	NPS 12 St. Laurent Aviation Pkwy[1]	2022	29.5	29.8	Condition	
	NPS 12 St. Laurent Queen Mary/Prince Albert[10]	2022	11.0	11.1	Condition	
	NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.	2024	18.3	18.3	Condition	
	NPS 10 Glenridge Avenue, St. Catharines	2025	11.8	11.8	Condition	
Distribution Stations	Harmer District Station	2022	13.1	13.1	Compliance & ILI requirements	This Distribution Stations Project would be excluded as a result of Enbridge Gas' Safety criterion.
Compressor Stations	SCOR: K701/2/3 Reliability - Replacement	2024	185.2	185.2	Obsolescence	These investments are driven by condition and obsolescence and would generally not qualify for IRPA - particularly if there was a short timeline. However, given the size of the facilities, opportunities to reduce the size of the replacement capacity through the use of IRPAs would be considered.
	Storage Crowland (SCRW): Station-Renewal In-Place	2025	27.9	27.9	Obsolescence	
	Dehydration Expansion	2023	41.0	41.0	Condition; Growth	The Expansion of De-hydration capacity is partially driven by growth and could be considered for IRPAs providing there is sufficient lead time.
	SCOR: Meter Area-Upgrade	Ph 1 - 2021	34.2	45.6	Condition	This project is driven by condition and is already underway. It would not be considered for IRPA's.
		Ph 2 - 2022				

[1] The St. Laurent portfolio of work consists of four phases of work, and each phase is comprised of separate projects. Phases 1 & 2 have been previously completed, with Phases 3 & 4 remaining in this forecast period. Phase 3 includes the following investments; Three PE main investments in 2021 including Lower Section, Coventry/Cummings/St Laurent, and Montreal to Rockcliffe. Phase 4 includes the following investments; Two steel main investments as included in this table in 2022. The investments comprising Phases 3 & 4 will be combined in a single Leave to Construct application that will be submitted in Fall 2020.

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total In-Service Capital ($M)	Driver	IRP Eligibility
Transmission Pipe & Storage	Crowland Pool (PCRW): Wells-Upgrade	2027	1.7	11.6	Compliance, Condition	This Transmission Pipe and Storage Project would be excluded as a result of Enbridge Gas' Safety criterion.
REWS	Kennedy Road Expansion	2024	26.3	26.3	Condition	These Real Estate and Workplace Services investments are not within the scope of the IRP Framework.
	Station B New Building	2021	15.5	17.6	Condition, Function, In Progress	
	SMOC/Coventry Facility Consolidation	2027	30.8	30.8	Function and Service Coverage Duplication	
	Kelfield Operations Centre	2023	10.8	10.8	Condition, Function	
	VPC Core and Shell	2025	20.0	20.0	Condition	

Table 6.1-4 ICM-Eligible Capital Projects – Union Rate Zones

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total In Service Capital ($M)	Driver	IRP Eligibility
Distribution Growth	Customer Stratford Reinforcement	2022	13.3	13.3	Mandatory: Reinforcement Specified per Network Analysis	Customer Stratford Reinforcement is driven by a specific customer and does not meet Enbridge Gas' Customer-Specific Builds criterion (EB-2020-0091 Exhibit B, Paragraph 38 iv).
	Dunnville Line Reinforcement (6.3 km of NPS 10)	2025	9.0	11.0	Mandatory: Reinforcement Specified per Network Analysis	Some of these Projects could be considered for IRPAs (Owen Sound Transmission Reinforcement, Goderich Transmission Reinforcement) providing there is sufficient lead time but the remainder are required within three years and do not meet Enbridge Gas' Timing criterion (EB-2020-0091, Exhibit B, Paragraph 38 ii).
	NBAY: Parry Sound Lateral Reinforcement (12.5 km of NPS 6)	2025	15.0	15.0	Mandatory: Reinforcement Specified per Network Analysis	
	WATE: Owen Sound Transmission System, Reinforcement (28.8km of NPS 16)	2025	81.7	83.6	Mandatory: Reinforcement Specified per Network Analysis	
	LOND: Goderich Transmission System, Reinforcement (11.4km of NPS 10)	2025	2.2	25.0	Mandatory: Reinforcement Specified per Network Analysis	
Distribution Pipe	NPS 8 Port Stanley Replacement	2024	20.6	20.6	Condition	These Distribution Pipe Projects would be excluded as a result of Enbridge Gas' Safety criterion (EB-2020-0091, Exhibit B, Paragraph 38 i)
	INTE: North Shore - Section A: Retrofit ECDA to ILI	2021	12.0	12.3	Mandatory: Retrofit for TIMP program (ILI Compliance)	
	Windsor Line Replacement	2020	7.2	90.3	Condition	
	LOND - London Lines Replacement	2021	102.6	108.2	Condition	
	Kirkland Lake Lateral Replacement	2022	16.8	16.8	Condition	
	SUDB: Marten River Compression, Reinforcement	2023	51.6	51.6	Mandatory: Reinforcement Specified per Network Analysis	These Projects could be considered for IRPAs providing there is sufficient lead time.
	WATE - Owen Sound Reinforcement Ph 4	2020	1.9	56.6	Mandatory: Reinforcement Specified per Network Analysis	
Compression Stations	Dawn Plant-C Compression Life Cycle	2024	130.9	130.9	Obsolescence	These Compression Stations Projects are driven by obsolescence and would be excluded as a result of Enbridge Gas' Safety criterion (EB-2020-0091, Exhibit B, Paragraph 38 i)
	Waubuno Compression Life Cycle	2024	12.9	12.9	Obsolescence	
Transmission Pipe & Storage	Panhandle Line Replacement	2023	29.7	29.7	Condition, High Consequence	These Projects are driven by condition and compliance and would not be considered for IRPAs (Safety criterion).
	INTE: Dawn - Cuthbert - ECDA to ILI Retrofit NPS 42, 34, 26	2022	24.6	25.0	Mandatory: Retrofit for TIMP program (ILI Compliance)	
	Dawn Parkway Expansion (Kirkwall-Hamilton NPS 48)	2022	176.1	181.7	Growth	These investments are driven by growth and would qualify for IRPA's unless there is insufficient time to meet Enbridge Gas' Timing criterion or it meeting the criteria of a Customer-Specific Build.
	Sarnia Expansion (NPS 20 Dow to Bluewater)	2021	19.2	20.5		
	Sarnia Expansion (Novacor Station)		6.5	6.5		

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total In Service Capital ($M)	Driver	IRP Eligibility
	Sarnia Expansion - Bluewater Energy Park (Asset #1)	2024	64.5	64.6		
	Sarnia Expansion Project- Bluewater Energy Park (Customer Station)		11.7	11.7		
	Sarnia Expansion - Bluewater Energy Park (Asset #2)		34.0	34.0		
REWS	Thunder Bay Regional Operations Centre	2026	10.2	10.2	Condition	These Real Estate and Workplace Services investments are not within the scope of the IRP Framework.
	New Site No. 4	2023	28.8	28.8	Operations Site Consolidation	

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / pp. 39-42 of 46

Additional Public Documents: Ontario Power Authority and Independent Electricity System Operator, Engaging Local Communities in Ontario's Electricity Planning Continuum: Enhancing Regional Electricity Planning and Siting, August 1, 2013.

Preamble:

Enbridge Gas discusses its proposed approach to stakeholder engagement in IRP.

Question:

a) Regarding the geographically-specific stakeholder engagement in response to a specific system need (component 3), does Enbridge Gas intend for this stage to seek input from stakeholders on how best to meet the system need (e.g., presenting information and seeking feedback on multiple potential solutions under consideration by Enbridge Gas, seeking stakeholder input on addition allocation-specific solutions Enbridge Gas may not have considered), or only to seek input on the specific preferred IRPA that Enbridge Gas has identified? Please describe the rationale behind Enbridge Gas's preferred approach.
b) Community engagement has been an important aspect of Ontario's regional electricity planning, including the referenced report by the Ontario Power Authority and Independent Electricity System Operator on this issue. Does Enbridge Gas have any views as to the community engagement approach discussed in this report and used for regional electricity planning in Ontario, and its applicability for Enbridge Gas regarding community engagement on solutions to geographically-specific system needs?

<u>Response</u>

a) Once a system constraint has been identified as potentially suitable from a timing perspective for a geotargeted IRP application it will require more targeted stakeholder and Indigenous community engagement.

Component 1 (*Gather and analyze data and insight from ongoing stakeholder engagement initiatives*) provides for the ongoing gathering of market data intelligence from existing stakeholder engagement channels, while mitigating incremental expenses. These existing channels to stakeholders, include: municipal outreach, Indigenous engagement, DSM, market surveys, LTC stakeholder outreach, utility regional directors, outreach to customer associations and formal/informal dialogue with customers of all types (e.g., through sales representatives). By utilizing this information Enbridge Gas will be able to bring forward for consideration and discussion with stakeholders potential IRPAs to address identified system constraints.

As part of Component 3 (*IRPA Project Geographically-Specific Stakeholder Engagement*), Enbridge Gas intends to seek feedback on multiple potential solutions. Component 3 will allow opportunities for stakeholders and Indigenous communities to review the IRPA's and facility alternatives under consideration and to provide feedback. This geographically and project specific stakeholder and Indigenous engagement provides an opportunity to consider specific initiatives that may be happening at the local level that may have a bearing on possible IRPAs such as confirmation of growth projections or Community Energy Planning. Enbridge Gas recognizes that as part of these activities, participating stakeholders and Indigenous communities could provide additional insight into IRPAs that the Company did not consider or was unaware of. For example, the stakeholder plan will seek to gain understanding from stakeholders and Indigenous communities on customer growth expectations and willingness to participate in potential demand response programming; economic activity and growth; low carbon alternative opportunities; energy efficiency and conservation potential opportunities; new and emerging technological advances.

Enbridge Gas expects that the stakeholders to be included in engagement activities may include: local government representatives; local LDC staff; IESO representatives; Indigenous communities; local key customer and industry groups, local private residential customers (including low income customers / local low-income representative groups and associations); and local project developers and builders. Engagement initiatives will be tailored according to the relevant geotargeted area and are anticipated to be in the form of open houses, webinars, surveys, and online opportunities to provide written feedback. Further, All three components of the Enbridge Gas Stakeholder Engagement Plan will allow transparency, while respecting the confidentiality of any sensitive information gathered.

b) Enbridge Gas reviewed the IESO model of stakeholder engagement and incorporated many of the same principles into its proposed Stakeholder engagement model, while at the same time leveraging its existing stakeholder channels to mitigate incremental costs. Enbridge Gas also reviewed stakeholder models of other natural gas utilities that conduct a form of integrated resource planning, such as the stakeholder engagement model used by FortisBC.[1]

While developing the IRP stakeholder engagement model proposed in its Additional Evidence, Enbridge Gas reviewed both the referenced report by the Ontario Power Authority and Independent Electricity System Operator (IESO) released in 2013 as well as the new stakeholder engagement framework released by the IESO on April 16, 2020.[2] Further, Enbridge Gas held discussions with members of the IESO stakeholder group to better understand the processes, tools and outreach efforts of its public information sessions on geographically specific system needs.

Enbridge Gas's IRP Stakeholder plan was influenced by the four IESO engagement categories:[3]

> "Forecasting and Planning: To support provincial and regional electricity planning over the next 20 years.
>
> Resource Acquisition: To ensure we have the tools and processes to acquire the resources we need to maintain a reliable and efficient system.
>
> Operations: To ensure that Ontario's electricity resources are operating reliably within the IESO-administered market, while also undertaking continuous market improvements.
>
> Sector Evolution: A look to the future to see how innovation, new technologies and new collaborations can improve how we conduct our business."

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[1] https://www.fortisbc.com/about-us/projects-planning/natural-gas-projects-planning/natural-gas-planning-stakeholder-engagement
[2] https://www.ieso.ca/en/Sector-Participants/IESO-News/2020/04/IESO-launches-new-stakeholder-engagement-framework
[3] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Overview/Stakeholder-Engagement-Framework

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit A, Tab 13 / p. 15 of 24; Exhibit B / p. 17, 36 of 46

Preamble:

Enbridge Gas notes that "once it is determined that an IRP/IRPA is preferable to an identified facility expansion/reinforcement project, Enbridge Gas will apply to the OEB for approval to recover the costs associated with that IRPA. This may be done in a rate application or as a separate stand-alone application." Enbridge Gas also indicates that it would seek OEB approval to adjust investments in such IRPAs as appropriate (e.g., to shift funding to an alternate IRPA or to increase/decrease/cease investment in IRPAs accordingly).

Question:

a) Pipeline projects meeting certain criteria require a facilities approval (Leave to Construct) under section 90 of the *OEB Act*. The Leave to Construct review includes consideration of need and alternatives. Leave to Construct approval also provides some level of assurance to Enbridge Gas that it will likely be eligible to recover prudently incurred costs associated with the project.
    a. Does Enbridge Gas propose that a similar process and a new form of OEB review and project approval be established for IRP Plans, in advance of seeking approval to recover costs through rate applications?
    b. If so, does Enbridge Gas propose that this approval would be required for all IRP Plans, or only in certain circumstances?
    c. If the latter, does Enbridge Gas have any proposals regarding what criteria would be used to determine if an IRP Plan approval would be required(e.g. cost threshold)?
b) Enbridge Gas indicates that it would also seek OEB approval to adjust investments in IRPAs as appropriate. Does Enbridge Gas propose that this approval would be sought for any adjustment to an approved IRP Plan, or would certain thresholds apply (regarding changes to level of spending, changes to IRPA technology or

implementation approach, etc.)? If the latter, please provide any views Enbridge Gas has as to what considerations might apply.

c) The OEB currently approves recovery of capital costs for facilities projects through rate applications, in particular, in a rebasing application or in a price cap incentive regulation application through an Incremental Capital Module to recover funding for significant capital investments for discrete projects during the period of incentive regulation between rebasing applications. Does Enbridge Gas believe that any adjustments to this approach would be needed to address rate approvals (s. 36 of the *OEB Act*) for recovery of costs for IRPAs (outside of Enbridge Gas's proposal to treat IRPA costs as capital, discussed under issue7)? If so, please describe.

Response

a) Enbridge Gas is seeking to establish similar assurances under similar thresholds and parameters for investments in natural gas IRPA(s) as the *Ontario Energy Board Act, 1998* (the "Act"), (Section 90 and 91) affords natural gas utilities through applications for leave-to-construct facilities (LTC), assuming associated costs of investment in IRPA(s) have been incurred prudently.

a. - c.
Yes, as set out in its Additional Evidence at page 32, Enbridge Gas expects that a similar process to that established by the Board for applications for LTC facilities should be established for IRPA applications:

> "Enbridge Gas will apply to the OEB for approval to recover the costs associated with investment in any IRPA. Enbridge Gas presumes that such an application would, similar to applications for LTC facility alternatives, include an explanation of the system constraint/need, a summary of stakeholder engagement input, rationale for investment in the IRPA, the estimated individual and overall costs of investment, proposed cost allocation and recovery methodologies, proposed ownership and operationalization arrangements and a commitment to ongoing annual monitoring and reporting on the relative effectiveness of the IRPA to relieve the identified constraint."

As part of this process, the Board could establish a threshold for IRPA applications that leverages Enbridge Gas's IRP Proposal which includes identification of a preferred facility alternative to IRPA(s) for the purposes of testing cost-effectiveness and as a risk mitigation strategy in instances where IRPA(s) are underperforming relative to forecast (in certain instances triggering an application for LTC facilities). In other words, for any IRPA(s) where their directly comparable facility alternative would trigger a requirement under Section 90 of the Act for Enbridge Gas to apply for LTC, an IRPA application should be made to the Board. Further, consistent with Section 91 of the Act, Enbridge Gas may also submit an IRPA application to the Board in instances where Section 90 of the Act does not apply, if it so chooses.

Where the identified system constraint and/or customer need underlying an IRPA investment would not trigger Section 90 of the Act and Enbridge Gas determines it is not necessary or appropriate to file an IRPA application under Section 91 of the Act, then Enbridge Gas expects that such investments would be subject to review by the Board and parties at such time that the Company applies to recover their costs from ratepayers.

In all instances, IRPA investments would be reflected in Enbridge Gas's AMP and Enbridge Gas would apply separately to the Board for cost recovery and rate changes resulting from OEB-approved IRPA investments.

b) Enbridge Gas proposes that the Board establish a threshold for adjustments to IRPA investments of 25% or greater of total OEB-approved costs of each IRPA investment in order to ensure that the Company and the Board are not overly burdened by the need to prepare and consider countless applications for adjustments to such investments in the future. This approach strikes a reasonable balance between maintaining regulatory efficiency and providing sufficient oversight of IRPA investments consistent with Enbridge Gas's Additional Evidence at page 32, where it stated:

> "To provide some certainty of the effectiveness of IRPAs as early as possible, Enbridge Gas will build off its existing evaluation, measurement and verification ("EM&V") expertise to determine how the IRPA or IRPA portfolio is progressing in relation to targets. Enbridge Gas will identify and, where possible, resolve unanticipated operational challenges or flaws in the design or delivery of IRPAs that could impede its ability to reliably serve the needs of customers. If no such resolution is reasonably possible, then Enbridge Gas will evaluate the potential of new/incremental/replacement IRPAs and may consider ceasing investment in existing IRPAs that are not achieving the peak period demand reductions originally forecast."

c) No, consistent with the response at part a) above, Enbridge Gas proposes to seek cost recovery for OEB-approved IRPA(s) investments under Section 36 of the Act in a similar manner to cost recovery of facility alternatives during an incentive period and through rate rebasing.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit A, Tab 13 / pp. 3-4 of 24; Exhibit C / p.7 of 26

Preamble:

Enbridge Gas submits that IRP should be reviewed and treated separately from Demand-Side Management (DSM). Enbridge Gas notes that forecasting and projecting potential system capacity needs/constraints up to ten years in advance is inherently more likely to result in less reliable results (e.g., the identification of needs/constraints and potential IRPA investments that are not absolutely necessary).

Question:

a) Does Enbridge Gas's preference that initiatives to address infrastructure needs should be addressed through IRP (and not through Enbridge Gas's post-2020DSM Plans) apply to both:
    a. Local/regional infrastructure needs affecting a limited geographic area/subset of Enbridge Gas customers
    b. Broad-based infrastructure needs where the need (and potential solutions) could impact a large number of Enbridge Gas customers (e.g. upgrades to the trunk routes on the transmission system)
b) If both, please provide more rationale as to why Enbridge Gas believes that broad-based infrastructure needs should not be considered in some manner (e.g. size of budget and savings targets, focus on peak demand savings vs. overall natural gas savings, program and measure mix, etc.) in informing Enbridge Gas's post-2020 DSM Plans and should instead be addressed through IRP.

c) In relation to longer-term system needs that may not materialize (and for which targeted spending on IRPAs or facility projects is not yet proposed), does Enbridge Gas believe that there is any opportunity to incorporate this planning information on system needs into its DSM plans and activities to allocate more of its DSM efforts to the areas where these longer-term needs have been identified, without negatively impacting the overall performance of its DSM efforts ("no regrets" DSM activities)?

Response

a) & b)
IRP is directed at alternatives to gas infrastructure to resolve identified future system constraints and, as such, IRP must reduce location-specific peak period demand in order for facility alternatives to be avoided, delayed or reduced. This is different than Enbridge Gas's DSM Framework which is aimed at reducing annual volumes across the franchise.

For the purposes of addressing identified local/regional system constraints affecting a limited geographic area/subset of Enbridge Gas customers, Enbridge Gas believes that IRP/IRPA(s), which include geo targeted energy efficiency programs, is more appropriate than traditional DSM due to its proposed targeted nature and focus upon peak period demand reductions.

For the purposes of addressing identified broad-based system constraints affecting a large geographic area and many customer groups, traditional DSM programming may be more appropriate than IRP/IRPA(s) due to its broad-based nature.

c) Enbridge Gas notes that DSM is currently built into forecasts and as such is addressing longer-term needs on an ongoing basis. In addition, Enbridge Gas believes that there may be a way to incorporate this planning information on system needs into its DSM plans to allocate more of its DSM efforts to the areas where these longer-term needs have been identified. However, this would be more appropriately considered within future DSM proceedings.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit M2.GEC-ED / pp. 27-29 of 55; Exhibit C / pp. 25-26 of 26, Appendix A / pp. 1-30

Preamble:

EFG recommends that Enbridge Gas develop two IRP pilot projects, noting that most jurisdictions considering IRP have started with pilot projects. Enbridge Gas agrees in principle with EFG's proposal. Enbridge Gas provides a case study on the results of its Ingleside pilot project.

Question:

a) Enbridge Gas proposes that the pilot projects be selected and implemented following the development and issuance of an IRP Framework for Enbridge Gas. Does Enbridge Gas believe that all aspects of an IRP Framework need to be addressed prior to proceeding with additional pilots? If not, which elements are most important to receive OEB direction on, in Enbridge Gas's view?
b) Enbridge Gas indicates that the primary goals of the Ingleside pilot were: to test the impact of geo-targeted energy efficiency programs on peak hourly demand (including the use of metering technology for this purpose), and to explore the cost of geo-targeted DSM pilot implementation. Does Enbridge Gas have any initial views as to which types of IRPAs and which other aspects of IRP would be most important to test in future pilots?
c) From the Ingleside study results, the small size and homogenous customer mix (few commercial/industrial customers) of the Ingleside study area appeared to limit the potential effectiveness of geotargeted DSM (or other IRPAs). The case study notes that "Ingleside was selected after consideration of various factors including size and infrastructure." Does Enbridge Gas believe this study area is representative of typical areas (in terms of system needs and/or viability of potential IRPAs) where IRP Plans may be proposed in the future? Please describe why or why not.

Response

a) - c)

In its Reply Evidence, Enbridge Gas agreed that two IRP pilot projects should be developed and implemented to continue to inform natural gas IRP in Ontario.[1] Enbridge Gas has not determined which technologies or projects nor what timeline it would pursue for IRP pilot projects. However, IRP pilot projects that might provide the most value immediately, include: a low carbon technology solution program, and a demand response program. Further, any IRP pilot project should be sited in an area that includes a broader diversity of customer types and complexities so as to better test deployment.

Enbridge Gas does not believe that all elements of an IRP Framework need to be addressed prior to proceeding with IRP pilot projects. The IRP Framework elements, or direction required from the Board in order to proceed with IRP pilot projects include:

- What IRPAs might be in scope for Enbridge Gas to explore.
- How costs/cost-effectiveness should be assessed.
- Approval of incremental IRP-related funding and clarity regarding its treatment in terms of cost-recovery. Enbridge Gas has proposed an approach for funding of IRP administrative costs and the cost of IRP pilot projects at Exhibit I.STAFF.22 d).
- The expected application and approval process for IRP pilot programs.

In exploring possible IRP pilot projects, Enbridge Gas expects to go through the proposed stakeholdering outlined in its IRP Proposal and Additional Evidence,[2] and as further clarified in the response at Exhibit I.STAFF.9 , including gathering input from low-income customers and Indigenous groups.[3]

Following the completion of any IRP pilot project, Enbridge Gas intends to document and share key learnings internally and through reporting to the Board and stakeholders, at a minimum through its proposed annual Monitoring and Reporting processes.[4]

Enbridge Gas anticipates that learnings from the pilot projects may be useful to inform evolution and/or completion of the Board's IRP Framework for Enbridge Gas. And will certainly allow the Company to gain experience and further insight into IRPAs.

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[1] Exhibit C, Reply Evidence, para. 13.
[2] Exhibit B, Additional Evidence, pp. 39-42.
[3] Enbridge Gas Additional Evidence pages 39 – 42, and at Reply Evidence pages 13 to 16.
[4] Exhibit B, Additional Evidence, pp. 37-38.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Appendix A / p. 67 of 92; Exhibit C / pp. 7-8 of 26

Additional Public Documents: Planning Process Working Group Report to the Board, The Process for Regional Infrastructure Planning in Ontario, May 17, 2013; Independent Electricity System Operator, Regional Planning Process Review Straw Man Design, February 28, 2020

Preamble:

ICF's report for Enbridge Gas discusses electricity system planning in Ontario, including the regional planning process and the consideration of non-wires solutions.
Enbridge Gas notes that there are some instances where electric Non-Wires Alternative ("NWA") insights apply to natural gas IRP, but that there are also key differences between electric and natural gas infrastructure planning.

The public documents listed provide more information on Ontario's experience considering non-wires alternatives in electricity system planning. The OEB-endorsed Process for Regional Infrastructure Planning in Ontario (2013) details the planning process for addressing regional infrastructure needs, including needs screening, and how non-wires alternatives should be considered as potential solutions, and has informed regional planning since that time. The regional planning process is currently under review. The IESO's Regional Planning Process Review Straw Man Design report summarizes many of the learnings of how this process has worked in practice to date, and recommendations for improving the regional planning process, including discussion of addressing barriers to non-wires alternatives.

Question:

a) Has Enbridge Gas considered Ontario's specific experience with non-wires alternatives in the regional planning process, including the documents mentioned above, in developing its IRP proposal?

b) If so, does Enbridge Gas have any observations or lessons learned from Ontario's experience with non-wires alternatives (e.g. practices that should or should not be transferred to IRP planning for Enbridge Gas)?

Response

a) & b)
Enbridge Gas notes that some of the elements of the regional planning process up until recently have been less relevant to natural gas utilities as it has been focused on identifying roles amongst the various players in the electricity sector, and articulating regional boundaries in Ontario. More recently, Enbridge Gas has been keenly watching the activity around the first Non-Wires RFP issued by the IESO in partnership with Alectra for filling peak capacity needs in the York Region. A key objective of the IESO York Region Non Wires Alternatives Demonstration Project is to better understand the potential of using Distributed Energy Resources (DERs) in place of traditional infrastructure by enabling them to operate in real-world applications.[1] As this demonstration program is still ongoing it is too early to establish observations or lessons learned. However, there are a few learnings from the market procurement process including that the market needs to be primed meaning that an RFP cannot just land in the market, time must be taken to engage with possible solution providers and once the successful proponents determined, negotiation of contract terms can be extensive. Furthermore, the criteria in an RFP may drive certain business models or IRPAs unintentionally.

[1] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/IESO-York-Region-Non-Wires-Alternatives-Demonstration-Project

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / pp. 21-30 of 46

Preamble:

Enbridge Gas describes a range of potential IRPA technologies.

Question:

a) Does Enbridge Gas have a view as to which of the described technologies appear most promising in the Ontario context in terms of deferring or avoiding Enbridge Gas infrastructure, considering cost-effectiveness, reliability, demand reduction potential, etc.?
b) In addition to their ability to reduce infrastructure costs (primarily by reducing peak demand), these technologies differ in the additional costs and benefits they would provide to customers and society (e.g. impact on customer commodity costs and carbon charges, etc.) Would Enbridge Gas's opinion as to which technologies would be most promising for IRP in Ontario change if the OEB determines that IRP cost-effectiveness should be assessed primarily from the viewpoint of customers or society, instead of from the utility perspective (e.g. using a Total Resource Cost+ test or Societal Cost Test)?

Response

a) & b)
Enbridge Gas has proposed several innovative natural gas and non-gas alternatives to resolve identified system constraints in its Additional Evidence.[1] Each alternative offers unique potential to resolve identified constraints in differing circumstances.

[1] Additional Evidence, pp. 21-30.

For example, GSHPs may be a good option for remote communities or new construction, however, GSHPs may be challenging to retrofit existing homes or commercial buildings. On the other hand, EASHPs may offer a good solution for heating during shoulder months, however, they may contribute to a peak in electric demand, increasing gas demand on the natural gas grid during a cold winter day when supplement/auxiliary heating will be provided with resistant heating. Although the efficiency of resistance heating is considered to be 100% at site, the source efficiency of marginal electricity produced from gas plants during winter peak will be about 40% as compared to a 95% efficiency of gas furnaces. Lastly, NGASHP are a good alternative to reducing peak natural gas demand on a consistent basis for both the retrofit and new construction market as their efficiency stays above the efficiency of a condensing furnace.

At such time that the OEB establishes an IRP Framework for Enbridge Gas and the Company subsequently identifies system constraints that can be resolved through investment in IRPAs, Enbridge Gas expects that the nature of those constraints, together with stakeholder feedback, and the unique environmental, policy and market conditions present at that time will inform its investigation into and potential selection of IRPAs.

Enbridge Gas also expects that the guidance set out within the IRP Framework ultimately established by the Board, including with regard to alternative cost-effectiveness tests, will also impact the viability of certain of the IRPAs proposed by the Company. However, at this time it is not possible to comment on all of the various possible variations to OEB guidance and their resulting impact upon the many potential IRPAs contemplated.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / pp. 25-27 of 46; OEB staff evidence (Guidehouse report) / p. 14 of 77

Additional Public Documents: Consolidated Edison Company of New York, Gas Demand Response Report on Pilot Performance – 2018/19, July 1, 2019, p. 5

Preamble:

Enbridge Gas notes that Contract Rate customers can contract for both a firm service level and an interruptible service level and that "it is unlikely that significant new DR {demand response} solutions exist for Contract Rate customers in Ontario". Within the General Service class, Enbridge Gas indicates that larger commercial and industrial customers may have additional factors that can mitigate their achievable demand reduction.

Question:

a) Does Enbridge Gas consider all three of the following solutions to be within the scope of potential IRPAs?:
    a. Encouraging customers to convert some or all of their load from firm to interruptible service, e.g. through better promotion of interruptible rates;
    b. Utilizing demand response programs (of some nature) for customers on firm rates;
    c. Rate design for firm and interruptible customers to disincent consumption at times of peak system demand.
b) Does Enbridge Gas's conclusion that "it is unlikely that significant new DR solutions exist for Contract Rate customers in Ontario" apply to all of the above categories of solutions? Please describe.
c) Con Ed's Gas DR pilot includes a stream ("Performance-Based Gas DR Pilot") targeted primarily at commercial and institutional gas customers and multi-family buildings with centralized gas heating systems, on firm rates. Does Enbridge Gas believe that a DR program of this nature is unlikely to be a viable solution in Ontario? Please describe.

Response

a) Yes, Enbridge Gas considers parts a) – c) to be within the scope of potential IRPAs.

b) Enbridge Gas's large commercial and industrial customers have been increasingly requesting firm service and moving away from interruptible services for their natural gas needs in recent years as these customers do not want to rely on interruptible services to meet their operational needs despite the cost advantage provided by interruptible rates.

   Enbridge Gas will continue to monitor customer trends and developments in demand response (DR) alternatives to ensure that such alternatives (including DR for firm customers and/or alternative rate designs for customers to disincent consumption during peak periods) are considered as IRPA(s), as appropriate.

c) Enbridge Gas believes that a DR program of this nature is unlikely to be a viable solution in Ontario. The ICF Report supports this conclusion:[1]

> "…the value of a DR program is dependent on the value of the peak demand reduction, which varies widely by jurisdiction. In regions with high cost capacity requirements, or limited ability to increase capacity to meet growth in demand, such as parts of New York State and New England, gas DR will be much more economic than in jurisdictions with lower cost capacity options, such as Ontario."

[1] Additional Evidence, Exhibit B Appendix A, pp. 16 -17.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / pp. 29 of 46; OEB staff evidence (Guidehouse report) / p. 14 of 77

Additional Public Documents: New York Joint LDCs, Modernized Gas Planning Process: Standards for Reliance on Peaking Services and Moratorium Management, July 17, 2020.

Preamble:

Enbridge Gas notes that it will consider long-term natural gas supply IRPAs, but that commercial alternatives such as peaking supply, delivered supply, exchanges and third-party assignments are not considered appropriate to meet long-term gas supply requirements.

Question:

a) Please provide more detail as to why Enbridge Gas does not consider commercial alternatives such as peaking supply, delivered supply, exchanges and third-party assignments as appropriate to meet long-term gas supply requirements. OEB staff notes that commercial alternatives such as delivered services play a large role in gas system planning in New York State, and that work is ongoing through the Modernized Gas Planning Process proceeding to assess and compare the reliability risks of these services with other resource options.
b) Does Enbridge Gas also believe that these types of solutions have no role in addressing distribution or transmission system infrastructure needs? Please describe.

Response

a) & b)

Enbridge Gas defines commercial alternatives as any supply-side service provided by a third-party. Commercial alternatives include, but are not limited to, upstream transportation services to enable the delivery of supply to a point on Enbridge Gas's system, peaking supply transactions, delivered supply transactions, exchanges, and third-party assignments of transportation capacity. The suitability of commercial alternatives to meet gas supply, distribution, and/or transmission system needs is dependent on the contractual terms of the agreement and therefore should be assessed on a case by case basis.

Enbridge Gas does not consider commercial alternatives such as peaking supply, delivered supply, exchanges and third-party assignments as appropriate to meet long-term gas supply requirements because these services are typically short-term in nature and do not contain renewal rights. There is no guarantee that these commercial alternatives will be available in future years nor is there certainty regarding the future cost of these alternatives in the event they continue to be available.

In its 5 Year Gas Supply Plan,[1] Enbridge Gas acknowledges that commercial alternatives are cost-effective and do not require long-term commitments but are less reliable and lack the diversity and flexibility of service attributes associated with firm transportation. For this reason, Enbridge Gas limits the use of these services to meeting short-term design day asset shortfalls no more than 2% of design day demand requirements.

The Guidehouse Report states at page 14:

> "Con Edison relies on delivered services for 17% of peak day capacity and rising to 22% by 2023."

In this context, delivered services are defined as:

> "…products offered by third parties that have firm contractual rights to pipeline capacity and who are willing to sell the capacity, bundled with natural gas commodity, for short durations (15 or 30 days)."

[1] EB-2019-0137 page 41, 44, 48

The Guidehouse Report goes on to acknowledge the same concerns Enbridge Gas has related to reliance on short-term commercial alternatives to meet long-term gas supply needs:

> "While delivered services are highly reliable when contracted, delivered services typically do not include long term renewal options, which creates long-term uncertainty of the availability for future years."

The level of delivered services relied upon by Con Ed is likely the result of a lack of any other available alternative to meeting peak day demand and not a situation whereby Con Ed views the alternative as a reliable long-term solution. This is reinforced in the *New York Joint LDCs, Modernized Gas Planning Process: Standards for Reliance on Peaking Services and Moratorium Management, July 17, 2020*, which states:[2]

> "Due to the recent challenges in siting new pipelines to serve New York markets, the downstate LDCs have increased their reliance on peaking resources. Some of these peaking resources either introduce concerns regarding deliverability reliability (e.g., CNG by truck) or recontracting/renewal reliability (e.g., delivered services that are based on the availability of pipeline capacity to service area delivery points)."

Enbridge Gas will consider commercial alternatives that provide sufficient assurance of meeting a demonstrated gas supply, transmission, or distribution system need for the foreseeable future at a cost that is reasonably predictable over the life of the agreement. For example, firm upstream transportation services with third-party pipeline operators generally contain renewal rights beyond the initial contract term and are subject to regulated tariffs. These services are reliable, contain contractual terms that ensure Enbridge Gas can renew them for as long as the need exists, and include a cost that can be reasonably forecasted over the life of the service. Enbridge Gas has and will continue to include a variety of firm upstream transportation alternatives when assessing gas supply, transmission, and distribution system needs.

[2] New York Joint LDCs, Modernized Gas Planning Process: Standards for Reliance on Peaking Services and Moratorium Management, July 17, 2020, p. 12.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit A, Tab 13 / p. 12 of 24; Exhibit B / p. 23 of 46

Preamble:

Enbridge Gas indicates that it is seeking confirmation that non-gas alternatives can be included in the range of possible and available IRPAs. Enbridge Gas notes that, if authorized by the OEB, it could offer non-gas alternatives such as electric heat pumps, but would need to include these assets in rate base.

Question:

a) Please clarify why any electric IRPA would require Enbridge Gas ownership and ratebasing of assets. Would this apply even if the goal of the IRPA was to reduce infrastructure needs for customers other than those directly using the heat pumps (or other electric technologies)?
b) Is Enbridge Gas requesting an OEB determination as to whether non-gas alternatives such as electric heat pumps would be eligible to include in rate base at this time, in advance of a specific electric IRPA being brought forward for consideration? Does Enbridge Gas believe that this determination is necessary for it to give consideration to electric IRPAs at the planning stage?
c) Are there any technologies other than electric heat pumps for which similar considerations apply?

Response

a) Enbridge Gas is seeking confirmation that non-gas solutions such as electric air source heat pumps, geothermal and district energy, be considered in the range of possible and available cost effective IRPAs in lieu of additional natural gas infrastructure to resolve identified system constraints. Ownership of these assets could have a moderating impact on rates if the result is a more cost effective IRPA than otherwise. This is described in Exhibit B, page 23:

> "Enbridge Gas notes that it could offer these alternatives if authorized by the OEB, to reduce peak period demand in targeted areas. Should this authorization be granted, these assets would need to be included into rate base <u>or else by investing in such alternatives the Company would be contributing to higher rates for existing customers since they would not receive the moderating advantage of new revenues from customer growth to help offset Enbridge Gas's overall costs</u>." [emphasis added]

b) Enbridge Gas's original IRP Proposal, Additional Evidence and Reply Evidence seek to establish an IRP Framework for the Company that provides a reasonable degree of clarity and certainty as to whether the non-gas IRPAs discussed therein could be eligible for rate base treatment. In the absence of such clarity and certainty it is unlikely that Enbridge Gas would go to the effort of completing detailed assessments and stakeholdering of such IRPAs and applying to the Board for approval to invest in the same.

In the case of many IRPAs, Enbridge Gas's involvement in offering non-gas solutions is in the best interest of the rate payer as it allows for the deployment of technologies that currently face technological or economic barriers to adoption.

The Board should consider allowing Enbridge Gas to own and include in rate base investments in non-gas IRPAs (excluding electric generation facilities) where the market for such technologies remains nascent, and where such solutions need support from the utility to commercialize. As the market for such IRPAs matures, Enbridge Gas could shift future investments to a competitive procurement model where the costs of procurement are amortized, recognizing the benefits that development of such markets could afford ratepayers.

Similarly, in instances where a competitive market for IRPAs is already established the Board should also consider allowing Enbridge Gas to include in rate base investments in non-gas IRPAs where the Company would partner with existing market players to procure and/or install IRPAs, assuming that participants are customers of Enbridge Gas.

c) There may be many other IRPAs that address thermal heating loads, but those that are evident currently include geothermal, district energy, and hybrid heating systems. The clarifications sought by Enbridge Gas discussed in part b) are necessary for Enbridge Gas to appropriately consider such non-gas IRPAs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

OEB staff evidence (Guidehouse report) / p. 40 of 77

Preamble:

Guidehouse describes the components of Con Ed's Smart Solutions Program in New York State, which include a market solicitation for non-pipeline solutions.

Question:

a) Con Ed's Smart Solutions Program includes a market solicitation for non-pipeline solutions, to seek demand-side reduction and alternative non-pipeline supply-side solutions from market participants. Does Enbridge Gas see any value in a similar market-based call for solutions in Ontario? Why or why not?

Response

Yes, Enbridge Gas sees value in a market solicitation for non-pipeline solutions where there is a competitive market for such solutions already exists, and where there is sufficient lead time in advance of an identified system constraint to facilitate a market solicitation. Please also see the response at Exhibit I.STAFF.17, for further discussion of the potential for future market solicitations for IRPAs.

Based on its observations of market solicitations conducted in New York State to date, Enbridge Gas estimates that the time required to complete a market solicitation for IRPAs would range from 1 – 2 years (from design to closing). However, any such solicitation must also take into account the lead time necessary to ensure that the program/solution is implemented in the field and effectively/measurably resolving the underlying identified system constraint 3 – 5 years in advance.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit A / pp. 12-14 of 24; Exhibit B / pp. 15-16 of 46

Preamble:

Enbridge Gas discusses a two-stage process for evaluating IRPAs in both Exhibit A and Exhibit B, however, there are some differences between these descriptions.

Question:

a) Please confirm whether the two-stage process for evaluating IRPAs described in Exhibit B is a complete description of Enbridge Gas's current proposal on this topic, and replaces the description of this two-stage process in Exhibit A. In particular, does the first stage of Enbridge Gas's proposed evaluation of IRPAs include any form of economic analysis (as indicated in Exhibit A) or does it only assess whether a particular IRPA has the technical potential to meet the system need, taking reliability into account (as indicated in Exhibit B)?

Response

a) Confirmed. Exhibit B describes Enbridge Gas's two-stage process for evaluating IRPAs. The first stage includes a high-level review for reasonability as to whether an IRPA can meet the identified need taking into account reliability and safety. The second stage will do a fulsome comparison of the facility alternative to the potential IRPA(s) on an economic basis.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / p.31 of 46; Exhibit C / pp. 8-13 of 46

Additional Public Documents: Consolidated Edison Company of New York, Inc, Gas Benefit-Cost Analysis Handbook (filed as part of Con Ed's NPA Framework Proposal filing), September 14, 2020, p. 9

Preamble:

Enbridge Gas discusses the economic evaluation that should be used to compare IRPAs and facility projects, and proposes that the OEB establish a staged economic evaluation standard for IRPAs through this proceeding that ultimately resembles a modified version of the OEB's E.B.O. 134 guidelines or a Discounted Cash Flow + (DCF+) test. Enbridge Gas compares its proposed approach to Consolidated Edison's Benefit-Cost Analysis Handbook used for its analysis of non-pipes alternatives in New York State.

Question:

a) Enbridge Gas proposes that "the economic feasibility for IRPAs will be assessed using a Discounted Cash Flow ("DCF") methodology consistent with principles underpinning the Board's E.B.O. 134 and E.B.O. 188." These methodologies were originally developed to assess potential expansions of the natural gas distribution and transmission system. If the OEB determines that IRP should be considered for other categories of infrastructure projects, does Enbridge Gas believe that this methodology remains appropriate to assessing and comparing the economic feasibility of IRPAs and facility projects, and if so, would any key modifications be required?
b) Enbridge Gas proposes that the OEB develop a staged economic evaluation, noting the three potential stages of cost-benefit analysis in the E.B.O. 134 process (economic, customer, and societal).
    a. Can Enbridge Gas provide a table identifying which categories of costs and benefits it would propose to include in the different stages of its proposed

cost-benefit evaluation, similar in nature to Table 3-1 (p. 9) in Con Edison's Gas-Benefit Cost Analysis Handbook? In particular, please clarify how impacts on commodity costs paid by Enbridge Gas customers would be treated.

Table 3-1: Summary of Cost-Effectiveness Tests by Benefit and Cost

Benefit/Cost	SCT	UCT	RIM
Benefits			
Avoided Peaking Services	✓	✓	✓
Avoided Pipeline & Storage Costs	✓	✓	✓
Avoided Commodity Costs	✓	✓	✓
Avoided On-System Capacity Infrastructure	✓	✓	✓
Avoided O&M	✓	✓	✓
Reliability/Resiliency	✓	✓	✓
Avoided CO2 Emissions	✓		
Other Avoided Emissions	✓		
Non-Energy Benefits*	✓	✓	✓
Other External Benefits	✓		
Costs			
Program Administration Costs	✓	✓	✓
Incremental On-System Investments	✓	✓	✓
Lost Utility Revenue			✓
Shareholder Incentives			✓
Incremental Participant Costs	✓		
Alt. Fuel Costs	✓	✓	✓
Alt. Fuel CO_2 Emissions	✓		
Alt. Fuel Other Emissions	✓		
Net Non-Energy Costs*	✓	✓	✓
Other External Costs	✓		

*It is necessary to identify which cost-effectiveness test should include the benefit or cost in the Net Non-Energy Benefit or Net Non-Energy Cost as it may apply to the SCT, UCT, and/or RIM.

b. Is Enbridge Gas proposing that all three stages of the cost-benefit analysis would always be conducted?
c. Does Enbridge Gas have a position as to how the results of the different tests would be used together, and which test, if any, would be given primacy in determining the preferred project?

Response

a) Enbridge believes using a Discounted Cash Flow ("DCF") methodology consistent with the principles underpinning the Board's E.B.O. 134 and E.B.O. 188 is an appropriate methodology to assess and compare economic feasibility of IRPAs and facility alternatives. Enbridge is not seeking to make any changes to E.B.O. 134. Enbridge proposes to use the DCF methodology of E.B.O. 134 and E.B.O. 188 to assess IRPAs without any modifications. However, as stated in Enbridge Gas's Reply Evidence at Exhibit C, Page 9, Enbridge is open to discussing additional costs and/or benefits that could be incorporated in the economic assessment of IRPAs. If additional costs or benefits are included in the economic evaluation of IRPAs, the additions need to evaluate facility alternatives and IRPAs equitably and fairly. For example, if the avoided commodity and delivery costs (benefits) of natural gas are included in the evaluation of an IRPA, then any additional costs such as electricity charges should also be included.

b)
   a. Please see Table 1 below:

Table 1

Benefit/Cost	Stage 1	Stage 2	Stage 3
Benefits			
Incremental Revenues	x		
Avoided Infrastructure Costs	x	x	
Avoided Commodity/Fuel Costs	x	x	
Avoided O&M	x		
Avoided GHG Emissions		x	
Other External Non-Energy Benefits			x
Costs			
Incremental Capital Expenditure	x		
Incremental O&M	x		
Incremental Taxes	x		
Incremental Commodity/Fuel Costs	x	x	
Incremental GHG Emissions		x	
Incremental Customer Costs		x	
Other External Non-Energy Costs			x

Note: Capital & O&M is inclusive of program administrative costs

b. Enbridge Gas expects that all three stages of the cost-benefit analysis will be conducted assuming that the necessary data and information to do so is available.

c. Enbridge Gas believes that the results of the three stages should be evaluated in totality with primacy to a specific stage determined based on factors such as reliability of data on a case by case basis.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / p.30-31 of 46; OEB staff evidence (Guidehouse report), p. 42-44 of 77

Preamble:

Enbridge Gas notes that in addition to cost, reliability, safety and sustainability and "broadly protecting the interests of customers" would be relevant factors in evaluating and comparing IRPAs and facility projects.

Guidehouse describes the criteria used by National Grid in New York State to compare IRPAs and facility projects.

Question:

a) Does Enbridge Gas have any specific considerations in mind in the phrase "broadly protecting the interests of customers" that the OEB and Enbridge Gas should consider when assessing whether to proceed with investment in an IRPA? If so, please describe.
b) In addition to cost, comparative factors used by National Grid are safety, reliability, environment, and community. These factors appear similar to those proposed by Enbridge Gas, with the exception of "community". Would Enbridge Gas consider the preference or views of impacted communities (including information obtained from stakeholder consultation) to be a relevant factor in comparing IRPAs and facility projects, and determining the preferred solution? If so, please describe how this factor would be taken into account in the evaluation and comparison of alternatives.

Response

a) The term "broadly protecting the interests of customers" refers to Enbridge Gas's obligation as the supplier of last resort to safely and reliably meet the firm contractual demands of its customers during peak/design periods. Please also see the response at Exhibit I.EP.6, for discussion of Enbridge Gas's obligation as a natural gas distributor in Ontario.

b) Yes, Enbridge Gas considers the preferences and views of impacted communities to be relevant to the assessment of IRPAs. Accordingly, its proposed stakeholder outreach approach is inclusive of communities, including municipalities and Indigenous peoples. Enbridge Gas's proposed outreach approach articulates how the Company intends to include communities in its IRP-related decision making sufficiently in advance to ensure that their feedback can be taken into account and reflected in Enbridge Gas's assessment of facility and non-facility alternatives. As detailed in Enbridge Gas's Additional Evidence at Exhibit B, page 41 under component 3:

> "The purpose of this component of stakeholder engagement is to share information about an identified IRPA with stakeholders from the specific geographic area relevant to the IRPA. Feedback from this consultation work will inform and help shape any IRPA implementation proposal that might ultimately be filed with the OEB for approval."

The preferences or views of any impacted community will be an important factor in the comparison of IRPAs with baseline facility alternatives. If any IRPA is to be successful it must be generally accepted and reflective of the needs of the communities where it is to be deployed. Enbridge Gas also intends to ensure that any quantifiable localized costs or benefits are considered as part of cost-benefit analysis conducted to assess facility and non-facility alternatives to resolve identified system constraints. For further discussion of component 3 of Enbridge Gas's proposed stakeholder engagement strategy, please see the response at Exhibit I.STAFF.9.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / pp. 32-34

Preamble:

Enbridge Gas proposes that the costs associated with an IRPA be included in its revenue requirement, and capitalized to rate base.

Question:

a) Does Enbridge Gas propose that IRP planning costs incurred prior to OEB approval of an IRP Plan would also be eligible for capitalization to rate base?
b) If so, would this treatment apply only to project-specific costs for the specific IRPA(s) approved in an IRP Plan?
c) Is Enbridge Gas proposing that IRP Plan costs would be eligible for cost recovery once the IRP Plan was "in-service", similar to the treatment for facility projects? Please describe any special considerations that might apply regarding the determination of an "in-service" date for IRPAs.
d) Does Enbridge Gas have any views as to how cost recovery for general investments to better enable Enbridge Gas to consider and implement IRP across its system (e.g. piloting of different IRPA technologies, improvements to system planning procedures, investments in AMI) should be treated?
e) Does Enbridge Gas have any views as to whether IRP raises any issues regarding the allocation of IRP costs to rate classes that need to be identified and addressed on a general basis within the IRP Framework?

Response

a) & b)
There are several categories of cost related to the implementation of IRPAs including the incremental administrative costs, the IRPA project costs and ongoing

operating and maintenance costs associated with the IRPA and the treatment of IRP planning costs incurred prior to OEB approval, as O&M or capital, will be consistent with accounting policy. These cost categories are also addressed through the Additional Evidence filed as Appendix B on page 36 where it states:

> "Enbridge Gas has also proposed to report annually on the actual annual and cumulative effects of OEB-approved IRPAs relative to associated peak period demand reductions originally forecast (via an IRP report) and to seek OEB approval to adjust investments in such IRPAs as appropriate (e.g., to shift funding to an alternate IRPA or to increase/decrease/cease investment in IRPAs accordingly). Enbridge Gas expects that any and all of the prudently incurred: (i) original costs to invest in OEB-approved IRPAs; (ii) costs associated with OEB-approved adjustments to IRPA investments; and (iii) costs of any subsequent OEB-approved LTC project (in the instance that an IRPA is determined to have been insufficiently effective), would be borne entirely by ratepayers subject to the Board's determination that in the course of incurring such costs Enbridge Gas acted prudently and responsibly in serving the firm needs of its ratepayers."

The cost categories are independent of whether the IRPA solution is proposed to be owned and operated by Enbridge Gas, or if it is completed through a market solicitation. Enbridge Gas expects the IRPA cost categories will include:

<u>Incremental IRP Administrative Costs</u>
IRP administrative costs include the additional staff and resources required to meet the increased workload related to IRP. Enbridge Gas proposes incremental IRP administrative costs be included in the O&M costs of the Company's revenue requirement. Please see the discussion of incremental IRP administrative costs at Exhibit I.APPrO.6.

<u>IRPA Project Costs</u>
IRPA project costs include the planning, implementing, administering, measuring and verifying the effectiveness of specific investments in IRPAs. Similar to traditional infrastructure projects, Enbridge Gas proposes that the IRPA project-related costs be capitalized to rate base

<u>Ongoing Operating and Maintenance Costs</u>
Ongoing operating and maintenance costs include the regular costs incurred to operate and maintain a specific IRPA investment after the project is in-service. Similar to traditional infrastructure projects, Enbridge Gas proposes that the O&M costs related to the ongoing operating maintenance of an IRPA be included in Enbridge Gas's O&M costs of the Company's revenue requirement.

c) Yes, Enbridge Gas expects that the IRPA costs would be eligible for cost recovery once the IRPA project is in-service. Enbridge Gas will seek approval of IRPA(s)-specific spending, including the manner and timing of cost recovery, through a separate approval from the OEB, as appropriate.

d) Enbridge Gas proposes that a deferral account be established for the incremental IRP costs not included in base rates. This deferral account is discussed in the response at Exhibit I.APPrO.6.

e) Enbridge Gas is seeking guidance from the Board on the issue of cross-subsidization between rate classes and the allocation of IRPA costs to rate classes, should the Board seek to include costs beyond the DCF analysis proposed (E.B.O. 134 stage 1 assessment e.g. commodity costs, etc.). Currently, broad-based DSM programs are accessible to all customers, with DSM costs allocated to the rate classes where the savings are achieved. This minimizes cross-subsidization between rate classes and between participants and non-participants under a maximum acceptable level; in the residential sector this is currently $2/month. The implementation of geo-targeted DSM (ETEE) for instance means that not all customers can participate in a geo-targeted program as they are not in the affected area, however as an IRPA, those costs will be allocated to all ratepayers, without having the benefit of participation. As such, either the full societal cost is less than the cost of the comparable facility alternative, only an economic assessment is undertaken, or the Board provides a maximum bill impact for all customers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / pp. 32-34; OEB staff evidence (Guidehouse report) / pp. 45-48 of 77

Preamble:

Guidehouse discusses Enbridge Gas's cost recovery proposal and the treatment of cost recovery for IRPAs in New York State.

Question:

a) Does Enbridge Gas have any views as to whether a single amortization period for all investments in IRP (Con Ed in New York State proposes a single 20-yearperiod for all IRP investments, as noted in the Guidehouse report) or a unique amortization period based on project-specific considerations is preferable?
b) Guidehouse notes that "Enbridge Gas does propose that O&M costs for IRPAs be capitalized, which is a notable difference in the capitalization approach between O&M costs for IRPAs and facility projects. Enbridge Gas indicates that the overall intention of its IRPA treatment is to incentivize IRPAs and facility projects equally, but the cost treatment between the two will vary slightly." Does Enbridge Gas agree with Guidehouse's statement that the cost treatment between IRPAs and facility projects would differ slightly if Enbridge Gas's proposal were to be adopted, and if so, would changes to the capitalization approach for facility projects (e.g. how ongoing O&M costs are treated) be needed to achieve the objective of like treatment of facility projects and IRPAs?

Response

a) At this time, given the uncertainty regarding the nature of IRPA(s) that the Board will allow via the establishment of its IRP Framework for Enbridge Gas in Ontario, the Company believes it is premature to attempt to establish an average amortization period that is reflective of all potential IRPA investments (e.g., a 20 year period).

Instead, Enbridge Gas proposes to evaluate the amortization period for each IRPA on a project specific basis.

b) To clarify, Enbridge Gas proposes to treat the O&M costs associated with investments in IRPAs in the same manner as it does for facility projects. Accordingly, no changes to the methodology applied to capitalize facility projects is warranted in order to achieve like treatment between facility investments and IRPA investments. Please also see the response at Exhibit I.STAFF.22 for further discussion of Enbridge Gas's proposed treatment of IRP/IRPA related costs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / p. 37 of 46; OEB staff evidence (Guidehouse report) / pp. 50-51 of 77

Preamble:

Enbridge Gas proposes that ratepayers, not Enbridge Gas, bear the costs associated with the success or failure of IRPAs, and states that such treatment of risk is consistent with investments in facility expansion/reinforcement projects.

Question:

a) OEB staff notes that, even for projects given LTC approval, the OEB can review the reasonableness of final project costs. Is Enbridge Gas proposing that the OEB would have a similar role in reviewing the final project costs for IRP Plans? If so, are there any specific considerations which Enbridge Gas believes should guide the OEB's review of final project costs for approved IRP Plans that would differ from that for traditional infrastructure projects?
b) Are there any other risks that Enbridge Gas is proposing to assume in its proposed investments in IRPAs, in return for its request for a rate of return that includes a risk premium?

Response

a) Yes, Enbridge Gas is proposing that the OEB would have a similar role in reviewing the final project costs for IRPA projects as it does for facility projects. Enbridge Gas expects that the OEB's review of final IRPA project costs will consider whether Enbridge Gas acted prudently and in accordance with any OEB conditions of approval. Enbridge Gas expects that the IRPA cost review would largely mimic those conducted for facility projects when such costs are added to rate base (assuming the Board approves such treatment of costs) with the exception that there will be recognition that Enbridge Gas may find it necessary to make adjustments to approved IRPAs as a result of underperformance (such adjustments will be identified within its annual IRP Report).

Recall, that in the event an IRPA is not meeting its intended goals Enbridge Gas will inform the OEB of the issue as part of its proposed annual IRP Report as described in Enbridge Gas's Additional Evidence at Exhibit B, paragraph 80:

> "Enbridge Gas has also proposed to report annually on the actual annual and cumulative effects of OEB-approved IRPAs relative to associated peak period demand reductions originally forecast (via an IRP report) and to seek OEB approval to adjust investments in such IRPAs as appropriate (e.g., to shift funding to an alternate IRPA or to increase/decrease/cease investment in IRPAs accordingly)".

b) No, there are no other risks that Enbridge Gas is proposing to assume in its proposed investments in IRPAs. Please also see the response at Exhibit I.EP.6, for discussion of IRP/IRPA related risk.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / pp. 33-34 of 46; OEB staff evidence (Guidehouse report) / pp. 50-51 of 77

Additional Public Documents: Ontario Energy Board, Report of the Board: The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario (EB-2009-0152), January 15, 2010, section 3.2.4; Consolidated Edison Company of New York, Inc, Proposal for use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure / pp. 26-31 of 33.

Preamble:

Enbridge Gas notes that the simplest and most effective means of creating a level playing field between IRPAs and facility infrastructure is by ensuring that Enbridge Gas is equally incented between the two types of investments (by earning an equal return on investment). Enbridge Gas suggests that the OEB could potentially consider an additional incentive above the regulated rate of return if it wished to prioritize IRPAs, but that the topic of incentives might be appropriately examined in a separate study.

Guidehouse discusses the incentive proposal included as part of Con Ed's Non-Pipeline Alternatives framework filing. The Con Ed proposal itself provides additional detail on this proposed incentive mechanism.

Question:

a) Enbridge Gas notes that ensuring it is equally incented between IRPAs and facility infrastructure would create a level playing field between these two types of investments (i.e. specific IRPA performance incentives may not be necessary). Does Enbridge Gas believe that this position might change if other elements of Enbridge Gas's IRP proposal (risk, approval mechanism, etc.) are modified by the OEB – i.e. would incentives then be necessary to overcome perceived risks associated with spending on IRPAs?

b) Enbridge Gas notes that a performance incentive for IRPAs could potentially be based on the net benefits achieved (in comparison with a facility project), which is the form of incentive proposed by Con Ed. Has Enbridge Gas considered a different form of performance incentive that could provide a (potentially higher)project-specific rate of return to address the perceived higher risk associated with IRPAs, as described in section 3.2.4 of the referenced OEB report, and if so, does it have any views on this type of incentive?
c) Con Ed's incentive proposal includes both a performance incentive (based on net project benefits relative to a traditional infrastructure solution) and a bi-directional cost-containment incentive, that could reward (or penalize) Con Ed for reducing(or increasing) the cost of the non-pipeline alternative during the implementation phase. Does Enbridge Gas believe that a cost-containment incentive could have value in the context of an Ontario IRP Framework, and if so, does Enbridge Gas believe that this type of incentive (as well as performance incentives) could also be examined in a separate study, outside of the initial review of Enbridge's IRP proposal?
d) Does Enbridge Gas believe that the IRP Framework should include any form of penalty if the OEB determines (e.g. in a decision on a Leave to Construct application) that Enbridge Gas failed to give adequate consideration to IRPAs and that Enbridge Gas's actions have had cost consequences for its customers? Why or why not?

<u>Response</u>

a) Enbridge Gas remains of the opinion that ensuring it is equally incented between IRPAs and facility alternatives will create a level playing field between these two types of investments.

   Please also see the responses at Exhibit I.CCC.17 and Exhibit I.EP.6, for discussion of IRP/IRPA related risk and incentives.

b) & c)
   Enbridge Gas notes that in addition to rate base treatment and the net benefits sharing proposal made by Con Ed, Con Ed also has a performance incentive to encourage cost containment around IRPA implementation.

   Enbridge Gas is open to considering incentive mechanisms. If the Board determines that investments in IRP should be prioritized then the Company should be adequately incentivized to undertake IRPA investments and the Board should recognize that as natural gas IRP is a new concept across North America there will necessarily be increased risk associated with such investments. These incentives might be a sharing of net benefits between customers and the utility shareholder, 70/30 as was done by Con Ed. In any case, Enbridge Gas's preference would be to have the opportunity to provide informed recommendations in this regard to the Board.

Enbridge Gas has reviewed the Con Ed cost containment performance incentive and is not convinced it is applicable in the Ontario context at this time. Con Ed's non-pipeline alternatives are being driven in large part by the natural gas pipeline moratoria in New York, which creates a specific urgency for the Con Ed non-pipeline solutions, hence the development of a cost containment incentive that works within the band of net benefits that can be achieved. For clarity, Con Ed's rate base approach plus sharing of net incentives has no penalty. They only penalize Con Ed within the band of the net benefit sharing should they not stay within forecasted costs up to a threshold amount that sees them still retain the rate base incentive. Enbridge Gas notes that at the outset of every new policy framework there is necessarily an adjustment period required where the Board and utilities learn and adjust in order to achieve optimal outcomes. Enbridge Gas is recommending that further exploration of incentives be the topic of a separate study completed outside the initial review of Enbridge's IRP Proposal.

d) As of the date of this submission, Enbridge Gas has complied with all OEB statements encouraging the consideration of IRP (please see section 1.0 of Enbridge Gas's Additional Evidence for a summary of these findings/statements). OEB Staff's expert evidence recognized at page 3, the fact that the Board and Enbridge Gas have taken a proactive approach to establishing a natural gas IRP Framework for Enbridge Gas:

> "Enbridge Gas and the OEB have taken a proactive approach to develop a Gas IRP framework. Enbridge Gas's proposed goal is to develop a framework to guide Enbridge Gas's assessment of IRP alternatives (IRPAs) relative to other facility and non-facility alternatives to serve the forecasted needs of Enbridge Gas customers. Ontario already has a framework for the deployment of natural gas Demand Side Management (DSM) programs. Enbridge Gas's IRP Proposal includes a definition of eligible IRPAs, screening and selection criteria for IRPA vs. traditional facility projects, monitoring and reporting guidelines and other elements that attempt to solidify the IRP Framework as a standalone construct that is distinct from the DSM and facility project frameworks."

Following the Board's direction to complete and IRP Study and to propose a preliminary Transition Plan as part of its 2015-2020 DSM Framework,[1] EGD and Union worked together with ICF Canada to comply and presented an executive summary of the IRP Study and an IRP Transition Plan to the Board and parties as part of the Board's Mid-Term Review of the 2015-2020 Demand Side Management (DSM) Framework for Natural Gas Distributors (EB-2017-0128/0127). As part of the IRP Study, ICF identified outstanding policy issues and concluded that:[2]

> "Change in Ontario energy policy and utility regulatory structure would be necessary to facilitate the use of DSM to reduce facility investments."

ICF went on to explain that these changes would include:[3]

> "Cost recovery guidelines for overlapping DSM and facilities planning and implementation costs, and criteria for addressing DSM impact risks. Approval to invest in, and recover the costs of the AMI necessary to collect hourly data on the impacts of DSM programs and measures. Changes in the approval process for DSM programs to be consistent with the longer lead time associated with facilities planning. Clarification on the allocation of risk associated with DSM programs that might or might not successfully reduce facility investments. Guidance on cross-subsidization and customer discriminations inherent in geotargeted DSM programs that do not provide similar opportunities to all customers. Guidance on how to treat conflicts between DSM programs designed primarily to reduce investment in new infrastructure and DSM programs designed to reduce carbon emissions or improve energy efficiency. Guidance on how to treat uncertainty associated with energy-efficiency programs outside the control of the Gas Utilities that impact peak hour and peak day demand."

Accordingly, and consistent with the Board's further encouragement as part of its Report on the Mid-Term Review of the 2015-2020 Demand Side Management (DSM) Framework for Natural Gas Distributors (EB-2017-0128/0127) to advance natural gas IRP Enbridge Gas included its original IRP Proposal as part of its 2021 Dawn Parkway Expansion Project application and evidence in support of establishing an IRP Framework that addresses the changes/gaps identified by ICF in its IRP Study and to guide the Company's assessment of IRPA's relative to other

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[1] 2015-2020 DSM Framework, p. 36.
[2] EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020, p. 167.
[3] EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020, p. 168.

facility and non-facility alternatives to serve the forecasted needs of Enbridge Gas customers. Enbridge Gas's IRP Proposal and related efforts to date are evidence of its compliance with the Board's encouragement to advance natural gas IRP and reflect the novelty of natural gas IRP across North America.

Further, it should not be lost that Enbridge Gas has long been engaged in passive forms of IRP having successfully conducted natural gas conservation/demand side management programs and having made interruptible services available to its customers for decades.

Overall, Enbridge Gas has shown commitment to the serious consideration and practical implementation of natural gas IRP in Ontario consistent with the Board's previous statements encouraging the same. Considering the above, in the absence of any evidence to the contrary, it is premature and unnecessary for the Board to contemplate the imposition of penalties upon Enbridge Gas for inadequate consideration of IRPA(s) as part of future applications for leave-to-construct ("LTC") facilities. Instead, the Board should focus upon establishing an IRP Framework for Enbridge Gas that provides the guidance necessary to support consideration of IRPA(s) relative to other facility and non-facility alternatives going forward.

As a natural gas distributor with an obligation to prudently serve the firm contractual demands of its customers in Ontario, Enbridge Gas already carries the responsibility to ensure that it considers the optimal and most prudent solutions for ratepayers. In the future, following the establishment of an IRP Framework for Enbridge Gas and as part of its review of future LTC applications, should the Board determine that the Company's consideration of IRPA(s) was deficient and caused undue costs for ratepayers, that would be the appropriate time to consider whether the Company should be subject to penalties based on the best available information and with consideration for the specific circumstances at that time. It is premature to establish punitive penalties at this time.

Please also see the response at Exhibit I.EP.6, for discussion of the risk to ratepayers of investments in natural gas IRP.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / p. 37-38 of 46

Additional Public Documents: Consolidated Edison Company of New York, Inc, Proposal for use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure / pp. 29-31 of 33.

Preamble:

Enbridge Gas proposes filing an annual report of the effectiveness of IRPAs in meeting system needs. Enbridge Gas notes that monitoring and reporting could include consideration of metrics.

Question:

a) Would Enbridge Gas's proposed annual IRP report also include progress updates on elements of IRP that are not tied to specific approved IRP Plans (e.g. updates on incorporating IRP into asset management planning, updates on planning status of potential IRPAs to meet system needs not yet in an IRP Plan, developments on IRP pilot projects, etc.)?
b) OEB staff notes that Con Ed's Non-Pipeline Alternatives Framework Proposal (pp. 29-31) discusses making use of updated reliability assessments to inform whether spending on previously approved non-pipeline alternatives may need to be increased or decreased. Within its proposed annual IRP report, in cases where IRP Plans to address specific system needs have been approved, would Enbridge Gas support providing updated information on the status of these system needs (e.g. current data on system peak demand, updated demand forecast for the affected area), for the purpose of assessing whether the system need remains and ongoing spending on IRPAs needs to be increased or decreased? Why or why not?
c) What, if any, outcomes or metrics does Enbridge Gas believe should be used to measure the progress of its IRP Plans? Is there any relationship between these

outcomes and the approach to incentives, cost recovery, and risk that Enbridge Gas has proposed? Please describe.

<u>Response</u>

a) Enbridge Gas's proposal is to file an annual IRP Report with the Board that identifies implemented IRPAs and provides an update on the performance of those specific projects. In the event an IRPA is underperforming, the IRP Report may propose a plan to address the underperformance. In addition, the IRP Report will provide an update on any IRP pilot projects planned or underway, including their status and related learnings. Enbridge Gas will also include any other IRP related matters that are required by the Board or that Enbridge Gas feels are necessary to bring to the Board's attention (potentially including those suggested by OEB Staff).

b) Yes, Enbridge Gas will provide an update on the status of previously identified system constraints in either its Asset Management Plan ("AMP") and/or in its annual IRP Report. Enbridge Gas proposes to include potential IRPAs in its AMP (or updates/addendum thereto) that will be filed along with annual rates applications. Enbridge Gas will continue to monitor identified system constraints underlying specific IRPA investments until such time that the IRPA is fully implemented. If the constraints change or are eliminated prior to full implementation then the AMP will be updated accordingly (e.g., for adjustments to the project size, costs and scope). Please also see the response at part a) where Enbridge Gas contemplates scenarios where IRPAs are determined to be underperforming and the Company advises of its plans to adjust its investments (increase, decrease or cease) accordingly.

c) Enbridge Gas has not proposed any metrics for IRP planning. The Company's request is to implement the optimal solution for its customers based on the screening criteria and the economic evaluation proposed. Therefore, metrics are not required. If OEB Staff is referring to the proposed monitoring and reporting of specific IRPAs implemented, a proposed monitoring and reporting process template was filed as part of Enbridge Gas's Additional Evidence at Exhibit B, Page 38, Table 3.2. This template is preliminary in nature and Enbridge Gas expects that it will be modified to suit the IRP Framework ultimately established by the Board for Enbridge Gas.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Anwaatin Inc. (Anwaatin)

INTERROGATORY

Reference:

Exhibit B, paras 30 and 90-93.
Exhibit C, paras 29-31.

Preamble:

Enbridge Gas Inc. (EGI) indicates that it will file Integrated Resource Planning (IRP) alternatives (IRPAs) applications that lay out respective anticipated savings or peak period impacts together with associated costs and ownership/operationalization arrangements. EGI indicates that it intends to consult with any impacted landowners, municipalities, First Nations, Indigenous groups, and other affected stakeholders prior to filing any IRPA application with the Ontario Energy Board (the Board).

Consequently, EGI's IRP Proposal (the IRP Proposal) may constitute, inform, or underpin strategic higher level decisions in relation to natural gas infrastructure and the selection of IRP alternatives (IRPAs).

In its Decision and Order in EB-2017-0319 dated October 18, 2018, the Board confirmed that "strategic, higher level decisions can trigger the duty to consult" First Nation and Métis communities (p. 25).

Questions:

a) Please describe, in detail, and provide evidence for whether — and, if so, how — EGI will determine, interpret, and apply:

   (i) its procedural requirements;
   (ii) the Crown's procedural requirements; and
   (iii) the Board's procedural requirements;

   in assisting the Crown in fulfilling its duty to consult and accommodate First Nation and Métis communities in relation to IRP, the planning of natural gas infrastructure, and the selection of IRPAs.

b) Please provide a detailed outline of EGI's Indigenous consultation process with respect to the IRP Proposal. Please include a description of all steps that EGI has taken or will take in order to engage, consult, and accommodate Indigenous communities on the IRP Proposal.

c) Please indicate whether EGI has or expects to make capacity funding available to Indigenous communities in order to facilitate their participation in relation to IRP, the planning of natural gas infrastructure, and the selection of IRPAs.

d) Please place EGI's Indigenous consultation policy with respect to IRPAs on the record in this proceeding.

e) Please describe, in detail, EGI's plans and modalities for involving Indigenous rights-holding communities in the IRP process and selection of IRPAs.

Response:

a) Enbridge Gas does not believe that the current application triggers the duty to consult. This proceeding is intended to establish an IRP Framework for Enbridge Gas. The OEB is not being asked to review or approve any specific IRPAs or to render a decision that may adversely affect rights of any Indigenous groups. If specific IRPA investments are proposed in the future, and such investments do give rise to a duty to consult, then Enbridge Gas expects that the Ministry of Energy and/or the OEB will provide direction to Enbridge Gas about how that duty is to be honoured, taking account of the OEB's existing processes as set out in the OEB's *2016 Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario* (the "Guidelines"), and Enbridge Gas will consult with potentially affected Indigenous groups as appropriate.

b) This approach is consistent with the approach that Enbridge Gas explained, and that the OEB accepted, in the EB-2017-0319 RNG Enabling Program proceeding.[1]

[1] EB-2017-0319, Decision and Order, October 18, 2018, pp. 24-25.

c) – e)

In Enbridge Inc.'s ("Enbridge") Indigenous Peoples Policy (Policy),[2] Enbridge states that it is committed "to working with Indigenous peoples to achieve benefits for them resulting from Enbridge's projects and operations, including opportunities in training and education, employment, procurement, business development, and community development." Enbridge Gas consults with Indigenous groups in accordance with this Policy and as appropriate.

The proposed IRP Stakeholder and Indigenous Engagement model proposed in Enbridge Gas's Additional Evidence at pages 39 to 42 and as clarified in the response at Exhibit I.STAFF.9, is meant to allow for fulsome public participation including with Indigenous communities and groups. Enbridge Gas notes that Anwaatin is an active participant in this proceeding before the OEB. Enbridge Gas will address any questions raised by members of Indigenous rights holding communities regarding the IRPAs as they arise. Given the nature of IRP, while Enbridge Gas does not expect to make separate capacity funding available to Indigenous communities and groups, it remains open to doing so depending on the specific circumstances of the community and the potential impact any IRPA may have on their rights and interests.

[2] https://www.enbridge.com/~/media/Enb/Documents/About%20Us/indigenous_peoples_policy.pdf?la=en

ENBRIDGE GAS INC.

Answer to Interrogatory from
Anwaatin Inc. (Anwaatin)

INTERROGATORY

Reference:

Exhibit B, paras 22 and 28.

Preamble:

EGI notes that its IRP Proposal and the illustrative process plan are underpinned by guiding principles, one of which is public policy. EGI notes that “IRP will be considered in a manner to ensure that is it supportive of and aligned with public policy, where appropriate.” Alignment with public policy is also considered in the second stage of IRPA evaluation.

Questions:

a) Please outline the current areas of public policy that EGI believes should be supported by, and aligned with:
   (i) its IRP Proposal; and
   (ii) the IRPA evaluation process.

b) How does EGI propose to monitor and report on the effectiveness of the IRP Proposal and the IRPA evaluation process in their support for, and alignment with, public policy? Please provide an example or examples.

c) Does EGI believe that its IRP Proposal and the IRPA evaluation process supports and is aligned with EGI’s consideration of non-gas or blended gas alternatives? If so, please explain why. If not, please explain why not.

d) Does EGI believe that its IRP Proposal and the IRPA evaluation process supports and is aligned with the expansion of natural gas access to First Nation reserve communities and off-reserve First Nation Members? If so, please explain why. If not, please explain why not.

<u>Response:</u>

a) Enbridge Gas is focused upon public policy priorities that enable all communities in which it operates to realize the benefits of clean, safe, reliable and affordable energy. In our view, this focus is consistent with its IRP Proposal and proposed IRPA evaluation process.

b) In its Additional Evidence at page 17, Enbridge Gas states:

> "Following the implementation of an IRPA(s), the effectiveness of the alternative in meeting the identified need will be carefully monitored to ensure the identified system constraints/needs are being sufficiently resolved. Enbridge Gas will provide an annual report of IRPA effectiveness to the OEB as part of either its annual Rates application or Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application or as otherwise directed by the Board. If the IRPA is not meeting the identified need, Enbridge Gas will propose corrective action in its report which may include, but not be limited to, proposals to implement additional IRPAs or a new facility build to meet the need. Given that natural gas IRP is still relatively nascent and forms an innovative approach to meeting natural gas facility needs, the process outlined above will necessarily be refined over time as experience is gained and opportunities for improvement in IRPA design and implementation are identified."

As Enbridge Gas has proposed that alignment with and support of public policy should be one of the Guiding Principles of natural gas IRP,[1] the Company expects that consideration of public policy will necessarily occur at each stage of IRPA review by the OEB and parties, including: (i) as part of the OEB's review of any IRP application made by Enbridge Gas for approval to invest in and/or recover the costs associated with IRPAs; (ii) at such time that Enbridge Gas provides an annual report of IRPA effectiveness to the OEB; and (iii) in instances where an OEB-approved IRPA is found to be underperforming relative to forecast and thus Enbridge Gas proposes corrective action which may include, but not be limited to, proposals to implement additional IRPAs or to construct new facilities to meet identified system constraints driving such investments.

c) Yes, Enbridge Gas believes that its IRP Proposal and the IRPA evaluation process supports, and is aligned with consideration of non-gas or blended gas alternatives where those alternatives may impact infrastructure and supply planning decisions (please also see the response at Exhibit I.STAFF.2). However, to be clear, although IRP alternatives should not create a higher greenhouse gas profile, reduction of such is not the primary goal IRP. For this reason, not all blended or non-gas solutions may be considered during IRP planning.

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[1] Additional Evidence, Exhibit B, pp. 12-17.

d) Yes, Enbridge Gas believes that its IRP Proposal and the IRPA evaluation process supports and is aligned with the expansion of natural gas access to First Nation on-reserve communities and off-reserve First Nation Members. Enbridge Gas's IRP Proposal includes: (i) exemptions related to policies and targeted funding for example for Community Expansion (as further discussed in the response at Exhibit I.Anwaatin.3)); and (ii) extensive Stakeholder Engagement including with First Nations on-reserve communities and off-reserve First Nation Members in order to consider feedback on potential IRPA(s) and any specific local initiatives that may have a bearing on alternatives considered to resolve identified system constraints (as further discussed in the response at Exhibit I.STAFF.9).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Anwaatin Inc. (Anwaatin)

INTERROGATORY

Reference:

Exhibit B, para 38(v)

Preamble:

EGI states that “[i]f a project has been driven by policy and related funding to explicitly deliver natural gas into communities to help bring heating costs down, then it is not reasonable to conduct an IRP analysis.”

Questions:

a) Please explain the above statement, including its underlying rationale.

b) Please clarify whether EGI believes that it is not appropriate to consider IRPAs in situations where community expansion is underway. Please explain.

Response:

a) & b)
Community expansion pertains to the expansion of natural gas to existing communities that do not currently have access to natural gas. These types of projects are governed by the Final Guidelines for Potential Projects to Expand Access to Natural Gas Distribution that were issued on March 5, 2020.[1] Where Government grants are not identified for the specific purpose of growing natural gas access, then, IRP could be considered for community expansion provided IRPAs such as district energy systems were included in scope. Please also see response at Exhibit I.STAFF.8.

In the case of economic development these projects are usually driven by customer requests and are often funded by contributions in aid of construction (“CIAC”) ensuring that the infrastructure project is financially feasible, such that this specific

[1] https://www.oeb.ca/sites/default/files/ltr-final-guidelines-gas-expansion-20200305.pdf

customer or group of customers bears the cost of the new or reinforced infrastructure without causing undue burden on other existing customers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

INTERROGATORY

Reference:

Integrated Resource Planning Proposal – Additional Evidence, Exhibit B, dated October 15, 2020, Page 40 of 46

Preamble:

Regarding stakeholder engagement, Enbridge identified three components of stakeholder engagement for IRP: (1) Gather and analyze data and insight from ongoing stakeholder engagement initiatives; (2) Discussion of IRP during Stakeholder Days; and (3) Conduct IRPA project geographically-specific stakeholder engagement prior to filing a proposed IRPA with the OEB.

Question:

a) With respect to gathering data and insights from stakeholder engagement initiatives, what type of data and insight does Enbridge intend to collect from stakeholders in relation to IRPAs? Please be as specific as is possible.

b) Please provide some examples of topics and questions to be discussed with stakeholders which Enbridge will find helpful in informing its IRP Plan?

c) Please provide some examples of topics and questions to be discussed with stakeholders which Enbridge will find helpful in informing proposed IRPAs with geographically-specific stakeholders?

d) In electricity system planning, demand response resources have proven to be a source of electrical capacity in the IESO's capacity auctions. Is Enbridge willing to engage with geographically-specific large volume gas customers (including but not limited to gas-fired generators ("GFG")) to see if they are able to provide services that may be beneficial as a potential IRPA? If no, why not?

e) When Enbridge is developing its IRPAs, is it Enbridge's intent to reach out to GFG customers to see if a commercial arrangement can be negotiated which itself may become a viable IRPA that can be assessed against other options? For example, if a GFG has excess contracted capacity it may be able to sell some of that capacity to Enbridge to meet a particular system need.

Response

a) – c)
Please see the response at Exhibit I.STAFF.9, for further discussion of Enbridge Gas's proposed stakeholder engagement activities.

d) & e)
Yes.

Further, Enbridge Gas's Expression of Interest process is used in in-franchise areas where incremental demands are less certain and new facilities are likely required to service new demands. This non-binding process accepts customer provided bids reflecting incremental firm demands, turnback of existing distribution capacity, and requests for interruptible services. The Expression of Interest process encourages all existing and future potential customers, within a specific geographical area to participate. In addition to customers requesting additional firm or interruptible capacity, existing customers can share their desire to reduce demands through the turn back or reverse open season component of the Expression of Interest.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

INTERROGATORY

Reference:

Reference 1: Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, by ICF Canada, Final Report, May 18, 2018 ("IRP Final Report"), page 168

Reference 2: IRP Final Report, page ES-5

Reference 3: IRP Final Report, page ES-4

Preamble:

Reference 1:

"The use of DSM to reduce facility investments remains relatively untried and untested. While ICF has identified areas where there is potential to use DSM to reduce facility investments, there remains uncertainty in both the potential and the cost of achieving that potential. There is little to no actual measured data on DSM program impacts on peak period demand for natural gas, and there are no real world examples that ICF can point to that indicate that DSM can be used effectively for this purpose.
[…]

Hence, one of the most important conclusions from this study is that additional research is necessary before the Gas Utilities would be able to rely on DSM to reduce new facility investments as part of the standard utility facilities planning process."

Reference 2:

"additional research and additional hourly data by way of additional metered hourly reads (i.e. automated meter reading or infrastructure installation (AMI), as well as pilot studies to determine the cost-effectiveness and implementation potential of DSM programs are necessary before the Gas Utilities would be able to rely on DSM to reduce new infrastructure investments as part of the standard facilities planning process."

Question:

a) Given the uncertainty around DSM at the present time, does Enbridge intend to rely on DSM as a viable IRPA in its system planning processes in the near term? Is this a prudent approach that will protect customers from risk if DSM programs fail to produce anticipated benefits?

b) In Reference 3, ICF's review indicates that changes to utility planning processes would be necessary to facilitate the use of DSM to reduce infrastructure investments. Does Enbridge agree with ICF's findings here? If no, why not? What are the challenges that Enbridge anticipates to face in implementing the changes to its utility planning processes as noted at Reference 3?

c) What does Enbridge anticipate to be the risks involved in proceeding with DSM without performing additional research?

d) As stated in Reference 2, additional research and additional hourly data by way of additional metered hourly reads (i.e. automated meter reading or infrastructure installation (AMI), as well as pilot studies will be required prior to relying on DSM.
   i. How much would it cost for Enbridge to undertake additional research, data gathering and pilot studies related to DSM?
   ii. What would be the amount of work involved in performing additional research and gathering additional hourly data? How much time would be involved?
   iii. Would the implementation of AMI involve an upgrade to all of Enbridge's existing meters as well as the metering systems? If so, how much would it cost to undergo such upgrade (roughly)? Would Enbridge need to dispose of any assets (e.g. meters) that have a remaining useful life – and if so what would the wasted value of these removals be?
   iv. Does Enbridge consider DSM as a viable IRPA given the costs involved? If yes, why? If no, why not?

Response

a) If broad based energy efficiency, or demand side management ("DSM"), is a cost-effective option to avoid, defer or reduce the need for a facility alternative, then yes, Enbridge Gas may consider such investments as an IRPA in the near term (please also see the response at Exhibit I.STAFF.11). Enbridge Gas is solely seeking to establish an IRP Policy Framework through this proceeding that would guide its assessment of such alternatives in the future. At such time that the Company applies to the OEB in the future to approve investment in specific IRPAs it expects that as part of that application it would provide evidence of the anticipated effectiveness of those IRPA(s) to relieve underlying system capacity constraints identified in support of receiving a determination from the Board that the proposed IRPA(s) is prudent and in the best interest of ratepayers.

b) Yes, Enbridge Gas agrees with ICF's findings with respect to the changes in utility planning processes that would be necessary to facilitate the use of IRPA(s) (ETEEs) and other IRPAs to resolve identified system capacity constraints in place of facility alternatives:

- Enbridge Gas anticipates challenges with reconciling the risk profiles between IRPA(s) (ETEEs) and facilities planning. For a IRPA (ETEE) to be relied upon instead of a facility alternative, it would need to satisfy the same risk criteria as the facility investment that it is replacing. Facilities planning needs to consider the consequences of the lack of required infrastructure. With broad based DSM programs, the associated risks are strictly financial.
- IRPAs will need to be implemented very early in the facilities planning cycle in order to garner measured results prior to the required facility investment being needed. By implementing the IRPA early in the planning cycle there is a risk that growth projections may not materialize, or growth projections may accelerate, requiring a facility alternative earlier than anticipated. This would result in costs for both the IRPA investment and facility investment being absorbed by the ratepayer.
- Differences between IRPAs and facility alternatives such as asset lifetimes, and cost-effectiveness criteria, will also need to be considered.

c) If, in the absence of such research and insight into the effectiveness of DSM (ETEE) to impact peak period demands, Enbridge Gas applied to the Board through an IRPA application and was approved to invest in DSM (ETEE) IRPAs in order to resolve identified system constraints, the Company may realize through its proposed Monitoring and Reporting processes and annual IRP Reporting that such IRPAs underperformed relative to forecast. In such instances, Enbridge Gas may need to apply to the Board to adjust or cease its investments into such IRPAs, and depending upon the lead time remaining before the identified constraint was forecast to be realized may need to apply separately for leave-to-construct ("LTC") facilities. In the instance that Enbridge Gas is required to adjust its investments in IRPAs or for LTC facilities, ratepayers may incur incremental costs related to the IRPA and the regulatory review of associated applications. Please also see the response at Exhibit I.EP. 6 for discussion of the risks associated with investments in IRP/IRPAs.

d)

i. - ii.

Given the data required for the Company to be comparably certain that investments in DSM (ETEE) IRPAs will be able to meet identified system constraints as it is of facility alternatives, AMI and/or a robust EM&V program will likely be required. At this time, in the absence of an IRP Framework for Enbridge Gas that provides guidance as to the nature of acceptable IRPA investments, reporting requirements, risk and other such attributes, the Company cannot provide any reasonable estimate of costs for AMI and/or EM&V associated specifically with DSM (ETEE) IRPA(s) investments. Similarly, Enbridge Gas is uncertain at this time of how much work is required to perform additional research and gather additional hourly data, as that information will depend heavily on the nature of the AMI system that is ultimately deployed. Please also see the response at Exhibit I.VECC.11, for discussion of Enbridge Gas's work to investigate AMI deployment.

iii. Enbridge Gas expects that as part of such an AMI deployment, all residential meters would be replaced with an ultrasonic meter.

An AMI deployment of this nature would take place over a number of years and is estimated to cost approximately $1.2 billion, which is in line with deployments by utilities of similar size to Enbridge Gas (e.g. Con Ed and SoCal Gas).

The $1.2 billion estimate includes the cost of meters, the network, installation, project management and an estimate for software integration. This estimate is based on discussions and pricing quotes provided by potential AMI vendors under the guises of confidentiality. This estimate does not include any of the associated savings with an AMI deployment. Savings include cost reductions in meter reading, call centre savings resulting from a decrease of incoming calls, operational cost reductions and avoided meter replacement costs.

Enbridge Gas has not determined a deployment plan for AMI and therefore is not able to determine the value of meters that may be retired early. Such information would require an in-depth plan indicating when and where the meters will be installed.

iv. Yes, DSM (ETEE) should be considered as a viable IRPA for review and analysis (please also see the response at Exhibit I.STAFF.11). Absent AMI implementation, the costs of evaluation and measurement to quantify the DSM (ETEE) and other IRPA savings achieved will be included in Enbridge Gas's cost benefit analysis. Whether DSM (ETEE) or other types of IRPAs are cos- effective or not, will be determined on a case-by-case basis relative to the identified system constraint such investments are meant to address and comparable baseline facilities identified.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

INTERROGATORY

Reference:

Integrated Resource Planning Proposal – Additional Evidence, Exhibit B, dated October 15, 2020, Page 2 of 46

Preamble:

When a need is identified in the planning process, it will be assessed to determine the appropriateness of developing IRPAs to address it. This approach will ensure that Enbridge Gas has adequate lead time to fully assess, put forward to the OEB and verify the effectiveness of IRPAs to address peak period demands, deferring or reducing the need to construct facility alternatives.

Question:

a) For IRPAs (non-DSM), what does Enbridge expect the lead time to assess the IRPA to be? Please explain how this lead time will be accounted for within and will affect Enbridge's existing planning process.

b) What measures does Enbridge propose to use to minimize the amount of lead time required in assessing an IRPA?

c) What types of evidence does Enbridge propose to file to demonstrate that Enbridge does not use the lead time requirement as a reason to avoid pursuing IRPAs? (E.g. All new projects are identified as "urgent" and therefore exempt from the IRPA analysis).

Response

a) & b)
Enbridge Gas anticipates the lead time to assess IRPAs to be roughly 5 years and to be accounted for as identified in Figure 2.1 IRP Integration at Enbridge Gas, found in Enbridge Gas's Additional Evidence at Exhibit B, page 13. Enbridge Gas is currently

undertaking a more detailed exercise to document how IRP is integrated into its planning processes (please see the response at Exhibit I.OSEA.1 c)). Enbridge Gas also anticipates that insights and refinements to the planning process and IRPA assessment lead times will be considered and accordingly adjusted over time as experience is gained. As noted throughout Enbridge Gas's IRP Proposal and Supplementary Evidence (Additional Evidence and Reply Evidence), the outcomes of Pilot Projects will be useful to inform and refine the IRP processes proposed:[1]

> "Pilot projects would provide the opportunity to test a number of elements associated with IRP and Enbridge Gas's IRP Proposal/Processes, including but not limited to: the design, review and assessment of IRPAs (including new and emerging technologies); procurement methodologies/strategy for IRPAs sought from existing competitive markets; the proposed stakeholder engagement model; proposed screening mechanisms and cost-effectiveness tests; and the ability to effectively and accurately measure actual achieved results of investments in IRPAs."

c) Enbridge Gas does not accept APPrO's insinuation that lead times would be intentionally used to avoid consideration of IRPAs. As discussed in response to interrogatories and throughout its original IRP Proposal, Additional Evidence, and Reply Evidence, Enbridge Gas has sought to establish an IRP Framework that provides the Board and parties transparency and reasonable opportunities for input and review. Please see the response at Exhibit I.STAFF.6, for discussion of the lead times and various opportunities for input and review that Enbridge Gas has proposed related to assessment of IRPAs.

It should be noted that proposals to serve larger volume customers, such as ex-franchise transportation customers or in-franchise industrial customers, are difficult to forecast. Requests for incremental capacity require final investment decisions, favourable market conditions and regulatory approvals, amongst other things, in order to commit to contracts or financial backstopping obligations. The requested quantities would be evaluated against forecast system capacity at the time needed. If there are system constraints to providing the requested quantities, then a baseline project would be identified and various IRPAs would be assessed to determine the preferred alternative. Please see the response at Exhibit I.STAFF.2, for further information on processes.

[1] EB-2020-0091, Reply Evidence, p. 25.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

INTERROGATORY

Reference:

Reference 1: IRP Jurisdictional Review Report by ICF Canada, Exhibit B, Appendix A, October 15, 2020 Page 15 of 92

Reference 2: Natural Gas Integrated Resource Planning in New York State and Ontario Final Report prepared for Ontario Energy Board by Guidehouse ("Guidehouse Report"), Section 7.0 – Industry Best Practices for Natural Gas IRP

Preamble:

Reference 1:

"Ontario differs from New York State on many of the aspects that determine the value of NPS. Despite these differences, the experience in New York State represents a valuable source of information and best practices regarding NPS for Ontario utilities."

Question:

a) For each of the identified best practices in Reference 2, please identify the extent to which Enbridge:
    i. has adopted such best practice in its IRP Proposal (and explain exactly how);
    ii. plans to adopt such best practice (and explain the effort required as well as an estimate of when such best practice would be adopted); or
    iii. believes that such best practice is not appropriate or applicable in the Ontario context (and explain why).

b) Has ICF Canada reviewed the evidence provided in Reference 2 and are they in agreement with this list of best practices? If no, please explain the differences and the reasons for the differences in detail.

Response

a) Please see Table 1 below for a listing of Best Practices identified in the expert evidence of OEB Staff in the Guidehouse Report and Enbridge Gas's position on the same.

Table 1

Guidehouse's Identified Best Practices	**Enbridge Gas's Positions**
Developing BCA procedures that evaluate infrastructure, supply-side, and demand-side solutions with a similar set of assumptions and recognize the risks associated with traditional vs. emerging options can allow for a more transparent IRP process.	Enbridge has proposed a staged economic review based on an existing and known cost-benefit framework. Enbridge Gas believes that this is consistent with the value derived from the BCA development work done in New York State which is cited by Guidehouse.
Utility program managers implementing demand-side IRP solutions require flexibility to adjust recruitment strategies, incentive amounts, budgets, operating procedures, and other parameters to achieve the goals of the programs.	Enbridge Gas agrees with this best practice and in its Additional Evidence on page 38 it indicated that "…ongoing monitoring and reporting will be regularly fed into the IRP process to ensure systems are able to meet their capacity requirements, to address any operational challenges, to address flaws in the design or delivery of IRPAs, and/or to make additional investments in IRPAs or new infrastructure". Further in its Reply Evidence on pages 5 & 6 Enbridge Gas stated, "Enbridge Gas has also proposed to report annually on the actual annual and cumulative effects of OEB-approved IRPAs relative to associated peak period demand reductions originally forecast (via an IRP report) and to seek OEB approval to adjust investments in such IRPAs as appropriate (e.g., to shift funding)."

Non-traditional supply-side and demand-side solutions carry greater uncertainty compared to traditional infrastructure projects, and utility program managers have overcome these risks by oversubscribing customers and diversifying the IRP solutions. Traditional demand-side solutions such as energy efficiency or heating electrification have a higher degree of certainty of load reduction for each participant whereas DR carries greater uncertainty of demand reduction on peak days because it is dependent on customer behavior on those days. To address these issues, utilities deploy a broad mix of solutions, but are cognizant of and adjust for these different levels of certainty. The initial pilot programs being deployed now will provide greater insight into more standardized assumptions for reliability.	Enbridge Gas in its Additional Evidence, in a discussion about demand response on page 27 noted that "…research would need to be done to understand what level of customer incentive is required to drive targeted outcomes from the end-use customer". Enbridge Gas has also been clear in its Reply Evidence that pilot projects are important to inform understanding and thereby creating more standardized assumptions for reliability. To the extent reasonably possible, Enbridge Gas will explore the potential of individual IRPAs as well as portfolios of IRPAs depending on the particular identified system constraints.
Deploying a diversity of IRP solutions is important to reduce risks in achieving the project goals. Smaller IRP projects may be able to achieve goals in a shorter timeline by expanding existing EE/DSM or DR programs, whereas larger IRP projects may be best suited for market solicitations and new program developments that have longer timelines.	To the extent reasonably possible, Enbridge Gas will explore individual IRPAs as well as portfolios of IRPAs depending on the particular identified system constraints. At page 6 of its Additional Evidence Enbridge Gas states, "Enbridge Gas will compare the facility alternative and selected IRPA(s) on an economic basis and will also consider one or several alternate IRPA portfolios based on the complexity and size of the system need." Further in the Additional Evidence at page 27, Enbridge Gas adopts the idea that "…leveraging existing DSM programs may prove to be a cost-effective and efficient means to address peak period demands..". In short, Enbridge Gas will consider the needs and timing of the identified system constraints in tandem with the attributes of IRPAs.

EM&V of IRP initiatives is critical both to confirm demand reduction as well as to ensure customer compliance with program goals and requirements. For example, Con Edison performed EM&V within their Demand Response program to measure the 24-hour gas demand reduction on a peak day and verify that customers did not offset gas consumption with fuel oil, which contradicts the program's environmental goals. Through the Gas DR pilot programs, Con Edison found performing EM&V for demand-side IRP solutions is more challenging without gas AMI deployed across the service territory. There are opportunities to perform EM&V without AMI, but these carry higher costs per unit of peak day reduction (see section 4.1.3). As experience is gained and lessons are learned from EM&V, firmer conclusions and guidance can be developed about performance, cost effectiveness, and robustness of results.	Enbridge Gas agrees that having AMI in place would keep costs of IRPAs lower by assisting with planning for and reporting on the results from IRPAs. Enbridge Gas notes in its Additional Evidence that its intention is to put forward an AMI application in the future, "Absent more granular consumption data that would be available from AMI implementation, more conservative derating factors will need to be applied towards consideration of a given alternative and, incremental evaluation policy and/or protocols may need to be designed and implemented at additional cost." Enbridge further notes on page 16 of the Additional Evidence that "A derating factor is a reduced effectiveness rate ascribed to an alternative's savings value to capture its inherent risks. Enbridge Gas anticipates that derating factors will be refined as experience with various alternatives in Ontario grows, technologies and solutions are tested and when ultrasonic metering is in place to provide more certain data." Enbridge Gas accepts Con Edison's learning that EM&V carries a higher cost per unit of peak day reduction without AMI in place.

New York State utilities have found the operational processes, program design, benefit-cost analyses, and other parameters for the Gas IRP solutions can be similar to existing gas energy efficiency programs or electric NWA programs. The NWA pilots have suggested significant investment in organizational resources (e.g., dedicated time for cross-functional managers and experts, IT system development, internal training updates) is needed upfront to develop the necessary internal processes and operationalize the programs, but that can be useful across both gas and electric IRP solutions. Nevertheless, they have found key differences relating to limitations around Natural Gas Integrated Resource Planning in New York State and Ontario space heating end-uses, building codes, customers switching to fuel oil, and other issues that require separate set of guidelines. The level of investment necessary to operationalize IRP programs will vary based on the capacity, expertise, and experience of utility staff and their current programs, as well as experiences of neighboring utilities that share similar regulatory processes.	Enbridge Gas agrees with these best practice ideas and has woven into its original IRP Proposal, Additional Evidence and Reply Evidence that it takes time and additional resources to develop the necessary internal processes and to operationalize IRPAs. The level of cross functional effort from across the utility is significant. Enbridge Gas has also been clear that although there are many lessons to be learned from other jurisdictions (from the electricity sector and from the natural gas sector in New York State), Ontario requires its own natural gas specific IRP Framework. The Ontario Natural Gas IRP Framework needs to reflect the unique energy system, diversity of customers, end-use technologies in place, regulatory construct, government policies, and existing utility structures present in Ontario.
IRP programs take significant time to develop, recruit, launch, and scale and may not align with the timelines of gas planning or engineering departments when looking at traditional infrastructure projects. Of note is that different IRP solutions have different lead times; for example, a DR program may have a shorter lead time than an electrification program. By taking these differences into account, utilities can use a mix of these IRP programs to reduce load before committing to more expensive infrastructure projects.	Enbridge Gas agrees that IRP programs take time to develop, recruit, launch and scale and may not align with the timelines of gas planning or engineering departments. Timing for implementing different IRPAs is recognized and addressed earlier in this response.

Gas utilities recognize that core planning processes including gas supply and transportation planning, infrastructure maintenance and expansion planning, energy efficiency / demand-side management planning, and IRP planning are interconnected and interdependent. For this reason, gas utilities are seeking to identify how to integrate these processes and sequence the activities to ensure that each planning process properly captures the output of adjacent processes. Having regular discussion with regulator and stakeholder groups around the needs for capacity additions, IRP solutions, and program design plans can reduce uncertainty and facilitate success.	Enbridge Gas has proposed a fulsome stakeholder engagement process in its Additional Evidence starting at page 39, and clarified aspects of it in its Reply Evidence. In its Reply Evidence on pages 15 & 16 Enbridge Gas clarified "Enbridge Gas's multi-component approach to Stakeholder Engagement is similar to the stakeholder engagements seen in the IESO Integrated Regional Resource Planning Process ("IRRP") in the sense that it seeks to be informed by public input… Enbridge Gas proposes that development of natural gas IRPAs will be subject to OEB review and a litigated process following receipt of public input and consideration. This point is important as it offers an official and Board-led review of Enbridge Gas's IRPA projects and investments in a manner similar to facility infrastructure projects and investments in Ontario."
Regulators need to design the proper incentives for utilities to pursue IRP solutions, including cost-recovery and sharing risk amongst stakeholders similar to a traditional infrastructure investment. EAMs have been successful in New York State in aligning the goals of the utilities, regulators, and key stakeholders, although their long-term effectiveness is still uncertain.	In its Additional Evidence starting at page 32, Enbridge Gas states "Enbridge Gas proposes that the costs associated with an IRPA be included in its revenue requirement." This proposal is made with the clear proposal that the Company should receive "Like Treatment for Like Results" meaning that meeting a customers' needs through facility or IRPA solutions should have the same effect on the utility and shareholders.

b) ICF Canada has reviewed the evidence provided in Reference 2. The listed best practices are generally sound but ICF Canada does not entirely agree with them.

The following items require additional context:

- The ConEd BCA Handbook[1] allows for the use of "de-rating factors" applicable to non-pipe alternative solutions to fairly represent the level of uncertainty, and different level of resource availability with demand-side and emerging resources compared with traditional supply-side solutions. The Downstate New York utilities are left to determine the value of these de-rating factors and are not necessarily asked to disclose them or debate them publicly. While systematically comparing

[1] ConEd. (2020). ConEd NPA Framework & BCA Handbook for NPA.

demand-side and emerging solutions based on their economic merit is desirable, the de-rating factors leave a degree of discretion in the hands of the utility system designers. For this reason, while the BCA procedures adopted by ConEd can be considered reasonable best practices, the level of transparency in New York with respect to BCA is lower than Reference 2 suggests.

- Downstate New York utilities have much smaller and more densely populated service territories than much of the EGI service territory. Downstate New York's utilities have been primarily focused on non-pipe alternatives aimed at alleviating constraints at the city gates (i.e. upstream constraints). Relieving distribution infrastructure constraints requires activities focused on narrower areas of the gas network, with lower energy use diversity and a requirement for higher accuracy of the load shape impacts. Alternatively, focusing on distribution infrastructure constraints lends itself to more conservative de-rating factors to ensure a fair comparison between supply- and demand-side resources. ConEd sought to make this distinction in their most recent Non-Pipe Alternative framework, which was published in September 2020 and is in the process of being adopted.[2] Any standard practices for non-pipe alternatives in Ontario should also make a distinction between solutions aimed at alleviating transmission system constraints and solutions aimed at alleviating distribution system constraints.

- It is too early to conclude on a full set of best practices based largely on the New York experience, as Downstate New York gas utilities are still at an early stage of their experimentation with non-pipe alternatives. To date, relevant learnings are based on a small number of initiatives. The listed best practices appear to be similar to best practices for non-wire alternative projects, which the Downstate New York joint electric and gas utilities[3] are much more experienced with. Practices surrounding non-pipe alternative will need to be tried and tested further before one can conclude that they are adequate and superior to others.

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[2] ConEd. (2020). ConEd NPA Framework & BCA Handbook for NPA.

[3] National Grid of New York and National Grid of Long Island are gas-only utilities. However, National Grid has an electric service territory in Upstate New York.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

INTERROGATORY

Reference:

Reference 1: Integrated Resource Planning Proposal – Additional Evidence, Exhibit B, dated October 15, 2020, Page 30 to 31

Reference 2: Integrated Resource Planning Proposal – Additional Evidence, Exhibit B, dated October 15, 2020, Page 16

Reference 3: Guidehouse Report, Figure 3, page 43.

Preamble:

Reference 1:
"cost/economic evaluation together with consideration of system reliability, safety and sustainability and broadly protecting the interests of customers will enable Enbridge Gas and the Board to determine whether it is preferable to proceed with investment in an IRPA."

Reference 2:
"If an IRPA(s) is the most economical solution to meet the system need and it satisfies the Guiding Principles, Enbridge Gas will incorporate that IRPA(s) in the AMP for inclusion into its broader planning activities, stakeholder touchpoints and implementation at the appropriate time."

Question:

a) Is there a circumstance where Enbridge envisions adopting an IRPA that is cost effective but fails to meet customer requirements with regards to reliability or safety of the system?

b) If yes, please explain in detail. Or is it the case that all projects must meet the basic reliability/safety/sustainability requirements before Enbridge will consider the cost/economic evaluation?

c) For evaluating the various considerations for potential IRPAs, does Enbridge intend to use a matrix similar to that in Reference 3? If no, why not?

Response

a) & b)
No, Enbridge Gas does not foresee any circumstance where it would invest in IRPAs that risk compromising the reliability or safety of its natural gas distribution, storage or transmission systems.

As stated in Enbridge Gas's Additional Evidence at Exhibit B, pages 30 to 31:

> "Ultimately, cost/economic evaluation together with consideration of system reliability, safety and sustainability and broadly protecting the interests of customers will enable Enbridge Gas and the Board to determine whether it is preferable to proceed with investment in an IRPA."

At page 31 of its Additional Evidence, Enbridge Gas goes on to stipulate that IRPAs must meet its proposed Guiding Principles in order to be considered viable:

> "If an IRPA can meet the demands of the future system capacity, is more cost effective than facility alternatives and meets the other important Guiding Principles, then Enbridge Gas will include the IRPA in the AMP as a future potential project".

c) Yes, the Guidehouse matrix referenced in Figure 3, page 43 of the Guidehouse Report represents a reasonable summary of key criteria considered in the evaluation and ranking of IRPAs that could ultimately be adopted by Enbridge Gas. Such a matrix, if adopted, should directly incorporate the Guiding Principles proposed by Enbridge Gas.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

INTERROGATORY

Reference:

Integrated Resource Planning Proposal – Additional Evidence, Exhibit B, dated October 15, 2020, Page 19

Preamble:

"If this full IRP planning process was undertaken for every forecasted peak period system constraint/need it would be exceedingly time and resource intensive, resulting in substantial incremental administrative cost burden to ratepayers. To avoid incurring such costs where limited potential value to ratepayers exists, and so that all existing resources are optimized, the first step in assessing the appropriateness of IRPAs to defer, avoid or reduce the need for new facilities is to establish the appropriate scope and scale of system constraints/needs that should qualify for IRPA assessment."

Question:

a) Does Enbridge propose to recover costs incurred from evaluating potential IRPAs from ratepayers?

b) How does Enbridge propose to manage the costs incurred from evaluating multiple potential IRPAs prior to selecting the best solution?

Response

a) Yes. Please see the response at Exhibit I.STAFF.22, for additional discussion of cost recovery associated with IRP.

b) Enbridge Gas acknowledges that there may be substantial incremental costs associated with evaluating multiple potential IRPAs prior to selecting the best solution. The Company will endeavor to keep such costs to a reasonable level, while at the same time ensuring that it is meeting the expectations set out in the IRP Framework that will result from this proceeding.

The cost of assessing, planning, implementing, and evaluating the performance of IRPAs and IRP pilot programs are an incremental cost not included in Enbridge Gas's base rates. These costs will be incurred by the Company as a result of the Board's direction to consider IRP as an alternative to traditional facilities. The additional IRP work and resulting additional cost is incremental to the traditional facility-based work that also must be completed in order to compare facility and non-facility alternatives. As stated in Enbridge Gas's Additional Evidence at Exhibit B, paragraph 81,

> "…it is entirely reasonable that ratepayers, not Enbridge Gas, bear the costs associated with the success or failure of such investments given that: (i) through its prior orders/directives/findings and the establishment of an IRP framework for Enbridge Gas, the Board has encouraged Enbridge Gas to pursue IRP as an alternative to proven facility expansion/reinforcement projects; (ii) Enbridge Gas remains obligated to serve the firm contractual peak period demands of its customers; (iii) such treatment of risk is consistent with investments in facility expansion/reinforcement projects that Enbridge Gas is seeking to defer, avoid or reduce through investment in IRPAs; (iv) the Board will have the opportunity to thoroughly review any future request for cost recovery associated with investment in IRPAs together with intervenors prior to Enbridge Gas initiating such expenditure; and (v) Enbridge Gas intends to report regularly to the OEB and stakeholders on the relative effectiveness of IRPAs to affect the peak period demand reductions forecasted, on the ongoing viability of supply-side alternatives, and to seek approval of the Board prior to adjusting such previously approved investments or to pursue investment in facility expansion/reinforcement project alternatives."

For these reasons, Enbridge Gas proposes a deferral account be established to record actual IRP costs not included in base rates. The deferral account will allow Enbridge Gas to track IRP-related costs and seek approval to clear such costs based on a prudence review at a later date. Enbridge Gas further discusses incremental IRP-related costs in its responses at Exhibit I.STAFF.22 and at Exhibit.I.GEC.6.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

INTERROGATORY

Reference:

Integrated Resource Planning Proposal – Additional Evidence, Exhibit B, dated October 15, 2020, Page 38

Preamble:

"Enbridge Gas acknowledges that ongoing monitoring and reporting of its investments in IRPAs is necessary to provide some certainty of the effectiveness of IRPAs as early as possible. This ongoing monitoring and reporting will be regularly fed into the IRP process to ensure systems are able to meet their capacity requirements, to address any operational challenges, to address flaws in the design or delivery of IRPAs, and/or to make additional investments in IRPAs or new infrastructure"

Question:

a) If during the ongoing monitoring and reporting of its investments in IRPAs, the IRPAs prove to be unable to meet their capacity requirements and there are flaws to the design and delivery of IRPAs, what remedial action plan does Enbridge have in place?

b) If additional investments in IRPAs or new infrastructure is required to remedy the flaw in the IRPA, does that mean that ratepayers will have to bear the costs for the original flawed IRPA and the additional investments?

c) How does Enbridge plan to mitigate the risk of a failed IRP Plan?

Response

a) This scenario is described in Enbridge Gas's Additional Evidence at Exhibit B, page 36:

> “Enbridge Gas has also proposed to report annually on the actual annual and cumulative effects of OEB-approved IRPAs relative to associated peak period demand reductions originally forecast (via an IRP report) and to seek OEB approval to adjust investments in such IRPAs as appropriate (e.g., to shift funding to an alternate IRPA or to increase/decrease/cease investment in IRPAs accordingly). Enbridge Gas expects that any and all of the prudently incurred: (i) original costs to invest in OEB-approved IRPAs; (ii) costs associated with OEB-approved adjustments to IRPA investments; and (iii) costs of any subsequent OEB-approved LTC project (in the instance that an IRPA is determined to have been insufficiently effective), would be borne entirely by ratepayers subject to the Board’s determination that in the course of incurring such costs Enbridge Gas acted prudently and responsibly in serving the firm needs of its ratepayers.”

Enbridge Gas expects that each instance where an IRPA is found to be underperforming will be unique. Thus, Enbridge Gas will investigate each such instance and take action based on the specific circumstances at the time. In doing so, Enbridge Gas will be guided by its obligation to serve the firm contractual demands of its customers safely and reliably during peak periods and by the proposed IRP Guiding Principles. Please also see the response at Exhibit.I.STAFF.26, for further discussion of the nature of proposed annual IRP Reporting.

b) Yes. Please see the response at Exhibit I.EP.6, for discussion of IRP/IRPA related risk.

c) Please see the responses to parts a) and b) above.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B

Question:

Please file all materials provided to EGI's Board of Directors related to this Application.

Response

No materials have been provided to Enbridge Gas's Board of Directors related to this Application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B

Question:

Please indicate the extent to which EGI has consulted with the Ontario Government Ministries – the Ministry of Energy, Northern Development and Mines and the Ministry of Environment, Conservation and Parks regarding its IRP proposals. Please file all materials related to any such consultations (written correspondence, presentations etc.)

Response

Enbridge Gas did not consult with Ontario Government Ministries regarding its IRP Proposal.

Please see the response at Exhibit I.PP.3, for discussion of external stakeholder feedback and IRP practices in other jurisdictions that informed Enbridge Gas's IRP Proposal.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B, p. 2

Question:

Please set out, in detail, the specific approvals being sought by EGI through this Application.

Response

Enbridge Gas is seeking OEB-approval and establishment of an IRP Policy Framework for the Company to guide its assessment of IRPAs and that reflects its original IRP Proposal, Additional Evidence and Reply Evidence, including proposed:

- IRP Guiding Principles;[1]
- IRPA screening criteria and assessment processes;[2]
- IRPA evaluation and assessment processes (first and second stages);[3]
- IRP cost recovery mechanisms and treatment;[4]
- IRPA application structure and principles (for new IRPA investments, their cost recovery and/or adjustment to existing IRPA investments);[5] and
- IRPA monitoring and reporting.[6]

Please also see the response at Exhibit I.STAFF.10, for discussion of IRP/IRPA related approvals that the Company proposes to seek in the future, following establishment of an IRP Framework for Enbridge Gas.

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[1] Additional Evidence, Exhibit B. para. 22.
[2] Additional Evidence, Exhibit B. pp. 15-21.
[3] Additional Evidence, Exhibit B. pp. 15-16, 30-31; Exhibit I.STAFF.20.
[4] Additional Evidence, Exhibit B. pp. 32-34; Exhibit I.STAFF.22.
[5] Additional Evidence, Exhibit B. para. 30.
[6] Additional Evidence, Exhibit B. pp. 17, 37-38.

Enbridge Gas is also seeking approval for the establishment of an IRP cost deferral account so that the Company can enable the incremental work that is required to complete IRP analysis of needs. Please see the responses at Exhibit I.APPrO.6 and at Exhibit I.GEC.6 for more information about the deferral account.

Please also see the response at Exhibit I.APPrO.2 d), for discussion regarding Enbridge Gas's ongoing investigation into AMI to support investments in IRPAs going forward.

As discussed in its Additional Evidence at Exhibit B, paragraph 3:

> "Approval of the IRP Proposal will enable Enbridge Gas to create actionable IRP plans to support deferment, avoidance or reduction of future infrastructure requirements and to gain important implementation experience. When a need is identified in the planning process, it will be assessed to determine the appropriateness of developing IRPAs to address it. This approach will ensure that Enbridge Gas has adequate lead time to fully assess, put forward to the OEB and verify the effectiveness of IRPAs to address peak period demands, deferring or reducing the need to construct facility alternatives. Where approvals are required in relation to IRPA(s)-specific spending, cost recovery, ownership or other items, Enbridge Gas will seek separate approval from the OEB, as appropriate."

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B, p. 5

Question:

Has EGI conducted an updated Avoided Distribution Cost Study since the original study (EB-2015-2020)? If so, please provide that updated study. If not, does the original study continue to be relevant?

Response

Enbridge Gas' has not conducted an updated Avoided Distribution Cost Study since the 2015-2020 DSM Plan Application. The original study continues to be relevant.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B, p. 20

Question:

Please explain, in detail, why community expansion projects driven by public policy and related funding should not be subject to an IRP analysis.

Response

As stated in Enbridge Gas's Additional Evidence at Exhibit B, page 20:

> "Community Expansion & Economic Development – If a project has been driven by policy and related funding to explicitly deliver natural gas into communities to help bring heating costs down, then it is not reasonable to conduct an IRP analysis."

For further discussion regarding the proposed exemption of community expansion and economic development projects to IRPA assessment, please see the responses at Exhibit I.Anwaatin.3. and at Exhibit I.STAFF.8 f).

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B, p. 21

Question:

Please provide a detailed list of all of the technologies or types of technologies EGI considered as potential candidates for IRPAs. For each of those technologies please explain why they have been rejected at this time.

Response

Enbridge Gas is not seeking OEB approval to implement any specific IRPAs or to recover the costs associated with investment in specific IRPAs as part of this proceeding. The purpose of this proceeding is to develop an IRP Policy Framework for Enbridge Gas to guide its assessment of IRPAs relative to other facility and non-facility alternatives. Therefore, no technologies have been rejected at this time. The types of IRPAs that will be considered by Enbridge Gas include those discussed in its Additional Evidence at Exhibit B, pages 21 – 30. Please also see the response at Exhibit I.STAFF.16, for discussion of supply-side alternatives. Please also see the response at Exhibit I.VECC.6 b), for further discussion regarding potential IRPA technologies.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B, p. 21-30

Question:

EGI has set out and described a number of technologies that would qualify as IRPAs. Please identify the technologies that EGI might consider first. Please explain why these technologies would be given priority over others. In effect, which are most feasible at this time vs those that may not yet be viable options.

Response

Enbridge Gas intends to continually consider new technologies and solutions as they become available. The list of technologies described is not ranked, exhaustive or final. Further, Enbridge Gas does not intend to apply any generic prioritization to the technologies being considered for application as IRPAs. Please also see the response at Exhibit I.CCC.6.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B, p. 22

Question:

Please provide a detailed overview of the ConEd Gas CNG and National Grid CNG projects.

Response

National Grid
The following relevant excerpts from page 104 of National Grid's Long-Term Capacity Report provide an overview of the utility's CNG projects:[1]

> (1) "National Grid's 2019/20 Winter Operations Plan includes operation of CNG sites in Glenwood Landing and Riverhead requiring up to 42 total trucks of CNG per day to reliably support minimum system pressures to all firm customers on the downstate New York systems."
>
> (2) "For the 2019/20 winter, the Glenwood site supplies 1,000 Dth/hr (peak), utilizing 10 CNG trailers over ~ 4 hours (operating 20 trucks in total to support morning and evening peak demand periods). There are plans to expand the Glenwood site next year to 2,200 Dth/hr utilizing 22 CNG trailers over ~ 4 hours (operating 44 trucks in total to support morning and evening peak demand periods). The Riverhead site will supply 1,100 Dth/hr (peak) utilizing 11 trailers over ~ 4 hours (operating 22 trucks in total to support morning and evening peak demand periods). Additionally, National Grid is in the process of identifying a third site which will be commissioned to support increased demands in the Winter of 20/21; this site is planned to supply 2,200 Dth/hr (peak) utilizing 22 CNG trailers over ~ 4 hours (operating 44 trucks in total to support morning and evening peak

[1] National Grid. (2020). Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY"). New York City, NY, USA.
https://millawesome.s3.amazonaws.com/Downstate_NY_Long-Term_Natural_Gas_Capacity_Report_February_24_2020.pdf>

demand periods). The total peak supply from these sites is approximately 5,500 Dth/hr (44 MDth/day) operating a total fleet of 110 CNG trucks for each cold weather event. An additional site with 20 trucks could be developed for 2021/22."

ConEdison

The following relevant excerpt from page 27 of ConEd's 2018 Non-Pipe Solution filing provides a useful overview of the utility's CNG projects proposed as NPS options:[2]

> "CNG and LNG injection facilities will be developed at 2-5 sites located in industrial areas in Westchester County, where upstream constraints are severe. The injection points will be leased and operated by third parties. Con Edison intends to use CNG deliveries at some locations and LNG deliveries at other locations. This will allow the Company to examine the pros and cons of each approach, and also provide additional experience working through permitting and operational issues specific to CNG and LNG. The CNG sites will be similar both in scale and operations to Con Edison's existing CNG injection point in Rye. That injection point, which is located close to a residential area, is scheduled to cease operation in 2020, after completion of on-system capital work intended to relieve constraints into the Rye area. (…) On peak winter days, supplies can be replenished as needed with additional trucked deliveries."

Page B-2 of ConEd's 2018 Non-Pipe Solution filing also notes that the capacity to be secured through CNG and LNG is 40 MDt/Day. In addition, page 38 of ConEd's 2020 Supply/Demand Analysis for Vulnerable Locations notes:[3]

> "Currently, the Companies are moving forward with one CNG location. We have chosen and contracted with the vendor and obtained approval from the local planning board."

This is a project in Westchester County, which is intended as a temporary solution until a long-term pipeline solution is adopted. As noted on page 58 of ConEd's 2020 Supply/Demand Analysis, the project is to deliver 25 MDth/day. Furthermore, page 47 of ConEd's 2020 Supply/Demand Analysis indicates that:

> "(the Astoria LNG in Queens) existing facility is a critical asset that contributes to the supply plan to meet peak demand and provides reliability in the case of an on-system or upstream event that causes an unexpected loss of pressure or supply. It is expected to continue to be an integral part of the plan for the

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[2] ConEdison, Case 17-G-0606 – Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program, 2018. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA7C3D0CD-E2B3-4B42-807C-82B553AE63F9%7D

[3] ConEdison, Case 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures – Supply/Demand Analysis for Vulnerable Locations, 2020. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BFCF94472-7929-4594-8CD0-C3903FDE6927%7D

> foreseeable future and is undergoing modernization upgrades approved as part of the most recent Con Edison rate plan."

The chart on page 47 suggest that the Astoria LNG plant delivers approximately 180 MDth/Day.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B, p. 24

Question:

Please explain how a district energy project works to avoid natural gas pipeline construction. Please indicate to what extent there are district energy projects in place in EGI's franchise area. For each of those projects please provide detailed descriptions and explain how those projects are providing benefits to EGI natural gas ratepayers.

Response

As detailed in paragraph 47 of Enbridge Gas's Additional Evidence, district energy systems operate by harnessing and converting various forms of energy, such as natural gas, geothermal, photovoltaic cells, and waste heat recovery, into useful thermal energy which can offset demand for natural gas. Through its investigation of and potential investment in district energy systems Enbridge Gas expects that it may be feasible to reduce, avoid or defer the construction of new natural gas facilities in the future.[1]

There are several public district energy systems within Enbridge Gas's franchise area. Markham District Energy operates two district energy systems in Markham, Ontario. The first system serves the City of Markham's downtown core, while the second system serves the Markham Stouffville Hospital and surrounding area.[2] Enwave, a subsidiary of Brookfield Infrastructure also operates district energy systems in several Canadian cities.[3] However, it should be noted that Enbridge Gas does not currently own or operate any district energy systems and thus is unable to provide detailed descriptions

[1] District energy systems may reduce, avoid or defer the need for new natural gas facilities and increase the need for other forms of infrastructure (e.g., electricity).
[2] www.markhamdistrictenergy.com
[3] www.enwave.com

of their nature or the costs/benefits afforded to the homes, businesses and/or institutions which are served by such systems, including to Enbridge Gas's customers.

At such time that the OEB establishes an IRP Framework for Enbridge Gas that enables consideration of district energy systems as IRPAs the Company expects that it would investigate such projects wherever economically feasible (subject to the cost-effectiveness test ultimately established by the Board for natural gas IRP in Ontario) and, if determined to be viable IRPAs, may apply to the Board for approval to invest in such projects.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B, p. 27

Question:

Please explain why Enhanced Targeted Energy Efficiency programs could not be part of the post 2021 DSM plans.

Response

In both its original IRP Proposal and its Additional Evidence, Enbridge Gas cited the ICF IRP Study which concluded that changes to the Utilities' (EGD and Union at the time) internal planning processes, to Ontario's energy policies and to the OEB's regulatory construct would be necessary to facilitate the use of enhanced targeted energy efficiency ("ETEE") to reduce distribution infrastructure investments.[1] Enbridge Gas is of the opinion that the regulatory framework for natural gas DSM in Ontario is not suitable for implementing and managing natural gas IRP.

Though DSM programs can impact infrastructure requirements and the cost savings associated with a broad-based reduction in distribution costs are included in the DSM planning process, the linkages between DSM planning and capital asset planning are currently passive rather than active. Current DSM programs are designed to produce annual energy savings through reduced natural gas consumption thus, by default, they may impact peak period demands (although this relationship is not linear or consistently positive).[2] DSM is not measured or evaluated on the basis of its ability to reduce peak period demand; no DSM targets, budgets, or incentive structures have been designed with this in mind either currently or historically. Further, as set out on page 28 of Enbridge Gas's Additional Evidence:

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[1] Additional Evidence, Exhibit B Appendix A.
[2] Additional Evidence, Exhibit B, para. 61.

> “Contrary to traditional DSM, which is focused on ensuring broad-based participation, ETEE [Enhanced Targeted Energy Efficiency] is focused on programs that achieve a high penetration in a specific geography to reduce peak period system demands corresponding to an identified system constraint/need. This fundamental difference will lead to ETEE requiring much greater levels of funding per unit of energy savings targeted when compared to what traditional DSM would expend in that specific geography absent IRP requirements.”

Enbridge Gas went on in its Additional Evidence at page 29:

> “…Enbridge Gas expects that separate funding and resources would be allocated to meet the differing goals and objectives of an IRP framework for Enbridge Gas. This would include covering the cost of implementation, tracking and monitoring the impacts of ETEE and/or other IRPAs.”

While the Board could direct that Enbridge Gas implement ETEEs as part of Enbridge Gas’s post-2021 multi-year DSM Plan, it would require substantial modification to the underlying DSM Framework principles from which that plan is anticipated to be based and otherwise might risk reducing the effectiveness and performance of traditional DSM programming going forward.

Please also see the response at Exhibit I.STAFF.11, for further discussion of the delineation between IRP and DSM.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B, p. 30-31

Question:

Please provide a detailed example of how a potential project will be run through EGI's DCF analysis. Please include all assumptions. How does EGI intend to estimate incremental overheads, incremental O&M costs, municipal property taxes?

Response

Please see the responses at Exhibit I.STAFF.20 and at Exhibit I.GEC.1 h), for discussion of the proposed DCF analysis and the types of costs and benefits that it may include. Please also see the response at Exhibit I.OSEA.1 c), for discussion of Enbridge Gas's efforts towards integrating IRP into existing processes going forward. The estimation of all costs, including incremental overheads, incremental O&M, and municipal property taxes will be done on a case by case basis.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B, p. 31

Question:

How often does EGI intend to update its Asset Management Plan? When was the current plan finalized? When is the next plan expected to be completed?

Response

Enbridge Gas will update its Asset Management Plan ("AMP") and file with the Board to support annual rate filings. Updates to the AMP for regulatory filings will either be through an Addendum that augments an existing AMP or through an updated version of the AMP. The most recent version of the AMP was finalized in mid-2020. An Addendum will be completed in 2021 to identify changes to 2022, and the next version of the AMP is expected to be completed in mid-2022.

For further discussion regarding Enbridge Gas's AMP please see the responses at Exhibit I.STAFF.2, at Exhibit I.STAFF.4, at Exhibit I.STAFF.6 and at Exhibit I.STAFF.8.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B, p. 36

Question:

EGI describes what it sees as incremental risk associated with the implementation of IRPAs. Why is it "entirely reasonable that ratepayers not shareholders bear the costs associated with the success or failure of such investments."? In proposing and implementing investments in IRPAs what, if any, are the risks to EGI's shareholders? If EGI follows its own policies, feasibility analyses and modelling in proposing an IRPA, and the project does not result in the anticipated avoidance of costs or reduced investment in facilities as proposed, why should EGI's ratepayers bear all of the costs?

Response

Please see the responses at Exhibit I.EP.6 and at Exhibit I.EP.14, for discussion of IRP/IRPA related risk.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. B, p. 44-46

Question:

EGI is not proposing to deploy Advanced Metering Infrastructure at this time. The evidence states that EGI will continue to assess the feasibility of an AMI implementation and it may be in a position to advance AMI-specific applications and a viable roll-out strategy to the Board as soon as 2022. Please provide any reports or analyses EGI has either contracted for, or carried out internally, assessing the overall cost of deploying an AMI system. How long would it take for EGI to fully implement and AMI system?

Response

Please see the response at Exhibit I.VECC.11, for discussion regarding the timing for Enbridge Gas to implement an AMI system. Please see the response at Exhibit I.APPrO.2 d) (iii) for discussion of the estimated cost to implement AMI.

The preliminary information that Enbridge Gas has gathered to investigate AMI deployment (and used to answer the interrogatories noted above) has been obtained on a confidential basis through interactions with third-parties under Non-Disclosure Agreements.

The Company expects to address AMI as part of its 2024 rebasing application and expects that at that time it will provide detail on the costs of deployment, including supporting documentation (where relevant). As Enbridge Gas is not seeking OEB approval to deploy AMI as part of this proceeding, the Company does not believe that disclosure of the confidential documents noted in the above paragraph is necessary or relevant in this proceeding.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex C. p. 4

Question:

The evidence states that, "…consistent with the Board's repeated determinations in this proceeding that it is not appropriate to duplicate matters/efforts that have been or are anticipated to be dealt with in other proceedings, the Board should remain focused on developing an IRP Framework for Enbridge Gas and not encourage re-hearing matters previously decided or currently before the Board in other proceedings or that are more appropriately dealt with through forthcoming proceedings." Please explain what proceedings EGI is referring to. In what context is EGI making this statement?

Response

Any issue that has already been decided by the Board through other recent OEB proceedings should not be re-heard through this proceeding. Examples of applications and proceedings for which the Board has made or has signaled an intent to make determinations or findings that need not be addressed in this proceeding include, but are not limited to:

- The now withdrawn 2021 Dawn Parkway Expansion Project proceeding (EB-2019-0159) or any other proceeding already decided or currently before the Board for leave-to-construct facilities;
- Enbridge Gas's 5 Year Gas Supply Plan review proceeding and associated annual updates;
- The EB-2017-0306/0307 MAADs proceeding;
- Enbridge Gas's 2024 Rebasing application; and
- Enbridge Gas's post-2021 multi-year DSM Plan proceeding.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex C. p. 26

Question:

The evidence states, 'When assessing the feasibility of natural gas facility (pipeline) infrastructure and comparing them to IRPAs, the Board should establish a staged economic evaluation standard to IRPAs through this proceeding that ultimately resembles a modified version of the OEB's E.B.O. 134 Guidelines or a DCF+ test." Please set out, in detail, what EGI is proposing as either a modified version of E.B.O. 134 or a DCF+ test. Is EGI asking for OEB approval of a specific methodology?

Response

Please see the response at Exhibit I.CCC.3, for discussion of the approvals sought by Enbridge Gas, including for its proposed IRPA evaluation and assessment processes.

For further detail of Enbridge Gas's proposed cost-effectiveness testing methodology please see the response at Exhibit I.STAFF.20.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex C. p. 17

Question:

The evidence states, "Consistent with its Additional Evidence. Enbridge Gas reiterate that should the Board wish to encourage Enbridge Gas to prioritize investments in IRPAs, in order to meet certain established targets, then it could consider adding an incremental incentive for such successful investments (e.g. an incentive based on the net benefits achieved.)". Doesn't EGI have an obligation, as a regulated entity to implement the optimal solution (pipe or non-pipe) that is the best solution for its customers? If not, why not? Please provide a complete list of incentive mechanisms EGI has assessed. Please indicate which incentive mechanism is EGI's preferred approach. At what point should the OEB establish an incentive mechanism?

Response

As discussed in its Additional Evidence at page 34:

> "As a regulated natural gas utility in Ontario, Enbridge Gas has an obligation to meet the firm contractual peak period (peak hour or design day) demands of its customers. Enbridge Gas's historic focus – and obligation - as the supplier of last resort has been to ensure that it has the assets required to safely and reliably meet its customers' immediate and long-term demands on an annual and design day basis (the coldest day of the year), and that will remain its top priority going forward in order to ensure that homes and businesses in Ontario have heat, hot water, cooking fuel and can perform the commercial/industrial activities (including electricity generation) that form the backbone of Ontario's economy."

To this end, Enbridge Gas has historically brought forward applications to the Board for approval of investments in and for Leave to Construct ("LTC") facilities and for cost recovery of the same. As part of LTC applications, Enbridge Gas has produced evidence supporting identified system constraints, an assessment of facility and non-facility alternatives considered, and an assessment of the cost of alternatives to ratepayers. Ultimately, the Board has made determinations based on its review of such evidence whether proposed facilities are prudent and in the best interests of ratepayers. Enbridge Gas expects that similar to investments in facility alternatives, the Board will make a determination on the prudency of IRPAs together with the need for such investments as part of its review of future Enbridge Gas applications to the Board for approval to invest in IRPAs and then when such costs are added to rate base (assuming the Board approves such treatment).

In response to the Board's statements regarding IRP in recent years, as discussed further in the response at Exhibit I.EP. 6, Enbridge Gas has developed an IRP Proposal in support of establishing an IRP Framework to guide its assessment of IRPAs relative to other facility and non-facility alternatives to serve the forecasted needs of its customers. Enbridge Gas's IRP Proposal (and supporting Additional Evidence and Reply Evidence as well as clarifications made through responses to interrogatories) and this proceeding in no way absolves the Company from its obligations as supplier of last resort.

As stated in the Additional Evidence at Exhibit B, page 32, Enbridge Gas is requesting that costs associated with IRPAs be included in rate base:

> "Enbridge Gas proposes that the costs associated with an IRPA be included in its revenue requirement. The nature of the benefits associated with investments in IRPAs is like the facility expansion/reinforcement projects that they serve to defer, avoid or reduce in that they resolve forecast system constraints/needs."

Further, as explained in Exhibit B, pages 33-34:

> "In Enbridge Gas's view, the simplest and most effective means of creating a level playing field from which to prioritize IRPAs and new facility infrastructure is by ensuring that Enbridge Gas is equally incented between the two types of investments. Should the Board wish to encourage Enbridge Gas to prioritize investments in IRPAs, then it could consider adding an incentive for such successful investments, over-and-above the regulated rate of return earned (e.g., an incentive based on the net benefits achieved, similar to the incentives proposed in other jurisdictions). The topic of incentives might be appropriately examined in a study completed by the Company and brought forward as part of an upcoming annual Rates setting proceeding, at the time of Rate Rebasing, or as otherwise directed by the Board for determination in due course."

Enbridge Gas has not completed an exhaustive analysis of potential incremental IRP incentive mechanisms at this time, beyond its proposal for the ability to rate base alternatives which the Company believes incentivizes it sufficiently to consider investments in IRPA(s) equitably compared to investments in facility alternatives.

Should the OEB deem it important to ensure a focus on IRPAs based on the nascent state of natural gas IRP in Ontario, or, should learning over time drive the conclusion that equal/sufficient consideration is not being given to IRPAs/non-facility alternatives, then that may necessitate the addition of incremental incentives either as part of the forthcoming IRP Framework, or future iterations of the same.

The Company does not currently have any preferred approach for incremental IRP incentive mechanisms at this time without specific study. Further, consideration of an appropriate incremental incentive mechanism may benefit from the experience gleaned from one or more pilot projects that the Company could pursue after the Board issues the IRP Framework as stated in Enbridge Gas's Reply Evidence at Exhibit C, pages 25 to 26.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex C. p. 21

Question:

EGI notes that it and its ratepayers have witnessed and been subjected to rapid and meaningful environmental policy changes in recent years. In the past five years alone there have been drastic changes in government policy, that make reliance on long-term impacts of those policies, difficult at best, and, more often than not high risk in nature. These changes came at significant administrative and regulatory costs to ratepayers. Please explain how EGI will manage this risk in the future especially with respect to its implementation of IRPAs.

Response

Enbridge Gas has proposed (through its original IRP Proposal and Additional Evidence) that the OEB establish an IRP Framework for the Company that provides, through the proposed annual Monitoring and Reporting function, flexibility to adjust investments in IRPAs should it be determined that they are not sufficiently resolving identified system constraints or customer needs as planned. Should rapid and meaningful environmental policy changes occur in the course of implementing IRPAs, then the Monitoring and Reporting function proposed by Enbridge Gas would ensure that the Company, the Board and stakeholders remain informed of the relative impacts of such changes. The Company notes that such changes may trigger a request by Enbridge Gas to the Board to adjust IRPA investments in response.

The expert evidence of OEB Staff makes a similar recommendation at page 11 of the Guidehouse Report:

> "The OEB should develop the gas IRP framework to provide utilities with sufficient flexibility to quickly adjust program designs, budgets, implementation plans, and other processes to adapt the IRP programs to each situation."

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex C. p. 26

Question:

EGI has provided a discussion regarding pilot projects and the timeline for those projects. Has EGI determined which projects it might pursue as pilot projects? If so, please describe the projects, the technologies and specify how those projects were selected. What type of projects are, from EGI's perspective the most cost-effective? Under what mechanism will EGI seek incremental funding for these pilots during the deferred rebasing period?

Response

As of the time of this submission, Enbridge Gas has not yet made any determinations regarding IRP pilot projects, including: the nature of such projects, potential IRP technologies (natural gas or non-gas) to employ, or the timing of such initiatives.

For further discussion of potential IRP pilot projects and related costs, please see the responses at Exhibit I.STAFF.12 and at Exhibit I.LMPA.15.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Consumers Council of Canada ("CCC")

INTERROGATORY

Reference:

Ex. A/B/C

Question:

In effect, the OEB, in both its GTA Project Decision (EB-2012-0451) and the 2015-2020 DSM Report directed EGI (formerly EGD and Union Gas) to develop an IRP transition plan.

In the absence of OEB Direction regarding IRP would EGI be developing an IRP Framework? If not, why not? Does EGI have concerns with ICF's conclusions that there has been little progress on implementation of IRP across North America, apart from New York State, since 2018?

Response

Enbridge Gas has a long history of considering IRP and IRPAs through:

(i) natural gas demand side management ("DSM") (energy efficiency) programming;
(ii) implementation of interruptible services/rates (demand response); and
(iii) assessment of and contracting for supply-side/market-based alternatives to resolve identified system constraints (this occurs as part of gas supply planning and also separately when assessing facility and non-facility alternatives).[1]

Therefore, the Company has already been taking steps to advance alternatives to new facilities and thus may not have come to the conclusion that it is necessary to establish an IRP Policy Framework for Enbridge Gas at this time, absent the Board's encouragement.

[1] Please also see the response at Exhibit I.STAFF.2, for discussion of the delineation between IRP and gas supply planning.

Enbridge Gas recognizes that natural gas IRP remains relatively new across North America and does not have any concerns with ICF's conclusion that there has been little progress on implementation of IRP across North America, apart from New York State, since the IRP Study was completed in May 2018. Further, Enbridge Gas accepts that the implementation of active natural gas IRPAs in North America is currently scarce and that work on natural gas IRP in other jurisdictions has largely been limited to: (i) adjustments to long-term planning methodologies; (ii) improved understanding of how DSM impacts infrastructure needs over an extended period of time; and (iii) implementation of IRPA pilot projects and related research.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

EB-2020-0091, Exhibit C, Page 7

Preamble:

> "Enbridge Gas also generally agrees that a ten-year time horizon for forecasting in-franchise system needs is appropriate to ensure adequate planning, deployment and adjustments (as needed) can be undertaken."

Question:

a) Is Enbridge agreeing that is would publish rolling ten-year forecasting of in-franchise system needs? Is it agreeing to do so annually? If not, how often is it proposing to do so?

b) Where is Enbridge proposing to publish its ten-year needs forecast?

c) Would Enbridge agree to include specific details, such as maps of each area where the need arises and the magnitude of the need?

Response:

a) & b)
Please see the responses at Exhibit I.STAFF.6 and at Exhibit I.CCC.12, for details regarding the forecast period and timing for updates to Enbridge Gas's Asset Management Plan ("AMP"). Enbridge Gas intends to provide IRPA details including identified system constraints in the AMP (or Addendum/updates thereto) which will be updated and filed with the Board to support annual Rates Case.

c) In the AMP, each investment represents a system constraint. For each system constraint, the baseline facility will be identified, as well as one or more IRPA's that would address that specific system constraint. The AMP only addresses capital investments so if the IRPA that is selected is not Capital, the resultant expenditure profile will not be reflected in the AMP. At such time that Enbridge Gas applies to the Board for approval to invest in IRPA(s) it would include the details sought by ED.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

EB-2020-0091, Exhibit C, Page 8

Question:

a) Is Enbridge opposed to using a version of the ConEd BCA test that is adapted to the Ontario context? If yes, please explain why.

Response:

Enbridge Gas is not opposed to using a version of ConEd BCA to evaluate IRPAs but believes that its proposal to use a modified version of the E.B.O. 134 guidelines (a DCF+ test) – which are similar to the ConEd BCA when all three stages are considered – is preferable as:[1]

(i) E.B.O. 134 is premised upon an economic assessment of impacts/benefits to Enbridge Gas's ratepayers as its starting point followed by secondary and tertiary objective assessments of distinct and quantifiable public interest costs and benefits;

(ii) it helps to ensure reasonable alignment with the established cost treatment for facility projects; and

(iii) it provides enhanced cost transparency when compared to the ConEd BCA, as discussed in Enbridge Gas's Reply Evidence.[2] Please also see the response at Exhibit I.STAFF.20 b), for additional details of the categories of costs and benefits that Enbridge Gas proposes to be considered in the DCF+ test.

[1] Exhibit C, Reply Evidence, pp. 8-9.
[2] Exhibit C, Reply Evidence, pp. 9-13.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

EB-2020-0091, Exhibit C, Page 31

Preamble:

> The following question relates to page 45 of Synapse Energy, *Benefit-Cost Analysis for Distributed Energy Resources*, September 22, 2014 - https://www.synapse-energy.com/sites/default/files/Final%20Report.pdf

Question**:**

a) Please provide a table indicating which of the following benefits would be accounted for in Enbridge's proposed approach to benefit cost analysis. Please also include a column indicating the way in which the benefit would be accounted for.

Table 18. Illustrative Benefit Valuation Options

Party Impacted	Benefits				Valuation Method		
	Benefit Category			Specific Benefits	Monetization	Proxy	Multi-Attribute
Utility Customers	1	Load Reduction & Avoided Energy Costs	a	Avoided energy generation	yes	---	---
			b	Avoided line losses	yes	---	---
			c	Wholesale energy market price suppression	yes	---	---
	2	Demand Reduction & Avoided Capacity Costs	a	Avoided generation capacity costs	yes	---	---
			b	Avoided power plant decommissioning	yes	---	---
			c	Wholesale capacity market price suppression	yes	---	---
			d	Avoided distribution system investment	yes	---	---
			e	Avoided transmission system investment	yes	---	---
	3	Avoided Compliance Costs	a	Avoided renewable energy and energy efficiency portfolio standard costs	yes	---	---
			b	Avoided environmental retrofits to fossil fuel generators	yes	---	---
	4	Avoided Ancillary Services	a	Scheduling, system control and dispatch	yes	---	---
			b	Reactive supply and voltage control	yes	---	---
			c	Regulation and frequency response	yes	---	---
			d	Energy imbalance	yes	---	---
			e	Operating reserve - spinning	yes	---	---
			f	Operating reserve - supplemental	yes	---	---
	5	Utility Operations	a	Financial and accounting	yes	---	---
			b	Customer service	yes	---	---
	6	Market Efficiency	a	Reduction of market power in wholesale electricity markets	---	---	yes
			b	Animation of retail market for DER products and services	---	---	yes
			c	Customer empowerment	---	---	yes
	7	Risk	a	Project risk	---	yes	---
			b	Portfolio risk	---	yes	---
			c	Resiliency	---	yes	---
Participants	8	Participant Non-Energy Benefits	a	Participant's utility savings (time addressing billing, disconnection, etc.)	---	yes	---
			b	Low-income-specific	---	yes	---
			c	Improved operations	---	yes	---
			d	Comfort	---	yes	---
			e	Health and safety	---	yes	---
			f	Tax credits to participant	---	yes	---
			g	Property improvements	---	yes	---
	9	Participant Resource Benefits	a	Other fuels savings	yes	---	---
			b	Water and sewer savings	yes	---	---
Society	10	Public Benefits	a	Economic development	---	---	yes
			b	Tax impacts from public buildings	yes	---	---
	11	Environmental Benefits	a	Avoided air emissions	yes	---	---
			b	Other natural resource impacts	---	---	yes

Response:

Please see the response at Exhibit I.STAFF.20 b), for discussion of the costs and benefits that Enbridge Gas proposes to include in future IRPA economic evaluations utilizing the Board's E.B.O.134 guidelines.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

EB-2020-0091, Exhibit C, Page 31

Question**:**

(a) Enbridge states that: “A project will be deemed economically feasible if the resulting Net Present Value (“NPV”) of the DCF is zero or greater.” Would the NPV calculations include the avoided commodity costs arising from the IRPA (e.g. forecast gas savings)?

(b) Enbridge states that: “A project will be deemed economically feasible if the resulting Net Present Value (“NPV”) of the DCF is zero or greater.” Wouldn’t the NPV for the non-pipe solution simply need to be higher than the NPV of the pipe-based solution?

(c) Enbridge states: “If an IRPA can meet the demands of the future system capacity, **is more cost-effective than facility alternatives** and meets the other important Guiding Principles, then Enbridge Gas will include the IRPA in the AMP as a future potential project.” Please list all of the elements that would be included in this cost-effectiveness comparison. Would this include avoided commodity costs?

(d) Please confirm that in EB-2019-0188, Exhibit I.ED.9(d), Enbridge indicated that the annual cost of heating with a heat pump would be lower than the cost of natural gas heating if the surcharge was considered. Please also provide the cost difference and underlying calculations.

Response:

a) & c)

Please see the response at Exhibit I.STAFF.20, for discussion of Enbridge Gas’s proposed economic evaluation methodology for IRP and details of costs/benefits that Enbridge Gas proposes to include in a staged economic evaluation standard for IRPAs.

b) No, it may be possible for IRPA to have a higher NPV than a facility alternative while both solutions have an NPV less than zero. In such instances neither alternative would be considered economically feasible by Enbridge Gas.

d) Please see the response at Exhibit I.ED.7 a) and d), for discussion of heat pumps.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

EB-2020-0091, Exhibit C, Page 31

Preamble:

In EB-2016-0186 (Panhandle Reinforcement Project), Union Gas stated as follows:

> "Union is proposing the Project at a time of uncertainty resulting from the Ontario Cap and Trade program and the recent issuance of the Ontario government's 5-year (2016-2020) Climate Change Action Plan ("CCAP"). In response to this risk, Union has calculated the revenue requirement and resulting rate impacts of the Project based on a 20-year estimated useful life of the assets rather than the weighted average useful life of approximately 50 years based on Board-approved depreciation rates. Union submits depreciating the asset over a 20-year term better aligns the cost with the timing of reported restrictions and potential elimination of natural gas heating in homes and businesses as noted in the CCAP."[1]

Question:

(a) Please describe and quantify how the above-referenced assumptions proposed in EB-2016-0186 would impact the NPV, PI, and other financial figures for pipe-based options in comparison to non-pipe options.

(b) Please provide all references to Board rules and directions on the appropriate and/or allowable depreciation period to be used in relation to gas infrastructure.

(c) What depreciation period does Enbridge currently use for its gas infrastructure projects? If different periods are used or have been used over the past decade, please explain this and describe the driver for this.

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[1] https://www.uniongas.com/-/media/about-us/regulatory/rate-cases/eb-2016-0186-panhandle-reinforcement/UNION_APPL_PanhandleReinforcement_20160610.pdf

Response:

a) A change in estimated useful life of an asset will impact the depreciation rate and therefore the depreciation expense of the asset. The Net Present Value (“NPV”) and Profitability Index (“PI”) of a project are determined by a discounted cashflow analysis (“DCF”). Depreciation expense is not included in a DCF analysis since it is non-cash. Therefore, the above referenced assumptions would not impact the NPV or PI of a pipe-based or non-pipe option. A shorter depreciable asset life would result in an increase to the annual revenue requirement of the asset caused by a higher annual depreciation expense. Further, the appropriate time and proceeding within which to discuss and potentially adjust OEB-approved depreciation rates is at rebasing.

b) The OEB’s Uniform System of Accounts provides details regarding depreciation rates including: [2]

- A separate rate is to be used for each group of detail accounts or sub-accounts;
- Depreciation rates shall be based on the estimated service values and estimated service lives of the plant developed by a study of the utility’s history and experience;
- Depreciation rates shall be developed by the utility by the method deemed most appropriate in the light of the utility’s retirement experience; and
- All new depreciation rates and modifications to existing rates are subject to approval by the Board.

The OEB’s Filing Requirements for Natural Gas Rate Applications require a natural gas utility to provide a copy of its depreciation/amortization policy and to provide a summary of changes to its depreciation/amortization policy since the last revenue requirement filing or since the OEB last approved a methodology, whatever is most recent. If the natural gas utility has developed a new depreciation study, the study must be filed.[3]

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[2] Uniform System of Accounts for Class A Gas Utilities dated April 1, 1996, Appendix A, Plant Accounting Instructions, 5. Depreciation.
[3] Ontario Energy Board’s Filing Requirements For Natural Gas Rate Applications dated February 16, 2017, page 31.

c) Enbridge Gas's current depreciation rates have been established through depreciation studies that were filed and approved as part of EGD's and Union's last cost of service proceedings for rates effective January 1, 2013 (EB-2011-0354[4] and EB-2011-0210, respectively) and determinations that have been made in subsequent decisions of the OEB.[5] The depreciation rates are unique for each group asset account and are derived through statistical analysis.

[4] In EGD's 2013 rates proceeding (EB-2011-0354), while the Gannett Fleming depreciation study was accepted for establishing most depreciation rates, there were two exceptions. In the Settlement Agreement, it was agreed that there would be an extension to the period over which certain assets (Distribution Mains and Distribution Services & Meter Installations) had been historically depreciated. The service lives for Distribution Mains – Plastic was increased from 55 to 65 years and the service lives for Distribution Services & Meter Installations was increased from 40 to 45 years.

[5] In EGD's 2014-2018 Custom IR proceeding (EB-2012-0459), the OEB approved a revised methodology for determining the net salvage percentages to be used by EGD in the calculation of its depreciation rates (the Constant Dollar Net Salvage (CDNS) approach). This resulted in a new schedule of depreciation rates for EGD effective January 1, 2014 (Appendix F in Decision and Rate Order).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Preamble:

In the issues list decision, with respect to issue 6, the OEB held that “[t]he question of whether non-gas alternatives, including electricity, should be eligible as IRPAs, is included within the scope of this issue.”

> This question explores the appropriateness and cost-effectiveness of electric heat pumps as an IRPA using North Bay as an example.

Question**:**

(a) In EB-2019-0188, Exhibit I.ED.9(d), Enbridge indicated that the annual cost of heating with a heat pump would be lower than the cost of natural gas heating if the surcharge was considered. Please provide the underlying calculations. Please file a live version of the “Residential Natural Gas Conversion Savings Estimate” excel document (I.ED.7 in EB-2019-0188) with the variables that produced the result in I.ED.9(d).

(b) Please comment on the applicability of this to other areas where a surcharge would be charged.

(c) Please update the analysis (i.e. input updated variables into the savings estimate tool) based on the latest carbon pricing information from the federal government (i.e. increases to $150/t CO2e in 2030). Please indicate the difference in cost between heat pumps and gas heating. Please file a live copy of the savings tool with these updated variables inputted into it.

Response:

a) – c)
Please see the responses at Exhibit I.ED.7 a) and d).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit B, pp. 23-24

Preamble:

> "Non-gas alternatives primarily include electrically powered geothermal heat pump systems and electric air source heat pumps ("EASHP"). …Enbridge Gas notes that it could offer these alternatives if authorized by the OEB, to reduce peak period demand in targeted areas. … Both electric GSHPs and EASHPs provide a solution that could be deployed to mitigate the need to build new infrastructure or to reduce the amount of new infrastructure required."

Question**:**

(a) What is the annual average coefficient of performance (i.e. efficiency) in a climate similar to Ontario's for the most efficient electric cold climate heat pump on the market? Please provide underlying information sources and studies. If Enbridge does not know which is the most efficient, please provide alternative information.

(b) Please provide all studies in Enbridge's possession on the cost-effectiveness and energy efficiency of electric heat pumps, including cold climate electric heat pumps.

(c) Please comment on the conclusions made here: https://rmi.org/heat-pumps-a-practical-solution-for-cold-climates/.

(d) Please compare the annual operating costs for space heating, water heating, and cooling for (i) a gas furnace, gas water heater, and electric air conditioner and (ii) all services provided by a cold climate air-source heat pump. Please provide the comparison over the next 10 years, including the federal governments increasing carbon price to $150 in 2030. Please make and state assumptions as necessary. Please cite all sources.

(e) How many tonnes of CO2e is produced by the average residential customer through consumption of natural gas?

(f) How many tonnes of CO2e is produced by the average residential customer with gas space and water hearing through consumption of natural gas?

(g) With respect to the OEB's July 20, 2017 MACC Report, please provide a copy of Table 30 and Table 31 (pages A-4 and A-5) that is based on the latest cold climate heat pumps.

Response:

a) The annual coefficient of performance ("COP") of Cold Climate Air Source Heat Pumps ("CCASHPs") in climates similar to Ontario is reported to be in the range of 2.5 to 2.75.[1] The Heating Season Performance Factor ("HSPF") (HSPF= Energy-out/Energy-in, BTU/Watt) of the most efficient CCASHPs are above 10, The COP of the units at -15°C are greater than 2.0 and the units maintain their maximum capacity at 15°C greater than 70% of their rated capacity at 8.3°C. There is a CSA standard EXP09 (under publication) for performance testing of CCASHPs. Northeast Energy Efficiency Partnerships ("NEEP") also lists all of the manufacturers that follow the set standards for CCASHPs.[2] Enbridge Gas is not in a position to comment on which model is the most efficient since performance of a heat pump is dependant on a number of factors including equipment selection and design, heat pump sizing, operating parameters and weather conditions throughout the year.

b) Enbridge Gas has supported a few studies to evaluate the performance of cold climate air source heat pumps. Results of a pilot study including 7 homes equipped with electric heat pumps were published as part of the ASHRAE 2019 conference. In addition, Enbridge Gas is supporting two NRCan studies to evaluate the field performance of CCASHP. NRCan is expected to publish results upon completion of these studies.

c) Enbridge Gas has not assessed or analyzed the conclusions or underlying study cited by ED. That said, CCASHPs could be used as an alternative for home heating and GHG reduction in Ontario, provided the marginal source of electricity used to power them is primarily generated from non-emitting renewable sources. In Ontario, marginal electricity is primarily produced from natural gas fired electricity generation.

[1] Field Assessment of Cold Climate Air Source Heat Pumps Ben Schoenbauer, Nicole Kessler, David Bohac, Center for Energy and Environment Marty Kushler, American Council for an Energy-Efficient Economy, ACEEE Summer Study on Energy Efficiency in Buildings, 2016. https://www.aceee.org/files/proceedings/2016/data/papers/1_700.pdf
[2] https://neep.org/high-performance-air-source-heat-pumps/ccashp-specification-product-list
[3] Farzin R, Nima A., Tom G., "Smart Control for Optimum Residential Fuel Switching between Natural-Gas and electricity" ASHRAE transactions 1 (Winter Conference), Feb 2020.

d) & g)
Enbridge Gas's IRP Proposal does not seek OEB approval to implement specific IRPAs or to recover the costs associated with investment in specific IRPAs and Enbridge Gas does not intend to seek any such IRPA-specific approval from the Board as part of this proceeding. The OEB has previously found this to be appropriate in its Decision on Issues List and Procedural Order No. 2:

> "The OEB expects that the IRP Framework to be determined will not reference specific facilities/IRPAs…"

Accordingly, it is not reasonable to expect Enbridge Gas to complete the analysis requested by ED as it is not immediately relevant to this proceeding and the establishment of an IRP Framework for Enbridge Gas. The variables that would be considered in calculating annual operating costs are numerous and dynamic and include such items as heating and cooling loads, efficiencies of appliances, commodity pricing and estimated inflation rates. These analyses would be more appropriately performed at such time when Enbridge Gas brings forward future applications for approval to invest in and/or recover the costs associated with IRPAs.

e) & f)
In the EGD rate zone, a typical residential customer with annual average consumption of 2,400 m^3 will produce approximately 4.5 tCO_2e. In the Union rate zones, a typical residential customer with annual average consumption of 2,200 m^3 will produce approximately 4.1 tCO_2e.[3]

[3] GHG emissions calculated using Ontario emission factor of 0.001874 tCO_2e/m^3 from Ministry of Environment, Conservation and Parks "Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions", April 2019.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit B, pp. 23-24

Preamble:

> "Non-gas alternatives primarily include electrically powered geothermal heat pump systems and electric air source heat pumps ("EASHP"). …Enbridge Gas notes that it could offer these alternatives if authorized by the OEB, to reduce peak period demand in targeted areas. … Both electric GSHPs and EASHPs provide a solution that could be deployed to mitigate the need to build new infrastructure or to reduce the amount of new infrastructure required."

Question**:**

(a) What is the annual average coefficient of performance (i.e. efficiency) in a climate similar to Ontario's for the most efficient reverse cycle chiller systems? Please provide underlying information sources and studies. If Enbridge does not know which is the most efficient, please provide alternative information.

(b) Please provide all studies in Enbridge's possession on the cost-effectiveness and energy efficiency of reverse cycle chillers.

(c) Please comment on the conclusions made here: https://rmi.org/heat-pumps-a-practical-solution-for-cold-climates/.

(d) Please compare the annual operating costs for space heating, water heating, and cooling for (i) a gas furnace, gas water heater, and electric air conditioner and (ii) all services provided by a reserve cycle chiller. Please provide the comparison over the next 10 years, including the federal governments increasing carbon price to $150 in 2030. Please make and state assumptions as necessary. Please cite all sources.

Response:

a) Please see the response at Exhibit I.ED.7 a). The reverse cycle chiller employs the same heat pump technology and thermodynamic cycle that is used for conventional

EASHP. The only difference is how the captured energy is delivered to heating and cooling loads. Therefore, the heat pump COP will be similar to that of an EASHP.

b) Enbridge Gas does not posses any studies on the cost-effectiveness and energy efficiency of reverse cycle chillers.

c) Please see the response at Exhibit I.ED.7 c).

d) Please see the response at Exhibit I.ED.7 d) & g).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit C, Page 19

Question:

(a) Please provide a table for each of the last three years for which data is available listing the Mt CO2e produced by Ontario (i) in total and (ii) arising from the combustion of natural gas. Please show all calculations and conversion rates. Please cite all sources.

Response:

a) Total greenhouse gas ("GHG") emissions and GHG emissions from the combustion of natural gas are set out in Table 1 below for the period of 2016 to 2018, the most recent years for which data was available.

Table 1

Year	**2016**	**2017**	**2018**
Total Emissions *(Mt CO_2e/yr)*	160	155	165
Emissions from Combustion of Natural Gas *(Mt CO_2e/yr)*	45	45	50

The total GHG emissions for Ontario are reported in the 2020 National Inventory Report.[1] The GHG emissions from combustion of natural gas in Ontario are calculated using the following formula:

GHG Emissions from Combustion = Volume x Emission Factor

[1] Environment and Climate Change Canada, 2020 National Inventory Report, Table A11-12. Available at: https://unfccc.int/documents/224829

Annual natural gas volume distributed (Volume) used in the above formula was obtained from Statistics Canada and an emission factor of 0.001874 tonnes CO_2e/m^3 was used.[2]

[2] Statistics Canada, Canadian Monthly Natural Gas Distribution, Canada and Provinces, Table 25-10-0059-01; Ministry of Environment, Conservation and Parks, Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions, April 2019.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit A, p. 13

Preamble:

> "Enbridge Gas proposes a two-stage process for analyzing IRPs/IRPAs. The first stage is a high-level review for reasonability that compares the cost of the facility expansion/reinforcement project with the cost of IRPAs that could reduce peak period demand sufficiently to defer or avoid the facility project."

Question**:**

(a) Is it still Enbridge's proposal that "The first stage is a high-level review for reasonability that compares the cost of the facility expansion/reinforcement project with the cost of IRPAs that could reduce peak period demand sufficiently to defer or avoid the facility project"? If yes, please explain why it would be reasonable to screen out IRPAs without ever considering the value of the avoided commodity costs.

Response:

a) The quote referenced by ED comes from Enbridge Gas's original IRP Proposal and is no longer relevant since Enbridge Gas filed its Additional Evidence. Consistent with its Additional Evidence at Exhibit B, pages 16-17, Enbridge Gas is proposing a two-stage process where, at Stage 1 the Company will review the system constraint and/or customer need for potential IRPA(s) that could be used to defer, avoid or reduce the need to construct facilities using screening criteria. If a potential IRPA cannot be used to defer, avoid or reduce the need for facilities then it will not pass the screening criteria and any avoided commodity costs are irrelevant. At Stage 2, Enbridge Gas would compare the facility alternative and selected IRPA(s) on an economic basis, including any potential avoided commodity costs resulting from investment in IRPA(s), subject to the guidance ultimately established by the Board in its IRP Framework for Enbridge Gas.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit A, p. 13

Preamble:

> The IRP study findings estimate that only 14-17% of reinforcements in the sample (which only included distribution reinforcements) could feasibly be replaced by an IRPA.

Question**:**

(a) Please redo this analysis and include the value of avoided commodity costs with respect to the IRPAs.

Response:

The requested analysis cannot be updated in an expeditious manner. In addition, the requested analysis would lead to an incomplete comparison of costs and benefits.

As noted by ICF in its May 2018 IRP Study, the primary design objective of DSM programs designed to reduce infrastructure investment would be to reduce peak period demand. The costs included in the study reflect this objective, and were focused on preparing a cost comparison consistent with the facilities planning process. However, ICF also pointed out (p. ES-26, p.55) that DSM programs implemented with the goal of impacting peak will also save avoided costs associated with annual energy efficiency including gas commodity cost savings, upstream capacity costs and the value of non-energy benefits including the value of carbon emission reductions.

ICF's analysis did not account for these benefits, deferring this analysis to a later date. However, ICF does not expect that the addition of avoided commodity cost would materially alter the results of the analysis. The rate of natural gas peak demand growth is the main limiting factor in terms of the proportion of facility investments that can potentially be deferred by investments in IRPA(s).

Additional details on ICF's analysis are included on pp. 137-138 of ICF's May 2018 IRP Study, which was filed by Enbridge Gas on July 22, 2020.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit A

Question:

Please comment on each of the following strengths of gas IRP in comparison to electric IRP and indicate whether Enbridge agrees with the statement:

(a) DER in the gas sector provide diversification away from fossil fuels and mitigates risks associated with future environmental regulation;

(b) Natural gas energy efficiency programs have historically been more cost-effective than electricity sector energy efficiency programs;[1]

(c) Natural gas energy efficiency programs are underfunded in comparison electricity sector programs;[2]

(d) The natural gas sector produces far more greenhouse gasses than the electricity sector;[3]

(e) Natural gas DERs provide additional benefits to Ontario's economy because they replace spending on out-of-provide gas with spending on Ontario-based energy contractors and made-in-Ontario energy;

(f) Avoided cost calculations in the gas sector are not complicated by the surplus baseload issues in the electricity sector; and

(g) There are fewer natural gas utilities, creating economies of scale.

Response:

a) Confirmed.

[1] EB-2015-0049: Exhibit K6.2; Transcript Vol. 6, p. 124, lns. 7-18.
[2] EB-2015-0049: Exhibit K6.2.
[3] EB-2015-0049: Exhibit K6.2.; Exhibit M.GEC.EP.3, p. 1; Exhibit M.GEC.ED.12, attachment 1 p. 17; Transcript Vol. 6, p. 123, lns. 3-8; Transcript Vol. 4, p. 16, lns. 8-12.

b) Enbridge Gas does not have the necessary firsthand knowledge of the cost-effectiveness of electric energy efficiency programs to state whether or not the Company agrees or disagrees with the statement. The 2019 Auditor General's Energy Conservation Progress Report states:[4]

> "Conservation programs delivered in 2017 delivered roughly two and a half dollars in benefits for every dollar spent, primarily from avoiding the need for new electricity generation and reducing fuel and operational costs for existing electricity generators."

and,

> "Natural gas programs remain highly cost-effective, saving Ontarians almost three dollars for every dollar spent in 2016"

c) Enbridge Gas respects the OEB's decision with regard to establishing current levels of funding for natural gas DSM.

On November 27, 2020, the Ministry of Environment, Conservation & Parks and the Ministry of Energy, Northern Development & Mines issued joint a letter to the OEB stating:[5]

> "While we would be supportive of cost effective rate payer funding of Natural Gas conservation in Ontario, it is recognized that the OEB must balance rate payer interests regarding bill impacts with the level of natural gas savings pursued."

And in its letter on the Post-2020 Natural Gas Demand Side Management Framework (EB-2019-0003) dated December 1, 2020, the OEB stated:

> "The OEB anticipates modest budget increases to be proposed by Enbridge Gas in the near term in order to increase natural gas savings, and expects Enbridge Gas to seek to improve the cost-effectiveness of programs."

d) In Ontario, the natural gas sector creates more greenhouse gas emissions than the electricity sector. However, the natural gas sector in Ontario can also create greenhouse gas reduction opportunities by converting heating systems using heating oil or by using compressed natural gas for heavy duty vehicles.

e) As Enbridge Gas does not currently own or operate any district energy systems it is unable to confirm. Please also see the response at Exhibit I.CCC.9, for further discussion of district energy systems.

[4] A Healthy, Happy, Prosperous Ontario: Why we need more energy conservation, 2017 pg 242
[5] https://www.oeb.ca/sites/default/files/ENDM-MECP-letter-to-OEB-20201127.pdf

f) Confirmed.

g) There are fewer natural gas utilities, however, Enbridge Gas is not clear as to what economies of scale Environmental Defense is referring.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2019-0159, Exhibit A, Tab 13, Pages 2 and 3

Preamble:

"Enbridge Gas has included its IRP Proposal with this Application for three reasons:

i. To be responsive to the direction received from the OEB: (a) in recent leave to construct application decisions where the OEB directed Enbridge Gas to provide sufficient and timely evidence of how traditional Demand Side Management ("DSM") has been considered as an alternative at the preliminary stage of project development; and (b) in the OEB's Report of the Board on the DSM Mid-Term Review where the OEB stated that it expects the natural gas utilities to develop more rigorous, robust and comprehensive procedures to ensure conservation and energy efficiency opportunities can be reasonably considered as alternatives to future capital projects.
ii. To establish the necessary IRP policy guidance required for Enbridge Gas to be successful in considering IRPAs as non-facility alternatives to future expansion/reinforcement projects effectively and efficiently, including acknowledgement of Advanced Metering Infrastructure ("AMI") as an IRP enabling element.
iii. To demonstrate that IRP is not a viable alternative to avoid or delay the proposed Project, which is required to meet demand that already exists and is forecast in the near future. This underlines the need to clarify the role of IRP, particularly in relation to high-volume transmission and distribution projects where IRPAs do not appear to be cost-effective and/or feasible."

Question:

a) Please confirm that Enbridge's reasons for its proposal in EB-2020-0091 are still as stated as reasons (i) (ii) and (iii) in EB-2019-0159. If the answer is no, please explain.

b) Please define and describe the AMI that is mentioned in (ii).

c) Please provide an explanation of the "acknowledgement" that Enbridge is seeking from the OEB. Specifically, does Enbridge expect the OEB to state in its decision or report that AMI is a necessary component of IRP and that without AMI consideration of IRPAs is not possible.

d) Please describe the types of projects where IRP is not a "viable alternative" including reasons.

Response

a) Confirmed, with the exception of point iii) noted by EP related to the now withdrawn 2021 Dawn Parkway Expansion Project. The purpose of this proceeding is to develop an IRP Policy Framework for Enbridge Gas to guide its assessment of IRPAs relative to other facility and non-facility alternatives to address system constraints. As stated by the Board in its OEB Decision on Issues List and Procedural Order No. 2 (dated July 15, 2020) ("PO No. 2"),

> "The OEB expects that the IRP Framework to be determined will not reference specific facilities/IRPAs…"[1]

Enbridge Gas's IRP Proposal does not seek OEB approval to implement specific IRPAs or to recover the costs associated with investment in specific IRPAs and Enbridge Gas does not intend to seek any such IRPA-specific approval from the Board as part of this proceeding.

b) Advanced Metering Infrastructure ("AMI") is an integrated system of meters, end points, communications networks, and data management systems that enable two-way communication between utilities and customer meters.

c) As discussed in Enbridge Gas's Additional Evidence at Exhibit B, page 36, the current lack of actual measured peak hourly data makes it difficult to understand the potential of IRPAs and will make it difficult to accurately measure the effectiveness of IRPAs in reducing peak period demand going forward. Without access to hourly customer consumption data to establish more precise baseline load profiles, the design of proposed IRPAs and their respective forecasted and measured energy savings are expected to be less reliable, increasing the risk to ratepayers that OEB-approved IRPAs are not successful in resolving identified system constraints/needs.

[1] OEB Decision on Issues List and Procedural Order No. 2, p. 12.

Enbridge Gas is asking that in its Report of the Board, which would establish an IRP Framework for Enbridge Gas, the OEB to acknowledge that: (i) AMI is an important enabler of IRP and without AMI the Company will need to rely on system modelling around less certain or less well tested solutions to meet demand versus actuals; and (ii) reliance on system modelling as opposed to actual measured peak hourly data will increase the risk to ratepayers associated with IRPA investments, may drive the need to overbuild IRPAs, and may require Enbridge Gas to conduct additional EM&V work, all of which should be expected to increase the costs to ratepayers of investment in IRPA(s).

d) Item (iii) in EP’s preamble refers specifically to facilities proposed as part of the now withdrawn 2021 Dawn Parkway Expansion Project proceeding (EB-2019-0159).

Enbridge Gas’s Additional Evidence at Exhibit B, pages 19 to 20, includes discussion of criteria for completing screening of system constraints in order to determine whether any type of potential IRPAs are viable. This discussion continues within Enbridge Gas’s Reply Evidence at Exhibit C, pages 17 to 18.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2019-0159, Exhibit A, Tab 13, Pages 3 and 4, Footnote 3; Exhibit A, Tab 13, page 10

Preamble:

"This is underlined by looking at various system demand forecast types and the appropriateness of IRPAs or DSM to reduce such demands, including: design day demand, which influences design of transmission systems (i.e. Dawn Parkway System), drives related transmission system expansion/reinforcement projects and is managed as part of Enbridge Gas's Transmission System Planning and Gas Supply Planning processes; peak hour demand, which influences design of distribution systems, drives related distribution system expansion/reinforcement projects, is managed as part of Enbridge Gas's Distribution System Planning processes and is most appropriate for consideration of IRPAs; and average annual demand, which is the metric by which energy savings resulting from traditional DSM is measured under the OEB-approved 2015-2020 DSM Framework."

Question:

a) Is Enbridge proposing that IRP be limited to the consideration of the impacts of IRPAs on peak hourly demand for distribution and peak daily demand for transmission only to avoid overlap with the DSM Framework or for other reasons? Please discuss.

b) Please explain how Enbridge currently monitors and measures peak hourly demand, including granularity of data and its record keeping. For example, for a large distribution network such as the City of Toronto, where and how is the peak hourly demand measured.

Response

a) Please see the response at Exhibit I.STAFF.11.

b) Peak hourly demand is typically measured and monitored at City Gate stations and at Large Volume Customer stations with hourly read meters. The Company has databases which store this data. There are other stations within Enbridge Gas's pipeline network with hourly measurement used by Gas Control to monitor the system, however, not every station has hourly measurement.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2019-0159, Exhibit A, Tab 13, Page 10

Preamble:

"IRP is a detailed process of reviewing supply and demand-side alternatives to address forecasted facility requirements. If this process was undertaken with every forecasted facility project, it would be extremely time intensive."

Question:

Please describe the steps involved in a typical IRP process with time estimates for each step.

Response

Please see the response at OSEA 1 c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2019-0159, Exhibit A, Tab 13, Page 11, Table 13-1

Question:

Please explain the reason for selecting 1.4% as the maximum annual load growth. The table implies that if load growth greater than 1.4%, IRP should not be considered.

Response

Enbridge Gas is no longer proposing a specific threshold for load growth. Please see the response at Exhibit I.STAFF.8, for further discussion regarding this assumption.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2019-0159, Exhibit A, Tab 13, Page 15

Preamble:

"Enbridge Gas proposes that the costs associated with planning, implementing, administering, measuring and verifying IRPAs within an approved IRP be treated in a similar manner to the capital costs that they enable the utility and ratepayers to avoid."

Question:

a) If the IRPA consists of conversion of a subdivision from gas space and water heating to electric space and water heating, is Enbridge proposing to include in its rate base the replacement electric furnaces and water heaters on customers' premises? If the answer is yes, would Enbridge also include in its OEB regulated revenue requirement the operation and maintenance of electrical equipment on customers' premises?

b) If the IRPA consists of conversion of a subdivision from gas space and water heating to geothermal energy is Enbridge proposing to include in its rate base the cost of drilling for and the installation of underground piping, the installation of electric motor driven pumps, space and water heating equipment and associated controls on customer's premises? If the answer is yes, would Enbridge also include in its OEB regulated revenue requirement the operation and maintenance of electrical equipment on customers' premises?

c) Considering that electrical and geothermal space and water heating is currently supplied by the competitive market, is Enbridge proposing to enter this as an OEB regulated utility? If the answer is yes, how does Enbridge propose to deal with issues of unfair competition?

Response

a) & b)
Please see the response at Exhibit I.STAFF.22, for details of Enbridge Gas's proposed treatment of IRP/IRPA costs.

c) Please see the response at Exhibit I.STAFF.17 part b), for discussion of how Enbridge Gas proposes to invest in IRPAs where a competitive market already exists.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2019-0159, Exhibit A, Tab 13, Page 16

Preamble:

"The implementation, measurement and verification of IRPAs will require Enbridge Gas to invest ratepayer funds on IRPAs in advance of the typical timing of expenditure on proven facility alternatives, exposing ratepayers to the risk of higher rate impacts should IRPAs not effectively reduce forecasted demand growth, forcing Enbridge Gas to apply for leave to construct facility expansion/reinforcement projects even though ratepayers have already paid for an IRPA. In that instance, ratepayers would bear the costs of both the IRPA and the facility expansion/reinforcement project required to ensure future demand growth is served."

Question:

a) Is Enbridge proposing that ratepayers bear 100% of the risk of IRPAs? If the answer is yes, please explain what incentive would Enbridge have to ensure that IRPAs are built on schedule and or budget and that they provide the necessary service to customers.

b) Do ratepayers bear 100% of the risk of pipeline and gas main projects? If the answer is no, please describe the risks that shareholders bear.

Response

a) & b)
Yes, similar to investments in facility alternatives Enbridge Gas proposes that, with the exception of instances where Enbridge Gas is found to have acted imprudently or has failed in its efforts to implement an IRPA in accordance with any future IRPA application and subsequent OEB approval for the same, ratepayers should bear the cost and associated risk for investments in IRPAs that were approved by the OEB.

Enbridge Gas's obligation as the supplier of last resort is to ensure that it has the facilities necessary to meet the firm contractual demands of its customers on a design day. It is this obligation that has historically driven applications to the OEB to invest in facility alternatives through applications for Leave to Construct and subsequently for cost recovery. As set out in its Additional Evidence at pages 34 to 35:

> "Should Enbridge Gas's investments into IRPAs not result in the reduction of peak period demand anticipated, or in the event that supply-side alternatives experience a failure to deliver, there are few, if any, firm, cost-effective alternatives that Enbridge Gas can rely upon on short notice. For these reasons, Enbridge Gas: (i) has historically limited its reliance upon third-party services and discretionary overrun services to meet design day needs; (ii) has historically invested in safe and reliable facility expansion/reinforcement projects far enough in advance to ensure that it can meet its customers' demands (having recovered the costs of these investments through its regulated rates); and (iii) is focused on establishing an IRP framework that recognizes the risk of system failures/outages and increased costs to its customers inherent in investment in IRPAs as opposed to proven facility alternatives (including the cost to gather and manage more granular customer consumption data)."

Through its many and varied statements regarding IRP in recent years,[1] the Board has encouraged Enbridge Gas to seek means by which it might rely upon IRPAs to resolve identified system constraints in the future. Accordingly, Enbridge Gas has developed an IRP Proposal in support of establishing an IRP Framework to guide its assessment of IRPAs relative to other facility and non-facility alternatives to serve the forecasted needs of its customers. Importantly, Enbridge Gas's IRP Proposal and supporting evidence (Additional Evidence, Reply Evidence and clarifications provided in response to interrogatories) in no way absolve the Company from its obligations as supplier of last resort.

Enbridge Gas expects that similar to investments in facility alternatives, the OEB will make a determination on the prudency of IRPAs together with the need for such investments as part of both its review of future Enbridge Gas applications to the Board for approval to invest in IRPAs and when such costs are added to rate base (assuming the Board approves such treatment of costs).[2]

In order to ensure that Enbridge Gas is adequately incented to invest in IRPAs the Company has proposed that the costs associated with investment in IRP be included in rate base (referred to as like treatment for like results).[3] This treatment also

[1] Exhibit B, Additional Evidence, pp. 3-12.
[2] Exhibit B, Additional Evidence, para. 73.
[3] Exhibit B, Additional Evidence, para. 74.

serves to eliminate any perceived bias towards facility investments. Enbridge Gas's proposed treatment of costs has been supported by Energy Futures Group.[4]

Increasing the Company's risk profile by allocating risk associated with investments in IRP to the Company's shareholders would act in the opposite manner, as a disincentive to treat investments in IRP on a level plane with facility investments. Further, Enbridge Gas, Guidehouse and certain intervenors have also acknowledged that it may be appropriate for the Company to be incented beyond earning a regulated return on IRP investments to ensure that the Company is adequately encouraged to pursue IRPAs.[5] One example of an approach that could be taken is seen in New York, where ConEd has proposed a true up mechanism which sees the sharing of cost overruns or underruns from the net benefits derived between customers and shareholders.[6] This proposal was in addition to rate base treatment of alternatives and an additional incentive to share net benefits from the alternatives 70/30 with customers, and is meant to encourage completion of NPA projects on or under budget.

For these reasons, Enbridge Gas submits that it is entirely appropriate that ratepayers continue to bear 100% of the cost and risk associated with any investment (either facility or non-facility) made by the Company in order to meet its obligation as the supplier of last resort, assuming that the Company acted prudently and in accordance with any future IRPA application and subsequent OEB approval for the same. However, if as a result of the establishment of an IRP Framework for Enbridge Gas, the Board determines that it is appropriate for the Company (shareholders) to bear increased risk associated with investments, then Enbridge Gas expects that commensurate adjustment to its allowed ROE and/or incentives for such investments would be necessary to account for the heightened risk profile taken on by Enbridge Gas.

[4] EFG Report, p. 47.
[5] Exhibit C, Reply Evidence, p. 17.
[6] Case 19-G-0066, Consolidated Edison Company of New York, Inc. Proposal for use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure, September 15, 2020, Section VIII. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2CCB0D2A-183A-483B-9F56-87878E0471FA}

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2019-0159, Exhibit A, Tab 13, Page 22

Preamble:

"If large numbers of customers switch to either electric air source heat pumps or electric heat pumps, additional stresses may be realized on the electrical grid. Furthermore, incremental electrical requirement on the grid will very likely increase the marginal electricity produced from the central gas power plants, thereby shifting the residential gas load to the central power plant."

Question:

Is Enbridge proposing to invest money in the construction or upgrading of the electricity distribution, transmission and generation facilities as part of IRPAs? If the answer is yes, is Enbridge proposing to such investments in its OEB regulated rate base.

Response

No.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2020-0091 Exhibit B, Page 14

Preamble:

"Need Identification – 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) How frequently Does Enbridge Gas analyze its entire distribution system to identify needs?

b) How far into the future are needs identified?

c) Does Enbridge Gas produce a priority list of projects based on the Needs Identification process?

Response

a) - c)
Enbridge Gas assesses its distribution system holistically on an annual basis in order to identify system constraints and/or customer needs. Needs are typically identified up to 10 years into the future. The result of the needs identification is a list of potential projects which is used to inform the growth portfolio of the Asset Management Plan. Some needs are the result of emergent trends in demand and require more immediate solutions (i.e., 0-3 years). Others are the result of more gradual changes in demand and have longer lead times (i.e., 3 to 10 years) before a solution is required.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2020-0091 Exhibit B, Pages 21 and 24

Preamble:

"The efficiency of NGASHPs make them an ideal IRPA candidate. NGASHPs operate at a greater efficiency than traditional natural gas furnaces due to their mode of operation. The efficiency of NGASHPs decreases as ambient temperatures fall, however, their efficiency should never fall below 100%."

"Similar to NGASHPs, as the ambient temperature falls, the efficiency of EASHPs also decreases, thus increasing electrical consumption. An EASHP's typical minimum efficiency is 100%."

Question:

a) The quoted texts imply that the efficiency of NGASHPs and EASHPs is at times greater than 100%. Please explain how a heat pump or any machine can have an efficiency greater than 100%

b) Please confirm NGASHPs use natural gas only medium for heat transfer and as a fuel while EASHPs do not use any natural gas.

c) Is Enbridge proposing to install, own and operate NGASHPs and EASHPs on customer's premises?

Response

a) EASHP systems operate by moving thermal energy from one medium to another leveraging the vapour compression cycle of refrigerant. The energy consumed by the heat pump is used to drive the thermal cycle which absorbs thermal energy from the outside air and transfers it into the space requiring heat. The amount of energy transferred from one medium to the other exceeds the amount of electrical energy consumed making the system perform at efficiencies in excess of 100%.

NGASHP's operate under a similar process by moving thermal energy from one location to another. Natural gas is used to drive the thermal cycle and additional energy from the source is absorbed and transferred into the space requiring heat.

b) Confirmed. NGASHPs use natural gas as a fuel source to move thermal energy from outside air into indoor space requiring heat, while EASHPs do not use natural gas.

c) Please see the response at Exhibit I.STAFF.17 b).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (“EP”)

INTERROGATORY

Reference:

EB-2020-0091 Exhibit B, Page 23

Preamble:

“Should this authorization be granted, these assets would need to be included into rate base or else by investing in such alternatives the Company would be contributing to higher rates for existing customers since they would not receive the moderating advantage of new revenues from customer growth to help offset Enbridge Gas’s overall costs.”

Question:

a) Please explain why the Company would be contributing to higher rates if IRPA assets are not in rate base.

b) Please discuss owning and operating costs of IRPAs, particularly the maintenance costs of pumps and compressors and their inclusion in the Operation and Maintenance costs of Enbridge Gas.

Response

a) Rates would be higher and more volatile if the cost of the IRPA were passed through to customers as a one-time cost as the IRPA cost is incurred rather than capitalized to rate base and passed through rates to customers over time.

a) Enbridge Gas expects that if a viable market does not exist to implement the IRPA(s) solution, Enbridge Gas may propose to implement and own and operate the IRPA. In such instances, the ongoing costs of owning and operating the IRPA would be treated in the same manner as it would for the operating and maintenance cost of servicing pipelines as an O&M cost in the Company’s revenue requirement. Please refer to Exhibit I.STAFF.22 part a) regarding the categories of cost related to the implementation of IRPAs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2020-0091 Exhibit B, Page 29

Preamble:

Given that the Board has approved funding in Enbridge Gas's 2015-2020 DSM Plans (EB-2015-0029/0049) to meet the goals and objectives of the 2015-2020 DSM Framework, Enbridge Gas expects that separate funding and resources would be allocated to meet the differing goals and objectives of an IRP framework for Enbridge Gas. This would include covering the cost of implementation, tracking and monitoring the impacts of ETEE and/or other IRPAs.

Question:

Please describe and discuss the "separate funding sources" mentioned in the quoted text. Do these separate sources consist of separate groups of ratepayers or non-ratepayer sources?

Response

As part of its 2015-2020 DSM Framework (EB-2015-0029/0049), the Board directed:[1]

> "If a gas utility identifies DSM as a practical alternative to a future infrastructure investment project, it may apply to the Board for incremental funds to administer a specific DSM program in that area where a system constraint has been identified."

More generally, the activities that will be necessary under an IRP Framework are new and separate from the Company's existing activities (including DSM). As such, these are not activities that are funded by Enbridge Gas's existing base rates.

[1] EB-2015-0029/0049, Report of the Board: Demand Side Management Framework for Natural Gas Distributors (2015-2020), p. 36. https://www.rds.oeb.ca/CMWebDrawer/Record/460473/File/document

Accordingly, Enbridge Gas anticipates that incremental funds (separate and distinct from any OEB-approved DSM funding) will be made available in support of meeting the objectives of the IRP Framework established by the Board broadly (not restricted in any way to ETEE). Please see the responses at Exhibit I.STAFF.22, at Exhibit.I.APPrO.6 and at Exhibit I.GEC.6 for more information about incremental costs of IRP/IRPAs. Enbridge Gas has not contemplated restricting cost recovery or funding to, or from, any separate groups of ratepayers or non-ratepayer sources as suggested by EP.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2020-0091 Exhibit B, Page 30

Preamble:

"If an IRPA, or IRPAs, can reliably meet the forecasted demands driving the constraint/need in place of new facility expansion/reinforcement projects, then Enbridge Gas will evaluate the IRPA on an economic basis compared to new facilities."

Question:

Electricity distribution typically has lower reliability than gas distribution. It is possible that non-gas IRPA's that rely on electricity as the alternative could have lower reliability. Would Enbridge consider and evaluate IRPA's that have lower reliability that the current Enbridge Gas distribution system? Please discuss.

Response

Yes, Enbridge Gas may consider and evaluate non-gas IRPAs that rely on electricity which could have a lower reliability than the Company's distribution, storage or transmission systems. As discussed in Enbridge Gas's Additional Evidence at page 16, reliability will be considered as part of Stage 1 of Enbridge Gas's proposed IRPA Evaluation:

- If the electricity reliability risk associated with a particular IRPA(s) (and/or its potential impacts) is deemed to be too high in the relevant geographic area in which a system constraint has been identified, then Enbridge Gas may conclude that a facility alternative is the preferred means to resolve that constraint/need.

- If the electricity reliability risk associated with a particular IRPA(s) (and/or its potential impacts) is deemed to be acceptable in the relevant geographic area in which a system constraint has been identified, to either Enbridge Gas or customers being served, then Enbridge Gas may conclude that it is appropriate to proceed with its assessment of and application to the OEB for approval to invest in IRPA(s).

Notably, in its Additional Evidence at Exhibit B, page 23 in reference to non-gas alternatives, Enbridge Gas states:

> "In certain situations where natural gas facilities are available, natural gas could be used to provide back-up functionality and resilience to these alternatives."

Thus, natural gas facilities may still play a part in maintaining overall energy system reliability, even in instances where a non-gas IRPA(s) is implemented.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2020-0091 Exhibit B, Page 32

Preamble:

"Enbridge Gas will apply to the OEB for approval to recover the costs associated with investment in any IRPA. Enbridge Gas presumes that such an application would, similar to applications for LTC facility alternatives…"

Question:

Can an application for approval of an IRPA be filed under the current OEB Act or would the OEB Act need to be changed? Please discuss.

Response

As explained in the response to Exhibit I.STAFF.25, Enbridge Gas believes that there should be like treatment of IRPA investments with the facilities alternatives that IRPAs are replacing. That means that the capital costs of IRPAs should be treated as rate base additions. Where Enbridge Gas owns the IRPA assets they would be treated like other rate base additions. When Enbridge Gas does not own the IRPA assets, then the costs incurred could, if outlined by the Board in the forthcoming IRP Framework, be recovered through the recognition and rate base addition of a regulatory asset representing the cost of the Company's investment to enable IRPA deployment.

Enbridge is of the view that the current *OEB Act* could permit: (i) the approval of an IRPA that does not directly store, transmit or distribute natural gas, and (ii) its cost recovery through rate base addition, since the intent of the IRPA is to ensure the reliability needs of natural gas ratepayers are met. If the OEB were to decide that certain IRPA investments should not be treated as additions to rate base without changes to the *OEB Act* because the asset is not directly associated with the storage, distribution, transmission or sale of gas, Enbridge Gas believes that it would be important for the Board to determine a manner in which the Company would be appropriately compensated for pursuing and investing in the subject IRPAs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2020-0091 Exhibit B, Page 37, paragraph 81; Exhibit C, pages 23 and 24

Question:

Considering IRPA's may rely on new technology or new energy delivery systems is it likely that implementation of IRPA's will increase the risk to ratepayers? Please discuss the following risks:

a) The risk that the IRPA cost is greater than forecast,

b) The risk that the IRPA reduces reliability of energy delivery to customers, and

c) The risk that the IRPA does not result in promised energy savings.

Response

a) – c)
Yes, as discussed in Enbridge Gas's Additional Evidence at Exhibit B, Pages 34-37, Enbridge Gas's investments in IRPAs create incremental risk to the ratepayer.

In paragraph 77, Enbridge Gas states,

> "Should Enbridge Gas's investments into IRPAs not result in the reduction of peak period demand anticipated, or in the event that supply-side alternatives experience a failure to deliver, there are few, if any, firm, cost-effective alternatives that Enbridge Gas can rely upon on short notice."

And in paragraph 80,

> "Enbridge Gas expects that any and all of the prudently incurred: (i) original costs to invest in OEB-approved IRPAs; (ii) costs associated with OEB-approved adjustments to IRPA investments; and (iii) costs of any subsequent OEB-approved LTC project (in the instance that an IRPA is determined to have

> been insufficiently effective), would be borne entirely by ratepayers subject to the Board's determination that in the course of incurring such costs Enbridge Gas acted prudently and responsibly in serving the firm needs of its ratepayers."

Please also see the response at Exhibit I.EP.6, for further discussion of IRP/IRPA risk.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

EB-2020-0091 Exhibit B, Page 45

Preamble:

"Recently more natural gas utilities across North America are considering the implementation of AMI technology. In Canada, FortisBC is expected to file with the British Columbia Utilities Commission to upgrade their natural gas meters as part of the Advanced Gas Meters project. In addition, ConEd, SoCal Gas and PG&E have all initiated or completed the roll out of natural gas AMI technology and networks."

Question:

a) Has FortisBC filed its application dealing with the upgrade of natural gas meters? If the answer is yes, please provide a link to the application.

b) Please file a description of the initiation and roll-out of natural gas AMI technology and networks for each of the referenced utilities, including whether the roll-out is a pilot program or a mass program, the date of the roll-out, the technology employed, the costs if available, and links to approvals of the roll-out by regulatory commissions.
   i. ConEd
   ii. SoCal Gas
   iii. PG&E

Response

a) According to the FortisBC "Advanced Gas Meters" web page, the anticipated timing of an application to the British Columbia Utility Commission is 2021, with a decision anticipated in 2022.[1]

[1] https://www.fortisbc.com/about-us/projects-planning/natural-gas-projects-planning/advanced-gas-meters#tab-1

b) Please see Table 1 below for details of AMI roll-out at each of the referenced utilities. Enbridge Gas does is not aware of the specific nature of the technologies being employed by ConEd, SoCal and PG&E at this time.

Table 1

	Utility	**Number of Meters & Type** *(millions)*	**Total Cost** *($Billion)*	**Nature of AMI Rollout**	**Links to Approvals**
i.	ConEd	**Natural Gas =** 1.2 **Electric =** 3.5	$1.2	Mass roll-out. Ongoing (paused due to COVID restrictions)	http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=156436&MatterSeq=47337
ii.	SoCal Gas	**Natural Gas =** 5.9	$1.05	Mass roll-out over 5 years (2013 – 2018)	https://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/116294.pdf
iii.	PG&E[2]	**Natural Gas =** 4.2 **Electric =** 5.1	$2.40	Mass roll-out over 7 years (2007 – 2013)	https://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/58362.htm https://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/98486-17.htm

[2] As of December 31, 2013.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Appendix A, ICF report, Page 8

Preamble:

"Although the number of NPS projects in the State are limited (with the exception of the implementation of distributed supply sources including LNG and CNG), the projects that have been implemented have generated useful results and led to ongoing discussions that are helping to lay the groundwork for a more widespread use of such solutions. However, to date, the demand side pilot projects have been too small in scale to lead to deferring or avoiding infrastructure."

Question:

a) Please provide a list of projects with a description of each project indicating if it is a pilot project or not.

b) Please describe the useful results including the methods used for monitoring, recording and the evaluation.

Response

a) Please see Exhibit B, Appendix A, ICF Report, Exhibit 15, for a list of projects with a description of each project. All of the projects in the list that are not CNG or LNG project are pilot projects (in a variety of stages) except for the following:

   - Central Hudson's transportation mode alternative; and

   - National Grid's C&I gas DR pilot, which is in the process of transitioning to full-scale deployment.

b) While the number of NPS projects were relatively limited, the projects that have been implemented: (i) illustrate the thinking of the utilities that have addressed these issues; (ii) identify many of the issues and concerns that were considered; and (iii) have led to useful results.

Of the projects included in Exhibit 15 of the ICF Report, two ConEdison pilot projects had published evaluation results when the ICF Report was being written. ConEdison had published two reports on the status of its Gas Demand Response program. In the second status report for winter 2019/2020,[1] ConEdison reported the following:

- **Commercial and industrial, and Multi-unit residential building Performance-Based Gas Demand Response Offering:** 309 customers pledged 78,675 m^3 of gas (2,886 Dth). ConEdison called one test and realized 54% of the pledged impact. The performance measurement and verification approach for this commercial and industrial demand program was based on gas interval meter commercial and industrial, as well as its multi-unit residential building customers.

- **Direct Load Control Gas Demand Response Offering in the residential sector:** Over 2,800 thermostats were enrolled in the program. The overall curtailment was an average reduction of 1,529 m^3 of natural gas (56.1 dth) per test event including the snapback effect,[2] with results hovering between 0.38 m^3 (0.014 dth) and 0.76 m^3 of natural gas (0.028 dth) per thermostat. ConEdison found that a smaller setback of 1 deg F resulted in higher impact than more stringent setbacks because ConEdison found fewer cases of customers overriding the demand response calls. The performance measurement and verification approach for this residential gas demand response program focused on smart thermostats was based on furnace runtime data from the thermostats.

All of the other pilot projects listed in Exhibit 15 of the ICF Report had estimated impacts that were based on engineering calculations.

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[1] ConEdison, *Gas Demand Response Report on Pilot Performance - 2019/2020, Case 17-G-0606 and Case 14-E-0423*, 2020.
[2] The snapback effect is an increase in energy demand that happens due to the synchronization of a fleet of asset because of a demand response event. In other words, the entire fleet of heating equipment that was curtailed start at the same time and operate at full capacity simultaneously to bring back the space temperature at its original setpoint. There are many demand response strategies to minimize and soften the snapback.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Appendix A, ICF report, page 21

Preamble:

"Gas to electricity conversion is a relatively new trend in NPS. Typically, the electrification that has been seen during this study is through the deployment of air-source and ground-source heat pumps due to the expected environmental benefits associated with the use of renewable power."

Question:

a) Has any utility in Canada or the US implemented a gas to electricity conversion as an IRPA? If the answer is yes, please identify the utility (or utilities) and describe the extent of the implementation.

b) Are the expected environmental benefits of air-source and ground-source heat pumps dependent on the use of renewable power? Please discuss including the types of power that can be considered as renewable.

Response

a) To ICF Canada's knowledge, the only North American utility with an existing program to implement gas to electricity (G2E) conversions as an IRPA is Central Hudson. The initiative is referred to as a "transportation mode alternative". This initiative consists of offering technical assistance and incentives to convince customers to cut off their gas connection and fully electrify their space heating via ground-source heat pumps or air-source heat pumps. The initiative targets pipes that are scheduled for replacement due to obsolescence, particularly when they connect to only a few customers. To avoid the replacement of a given pipe, all customers served by the pipe need to agree to give up their gas connection, which is a challenging requirement to meet.

Some Canadian utilities have a history of seeking electrification but based on ICF Canada's knowledge they have not specifically targeted G2E as an IRPA.

New York State gas utilities may currently be promoting G2E conversion, but only as an unintended result of their latest energy efficiency target which included a special allocation of target and funding for achieving savings through the deployment of heat pumps in buildings using any kind baseline fuel. Consequently, the current heat pump deployment may or may not include G2E conversion depending on utility strategy to meet target and customer preference. Furthermore, the energy efficiency targets were not meant to be IRPAs in the sense observed by Enbridge Gas. The heat pump programs launched by the New York State utilities to meet the energy efficiency target are not required to avoid the need for specific pipeline infrastructure investments.

In its long-term capacity report,[1] National Grid suggested to use G2E conversion to meet the long-term upstream supply shortage, but only using money above and beyond what is already being allocated to meet their energy efficiency target. In addition, National Grid has not started deploying this incremental funding, leaving this option for the later part of its demand forecasting window. A final decision on this initiative is pending.

b) The expected environmental benefits of air-source and ground-source heat pumps depend on the power generation supply mix at the time that they are drawing load from the electricity grid. For a discussion of the types of electricity generation that are considered renewable in the State of New York, please consult the definition according to the United States Environmental Protection Agency (EPA).[2]

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[1] National Grid. (2020). Natural Gas Long-Term Capacity Supplemental Report for Brooklyn, Queens, Staten Island and Long Island. New York City, NY, USA. https://millawesome.s3.amazonaws.com/Downstate_NY_Long-Term_Natural_Gas_Capacity_Supplemental_Report_May_8_2020.pdf

[2] US EPA. (2021). What Is Green Power?. USA. https://www.epa.gov/greenpower/what-green-power

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

In EGI’s initial IRP filing at Tab 13 of Exhibit B in EB-2019-0159, EGI appeared to limit the scope of IRPAs to measures that reduced peak day demand. That narrow scope for IRPAs was rejected by the OEB in its OEB’s July 15, 2020 Decision on the Issues List.

At page 6 of that Decision the OEB defined an IRPA as “a potential solution considered under the IRP Plan in response to a specific system need of Enbridge Gas”

In its Additional and Reply Evidence in this proceeding, EGI has broadened its initially proposed scope for IRPAs to include “Innovative Technologies” consisting of “Gas Alternatives”, “Non-gas Alternatives”, “Demand Response”, “Enhanced Targeted Energy Efficiency”, and “Gas Supply Alternatives”.

The evidence does not specifically describe or address the sub-set of IRPAs that is described in the Board’s Decision on the Issues List as Non-Facility SUPPLY SIDE Alternatives to an infrastructure build. As already noted, these “supply side” alternatives are considered in a facilities need context to avoid or defer an infra structure build, and not as a source of long-term gas supply.

Under the practice being followed by EGI, when it submitted its Dawn Parkway system expansion application in EB 2019=0159, the Non-Facility Alternatives to the infrastructure build that were identified and evaluated were:

(i) Parkway Delivery Obligations;
(ii) Utilizing Third Party Deliveries at Parkway;
(iii) Winter Peaking Transport Service; and
(iv) IRP- limited in scope to peak period demand reduction measures (see EB-2019-0159, Exhibit A, Tab 7, pages 19-22)

Question:

Having regard to the foregoing preamble:

a) What is EGI’s definition for the Non-Facility SUPPLY SIDE Alternatives to an Infrastructure build?

b) Do each of the Non facility Alternatives identified above in the transmission build proposed in EB 2019-0159 fall within the ambit of EGI's definition of an IRPA?
c) Does EGI accept that contracting or market mechanisms that can assure that the utility of meeting its firm peak day delivery obligations is a Non-Facility SUPPLY SIDE Alternative to the construction of incremental pipeline infrastructure? Please provide EGI's rationale for its response to this question.

<u>Response</u>

Enbridge Gas does not accept FRPO's interpretation of the Board's Decision on Issues List and Procedural Order No. 2 ("PO No. 2") dated July 15, 2020. FRPO's characterization of the contrast between Enbridge Gas's original IRP Proposal and Additional Evidence is simply wrong as both outline IRPAs such as: Demand Response, Enhanced Energy Efficiency, CNG, and Low-Carbon and Non-Gas solutions. Regarding consideration of supply-side or market-based alternatives, Enbridge Gas has a long history of considering such alternatives to relieve identified system constraints as part of its applications to the OEB for Leave to Construct facilities. In numerous historical instances such alternatives have proven to be either uneconomic or insufficiently reliable compared to facility-based alternatives.

Enbridge Gas also notes in PO No. 5 the Board specifically stated that:

> "The OEB concludes that the concerns of FRPO can be addressed by putting to Enbridge Gas <u>proposals for evaluation criteria for supply-side alternatives, and suggestions for the timing to assess these alternatives</u>, through the interrogatory process." <u>[emphasis added]</u>

Importantly, nowhere did the Board invite FRPO to include argument, or requests that Enbridge Gas provide assessment or analyses of supply-side (market-based) alternatives to specific or hypothetical system constraints, including those associated with the now withdrawn 2021 Dawn Parkway Expansion Project. As set out in the Board's Procedural Order No. 1 in the 2021 Dawn Parkway Expansion Project proceeding dated January 30, 2020, the OEB determined that Enbridge Gas's IRP Proposal would be heard separately from the 2021 Dawn Parkway Expansion Project as it "…raises issues of broad applicability that are best dealt with outside the context of a project-specific Leave to Construct proceeding."

Further, as set out in the Board's Procedural Order No. 2,

> "The OEB agrees that this proceeding is not the forum to duplicate matters being considered in other policy reviews, such as the Post-2020 DSM Framework for Natural Gas Distributors."

> "The OEB expects that the IRP Framework to be determined with not reference specific facilities/IRPAs…"

None of Enbridge Gas's original IRP Proposal, Additional Evidence or Reply Evidence seek 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. The purpose of this proceeding is to develop an IRP policy framework for Enbridge Gas to guide its assessment of IRPAs relative to other facility and non-facility alternatives to serve the forecasted needs of its customers. Accordingly, Enbridge Gas has attempted to be as responsive as reasonably possible. However, as a number of the questions posed by FRPO exceed the scope of this proceeding as previously defined by the Board in Procedural Order No. 2 and further refined in its subsequent findings, Enbridge Gas has objected to certain of them based on their relevance.

a) - c)

Enbridge Gas defines non-facility supply-side alternatives as any market-based solutions that would resolve identified system constraints. There could be any number of unique non-facility supply-side alternatives possible depending upon the precise market conditions, geographic location, and nature of the constraint which the Company is seeking to resolve at a particular time. As such, it is not reasonable or practical to strictly define the nature, feasibility and/or cost-effectiveness of any such alternatives as part of this proceeding. Instead, Enbridge Gas requests that the Board establish an IRP Framework for Enbridge Gas that enables consideration of, assessment of, and investment in all appropriate facility and non-facility alternatives, including supply-side/market-based alternatives. Please also see the responses at Exhibit I.STAFF.2, at Exhibit I.STAFF.16 and at Exhibit I.FRPO.2.

Provided that Enbridge Gas finds the non-facility supply-side/market-based alternatives to be feasible, economic, safe, reliable and meet minimum renewal terms, Enbridge Gas will continue to consider and assess them for the purposes of resolving system constraints. Importantly, Enbridge Gas has historically completed such assessments and presented them to the Board as part of applications for Leave to Construct facilities.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

In EGI's initial IRP filing at Tab 13 of Exhibit B in EB-2019-0159, EGI appeared to limit the scope of IRPAs to measures that reduced peak day demand. That narrow scope for IRPAs was rejected by the OEB in its OEB's July 15, 2020 Decision on the Issues List.

At page 6 of that Decision the OEB defined an IRPA as "a potential solution considered under the IRP Plan in response to a specific system need of Enbridge Gas"

In its Additional and Reply Evidence in this proceeding, EGI has broadened its initially proposed scope for IRPAs to include "Innovative Technologies" consisting of "Gas Alternatives", "Non-gas Alternatives", "Demand Response", "Enhanced Targeted Energy Efficiency", and "Gas Supply Alternatives".

The evidence does not specifically describe or address the sub-set of IRPAs that is described in the Board's Decision on the Issues List as Non-Facility SUPPLY SIDE Alternatives to an infrastructure build. As already noted, these "supply side" alternatives are considered in a facilities need context to avoid or defer an infra structure build, and not as a source of long-term gas supply.

Under the practice being followed by EGI, when it submitted its Dawn Parkway system expansion application in EB 2019=0159, the Non-Facility Alternatives to the infrastructure build that were identified and evaluated were:

(i) Parkway Delivery Obligations;
(ii) Utilizing Third Party Deliveries at Parkway;
(iii) Winter Peaking Transport Service; and
(iv) IRP- limited in scope to peak period demand reduction measures (see EB-2019-0159, Exhibit A, Tab 7, pages 19-22)

Question:

Please provide EGI's current list of all of the potential activities/projects that EGI classifies as Non-Facility Alternatives. Segregate that list between its SUPPLY SIDE and Non-Supply side Components.

<u>Response</u>

Enbridge Gas is not seeking OEB approval to implement any specific IRPAs or to recover the costs associated with investment in specific IRPAs as part of this proceeding. The purpose of this proceeding is to develop an IRP Policy Framework for Enbridge Gas to guide its assessment of IRPAs relative to other facility and non-facility alternatives. The types of IRPAs that will be considered by Enbridge Gas include those discussed in its Additional Evidence at Exhibit B, pages 21 to 30. Please see the response at Exhibit I.STAFF.16, for discussion of supply-side alternatives. Please also see the response at Exhibit I.VECC.6 b), for further discussion regarding potential IRPA technologies.

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:

Please produce a complete copy of EGI's current system planning process manual(s) into which IRP is to be incorporated.

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 before the Board in this proceeding.

Please see the responses at Exhibit I.STAFF.4 d) and e), Exhibit I.OSEA.1 c) and at Exhibit I.STAFF.2.

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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 is required under current system planning process in connection with the identification and assessment of need?

Response

Please see the response at Exhibit I.FRPO.3.

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:

Going forward, what does EGI propose, if anything, to involve stakeholders and/or the OEB during the need assessment process?

Response

Please see the response at Exhibit I.STAFF.9, for discussion of Enbridge Gas’s proposed IRP-related stakeholder engagement activities.

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:

In connection with the "need" assessment calculation please provide the following information related to EGI's ability to manage a "shortfall" of different magnitudes ranging between 28,602 GJ/d to 72,624 GJ/d as described in the evidence in EB 2019-0159 at Exhibit A, Tab 7, page 14-16 by responding to the following "shortfall management questions:

a) How does EGI intend to manage these forecasted shortfalls?
b) What are some of the most effective approaches?
c) Please describe and provide the economics associated with each approach.

Response

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

a) & b)
Enbridge Gas generally manages system shortfalls through a variety of mechanisms including investment in facility alternatives (e.g., construction of pipelines, compression and storage assets), non-facility alternatives (e.g., supply-side/market-

based service solutions), and through re-assignment of capacity turned back by existing customers.

The most effective approach to managing shortfalls is dependent on a number of factors including the magnitude and duration of the forecasted shortfall, current market conditions and forecasted market conditions.

c) Please see the response at Exhibit I.FRPO.1. Completing economic evaluations on all possible types of facility and non-facility alternatives based on a hypothetical system constraint is not reasonable nor is it appropriate as it exceeds the scope of this proceeding to establish an IRP Policy Framework for Enbridge Gas to guide its consideration of IRPAs going forward. The information sought is more appropriate to consider at such time that Enbridge Gas brings forward an application to the Board to invest in IRPAs or for Leave to Construct facilities.

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 is the largest shortfall forecasted by the utility in the last 5 years?

Response

Year to year, the Company can manage a small level of shortfall on the Dawn Parkway System. The largest Dawn Parkway System shortfall over the past 5 years was 26,545 GJ/day. Please see the response at Exhibit I.FRPO.8, for a discussion on how this shortfall was mitigated.

The largest forecasted shortfall on the Dawn Parkway System over the past 5 years, after incremental demands have been identified, occurred in Winter 2017/2018 at 426,254 GJ/day. To address this incremental demand and the capacity shortfall, the Lobo D, Bright C and Dawn H compressor facilities were constructed as per EB-2015-0200.

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:

How was that shortfall managed? Please provide both from a planned and operational perspective.

Response

As discussed at Exhibit I FRPO.7, the Winter 2017/2018 shortfall was managed by monitoring the demands on the system and weather forecasts during the winter season. Actual use and forecasted HDDs in the Union South rate zone did not approach design conditions, so there was no need to take any specific action to address the shortfall. The Company was prepared to purchase services on short notice if required.

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 were the costs incurred in prior contracting or short-term adjustments and/or contracts?

Response

There were no costs incurred in prior contracting or short-term adjustments and/or contracts.

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:

In connection with the "need" assessment, please explain on what basis EGI discontinues Non-Facility Supply Side alternatives in order to replace them with service from an infrastructure build by reference to the elimination of third-party services of 40 TJ/d referenced in the EB-2019-0159 case.

Response

The question of Enbridge Gas's historical reliance upon supply-side/market-based services (third-party services) as part of its Gas Supply Plan is an issue addressed as part of Enbridge Gas's 5-Year Gas Supply Plan (EB-2019-0137). Enbridge Gas will file its Annual Update to the current 5-Year Gas Supply Plan in February 2021. The evaluation of third-party services against firm transportation alternatives would be detailed in a future 5-Year Gas Supply Plan or Annual Update, and, potentially, in a facilities application (where Company-owned infrastructure is required). Please see the response at Exhibit I.STAFF.16 for more information on the applicability of third-party services as an IRPA.

As set out in the response at Exhibit I.FRPO.1, Enbridge Gas's withdrawn 2021 Dawn Parkway Expansion Project application and evidence, including alternatives assessed, is not currently before the Board in this proceeding. The Board has also previously stated that it is not appropriate to duplicate matters considered in other recent proceedings.[1]

[1] Procedural Order No. 4, August 20, 2020, p. 4.

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:

Please respond to the following additional questions about this Non-Facility Supply Side discontinuance transaction:

a) Please confirm the biggest contributor to the increase in shortfall is the elimination of third-party services (40 TJ/day).
b) Please describe the nature of these services (e.g., peaking service, exchange service, etc).
c) Was an RFP performed in prior years and for the year 2020?
d) Please provide copies of the RFPs made in prior years, copies of the ensuing contracts and details on the cost of service for the 2019 year including:
    i) Amount contracted
    ii) Location of delivery area
    iii) Number of days of call
    iv) Cost of the contract.
    v) If EGI believes any of the above items are confidential, please file them as appropriate but please provide the total cost of the demand portion of contract for 2019 publicly as it ought to be something that has been reported in gas costs previously.

e) Please provide all internal analysis, memos and other communications which contributed to the decision to eliminate these services.

Response

The question of Enbridge Gas's historical reliance upon supply-side/market-based services (third-party services) as part of its Gas Supply Plan is an issue addressed as part of Enbridge Gas's 5-Year Gas Supply Plan (EB-2019-0137). Enridge Gas will file its Annual Update to the current 5-Year Gas Supply Plan in February 2021.

As set out in the response at Exhibit I.FRPO.1, Enbridge Gas's withdrawn 2021 Dawn Parkway Expansion Project application and evidence, including alternatives assessed, is not currently before the Board in this proceeding. The Board has also previously stated that it is not appropriate to duplicate matters considered in other recent proceedings.[1]

[1] Procedural Order No. 4, August 20, 2020, p. 4.

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 is currently required under the current system planning process in connection with the identification, screening, and assessment of alternatives?

Response

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

Please see the responses at Exhibit I.STAFF.4 d) and e), at Exhibit I.STAFF.19, at Exhibit I.OSEA.1 c) and at Exhibit I.STAFF.2.

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:

Going forward, what does EGI propose, if anything, to involve stakeholders and/or the OEB during the identification and assessment of alternatives?

Response

Please see the response at Exhibit I.STAFF.9, for discussion of Enbridge Gas's proposed IRP-related stakeholder engagement activities.

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:

Please flag the timing requirements that are currently specified in these manuals related to identifying need; identifying, screening, assessing and evaluating alternatives; and selecting the alternative that EGI prefers.

Response

As identified in Enbridge Gas's Additional Evidence at Exhibit B, page 13, Figure 2.1 system needs are typically identified over a 10 year forecast. Please also see the response at Exhibit I.STAFF. 3 b).

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.

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 are the current requirements, if any, in EGI's System Planning process, related to the costing methodologies that are to be applied to a Non-Facility Supply Side Alternative to an infrastructure build such as the Parkway Delivery Obligation Non-Facility Alternative identified in the EB-2019-0159 proceeding?

Response

To evaluate facility and non-facility alternatives Enbridge Gas demonstrates economic feasibility utilizing Board-approved economic feasibility tests using Discounted Cash Flow ("DCF") analysis and calculation of Net Present Value ("NPV") consistent with the Board's E.B.O.134 guidelines.

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 costing and assessment criteria are currently applied to compare an alternative that uses existing utility and interconnected infrastructure in a way that defers a facility addition by a period of 3 years or more?

Response

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

Please see the response at Exhibit.I.FRPO.16 for a description of Enbridge Gas's current approach to evaluation of economic feasibility.

Enbridge Gas assumes that FRPO is referring to supply-side or market-based alternatives for the purposes of providing this response. Enbridge Gas has historically and currently evaluates commercial alternatives where such services carry a minimum term renewal right so that, subject to non-renewal, the Company can ensure that it has sufficient time to re-evaluate both facility and non-facility alternatives. In the case that a facility alternative is preferred, based on Enbridge Gas's 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.

Non-facility supply-side or market-based alternatives are compared against other alternatives (both facility and non-facility) in terms of cost, type and terms of service, reliability, term and renewal rights, and counterparty credit status.

Please also see the responses at Exhibit I.STAFF.4 d) and e) and at Exhibit I.STAFF.19.

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:

Going forward, is EGI proposing any changes to the current cost comparison approach that is applied in this type of scenario?

Response

No, Enbridge Gas does not propose any additional changes to its cost comparison approach.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, page 3

Preamble:

EGI evidence states: "*Enbridge Gas supports the concept of adding costs and benefits to the Board's E.B.O. 134 guidelines to create a modified E.B.O. 134 or staged Discounted Cash Flow ("DCF") Plus (DCF+) standard for the purposes of assessing IRPAs in Ontario. There is benefit to a staged approach that enables clear and transparent conclusions to be drawn at each stage of analysis and which is based foremost on an economic (DCF) analysis.*"

Question:

How does the availability of a Non-Facility Supply Side Alternative for a term of 5 years influence the cost comparison calculations?

Response

Please see the response at Exhibit I.FRPO.16 for discussion of economic feasibility and the response at Exhibit.I.FRPO.17 for discussion on assessment criteria.

Term is a single component of the evaluation of market-based services considered by Enbridge Gas. The term sought by Enbridge Gas influences the cost that third-parties place on market-based services but the degree of its impact is unique to the services sought in each instance, the commercial interests of third-party service providers, and market conditions at the time such services are solicited.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, page 3

Preamble:

EGI evidence states: “*Enbridge Gas supports the concept of adding costs and benefits to the Board’s E.B.O. 134 guidelines to create a modified E.B.O. 134 or staged Discounted Cash Flow (“DCF”) Plus (DCF+) standard for the purposes of assessing IRPAs in Ontario. There is benefit to a staged approach that enables clear and transparent conclusions to be drawn at each stage of analysis and which is based foremost on an economic (DCF) analysis.”*

Question:

Please illustrate by providing the following calculation:

a) Using the cost of and any other factors from the applied for 2021 expansion of the Dawn Parkway system, please perform staged DCF+ calculation.
b) This section of pipe was to provide 92,174 GJ/day of capacity to the Dawn-Parkway system. As an IRPA, we ask that you provide a DCF+ calculation for increasing PDO commitments by the same 92,174 GJ/day using the Parkway Delivery Commitment Incentive (PDCI) using a simplifying assumption that the quantity of commitment stays constant at 92,174 GJ/day for the term analyzed and no additional facilities are added to the Dawn-Parkway system.

Response

a) & b)
As set out in the response at Exhibit I.FRPO.1, Enbridge Gas’s withdrawn 2021 Dawn Parkway Expansion Project application and evidence, including the associated economic analyses conducted, is not currently before the Board in this proceeding.

Further, Enbridge Gas has proposed that the Board adopt the E.B.O. 134/188 guidelines as a base for IRP-related cost-effectiveness assessments in support of establishing an IRP Framework for Enbridge Gas.[1] These are the same guidelines which Enbridge Gas followed in completing its economic analyses as part of the 2021 Dawn Parkway Expansion Project application.[2]

Enbridge Gas did not propose the DCF+ cost-effectiveness test as part of either its original IRP Proposal nor its Additional Evidence, but rather, in response to the expert evidence of OEB Staff stated:

> "Enbridge Gas supports the concept of adding costs and benefits to the Board's E.B.O. 134 guidelines to create a modified E.B.O. 134 or staged Discounted Cash Flow ("DCF") Plus (DCF+) standard for the purposes of assessing IRPAs in Ontario."[3]

Following the establishment of an IRP Framework for Enbridge Gas that sets out the appropriate cost-effectiveness tests and assessment process to apply to IRPAs going forward, the Company expects that it would include the detailed calculations underlying its decisions to proceed with investments in IRPAs and/or facilities accordingly. It is not reasonable to require Enbridge Gas to do so now, based on the volumes and historic market conditions associated with its withdrawn 2021 Dawn Parkway Expansion Project.

Please see the response at Exhibit I.STAFF.20, for discussion of Enbridge Gas's proposed cost-effectiveness assessment process including the nature of costs and benefits proposed to be included for consideration therein.

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[1] Additional Evidence, Exhibit B, p. 34 and Reply Evidence, Exhibit C, pp. 3, 9-11.
[2] EB-2019-0159, Exhibit A, Tab 8, pp. 1-3.
[3] Reply Evidence, Exhibit C, p. 3.

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Question:

What, if anything, do the existing planning processes require for addressing perceived conflict of interest situations that might arise, for example, when EGI expresses a preference for constructing incremental capacity instead of preferring a more cost-effective alternative to respond to a need attributable to in franchise demands served by EGI’s gas distribution systems?

Response

Existing planning processes are focused upon ensuring that Enbridge Gas fulfils its obligation as the supplier of last resort to safely and reliably meet the firm contractual demands of ratepayers during peak/design periods.

As discussed in its response at Exhibit I.FRPO.1, regarding consideration of supply-side or market-based alternatives (which Enbridge Gas can only assume FRPO is referring to as ‘more cost-effective alternative’), Enbridge Gas has a long history of considering such alternatives to resolve identified system constraints as part of its applications to the OEB for Leave-to-Construct (“LTC”) facilities. When an LTC application for new facilities or an IRPA application is brought forward, the Board and stakeholders can test the analyses upon which such applications are based, including market-based alternatives. In numerous historical instances such market-based alternatives have proven to be either uneconomic or insufficiently reliable compared to facility-based alternatives.

As noted above, the Board and stakeholders have an opportunity to test the appropriateness of facilities or IRPA(s) proposed when an application is made. If parties believe that there is a more cost-effective alternative to respond to an identified system constraint as compared to Enbridge Gas's proposal within its application, then that position can be put to the OEB as part of its review of the same.

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Question:

In such perceived conflict of interest situations, is there any process requirement for EGI to have the appropriate response determined by the OEB or some other independent assessor or adjudicator?

Response

Please see the response at Exhibit I.FRPO.21.

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Question:

Are there any provisions in EGI's existing planning requirements that relates to a consideration of the reliability of a Non-Facility Supply Side alternative to an infrastructure build based on contractual obligations from a third party to EGI (such as the PDO) compared to an alternative based on EGI's ownership and operation of incremental facilities? If so, then please direct our attention to these provisions of the planning manual(s).

Response

Please see the response at Exhibit.I.FRPO.17 where Enbridge Gas provided market-based service assessment criteria that included the evaluation of reliability, as well as cost and security of supply. Reliability of a commercial service is an important component of alternative evaluation as it addresses the counterparty's ability to schedule and deliver a call for gas delivery. If a counterparty does not underpin the contracted service with firm upstream assets, this increases the risk of the counterparty's ability to deliver. Failure to deliver increases operational risk to Enbridge Gas and may result in loss of service to customers and financial and reputational risks for the Company. As discussed in the response at Exhibit.I.FRPO.21, when an application for new facilities or an IRPA is brought forward, the Board and stakeholders have an opportunity to test the appropriateness of the preferred alternative.

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Question:

What is EGI's response to the question whether any OEB approvals are "required" under the IRP Framework that it envisages?

Response

Please see the responses at Exhibit I.CCC.3, at Exhibit I.STAFF.10, at Exhibit I.STAFF.6, and at Exhibit I.STAFF.24, for discussion of IRP/IRPA related approvals envisaged by Enbridge Gas following the establishment of an IRP Framework.

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Question:

What is EGI's response to the question whether the IRP Framework that it envisages will necessitate changes to other policies rules, or guidelines.

Response

Enbridge Gas has not specifically proposed changes to any policies, rules or guidelines in this proceeding. In its Reply Evidence at Exhibit C, page 8 Enbridge Gas states:

> "In its Additional Evidence, Enbridge Gas proposed that economic feasibility of IRPAs be assessed using a DCF methodology consistent with principles underpinning the Board's E.B.O. 134 and E.B.O. 188."

Enbridge Gas goes on at page 9 to state:

> "Therefore, Enbridge Gas supports the OEB's consideration of other costs and benefits similar and in addition to those set out in E.B.O. 134 as part of its development of an IRP Framework for Enbridge Gas. When assessing the feasibility of natural gas facility (pipeline) infrastructure and comparing them to IRPAs, the Board should establish a staged economic evaluation standard for IRPAs through this

> proceeding that ultimately resembles a modified version of the OEB's E.B.O. 134 guidelines or a DCF+ test."

Please see the response at Exhibit I.STAFF.20 a), for further discussion of Enbridge Gas's proposal to rely upon the Board's E.B.O. 134 for the purposes of assessing and comparing the economic feasibility of IRPAs and facility alternatives.

ENBRIDGE GAS INC.

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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 is counted on to meet EGI's design criteria for the Dawn-Parkway system.

Response

Confirmed.

The PDO is counted on to meet demand on the Dawn Parkway System only. It is not relevant to any other pipeline system and should not be considered as part of the overall IRP program for other distribution or transmission pipeline systems.

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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.

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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.

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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%

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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 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.

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.

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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:

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

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Question:

If PDO is not as described above, please clarify and categorize how it is viewed by EGI.

Response

Please see the response at Exhibit I.FRPO.32.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

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Question:

Does EGI accept obligated deliveries at other locations besides Parkway and Dawn?

a) If so, where (e.g., Ojibway, St. Clair, Kirkwall)?

Response

Enbridge Gas's Direct Purchase ("DP") customers may also be obligated at Empress, the Enbridge EDA delivery area on the TCPL Mainline, or the Enbridge CDA delivery area on the TCPL Mainline.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

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Question:

Does EGI provide a financial incentive to deliver at these other location(s) of obligated delivery?

Response

No.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, page 8

Preamble:

EGI's evidence states: *"Once Enbridge Gas identifies the need for infrastructure expansion/reinforcement driven by increased peak period demands, facility alternatives (traditionally pipelines, compressors and ancillary facilities but could also include CNG / LNG options), non-facility alternatives (such as winter peaking service and supply options) and IRPAs with the potential to reduce peak period demand will be investigated."*

Our focus is getting confirmation or clarification on aspects this process of non-facility supply-side options that can be considered.

We have asked questions above about the use of Delivery Point commitments, but we understand that Receipt Point commitments can also contribute to the ability of an LDC or pipeline to meets its obligations. We understand that TransCanada Pipelines (TCPL) used receipt point commitments in combination with its facilities to meet its customer receipt and delivery obligations.

Question:

Please describe the Dawn Overrun Service - Must Nominate that TCPL put in place as a contracted, non-facility solution to meet a shortfall in facilities in meeting its customer obligations.

Response

Dawn Overrun Service – Must Nominate ("DOS-MN") was a temporary service enhancement provided by TCPL in the winter of 2008/2009 and the winter of 2009/2010. Firm transportation shippers made a commitment to deliver gas to TCPL at

Empress and receive gas from TCPL at Dawn each day of the winter, paying substantially less than the demand charge for transportation service from Empress to Dawn. This was incremental to the firm transportation quantities for which shippers had contracted. DOS-MN was put in place to allow TCPL to manage its short haul capacity shortfall from Dawn to points east of Parkway. DOS-MN is no longer offered by TCPL and has been removed from the Mainline tariff.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, page 8

Preamble:

EGI's evidence states: *"Once Enbridge Gas identifies the need for infrastructure expansion/reinforcement driven by increased peak period demands, facility alternatives (traditionally pipelines, compressors and ancillary facilities but could also include CNG / LNG options), non-facility alternatives (such as winter peaking service and supply options) and IRPAs with the potential to reduce peak period demand will be investigated."*

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Question:

From the EGI/Union Gas experience with that service, were there any supply interruptions that occurred as a result of that service being used.

Response

DOS MN service was offered by TCPL and contracted by Union for Winter 2008/2009 and Winter 2009/2010. Enbridge Gas does not have any record of DOS-MN firm service interruptions during these contracted periods. EGD did not contract for the DOS-MN service.

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:

If the above definition is deficient, please provide EGI's concise definition.

Response

Enbridge Gas defined peaking supplies in its 5 Year Gas Supply Plan:[1]

> "Peaking supply arrangements source gas from third-party suppliers for firm delivery directly to EGI's franchise areas during the winter season. Since supplies are only required a few days per year (contracts are typically for a maximum of 10 days per winter season), they are traded at a premium to conventional supplies over a longer period. The agreed upon supply must be available to EGI on the days determined by EGI."

FRPO's definition neglects the following attributes of such services:

i. In addition to the fixed demand charge noted by FRPO (which is often paid monthly), peaking services also include a variable component. The variable component is a premium supply price that is typically indexed to daily settlement prices at nearby locations. The cost of peaking services varies depending on the term of the agreement, the number of days during the term that gas can be called, and the market price for natural gas at or near the delivery location.

[1] EB-2019-0137, Enbridge Gas Inc. – 5 Year Gas Supply Plan, May 1, 2019, p. 11.

ii. Peaking services typically only make supply available for one daily nomination window, meaning that they cannot be relied upon to balance intra-day demand changes during peak periods.

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.

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:

Please provide copies of the Requests for Expression of Interest sent out by EGI in the most recent request for Interest in providing this service.

Response

Please see the response at Exhibit I.FRPO.39.

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:

How many parties did EGI send the Request to?

Response

Please see the response at Exhibit I.FRPO.39.

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:

In the most recent year of contracting, please provide:

i. Amount contracted
ii. Location of delivery area
iii. Maximum number of days of call
iv. The notice required to make the call

Response

Please see the response at Exhibit I.FRPO.39.

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:

Please file the resulting contract(s) appropriately redacted for the counter-party name and any other financial matters EGI deems confidential. To be clear, we do expect that the description of the type of relief for non-performance would be evident to the reader.

Response

Please see the response at Exhibit I.FRPO.39.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

We understand that the design standards include assumptions regarding temperature conditions measured in Heating Degree Days (HDD) and status of interruptible contracts.

Question:

Please confirm the EGI/Union Gas South system has had criteria has two design conditions over time: 43.1 HDD, interruptibles off and 35 HDD, interruptibles on. If not, then please clarify.

Response

Generally confirmed. Please also see the response at Exhibit I.FRPO.47, for further clarification.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

We understand that the design standards include assumptions regarding temperature conditions measured in Heating Degree Days (HDD) and status of interruptible contracts.

Question:

What are the current design conditions for the Dawn-Parkway system including status of ex-franchise customers?

Response

Please see the response at Exhibit I.STAFF.4, Attachment 1, Section 3.2.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

We understand that the design standards include assumptions regarding temperature conditions measured in Heating Degree Days (HDD) and status of interruptible contracts.

Question:

Did Union Gas historically use a condition of interruptibles off for the purposes of planning the Dawn-Parkway system?

Response

Yes.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

We understand that the design standards include assumptions regarding temperature conditions measured in Heating Degree Days (HDD) and status of interruptible contracts.

Question:

Does EGI have design conditions contingent on the status of interruptible customers in any other rate zone? If so, then please specify the rate zone and the applicable design conditions.

Response

Yes. The standard condition for pipeline design on design day is interruptible OFF ("IOFF") for all rate zones. There are a few exceptions for pipeline systems that feed power generating customers or process driven demand, where the pipeline is designed with interruptible ON ("ION") to serve peak demand during non-design day conditions. For example, Sarnia Industrial Line system which serves mainly process driven demand is designed with ION.

The standard condition in the Gas Supply Plan is IOFF on design day.

IOFF means 100% of the interruptible demand is curtailed on design day and not de-rated (if de-rated is to mean a staged off reduction rather than a full interruption) unless otherwise noted above.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

EGI”s evidence at Exhibit C, page 3, states: “*Beyond its safety record, Enbridge Gas has also: (i) been a leader in North America and dominant force in Ontario in achieving demand side management (“DSM”) energy and bill savings for the past two and a half decades; (ii) long optimized its rate design in order to offer interruptible services to its customers and reflected utilization of those services for system planning purposes;…” (emphasis added)*

We are interested in understanding the design and utilization of Interruptible Service in both legacy EGD and Union South rate zone systems.

Question:

For the Union South rate zone, please provide a brief description, the year, and the applicable Board approval of the last re-design of interruptible rates.

Response

Interruptible service offerings are available to Union South rate zone customers as part of the following rate classes: Rate M4, Rate M5, Rate M7, Rate T1 and Rate T2.

The design of Union South interruptible rates has changed over time with the last OEB approval for all components of the interruptible services received as part of Union’s 2013 Cost of Service proceeding (EB-2011-0210). Union’s 2013 Cost of Service proceeding included the following proposals and OEB approvals related to Union South interruptible rates:

- The introduction of an interruptible service option for firm Rate M4 customers. The Rate M4 interruptible pricing was set to match the interruptible rates calculated under Rate M5.

- Revising the Rate M5 eligibility downward from a minimum contract demand of 4,800 m^3/d to 2,400 m^3/d to align with the proposed change in eligibility of the Rate M4 rate class.

- Including an interruptible service option for eligible customers as part of the newly created Rate T2 rate class.

Since the changes made as part of Union's 2013 Cost of Service proceeding, the OEB has also approved an unauthorized overrun non-compliance rate of $60/GJ applicable to all interruptible service offerings to ensure customers comply with their contractual obligations when a distribution interruption is called (Union's 2016 Rates proceeding: EB-2015-0116).

ENBRIDGE GAS INC.

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

INTERROGATORY

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We are interested in understanding the design and utilization of Interruptible Service in both legacy EGD and Union South rate zone systems.

Question:

Please provide the total amount of hourly and daily load that could be shed on the Union Gas system:

i. In the year of that latest change
ii. In 2013 (last year of rebasing)
iii. Forecast for 2021

Response

For the Union rate zones,[1] all interruptible load is considered shed (or off) on design day. Please also see the response at Exhibit I.FRPO.47.

Enbridge Gas was not able to compile the additional data requested by FRPO related to hourly and daily load. However, the Company expects that it will be able to do so by the date of the Technical Conference scheduled for this proceeding (February 10, 2020) and will do so sooner if possible.

[1] Collectively, the Union North and Union South rate zones are referred to as the "Union rate zones".

ENBRIDGE GAS INC.

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

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We are interested in understanding the design and utilization of Interruptible Service in both legacy EGD and Union South rate zone systems.

Question:

When evaluating the impact of an interruptible contract on peak day load, did Union Gas/EGI deduct the entire interruptible contract in its system design or was the load derated? Please explain.

Response

Please see the response at Exhibit I.FRPO.47.

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We are interested in understanding the design and utilization of Interruptible Service in both legacy EGD and Union South rate zone systems.

Question:

Please provide the responses to the above questions in relation to the EGD rate zone.

Response

Please see response at Exhibit I.FRPO.47, for discussion of the design day status of interruptible customers in the EGD rate zone.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

EGI's EB-2019-0159 evidence at Exhibit A, Tab 7, page 21, states: "*Enbridge Gas examined the potential for TC Energy to provide an exchange service utilizing a Dawn Long Term Fixed Price service ("LTFP"). LTFP service expires in 2028 with an early termination option in 2023. The LTFP contracts can be terminated with two years notice. Further, LTFP shippers are not obligated to flow contracted volumes every day. This alternative is not a reliable long-term option to serve Enbridge Gas design day demand as it poses significant operational and commercial risk if not available beyond the original term or if shippers elect to not nominate for sufficient flow on design day to support the exchange service."*

We understand that the Dawn LTFP service has significantly increased daily deliveries to Ontario since its inception in November 2017. We believe these volumes, if secured financially, could provide opportunity for IRP solutions and that it warrants further examination. We would like the Board to understand more about this service and EGI's dismissal of its potential.

Question:

Please describe the attributes of the Dawn LTFP Service that TCPL provides. In particular:

a) Please provide the amount of firm contracting from Empress to Dawn that was contracted for through the Dawn LTFP service?
b) Have all Dawn LTFP shippers made a 10-year fixed price demand charge commitment to TCPL (subject to early termination rate escalation)?
    i. Please describe what a shipper must do to terminate earlier than 10 years.

c) Using publicly available information, please confirm that there has only been a very small reduction in the contracting of Dawn LTFP over the three years of initial service.
d) Can all Dawn LTFP shippers nominate and is TCPL obliged to deliver their firm transport quantity on each and every day of a contract year?

Response

a) The Dawn LTFP Application filed by TransCanada states:

> "In total, 1.5 PJ/d of new long-haul contracts were executed."[1]

b) No. The Dawn LTFP Application filed by TransCanada states:

> "shippers may elect to reduce the term of all or a portion of their contract quantity by 1, 2, 3, 4 or 5 years, subject to a minimum two-years' notice prior to the amended end date of the applicable contract quantity, and as described below subject to an increase in the toll."[2]

> "for any portion of contract quantity that is reduced in term, a higher fixed toll will apply to that portion of the contract quantity for the final two years of the reduced term.[3] As is the case for the $0.77/GJ/d toll, the applicable tolls for the last two years of any reduced term were determined through negotiations with prospective shippers, all of which are arm's length entities to TransCanada, and are market-based."[4]

c) To the best of Enbridge Gas's knowledge, this information would not be publicly available given the minimum two-year notice required as described above.

d) Yes. As per Article IV §4.1 of the Dawn LTFP Contract template:

> "TransCanada shall provide transportation service hereunder for Shipper in respect of a quantity of gas which, in any one day from the Date of Commencement until the Dawn LTFP End Date." [5]

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[1] CER document A82887-2 Dawn Long Term Fixed Price Application, §1.2, paragraph 12.
[2] CER document A82887-2 Dawn Long Term Fixed Price Application, §2.3.2, paragraph 44.
[3] The fixed demand toll of $0.77/GJ/d will continue to apply in all years prior to the final two years of the reduced term.
[4] CER document A82887-2 Dawn Long Term Fixed Price Application, §2.3.3, paragraph 47.
[5] http://www.tccustomerexpress.com/docs/ml_regulatory_tariff/33%20Dawn%20LTFP%20Contract.pdf

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

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We understand that the Dawn LTFP service has significantly increased daily deliveries to Ontario since its inception in November 2017. We believe these volumes, if secured financially, could provide opportunity for IRP solutions and that it warrants further examination. We would like the Board to understand more about this service and EGI's dismissal of its potential.

Question:

What paths can TCPL select to carry Dawn LTFP shipper nominated? volumes?

Response

The NEB's reason's for decision on the Dawn LTFP Service states:[1]

> "TransCanada submitted that there are two options to facilitate the receipt of gas at Empress for delivery to Dawn: the Northern Route and the Southern Route. The Northern Route consists of transport on the Prairies Line and the Northern Ontario Line from Empress to North Bay Junction (NBJ), the Barrie Line from NBJ to Parkway, and TBO capacity from Parkway to Dawn on the Union Gas system. The Southern Route consists of transport on the Prairies Line and the Emerson

[1] CER document A88125-1 NEB – Reasons for Decision – TransCanada – Dawn LTFP – RH-003-2017.

> Extension from Empress to Emerson 2, and TBO Capacity on GLGT and GLGC from Emerson 2 to Dawn."

TCPL determines the daily operation of its system to provide the Dawn LTFP service as well as all other services on its system.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

EGI's EB-2019-0159 evidence at Exhibit A, Tab 7, page 21, states: "*Enbridge Gas examined the potential for TC Energy to provide an exchange service utilizing a Dawn Long Term Fixed Price service ("LTFP"). LTFP service expires in 2028 with an early termination option in 2023. The LTFP contracts can be terminated with two years notice. Further, LTFP shippers are not obligated to flow contracted volumes every day. This alternative is not a reliable long-term option to serve Enbridge Gas design day demand as it poses significant operational and commercial risk if not available beyond the original term or if shippers elect to not nominate for sufficient flow on design day to support the exchange service."*

We understand that the Dawn LTFP service has significantly increased daily deliveries to Ontario since its inception in November 2017. We believe these volumes, if secured financially, could provide opportunity for IRP solutions and that it warrants further examination. We would like the Board to understand more about this service and EGI's dismissal of its potential.

Question:

Please confirm that no party holds capacity from Empress to Parkway or Dawn on TCPL except Dawn LTFP shippers.

a) If not, please indicate the quantity of daily delivery in GJ/day.

Response

Please see Attachment 1, Contract Demand Energy (CDE) Report (TC Customer Express website)[1] which describes FT (firm transportation), FT-NR (non-renewable), FT-SN (short-notice), STS (storage transportation service), ENB (enhanced balancing) and LTFP (long-term fixed price) services contracted on the Mainline as of January 4, 2021.

[1] http://www.tccustomerexpress.com/888.html

CONTRACT DEMAND ENERGY (CDE) REPORT - Mainline

As Of Date: 2021-Jan-04

Service Type: FT, FT-NR, FT-SN, STS, EMB, LTFP

Contract Number	Service Requester	Contract Start Date	Contract End Date	Service Type	Primary Receipt	Primary Delivery	Contract Demand (GJ/d)	Operational Demand (GJ/d)	Shifted Qty (GJ/d)	Temp Assigned Qty (GJ/d)
56446	BP Canada Energy Group ULC	2018-Jan-01	2022-Dec-31	FT	Empress	Centram MDA	1,300	1,300	0	0
58428	BP Canada Energy Group ULC	2018-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	3,900	3,900	0	0
59035	BP Canada Energy Group ULC	2019-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	1,418	1,418	0	0
5107	Bunge Canada	1994-Nov-01	2022-Oct-31	FT	Welwyn	Centram MDA	1,332	0	0	1,332
37575	Centra Gas Manitoba Inc.	2009-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	90,000	0	0	90,000
44646	Centra Gas Manitoba Inc.	2012-Nov-01	2022-Oct-31	FT	Emerson 2	Centram MDA	20,625	625	0	20,000
44686	Centra Gas Manitoba Inc.	2012-Nov-01	2022-Oct-31	FT	Emerson 2	Centram MDA	375	375	0	0
47199	Centra Gas Manitoba Inc.	2013-Oct-01	2022-Oct-31	FT	Emerson 2	Centram MDA	48,750	27,649	0	21,101
47882	Centra Gas Manitoba Inc.	2013-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	15,000	0	0	15,000
52663	Centra Gas Manitoba Inc.	2015-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	20,000	0	0	20,000
54691	Centra Gas Manitoba Inc.	2016-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	15,000	0	0	15,000
57571	Centra Gas Manitoba Inc.	2018-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	20,000	10,000	0	10,000
57745	Centra Gas Manitoba Inc.	2019-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	5,000	5,000	0	0
29802	Diageo Canada Inc.	2006-May-15	2022-Oct-31	FT	Empress	Centram MDA	400	0	0	400
29803	Diageo Canada Inc.	2006-May-15	2022-Oct-31	FT	Empress	Centram MDA	2,400	0	0	2,400
48696	Husky Oil Operations Limited	2014-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	5,000	5,000	0	0
60644	Koch Canada Energy Services, LP	2020-Jan-01	2022-Oct-31	FT-NR	Empress	Centram MDA	27,000	27,000	0	0
60645	Koch Canada Energy Services, LP	2019-Dec-01	2022-Oct-31	FT-NR	Empress	Centram MDA	16,000	16,000	0	0
62388	Koch Canada Energy Services, LP	2020-Nov-01	2033-Oct-31	FT	Empress	Centram MDA	42,202	42,202	0	0
5665	Maple Leaf Foods Inc.	1995-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	706	0	0	706
56674	Richardson International Limited	2017-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	325	0	0	325
56673	Simplot Canada (II) Limited	2017-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	2,000	0	0	2,000
58357	Simplot Canada (II) Limited	2019-Nov-01	2024-Oct-31	FT	Empress	Centram MDA	2,000	0	0	2,000
56675	Viterra Inc.	2017-Nov-01	2022-Oct-31	FT	Empress	Centram MDA	750	0	0	750
						Centram MDA Total	**341,483**	**140,469**	**0**	**201,014**
56444	BP Canada Energy Group ULC	2018-Jan-01	2022-Dec-31	FT	Empress	Centram SSDA	675	675	0	0
3036	Centra Gas Manitoba Inc.	1993-Dec-01	2022-Oct-31	FT	Empress	Centram SSDA	1,200	1,200	0	0
47883	Centra Gas Manitoba Inc.	2013-Nov-01	2022-Oct-31	FT	Empress	Centram SSDA	2,000	2,000	0	0
56669	TransGas Limited	2018-Jan-01	2022-Oct-31	FT	Empress	Centram SSDA	1,507	1,507	0	0
						Centram SSDA Total	**5,382**	**5,382**	**0**	**0**
56658	Centra Gas Manitoba Inc.	2017-Nov-01	2022-Oct-31	FT	Empress	Centrat MDA	90	90	0	0
6309	Enbridge Gas Inc.	1996-Jul-01	2022-Oct-31	FT	Empress	Centrat MDA	4,522	4,522	0	0
48480	Enbridge Gas Inc.	2015-Nov-01	2022-Oct-31	FT	Empress	Centrat MDA	1,043	1,043	0	0
						Centrat MDA Total	**5,655**	**5,655**	**0**	**0**
2939	Rochester Gas and Electric Corporation	1993-Nov-01	2022-Oct-31	FT	St. Clair	Chippawa	49,513	0	0	49,513
						Chippawa Total	**49,513**	**0**	**0**	**49,513**
54380	Brasher Falls Central School District	2016-Nov-01	2022-Oct-31	FT	Empress	Cornwall	50	0	0	50
18342	Canton Central School District	2002-Nov-01	2022-Oct-31	FT	Empress	Cornwall	63	0	0	63
27539	Canton Central School District	2005-Nov-01	2022-Oct-31	FT	Empress	Cornwall	3	0	0	3
13292	City of Ogdensburg	1999-Nov-01	2022-Oct-31	FT	Empress	Cornwall	19	0	0	19
18321	Clarkson University	2002-Nov-01	2022-Oct-31	FT	Empress	Cornwall	525	0	0	525
18320	Heuvelton Central School District	2002-Nov-01	2022-Oct-31	FT	Empress	Cornwall	34	0	0	34
18349	Hoosier Magnetics, Inc.	2002-Nov-01	2022-Oct-31	FT	Empress	Cornwall	330	0	0	330
62953	Husky Oil Operations Limited	2020-Nov-01	2021-Oct-31	FT	Empress	Cornwall	1,219	1,219	0	0
19233	Liberty Utilities (St. Lawrence Gas) Corp.	2002-Nov-01	2026-Oct-31	STS	Union Parkway Belt	Cornwall	10,300	10,300	0	0
57057	Liberty Utilities (St. Lawrence Gas) Corp.	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Cornwall	10,000	0	0	10,000
58192	Liberty Utilities (St. Lawrence Gas) Corp.	2018-Aug-01	2033-Jul-31	FT	Iroquois	Cornwall	4,000	0	0	4,000
60751	Liberty Utilities (St. Lawrence Gas) Corp.	2019-Nov-01	2030-Dec-31	FT	North Bay Junction	Cornwall	3,200	3,200	0	0
60752	Liberty Utilities (St. Lawrence Gas) Corp.	2019-Nov-01	2030-Dec-31	FT	North Bay Junction	Cornwall	7,050	7,050	0	0

CONTRACT DEMAND ENERGY (CDE) REPORT - Mainline

As Of Date: 2021-Jan-04

Service Type: FT, FT-NR, FT-SN, STS, EMB, LTFP

Contract Number	Service Requester	Contract Start Date	Contract End Date	Service Type	Primary Receipt	Primary Delivery	Contract Demand (GJ/d)	Operational Demand (GJ/d)	Shifted Qty (GJ/d)	Temp Assigned Qty (GJ/d)
18338	Lisbon Central School District	2002-Nov-01	2022-Oct-31	FT	Empress	Cornwall	19	0	0	19
27537	Lisbon Central School District	2005-Nov-01	2022-Oct-31	FT	Empress	Cornwall	2	0	0	2
18328	Madrid-Waddington Central School District	2002-Nov-01	2022-Oct-31	FT	Empress	Cornwall	26	0	0	26
18318	Massena Central School District	2002-Nov-01	2022-Oct-31	FT	Empress	Cornwall	135	0	0	135
27538	Massena Central School District	2005-Nov-01	2022-Oct-31	FT	Empress	Cornwall	4	0	0	4
18341	Norwood-Norfolk Central School District	2002-Nov-01	2022-Oct-31	FT	Empress	Cornwall	49	0	0	49
31593	Ogdensburg City School District	2006-Nov-01	2022-Oct-31	FT	Empress	Cornwall	19	0	0	19
31594	Ogdensburg City School District	2006-Nov-01	2022-Oct-31	FT	Empress	Cornwall	75	0	0	75
18340	Potsdam Central School District	2002-Nov-01	2022-Oct-31	FT	Empress	Cornwall	83	0	0	83
13375	St. Lawrence University	1999-Nov-01	2022-Oct-31	FT	Empress	Cornwall	362	0	0	362
33328	St. Lawrence University	2007-Nov-01	2022-Oct-31	FT	Empress	Cornwall	54	0	0	54
43348	St. Lawrence-Lewis BOCES	2011-Nov-01	2022-Oct-31	FT	Empress	Cornwall	25	0	0	25
18317	St. Regis Nursing Home and Health Related Facility, Inc.	2002-Nov-01	2022-Oct-31	FT	Empress	Cornwall	29	29	0	0
						Cornwall Total	**37,675**	**21,798**	**0**	**15,877**
58580	Boston Gas Company	2018-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	22,332	0	0	22,332
60656	Boston Gas Company	2019-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	31,144	0	0	31,144
63259	Boston Gas Company	2020-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	6,852	1	0	6,851
63397	Eversource Gas Company of Massachusetts	2020-Oct-09	2026-Oct-31	FT	Union Dawn	East Hereford	16,881	0	0	16,881
63399	Eversource Gas Company of Massachusetts	2020-Oct-09	2040-Oct-31	FT	Union Parkway Belt	East Hereford	13,399	0	0	13,399
63400	Eversource Gas Company of Massachusetts	2020-Oct-09	2040-Oct-31	FT	Union Parkway Belt	East Hereford	48,005	0	0	48,005
63401	Eversource Gas Company of Massachusetts	2020-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	1,717	0	0	1,717
58578	Heritage Gas Limited	2018-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	3,913	0	0	3,913
60657	Heritage Gas Limited	2019-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	5,439	0	0	5,439
63261	Heritage Gas Limited	2020-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	1,200	0	0	1,200
57056	Irving Oil Limited	2017-Dec-01	2032-Nov-30	FT	Union Parkway Belt	East Hereford	27,095	27,095	0	0
58621	Irving Oil Limited	2018-Nov-01	2033-Oct-31	FT	Union Parkway Belt	East Hereford	10,582	10,582	0	0
61068	Irving Oil Limited	2019-Nov-01	2021-Oct-31	FT	North Bay Junction	East Hereford	21,315	21,315	0	0
59728	Liberty Utilities (EnergyNorth Natural Gas) Corp.	2019-Apr-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	1,957	0	0	1,957
60658	Liberty Utilities (EnergyNorth Natural Gas) Corp.	2019-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	2,728	0	0	2,728
63262	Liberty Utilities (EnergyNorth Natural Gas) Corp.	2020-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	600	0	0	600
58575	Liberty Utilities (Gas New Brunswick) LP	2018-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	2,651	0	0	2,651
58576	Liberty Utilities (Gas New Brunswick) LP	2018-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	112	0	0	112
60652	Liberty Utilities (Gas New Brunswick) LP	2019-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	4,830	0	0	4,830
63263	Liberty Utilities (Gas New Brunswick) LP	2020-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	959	0	0	959
61065	New Brunswick Energy Marketing Corporation	2019-Nov-01	2021-Oct-31	FT	North Bay Junction	East Hereford	6,277	0	0	6,277
61064	New England NG Supply Limited	2019-Nov-01	2021-Oct-31	FT	North Bay Junction	East Hereford	17,408	17,408	0	0
57055	Northern Utilities, Inc.	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	East Hereford	6,333	0	0	6,333
57901	Northern Utilities, Inc.	2018-Apr-01	2033-Mar-31	FT	Union Parkway Belt	East Hereford	35,872	0	0	35,872
63265	Northern Utilities, Inc.	2020-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	10,569	0	0	10,569
58567	Portland Natural Gas Transmission System	2018-Nov-01	2040-Oct-31	FT	Union Dawn	East Hereford	0	0	0	0
60655	The Berkshire Gas Company	2019-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	3,757	2,848	0	909
63260	The Berkshire Gas Company	2020-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	482	482	0	0
58577	The Narragansett Electric Company	2018-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	11,349	0	0	11,349
60659	The Narragansett Electric Company	2019-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	15,825	0	0	15,825
63264	The Narragansett Electric Company	2020-Nov-01	2040-Oct-31	FT	Union Parkway Belt	East Hereford	3,482	0	0	3,482
						East Hereford Total	**335,065**	**79,731**	**0**	**255,334**
57859	BP Canada Energy Group ULC	2018-Nov-01	2022-Oct-31	FT	Empress	Emerson 1	26,904	26,904	0	0
60409	BP Canada Energy Group ULC	2020-Nov-01	2022-Oct-31	FT	Empress	Emerson 1	10,551	10,551	0	0
60639	BP Canada Energy Group ULC	2019-Nov-01	2022-Oct-31	FT	Empress	Emerson 1	26,376	26,376	0	0
62413	Direct Energy Marketing Limited	2020-Nov-01	2021-Oct-31	FT	Empress	Emerson 1	5,275	5,275	0	0
62389	J. Aron & Company LLC	2020-Nov-01	2023-Oct-31	FT	Empress	Emerson 1	4,764	4,764	0	0

CONTRACT DEMAND ENERGY (CDE) REPORT - Mainline

As Of Date: 2021-Jan-04

Service Type: FT, FT-NR, FT-SN, STS, EMB, LTFP

Contract Number	Service Requester	Contract Start Date	Contract End Date	Service Type	Primary Receipt	Primary Delivery	Contract Demand (GJ/d)	Operational Demand (GJ/d)	Shifted Qty (GJ/d)	Temp Assigned Qty (GJ/d)
56672	J. R. Simplot Company	2017-Nov-01	2022-Oct-31	FT	Empress	Emerson 1	3,000	0	0	3,000
61346	Macquarie Energy Canada Ltd.	2020-Dec-01	2022-Mar-31	FT-NR	Empress	Emerson 1	50,000	50,000	0	0
60628	Mercuria Commodities Canada Corporation	2020-Nov-01	2022-Oct-31	FT	Empress	Emerson 1	10,551	10,551	0	0
60237	Shell Energy North America (Canada) Inc.	2020-Nov-01	2023-Oct-31	FT	Empress	Emerson 1	31,652	31,652	0	0
60352	Shell Energy North America (Canada) Inc.	2020-Apr-01	2021-Mar-31	FT	Empress	Emerson 1	31,652	31,652	0	0
61288	Shell Energy North America (Canada) Inc.	2020-Apr-01	2021-Mar-31	FT-NR	Empress	Emerson 1	31,652	31,652	0	0
60624	Tidal Energy Marketing Inc.	2020-Nov-01	2022-Oct-31	FT	Empress	Emerson 1	44,840	44,840	0	0
60411	Twin Eagle Resource Management Canada, LLC	2020-Nov-01	2022-Oct-31	FT	Empress	Emerson 1	10,551	10,551	0	0
						Emerson 1 Total	**287,768**	**284,768**	**0**	**3,000**
61166	Advantage Oil & Gas Ltd.	2020-Nov-01	2032-Oct-31	FT	Empress	Emerson 2	28,300	0	0	28,300
60408	BP Canada Energy Group ULC	2020-Nov-01	2022-Oct-31	FT	Empress	Emerson 2	26,376	26,376	0	0
60640	BP Canada Energy Group ULC	2019-Nov-01	2022-Oct-31	FT	Empress	Emerson 2	26,376	26,376	0	0
57752	Canadian Natural Resources	2020-Nov-01	2022-Oct-31	FT	Empress	Emerson 2	211,011	211,011	0	0
62390	Castleton Commodities Merchant Trading L.P.	2020-Nov-01	2023-Oct-31	FT	Empress	Emerson 2	7,145	7,145	0	0
2771	Centra Gas Manitoba Inc.	1993-Apr-01	2023-Mar-31	STS	Centram MDA	Emerson 2	54,000	54,000	0	0
12359	City of Duluth	1999-Nov-01	2024-Oct-31	FT	Empress	Emerson 2	6,532	0	0	6,532
60399	ConocoPhillips Canada Marketing & Trading ULC	2019-Nov-01	2022-Oct-31	FT	Empress	Emerson 2	21,101	21,101	0	0
60075	Enbridge Gas Inc.	2019-Nov-01	2022-Oct-31	FT	Empress	Emerson 2	21,418	0	0	21,418
62392	Husky Oil Operations Limited	2020-Nov-01	2025-Oct-31	FT	Empress	Emerson 2	5,275	5,275	0	0
61347	Macquarie Energy Canada Ltd.	2020-Dec-01	2022-Mar-31	FT-NR	Empress	Emerson 2	28,952	28,952	0	0
61348	Macquarie Energy Canada Ltd.	2021-Jan-01	2022-Mar-31	FT-NR	Empress	Emerson 2	17,833	17,833	0	0
62469	Macquarie Energy Canada Ltd.	2020-Dec-01	2021-Nov-30	FT	Empress	Emerson 2	21,101	21,101	0	0
62391	Mercuria Commodities Canada Corporation	2020-Nov-01	2023-Oct-31	FT	Empress	Emerson 2	4,764	4,764	0	0
62408	Morgan Stanley Capital Group Inc.	2020-Nov-01	2021-Oct-31	FT	Empress	Emerson 2	5,000	5,000	0	0
62460	Morgan Stanley Capital Group Inc.	2020-Nov-01	2021-Oct-31	FT	Empress	Emerson 2	275	275	0	0
58196	Peyto Exploration & Development Corp.	2018-Nov-01	2022-Oct-31	FT	Empress	Emerson 2	26,376	0	0	26,376
58203	Peyto Exploration & Development Corp.	2018-Nov-01	2022-Oct-31	FT	Empress	Emerson 2	15,686	0	0	15,686
58655	TAQA North	2018-Nov-01	2022-Oct-31	FT	Empress	Emerson 2	15,000	0	0	15,000
60407	Tenaska Marketing Canada, a division of TMV Corp.	2020-Apr-01	2022-Mar-31	FT	Empress	Emerson 2	15,826	15,826	0	0
60509	Tenaska Marketing Canada, a division of TMV Corp.	2020-Apr-01	2022-Mar-31	FT	Empress	Emerson 2	26,376	26,376	0	0
60510	Tenaska Marketing Canada, a division of TMV Corp.	2020-Nov-01	2022-Oct-31	FT	Empress	Emerson 2	26,376	26,376	0	0
62406	Tidal Energy Marketing Inc.	2020-Nov-01	2021-Oct-31	FT	Empress	Emerson 2	10,551	10,551	0	0
60410	Twin Eagle Resource Management Canada, LLC	2020-Nov-01	2022-Oct-31	FT	Empress	Emerson 2	10,551	10,551	0	0
60649	Twin Eagle Resource Management Canada, LLC	2019-Nov-01	2022-Oct-31	FT-NR	Empress	Emerson 2	10,551	10,551	0	0
61148	Twin Eagle Resource Management Canada, LLC	2019-Nov-07	2022-Oct-31	FT-NR	Empress	Emerson 2	5,275	5,275	0	0
						Emerson 2 Total	**648,027**	**534,715**	**0**	**113,312**
2623	Enbridge Gas Inc.	1992-Nov-01	2026-Oct-31	STS	Union Parkway Belt	Enbridge CDA	153,700	153,700	0	0
15957	Enbridge Gas Inc.	2001-Nov-01	2026-Oct-31	STS	Union Parkway Belt	Enbridge CDA	92,822	92,822	0	0
18786	Enbridge Gas Inc.	2002-Nov-01	2026-Oct-31	STS	Union Parkway Belt	Enbridge CDA	37,370	37,370	0	0
20260	Enbridge Gas Inc.	2003-Nov-01	2026-Oct-31	FT	Union Dawn	Enbridge CDA	4,818	4,818	0	0
20266	Enbridge Gas Inc.	2003-Nov-01	2026-Oct-31	FT	Union Dawn	Enbridge CDA	145,000	145,000	0	0
35516	Enbridge Gas Inc.	2008-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Enbridge CDA	572	572	0	0
57061	Enbridge Gas Inc.	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Enbridge CDA	40,093	40,093	0	0
57062	Enbridge Gas Inc.	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Enbridge CDA	15,000	15,000	0	0
57063	Enbridge Gas Inc.	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Enbridge CDA	8,375	8,375	0	0
57065	Enbridge Gas Inc.	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Enbridge CDA	24,484	24,484	0	0
58615	Enbridge Gas Inc.	2019-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Enbridge CDA	70,000	70,000	0	0
60706	Enbridge Gas Inc.	2019-Nov-01	2034-Oct-31	FT	Union Parkway Belt	Enbridge CDA	75,000	75,000	0	0
60755	Enbridge Gas Inc.	2021-Jan-01	2030-Dec-31	FT	North Bay Junction	Enbridge CDA	5,000	4,897	0	103
58439	Equinor Natural Gas LLC	2018-Nov-01	2026-Oct-31	FT	Niagara Falls	Enbridge CDA	211,011	131,882	0	79,129
58440	Equinor Natural Gas LLC	2018-Nov-01	2026-Oct-31	FT	Niagara Falls	Enbridge CDA	44,607	44,607	0	0

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28756	Greater Toronto Airports Authority	2006-Apr-01	2022-Oct-31	FT	Union Parkway Belt	Enbridge CDA	7,500	4,150	0	3,350
52843	Jungbunzlauer Canada Inc.	2015-Dec-16	2026-Oct-31	FT	Union Dawn	Enbridge CDA	4,000	4,000	0	0
20224	Oxy Vinyls Canada Co.	2003-Apr-01	2026-Oct-31	FT	Union Dawn	Enbridge CDA	1,800	1,800	0	0
38224	Shell Energy North America (Canada) Inc.	2009-Oct-01	2022-Oct-31	FT	Union Dawn	Enbridge CDA	2,600	2,600	0	0
						Enbridge CDA Total	**943,752**	**861,170**	**0**	**82,582**
61617	EBI Energie Inc.	2020-Jan-13	2021-Jan-31	FT	Ste. Genevieve	Enbridge EDA	186	186	0	0
63931	EBI Energie Inc.	2021-Jan-01	2022-Dec-31	FT	Ste. Genevieve	Enbridge EDA	197	197	0	0
1140	Enbridge Gas Inc.	1989-Aug-08	2026-Oct-31	STS	Union Parkway Belt	Enbridge EDA	35,089	35,089	0	0
13307	Enbridge Gas Inc.	1999-Nov-01	2026-Oct-31	STS	Union Parkway Belt	Enbridge EDA	35,806	35,806	0	0
21854	Enbridge Gas Inc.	2003-Nov-01	2026-Oct-31	STS	Union Parkway Belt	Enbridge EDA	9,716	9,716	0	0
21987	Enbridge Gas Inc.	2003-Nov-01	2026-Oct-31	FT	Union Dawn	Enbridge EDA	114,000	114,000	0	0
55196	Enbridge Gas Inc.	2016-Dec-20	2031-Oct-31	FT	Union Parkway Belt	Enbridge EDA	170,000	170,000	0	0
58616	Enbridge Gas Inc.	2019-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Enbridge EDA	13,114	13,114	0	0
60756	Enbridge Gas Inc.	2021-Jan-01	2030-Dec-31	FT	North Bay Junction	Enbridge EDA	26,956	26,954	0	2
60758	Enbridge Gas Inc.	2021-Jan-01	2030-Dec-31	FT	North Bay Junction	Enbridge EDA	70,000	70,000	0	0
60760	Enbridge Gas Inc.	2021-Jan-01	2030-Dec-31	FT	North Bay Junction	Enbridge EDA	163,044	163,044	0	0
						Enbridge EDA Total	**638,108**	**638,106**	**0**	**2**
52622	Enbridge Gas Inc.	2016-Jan-01	2030-Oct-31	FT	Chippawa	Enbridge Parkway CDA	123,441	0	123,441	0
52623	Enbridge Gas Inc.	2015-Nov-01	2030-Oct-31	FT	Niagara Falls	Enbridge Parkway CDA	76,559	76,559	0	0
						Enbridge Parkway CDA Total	**200,000**	**76,559**	**123,441**	**0**
44175	BP Canada Energy Group ULC	2012-Apr-01	2022-Oct-31	FT	Iroquois	Energir EDA	8,267	8,267	0	0
44176	BP Canada Energy Group ULC	2012-Apr-01	2022-Oct-31	FT	Iroquois	Energir EDA	18,685	18,685	0	0
1141	Energir, L.P.	1985-Nov-01	2026-Oct-31	STS	Union Parkway Belt	Energir EDA	25,629	25,629	0	0
6245	Energir, L.P.	1996-Apr-16	2026-Oct-31	STS	Union Parkway Belt	Energir EDA	125,545	125,545	0	0
16106	Energir, L.P.	2001-Nov-01	2026-Oct-31	STS	Union Parkway Belt	Energir EDA	45,000	45,000	0	0
20268	Energir, L.P.	2003-Nov-01	2026-Oct-31	FT	Union Dawn	Energir EDA	50,000	50,000	0	0
21989	Energir, L.P.	2005-Nov-01	2026-Oct-31	FT	Union Dawn	Energir EDA	33,048	33,048	0	0
22306	Energir, L.P.	2005-Nov-01	2026-Oct-31	STS	Union Parkway Belt	Energir EDA	20,000	20,000	0	0
33680	Energir, L.P.	2007-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Energir EDA	65,000	65,000	0	0
54666	Energir, L.P.	2016-Nov-16	2031-Oct-31	FT	Union Parkway Belt	Energir EDA	239,148	239,148	0	0
55193	Energir, L.P.	2016-Dec-20	2031-Oct-31	FT	Union Parkway Belt	Energir EDA	85,000	35,000	0	50,000
55194	Energir, L.P.	2016-Dec-15	2031-Oct-31	FT	Union Parkway Belt	Energir EDA	19,500	19,500	0	0
55195	Energir, L.P.	2016-Dec-20	2031-Oct-31	FT	Union Parkway Belt	Energir EDA	39,000	9,000	0	30,000
57066	Energir, L.P.	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Energir EDA	11,400	11,400	0	0
57067	Energir, L.P.	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Energir EDA	24,800	24,800	0	0
60763	Energir, L.P.	2021-Jan-01	2030-Dec-31	FT	North Bay Junction	Energir EDA	73,000	73,000	0	0
45506	Mercuria Commodities Canada Corporation	2013-Nov-01	2026-Oct-31	FT	Niagara Falls	Energir EDA	82,000	82,000	0	0
29557	TransCanada Energy Ltd.	2006-Dec-02	2026-Oct-31	FT	Union Dawn	Energir EDA	10,000	10,000	0	0
						Energir EDA Total	**975,022**	**895,022**	**0**	**80,000**
54667	Energir, L.P.	2016-Nov-16	2031-Oct-31	FT	Union Parkway Belt	Energir NDA	15,327	15,327	0	0
60765	Energir, L.P.	2021-Jan-01	2030-Dec-31	FT	North Bay Junction	Energir NDA	2,000	2,000	0	0
60767	Energir, L.P.	2021-Jan-01	2030-Dec-31	FT	North Bay Junction	Energir NDA	10,000	10,000	0	0
						Energir NDA Total	**27,327**	**27,327**	**0**	**0**
36992	Goreway Station Partnership	2009-Jan-01	2028-Oct-31	FT-SN	Union Parkway Belt	Goreway CDA	20,000	20,000	0	0
36993	Goreway Station Partnership	2009-Jan-01	2026-Oct-31	FT-SN	Union Parkway Belt	Goreway CDA	120,000	120,000	0	0
						Goreway CDA Total	**140,000**	**140,000**	**0**	**0**
60134	TransGas Limited	2019-Jul-01	2029-Jun-30	LTFP	Empress	Herbert Delivery	58,000	58,000	0	0

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						Herbert Delivery Total	**58,000**	**58,000**	**0**	**0**
63478	Boston Gas Company	2020-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	17,718	0	0	17,718
60236	BP Canada Energy Group ULC	2019-Nov-01	2021-Oct-31	FT-NR	North Bay Junction	Iroquois	13,188	13,188	0	0
41233	Central Hudson Gas & Electric Corporation	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	10,674	0	0	10,674
42389	Central Hudson Gas & Electric Corporation	2011-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	5,399	0	0	5,399
49441	Complexe Enviro Connexions Ltee	2014-Sep-12	2034-Sep-30	FT	Lachenaie	Iroquois	6,900	6,900	0	0
59990	Complexe Enviro Connexions Ltee	2019-May-15	2034-Oct-31	FT	Lachenaie	Iroquois	700	700	0	0
41224	Connecticut Natural Gas Corporation	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	264	264	0	0
41225	Connecticut Natural Gas Corporation	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	6,436	6,436	0	0
41238	Connecticut Natural Gas Corporation	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	17,879	17,879	0	0
41239	Connecticut Natural Gas Corporation	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	8,807	8,807	0	0
42382	Connecticut Natural Gas Corporation	2011-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	6,330	6,330	0	0
42379	Consolidated Edison Company of New York, Inc.	2011-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	11,859	0	0	11,859
42380	Consolidated Edison Company of New York, Inc.	2011-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	9,695	0	0	9,695
54278	EBI Energie Inc.	2016-Nov-01	2023-Oct-31	FT	Ste. Genevieve	Iroquois	1,200	1,200	0	0
55960	EBI Energie Inc.	2017-Jun-15	2023-Dec-31	FT	Ste. Genevieve	Iroquois	2,200	2,200	0	0
63932	EBI Energie Inc.	2020-Dec-01	2022-Nov-30	FT	Ste. Genevieve	Iroquois	1,000	1,000	0	0
40085	Enbridge Gas Inc.	2010-Sep-01	2026-Oct-31	FT	Union Dawn	Iroquois	40,000	40,000	0	0
63398	Eversource Gas Company of Massachusetts	2020-Oct-09	2026-Oct-31	FT	Union Parkway Belt	Iroquois	27,498	0	0	27,498
58572	Freepoint Commodities LLC	2018-Nov-01	2022-Oct-31	FT	North Bay Junction	Iroquois	75,000	75,000	0	0
63476	KeySpan Gas East Corporation	2020-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	39,494	0	0	39,494
60738	Koch Canada Energy Services, LP	2019-Nov-01	2030-Dec-31	FT	North Bay Junction	Iroquois	2,110	2,110	0	0
41232	Liberty Utilities (EnergyNorth Natural Gas) Corp.	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	4,270	0	0	4,270
58284	Mercuria Commodities Canada Corporation	2018-Nov-01	2022-Oct-31	FT	North Bay Junction	Iroquois	55,523	55,523	0	0
60740	Modern Resources Inc.	2019-Nov-01	2031-Mar-31	FT	North Bay Junction	Iroquois	10,551	0	0	10,551
42385	Niagara Mohawk Power Corporation	2011-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	54,437	0	0	54,437
60742	Storm Resources Ltd.	2019-Nov-01	2030-Dec-31	FT	North Bay Junction	Iroquois	7,508	0	0	7,508
60744	Tamarack Acquisition Corp.	2019-Nov-01	2031-Mar-31	FT	North Bay Junction	Iroquois	10,551	0	0	10,551
63477	The Brooklyn Union Gas Company	2020-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	42,696	0	0	42,696
42386	The Narragansett Electric Company	2011-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	1,068	0	0	1,068
41221	The Southern Connecticut Gas Company	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	475	475	0	0
41222	The Southern Connecticut Gas Company	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	9,656	9,656	0	0
41230	The Southern Connecticut Gas Company	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	34,567	34,567	0	0
41231	The Southern Connecticut Gas Company	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	13,342	13,342	0	0
41223	Yankee Gas Services Company	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	5,336	0	0	5,336
41236	Yankee Gas Services Company	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	42,642	0	0	42,642
41237	Yankee Gas Services Company	2010-Dec-01	2026-Oct-31	FT	Union Parkway Belt	Iroquois	20,334	0	0	20,334
						Iroquois Total	**617,307**	**295,577**	**0**	**321,730**
57069	1425445 Ontario Limited	2017-Nov-01	2032-Oct-31	FT	Niagara Falls	Kirkwall	1,000	1,000	0	0
45507	DTE Energy Trading, Inc.	2012-Nov-01	2023-Mar-31	FT	Niagara Falls	Kirkwall	25,585	25,585	0	0
52370	DTE Energy Trading, Inc.	2015-Nov-01	2031-Oct-31	FT	Niagara Falls	Kirkwall	73,854	73,854	0	0
55107	Emera Energy Limited Partnership	2016-Dec-01	2023-Oct-31	FT	Niagara Falls	Kirkwall	26,376	26,376	0	0
55108	Emera Energy Limited Partnership	2016-Dec-01	2031-Oct-31	FT	Niagara Falls	Kirkwall	73,854	73,854	0	0
45509	Enbridge Gas Inc.	2012-Nov-09	2022-Oct-31	FT	Niagara Falls	Kirkwall	21,101	21,101	0	0
54252	Seneca Resources Company, LLC	2016-Nov-01	2031-Oct-31	FT	Niagara Falls	Kirkwall	18,991	0	0	18,991
57071	The Corporation of the City of Kitchener	2017-Nov-01	2032-Oct-31	FT	Niagara Falls	Kirkwall	10,000	0	0	10,000
						Kirkwall Total	**250,761**	**221,770**	**0**	**28,991**
1066	1425445 Ontario Limited	1989-Jan-01	2022-Oct-31	FT	Empress	KPUC EDA	350	350	0	0
1138	1425445 Ontario Limited	1975-Apr-01	2026-Oct-31	STS	Union Parkway Belt	KPUC EDA	13,167	13,167	0	0
47858	1425445 Ontario Limited	2013-Nov-01	2026-Oct-31	FT	Niagara Falls	KPUC EDA	2,000	2,000	0	0

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48020	1425445 Ontario Limited	2013-Nov-01	2026-Oct-31	STS	Union Parkway Belt	KPUC EDA	175	175	0	0
57068	1425445 Ontario Limited	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	KPUC EDA	3,000	3,000	0	0
57070	1425445 Ontario Limited	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	KPUC EDA	3,000	3,000	0	0
58191	1425445 Ontario Limited	2018-Aug-01	2033-Jul-31	FT	Iroquois	KPUC EDA	2,000	0	0	2,000
60748	1425445 Ontario Limited	2019-Nov-01	2030-Dec-31	FT	North Bay Junction	KPUC EDA	650	650	0	0
57054	Queen's University at Kingston	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	KPUC EDA	1,000	1,000	0	0
						KPUC EDA Total	**25,342**	**23,342**	**0**	**2,000**
62418	Portlands Energy Centre L.P.	2020-Apr-29	2032-Nov-30	FT-SN	Union Parkway Belt	Napanee #2 EDA	90,000	90,000	0	0
62419	Portlands Energy Centre L.P.	2020-Apr-29	2032-Nov-30	FT-SN	Union Parkway Belt	Napanee #2 EDA	52,000	52,000	0	0
						Napanee #2 EDA Total	**142,000**	**142,000**	**0**	**0**
51369	New York State Electric & Gas Corporation	2015-Jul-01	2026-Oct-31	FT	Empress	Napierville	3,165	0	0	3,165
58623	New York State Electric & Gas Corporation	2018-Nov-01	2033-Oct-31	FT	Iroquois	Napierville	6,930	0	0	6,930
58624	New York State Electric & Gas Corporation	2018-Nov-01	2033-Oct-31	FT	Iroquois	Napierville	5,415	0	0	5,415
						Napierville Total	**15,510**	**0**	**0**	**15,510**
60747	1425445 Ontario Limited	2019-Nov-01	2030-Dec-31	LTFP	Empress	North Bay Junction	650	650	0	0
60757	Enbridge Gas Inc.	2021-Jan-01	2030-Dec-31	LTFP	Empress	North Bay Junction	5,000	4,897	0	103
60759	Enbridge Gas Inc.	2021-Jan-01	2030-Dec-31	LTFP	Empress	North Bay Junction	26,956	26,954	0	2
60761	Enbridge Gas Inc.	2021-Jan-01	2030-Dec-31	LTFP	Empress	North Bay Junction	70,000	70,000	0	0
60762	Enbridge Gas Inc.	2021-Jan-01	2030-Dec-31	LTFP	Empress	North Bay Junction	163,044	163,044	0	0
60764	Energir, L.P.	2021-Jan-01	2030-Dec-31	LTFP	Empress	North Bay Junction	2,000	2,000	0	0
60766	Energir, L.P.	2021-Jan-01	2030-Dec-31	LTFP	Empress	North Bay Junction	10,000	10,000	0	0
60768	Energir, L.P.	2021-Jan-01	2030-Dec-31	LTFP	Empress	North Bay Junction	73,000	73,000	0	0
61067	Irving Oil Limited	2019-Nov-01	2021-Oct-31	LTFP	Empress	North Bay Junction	21,315	21,315	0	0
60737	Koch Canada Energy Services, LP	2019-Nov-01	2030-Dec-31	LTFP	Empress	North Bay Junction	2,110	2,110	0	0
60749	Liberty Utilities (St. Lawrence Gas) Corp.	2019-Nov-01	2030-Dec-31	LTFP	Empress	North Bay Junction	3,200	3,200	0	0
60750	Liberty Utilities (St. Lawrence Gas) Corp.	2019-Nov-01	2030-Dec-31	LTFP	Empress	North Bay Junction	7,050	7,050	0	0
60739	Modern Resources Inc.	2019-Nov-01	2031-Mar-31	LTFP	Empress	North Bay Junction	10,551	0	0	10,551
61066	New Brunswick Energy Marketing Corporation	2019-Nov-01	2021-Oct-31	LTFP	Empress	North Bay Junction	6,277	0	0	6,277
61063	New England NG Supply Limited	2019-Nov-01	2021-Oct-31	LTFP	Empress	North Bay Junction	17,408	17,408	0	0
60741	Storm Resources Ltd.	2019-Nov-01	2030-Dec-31	LTFP	Empress	North Bay Junction	7,508	0	0	7,508
60743	Tamarack Acquisition Corp.	2019-Nov-01	2031-Mar-31	LTFP	Empress	North Bay Junction	10,551	0	0	10,551
60753	Vale Canada Limited	2019-Nov-01	2030-Dec-31	LTFP	Empress	North Bay Junction	5,000	0	0	5,000
						North Bay Junction Total	**441,620**	**401,628**	**0**	**39,992**
33556	Vermont Gas Systems, Inc.	2007-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Philipsburg	10,000	0	0	10,000
36188	Vermont Gas Systems, Inc.	2008-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Philipsburg	10,000	0	0	10,000
36190	Vermont Gas Systems, Inc.	2008-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Philipsburg	2,000	0	0	2,000
47856	Vermont Gas Systems, Inc.	2013-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Philipsburg	3,500	2,289	0	1,211
47857	Vermont Gas Systems, Inc.	2013-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Philipsburg	4,500	4,500	0	0
55180	Vermont Gas Systems, Inc.	2017-Jan-01	2031-Oct-31	FT	Union Parkway Belt	Philipsburg	6,500	6,500	0	0
55181	Vermont Gas Systems, Inc.	2017-Jan-01	2031-Oct-31	FT	Union Parkway Belt	Philipsburg	12,000	12,000	0	0
55187	Vermont Gas Systems, Inc.	2016-Dec-22	2031-Oct-31	FT	Union Parkway Belt	Philipsburg	6,000	6,000	0	0
57251	Vermont Gas Systems, Inc.	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Philipsburg	20,279	20,279	0	0
57252	Vermont Gas Systems, Inc.	2017-Dec-01	2032-Nov-30	FT	Union Parkway Belt	Philipsburg	6,000	6,000	0	0
58715	Vermont Gas Systems, Inc.	2018-Nov-01	2033-Oct-31	FT	Union Parkway Belt	Philipsburg	4,000	4,000	0	0
						Philipsburg Total	**84,779**	**61,568**	**0**	**23,211**
44483	York Energy Centre LP	2012-Nov-01	2026-Oct-31	FT-SN	Union Parkway Belt	Schomberg #2 CDA	87,654	87,654	0	0
						Schomberg #2 CDA Total	**87,654**	**87,654**	**0**	**0**

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Contract Number	Service Requester	Contract Start Date	Contract End Date	Service Type	Primary Receipt	Primary Delivery	Contract Demand (GJ/d)	Operational Demand (GJ/d)	Shifted Qty (GJ/d)	Temp Assigned Qty (GJ/d)
59841	Packaging Corporation of America	2019-Nov-01	2022-Oct-31	FT	Empress	Spruce	7,385	7,385	0	0
						Spruce Total	**7,385**	**7,385**	**0**	**0**
38101	Thorold CoGen L.P.	2009-Sep-01	2022-Aug-31	FT-SN	Kirkwall	Thorold CDA	49,500	0	0	49,500
						Thorold CDA Total	**49,500**	**0**	**0**	**49,500**
61168	BP Canada Energy Group ULC	2019-Nov-13	2022-Oct-31	FT-NR	Empress	Transgas SSDA	31,652	31,652	0	0
62411	BP Canada Energy Group ULC	2020-Nov-01	2022-Oct-31	FT	Empress	Transgas SSDA	21,101	21,101	0	0
62412	BP Canada Energy Group ULC	2020-Nov-01	2023-Oct-31	FT	Empress	Transgas SSDA	21,101	21,101	0	0
60641	Castleton Commodities Merchant Trading L.P.	2020-Nov-01	2021-Oct-31	FT	Empress	Transgas SSDA	10,551	10,551	0	0
60642	Castleton Commodities Merchant Trading L.P.	2019-Nov-01	2021-Oct-31	FT	Empress	Transgas SSDA	10,551	10,551	0	0
61307	Castleton Commodities Merchant Trading L.P.	2020-Apr-01	2021-Mar-31	FT-NR	Empress	Transgas SSDA	15,826	15,826	0	0
63475	Citadel Energy Marketing LLC	2020-Dec-01	2021-Nov-30	FT	Empress	Transgas SSDA	26,376	26,376	0	0
62414	Direct Energy Marketing Limited	2020-Nov-01	2021-Oct-31	FT	Empress	Transgas SSDA	5,275	5,275	0	0
61343	Freepoint Commodities LLC	2020-Apr-01	2021-Mar-31	FT-NR	Empress	Transgas SSDA	96,785	86,785	0	10,000
61344	Freepoint Commodities LLC	2020-Nov-01	2021-Oct-31	FT-NR	Empress	Transgas SSDA	300,000	300,000	0	0
60648	Koch Canada Energy Services, LP	2019-Dec-01	2022-Oct-31	FT-NR	Empress	Transgas SSDA	16,000	16,000	0	0
62396	Koch Canada Energy Services, LP	2020-Apr-10	2021-Apr-30	FT-NR	Empress	Transgas SSDA	600	600	0	0
62404	Koch Canada Energy Services, LP	2020-Nov-01	2021-Oct-31	FT	Empress	Transgas SSDA	10,551	10,551	0	0
62405	Koch Canada Energy Services, LP	2021-Jan-01	2022-Dec-31	FT	Empress	Transgas SSDA	10,551	10,551	0	0
60344	Macquarie Energy Canada Ltd.	2020-Feb-01	2021-Jan-31	FT	Empress	Transgas SSDA	10,551	10,551	0	0
60405	Macquarie Energy Canada Ltd.	2020-Feb-01	2021-Jan-31	FT	Empress	Transgas SSDA	10,551	10,551	0	0
61326	Macquarie Energy Canada Ltd.	2020-Nov-01	2021-Oct-31	FT-NR	Empress	Transgas SSDA	52,752	52,752	0	0
60130	Mercuria Commodities Canada Corporation	2019-Nov-01	2022-Oct-31	FT	Empress	Transgas SSDA	15,000	15,000	0	0
60400	Mercuria Commodities Canada Corporation	2019-Nov-01	2022-Oct-31	FT	Empress	Transgas SSDA	10,551	10,551	0	0
60401	Mercuria Commodities Canada Corporation	2019-Nov-01	2022-Oct-31	FT	Empress	Transgas SSDA	10,551	10,551	0	0
61308	Mercuria Commodities Canada Corporation	2020-Nov-01	2021-Oct-31	FT-NR	Empress	Transgas SSDA	21,101	21,101	0	0
62409	Morgan Stanley Capital Group Inc.	2020-Nov-01	2021-Oct-31	FT	Empress	Transgas SSDA	10,000	10,000	0	0
62461	Morgan Stanley Capital Group Inc.	2020-Nov-01	2021-Oct-31	FT	Empress	Transgas SSDA	551	551	0	0
53079	TransGas Limited	2016-Feb-01	2022-Oct-31	FT	Empress	Transgas SSDA	30,000	30,000	0	0
54768	TransGas Limited	2016-Nov-01	2022-Oct-31	FT	Empress	Transgas SSDA	28,000	28,000	0	0
54769	TransGas Limited	2016-Nov-01	2022-Oct-31	FT	Empress	Transgas SSDA	22,000	22,000	0	0
56667	TransGas Limited	2017-Nov-01	2022-Oct-31	FT	Empress	Transgas SSDA	10,000	10,000	0	0
56684	TransGas Limited	2018-Sep-01	2022-Oct-31	FT	Empress	Transgas SSDA	10,000	10,000	0	0
56685	TransGas Limited	2017-Nov-01	2022-Oct-31	FT	Empress	Transgas SSDA	12,000	12,000	0	0
57583	TransGas Limited	2018-Jan-18	2022-Oct-31	FT	Empress	Transgas SSDA	20,000	20,000	0	0
57584	TransGas Limited	2019-Nov-01	2022-Oct-31	FT	Empress	Transgas SSDA	80,000	80,000	0	0
60643	Twin Eagle Resource Management Canada, LLC	2020-Nov-01	2022-Oct-31	FT	Empress	Transgas SSDA	10,551	10,551	0	0
61149	Twin Eagle Resource Management Canada, LLC	2019-Nov-07	2022-Oct-31	FT-NR	Empress	Transgas SSDA	5,275	5,275	0	0
						Transgas SSDA Total	**946,354**	**936,354**	**0**	**10,000**
54668	Enbridge Gas Inc.	2016-Nov-01	2032-Oct-31	FT	Kirkwall	Union CDA	135,000	135,000	0	0
						Union CDA Total	**135,000**	**135,000**	**0**	**0**
54435	Enbridge Gas Inc.	2014-Nov-01	2022-Oct-31	FT	Union Dawn	Union ECDA	8,000	8,000	0	0
54438	Enbridge Gas Inc.	2010-Nov-01	2022-Oct-31	FT	Empress	Union ECDA	3,000	3,000	0	0
						Union ECDA Total	**11,000**	**11,000**	**0**	**0**
1048	Enbridge Gas Inc.	1989-Jan-01	2022-Oct-31	FT	Empress	Union EDA	1,089	1,000	0	89
1142	Enbridge Gas Inc.	1992-Apr-01	2026-Oct-31	STS	Union Parkway Belt	Union EDA	26,351	26,351	0	0
29591	Enbridge Gas Inc.	2006-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Union EDA	30,000	30,000	0	0
33559	Enbridge Gas Inc.	2007-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Union EDA	5,000	5,000	0	0
54663	Enbridge Gas Inc.	2016-Nov-18	2031-Oct-31	FT	Union Parkway Belt	Union EDA	75,000	75,000	0	0

CONTRACT DEMAND ENERGY (CDE) REPORT - Mainline

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54664	Enbridge Gas Inc.	2016-Nov-18	2031-Oct-31	EMB	Union Parkway Belt	Union EDA	25,000	25,000	0	0
55186	Enbridge Gas Inc.	2016-Dec-22	2031-Oct-31	FT	Union Parkway Belt	Union EDA	181	181	0	0
55189	Enbridge Gas Inc.	2016-Dec-22	2031-Oct-31	FT	Union Parkway Belt	Union EDA	9,105	7,843	0	1,262
57053	Enbridge Gas Inc.	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Union EDA	5,000	5,000	0	0
58370	Enbridge Gas Inc.	2018-Nov-01	2033-Oct-31	FT	Union Parkway Belt	Union EDA	9,128	9,128	0	0
35657	Greenfield Global Inc.	2008-Nov-01	2026-Oct-31	FT	Union Parkway Belt	Union EDA	2,000	0	0	2,000
55192	Greenfield Global Inc.	2016-Dec-21	2031-Oct-31	FT	Union Parkway Belt	Union EDA	2,000	1,750	0	250
57050	Greenfield Global Inc.	2017-Dec-01	2032-Nov-30	FT	Union Parkway Belt	Union EDA	1,100	1,100	0	0
20396	Ingredion Canada Incorporated	2003-Nov-01	2022-Oct-31	FT	Union Dawn	Union EDA	1,020	1,020	0	0
20398	Ingredion Canada Incorporated	2004-Jan-01	2022-Oct-31	FT	Union Dawn	Union EDA	490	490	0	0
60646	Koch Canada Energy Services, LP	2019-Nov-01	2021-Oct-31	FT-NR	Empress	Union EDA	1,700	1,700	0	0
						Union EDA Total	**194,164**	**190,563**	**0**	**3,601**
1049	Enbridge Gas Inc.	1989-Jan-01	2022-Oct-31	FT	Empress	Union NCDA	1,412	1,000	0	412
55185	Enbridge Gas Inc.	2016-Dec-22	2031-Oct-31	FT	Union Parkway Belt	Union NCDA	661	661	0	0
55188	Enbridge Gas Inc.	2016-Dec-22	2031-Oct-31	FT	Union Parkway Belt	Union NCDA	439	439	0	0
57051	Enbridge Gas Inc.	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Union NCDA	887	887	0	0
57052	Enbridge Gas Inc.	2017-Nov-01	2032-Oct-31	FT	Union Parkway Belt	Union NCDA	2,000	2,000	0	0
58371	Enbridge Gas Inc.	2018-Nov-01	2033-Oct-31	FT	Union Parkway Belt	Union NCDA	6,912	6,912	0	0
58372	Enbridge Gas Inc.	2018-Nov-01	2033-Oct-31	FT	Union Parkway Belt	Union NCDA	884	884	0	0
						Union NCDA Total	**13,195**	**12,783**	**0**	**412**
47207	Domtar Inc.	2013-Aug-01	2022-Oct-31	FT	Empress	Union NDA	2,500	2,500	0	0
48807	Domtar Inc.	2014-May-01	2022-Oct-31	FT	Empress	Union NDA	2,500	2,500	0	0
49236	EACOM Timber Corporation	2014-Nov-01	2022-Oct-31	FT	Empress	Union NDA	377	377	0	0
1045	Enbridge Gas Inc.	1989-Jan-01	2022-Oct-31	FT	Empress	Union NDA	4,442	2,085	0	2,357
54665	Enbridge Gas Inc.	2016-Nov-18	2031-Oct-31	FT	Union Parkway Belt	Union NDA	10,000	10,000	0	0
55182	Enbridge Gas Inc.	2016-Dec-22	2031-Oct-31	FT	Union Parkway Belt	Union NDA	9,000	9,000	0	0
55183	Enbridge Gas Inc.	2016-Dec-22	2031-Oct-31	FT	Union Parkway Belt	Union NDA	24,000	24,000	0	0
55184	Enbridge Gas Inc.	2016-Dec-22	2031-Oct-31	FT	Union Parkway Belt	Union NDA	10,401	0	0	10,401
55190	Enbridge Gas Inc.	2016-Dec-22	2031-Oct-31	FT	Union Parkway Belt	Union NDA	6,228	3,029	0	3,199
55191	Enbridge Gas Inc.	2016-Dec-22	2031-Oct-31	FT	Union Parkway Belt	Union NDA	67,000	67,000	0	0
49239	Glencore Canada Corporation	2014-Nov-01	2022-Oct-31	FT	Empress	Union NDA	5,100	5,100	0	0
49298	Glencore Canada Corporation	2014-Nov-01	2022-Oct-31	FT	Empress	Union NDA	550	550	0	0
58622	Kirkland Lake Power Corp.	2018-Nov-01	2031-Oct-31	FT	Union Parkway Belt	Union NDA	18,000	18,000	0	0
63938	Toromont Energy Ltd.	2021-Jan-01	2022-Oct-31	FT	Empress	Union NDA	300	300	0	0
63939	Toromont Energy Ltd.	2021-Jan-01	2021-Apr-30	FT	Empress	Union NDA	374	374	0	0
47206	Vale Canada Limited	2013-Nov-01	2022-Oct-31	FT	Empress	Union NDA	6,000	0	0	6,000
60754	Vale Canada Limited	2019-Nov-01	2030-Dec-31	FT	North Bay Junction	Union NDA	5,000	0	0	5,000
						Union NDA Total	**171,772**	**144,815**	**0**	**26,957**
1142	Enbridge Gas Inc.	1992-Apr-01	2026-Oct-31	STS	Union WDA	Union Parkway Belt	3,150	3,150	0	0
1142	Enbridge Gas Inc.	1992-Apr-01	2026-Oct-31	STS	Union NDA	Union Parkway Belt	49,100	49,100	0	0
61327	Castleton Commodities Merchant Trading L.P.	2019-Dec-01	2022-Aug-31	FT-NR	Niagara Falls	Union Parkway Belt	34,621	34,621	0	0
54443	Shell Energy North America (Canada) Inc.	2003-Nov-01	2023-Mar-31	FT	Union Dawn	Union Parkway Belt	31,652	31,652	0	0
						Union Parkway Belt Total	**118,523**	**118,523**	**0**	**0**
53096	Active Transportation Services Inc.	2016-Feb-01	2022-Dec-31	FT	SS. Marie	Union SSMDA	6,143	6,143	0	0
53097	Active Transportation Services Inc.	2016-Feb-01	2022-Oct-31	FT	SS. Marie	Union SSMDA	7,385	7,385	0	0
53098	Active Transportation Services Inc.	2016-Feb-01	2022-Nov-30	FT	SS. Marie	Union SSMDA	26,215	26,215	0	0
1047	Enbridge Gas Inc.	1989-Jan-01	2022-Oct-31	FT	Empress	Union SSMDA	2,700	2,000	0	700
48980	Enbridge Gas Inc.	2014-Nov-01	2022-Oct-31	FT	Empress	Union SSMDA	6,143	6,143	0	0
52563	Enbridge Gas Inc.	2015-Nov-01	2022-Oct-31	FT	Empress	Union SSMDA	12,800	12,800	0	0

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43607	Flakeboard Company Limited	2012-Jan-01	2022-Oct-31	FT	Empress	Union SSMDA	300	300	0	0
49442	Flakeboard Company Limited	2014-Nov-01	2022-Oct-31	FT	Empress	Union SSMDA	1,000	1,000	0	0
						Union SSMDA Total	**62,686**	**61,986**	**0**	**700**
56689	Advantage Oil & Gas Ltd.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	55,608	0	0	55,608
56692	ARC Resources Ltd.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	47,477	47,477	0	0
56696	Birchcliff Energy Ltd.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	120,000	120,000	0	0
56699	Birchcliff Energy Ltd.	2018-Nov-01	2028-Oct-31	LTFP	Empress	Union SWDA	30,000	30,000	0	0
56703	Birchcliff Energy Ltd.	2019-Nov-01	2029-Oct-31	LTFP	Empress	Union SWDA	25,000	25,000	0	0
56706	Bonavista Energy Corporation	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	43,486	0	0	43,486
56708	Canadian Natural Resources	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	166,824	166,824	0	0
56710	Crew Energy Inc.	2018-Apr-01	2028-Mar-31	LTFP	Empress	Union SWDA	16,682	0	0	16,682
56707	Hammerhead Resources Inc.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	36,869	0	0	36,869
56713	Kelt Exploration Ltd.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	25,000	0	0	25,000
56714	Murphy Canada, Ltd.	2018-Apr-01	2028-Mar-31	LTFP	Empress	Union SWDA	10,850	0	0	10,850
56715	NuVista Energy Ltd.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	44,486	0	0	44,486
56711	Ovintiv Canada ULC	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	333,649	196,893	0	136,756
56690	Painted Pony Energy Ltd.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	30,940	4,250	0	26,690
56691	Painted Pony Energy Ltd.	2018-Apr-01	2028-Mar-31	LTFP	Empress	Union SWDA	33,465	33,465	0	0
56704	Painted Pony Energy Ltd.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	12,485	12,485	0	0
56705	Painted Pony Energy Ltd.	2019-Nov-01	2029-Oct-31	LTFP	Empress	Union SWDA	16,260	0	0	16,260
56693	Paramount Resources Ltd.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	28,991	0	0	28,991
56694	Paramount Resources Ltd.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	28,991	0	0	28,991
56697	PETRONAS Energy Canada Ltd.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	50,000	0	0	50,000
56695	Pine Cliff Energy Ltd.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	11,273	0	0	11,273
56698	Seven Generations Energy Ltd.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	83,412	83,412	0	0
56700	Shell Canada Energy	2017-Nov-01	2022-Oct-31	LTFP	Empress	Union SWDA	25,000	0	0	25,000
56701	TAQA North	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	36,199	0	0	36,199
56702	Tourmaline Oil Corp.	2017-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	123,450	123,450	0	0
61013	Uniper Trading Canada Ltd.	2019-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	26,377	26,377	0	0
63483	Uniper Trading Canada Ltd.	2020-Nov-01	2027-Oct-31	LTFP	Empress	Union SWDA	26,376	26,376	0	0
						Union SWDA Total	**1,489,150**	**896,009**	**0**	**593,141**
49232	Comsatec Inc.	2014-Nov-01	2022-Oct-31	FT	Empress	Union WDA	750	750	0	0
47208	Domtar Inc.	2013-Aug-01	2022-Oct-31	FT	Empress	Union WDA	2,000	2,000	0	0
1046	Enbridge Gas Inc.	1989-Jan-01	2022-Oct-31	FT	Empress	Union WDA	39,880	39,880	0	0
48468	Enbridge Gas Inc.	2015-Nov-01	2022-Oct-31	FT	Empress	Union WDA	11,527	11,527	0	0
58186	Resolute FP Canada Inc.	2018-Nov-01	2021-Oct-31	FT	Empress	Union WDA	7,200	7,200	0	0
62954	Resolute FP Canada Inc.	2020-Nov-01	2022-Oct-31	FT	Empress	Union WDA	2,400	2,400	0	0
						Union WDA Total	**63,757**	**63,757**	**0**	**0**
37017	Enbridge Gas Inc.	2009-Jan-12	2026-Oct-31	FT-SN	Union Parkway Belt	Victoria Square #2 CDA	85,000	85,000	0	0
37098	Portlands Energy Centre L.P.	2009-Jan-22	2026-Oct-31	FT-SN	Union Parkway Belt	Victoria Square #2 CDA	100,000	100,000	0	0
						Victoria Square #2 CDA Total	**185,000**	**185,000**	**0**	**0**
56668	TransGas Limited	2018-Jan-01	2022-Oct-31	FT	Empress	Welwyn	1,332	1,332	0	0
62395	TransGas Limited	2020-Nov-01	2028-Oct-31	FT	Empress	Welwyn	14,000	14,000	0	0
						Welwyn Total	**15,332**	**15,332**	**0**	**0**
						Grand Total	**9,820,568**	**7,780,748**	**123,441**	**1,916,379**

- CONTRACT DEMAND is equal to the current version contract demand plus the CD TEMP SHIFTED QTY in effect.
- OPERATIONAL DEMAND is equal to CONTRACT DEMAND minus CD TEMP SHIFTED QTY and CD TEMP ASSIGNED QUANTITY.
- CD TEMP SHIFTED QTY is equal to the Shifts in effect off of the originating FT contract.
- CD TEMP ASSIGNED QUANTITY is equal to the Temporary Assignments in effect off of the originating FT contract.

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- 'Permanent Assignments' in effect are shown on the report as new FT contracts for the assignee.										
- STS (Storage Transportation Service) quantities and all demand paths are stated for these contracts.										
- Only current contract information is included in this report. I.e., no future dated contracts (or amendments) are posted.										

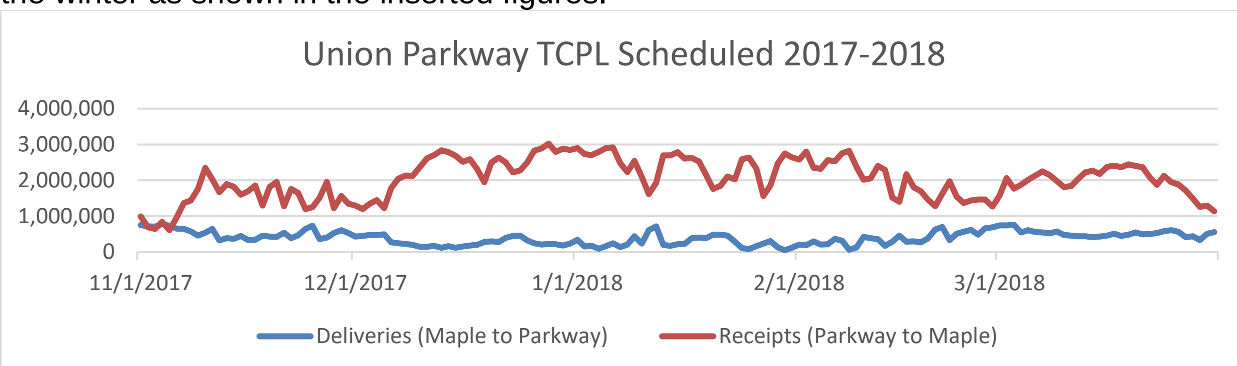
ENBRIDGE GAS INC.

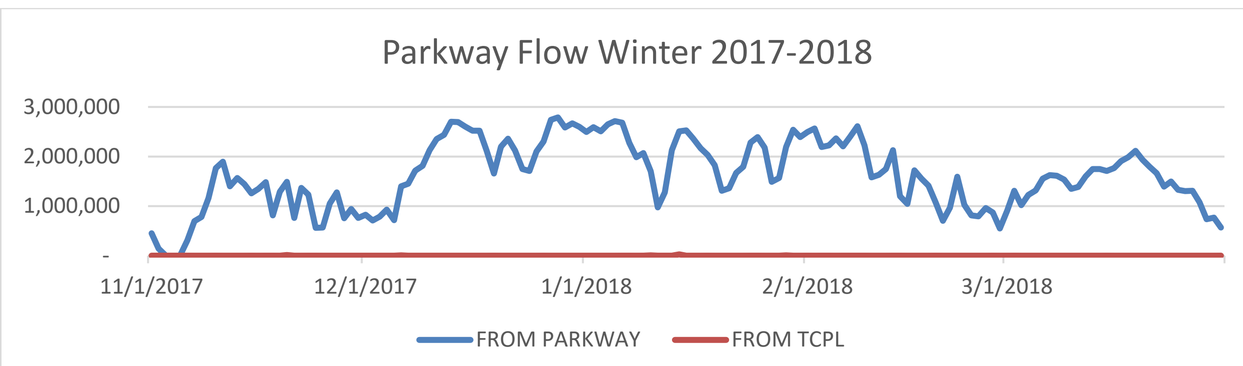
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

As outlined above, we understand that since late 2017, incremental deliveries of gas have been contracted to be transported from Empress to Dawn using Dawn LTFP contracts through two paths, one of which is through Parkway. However, the scheduled flows to Parkway from TCPL do not show this stream of deliveries getting to Parkway in the winter as shown in the inserted figures.





Source: http://www.tccustomerexpress.com/gasdaysummaryreport.html
We understand this effect is a result of displacement[1].

[1] Displacement transactions permit the lateral movement of gas through a transportation network. The configuration of many pipelines is such that it may not be apparent whether a given movement of gas is forward or backward from the point of receipt. It can be argued that all transportation service is performed by displacement as the physical delivery of the same molecules of gas is impossible. Source: www.aga.org/natural-gas/glossary

Question:

Please confirm that subsequent to early November no gas molecules physically arrived at Parkway from TCPL during the above period.

Response

Excluding Gas Day's November 3rd, 4th and 5th the flow at Parkway was from Enbridge Gas to TCPL for the period from November 1st, 2017 to March 31st, 2018.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

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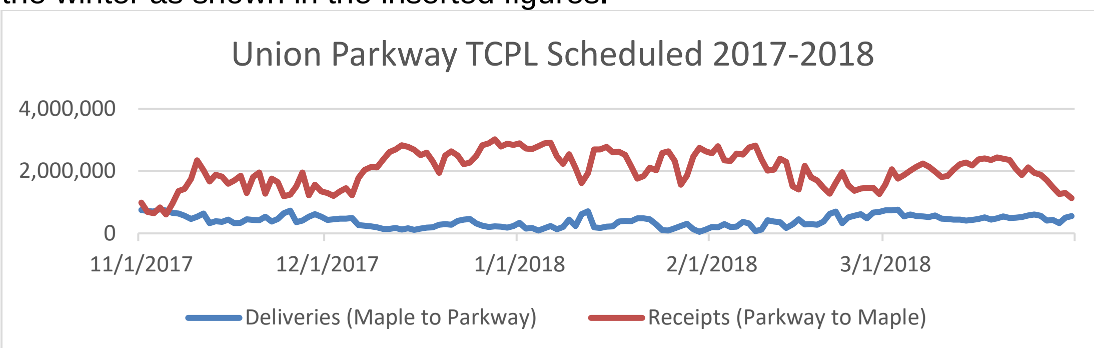

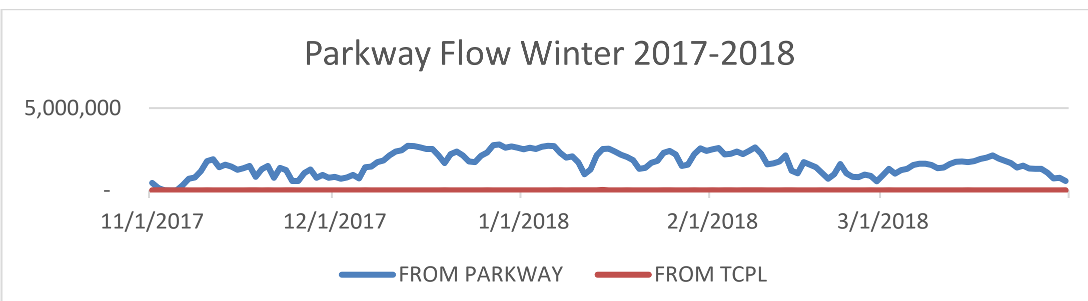

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<u>Question</u>:

Please confirm that displacement services in this situation resulting in less actual flow requirements on the Dawn-Parkway system.

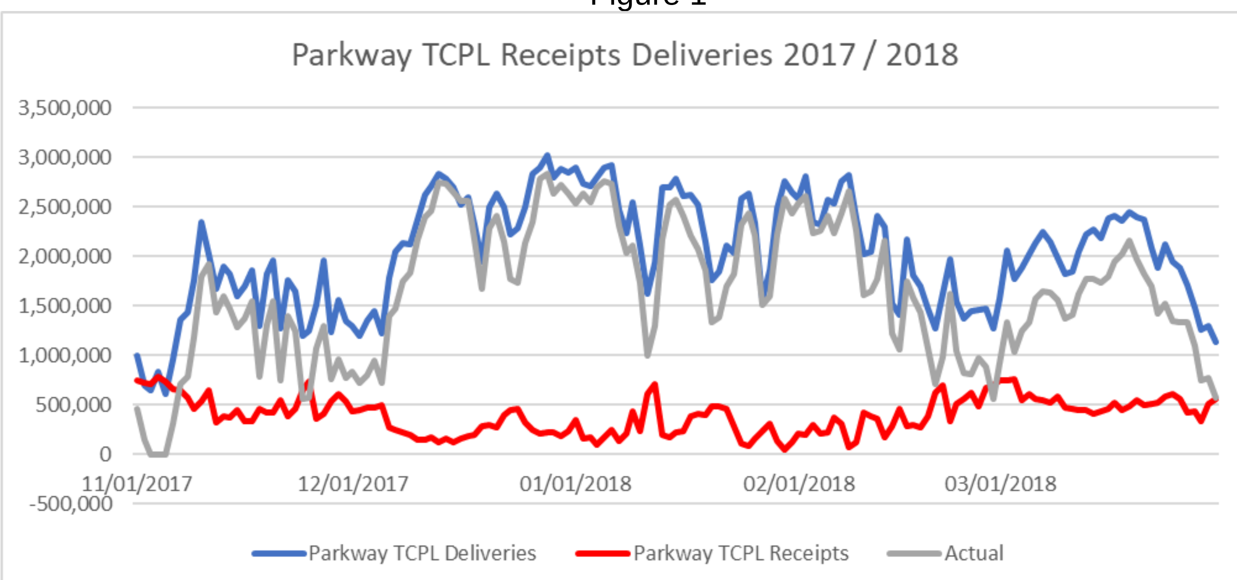
a) For the period shown, please provide a graph that represents the amount scheduled to flow from Parkway to TCPL vs. actual flow to TCPL
b) Please confirm that this reduced requirement can allow EGI to schedule additional transportation through its short-term and interruptible contracts.

<u>Response</u>

Confirmed

a) Please see Figure 1 for Deliveries, Receipts and Actual flows to TCPL.

Figure 1



b) Not confirmed. Any reduced Dawn to Parkway flow requirement due to non-obligated gas deliveries at Parkway from the TCPL system does not allow Enbridge Gas to schedule additional transportation through short term and interruptible contracts. The graph in part a) shows that the quantity scheduled through Parkway varies from day to day as shippers nominate quantities both easterly and westerly on the Dawn Parkway system. The first indication of the flows through Parkway for the day happen after the nominations for the timely window are received. Demands for services after the timely window are limited, firm services on Enbridge Gas's system are only firm on the timely window.

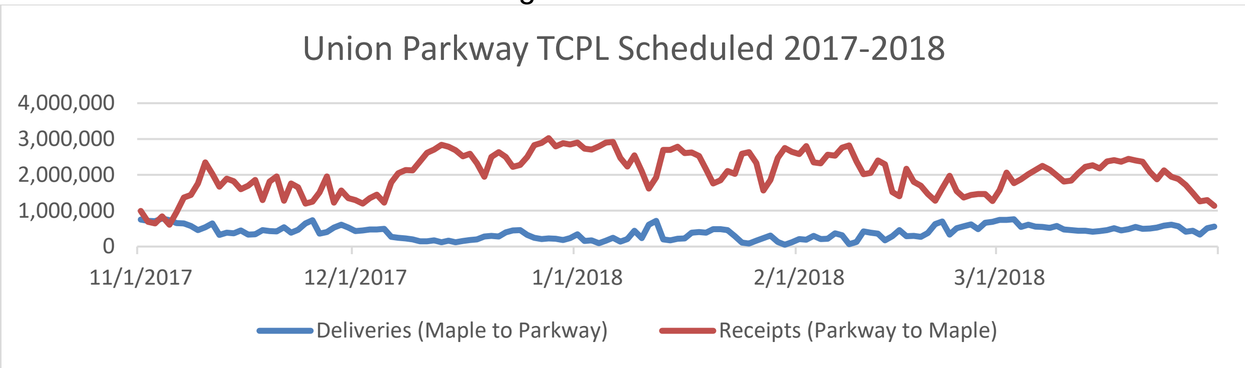
ENBRIDGE GAS INC.

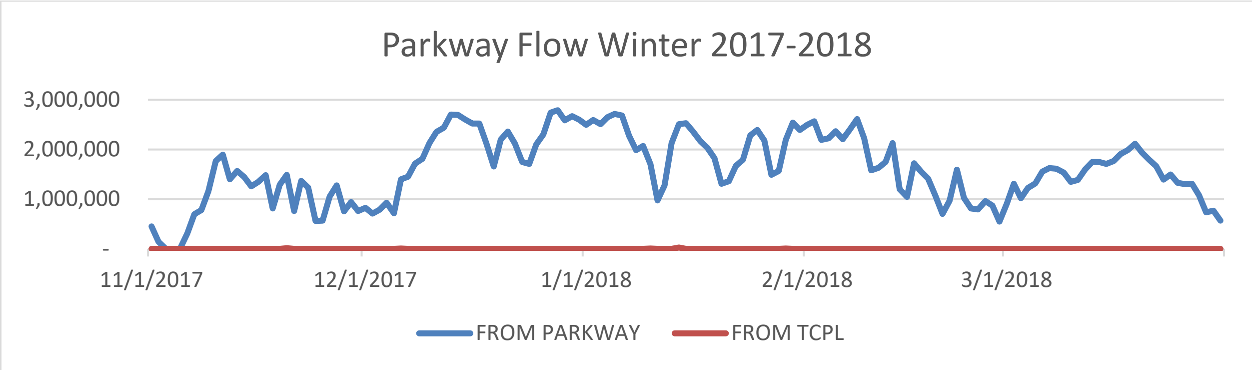
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

As outlined above, we understand that since late 2017, incremental deliveries of gas have been contracted to be transported from Empress to Dawn using Dawn LTFP contracts through two paths, one of which is through Parkway. However, the scheduled flows to Parkway from TCPL do not show this stream of deliveries getting to Parkway in the winter as shown in the inserted figures.





Source: http://www.tccustomerexpress.com/gasdaysummaryreport.html
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Question:

Please elaborate on what constitutes an "exchange service" as described in the above reference?

a) Please clarify if there was custody transfer of the natural gas in the exchange service or would the service be considered a displacement in terms of American Gas Association terminology (www.aga.org/natural-gas/glossary/)
b) Please describe how EGI uses displacement to reduce costs at inter-connection points with other pipelines.

Response

An exchange service is a transaction between two counterparties that provides for the receipt of gas at one point in exchange for the delivery of an equivalent amount of gas at a different point.

a) There is custody transfer of gas in exchange services as ownership of the gas is transferred between the parties at the receipt and delivery points. Depending on the parties transacting the exchange service, it can either be fulfilled through displacement, as defined by the AGA, or through physical flow of gas to the receipt and delivery points.

b) Services nominated at a point in offsetting directions can reduce compressor fuel usage on the day if there is in fact compression at that point.

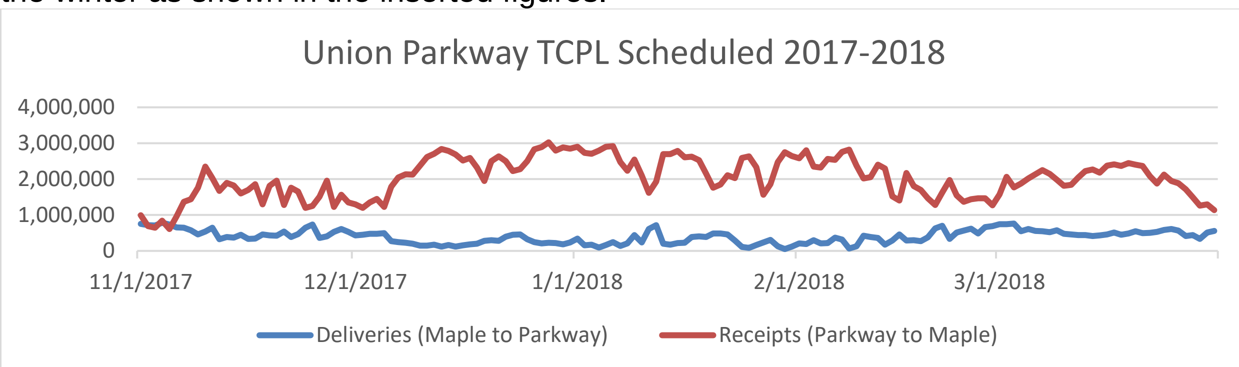
ENBRIDGE GAS INC.

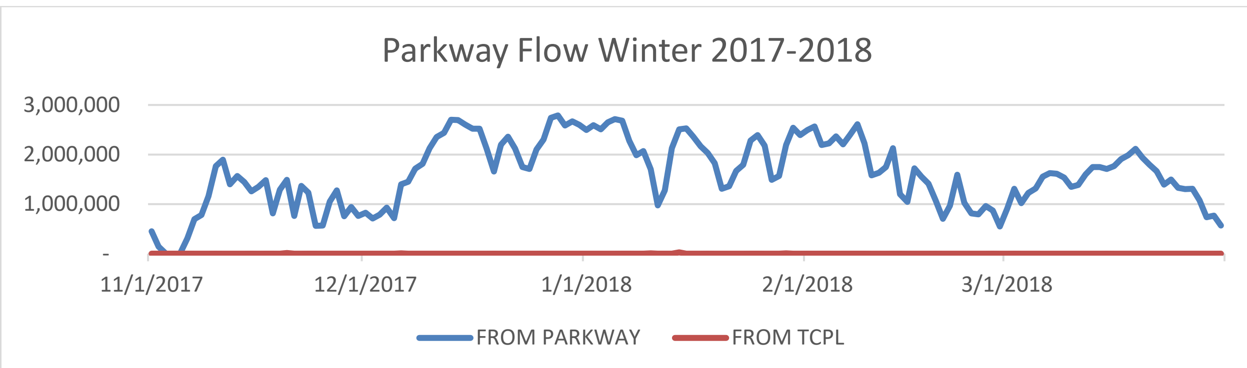
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

As outlined above, we understand that since late 2017, incremental deliveries of gas have been contracted to be transported from Empress to Dawn using Dawn LTFP contracts through two paths, one of which is through Parkway. However, the scheduled flows to Parkway from TCPL do not show this stream of deliveries getting to Parkway in the winter as shown in the inserted figures.





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Question:

Please produce all records and documents related to EGI's identification and examination of the Dawn LTFP exchange service described in its evidence, including all e-mail exchanges, power point presentations and any other written records pertaining to this topic.

Response

As stated at Exhibit I.FRPO.1, the purpose of this proceeding is to develop an IRP Policy Framework for Enbridge Gas to guide its assessment of IRPAs relative to other facility and non-facility alternatives to serve the forecasted needs of its customers. Accordingly, assessment or analyses of specific supply-side (market-based) alternatives to address specific system constraints, including review of Enbridge Gas's historic activities with regard to the assessment of market-based services offered by third parties associated with the now withdrawn 2021 Dawn Parkway Expansion Project (EB-2019-0159), bear no relevance to the establishment of an IRP Policy Framework.

In its Procedural Order No. 4 dated August 20, 2020, the Board stated:

> "The OEB also agrees with comments from Enbridge Gas that natural gas market fundamentals in Ontario are dynamic, and that a snapshot of information and data on the natural gas market and flow dynamics in Ontario at a particular point in time may be more relevant in the context of future applications to address specific system needs than in the development of an IRP framework."

Please see the response at Exhibit I.STAFF.16, for a discussion regarding non-facility, supply-side solutions.

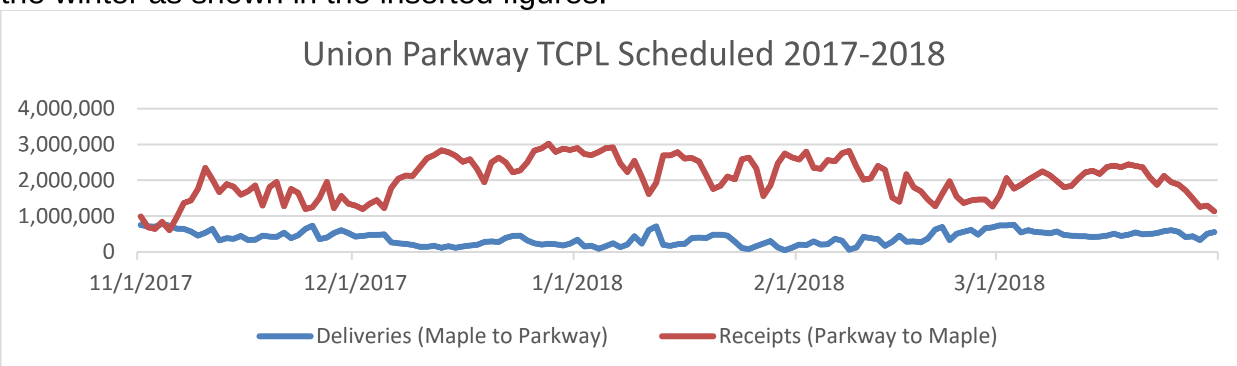
ENBRIDGE GAS INC.

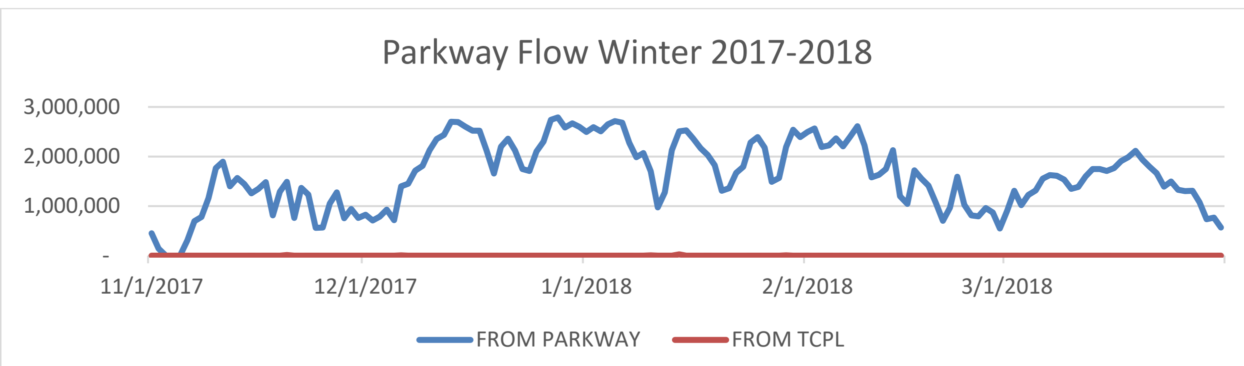
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

As outlined above, we understand that since late 2017, incremental deliveries of gas have been contracted to be transported from Empress to Dawn using Dawn LTFP contracts through two paths, one of which is through Parkway. However, the scheduled flows to Parkway from TCPL do not show this stream of deliveries getting to Parkway in the winter as shown in the inserted figures.





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Question:

Please identify the EGI representative(s) who conducted and are responsible for the identification of and the examination of this potential non-facility alternative.

Response

Please see the response at Exhibit I.FRPO.58.

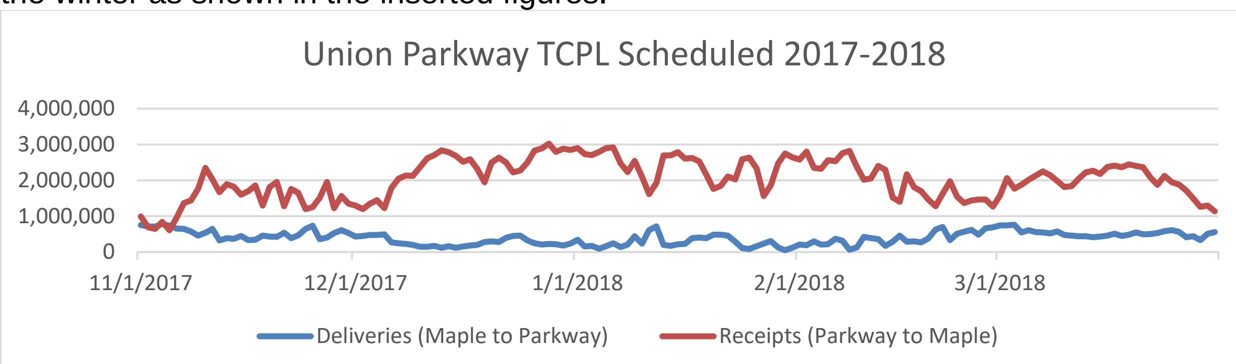
ENBRIDGE GAS INC.

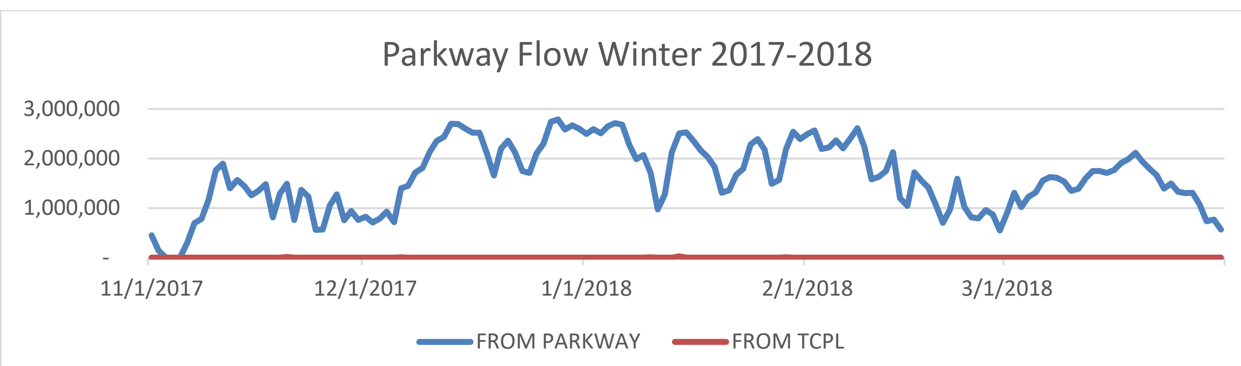
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (“FRPO”)

INTERROGATORY

Preamble:

As outlined above, we understand that since late 2017, incremental deliveries of gas have been contracted to be transported from Empress to Dawn using Dawn LTFP contracts through two paths, one of which is through Parkway. However, the scheduled flows to Parkway from TCPL do not show this stream of deliveries getting to Parkway in the winter as shown in the inserted figures.





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Question:

Please describe the essential features of the potential exchange service that EGI identified and examined including:

a) The parties to the arrangements (for e.g. Was a three-party agreement between EGI, a Dawn LTFP shipper and TCPL as the owner of the Mainline, envisaged); and
b) The obligations on each of these parties considered by EGI to be essential to make the agreement feasible.

Response

Please see the responses at Exhibit I.FRPO.57, and at Exhibit I.FRPO.58.

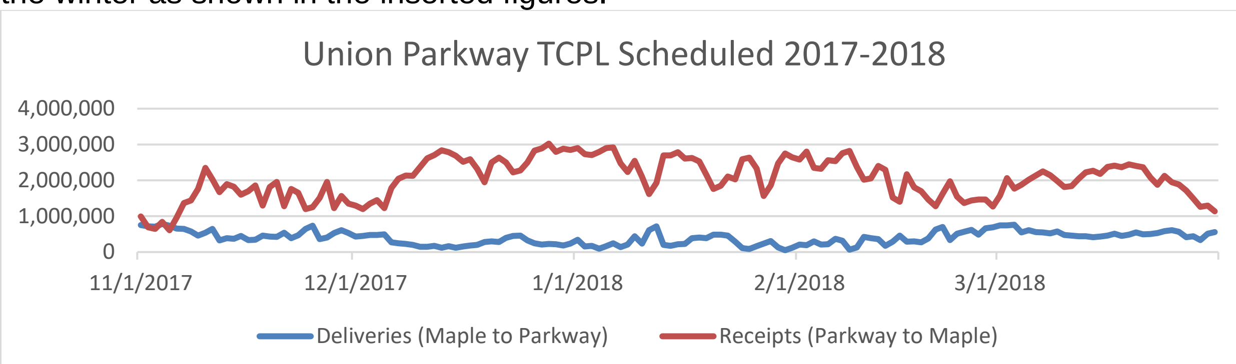
ENBRIDGE GAS INC.

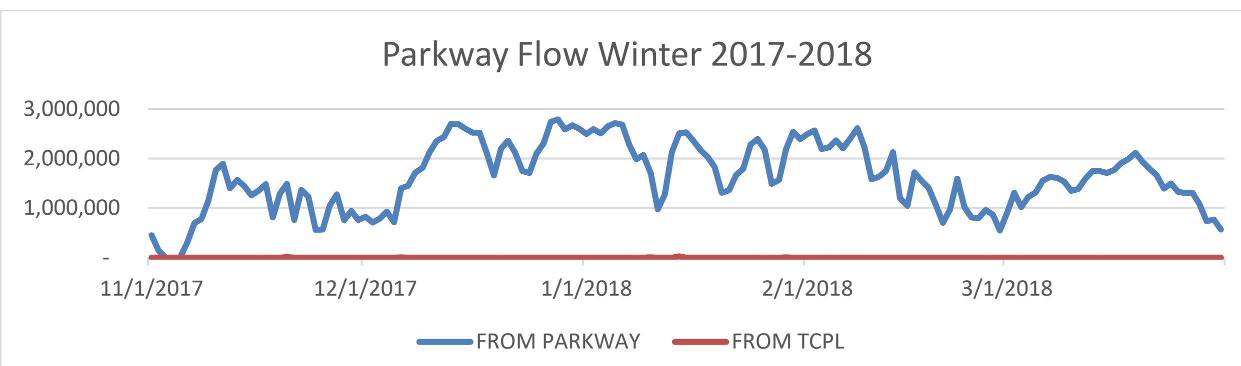
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

As outlined above, we understand that since late 2017, incremental deliveries of gas have been contracted to be transported from Empress to Dawn using Dawn LTFP contracts through two paths, one of which is through Parkway. However, the scheduled flows to Parkway from TCPL do not show this stream of deliveries getting to Parkway in the winter as shown in the inserted figures.





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Question:

Please identify all of the resources external to EGI who were consulted in connection with the identification and examination of this non-facility alternative.

Response

Please see the response at Exhibit I.FRPO.58.

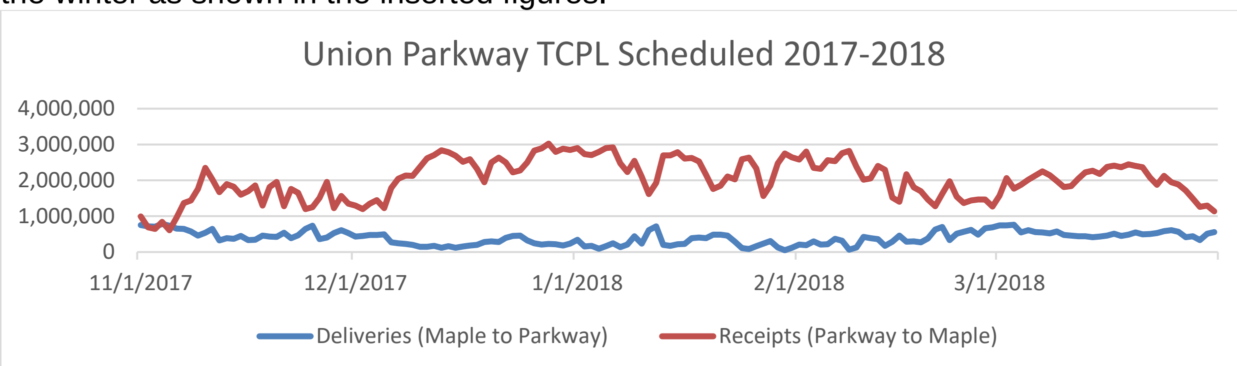
ENBRIDGE GAS INC.

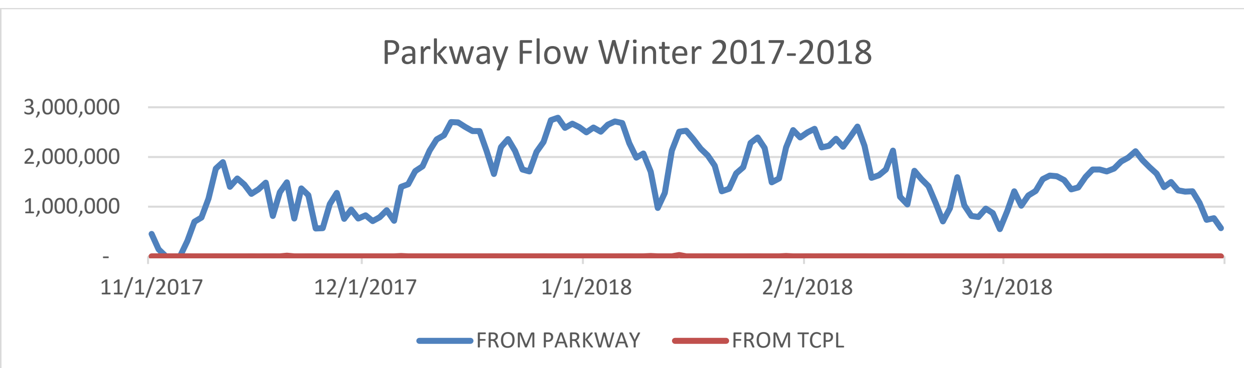
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

As outlined above, we understand that since late 2017, incremental deliveries of gas have been contracted to be transported from Empress to Dawn using Dawn LTFP contracts through two paths, one of which is through Parkway. However, the scheduled flows to Parkway from TCPL do not show this stream of deliveries getting to Parkway in the winter as shown in the inserted figures.





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Question:

Did EGI consider the Dawn LTFP “exchange” arrangement in the context of:

a) The ability of Dawn LTFP shippers to voluntarily agree to commit to daily deliveries at Parkway as a term of the “exchange” arrangement
b) The ability of Dawn LTFP shippers to voluntarily agree to refrain from exercising their termination rights under LTFP service for the duration of the exchange arrangement; and
c) The ability of TCPL to voluntarily agree to use the Northern Ontario line to carry all volumes covered by the exchange arrangement?

Response

Please see the response at Exhibit I.FRPO.58.

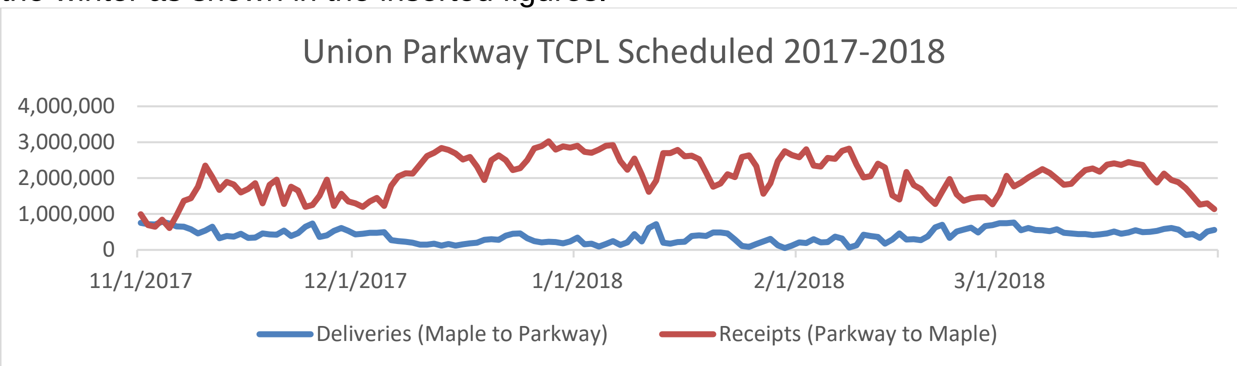
ENBRIDGE GAS INC.

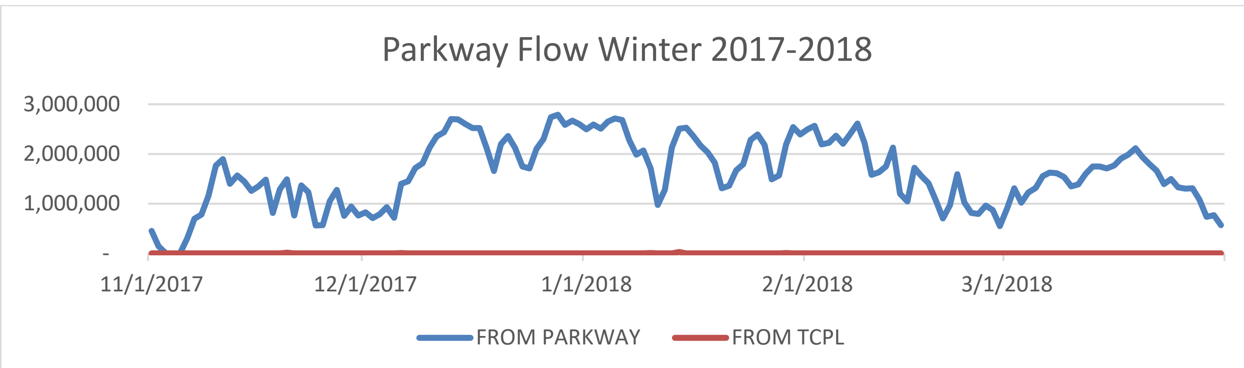
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (“FRPO”)

INTERROGATORY

Preamble:

As outlined above, we understand that since late 2017, incremental deliveries of gas have been contracted to be transported from Empress to Dawn using Dawn LTFP contracts through two paths, one of which is through Parkway. However, the scheduled flows to Parkway from TCPL do not show this stream of deliveries getting to Parkway in the winter as shown in the inserted figures.





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Question:

What estimated incentive amount would EGI consider to be appropriate to prompt a Dawn LTFP shipper to voluntarily commit to deliver exchange volumes to Parkway for the 151 days of the winter.

Response

Please see the response at Exhibit I.FRPO.58.

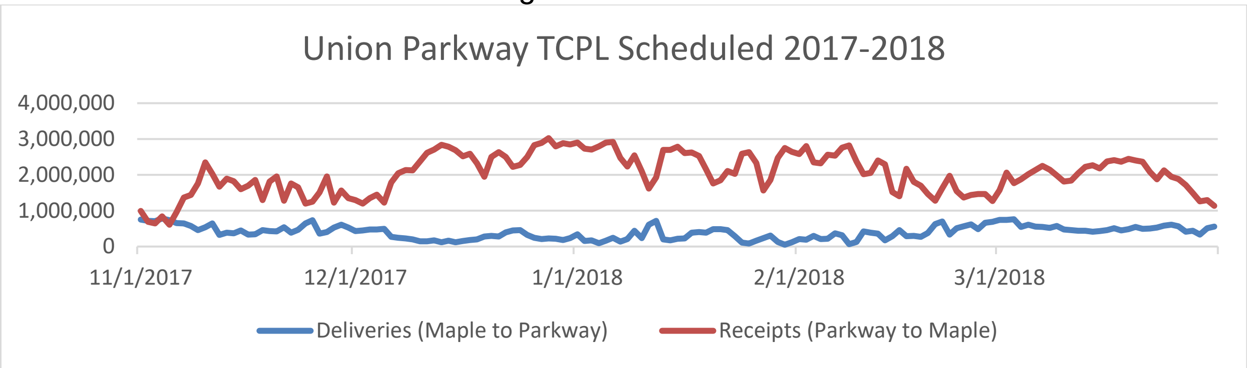
ENBRIDGE GAS INC.

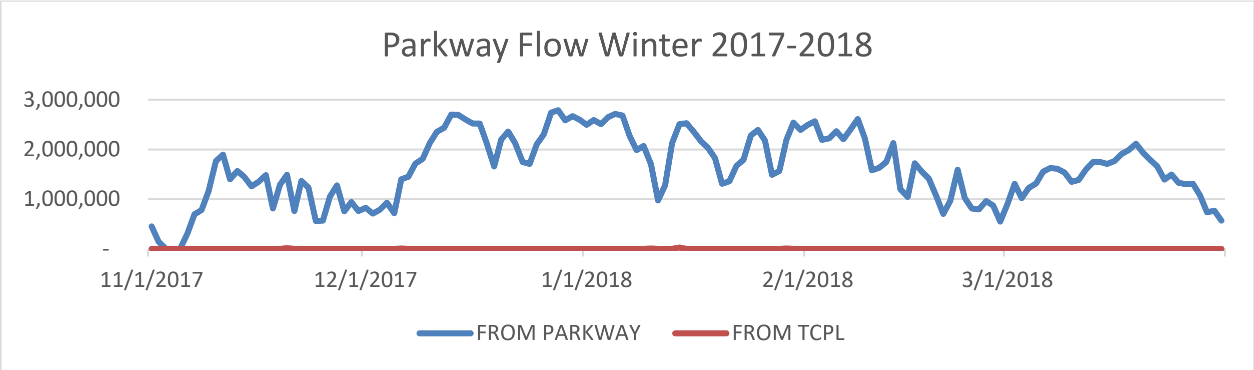
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (“FRPO”)

INTERROGATORY

Preamble:

As outlined above, we understand that since late 2017, incremental deliveries of gas have been contracted to be transported from Empress to Dawn using Dawn LTFP contracts through two paths, one of which is through Parkway. However, the scheduled flows to Parkway from TCPL do not show this stream of deliveries getting to Parkway in the winter as shown in the inserted figures.





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Question:

From what market information would an estimate of this incentive amount be derived?

Response

Please see the response at Exhibit I.FRPO.58.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

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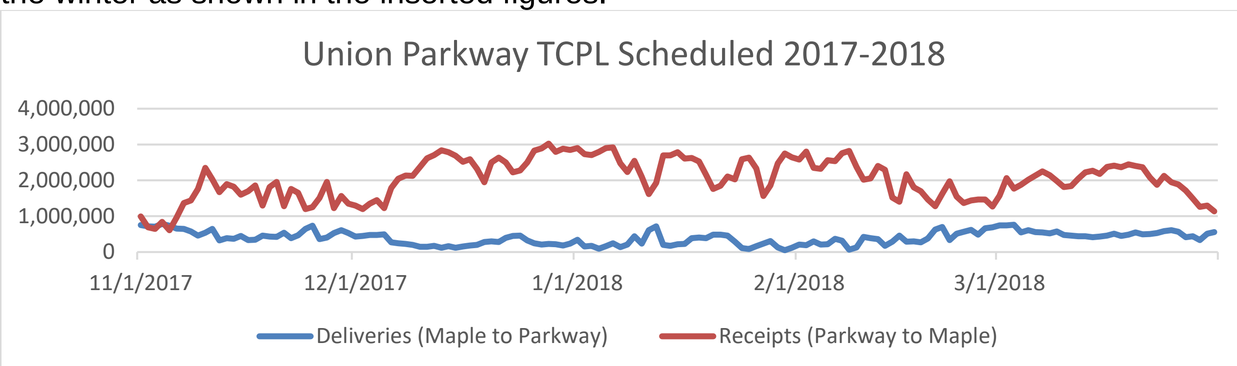

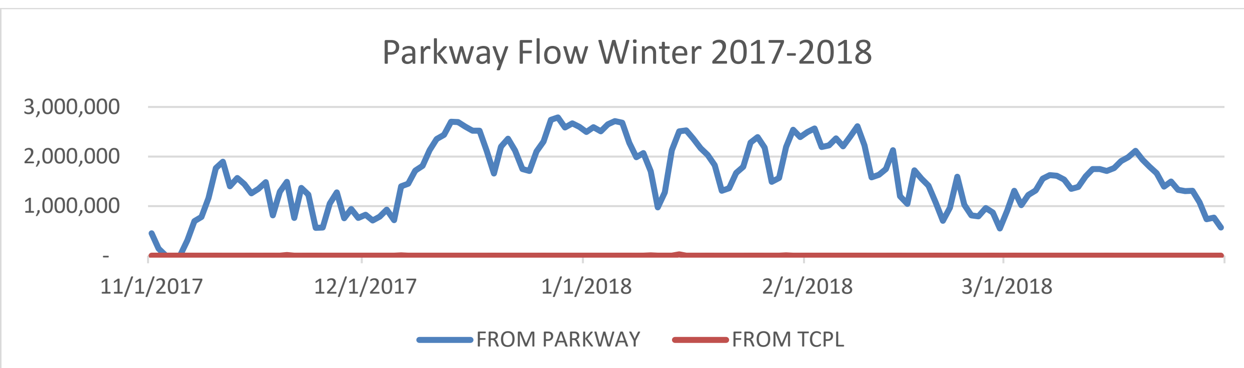

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Question:

Please provide the approximate number of such shippers who contract for Dawn LTFP service.

Response

Please see the response at Exhibit I.FRPO.58.

Given that the information requested here is publicly available, Enbridge Gas is prepared to response to this question.

As per Exhibit I.FRPO.54. Attachment 1, according to the "January 4, 2021 Contract Demand Energy ('CDE') report" (found on the TransCanada Customer Express website) there are approximately 20 Dawn LTFP shippers as of January 4, 2021.[2]

[2] http://www.tccustomerexpress.com/888.html

ENBRIDGE GAS INC.

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

INTERROGATORY

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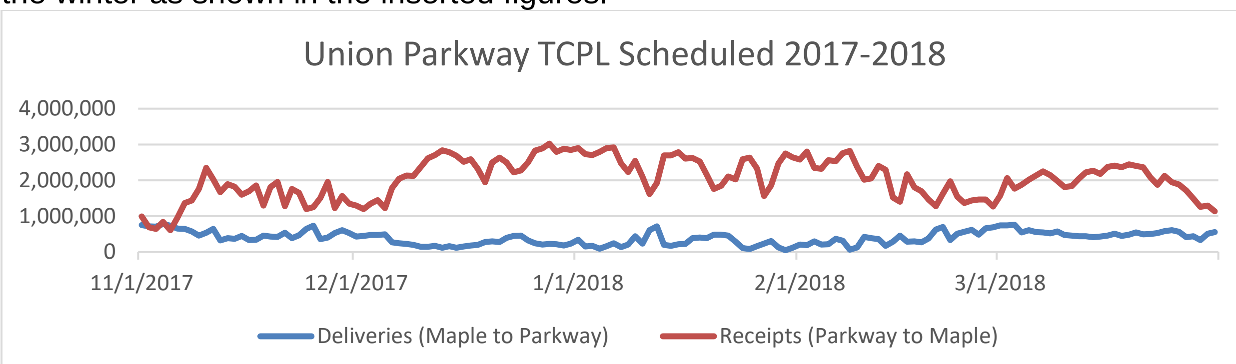

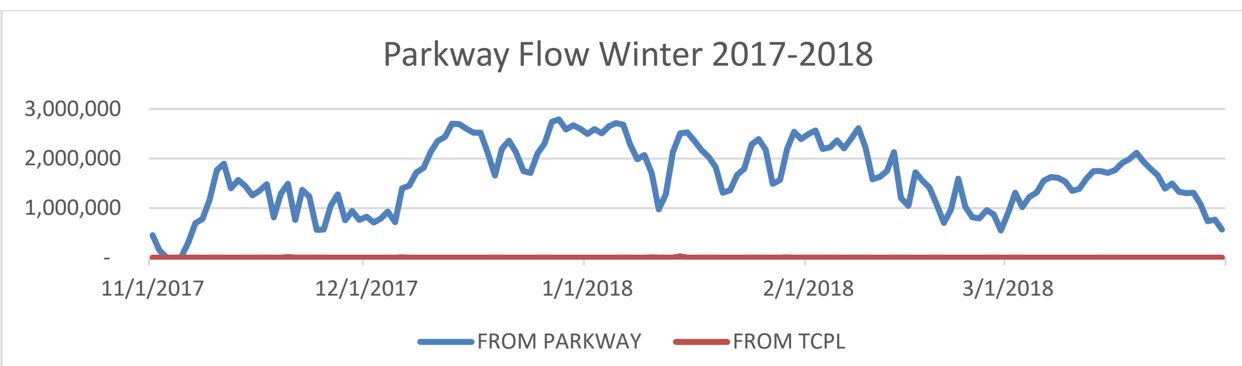

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Question:

What benefits, if any, does a Dawn LTFP gas producer and/or marketer shipper relinquish by committing to ship contracted quantity on TCPL's Northern Ontario line; and what benefits does that shipper realize by having its volumes at Dawn under the exchange transaction for each of the 151 winter days?

Response

Please see the response at Exhibit I.FRPO.58.

Dawn is the only delivery point allowed within Ontario for the Dawn LTFP service, where shippers can nominate transportation between Empress and Dawn. Shippers are not entitled to nominate flow on a specific physical transportation path (i.e., Great Lakes Gas Transmission System or the TransCanada Mainline). As such, Dawn LTFP Shippers do not have the ability to commit to shipping contracted quantities on the Northern Ontario Line.

Per CER RH-003-2017 Reasons for Decision Part 3 – Views of the Board (Need for Dawn LTFP Service), the Dawn LTFP service is intended to

> "…attract long-term, long-haul contracts from WCSB producers seeking access to the Dawn hub."

The main intent and benefit provided to the Dawn LTFP Shippers is to gain access to the liquid Dawn Hub. Once gas is delivered by TransCanada to the Dawn Hub, parties contracting the Dawn LTFP service can then transact in the market, including selling their natural gas at Dawn or making other arrangements with other parties.

In order to provide a long-term exchange service, TransCanada would need certainty regarding shipper nominations each gas day. Dawn LTFP shippers are entitled to use the service as they see fit such that TransCanada does not control shipper Dawn LTFP service nominations. TransCanada manages the daily operations and Mainline flows to meet all customer demands on the Mainline system. TransCanada would also need certainty regarding Dawn LTFP service term. Shippers can turn back Dawn LTFP capacity with two years notice (firm transportation Shippers can turn back capacity with one year notice).

It is worth noting that the Mainline has seen long-term contracting volatility in the past, including eastern utilities shifting supply directly from western Canada to purchasing gas at market hubs closer to the markets. As a means of increasing long haul Mainline contracting, TransCanada applied for, and its regulator approved, the Dawn LTFP service. This service was offered with fewer attributes and lower rates than the Mainline firm contracting (FT) service from Empress to Dawn.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

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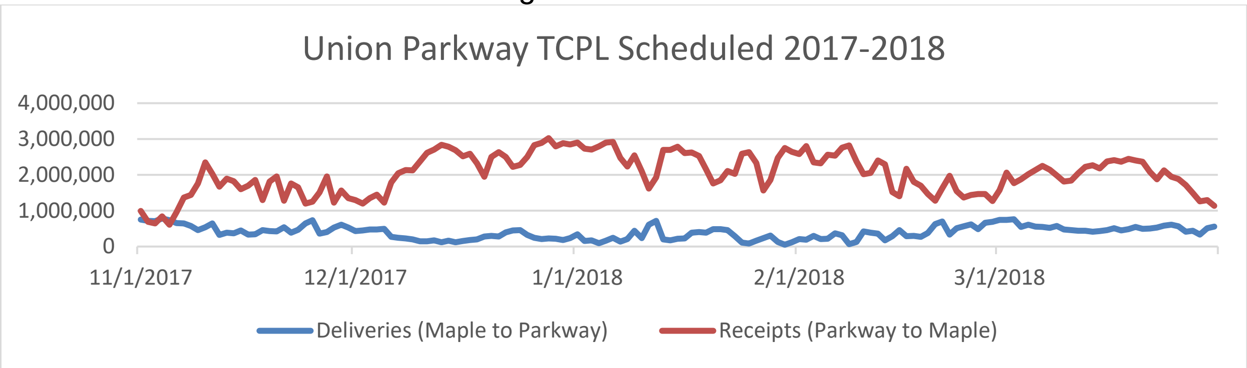

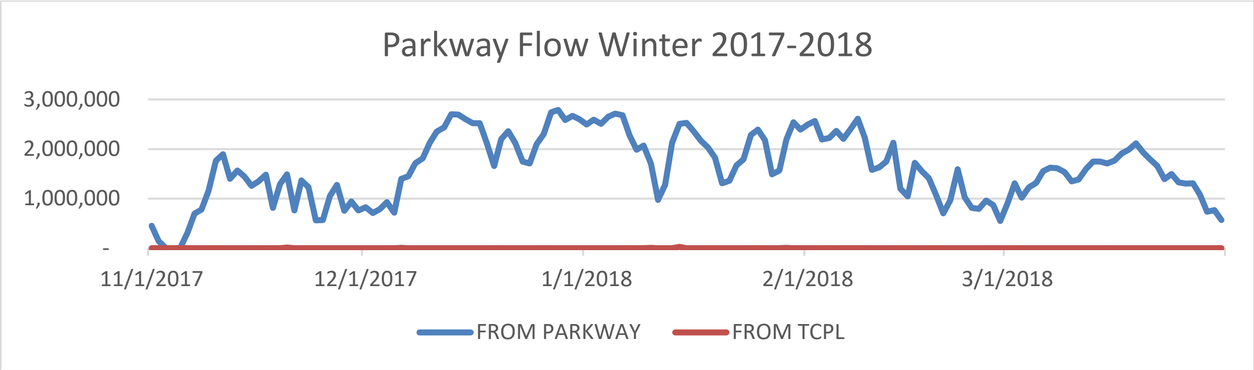

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Question:

Please provide particulars of and quantify the incremental costs, if any, is TCPL likely incur by committing to carry the Dawn LTFP shipper volumes on its Northern Ontario line under the auspices of the exchange transaction?

Response

Please see the response at Exhibit I.FRPO.58.

ENBRIDGE GAS INC.

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

INTERROGATORY

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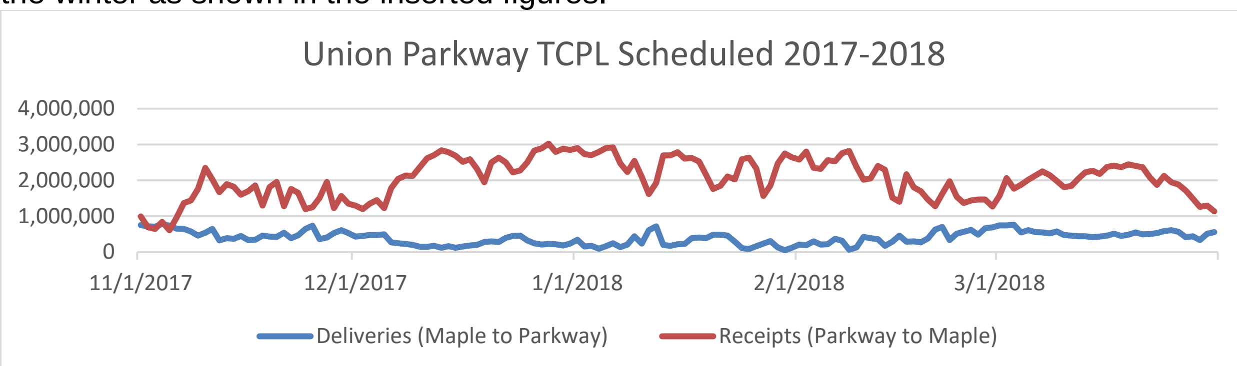

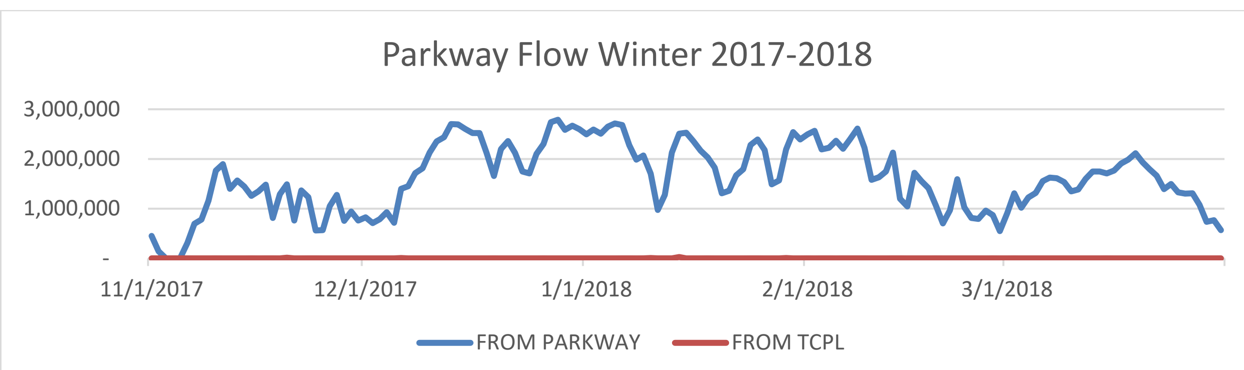

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Question:

In its RH-003-2017 Letter Decision on the Dawn LTFP service at pages 26 and 30, did the NEB direct TCPL to maximize the benefits to the Mainline from the availability of Dawn LTFP service?

Response

The National Energy Board's ("NEB")/Canadian Energy Regulator's ("CER") Reason for Decision on TransCanada Pipelines Ltd.'s ("TCPL") Application for Dawn Long Term Fixed Price (LTFP) Service (RH-003-2017), states:

> "It is a key consideration for the Board that Dawn LTFP service provides a benefit to the Mainline."[2]

> "The Board expects TransCanada to optimize net revenue benefits for the Mainline and its shippers over the term of Dawn LTFP, and this is largely affected by GLGT TBO costs."[3]

[2] RH-003-2017, Reason for Decision, November 23, 2017, p. 26.
[3] RH-003-2017, Reason for Decision, November 23, 2017, p. 30.

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

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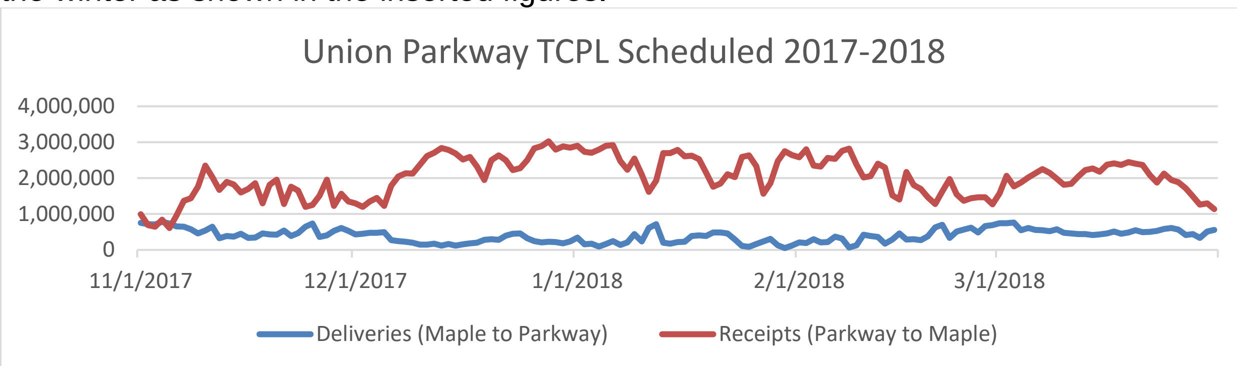

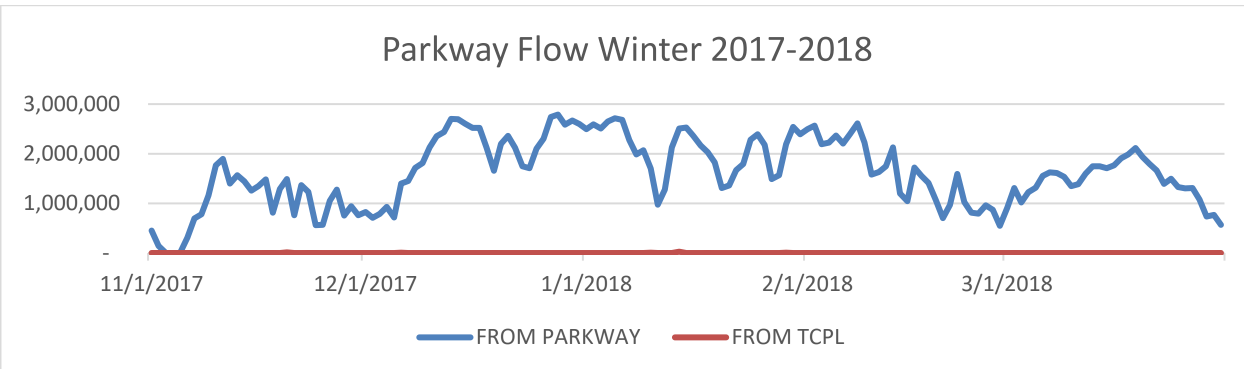

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[1] Displacement transactions permit the lateral movement of gas through a transportation network. The configuration of many pipelines is such that it may not be apparent whether a given movement of gas is forward or backward from the point of receipt. It can be argued that all transportation service is performed by displacement as the physical delivery of the same molecules of gas is impossible. Source: www.aga.org/natural-gas/glossary

Question:

What further incentive amount for TCPL, if any, would EGI consider to be appropriate to compensate TCPL for any incremental costs that it is likely to occur to carry the Dawn LTFP shipper volumes under the auspices of the exchange or displacement transaction? What information would EGI propose to use to determine the amount of this incentive?

Response

Please see the response at Exhibit I.FRPO.58.

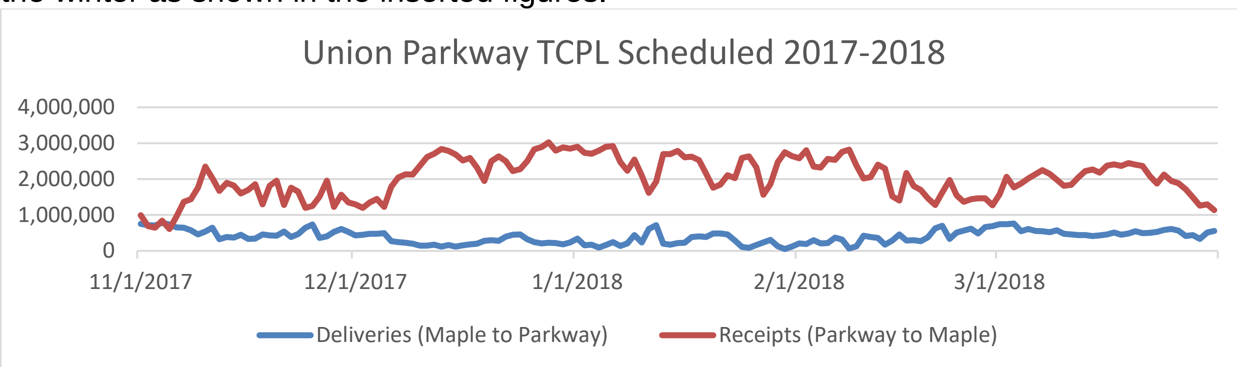
ENBRIDGE GAS INC.

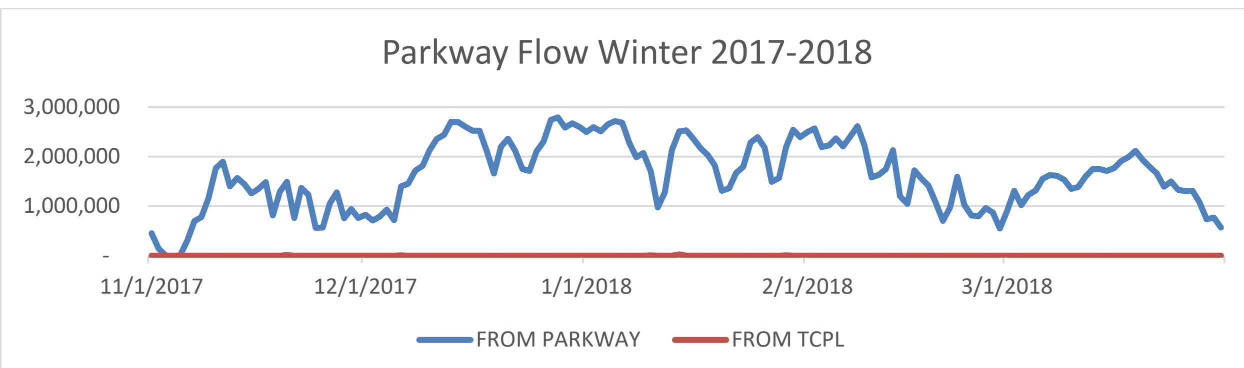
Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

As outlined above, we understand that since late 2017, incremental deliveries of gas have been contracted to be transported from Empress to Dawn using Dawn LTFP contracts through two paths, one of which is through Parkway. However, the scheduled flows to Parkway from TCPL do not show this stream of deliveries getting to Parkway in the winter as shown in the inserted figures.





Source: http://www.tccustomerexpress.com/gasdaysummaryreport.html
We understand this effect is a result of displacement[1].

[1] Displacement transactions permit the lateral movement of gas through a transportation network. The configuration of many pipelines is such that it may not be apparent whether a given movement of gas is forward or backward from the point of receipt. It can be argued that all transportation service is performed by displacement as the physical delivery of the same molecules of gas is impossible. Source: www.aga.org/natural-gas/glossary

Question:

In its “identification” of an “exchange” using the Dawn LTFP as a potential non-facility alternative to the Project, did EGI draft an RFP to LTFP shippers and TCPL containing the elements of the service that EGI would consider as feasible.

Response

Please see the response at Exhibit I.FRPO.58.

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

Without responses to the information requested herein about EGI's current approach to Non-Facility Supply-Side Alternatives to an infrastructure build, FRPO cannot formulate anything more than a preliminary outline of its proposal for evaluation for such alternatives and its suggested timing to assess these alternatives.

By way of a preliminary overview FRPO expects that these proposals will include matters related to:

(i) The assessment of 'need" in a manner that excludes "shortfall management" capacity above a materiality threshold.
(ii) EGI's creation and updates, as necessary of its comprehensive list of all Non-Facility Alternatives (Supply side and Non-Supply) that could possibly be adopted.
(iii) The ranking of those Alternatives on the basis of Costs/Economic criteria or methodologies with the results of supporting market solicitations in the case of alternatives that are market based. An example of the type of market solicitation that should be used in the case of an assessment of the PDO Alternative is attached.
(iv) The "track record" related to the actual implementation of the Alternatives and whether they are well established best practices or novel and untested
(v) Other matters related to the timely "availability' of the alternative.
(vi) Other matters related to the "reliability of such alternatives
(vii) The degree of timely stakeholder involvement in the Need Assessment and Alternatives selection process.
(viii) Alternative selection process and the involvement of the regulator therein.

Question:

Please provide EGI's comments, if any, on the foregoing preliminary list of topics that are expected to form part of FRPO's final proposals in this proceeding.

Response

Enbridge Gas has no specific comments on the topic list provided by FRPO at this time. Enbridge Gas's original IRP Proposal, Additional Evidence, Reply Evidence, and clarifications provided through responses to interrogatories articulate the details of Enbridge Gas's IRP Proposal and reflect its positions in this proceeding.

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.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

On p. 9, paragraph 19 of its reply evidence, Enbridge reaffirms its support for "a staged economic evaluation standard for IRPAs…that ultimately resembles a modified version of the OEB's E.B.O. 134 guidelines or a DCF+ test."

a. Is Enbridge aware of any other jurisdiction that it considers to be seriously considering either non-wires alternatives or non-pipe alternatives that is using a similar economic test? If so, please:
    i. List all such jurisdictions.
    ii. Provide references to document the economic tests that they are using to determine whether or when to proceed with non-wires or non-pipe solutions.
    iii. Describe and document the policy each jurisdiction has taken with respect to non-pipe solutions and/or non-wires solutions.
    iv. Document the number of actual non-pipe and/or non-wires solutions projects each jurisdiction has undertaken in the past decade under the existing cost-effectiveness policy.
b. Please describe exactly what Enbridge means by a "modified version of the OEB's E.B.O. 134 guidelines".
c. Please list all costs that would be included in Enbridge's proposed DCF+ test.
d. Please list all benefits that would be included in Enbridge's proposed DCF+ test.
e. Would the value of avoided gas commodity purchase resulting from a geotargeted efficiency program be considered a cost, a benefit or not considered at all in Enbridge's proposed DCF+ test? Please explain how and why it would be a cost, benefit or not considered.
f. Would the value of avoided carbon emission taxes resulting from a geotargeted efficiency program be considered a cost, a benefit or not considered at all in Enbridge's proposed DCF+ test? Please explain how and why it would be a cost, benefit or not considered.
g. Please provide the calculation formula(e), including all applicable benefits and costs, that would be used to under the DCF+ test proposed by Enbridge.

h. Has Enbridge ever used the DCF+ test in the past? If so, please provide the two most recent examples, with references that show how the calculations for the test were performed in those examples.
i. If Enbridge has not previously used the DCF+ test, please provide a hypothetical example of how the calculation for the test would be performed for a geotargeted efficiency program.

<u>Response</u>

a) The only other jurisdiction using a similar economic test that Enbridge Gas is aware of is ConEd and their use of BCA analysis, for which GEC has previously filed detailed expert evidence on in this proceeding.

b) - d)
Please see the response at Exhibit I.STAFF.20.

e) In the case of assessment of investments in ETEEs (geotargeted efficiency program), Enbridge Gas would consider a reduction in gas commodity consumed by the customer to be a benefit to the customer. This benefit would be measured by determining the reduced financial cost of energy a customer would experience.

f) Enbridge Gas views Federal Carbon Charge ("FCC") treatment to be similar to the treatment of gas commodity costs. An ETEE (geotargeted efficiency program) that results in a gas commodity cost reduction benefit would also result in a FCC reduction benefit to customers.

g) - i)
The DCF+ test would resemble an economic analysis using the OEB's E.B.O.134 guidelines. Modifications that are anticipated to be made to the OEB's guidelines would be to the specific costs and benefits that are included in the evaluation. Please see the response at Exhibit I.STAFF.20, for discussion regarding the various categories of costs and benefits Enbridge Gas is proposing to include at different stages of the cost-benefit evaluation. A DCF+ test has not been used to date but will resemble the examples provided. Examples of previously filed economic analysis using E.B.O. 134 guidelines are attached as Attachment 1 and Attachment 2.

Please also see the response at Exhibit I.OSEA.1 c), for discussion of Enbridge Gas's efforts towards integrating IRP into existing processes going forward. The estimation of all costs and benefits of a particular investment in IRPA(s) will be done on a case by case basis consistent with the guidance ultimately set out by the Board through its establishment of an IRP Framework for Enbridge Gas.

Stratford Reinforcement Project
InService Date: Nov-01-2019

Project Year ($000's)	1	2	3	4	5	6	7	8	9	10
Cash Inflow										
Revenue	29	83	137	196	249	299	358	408	433	433
Expenses:										
O & M Expense	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Municipal Tax	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)
Income Tax	889	619	534	461	396	339	284	236	199	172
Net Cash Inflow	844	628	598	583	571	563	568	570	558	531
Cash Outflow										
Incremental Capital	27,933	607	-	-	-	-	-	-	-	-
Change in Working Capital	0	-	-	-	-	-	-	-	-	-
Cash Outflow	27,933	607	-	-	-	-	-	-	-	-
Cumulative Net Present Value										
Cash Inflow	823	1,404	1,929	2,416	2,869	3,293	3,700	4,087	4,447	4,773
Cash Outflow	27,933	28,510	28,510	28,510	28,510	28,510	28,510	28,510	28,510	28,510
NPV By Year	(27,110)	(27,106)	(26,580)	(26,093)	(25,641)	(25,216)	(24,810)	(24,422)	(24,062)	(23,737)
Project NPV	-20,266									
Profitability Index										
By Year PI	0.03	0.05	0.07	0.08	0.10	0.12	0.13	0.14	0.16	0.17
Project PI	0.29									

Stratford Reinforcement Project
InService Date: Nov-01-2019

Project Year ($000's)	11	12	13	14	15	16	17	18	19	20
Cash Inflow										
Revenue	433	433	433	433	433	433	433	433	433	433
Expenses:										
O & M Expense	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Municipal Tax	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)
Income Tax	148	126	107	89	73	59	46	34	23	13
Net Cash Inflow	506	485	465	447	432	417	404	392	381	372
Cash Outflow										
Incremental Capital	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-
Cash Outflow	-	-	-	-	-	-	-	-	-	-
Cumulative Net Present Value										
Cash Inflow	5,068	5,336	5,580	5,803	6,008	6,196	6,369	6,528	6,675	6,811
Cash Outflow	28,510	28,510	28,510	28,510	28,510	28,510	28,510	28,510	28,510	28,510
NPV By Year	(23,442)	(23,174)	(22,929)	(22,706)	(22,502)	(22,314)	(22,141)	(21,982)	(21,834)	(21,698)
Project NPV										
Profitability Index										
By Year PI	0.18	0.19	0.20	0.20	0.21	0.22	0.22	0.23	0.23	0.24
Project PI										

Stratford Reinforcement Project
InService Date: Nov-01-2019

Project Year ($000's)	21	22	23	24	25	26	27	28	29	30
Cash Inflow										
Revenue	433	433	433	433	433	433	433	433	433	433
Expenses:										
O & M Expense	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Municipal Tax	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)
Income Tax	4	(4)	(11)	(18)	(25)	(30)	(36)	(40)	(45)	(49)
Net Cash Inflow	363	355	347	340	334	328	323	318	314	310
Cash Outflow										
Incremental Capital	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-
Cash Outflow	-	-	-	-	-	-	-	-	-	-
Cumulative Net Present Value										
Cash Inflow	6,938	7,055	7,164	7,265	7,360	7,448	7,531	7,608	7,680	7,748
Cash Outflow	28,510	28,510	28,510	28,510	28,510	28,510	28,510	28,510	28,510	28,510
NPV By Year	(21,572)	(21,455)	(21,346)	(21,244)	(21,150)	(21,062)	(20,979)	(20,902)	(20,829)	(20,762)
Project NPV										
Profitability Index										
By Year PI	0.24	0.25	0.25	0.25	0.26	0.26	0.26	0.27	0.27	0.27
Project PI										

Stratford Reinforcement Project
InService Date: Nov-01-2019

Project Year ($000's)	31	32	33	34	35	36	37	38	39	40
Cash Inflow										
Revenue	433	433	433	433	433	433	433	433	433	433
Expenses:										
O & M Expense	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Municipal Tax	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)	(69)
Income Tax	(53)	(56)	(59)	(62)	(65)	(67)	(69)	(71)	(73)	(75)
Net Cash Inflow	306	302	299	296	294	291	289	287	285	283
Cash Outflow										
Incremental Capital	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-
Cash Outflow	-	-	-	-	-	-	-	-	-	-
Cumulative Net Present Value										
Cash Inflow	7,811	7,871	7,927	7,980	8,030	8,077	8,121	8,163	8,202	8,244
Cash Outflow	28,510	28,510	28,510	28,510	28,510	28,510	28,510	28,510	28,510	28,510
NPV By Year	(20,698)	(20,638)	(20,582)	(20,529)	(20,480)	(20,433)	(20,389)	(20,347)	(20,308)	(20,266)
Project NPV										
Profitability Index										
By Year PI	0.27	0.28	0.28	0.28	0.28	0.28	0.28	0.29	0.29	0.29
Project PI										

Stratford Reinforcement Project
InService Date: Nov-01-2019
(Project Specific DCF Analysis)

Stage 1 DCF - Listing of Key Input Parameters, Values and Assumptions
($000'S)

Discounting Assumptions	
Project Time Horizon	40 years commencing at facilites in-service date of 01 Nov 19
Discount Rate	Incremental after-tax weighted average After Tax Cost of Capital of 5.28%
Key DCF Input Parameters, Values and Assumptions	
Net Cash Inflow:	
Incremental Revenue:	
Tranmission portion of customer rates	0.17788 $/ M3 / month applied to Contract Demand 0.01980 Transmission Margin $ / M3 consumed applied to general service demands
Operating and Maintenance Expense	Estimated incremental cost
Incremental Tax Expenses:	
Municipal Tax	Estimated incremental cost
Income Tax Rate	26.50%
CCA Rates:	
CCA Classes:	Declining balance rates by CCA class:

CCA Classes:	CCA Class	CCA Rate
Land Rights	14.1	5%
Steel Mains	49	8%
Valve Site	8	20%

Cash Outflow:	
Incremental Capital Costs Attributed	Refer to DCF Schedule 13
Change in Working Capital	5.05% applied to O&M

Calculation of Revenue (Transmission Margins)

Stratford Reinforcement Project
InService Date: Nov-01-2019

Line	Project Year ($000's)		1	2	3	4	5	6	7	8	9	10
	Transmission costs are recovered from Contract rate classes based on Firm Contract Demand (CD)											
	The deemed incremental revenue is based on the capacity created on the FHG system											
	Contract Methodology: Total CD * 12 *Transmission Margin											
1	Transmission Margin $/M3 / month	0.1779										
2	Contract Demand 10^3m^3/month		1	1	2	6	6	6	11	11	11	11
3	Transmission Margin		$2	$2	$4	$12	$14	$14	$24	$24	$24	$24
	General Service Transmission Margin = Volumes * Transmission Margin											
4	Transmission Margin $ / M3 consumed	0.01980										
5	Volume 10 ^3 M^3		1,358	4,092	6,753	9,314	11,863	14,390	16,895	19,399	20,650	20,650
6	Transmission Margin		$27	$81	$134	$184	$235	$285	$334	$384	$409	$409
7	Total Transmission Margin		$29	$83	$137	$196	$249	$299	$358	$408	$433	$433

Stage 2 (Customer Fuel Savings) Data for Owen Sound Reinforcement

Assumptions

Line (a) (b) (c) (d)=(b)-(c)

(a) Fuel Prices	(b) $/m^3	(c) Gas $/m^3	(d)=(b)-(c) Diff $/m^3
Heating Oil	1.02	0.16	0.86
Number 6 Oil	0.37	0.16	0.22
Diesel	0.76	0.16	0.61
Propane	0.86	0.16	0.70
Electricity	1.02	0.16	0.87

Fuel Mix in the Event Gas is Not Available

	(e) General Service Fuel Mix	(f)=(d)*(e) General Service Wt Ave Diff $/ M^3
Heating Oil	20%	0.172
Number 6 Oil	-	-
Diesel	-	-
Propane	50%	0.350
Electricity	30%	0.261
Total %	100%	
Weighted Savings $/m^3		0.783

Gas and alternative fuel prices are the average posted prices for the 12 month period ending December 2017

Calculation for Stage 2 Incremental Energy Demand

	Estimated Energy Demand with Pipeline Built
Equals	Potential annual energy demand (for Stage 2 calculations)
Times	Weighted Average Savings per M3
Equals	Annual Fuel Savings: Natural Gas Vs Alt Fuels

Discount Rate for Net Present Values 4.0%

Length of Term for Fuel Savings

Stage 2 estimated based on 20 years and 40 years

Present Value of Customer Fuel Savings

For conservatism, the NPV is assessed over 20 years with sensitivity at 40 years

Figures in $ Millions	20 Years	40 Years
General Service Fuel Savings	175	282

NPV Fuel Savings Range from $175 Mil over 20 yrs to $282 Mil over 40 yrs

Stratford Reinforcement Project
Economic Benefits from Infrastructure Spending
Figures in $ Millions

Line No	Description	Capex Spend Out of Country (a)	Capex Spend within Ontario (b)	Capex Spend within Canada Excluding Ontario (c)	Capex Total (d)= sum (a-c)	
1	Proposed Facilities	$ 0.3	$ 24.8	$ 3.4	$ 28.5	
2						
3	% of Total Spend	1%	87%	12%	100%	Line 1 /Total Line 1 Col (d)
4						
5	GDP					
6	GDP Factor		1.14			
7	GDP Impact $ Millions		$ 28			Line 1 * Line 6
8						
9	Employment (Jobs)					
10	Jobs Factor		16.7			
11	Jobs Created		415			Line 1 * Line 10
12						
13	Taxes Paid by Union Gas					
14	Property Tax		$ 2			Source: NPV DCF
15	Provincial Income Tax		$ 3			Source: NPV DCF
16	Total Provincial Taxes		$ 5			
17	Federal Income Tax		$ 2			Source: NPV DCF
18	Total Taxes Paid		$ 7			
19						
20	Total Value to Ontario					
21	GDP Impact $ Millions		$ 28			Line 7
22	Total Provincial Taxes		$ 5			Line 16
23	NPV Total Value to Ontario		$ 33			

Owen Sound Reinforcement

InService Date: Nov-01-2020

Project Year ($000's)	1	2	3	4	5	6	7	8	9	10
Cash Inflow										
Revenue	553	715	877	959	959	959	959	959	959	959
Expenses:										
O & M Expense	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)
Municipal Tax	(370)	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)
Income Tax	1,915	880	735	641	573	512	455	402	354	310
Net Cash Inflow	2,082	1,395	1,413	1,399	1,332	1,270	1,214	1,161	1,113	1,069
Cash Outflow										
Incremental Capital	52,809	1,921	-	-	-	-	-	-	-	-
Change in Working Capital	1	-	-	-	-	-	-	-	-	-
Cash Outflow	52,810	1,921	-	-	-	-	-	-	-	-
Cumulative Net Present Value										
Cash Inflow	2,031	3,325	4,572	5,747	6,811	7,776	8,653	9,452	10,180	10,845
Cash Outflow	52,810	54,637	54,637	54,637	54,637	54,637	54,637	54,637	54,637	54,637
NPV By Year	(50,779)	(51,312)	(50,065)	(48,890)	(47,826)	(46,860)	(45,983)	(45,185)	(44,457)	(43,792)
Project NPV	(37,742)									
Profitability Index										
By Year PI	0.04	0.06	0.08	0.11	0.12	0.14	0.16	0.17	0.19	0.20
Project PI	0.31									

Owen Sound Reinforcement
InService Date: Nov-01-2020

Project Year ($000's)	11	12	13	14	15	16	17	18	19	20
Cash Inflow										
Revenue	959	959	959	959	773	773	773	773	773	773
Expenses:										
O & M Expense	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)
Municipal Tax	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)
Income Tax	269	232	197	166	185	159	134	111	90	71
Net Cash Inflow	1,028	991	956	924	759	732	707	684	663	644
Cash Outflow										
Incremental Capital	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-
Cash Outflow	-	-	-	-	-	-	-	-	-	-
Cumulative Net Present Value										
Cash Inflow	11,453	12,011	12,523	12,994	13,361	13,699	14,009	14,294	14,557	14,801
Cash Outflow	54,637	54,637	54,637	54,637	54,637	54,637	54,637	54,637	54,637	54,637
NPV By Year	(43,184)	(42,626)	(42,114)	(41,643)	(41,275)	(40,938)	(40,628)	(40,342)	(40,079)	(39,836)
Project NPV										
Profitability Index										
By Year PI	0.21	0.22	0.23	0.24	0.24	0.25	0.26	0.26	0.27	0.27
Project PI										

Owen Sound Reinforcement
InService Date: Nov-01-2020

Project Year ($000's)	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**
Cash Inflow										
Revenue	773	773	773	773	773	773	773	773	773	487
Expenses:										
O & M Expense	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)
Municipal Tax	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)
Income Tax	53	37	22	8	(5)	(16)	(27)	(37)	(46)	21
Net Cash Inflow	626	610	595	581	568	557	546	536	527	309
Cash Outflow										
Incremental Capital	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-
Cash Outflow	-	-	-	-	-	-	-	-	-	-
Cumulative Net Present Value										
Cash Inflow	15,026	15,234	15,427	15,607	15,774	15,930	16,075	16,211	16,338	16,408
Cash Outflow	54,637	54,637	54,637	54,637	54,637	54,637	54,637	54,637	54,637	54,637
NPV By Year	(39,611)	(39,403)	(39,209)	(39,030)	(38,863)	(38,707)	(38,562)	(38,426)	(38,299)	(38,228)
Project NPV										
Profitability Index										
By Year PI	0.28	0.28	0.28	0.29	0.29	0.29	0.29	0.30	0.30	0.30
Project PI										

Owen Sound Reinforcement
InService Date: Nov-01-2020

Project Year ($000's)	31	32	33	34	35	36	37	38	39	40
Cash Inflow										
Revenue	487	487	487	487	487	487	487	487	487	487
Expenses:										
O & M Expense	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)
Municipal Tax	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)
Income Tax	13	6	(0)	(6)	(12)	(17)	(22)	(26)	(30)	(34)
Net Cash Inflow	301	294	287	281	276	270	266	261	257	254
Cash Outflow										
Incremental Capital	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-
Cash Outflow	-	-	-	-	-	-	-	-	-	-
Cumulative Net Present Value										
Cash Inflow	16,474	16,535	16,591	16,644	16,693	16,739	16,782	16,822	16,860	16,895
Cash Outflow	54,637	54,637	54,637	54,637	54,637	54,637	54,637	54,637	54,637	54,637
NPV By Year	(38,163)	(38,102)	(38,045)	(37,993)	(37,944)	(37,898)	(37,855)	(37,815)	(37,777)	(37,742)
Project NPV										
Profitability Index										
By Year PI	0.30	0.30	0.30	0.30	0.31	0.31	0.31	0.31	0.31	0.31
Project PI										

Owen Sound Reinforcement
InService Date: Nov-01-2020
(Project Specific DCF Analysis)

Stage 1 DCF - Listing of Key Input Parameters, Values and Assumptions
($000'S)

Discounting Assumptions	
Project Time Horizon	40 years commencing at facilites in-service date of Nov 1, 2020
Discount Rate	Incremental weighted average after tax cost of capital of 5.12%
Key DCF Input Parameters, Values and Assumptions	
Net Cash Inflow:	
Incremental Revenue:	
Transmission portion of customer rates	4.43100 $/GJ/month applied to M17 contract demand 0.01953 Transmission Margin $ / M3 consumed applied to general service demands
Operating and Maintenance Expense	Estimated incremental cost
Incremental Tax Expenses:	
Municipal Tax	Estimated incremental cost
Income Tax Rate	26.50%
CCA Rates:	
CCA Classes: — CCA Class — CCA Rate	Declining balance rates by CCA class
Land Rights — 14 — 5%	Accelerated CCA (Bill C-97) included.
Steel Mains — 49 — 8%	
Cash Outflow:	
Incremental Capital Costs Attributed	Indirect overhead costs not included Refer to DCF Schedule 4
Change in Working Capital	5.051% applied to O&M

Calculation of Revenue (Transmission Margins)

Owen Sound Reinforcement
InService Date: Nov-01-2020

Line	Project Year ($000's)		1	2	3	4	5	6	7	8	9	10
	M17 Methodology: Total CD * 12 * Transmission Margin											
1	Transmission Margin $/GJ/month	4.4310										
2	Contract Demand GJ/day/month		8,863	8,863	8,863	8,863	8,863	8,863	8,863	8,863	8,863	8,863
3	Transmission Margin		$ 471	$ 471	$ 471	$ 471	$ 471	$ 471	$ 471	$ 471	$ 471	$ 471
	General Service Transmission Margin = Volumes * Transmission Margin											
4	Transmission Margin $ / M3 consumed	0.01953										
5	Volume 10 ^3 M^3		4,159	12,477	20,795	24,954	24,954	24,954	24,954	24,954	24,954	24,954
6	Transmission Margin		$ 81	$ 244	$ 406	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487
7	Total Transmission Margin		$ 553	$ 715	$ 877	$ 959	$ 959	$ 959	$ 959	$ 959	$ 959	$ 959

Calculation of Revenue (Transmission Margins)

Owen Sound Reinforcement
InService Date: Nov-01-2020

Line	Project Year ($000's)		11	12	13	14	15	16	17	18	19	20
	M17 Methodology: Total CD * 12 * Transmission Margin											
1	Transmission Margin $/GJ/month	4.4310										
2	Contract Demand GJ/day/month		8,863	8,863	8,863	8,863	5,375	5,375	5,375	5,375	5,375	5,375
3	Transmission Margin		$ 471	$ 471	$ 471	$ 471	$ 286	$ 286	$ 286	$ 286	$ 286	$ 286
	General Service Transmission Margin = Volumes * Transmission Margin											
4	Transmission Margin $ / M3 consumed	0.01953										
5	Volume 10 ^3 M^3		24,954	24,954	24,954	24,954	24,954	24,954	24,954	24,954	24,954	24,954
6	Transmission Margin		$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487
7	Total Transmission Margin		$ 959	$ 959	$ 959	$ 959	$ 773	$ 773	$ 773	$ 773	$ 773	$ 773

Calculation of Revenue (Transmission Margins)

Owen Sound Reinforcement
InService Date: Nov-01-2020

Line	Project Year ($000's)		21	22	23	24	25	26	27	28	29	30
	M17 Methodology: Total CD * 12 * Transmission Margin											
1	Transmission Margin $/GJ/month	4.4310										
2	Contract Demand GJ/day/month		5,375	5,375	5,375	5,375	5,375	5,375	5,375	5,375	5,375	-
3	Transmission Margin		$ 286	$ 286	$ 286	$ 286	$ 286	$ 286	$ 286	$ 286	$ 286	$ -
	General Service Transmission Margin = Volumes * Transmission Margin											
4	Transmission Margin $ / M3 consumed	0.01953										
5	Volume 10 ^3 M^3		24,954	24,954	24,954	24,954	24,954	24,954	24,954	24,954	24,954	24,954
6	Transmission Margin		$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487
7	Total Transmission Margin		$ 773	$ 773	$ 773	$ 773	$ 773	$ 773	$ 773	$ 773	$ 773	$ 487

Calculation of Revenue (Transmission Margins)

Owen Sound Reinforcement
InService Date: Nov-01-2020

Line	Project Year ($000's)		31	32	33	34	35	36	37	38	39	40
	M17 Methodology: Total CD * 12 * Transmission Margin											
1	Transmission Margin $/GJ/month	4.4310										
2	Contract Demand GJ/day/month		-	-	-	-	-	-	-	-	-	-
3	Transmission Margin		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	General Service Transmission Margin = Volumes * Transmission Margin											
4	Transmission Margin $ / M3 consumed	0.01953										
5	Volume 10 ^3 M^3		24,954	24,954	24,954	24,954	24,954	24,954	24,954	24,954	24,954	24,954
6	Transmission Margin		$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487
7	Total Transmission Margin		$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487	$ 487

Stage 2 (Customer Fuel Savings) Data for Owen Sound Reinforcement

Assumptions

Line (a) (b) (c) (d)=(b)-(c)

Fuel Prices	$/m^3	Gas $/m^3	Diff $/m^3
Heating Oil	1.19	0.13	1.06
Number 6 Oil	0.53	0.13	0.40
Diesel	0.93	0.13	0.80
Propane	1.00	0.13	0.87
Electricity	0.89	0.13	0.76

Fuel Mix in the Event Gas is Not Available

	(e)	(f)=(d)*(e)
	General Service	
	Fuel Mix	Wt Ave Diff $/ M^3
Heating Oil	20%	0.212
Number 6 Oil	-	-
Diesel	-	-
Propane	50%	0.436
Electricity	30%	0.228
Total %	100%	
Weighted Savings $/m^3		0.876

Gas and alternative fuel prices are the average posted prices for the 12 month period ending December 2018
Prices in the table are before the added cost of Carbon.

Carbon Prices The cost of carbon is added to the price of each fuel in above table

	2019	2020	2021	2022	2023	2024	2025	
Cost per tonne	$20	$30	$40	$50	$50	$50	$50	
	2026	2027	2028	2029	2030	2031	2032	
Cost per tonne	$50	$50	$50	$50	$50	$50	$50	Future Yrs at cost $50

Calculation for Stage 2 Incremental Energy Demand

	Estimated Energy Demand with Pipeline Built
Equals	Potential annual energy demand (for Stage 2 calculations)
Times	Weighted Average Savings per M3
Equals	Annual Fuel Savings: Natural Gas Vs Alt Fuels

Discount Rate for Net Present Values 4.0%

Length of Term for Fuel Savings
Stage 2 estimated based on 20 years and 40 years

Present Value of Customer Fuel Savings
For conservatism, the NPV is assessed over 20 years with sensitivity at 40 years

Figures in $ Millions	20 Years	40 Years
General Service Fuel Savings	269	405

NPV Fuel Savings Range from $269 million over 20 yrs to $405 million over 40 yrs

Owen Sound Reinforcement
Economic Benefits from Infrastructure Spending

Figures in $ Millions

Line No	Description	Capex Spend Out of Country (a)	Capex Spend within Ontario (b)	Capex Spend within Canada Excluding Ontario (c)	Capex Total * (d)= sum (a-c)	
1	Proposed Facilities	$ 1	$ 54	$ 6	$ 60.1	
2						
3	% of Total Spend	1%	89%	9%	100%	Line 1 /Total Line 1 Col (d)
4						
5	GDP					
6	GDP Factor		1.14			
7	GDP Impact $ Millions		$ 61			Line 1 * Line 6
8						
9	Employment (Jobs)					
10	Jobs Factor		16.7			
11	Jobs Created		894			Line 1 * Line 10
12						
13	Taxes Paid by Enbridge Gas					
14	Property Tax		$ 4			Source: NPV DCF
15	Provincial Income Tax		$ 6			Source: NPV DCF
16	Total Provincial Taxes		$ 10			
17	Federal Income Tax		$ 4			Source: NPV DCF
18	Total Taxes Paid		$ 14			
19						
20	Total Value to Ontario					
21	GDP Impact $ Millions		$ 61			Line 7
22	Total Provincial Taxes		$ 10			Line 16
23	NPV Total Value to Ontario		$ 71			

* excludes indirect overheads

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

On p. 10, paragraph 22 of its reply evidence, Enbridge states that the “perspective, drivers and objectives” of ConEd’s benefit-cost analysis (BCA) framework for IRP projects “are not entirely applicable to natural gas IRP for Enbridge Gas in Ontario.”

a. What does Enbridge interpret to be the ConEd BCA “perspective”?
b. What aspects of the ConEd BCA “perspective” are applicable to Enbridge and Ontario?
c. What aspects of the ConEd BCA “perspective” are not applicable to Enbridge and Ontario? Please explain in detail why they are not applicable.
d. What does Enbridge interpret to be the “drivers” underpinning the ConEd BCA framework? Please list and describe all such drivers.
e. Which of the “drivers” underpinning the ConEd BCA framework does Enbridge consider to be applicable in Ontario?
f. Which of the “drivers” underpinning the ConEd BCA framework does Enbridge consider not applicable in Ontario? Please explain in detail, for each such non-applicable driver identified, why it is not applicable to Enbridge and Ontario.
g. What does Enbridge interpret to be the “objectives” underpinning the ConEd BCA framework? Please list and describe all such objectives.
h. Which of the “objectives” underpinning the ConEd BCA framework does Enbridge consider to be applicable in Ontario?
i. Which of the “objectives” underpinning the ConEd BCA framework does Enbridge consider not applicable in Ontario? Please explain in detail, for each such non-applicable objective identified, why it is not applicable to Enbridge and Ontario.

Response

a) - c)
There are two notable differences between ConEd and Enbridge Gas which impact the perspective of the two utilities:

- First, ConEd is a utility that offers electricity and natural gas distribution services whereas Enbridge Gas only offers natural gas distribution services. In the event ConEd implements an IRPA and customers switch from natural gas to electricity, ConEd is somewhat indifferent from a revenue and return perspective. If Enbridge Gas customers switch fuels, Enbridge Gas receives less revenue resulting higher rates for the remaining natural gas customers.

- Second, ConEd's service territory is located in a geographic area where it is difficult to deliver incremental volumes of natural gas to meet growing energy needs due to upstream transmission and downstream distribution system constraints. Enbridge Gas's service territory, by contrast, has access to large quantities of natural gas supply through many upstream transmission systems which are not similarly constrained and does not experience similar downstream distribution system constraints. Further, in the event that Enbridge Gas's customers require incremental natural gas volumes on short notice, such services can normally be contracted albeit at prices that reflect the market value for such services.

d) - i)
The drivers and objectives for ConEd include the policy context for New York State including the existence of the electricity Non-Wires Alternative framework and related Cost-Benefit Analysis handbook as well as the announcement of moratoria on new customer natural gas connections in certain jurisdictions within New York State. Although well in progress, Enbridge Gas is not building off an existing set of rules or an IRP Framework for electricity in Ontario. In addition, Enbridge Gas is not in a position where it must call moratoria on new customer connections in parts of the province.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

On p. 10, paragraph 23 of its reply evidence, Enbridge states that "Forcing alignment where it may not be appropriate between natural gas planning policy frameworks should be avoided."

a. Please explain the conditions under which "it may not be appropriate" to have alignment between gas planning frameworks?
b. Would Enbridge consider it appropriate to use the DCF+ test to assess the merits of investing in renewable natural gas (outside of the context of a non-pipe solution)? If not, why not?

Response

The referenced statement from Enbridge Gas's Reply Evidence, was made in the context of the ConEd BCA. Importantly, the preceding paragraph states:[1]

> "Both Guidehouse and EFG highlight that additional system impacts should be considered, beyond DCF analysis, when assessing the cost-effectiveness of IRPAs and facility alternatives. Both point to the ConEd BCA as an example for the OEB to consider when establishing an IRP Framework for Enbridge Gas. While the ConEd BCA lays out a framework for calculating the benefits and costs of IRP projects in New York, its perspective, drivers and objectives are not entirely applicable to natural gas IRP for Enbridge Gas in Ontario.
>
> Enbridge Gas supports a reasonable and practical approach to leverage existing and reliable methodologies as a base and to direct, as part of the IRP Framework for Enbridge Gas, that additional system impacts be considered when comparing IRPAs to facility alternatives. It is important to preserve symmetry of benefits and costs, and when comparing to real and direct costs incurred for a facility investment it is also important to ensure that estimates of other benefits and costs are reasonable and supported by quantifiable data. Forcing alignment where it may not be appropriate between natural gas planning policy frameworks should be avoided."

[1] Reply Evidence, Exhibit C p. 10.

a) It is important to understand the differences and similarities between the markets in New York State and Ontario when considering any type of alignment in IRP Frameworks. As noted by ICF in the recently updated jurisdictional review report the following factors are the main drivers for NPS in New York State and may not be the same in Ontario:[2]

- The high natural gas and power distribution infrastructure costs, particularly in Downstate New York (New York City and Long Island), which makes the economics of both non-wires solutions (NWS) and NPS better than the economics of NWS and NPS in other jurisdictions.

- A high percentage of residential and commercial demand, which has reduced the load factor of natural gas demand in New York State relative to jurisdictions with higher percentage of industrial demand, including Ontario. The peaky nature of natural gas demand in the state improves the economics of many of the forms of NPS.

- A unique and challenging situation related to continuing demand growth as New Yorkers switch from using heating oil to cleaner burning natural gas and the difficulties associated with building new pipeline capacity to serve natural gas demand growth, particularly in Downstate New York.

- The presence of joint natural gas and electric utilities that may have a higher degree of comfort with certain NPS options, such as gas-to-electricity conversion.

- Clear, consistent top-down policy direction from the New York State government related to transitioning to a decarbonized economy and prioritizing DSM and other demand-side options as alternatives to investments in new pipeline capacity.

- An extensive precedence with distributed energy resources (DERs) used to alleviate local electricity distribution system constraints (i.e. non-wire solutions (NWS)).

These conditions and factors indicate why it may not be appropriate to have alignment between gas planning frameworks in New York State and Ontario.

b) Enbridge Gas is unclear as to the context of this question as it appears to be asking about RNG outside of the context of an IRPA. If GEC is asking whether Enbridge

[2] IRP Jurisdictional Review Report, Exhibit B Appendix A, p. 4.

Gas would apply its proposed DCF+ test to the assessment of RNG related IRPA(s) relative to comparable baseline facilities then the answer is yes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

On pp. 11-12, paragraph 27 of its reply evidence, Enbridge states that the "The Board should be cautious to not simply accept the principles and magnitudes established for cost/benefits set out in the ConEd BCA as they may not reflect Ontario's market and regulatory realities." Enbridge goes on to identify three key differences: (1) that peaking services are the marginal source of supply for ConEd and that Enbridge "does not rely upon peaking services to comparable extent"; (2) that ConEd is a dual fuel utility; and (3) that Enbridge "owns and operates ex-franchise natural gas transmission and storage assets."

a. Why would different levels of reliance on peaking services affect the cost-effectiveness test (not the inputs to the test, but the test framework itself) used to assess non-pipe alternatives?
b. Why would the fact that Enbridge is a single fuel utility affect the choice of cost-effectiveness test to assess the economic merits of non-pipe alternatives? Is the Company suggesting that the choice of cost-effectiveness test should be a function of what is best for utility shareholders rather than consumers? If not, how is the fact that Enbridge is a single-fuel utility relevant to the question of what is in the best interest of gas ratepayers?
c. Why would the fact that Enbridge owns ex-franchise transmission and storage assets affect the choice of cost-effectiveness test to assess the economic merits of non-pipe alternatives? How is that relevant to what is in the best interest of gas ratepayers?

Response

Preamble

The sentence referenced in Enbridge Gas's Reply Evidence is meant to point out that there are significant differences between ConEd and Enbridge Gas and that the Board should not simply adopt the ConEd BCA without understanding those similarities and differences between the BCA and Enbridge Gas' IRP Proposal (DCF/DCF+).

a) The cost-effectiveness test is not directly affected by the difference in the reliance on peaking services between ConEd and Enbridge Gas. However, ConEd's unique system constraints, which drive its reliance on peaking services from both a gas supply planning and IRP/NPA perspectives, are not comparable to Enbridge Gas's system or Ontario's natural gas systems and market. Accordingly, Enbridge Gas does not consider peaking supply to be appropriate to meet long-term gas supply requirements because of their short-term nature and increased risk profile as they do not contain renewal rights. Please see the response at Exhibit.I.STAFF.16 for additional discussion of the nature of peaking services.

b) Please see the response at Exhibit.I.GEC.2.

c) The fact that Enbridge Gas owns and operates major transmission pipelines and underground storage facilities (which transport and store volumes of natural gas on behalf of ex-franchise customers in-part) may not directly affect the cost effectiveness test when comparing facility builds and IRPAs. However, similar to the response at part a), the unregulated assets owned and operated by Enbridge Gas play a significant role in Ontario and downstream markets uniquely connecting Ontario's and Enbridge Gas's natural gas system and markets to multiple sources of supply at various points, enabling Enbridge Gas to avoid the system constraints experienced by ConEd. Those constraints are some of the fundamental drivers which have shaped ConEd's IRP strategy and resulting BCA handbook. Further, these assets may be needed in some manner to support Enbridge Gas's investments in IRPAs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

On p. 15, paragraph 32 of its reply evidence, Enbridge states that in the context of "natural gas facilities planning where decisions to advance or delay projects are based on regularly updated growth projections" a planning committee modelled on Vermont' System Planning Committee "may prove overly cumbersome to navigate given the complexities of system design and planning."

a. Is Enbridge suggesting that the context in which "decisions to advance or delay projects are based on regularly updated growth projections" is different for gas facilities planning than for electric facilities planning? If so, please explain why? Isn't the planning for electric facilities also based on load growth projections that also change over time?
b. Is Enbridge suggesting that such a committee would be more cumbersome for gas planning than for electric planning? If so, why? What specifically would make it more cumbersome for gas?
c. What is Enbridge's understanding or assumption regarding the role that the Vermont System Planning Committee plays in developing load forecasts upon which transmission and/or distribution system investment decisions are made?
d. What is Enbridge's understanding or assumption regarding the role of the Vermont System Planning Committee in delving into the transmission and/or distribution system design?

Response

a) Enbridge Gas is not indicating that the context in which decisions to advance or delay projects based on regularly updated growth projections is different for natural gas facilities planning than for electricity facilities planning. Rather, Enbridge Gas recognizes that the complexities of Enbridge Gas's system design far surpass those of the electricity system in Vermont and thus do not lend themselves to a stakeholder model similar to Vermont's System Planning Committee ("VSPC"). Further, such a model could lead to excessive administrative costs being borne by ratepayers and could cause excessive delays in decision making around resolution of identified system constraints and customer needs, increasing the risk to ratepayers and the Company alike. Further, based on the information found in the most recent Vermont Gas Integrated Resource Plan,[1] the natural gas utility in Vermont does not utilize the VSPC model. Instead, the stakeholder model that Vermont Gas currently utilizes is very similar to the IRPA Project Geographically-Specific Stakeholder Engagement described in Component 3 of Enbridge Gas's proposed stakeholder model.[2]

b) The VSPC includes voting memberships made up of grid operators, ISO, distributors and the public. This model does not reflect the environment in Ontario where the natural gas system is operated by Enbridge Gas who is both the transmission operator and the distributor. Enbridge Gas has put forward an Ontario focused stakeholder engagement model that takes into account the vast geographic differences as well as diverse populations that are impacted by the natural gas system. Enbridge Gas's proposed model is similar to the IESO stakeholder model which has evolved in recent years in response to a cycle of continuous improvement, informed by government policy and the OEB, and is used to engage with stakeholders across a similarly complex energy system.

c) & d)
Enbridge Gas has made no assumptions regarding the role that the VSPC plays in developing load forecasts and influencing system design. Enbridge Gas has reviewed the VSPC model from a purely theoretical viewpoint recognizing that a stakeholder model that is used to plan and make electric investment decisions for a state with a population of less than 650,000 people may not be transferable to a Province with over 14.5 million people and natural gas and electricity systems that are vastly larger and more complex.

[1] http://www.vermontgas.com/wp-content/uploads/2021/01/2021-01-15-VGS-Integrated-Resource-Plan-including-Attachments-00306267-2xE4196.pdf
[2] Exhibit B, Additional Evidence, pp. 41-42

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

On pp. 17-18, paragraph 37 of its reply evidence, Enbridge states that "screening of virtually all projects identified in the asset management plan…is not reasonably possible without dedicating exponentially increased resources to such work and without incurring substantial incremental administrative costs."

a. What is Enbridge's best estimate of the annual cost it currently incurs to develop its asset management plan? Please provide a breakdown of those costs by task, including load forecasting, engineering assessments, management and any other relevant cost categories.
b. What is Enbridge's best estimate of the annual cost of project screening that it would incur annually under its proposed screening process? Please describe the basis for the estimate and provide all assumptions and calculations used to develop the estimate. Also, please indicate whether the extent to which this is an additional cost over and above what is provided in response to part "a" of this question for development of the Company's asset management plan.
c. What is Enbridge's best estimate of the annual cost of project screening that it would incur annually if it had to screen "virtually all projects identified in the asset management plan"? Please describe the basis for the estimate and provide all assumptions and calculations used to develop the estimate. Also, please indicate whether the extent to which this is an additional cost over and above what is provided in response to part "a" of this question for development of the Company's asset management plan.
d. How does Enbridge define "screening" in answering these questions? What level of analysis does it assume would be necessary?
e. How would the answer to part "c" of this question change if only projects with a cost greater than each of the following thresholds were screened:
    i. $2 million
    ii. $5 million
    iii. $10 million

Response

a) Enbridge Gas does not track costs in a way that would make it possible to determine an annual cost to develop its Asset Management Plan ("AMP"). Costs are incurred in various departments to support the various aspects of the Core Asset Management Process as outlined in the AMP Section 4.2. The comments in the paragraphs below are limited to the processes surrounding the identification and development of larger transmission and distribution pipeline reinforcement needs.

Needs Identification
In the Needs Identification stage, areas that require reinforcement to meet the needs of existing and anticipated customers and loads are evaluated by the Distribution and Transmission system design departments. In some cases, there are various facility alternatives that can be considered to meet these needs.

Investment Development
The Investment Development stage includes market evaluation, identification and analysis of alternatives, cost estimating, and the development of an economic or value assessment. This work is done in various functional, regional and centralized planning groups as well as in the economic and risk management functions where the value related to the investment alternatives is established.

Portfolio Optimization
The Portfolio Optimization stage is led by the Asset Management team. They compile a portfolio of investments that deliver the highest value within a capital constraint. The portfolio of investments is then shared with a wide number of stakeholders to confirm that risks and opportunities are addressed appropriately, and to ensure that there are sufficient resources to deliver the portfolio of work as specified in the plan.

Portfolio Delivery
The Portfolio Delivery stage involves the planning and execution of the investments in the Asset Management Plan. Regional and centralized planning groups as well as field operations are involved in delivering these activities.

Enbridge Gas anticipates that all of the activities described above would require additional capacity and that there would be further development needed to understand various IRPA's and where they could be effectively deployed, preparation of regulatory documentation to proceed with IRPA's, and efforts to monitor and report IRPA's.

b) c) & e)
At this very preliminary stage, in the absence of an IRP Framework for Enbridge Gas, it is difficult to say with certainty exactly how its processes will ultimately change and what additional resources will be required at what time to support IRP. However, Enbridge Gas is undertaking a review of how its IRP Proposal can be integrated into existing planning process. Please see Exhibit I.OSEA.1 c) for an explanation of this review. It is expected that this review will provide the Company with a more refined estimate of the costs to fully assess IRPAs. In the interim, Enbridge Gas estimates that it will need roughly 12 to 15 additional full-time equivalents to integrate IRP into its planning processes, complete the incremental stakeholdering, assess identified system constraints for IRPA(s), and complete necessary IRP Monitoring and Reporting. To review virtually all projects in the Asset Management Plan may require several incremental full-time equivalents in addition to the 12 to 15 estimated above, for which the costs would provide ratepayers little to perhaps no additional benefits. For information on how Enbridge Gas proposes to track and seek recovery of costs, please see the response at Exhibit I.APPrO.6.

d) Please see Enbridge Gas's Additional Evidence at Exhibit B, pages 15 to16 and 19 to 20, for Enbridge Gas's proposals regarding IRPA screening.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

On p. 18, paragraph 38 of its reply evidence, Enbridge appears to suggest that allowing for consideration of a broader range of potential IRPA projects could affect the nature and severity of outage risks. Why would that be the case? If the Company is forecasting needs 10 years into the future, couldn't the Company consider IRPAs with enough lead time to ensure that such consideration would not affect outage risks (i.e. such that consideration of IRPAs is started early enough to allow for deployment of a supply-side solution if the IRPA proves to be infeasible or uneconomic)? If not, why not?

Response

Outage risk is not purely driven by the timing of a need. See ICF's Jurisdictional Review Report at Exhibit B, Appendix A, Page 6:

> "The gas industry has a particularly low risk tolerance for outages because of the amount of manpower, time and cost required to restart their systems. There are also health and safety risks associated with customers not having access to space heating during the extended period of an outage during the middle of winter. It remains to be proven that geo-targeted DSM can result in peak period reductions that are as reliable as traditional pipes."

Enbridge Gas has proposed a broad range of IRPAs for the Board's consideration. Each of them is anticipated to impact the Company's processes and systems uniquely (especially compared to facility alternatives) and to require unique design, implementation and measurement/evaluation processes. Accordingly, Enbridge Gas expects that the lead times required to consider each IRPA and their ultimate impact to Enbridge Gas's systems will differ.

Outage risk is also not entirely mitigated by an extended forecast period. Even if Enbridge Gas acts immediately following the identification of a system constraint to assess IRPAs and seek OEB approval, it will still take considerable time to receive OEB approval to proceed with investment, to design, implement, potentially procure and monitor the performance of those investments. Further, Enbridge Gas expects that at least initially, evaluating the performance of IRPAs and seeking further OEB approval to adjust investments will also be time intensive. Each of these steps reduces the amount of remaining time before the underlying system constraint is realized.

Further, IRPAs have varying levels of risk associated with them, in part due to their differing amounts of reliance on human behavior to drive the effectiveness of the solution, regardless of how long the lead time is. Also, if the IRPA solution relies on the electricity system, that system is inherently less reliable than the natural gas system and subject to electrical system outages.

Please also see the response at Exhibit I.EP.6, for discussion of IRP/IRPA risk.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

On p. 22, at the end of paragraph 43 of its reply evidence, Enbridge states that volatility in carbon emissions policy since 2016 make it unreasonable to “speculate” on the cost of future carbon emissions and that uncertainty regarding future efficiency programming and the timeline for commercialization of new low carbon technologies make forecasting of carbon emission reductions “even more challenging and unreliable.”

a. Is Enbridge effectively saying that because forecasting the effects of future climate policy is difficult that forecasts of gas infrastructure investment needs should be based solely on current policies – i.e., assuming they will not change? If not, please explain.
b. Is Enbridge suggesting that analyses of the cost-effectiveness of non-pipe alternatives (relative to gas infrastructure investments) should be based solely on cost impacts under current policies, ignoring entirely – in cost-effectiveness calculations at least – how future changes in climate policies might alter cost-effectiveness? If not, please explain.
c. How does Enbridge propose to deal with uncertainty in the future cost forecasts of gas commodity, and of alternative fuel costs, and uncertainty of load in its IRPA analyses?

Response

a) Enbridge Gas does not forecast the effects of future climate policy where such future policy is not currently approved and set for future implementation. Enbridge Gas prudently develops its planning processes with consideration of OEB-approved methodologies and policies that are in place where impacts are known and quantifiable. This approach is done with the intention of mitigating unnecessary customer costs and risks where possible.

b) Enbridge Gas does not speculate on future changes in climate policies and their hypothetical impact to the analyses of IRPA(s), nor does the Company suggest that as these policies come to light there is no basis for further consideration or adjustment of IRP-related cost-effectiveness analyses.

Rather, Enbridge Gas supports Recommendation 4 of OEB Staff's expert evidence (the Guidehouse Report) set out at page 5 of the Guidehouse Report, which states:

> "It is recognized that the OEB considers provincial policy in its decision-making and is guided by statutory objectives (including a statutory objective related to natural gas to promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances). To the extent that the OEB is providing direction that may influence or be impacted by provincial environmental and policy goals, the OEB should clearly define their underlying assumptions regarding applicable provincial policy goals. For example, since future gas demand scenarios are likely to be impacted by energy and environmental policy, clearly defining underlying assumptions relating to provincial climate change policies and decarbonization targets will help to better inform gas network infrastructure decisions going forward."

c) The uncertainty referenced by GEC is not novel or unique to this proceeding. In fact, over the past two decades alone, natural gas commodity and alternative fuel prices (both spot and forecast) have fluctuated significantly due to forecasted natural gas supply shortfall risks driven by declines in traditional North American natural gas production followed by discovery and production of vast quantities of unconventional North American natural gas supply which became accessible due to advances in natural gas production technology. Further, as noted by GEC and set out in Enbridge Gas's Reply Evidence at Section 6.0, in 2016 the Ontario government put in place a Cap and Trade program which placed a price on emissions associated with volumes delivered by Enbridge Gas to ratepayers. That program was subsequently cancelled in 2018 and then replaced nearly a year later by a federal program in 2019. Throughout this period, despite the volatility in forecast prices and volumes, Enbridge Gas brought applications for Leave-to-Construct facilities to the Board for review and approval. As part of its review of those applications, the Board effectively and efficiently considered market conditions (both current and forecast) as well as the underlying Need for proposed facilities based on the best information available at the time. Enbridge Gas is proposing that the Board continue this best practice, by establishing an IRP Framework for Enbridge Gas that includes a means for assessing the cost-effectiveness of facility and non-facility alternatives based on the best available known and quantifiable costs, benefits and policies at the time that Enbridge Gas applies to the OEB for approval to invest in and to recover the costs associated with IRPAs.

Enbridge Gas's forecasting practices and proposal are similarly not unique to IRP. Enbridge Gas uniformly ascribes to the principles set out in its Reply Evidence at page 23:

"Only where the information concerning such policy and initiatives is known to be certain is it reasonable to forecast. Doing so based on a variety of hypothetical assumptions at a certain point in time [now as part of the development of an IRP Framework for Enbridge Gas], as recommended by EFG, would not produce information that is helpful or relevant to the Board in its review of future applications by Enbridge Gas for approvals related to either IRP or LTC investments as it would be entirely unreliable [and thus require adjustment in each such instance anyway]."

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

On pp. 22-23, paragraph 45 of its reply evidence, Enbridge states that "Despite the establishment of GHG emissions reductions targets by the governments of Ontario and Canada, the ultimate path to achieving such reductions remains uncertain…"

a. Would Enbridge agree that the only ways to substantially reduce carbon emissions otherwise resulting from consumption of natural gas are to (1) increase efficiency of gas use (i.e. reduce gas consumption); (2) electrify gas end uses (i.e. another way to reduce gas consumption); or (3) to switch from burning of fossil gas to burning of renewable gas, hydrogen or another GHG-neutral fuel? If not, please explain what other options exist and what portion of GHG emissions resulting from current gas consumption in homes and businesses they could potentially eliminate.
b. In its report, EFG made reference to a 2019 study by ICF for the American Gas Foundation which found that the marginal cost of renewable gas under optimistic assumptions about quantities available would be on the order of $55 (CDN) per Gj – or nearly 20 times the recent Henry Hub spot prices.
    i. Does the Company have any reason to believe that renewable gas could be produced in volumes comparable to current gas consumption levels at costs appreciably lower than $55 per Gj? In responding, please assume that all jurisdictions have the same goals – i.e., Enbridge could only access RNG in proportion to its current gas consumption levels relative to other jurisdictions in Canada and/or North America)?
    ii. If the answer to subpart (i) of this question is yes, at how much lower cost?
    iii. Please provide all references to support conclusions reached in response to this question.
c. What is Enbridge's best estimate of both the short-term and long-term price elasticity of demand for natural gas from customers in its service territory? Please specify the periods of time the Company assumes to be "short-term" and "long-term" in providing the answer. Also, please provide the basis for the response.

Response

a) Enbridge Gas agrees that GEC has identified some of the ways in which to reduce carbon emissions otherwise resulting from consumption of natural gas and that a combination of these approaches may work in collaboration with the other(s). In addition to options listed by GEC, Enbridge Gas has identified other measures that can support GHG reductions, which include:

   (4) atmospheric capture of CO_2 and conversion or sequestration through nature-based solutions (e.g., photosynthesis);

   (5) capture of emissions from combusted fuels at customer facilities and subsequent utilization or sequestration of CO_2 through man made equipment; and

   (6) atmospheric capture of CO_2 and utilization or sequestration through man-made equipment (e.g., direct air capture).

b) Enbridge Gas is not pursuing RNG as a specific IRPA as part of this proceeding. Furthermore, the ICF study for American Gas Foundation referenced may not be applicable as it is not Ontario focused nor does it necessarily represent the current government, regulatory or market conditions for RNG in Ontario or Canada.

c) The annual demand forecast for the EGD and Union rate zones are both developed using Board-approved methodologies. There are no different methodologies/models used for EGD and Union’s short- and long-term general service demand forecasts. Therefore, there is one set of price elasticity determined from those models.

   As discussed on page 31 and page 70 of Enbridge Gas’s 5 Year Gas Supply Plan (EB-2019-0137), gas demand is price-inelastic. A 10% price increase is estimated to reduce demand by approximately 0.3%* for the Union rate zones and 0.2% for the EGD rate zone.

   **Note, page 70 of the Plan states 0.03% price impact per 10% change in price; this should read 0.3%.*

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

On p. 25, paragraph 48 of its reply evidence, Enbridge states that its system infrastructure “will remain used and useful”, especially when considering “that development of RNG and hydrogen in Ontario and in many other jurisdictions is linked to maintaining high utilization of natural gas systems.”

a. Is Enbridge aware of any studies suggesting that the amount of RNG and/or hydrogen that could be produced in the future in Canada is as large as current Canadian natural gas consumption? Note: Enbridge may provide estimates of North American production potential relative to current North American gas consumption levels if it prefers.
b. If the answer to part “a” of this question is yes, please provide the forecast marginal cost (or market clearing price) for such levels of production.
c. Please provide Enbridge’s understanding of what proportion of the gas mix provided to end users can be hydrogen while ensuring the safe operation of current end use technologies, and please provide Enbridge’s understanding of any other limiting factors to hydrogen use such as hydrogen permeation in plastic piping, pipeline embrittlement etc.

Response

a) No, Enbridge Gas is not aware of such studies. However, the Company notes that since hydrogen may be derived from natural gas Enbridge expects the theoretical potential for hydrogen to be similar in magnitude to natural gas.

b) The Hydrogen Strategy for Canada estimates that by 2030, the cost of hydrogen produced from natural gas with carbon capture is expected to be in the range of $1 to $2/kg ($7 to $14/GJ) of hydrogen.[1]

c) The proportion of hydrogen that does not affect the safe operation of current natural gas end-use equipment varies according to each type of end-use and maintenance

[1] https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

of equipment. Where Enbridge Gas may consider expanding the distribution of hydrogen to its customers, it would undertake an Engineering Assessment Study, including an area specific customer equipment survey (as performed in the Low Carbon Energy Project - EB-2019-0294) to assess the appropriate levels of hydrogen blending in accordance with the specific end-use equipment encountered. Through the Low Carbon Energy Project, Enbridge Gas aims to better understand the proportion of hydrogen that may be distributed through our system to various types of customers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

On p. 3 of Appendix B of its reply evidence, Enbridge states that it has analyzed data from its Deep River study for the period between mid-February 2020 through October 2020. No further information is provided.

a. Please explain how the data were analyzed. For example, what questions was the analysis attempting to address and how was the analysis designed to address those questions.
b. Please provide the results of the analysis of the period described.

Response

a) Enbridge Gas has analyzed incomplete and preliminary hourly consumption data captured from the metering installed in the case study area. The case study was designed to inform the understanding of peak hour consumption impacts. The Company sought to further understand how individual customer demands on hourly intervals is reflected as gate station demands, and how individual metered consumption compares to estimated customer demand at the same temperature.

b) The analysis is currently incomplete. At such time that Enbridge Gas completes this analysis, the Company expects that it would make it available to the Board and intervenors.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, Exhibit ES-8 on p. ES-29:

a. Are the costs shown net of other benefits (other than the benefit of deferring a capital expenditure for infrastructure investment) such as the net present value (NPV) of avoided energy costs or avoided carbon taxes?
b. Please provide the graph net of such other benefits.

Response

a) Only the utility program costs are included in this exhibit. As such, the costs shown are not net of any other benefits.

b) It is not appropriate to consider any other costs or benefits in this exhibit. This exhibit is a natural gas DSM program cost supply curve that shows the utility cost per unit natural gas peak demand impact for a broad-based DSM program.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, Exhibits ES-9 through ES-12 (pp. ES-29 through ES-33):

a. What do the costs on the vertical axis represent? What are they the present value of?
b. In determining where the lines that define whether DSM is cost-effective, what cost-effectiveness test was used? Are other system benefits, such as avoided energy costs and avoided carbon taxes, treated as benefits (or negative costs)?

Response

a) The vertical axis represents the present values of DSM program costs and system reinforcement investment costs.

b) A cost-effectiveness test was not used for this comparison. Rather, these exhibits provide a graphical comparison of reinforcement investment costs and DSM program costs. Other benefits and costs were not considered as part of this comparison.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, on p. ES-34, ICF states that for the amount of peak demand reduction it estimates to be possible would only be enough to defer about 20% of Enbridge's planned facility investments.

a. Is 20% the fraction of infrastructure projects, infrastructure capacity additions or infrastructure investment costs? If it is 20% of infrastructure projects, please provide the percent of both (i) infrastructure capacity additions (which would put more weight on larger projects) and (ii) infrastructure investment costs (which would put more weight on more expensive projects).
b. Please provide a table with ICF's assumptions regarding the following for each efficiency measure considered:
    i. peak hour m3 savings;
    ii. peak day m3 savings;
    iii. annual m3 savings;
    iv. the ratio of peak hour to annual m3 savings; and
    v. the ratio of peak day to annual m3 savings.
c. Did ICF assess how much larger the 20% could be if gas demand response measures were also considered? If so, please provide that assessment.

Response

a) The 20% mentioned on p. ES-34 of the May 2018 IRP Study represents the approximate fraction of infrastructure capacity additions. More detail is provided on pages 137-138 of the May 2018 report and illustrated in Exhibit 93 on page 138.

   Table 1 below presents the share of planned facility investments with technical feasibility for deferral by (i) capacity, (ii) infrastructure investment costs, and (iii) number of projects.

Table 1

Share of planned facility investments with technical feasibility of deferral via targeted DSM

Share of planned facility investments by…	Enbridge	Union Gas
Capacity	14%	17%
Expenditures	41%	2%
# Projects	29%	12%

b) As described in detail in Section IV of ICF's May 2018 IRP Study and throughout ICF's 2016 OEB Conservation Potential Study (CPS),[1] ICF estimated the annual, peak day, and peak hour m^3 savings for over 150 energy efficiency measures. Savings estimates were based on the best available information, including the latest relevant OEB Technical Resource Manual (TRM) entries, and ICF modeling and analysis and they were also differentiated by region and sub-sector (e.g. offices, food retail, etc.) where appropriate. This included original building energy modeling to develop representative end use load profiles that differed by region and sub-sector and were calibrated to utility gate station data at an aggregate level, and the development of measure-level load profiles that were used to estimate peak day and peak hour impacts.

A significant amount of effort would be required in order to provide these detailed input assumptions as part of this proceeding. In addition, the fully disaggregated input assumptions were not provided to EGI as a direct deliverable related to the 2018 IRP Study. The data is proprietary to ICF and is considered to be a valuable business asset by ICF.

c) The impact of gas demand response ("DR") measures was not quantified as part of the May 2018 IRP Study. At the moment, the primary contributor of gas DR is interruptible rates and that is already built into Enbridge Gas's forecasts and utility practices. Natural gas DR measures were not quantified as part of the May 2018 IRP Study due to the limited experience with natural gas DR measures across North America and the limited capacity of each measure to defer natural gas peak demand

[1] ICF, Natural Gas Conservation Potential Study: Final Report, completed on behalf of the Ontario Energy Board (OEB), July 7, 2016, available at: https://secure-web.cisco.com/1fAQnjSGQiO55uFiznH7ahmlrZ-XNFo-QBWp2CO-ugAQbGZM78H8nKUoXITWd1xdFv2EvEavZ7nM7L22uEeJBGwsG4BiuTeVbR5RaiYCCCemoohOvYTvpeZ5gdpgG3SP_fXDBuEmBU0jlbnP8NK-vKv0Cq-USy6D0j3G_42OiBljQP1dbrT8UsEF4RExLOMxs3nIWu--QWzQe5ZnFWTm0G1a58VQKUKAy1OltKQorxQv7FXxT_OcvUzktLUXYyfqS2dtzdsqkPvEqKHRE2Bd5dW_DWDkOJAUVCg43m0J0Psy9N_XjWeZ7AjYWWkzjIpPo/https%3A%2F%2Fwww.oeb.ca%2Foeb%2F_Documents%2FEB-2015-0117%2FICF_Report_Gas_Conservation_Potential_Study.pdf

for multiple hours or days. Although the technology for natural gas DR measures has continued to evolve in recent years, there has been limited progress to address these concerns.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, on p. 38 ICF states that it found "peak hour swing over average peak day consumption" to be 8-9% in New England and 11-13% in northern Illinois.

a. Please define what is meant by "peak hour swing". What do the percentages represent (what is in the numerator and what is in the denominator of the calculatins)?
b. Given the results presented, wouldn't a 1.1 multiplier be more appropriate than the 1.2 multiplier being used?
c. Would use of a 1.1 multiplier instead of a 1.2 multiplier result in a smaller estimate of peak demand reduction required? If not, why not?

Response

a) "Peak hour swing" is defined as the ratio of hourly swing (numerator) to total daily gas consumption on a peak day (denominator), where hourly swing is the sum of hourly demand levels that are above average daily demand during a winter peak day. This is different from the ratio of peak hour load to peak day load (peak hour load factor). ICF's 2014 study for EISPC also assessed the "peak hour load factor" for these regions, which was defined as the peak day's average hourly gas consumption (numerator) divided by the peak day's hourly peak gas consumption (denominator). Please see the response at Exhibit I. GEC.15 b), for additional discussion on this point.

b) No. ICF's 2014 study for EISPC estimated that the peak hour swing of 8-9% in New England and 11-13% in Northern Illinois would correspond to an estimated peak hour load factor of 0.82-0.85 for the New England region and 0.76 for the North Illinois region. This suggests that the peak hour consumption is 1.18-1.22 times higher than the peak day's hourly gas consumption in the New England region and 1.32 higher in the North Illinois region.

The appropriate ratio to convert average hourly flow on design day to peak hour flow for design day conditions is very jurisdiction-specific and is more challenging to estimate at the level of individual communities and/or infrastructure projects. For instance, the ratio is highly dependent on the distribution of customers, with the presence of industrial customers who typically have relatively flat load profiles throughout the day tending to decrease the peak hour swing and peak hour load factor in any given area.

c) The analysis in ICF's May 2018 report would not be impacted by this change since it did not make use of a ratio to estimate natural gas peak hour demand based on peak day demand. Rather, the analysis employed a combination of hourly gate station data from Enbridge Gas and calibrated building modeling to generate representative peak day profiles.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, on p. 58 ICF states that "A general residential and commercial load profile for a representative design day was created by scaling the general load profile for a typical cold winter day based on the Gas Utilities' design day HDDs." On p. 66, in Exhibit 16, ICF presents the aggregate residential and commercial load profiles for a typical cold day and representative design day.

a. When ICF scaled the general load profile to a design day profile, was the scaling linear based on HDDs? If not, how was it performed?
b. Was the scaling applied only to the space heating portions of residential and commercial loads or to the entire loads? If the latter, please explain why non-space heating loads would need to be scaled up based on HDDs.
c. How were the utility design day HDDs developed? What were they based on?
d. What city is the proxy for Enbridge Central region shown in Exhibit 16?

Response

a) Yes, linear scaling was used to scale the space heating component of the load profile for the "typical" cold day to generate a load profile for the representative design day. For example, the space heating demand for Hour 1 of the "typical" cold day (~2,500 thousand m^3) would be scaled by a factor of 1.22 (42.6 HDD / 34.9 HDD) to estimate the design day space heating demand (3,052 thousand m^3).

b) Yes, the scaling was only applied to the space heating portions of residential and commercial loads.

c) Enbridge Gas's 5-Year Gas Supply Plan, which was filed in May 2019 as part of EB-2019-0137, provides details on the approach that was used to develop design HDD values in each service territory. The development of the design day HDDs for the legacy Union service territories is discussed in Section 11.2 of the 5-Year Gas

Supply Plan (pages 72-75), while the approach for the legacy EGD service territories is discussed in Section 4.2 (pages. 34 to 37).

d) Toronto (Pearson Airport) was used as the proxy for the Enbridge Gas Central Delivery Area (CDA). As noted on page 28 of Enbridge Gas's 5-Year Gas Supply Plan, Enbridge Gas's CDA includes "the GTA (Greater Toronto Area), the Niagara Peninsula, Barrie, Midland, Peterborough, and the surrounding area".

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, p. 74, please provide the "hours use factors" developed for each end use and each region.

Response

Please see the response at Exhibit I.GEC.14 b).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, Exhibit 92 on p. 137:

a. Why is the top of the graph at $2500? Is the last 5% of Union and last 10% of Enbridge more expensive than that? If so, please provide a graph that show the actual costs for without a cut-off for the most expensive projects.
b. Please provide a similar graph where the horizontal axis is expressed in percent of facility expansion investment by dollar of investment (rather than by capacity as in the current graph).
c. Please provide the underlying data for the graph as presented.

Response

a) Yes, Exhibit 92 on page 137 of ICF's initial May 2018 report was cut off at $2,500 because including a number of the low capacity, high cost projects would have rendered the graph more difficult to read. In addition, larger and more expensive projects tend to have more uncertainty in their costs. See Figure 1 below for a version of the chart with all projects, as well as a version of the same chart on a log scale at Figure 2.[1]

[1] While creating these updated exhibits, an error was uncovered related to the Enbridge Gas data. This issue has been corrected in the exhibits below.

Figure 1

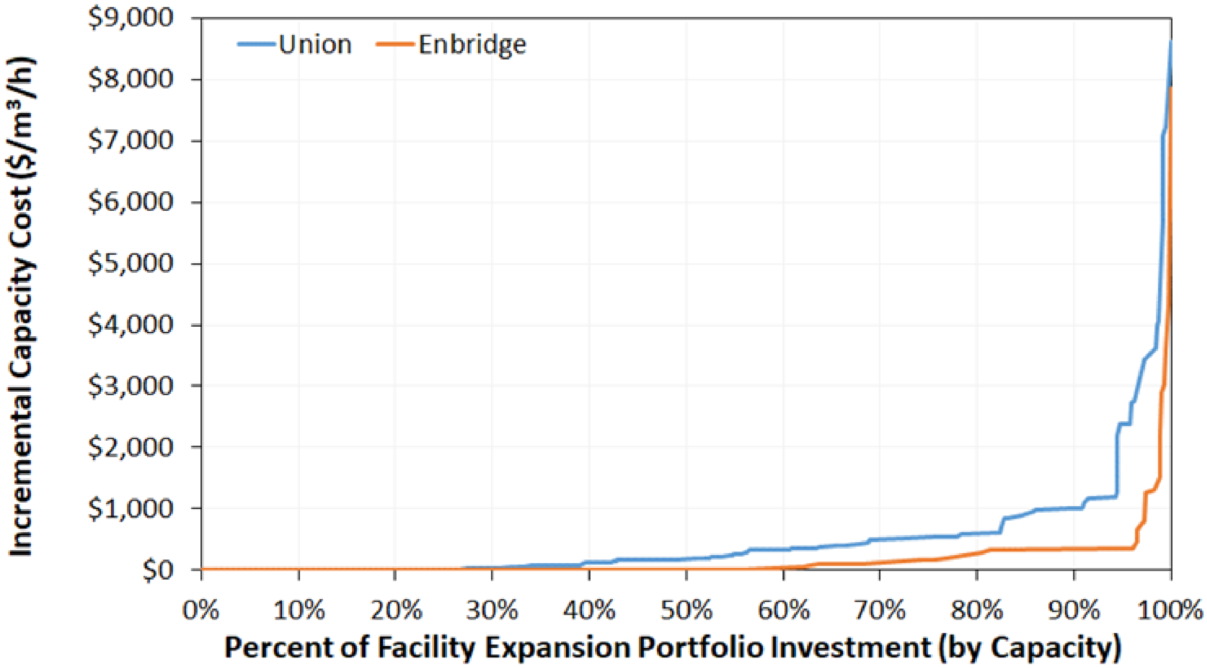
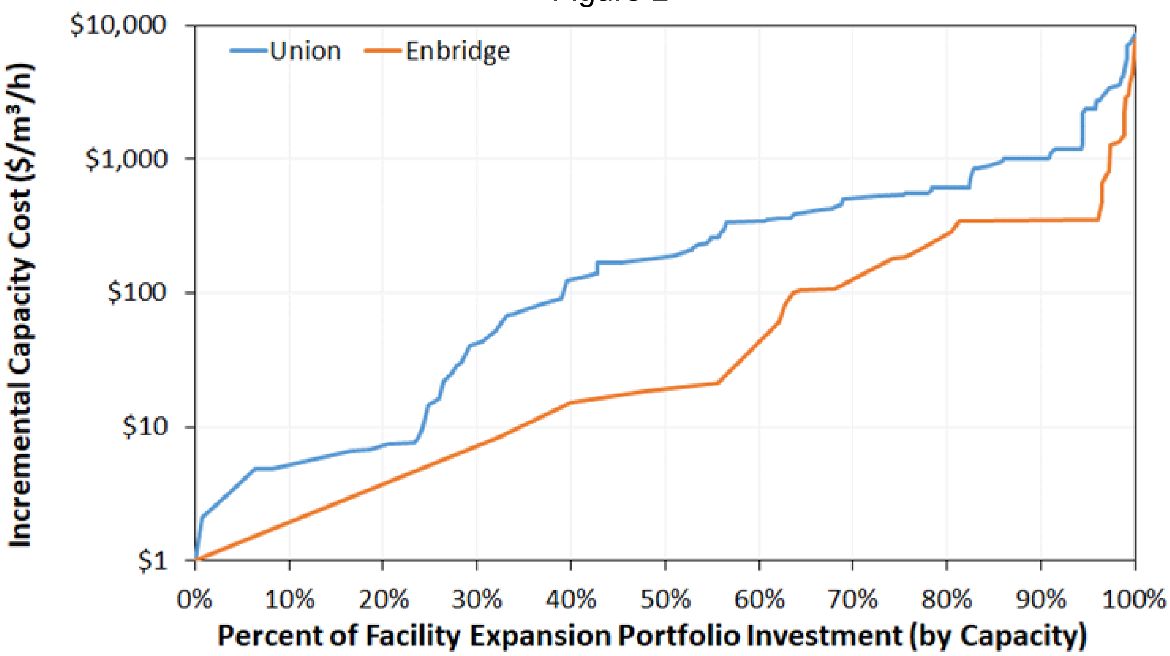


Figure 2



b) Please see Figure 3 below for the requested graph, as well as the same graph on a log scale at Figure 4.

Figure 3

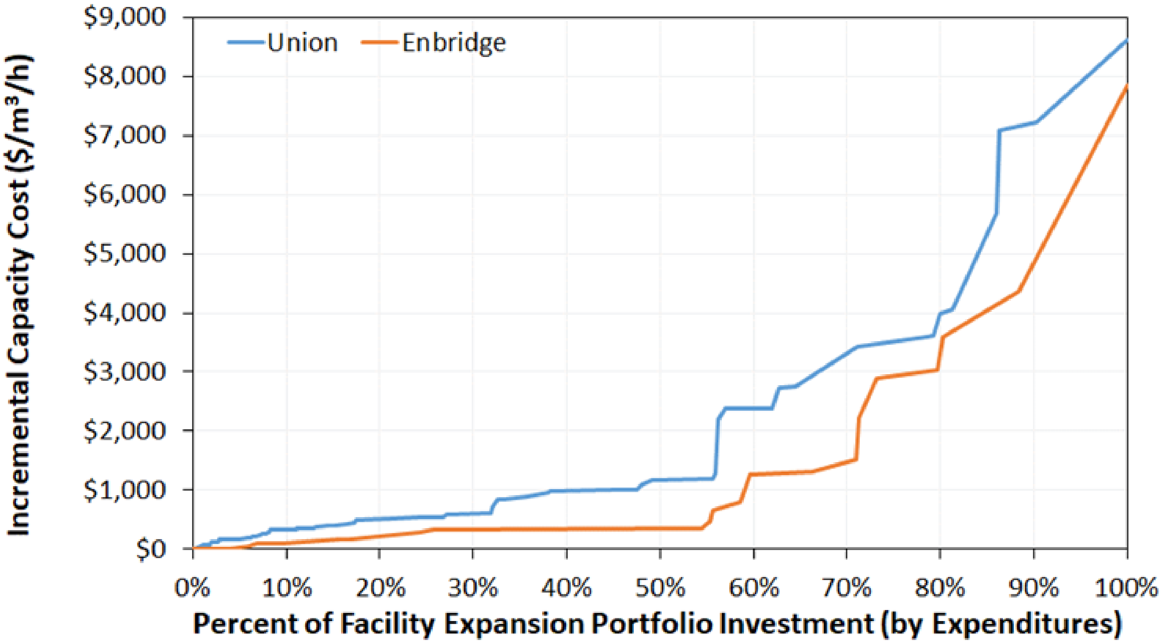
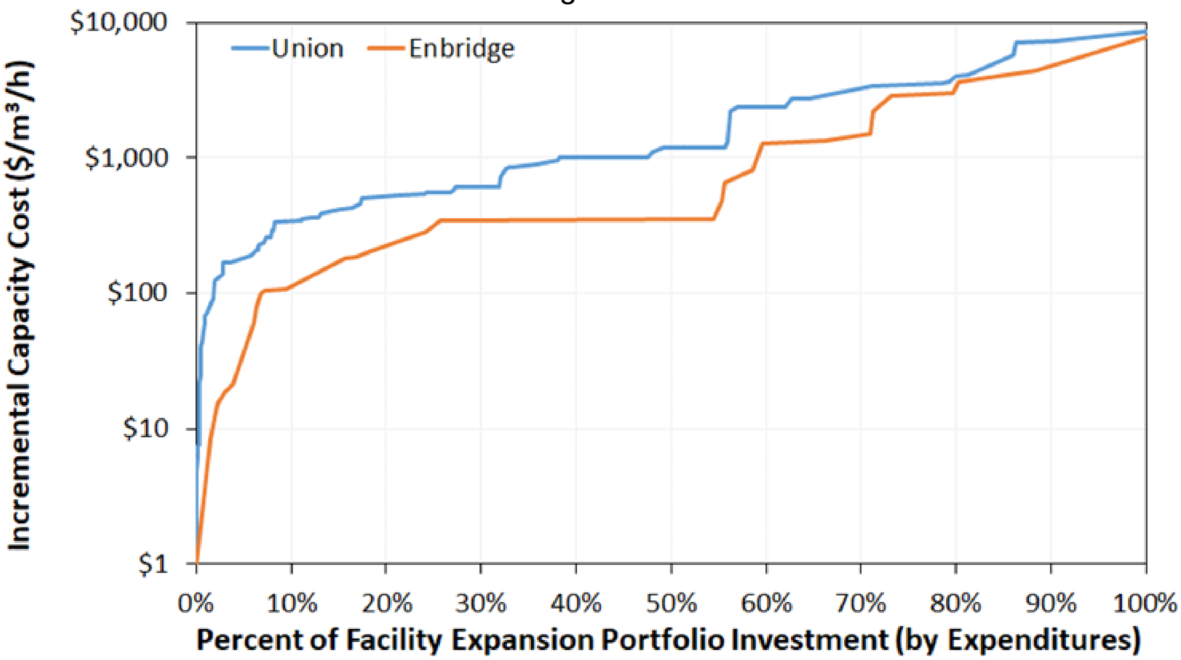
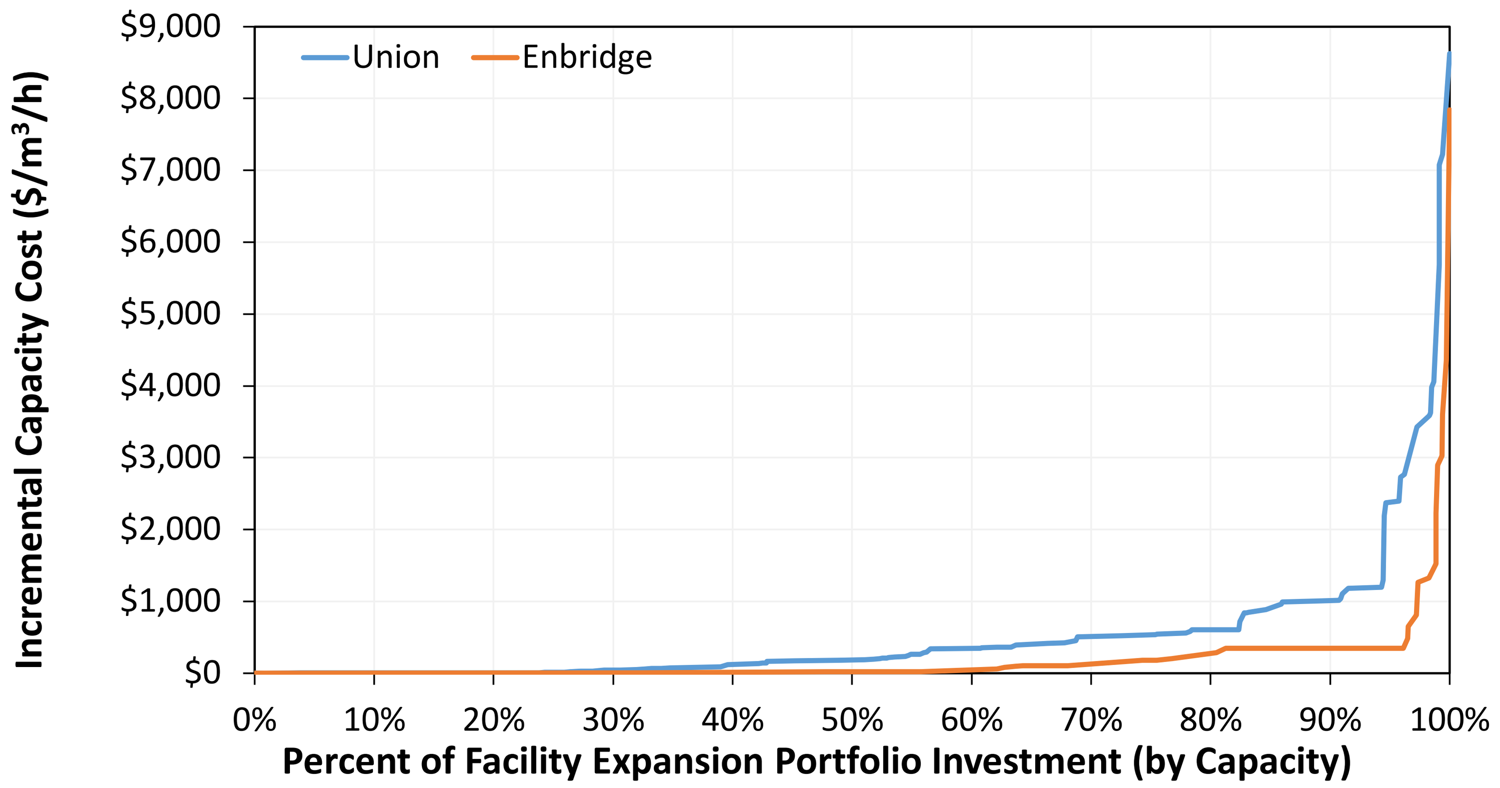
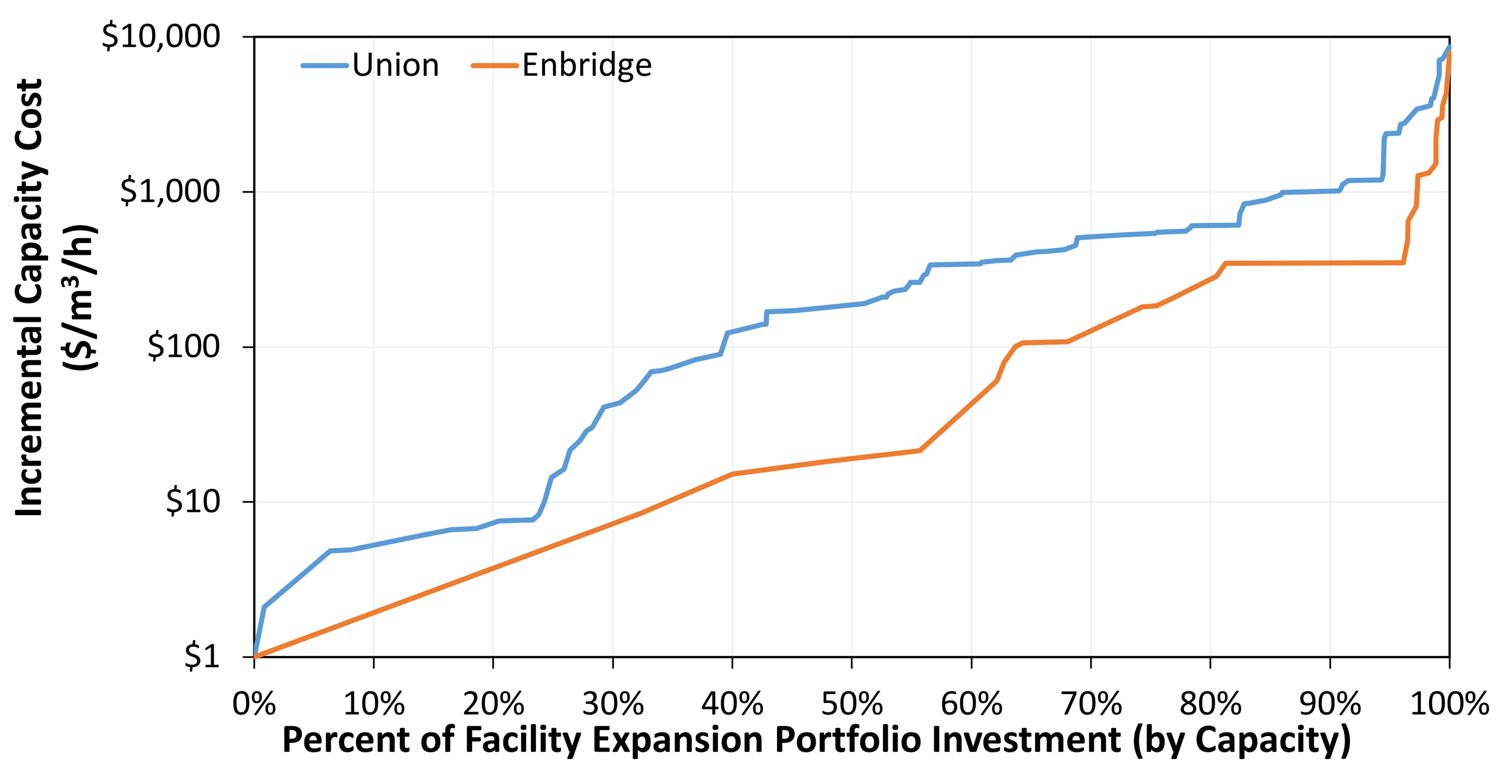


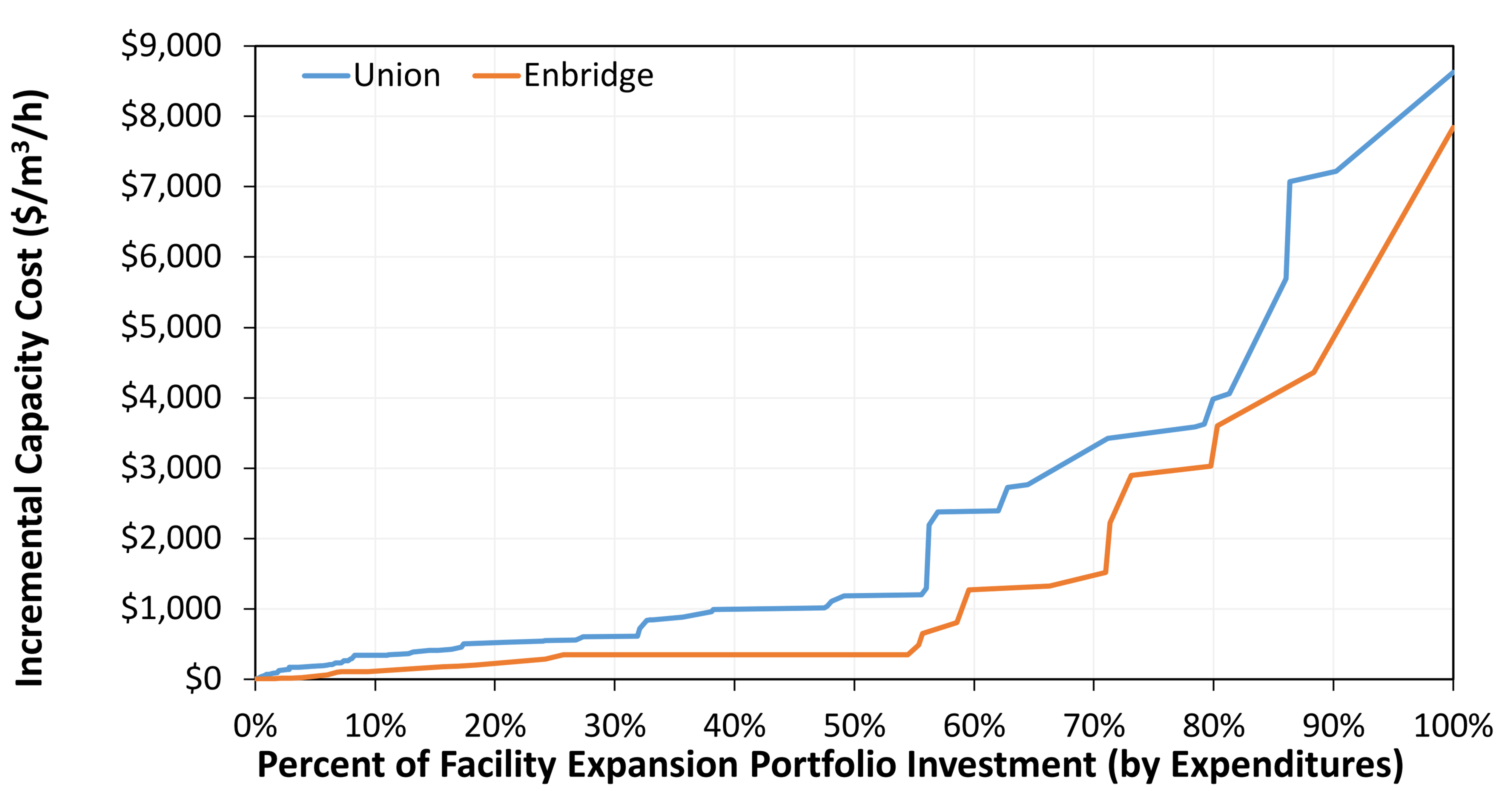
Figure 4



c) Please see the response at Exhibit I.GEC.18 Attachment 1.





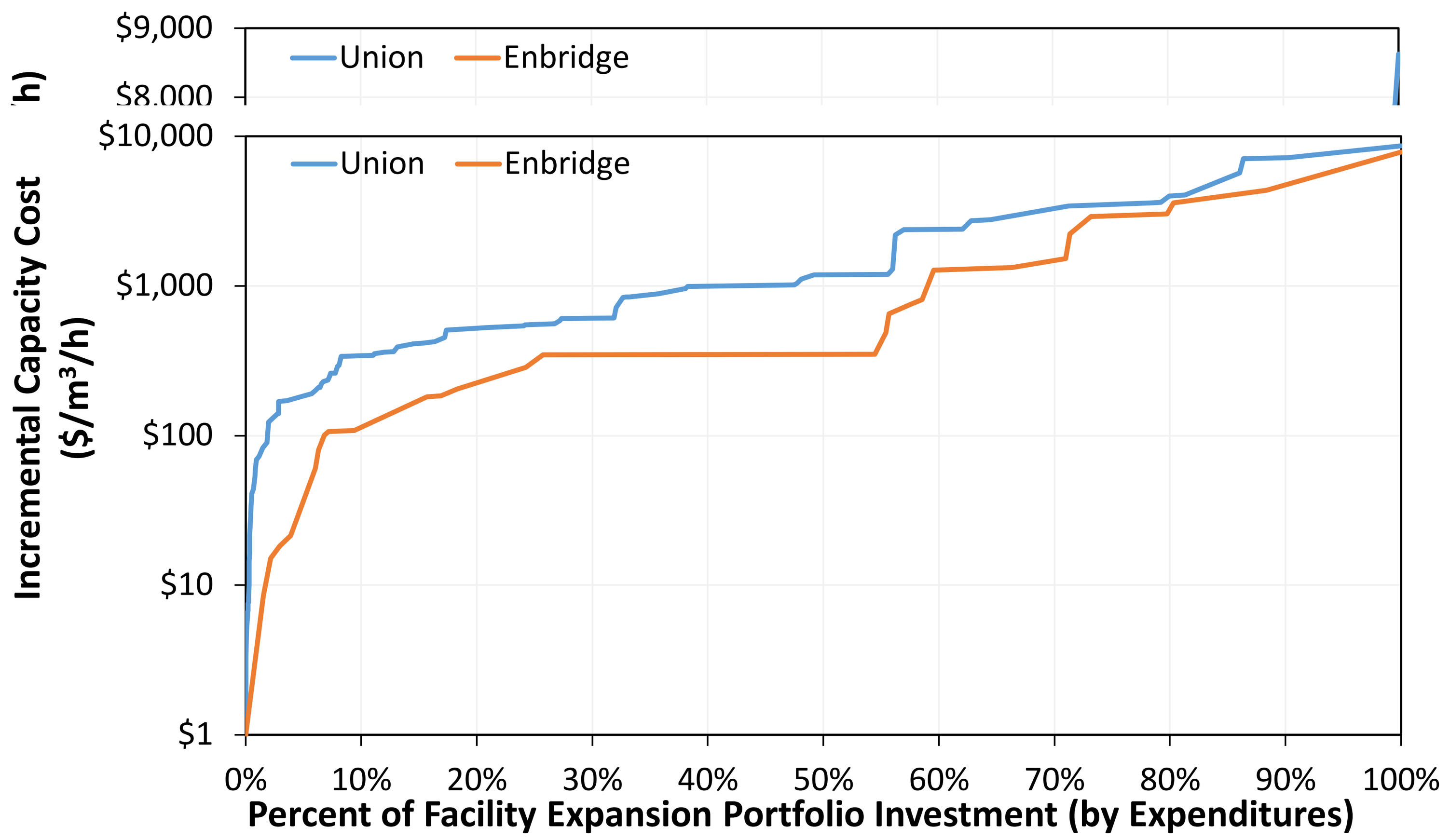


Enbridge

Project #	Capacity Addition (m3/h)	Cumulative Capacity Addition (%)	Cost per Added Capacity ($ per m3/h)	Cumulative Costs	Cumulative Costs (%)	Cumulative Capacity (m3/h)
0	0	0.0%	$1.00	$0	0.0%	0
1	249,002	32.3%	$8.43	$2,100,000	1.5%	249,002
2	59,223	40.0%	$15.20	$3,000,000	2.2%	308,225
3	60,271	47.8%	$18.25	$4,100,000	2.9%	368,496
4	60,491	55.7%	$21.49	$5,400,000	3.9%	428,988
5	49,535	62.1%	$60.56	$8,400,000	6.0%	478,523
6	5,001	62.8%	$79.98	$8,800,000	6.3%	483,524
7	6,973	63.7%	$100.39	$9,500,000	6.8%	490,497
8	4,712	64.3%	$106.11	$10,000,000	7.2%	495,209
9	28,752	68.0%	$107.82	$13,100,000	9.4%	523,961
10	48,287	74.3%	$180.74	$21,827,565	15.7%	572,248
11	9,259	75.5%	$183.61	$23,527,565	16.9%	581,507
12	9,755	76.8%	$205.02	$25,527,565	18.3%	591,262
13	28,713	80.5%	$285.58	$33,727,565	24.2%	619,975
14	6,040	81.3%	$347.70	$35,827,565	25.7%	626,015
15	114,372	96.1%	$349.74	$75,827,565	54.5%	740,387
16	2,680	96.5%	$485.10	$77,127,565	55.4%	743,066
17	612	96.5%	$653.20	$77,527,565	55.7%	743,679
18	3,442	97.0%	$755.29	$80,127,565	57.6%	747,121
19	1,731	97.2%	$808.92	$81,527,565	58.6%	748,852
20	1,103	97.4%	$1,269.43	$82,927,565	59.6%	749,955
21	7,102	98.3%	$1,323.56	$92,327,565	66.3%	757,057
22	4,271	98.8%	$1,521.84	$98,827,565	71.0%	761,328
23	225	98.9%	$2,226.10	$99,327,565	71.3%	761,553
24	863	99.0%	$2,896.81	$101,827,565	73.1%	762,416
25	3,040	99.4%	$3,025.84	$111,027,565	79.7%	765,456
26	222	99.4%	$3,601.12	$111,827,565	80.3%	765,678
27	2,567	99.7%	$4,362.94	$123,027,565	88.4%	768,245
28	2,066	100.0%	$7,842.93	$139,227,565	100.0%	770,311

Union

Project #	Capacity Addition (m3/h)	Cumulative Capacity Addition (%)	Cost per Added Capacity ($ per m3/h)	Cumulative Costs	Cumulative Costs (%)	Cumulative Capacity
0	0	0.0%	$1.00	$0	0.0%	0
1	3,817	0.8%	$2.10	$8,024	0.0%	3,817
2	13,920	3.8%	$3.30	$54,024	0.0%	17,737
3	11,634	6.3%	$4.83	$110,274	0.0%	29,371
4	8,162	8.1%	$4.90	$150,274	0.1%	37,533
5	29,969	14.6%	$6.24	$337,274	0.1%	67,502
6	9,075	16.5%	$6.61	$397,274	0.2%	76,576
7	9,490	18.6%	$6.74	$461,274	0.2%	86,067
8	8,913	20.5%	$7.54	$528,474	0.2%	94,980
9	13,034	23.3%	$7.65	$628,224	0.3%	108,014
10	2,398	23.8%	$8.34	$648,224	0.3%	110,412
11	2,090	24.3%	$10.05	$669,224	0.3%	112,503
12	2,770	24.9%	$14.44	$709,224	0.3%	115,273
13	4,910	25.9%	$16.29	$789,224	0.3%	120,183
14	2,307	26.4%	$21.67	$839,224	0.3%	122,490
15	3,987	27.3%	$25.08	$939,224	0.4%	126,477
16	2,325	27.8%	$28.61	$1,005,724	0.4%	128,802
17	2,307	28.3%	$30.34	$1,075,724	0.4%	131,109
18	4,352	29.2%	$40.96	$1,253,975	0.5%	135,461
19	6,418	30.6%	$43.63	$1,533,975	0.6%	141,880
20	6,418	32.0%	$52.55	$1,871,225	0.8%	148,298
21	3,062	32.7%	$60.74	$2,057,225	0.9%	151,360
22	2,466	33.2%	$69.00	$2,227,391	0.9%	153,827
23	3,817	34.0%	$70.16	$2,495,176	1.0%	157,644
24	3,397	34.7%	$72.98	$2,743,103	1.1%	161,041
25	10,022	36.9%	$82.84	$3,573,268	1.5%	171,062
26	9,785	39.0%	$89.94	$4,453,268	1.8%	180,847
27	2,713	39.6%	$122.56	$4,785,768	2.0%	183,560
28	12,041	42.2%	$137.44	$6,440,768	2.7%	195,601
29	1,426	42.5%	$139.89	$6,640,268	2.8%	197,028
30	1,426	42.8%	$140.24	$6,840,268	2.8%	198,454
31	192	42.9%	$168.39	$6,872,644	2.9%	198,646
32	10,545	45.1%	$170.70	$8,672,644	3.6%	209,191
33	16,947	48.8%	$182.92	$11,772,644	4.9%	226,138
34	10,496	51.0%	$190.54	$13,772,644	5.7%	236,634
35	3,610	51.8%	$199.43	$14,492,644	6.0%	240,244
36	2,325	52.3%	$206.47	$14,972,644	6.2%	242,569
37	1,051	52.6%	$209.39	$15,192,644	6.3%	243,620
38	1,305	52.8%	$209.69	$15,466,191	6.4%	244,924
39	192	52.9%	$210.49	$15,506,661	6.4%	245,117
40	764	53.0%	$220.64	$15,675,285	6.5%	245,881
41	2,219	53.5%	$228.67	$16,182,785	6.7%	248,100
42	4,250	54.4%	$235.27	$17,182,785	7.1%	252,351
43	1,374	54.7%	$248.88	$17,524,785	7.3%	253,725
44	764	54.9%	$261.70	$17,724,785	7.4%	254,489
45	3,667	55.7%	$261.81	$18,684,785	7.8%	258,156
46	1,475	56.0%	$289.89	$19,112,285	7.9%	259,631
47	1,054	56.2%	$294.30	$19,422,598	8.1%	260,685
48	1,468	56.6%	$337.64	$19,918,098	8.3%	262,153
49	19,325	60.7%	$344.62	$26,578,098	11.0%	281,478
50	477	60.8%	$351.70	$26,745,870	11.1%	281,955
51	6,007	62.1%	$359.58	$28,905,870	12.0%	287,962
52	5,379	63.3%	$362.50	$30,855,870	12.8%	293,341
53	2,032	63.7%	$389.94	$31,648,186	13.1%	295,373
54	8,161	65.5%	$411.41	$35,005,742	14.5%	303,534
55	4,130	66.4%	$412.85	$36,710,742	15.2%	307,664
56	6,362	67.7%	$424.77	$39,413,255	16.4%	314,026
57	4,575	68.7%	$453.84	$41,489,606	17.2%	318,601
58	656	68.9%	$506.81	$41,822,106	17.4%	319,257
59	16,938	72.5%	$525.45	$50,722,106	21.1%	336,195
60	13,250	75.4%	$538.81	$57,861,530	24.0%	349,446
61	660	75.5%	$548.52	$58,223,530	24.2%	350,106
62	11,114	77.9%	$557.87	$64,423,530	26.8%	361,219
63	1,777	78.3%	$585.12	$65,463,530	27.2%	362,997
64	570	78.4%	$603.41	$65,807,477	27.3%	363,567
65	18,080	82.3%	$608.39	$76,807,477	31.9%	381,647
66	599	82.5%	$716.76	$77,236,879	32.1%	382,246
67	1,670	82.8%	$838.56	$78,636,879	32.7%	383,916
68	770	83.0%	$844.44	$79,286,879	32.9%	384,686
69	764	83.2%	$845.28	$79,932,879	33.2%	385,450
70	6,773	84.6%	$885.88	$85,932,879	35.7%	392,223
71	5,976	85.9%	$958.98	$91,663,986	38.1%	398,199
72	432	86.0%	$994.67	$92,093,388	38.2%	398,631
73	15,339	89.3%	$1,010.52	$107,593,388	44.7%	413,969
74	6,715	90.8%	$1,012.64	$114,393,388	47.5%	420,684



Enbridge

Project #	Capacity Addition (m3/h)	Cumulative Capacity Addition (%)	Cost per Added Capacity ($ per m3/h)	Cumulative Costs	Cumulative Costs (%)	Cumulative Capacity (m3/h)

Union

Project #	Capacity Addition (m3/h)	Cumulative Capacity Addition (%)	Cost per Added Capacity ($ per m3/h)	Cumulative Costs	Cumulative Costs (%)	Cumulative Capacity
75	516	90.9%	$1,039.98	$114,930,038	47.7%	421,200
76	770	91.0%	$1,106.62	$115,781,854	48.1%	421,970
77	2,183	91.5%	$1,181.70	$118,361,854	49.2%	424,153
78	12,944	94.3%	$1,197.45	$133,861,854	55.6%	437,098
79	764	94.5%	$1,292.78	$134,849,854	56.0%	437,862
80	241	94.5%	$2,193.92	$135,378,575	56.2%	438,103
81	736	94.7%	$2,374.44	$137,126,938	57.0%	438,839
82	5,117	95.8%	$2,392.61	$149,368,872	62.0%	443,956
83	660	95.9%	$2,727.46	$151,168,872	62.8%	444,616
84	1,476	96.2%	$2,765.03	$155,248,872	64.5%	446,091
85	4,712	97.2%	$3,427.38	$171,398,872	71.2%	450,803
86	4,876	98.3%	$3,589.11	$188,898,872	78.5%	455,679
87	496	98.4%	$3,627.01	$190,698,872	79.2%	456,175
88	452	98.5%	$3,981.43	$192,498,872	79.9%	456,628
89	798	98.7%	$4,061.08	$195,740,337	81.3%	457,426
90	2,003	99.1%	$5,691.60	$207,140,337	86.0%	459,429
91	111	99.1%	$7,076.52	$207,923,267	86.4%	459,539
92	1,295	99.4%	$7,222.81	$217,276,925	90.2%	460,834
93	2,724	100.0%	$8,626.41	$240,776,925	100.0%	463,559

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

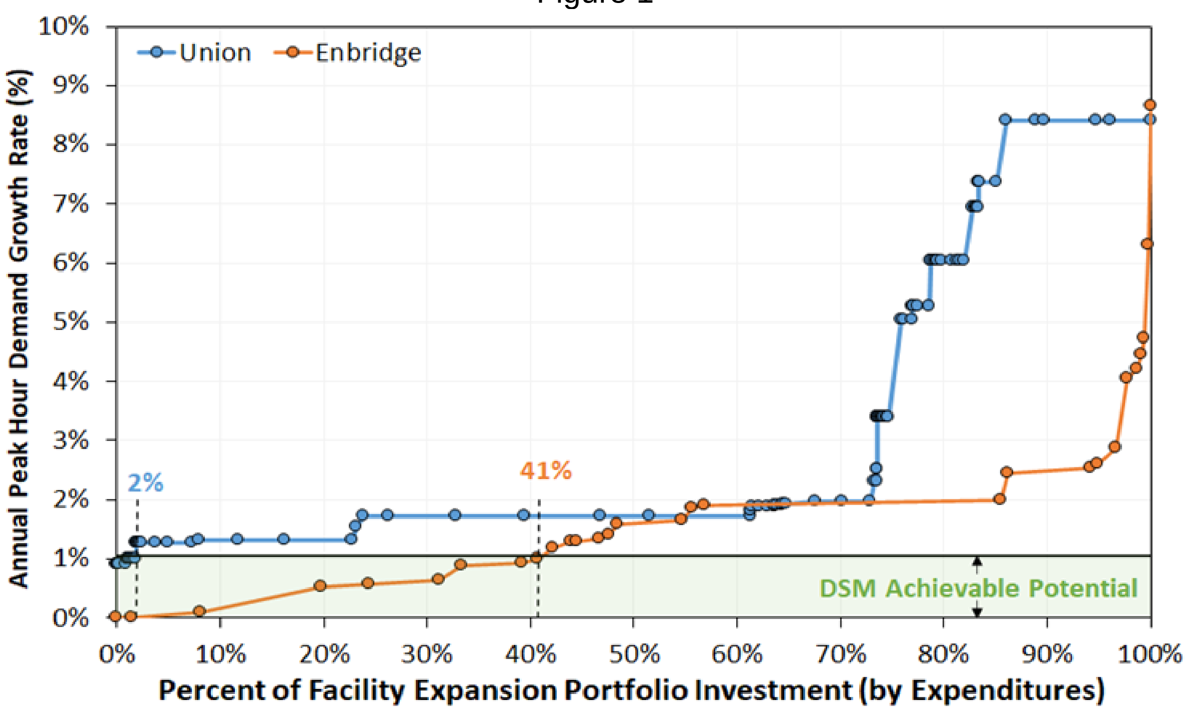
With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, Exhibit 93 on p. 138:

a. Please provide a similar graph where the horizontal axis is expressed as percent of facility expansion portfolio investment by dollars of investment (rather than by capacity as in the current graph)
b. Please provide the underlying data for the graph as presented.

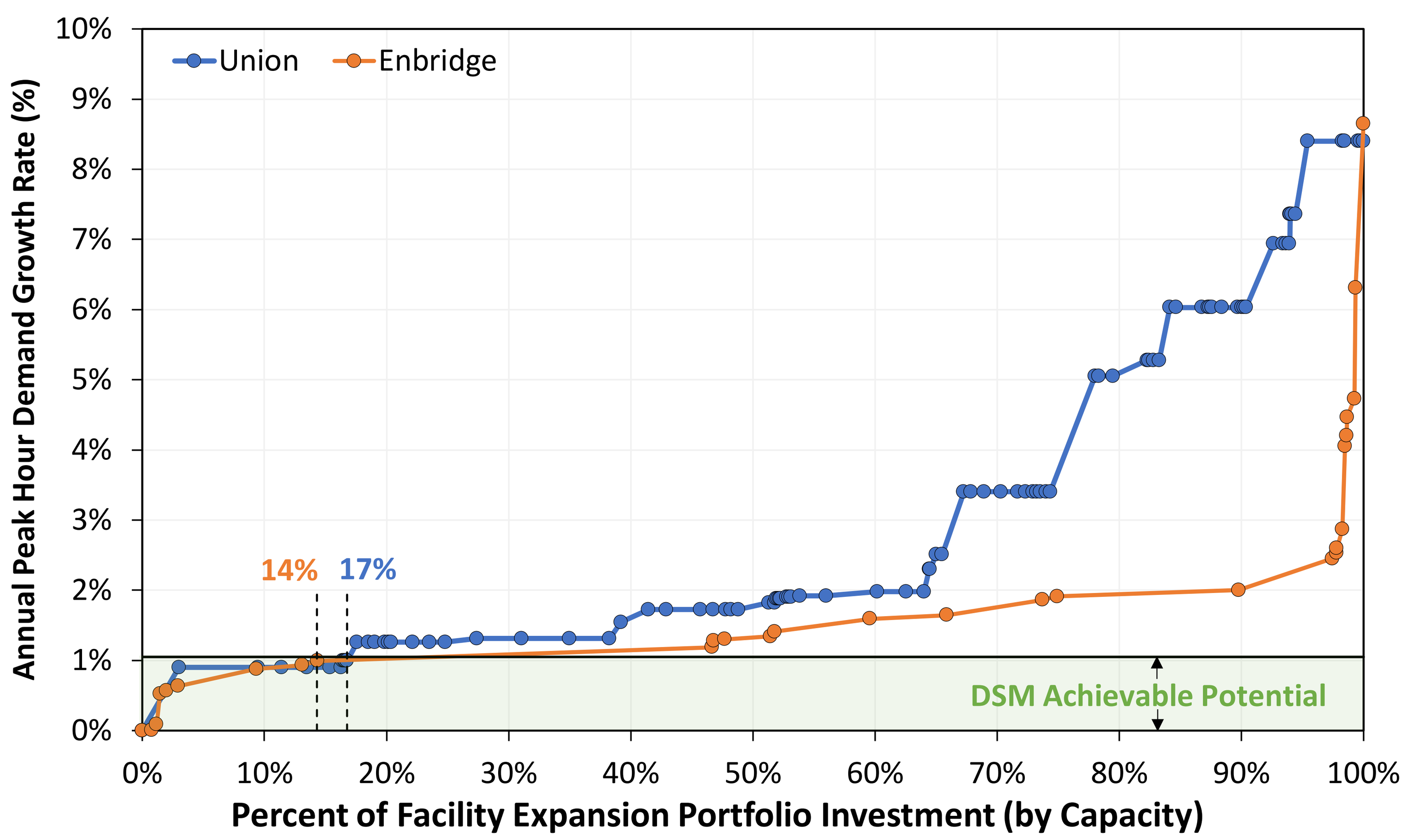
Response

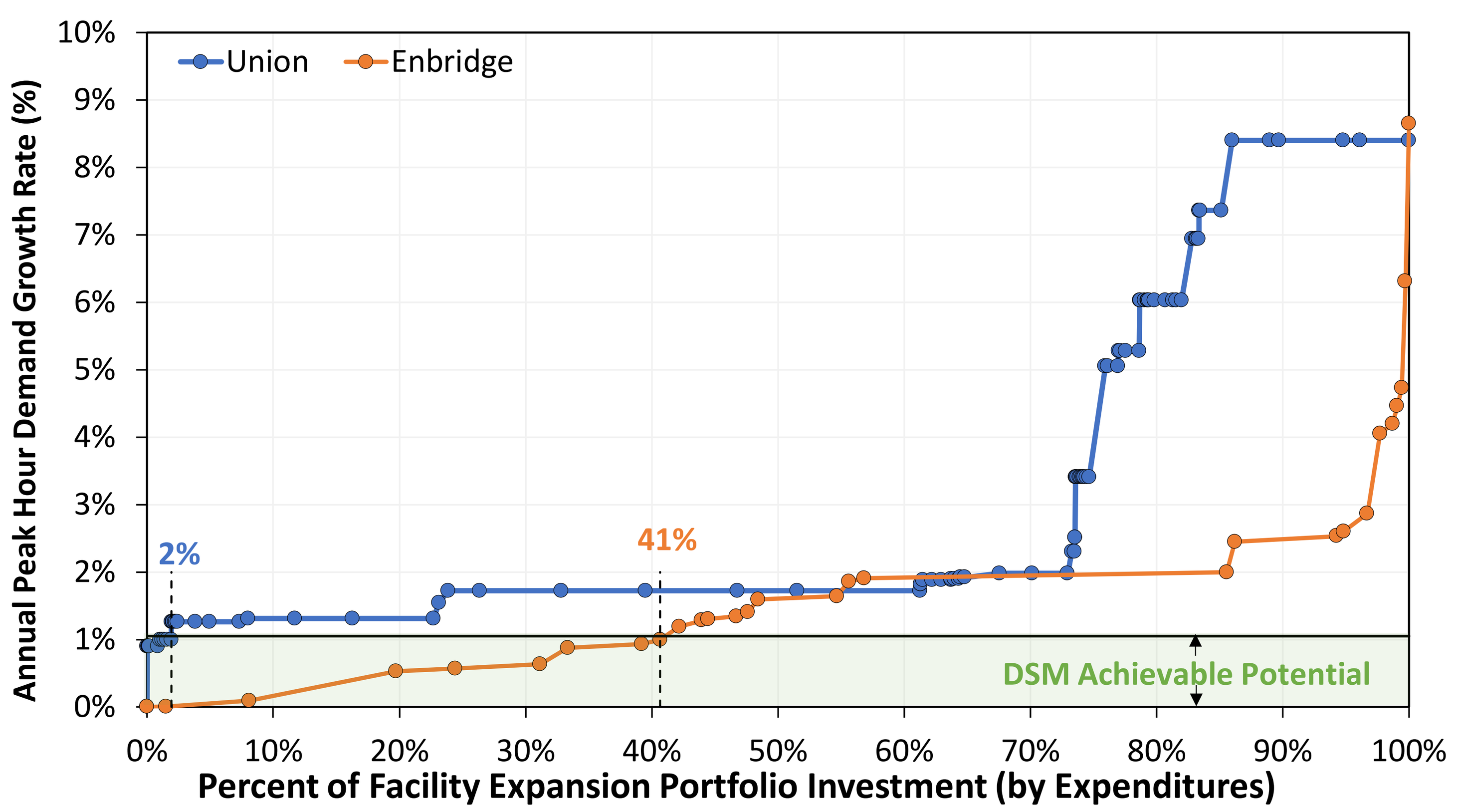
a) Please see Figure 1 below for the requested graph.

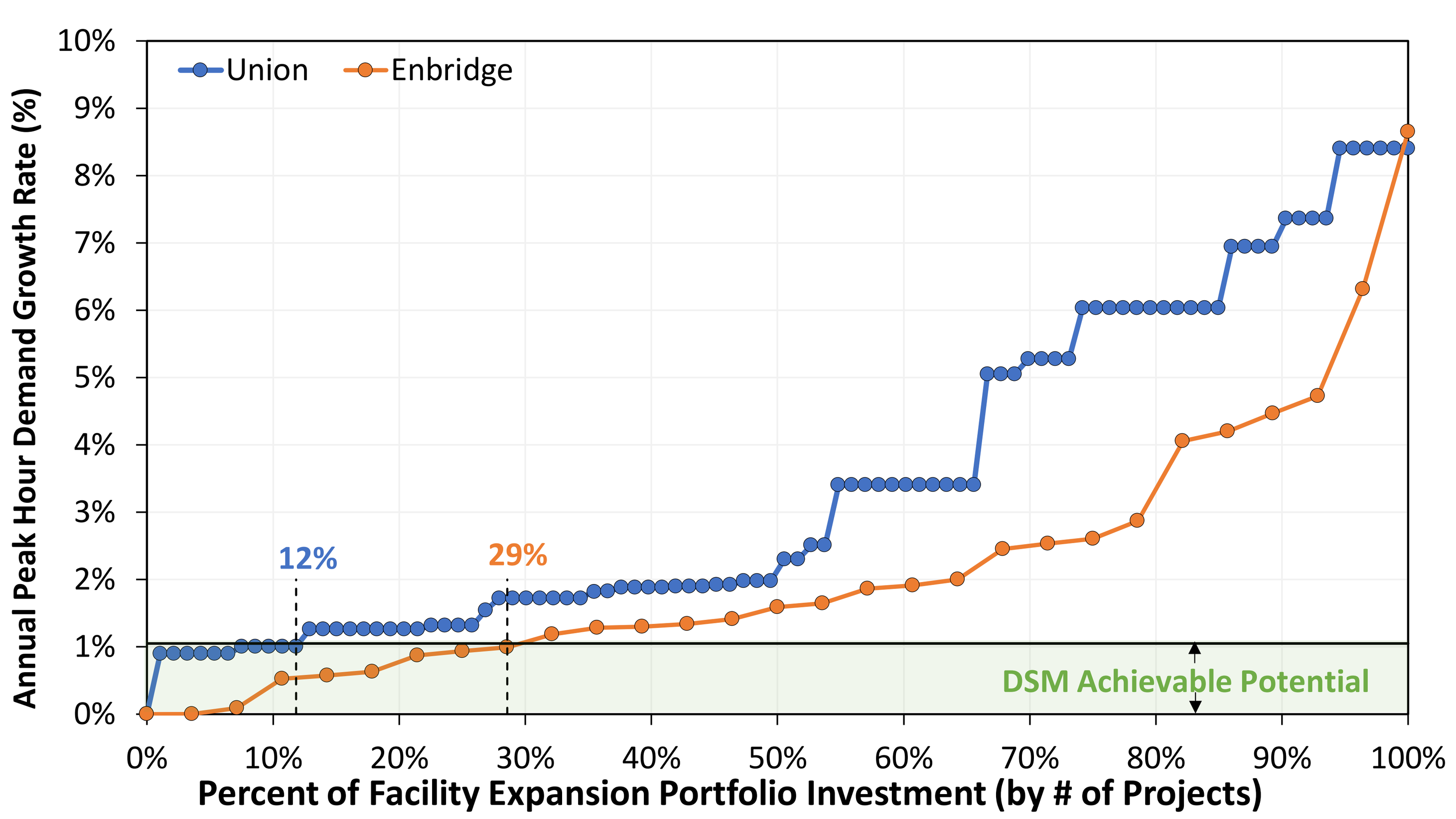
Figure 1



b) Please see the response at Exhibit I.GEC.19 Attachment 1.







DSM Achievable Potential Threshold Line

0.0%	1.1%
100.0%	1.1%
Enbridge	
14.3%	0.0%
14.3%	2.0%
Union	
16.8%	0.0%
16.8%	2.0%

Enbridge	
40.7%	0.0%
40.7%	2.0%
Union	
1.9%	0.0%
1.9%	2.0%

Enbridge	
28.6%	0.0%
28.6%	2.0%
Union	
11.8%	0.0%
11.8%	2.0%

Enbridge

Project #	Expected Customer Growth Rate (%/Yr)	Cumulative Capacity Addition (%)	Cumulative Costs (%)	Cumulative Share of Projects (%)
0	0.00%	0.0%	0.0%	0.0%
1	0.00%	0.8%	1.5%	3.6%
2	0.09%	1.2%	8.1%	7.1%
3	0.53%	1.4%	19.8%	10.7%
4	0.57%	2.0%	24.4%	14.3%
5	0.63%	2.9%	31.2%	17.9%
6	0.88%	9.4%	33.3%	21.4%
7	0.93%	13.1%	39.2%	25.0%
8	0.99%	14.3%	40.7%	28.6%
9	1.19%	46.7%	42.2%	32.1%
10	1.28%	46.8%	44.0%	35.7%
11	1.30%	47.7%	44.5%	39.3%
12	1.34%	51.4%	46.7%	42.9%
13	1.41%	51.8%	47.6%	46.4%
14	1.59%	59.6%	48.4%	50.0%
15	1.65%	65.9%	54.7%	53.6%
16	1.86%	73.7%	55.6%	57.1%
17	1.91%	74.9%	56.8%	60.7%
18	2.00%	89.8%	85.6%	64.3%
19	2.45%	97.5%	86.2%	67.9%
20	2.53%	97.8%	94.3%	71.4%
21	2.60%	97.8%	94.8%	75.0%
22	2.87%	98.3%	96.7%	78.6%
23	4.06%	98.5%	97.7%	82.1%
24	4.20%	98.6%	98.7%	85.7%
25	4.47%	98.7%	99.1%	89.3%
26	4.73%	99.3%	99.4%	92.9%
27	6.31%	99.4%	99.7%	96.4%
28	8.65%	100.0%	100.0%	100.0%

Union

Project #	Expected Customer Growth Rate (%/Yr)	Cumulative Capacity Addition (%)	Cumulative Costs (%)	Cumulative Share of Projects (%)
0	0.0%	0.0%	0.0%	0.0%
1	0.9%	3.0%	0.0%	1.1%
2	0.9%	9.5%	0.1%	2.2%
3	0.9%	11.4%	0.1%	3.2%
4	0.9%	13.5%	0.1%	4.3%
5	0.9%	15.4%	0.2%	5.4%
6	0.9%	16.3%	0.9%	6.5%
7	1.0%	16.4%	1.0%	7.5%
8	1.0%	16.5%	1.2%	8.6%
9	1.0%	16.6%	1.4%	9.7%
10	1.0%	16.7%	1.6%	10.8%
11	1.0%	16.8%	1.9%	11.8%
12	1.3%	17.6%	1.9%	12.9%
13	1.3%	18.5%	2.0%	14.0%
14	1.3%	19.1%	2.1%	15.1%
15	1.3%	19.9%	2.2%	16.1%
16	1.3%	20.2%	2.3%	17.2%
17	1.3%	20.4%	2.4%	18.3%
18	1.3%	22.2%	3.8%	19.4%
19	1.3%	23.5%	5.0%	20.4%
20	1.3%	24.8%	7.3%	21.5%
21	1.3%	27.4%	8.0%	22.6%
22	1.3%	31.1%	11.7%	23.7%
23	1.3%	35.0%	16.3%	24.7%
24	1.3%	38.3%	22.7%	25.8%
25	1.5%	39.2%	23.1%	26.9%
26	1.7%	41.5%	23.9%	28.0%
27	1.7%	42.9%	26.4%	29.0%
28	1.7%	45.7%	32.8%	30.1%
29	1.7%	46.7%	39.5%	31.2%
30	1.7%	47.8%	46.8%	32.3%
31	1.7%	48.2%	51.5%	33.3%
32	1.7%	48.8%	61.3%	34.4%
33	1.8%	51.3%	61.3%	35.5%
34	1.8%	51.8%	61.3%	36.6%
35	1.9%	51.9%	61.5%	37.6%
36	1.9%	52.1%	62.2%	38.7%
37	1.9%	52.2%	63.0%	39.8%
38	1.9%	52.3%	63.7%	40.9%
39	1.9%	52.8%	63.7%	41.9%
40	1.9%	52.9%	64.0%	43.0%
41	1.9%	53.1%	64.3%	44.1%
42	1.9%	53.8%	64.4%	45.2%
43	1.9%	56.0%	64.8%	46.2%
44	2.0%	60.2%	67.6%	47.3%
45	2.0%	62.6%	70.1%	48.4%
46	2.0%	64.0%	73.0%	49.5%
47	2.3%	64.5%	73.3%	50.5%
48	2.3%	64.5%	73.5%	51.6%
49	2.5%	65.0%	73.5%	52.7%
50	2.5%	65.5%	73.6%	53.8%
51	3.4%	67.3%	73.6%	54.8%
52	3.4%	67.9%	73.6%	55.9%
53	3.4%	68.9%	73.6%	57.0%
54	3.4%	70.3%	73.7%	58.1%
55	3.4%	71.7%	73.9%	59.1%
56	3.4%	72.4%	74.0%	60.2%
57	3.4%	72.9%	74.1%	61.3%
58	3.4%	73.2%	74.2%	62.4%
59	3.4%	73.6%	74.3%	63.4%
60	3.4%	74.0%	74.5%	64.5%
61	3.4%	74.3%	74.6%	65.6%
62	5.1%	78.0%	75.9%	66.7%
63	5.1%	78.3%	76.1%	67.7%
64	5.1%	79.5%	76.9%	68.8%
65	5.3%	82.3%	77.0%	69.9%
66	5.3%	82.4%	77.1%	71.0%
67	5.3%	82.8%	77.6%	72.0%
68	5.3%	83.3%	78.6%	73.1%
69	6.0%	84.1%	78.7%	74.2%
70	6.0%	84.7%	78.7%	75.3%
71	6.0%	86.8%	79.1%	76.3%
72	6.0%	87.3%	79.3%	77.4%
73	6.0%	87.4%	79.3%	78.5%
74	6.0%	87.6%	79.4%	79.6%
75	6.0%	88.4%	79.8%	80.6%
76	6.0%	89.7%	80.7%	81.7%
77	6.0%	90.0%	81.3%	82.8%
78	6.0%	90.2%	81.6%	83.9%
79	6.0%	90.4%	82.0%	84.9%
80	6.9%	92.6%	82.8%	86.0%
81	6.9%	93.4%	83.1%	87.1%
82	6.9%	93.6%	83.2%	88.2%
83	6.9%	93.9%	83.3%	89.2%
84	7.4%	94.0%	83.3%	90.3%
85	7.4%	94.0%	83.4%	91.4%
86	7.4%	94.1%	83.4%	92.5%
87	7.4%	94.4%	85.1%	93.5%
88	8.4%	95.4%	86.0%	94.6%
89	8.4%	98.3%	89.0%	95.7%
90	8.4%	98.4%	89.7%	96.8%
91	8.4%	99.5%	94.8%	97.8%
92	8.4%	99.7%	96.1%	98.9%
93	8.4%	100.0%	100.0%	100.0%

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Exhibit B, Page 13, Figure 2.1
The diagram indicates that IRPA screening does not start until 5 years before the need date.

a) Does Enbridge agree that some DSM programs may take several years to plan and implement and that multiple years of implementation may be needed to achieve the optimal level of reduction?

b) If so, why would screening not occur during the preceding five year period?

c) How does Enbridge propose to integrate IRP with the regulatory requirements for a five year gas supply plans and for USPs so that gas supply contracts and other infrastructure investment commitments don't constrain IRPAs and so that gas supply and system plans capture the impact of IRPAs?

Response

a) Yes.

b) The timeframe in Figure 2.1 is intended to be illustrative only. Enbridge Gas's Asset Management Plan ("AMP") will have a 10-year outlook and will include IRPAs within the full timeframe of that outlook, should they meet the evaluation criteria. It should also be noted that DSM programs are in place and anticipated to continue. Thus, DSM programs will continuously provide meaningful reductions to both annual average demand and peak period demand.

c) IRPA analysis, which will provide input into the 10-year planning horizon in the AMP, will take into account Enbridge Gas's long-term plans for gas supply contracts and other infrastructure investments. Please see the response at Exhibit I.STAFF.2 for additional detail.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Exhibit B, Page 14

> "26. Baseline Facility Setting – A second step following identification of a system need is to understand the baseline facility that would have been suggested in the absence of the IRP process. It is necessary to know what that baseline facility is so that the IRPA(s) can be compared against that solution."

Please explain why the baseline study needs to precede, rather than be simultaneously conducted with, IRPA(s) screening and evaluation?

Response

Once a system need is identified, Enbridge Gas can identify the baseline facility and any potential IRPAs simultaneously. The main premise of the statement referenced by GEC, is to illustrate that the baseline facility needs to be identified so that the IRPAs can be compared to it.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Exh. B, Page 18

> "Consistent with the Guiding Principle of Cost Effectiveness, given that the least cost option is a central driver for selection of either a facility or non-facility solution, the recommended solution should be a lesser cost for customers on-the-whole."

How will competing government policy goals such as GHG goals be addressed if the least cost option is not the optimal alternative for addressing the policy goal?

Response

As described in Enbridge Gas's Additional Evidence at Exhibit B, page 18:

> "Consistent with the Guiding Principle of Cost Effectiveness, given that the least cost option is a central driver for selection of either a facility or non-facility solution, the recommended solution should be a lesser cost for customers on-the-whole. However, as pointed out in the IRP Study completed by ICF, this is an important approach that needs to be confirmed by the OEB as it will have a major impact on the development of an IRP framework for Enbridge Gas. For the purposes of this IRP proposal the remainder of this evidence assumes that the Board will prioritize the most economic (lowest cost) alternative." [emphasis added]

If government policy changes such that the least cost option should no longer be considered to be the central driver for the selection of facility or non-facility solutions and this approach is confirmed by the Board, Enbridge Gas would comply with the new policy goals established by government and confirmed by the Board. The same would be true if, as part of its establishment of an IRP Framework for Enbridge Gas in this proceeding, the Board were to determine that its role as an economic regulator does not necessitate ensuring that Enbridge Gas prioritize the most economic alternatives to resolve identified system constraints going forward. However, Enbridge Gas assumes that in its role as an economic regulator, the Board will determine that it is appropriate to prioritize the most economic alternatives going forward and will establish an IRP

Framework that ensures that all relevant and quantifiable costs and benefits are taken into account when determining the cost-effectiveness of IRPA(s) going forward.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Exhibit B, Page 20

> "Community Expansion & Economic Development – If a project has been driven by policy and related funding to explicitly deliver natural gas into communities to help bring heating costs down, then it is not reasonable to conduct an IRP analysis."

Does the company submit that this policy should apply even if an IRPA could lower heating costs even more (for example if building shell improvements and air source heat pumps and electricity could meet heating needs in a new subdivision at a cost lower than new pipeline, gas and gas furnaces)?

Response

New subdivisions are treated differently than community expansion. New subdivisions tend to be relatively close proximity extensions of existing natural gas infrastructure and are typically developed by builders and developers for the residential and commercial new building market. Currently builders have an opportunity to participate in the Optimum Home or Savings by Design energy efficiency demand side management ("DSM") programs in order to lower heating costs in the buildings that they are constructing.

Please see the responses at Exhibit I.Anwaatin.3 and Exhibit.I.STAFF.8 f), for more detail on Enbridge Gas's proposal related to Community Expansion.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Exh. B, p. 27

> “Enbridge Gas’s commercial and industrial customers have been moving away from interruptible rates for their natural gas volumes as they value certainty of supply over the cost reduction.”

Does the company agree that this phenomenon is to some degree a function of the price difference between firm and interruptible? Please provide any analysis of the elasticity of response dependent upon that differential.

Response

A customer’s choice between interruptible and firm service is influenced by a combination of factors. These factors include, but are not limited to, the price spread between firm and interruptible distribution service, the costs of owning and maintaining alternate fuel systems (commodity, storage, supply risk, availability of operations personnel required for switch over) and the risk of business interruption impacting production. Enbridge Gas has not completed an analysis of the elasticity of response when setting firm and interruptible rates

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Exh. B, p. 28

> "61. While all traditional DSM measures positively impact daily peak period demands to varying degrees, not all necessarily have a positive impact on hourly peak demand. An example includes space heating controls for temperature setback, where the temperature setpoint is reduced overnight resulting in lower heating consumption and annual bills. However, at the end of the setback period, building setpoints are returned to daytime levels which may result in higher peak hourly flows on the natural gas system. This reality may require a prioritization of the differing goals and objectives of DSM and IRP in some instances."

Has the company investigated the potential to control thermostats and offer incentives to obtain staggered return to higher temperature, and thereby mitigate the impact on peak demand (as is done with electric water heater load control programs)? Please provide any study insights the company may have on this option.

Response

Although Enbridge Gas has not completed any formal studies on Demand Response ("DR") programs, the Company has been monitoring natural gas only DR programs that have been implemented in other jurisdictions. To date, there are very few examples of standalone natural gas DR projects, and those projects that do exist tend to focus on residential and small commercial thermostat setback programs. These DR programs generally include a temperature set back utilizing a smart thermostat during a demand response event. Other DR options include behavioural programs which send tips and suggestions to customers on how to reduce natural gas use during peak events.

Additionally, through 2020 Enbridge Gas partnered with Hydro Ottawa in a targeted residential conservation program called "Kanata North Smart Thermostat Program" to address an area of grid constraint.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Exh.B, p. 28

> “62.Contrary to traditional DSM, which is focused on ensuring broad-based participation, ETEE is focused on programs that achieve a high penetration in a specific geography to reduce peak period system demands corresponding to an identified system constraint/need.”

Can an IRPA approach be applicable where the geographic region driving the need is the entire system or a large portion of?

Response

Please see the response at Exhibit I.STAFF.11.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Exh.B, p.31

> 70. The project horizon will be set to align with the OEB-approved depreciable life of the infrastructure asset(s) to which the IRPA is being compared.

Please clarify the meaning of "project horizon". How will the full life cycle impacts of all alternatives be compared?

Response

Please see the response at Exhibit I.VECC.9, for discussion of the definition of project horizon in this context.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Exh. B, p. 33

The Company does not seek incentives apart from rate basing. How fully does rate basing address the differential impact of supply versus demand alternatives on the company, its parent company and its shareholders given related upstream business interests?

Response

Enbridge Gas proposes to include in rate base the costs of IRPA investments, similar to new facility infrastructure projects, to create a level playing field between IRPAs and new facility infrastructure, ensuring that Enbridge Gas is equally incented between the two types of investments. For more discussion on the IRP related risk and incentives, please see the responses at Exhibit I.EP.6 and at Exhibit I.CCC.17.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Exh. B, p. 36

The company is not seeking approval of AMI at this time but anticipates federal meter approvals within a year. What cost is anticipated for AMI? Can limited AMI sampling facilitate IRPA analysis?

Response

For an estimated cost for AMI please see the response at Exhibit I.APPrO.2 d) (iii). For discussion regarding limited AMI sampling please see the response at Exhibit I.OSEA.4 c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Exhibit B, Page 38

The company proposes monitoring and reporting on IRPA's that are implemented. What reporting will there be of screened out IRPAs? What will be the timing of any such reporting? What mechanism does the company foresee will allow interested parties to review and challenge such determinations in a timely fashion?

Response

Consistent with the response at Exhibit I.STAFF.6 and its Additional Evidence, Enbridge Gas will reflect preferred facility alternatives and/or IRPAs in its Asset Management Plan ("AMP") filed with the Board which will be subject to review by the Board and intervenors. Enbridge Gas will continue to monitor underlying system constraints until such time that an IRPA(s) or facility alternative is fully implemented. In the event the underlying constraint changes prior to implementation, Enbridge Gas may need to revise its plans and update the AMP. Enbridge Gas intends to file an IRP Report on the performance of OEB-approved IRPAs annually with the Board.

Enbridge Gas does not intend to report on any IRPAs that have been screened out as part of Enbridge Gas's proposed IRPA screening process as doing so would require excessive administration and management at considerable incremental cost to ratepayers for limited incremental value in return. Such indefinite and infinite re-assessment of IRPA(s) would not be efficient and may encourage inappropriate re-assessment of investment decisions in hindsight. Instead, consistent with Enbridge Gas's proposal for Monitoring and Reporting and the response at Exhibit I.STAFF.10, Enbridge Gas will report annually on the performance of OEB-approved IRPA(s) and in instances of underperformance may make adjustments to resolve unanticipated operational challenges or flaws in the design or delivery of IRPAs. Wherever such adjustments could lead to increased costs greater than 25% of total OEB-approved costs for individual IRPA investments Enbridge Gas would apply to the OEB for approval to make the adjustments, at which time the Board and intervenors would have the opportunity to review and ensure that the adjustments proposed by the Company are optimal and prudent.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

In EB-2019-0159 19 Exh A. Tab 7, pp. 24-25, Enbridge offers several reasons why it stated that geo-targeting of DSM "is not a reasonable solution". A part of the third reason is that "…given the need to evaluate the impacts of the IRPA, the program would need to be completed or demonstrating measurable results, at least three years prior to the date at which the additional capacity provided by the infrastructure project was initially proposed to be required" which means that "a successful IRPA would need to be approved and put into motion no less than four years prior to the expected in-service date of the preferred facility alternative".

a) Is this still the company's position? If not, please explain.

b) Can smaller projects have shorter IRPA lead times?

c) What additional lead time is needed for the planning and approval of the IRPA before it is "put in motion"?

d) Please indicate the range of lead times that the company experiences for various types of supply projects.

Response

a) As set out in the response at Exhibit I.FRPO.1, Enbridge Gas has now withdrawn its 2021 Dawn Parkway Expansion Project application and evidence, including alternatives assessed. Geo-targeted DSM programs (ETEEs) are a reasonable solution for IRPAs under the right circumstances and with the appropriate lead time. The reference in the question above is from Enbridge Gas's now withdrawn 2021 Dawn Parkway Expansion Project proceeding (EB-2019-0159) where the Company specifically determined that geo-targeted DSM programs were not a viable IRPA to resolve the underlying identified system constraint associated with the proposed high-volume transmission facilities proposed.

b) & c)
Lead times for IRPAs are entirely dependent upon: the unique nature of each type of IRPA, project scope and complexity, Enbridge Gas's prior experience with such IRPA(s), approvals required, and the level of effort required to implement the IRPA. There is no simple rule of thumb that can be applied to determine IRPA lead times based on IRPA type. However, as Enbridge Gas gains experience implementing investments in IRPA(s) it is anticipated that over time it may become possible to better predict lead times.

d) The lead times for supply side IRPAs can range from several months for services where existing capacity is available to three years or more if upstream capacity must be constructed to meet an identified need.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Where the company is found to have failed to propose a lesser cost IRPA on a timely basis, what regulatory consequence is the company proposing?

Response

Please see the response at Exhibit I.STAFF.25 d).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Low Income Energy Network (LIEN)

INTERROGATORY

Reference:

Exhibit B, page 26 of 46:

"*When compared with other IRPAs, leveraging existing DSM programs may prove to be a cost-effective and efficient means to address peak period demands, recognizing that various factors would still need to be taken into consideration to design and implement an effective solution.*", and Exhibit C, page 25 of 26 "*Enbridge Gas agrees in principle with EFG's proposal to develop and implement two pilot projects.*"

Question:

a) In addition to the ICF IRP Study already filed, we understand that Enbridge plans to conduct two pilot projects. Please provide details about what Enbridge is planning for these pilot projects including details about:
   i. program design
   ii. measures/activities
   iii. timing
   iv. budget
   v. geographic areas targeted
   vi. whether/how Enbridge plans to consider low-income consumers in these pilot projects, and
   vii. how these pilot projects may be complemented by Enbridge's existing and/or future DSM programs.

Response

Please see the response at Exhibit I.STAFF.12.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Low Income Energy Network (LIEN)

INTERROGATORY

Reference:

Exhibit B, page 36 of 46:

"*Enbridge Gas expects that any and all of the prudently incurred: (i) original costs to invest in OEB-approved IRPAs; (ii) costs associated with OEB-approved adjustments to IRPA investments; and (iii) costs of any subsequent OEB-approved LTC project (in the instance that an IRPA is determined to have been insufficiently effective), would be borne entirely by ratepayers subject to the Board's determination that in the course of incurring such costs Enbridge Gas acted prudently and responsibly in serving the firm needs of its ratepayers.*"

Question:

a) How will Enbridge consider the impact to low-income customers associated with IRPAs?

b) What mechanisms, if any, is Enbridge considering to reduce costs to low-income customers associated with IRPAs?

Response

a) & b)
Enbridge Gas anticipates that in general, the costs of IRPAs (including those specific IRPAs which may be targeted to low-income customers) will be allocated across all rate classes and recovered through OEB-approved rates in a manner consistent with facility investments that they serve to reduce, avoid or defer. Enbridge Gas has proposed a phased economic review in part to ensure transparency. Enbridge Gas expects that as part of its review of IRPA applications, the Board will make a determination whether the IRPA investments proposed by Enbridge Gas are in the best interests of ratepayers. As part of its IRP Proposal, Enbridge Gas has not contemplated any mechanism to consider or address impacts to low-income to customers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Low Income Energy Network (LIEN)

INTERROGATORY

Reference:

Exhibit B, pages 39 to 42 of 46:

"…*Enbridge Gas accepts that there may be room to enhance its stakeholder engagement in order to glean IRP-specific insights. These additional insights could be geographically-specific and include information on customer types (e.g., residential, commercial, industrial), socioeconomic customer attributes, housing stock, saturation of current DSM programming, and an understanding of the status of electricity CDM programs as well as transmission and distribution capacity*", and

Exhibit C, page 13 of 26:

"*Enbridge Gas acknowledges the importance of obtaining stakeholder input ahead of developing IRPAs to address identified system needs/constraints and of establishing a feedback loop to keep stakeholders (including municipal and government representatives, First Nations, end use customers from all sectors, customer and business associations) informed of its investments in and the impact of their respective input into the development of IRPAs."*

Question:

a) What is Enbridge's plan for consulting with low-income consumers? Through what channels (social service agencies, LIEN, others)? Please provide a breakdown of how Enbridge intends to roll-out this consultation with low-income consumer representatives for each of Enbridge's engagement components 1, 2 and 3.

b) As part of engagement component 3, how will Enbridge determine (i.e., what criteria will Enbridge apply) to determine if/how Enbridge will consult with low-income consumer representatives on a geographically-targeted basis?

c) Does Enbridge intend to engage with stakeholders, including low-income consumer representatives, concurrently about both IRPAs and DSM programming, including low-income DSM programming? How will this engagement occur?

Response

a) – c)
Please see the response at Exhibit I.STAFF.9, for further details regarding Enbridge Gas's proposed IRP-related stakeholder engagement activities. Enbridge Gas will seek efficiencies in its stakeholdering, including with low-income consumer representatives, as appropriate.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Low Income Energy Network (LIEN)

INTERROGATORY

Reference:

Exhibit C, page 8 of 26

"*In its Additional Evidence, Enbridge Gas proposed that economic feasibility of IRPAs be assessed using a DCF methodology consistent with principles underpinning the Board's E.B.O. 134 and E.B.O. 188. The primary difference between Enbridge Gas's proposal and ConEd's BCA is one of perspective: Enbridge Gas's proposed DCF-based test being premised upon an economic assessment of impacts/benefits to Enbridge Gas's ratepayers as its starting point followed by secondary and tertiary objective assessments of distinct and quantifiable public interest costs and benefits*..."

Question:

a) What does Enbridge propose to consider as part of its:

i. economic assessment of impacts/benefits to customers, and

ii. secondary and/or tertiary assessments of public interest costs and benefits?

b) Will Enbridge consider as part of these assessments:

i. health and safety impacts

ii. disconnection and connection impacts/costs

iii. costs/benefits specific to low-income customers?

Response

a) Please see the response at Exhibit I.STAFF.20 for a table identifying which categories of costs and benefits Enbridge Gas is proposing to include in the different stages of cost benefit-evaluation.

b) Enbridge Gas has not included health and safety impacts, disconnection and connection impacts/costs, or costs/benefits specific to low-income customers as part of an economic feasibility analysis of IRPAs per its response at Exhibit I.STAFF.20 b). However, Enbridge Gas intends to consider other costs and benefits as part of its efforts to integrate IRP into existing systems and processes as discussed in the response at Exhibit I.OSEA.1 c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B, page 1

Question:

a) Does the reference to the forecasted needs of Enbridge Gas customers include both current and potential future customers, or only current customers?

Response

The reference to forecasted needs of Enbridge Gas customers includes both current and potential future customers based on contracted demands, OEB-approved methodologies for demand forecasting and other known and quantifiable drivers of demand growth and customer need including regulatory directives, government policy and legislation.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (“LPMA”)

Interrogatory

Reference:

Exhibit B, page 13

At point iii Public Policy, EGI states that IRP will be considered in a manner to ensure that it is supportive of and aligned with public policy, where appropriate.

Question:

a) Does public policy include those of federal, provincial and municipal governments? If not please explain which government public policies may not be considered and why.

b) What does EGI mean by “where appropriate”? Please provide examples of where the alignment with public policy may not be appropriate.

Response

a) Yes, public policy includes federal, provincial and municipal governments.

b) For instance, the governments of Ontario and Canada have set targets to reduce greenhouse gas emissions and are at various stages of developing and implementing plans intended to achieve these targets. These plans typically include a variety of measures, some of which may see an increased use of existing natural gas infrastructure such as through the increase in blending of clean fuels such as RNG and hydrogen, and increased throughput of natural gas and blended clean fuels for electricity production and compressed natural gas refueling stations. Only where the information concerning such initiatives is known to be reasonably certain are these items considered in Enbridge Gas’s IRP planning.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B, page 20

Question:

a) With respect to timing, on average, how long in advance is a system need identified?

b) Over the last three years, how many system needs have been identified that must be met in under three years and how many system needs have been identified that can be met in over three years?

Response

a) System constraints are identified through many channels and for many reasons. Accordingly, they can be identified: (i) the moment that there is a safety or integrity issue; (ii) months or a short number of years in advance in instances where new industrial or ex-franchise demands are identified; or (iii) many years in advance in instances of general service customer growth. Growth forecasts are typically incorporated into the next revision of Enbridge Gas's Asset Management Plan (or Addendum/update thereto), which is refreshed annually to support business needs and Regulatory requirements.

   In addition, a new system constraint may be identified through a customer request (either a new customer, or existing customer) adding demand to the system. This request for system service may also create a need for a new project significantly in advance of an existing planned project, or cause delay/changes to an existing project. Other timing considerations such as construction moratoriums may also impact existing or planned projects.

b) Please see the response at Exhibit I.STAFF.8 d).

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B, page 20

Question:

With respect to project-specific considerations, how would EGI determine the sizing of any relocation of natural gas infrastructure in a particular corridor if a project was being advanced for road works or water main replacements as an example? How would EGI take into account potential IRPA solutions that may impact the size of a line being moved over the life of the line?

Response

Typically, a relocation project would result in a portion of an existing line being relocated. It would be unusual for the complete line from source to demand to be relocated. As such, industry best practice is to not undersize a portion of the line. This would create a 'bottleneck' and inefficiencies in the gas network. This bottleneck may also impede Enbridge Gas's ability to complete in-line inspection of the line. Enbridge Gas would seek to relocate the line with a solution that preserves the existing capabilities of the network.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B, page 20

Question:

With respect to customer-specific builds, would EGI provide an IRP analysis to the customer in order to minimize the facilities required to serve that customer, such as customer owned compressed storage or facilities to connect CNG trailers in order to reduce peak demand, saving the customers firm demand charges and resulting in smaller facilities? Please explain fully.

Response

Customer-specific builds are one of the binary screening factors Enbridge Gas considers before applying an IRP analysis. Builds of the gas distribution system are driven by the customers' specific determination of their service requirements, including: minimum operating pressure, maximum hourly flow and the required in-service date. The ensuing development process to determine the required infrastructure and costs to serve is a staged process that allows customers to consider other design options including reduced service requirements that may reflect third party solutions such as CNG and other alternative fuels before finalizing project design.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B, page 20

Question:

With respect to community expansion & economic development, please explain why an IRP analysis that could include such things as targeted DSM, CNG or LNG, the promotion of non-natural gas alternatives such as propane or hydrogen injection, air source heat pumps, geothermal heating/cooling, solar water heating, etc., should not be undertaken as part of an IRP analysis in order to minimize the sizing of the distribution pipe and any upstream high pressure distribution/transmission required to service the expansion.

Response

Please see the responses at Exhibit I.Anwaatin.3 and at Exhibit.I.STAFF.8 f), for discussion of the applicability of IRP to community expansion and economic development initiatives.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B, page 20

Question:

Please explain how EGI's proposed IRPA would take into account proposals that may impact more than one project. For example, consider a third-party provider of compressed natural gas that can be shipped to multiple locations (expansion projects, customer-specific builds, etc.) across the province and used to provide peak day/hour capacity resulting in smaller facility requirements. How would the proposed IRPA estimate the costs in such a circumstance?

Response

Given the variety of factors that could impact the cost of the alternative such as: volume of gas required at site, land costs at site, deliverability costs and risks, O&M costs to operate the injection operation, delivered fuel costs, distance from CNG compression facility and availability challenges associated with the on-demand nature of the alternative, each project will require bespoke costing at the time that a specific system constraint is identified.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B, page 21

Question:

a) Does EGI currently have any customers that provide CNG to Ontario customers? Has EGI ever had any such customers? If yes, provide details while maintaining confidentiality.

b) Would the local production of natural gas be included within an IRP if the local production could be counted on to provide a firm amount of gas each day? Please explain fully.

c) Would pipe farms be included within an IRP if they were of sufficient size to deliver meaningful peak day/hour volumes? Please explain fully.

d) Would propane injection into the natural gas distribution system to meet system peaks be included as an IRP? If not, please explain why not.

Response

a) Yes, Enbridge Gas does currently have customers that provide CNG to Ontario customers for both mobile (vehicle) applications and stationary applications. These customers are located throughout the system including locations in northern Ontario and southwestern Ontario. The largest of these customers is Certarus which owns and operates CNG facilities in Red Rock, Timmins and Mount Forest, Ontario.

b) Firm deliveries from an Ontario producer into Enbridge Gas's system may be considered an IRPA provided those deliveries can be relied upon during a peak day and for a sufficient future timeframe given that natural gas production wells have a finite supply. Enbridge Gas would need to evaluate reliability and security of supply on a case by case basis. There may be situations where Enbridge Gas considers additional capital expenditures on its system to ensure reliability of deliveries from an Ontario producer.

c) Enbridge Gas assumes the term “pipe farm” to mean a piece of land which contains long lengths of large diameter high pressure pipeline which zig zag back and forth to act like an above grade storage tank. Conceptually, a pipe farm could provide similar benefit as a CNG/LNG facility dependent upon factors such as the type of customer served, reliability, location, volume, economics and pressure. Enbridge Gas would need to conduct a review to consider its value as an alternative.

d) Equipment combusts propane significantly differently than natural gas and would require adjustment at a certain level, thus limiting any IRPA opportunity. Additionally, too much propane blended into the natural gas stream can cause efficiency and maintenance problems with certain equipment such as CNG vehicles. A more suitable method of providing peak shaving would be LNG.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B, page 21

Question:

Does EGI consider rate design, including new rate classes, as a potential IRPA? If not, please explain why not?

Response

Enbridge Gas does consider rate design, including new rate classes, as a potential IRPA. Enbridge Gas currently offers interruptible and firm seasonal services to customers, and their consumption is not reflected in the firm peak demand forecast for system planning purposes. Current customers have contracted for interruptible and firm seasonal services when the service offering meets the needs of their specific business operation.

Additionally, Enbridge Gas recognizes that demand response may include a rate design component that could contribute to a reduction in peak demand.

Installation of AMI would facilitate demand response programming and could provide the necessary granular usage insight that is required to enable further expansion of rate design for IRP purposes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B, pages 21 – 22

Question:

What is the expected cost of a NGASHP relative to a conventional air source heat pump and a conventional geothermal system?

Response

The residential NGASHP technology is at a pre-commercialization stage. The initial market entry cost is expected to be higher than Electric Air Source Heat Pumps ("EASHPs"). However, as the market for NGASHP matures and large scale NGASHPs are rolled out, the price of a residential unit is expected to be cost competitive with EASHPs.

The approximate cost of an EASHP (standard climate) is $4,500 - $7,500 and for an EASHP (Cold Climate), it is $7,000 - $15,000

The approximate cost of a residential Ground Source Heap Pump or Geothermal Heat Pump (GSHP) is $10,000 - $15,000 plus the loop cost of $10,000 - $15,000.

For the commercial sector, the equipment cost of a fully commercialized NGASHP is competitive with EASHPs. For example, the cost of a 2-pipe Variable Refrigerant Flow ("VRF") engine driven NGASHP is similar to the cost of an electric VRF in the range of $45,000.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B, page 23, para. 45

Question:

a) Could an unregulated third party offer the alternatives noted in paragraph 44? If not, why not?

b) Please describe the associated assets that EGI would include in rate base should the OEB grant authorization to do so.

c) Would the assets noted above be customer specific or would the assets provide service to more than one customer? Please explain fully.

d) Would EGI consider an IRPA that encourages third party providers of geothermal heat pump systems and electric air source heat pumps to target specific geographical areas in order to reduce or delay the expansion of regulated natural gas assets? If not, why not?

Response

a) & d)
Yes, an unregulated third party could offer the alternatives noted in paragraph 44. However, Enbridge Gas cautions that it may need to retain some or all aspects of operation, maintenance and technical support for customer IRPAs in order to maximize reliability and/or ensure safety, or where there is not a well-functioning competitive market established for an IRPA in Ontario.

b) Enbridge Gas proposes that expenditures towards project specific IRPA(s) would be capitalized to rate base and the revenue requirement would be recovered through an appropriate mechanism until the Company's rebasing application. At rebasing, Enbridge Gas would seek to include the undepreciated rate base amount in the calculation of base rates. Collecting IRPA costs through the revenue requirement on rate base will lessen immediate customer impact and better align recovery of program costs with the delivery of customer benefits. Please also see the response at Exhibit I.STAFF.22, for further discussion regarding IRP/IRPA cost recovery.

c) It depends on the specific IRPA. If the IRPA involves a Natural Gas Air Source Heat Pump ("NGASHP") for example, it may be a solution sited with an individual customer. If the IRPA is a district energy solution, it would be a more community-based solution that would likely involve more than one customer.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B, page 21

Question:

a) What is the current status/availability of natural gas fired air conditioning for each of the residential and commercial/industrial sectors?

b) Could the use of natural gas fired air conditioning be used to reduce peak electricity demand while at the same time increasing the load factor of the gas distribution system without increasing the peak demand on the system?

c) What is the current status/availability of natural gas fired generators for each of the residential and commercial/industrial sectors beyond their ability to provide backup generation in the event of a disruption in the electrical grid?

d) Would there be any impact on the peak day/hour demand of a residential or small commercial customer using a natural gas fired generator to power electrical heating utilizing an air-source heat pump or geothermal system relative to a high efficiency gas furnace? Please explain fully.

Response

a) Natural gas fired air conditioners, also called gas-fired chillers, have been commercially available for decades (cooling only application for the commercial sector). However, they are not cost effective in colder climate areas such as Ontario due to low cooling building loads.

   Natural Gas Air Source Heat Pumps ("NGASHPs") are commercially available for the commercial and industrial sector. Vapor compression engine driven NGASHPs provide both heating and cooling for the commercial and industrial sector. The NGASHPs for the residential sector are still at a pre-commercialized stage.

b) Yes.

c) Natural gas fired generators are commercially available in sizes from 1.5 kW to over 20,000 kW for residential, commercial and industrial applications. These generators are designed for continuous duty cycle to generate on-site power. For most applications, these units are designed to run in the combined heat and power ("CHP") mode to maximize system efficiencies reaching above 80%.

d) Stand-alone natural gas fired generators to power electrical heating utilizing an air-source heat pump or geothermal system relative to a high efficiency gas furnace would not result in a decrease in peak day/hour demand.

   The electricity generation efficiency of a residential backup generator is about 19%.[1] The electrical efficiency of a generator designed to run long hours in continuous duty cycle is about 26% (on a Higher Heating Value basis).[2] If on-site generated electricity is used to run an electric heat pump with a COP of 2.5, the overall efficiency of this heat pump will be in the range of 47% – 65%. This efficiency is much lower than a high efficiency gas furnace which is around 95%.

[1] https://www.generac.com/Industrial/GeneracIndustrialPower/media/library/Downloads/Brochures/Generac-Industrial-Power_Brochure_Small-Business-Generators.pdf
[2] https://www.yanmar.com/media/news/2020/07/16011514/cp.pdf

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B, page 44

Question:

a) Would the move to AMI provide EGI with the information to implement a fundamental change in the rate design for the non-contract general service rate classes to include any of the following changes:

   i. the addition of a demand charge based on the highest consumption day in the month/year;
   ii. the development of non-contract general service rate classes based on similar peak day demands (for example, one class with peak day demand less than X m^3, one class with peak day demand more than X m^3 but less than Y m^3 and one class with peak day demand more than Y m^3;
   iii. a combination of the above such as the implementation of a peak day demand charge for customers in the class with a peak day demand of more than Y m^3, with no peak day demand charge for the other two classes?

b) Would the ability to track the peak demand requirements into the three groupings noted in a) ii) above result in a greater ability to forecast peak day requirements? Please explain fully.

c) Would the use of a peak day demand charge for non-contract general service customers above a certain level (as proposed in a) iii) above) enhance the ability of EGI to forecast peak day requirements, similar to that for contract customers? Please explain fully.

d) EGI currently uses an annual volume consumption (50,000 m^3) to assign non-contract general service customers to different rate classes. If the annual volume consumption criteria were replaced with the peak day demand, would the allocation of costs between the two rate classes be more reflective of cost causality? Please explain fully.

e) Please provide a table that breaks down the peak day design capacity for each of the Union South, Union North and EGD rate zones between contract customers with contracted firm demands and non-contract general service volumes.

<u>Response</u>

a) An Advanced Metering Infrastructure ("AMI") system will allow for the collection of hourly and daily data that could be used to design rate structures for general service rate classes. Enbridge Gas expects the hourly and daily information will provide the information necessary to design a demand-based charge for all or a subset of the customer group. A demand-based charge could be used to recover the allocation demand-based costs determined through a cost allocation study.

b) Being able to categorize consumption into the groupings described in part a) ii) would not impact Enbridge Gas's ability to forecast or manage peak period demands. The ability to forecast peak period demands would be enhanced by a better understanding of and ability to measure peak period demands through AMI. Please see the response at Exhibit I.STAFF.4 part f), for further discussion of the benefits of AMI to Enbridge Gas and its customers.

c) A rate structure that included a demand-based charge for general service customers would not impact the ability for the Company to forecast the peak period demands. The ability to forecast peak period demands would be enhanced by the hourly and daily information provided by AMI which is independent of the rate design.

d) For clarity, the annual volume consumption of 50,000 m^3 to assign general service customers to different rate classes is only applicable to the Union rate zones.

   A rate structure for general service customers that includes a demand-based charge would be more reflective of cost causality compared to the current rate structure that recovers demand-based costs through volumetric charges due to the alignment of cost allocation with the cost recovery (i.e., fixed demand-based costs would be recovered through fixed demand-based charges rather than volumetrically).

e) Please see response at Exhibit I.LPMA.14, for design day demand details.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit B

Question:

Please provide a table that shows for each of 2011 through 2020 by rate zone (Union South, Union North, EGD) the normalized annual volume broken down between the contract rate classes and the general service rate classes as well as the design day demand, also broken down between the contract rate classes and the general service rate classes.

Response

Please see Attachment 1 for the actual normalized annual volumes for each of the years 2011 to 2020 and Attachment 2 for the firm and interruptible design day demands for each of Winter 2011/2012 to Winter 2020/2021.

ENBRIDGE GAS INC.
Actual Normalized Annual Throughput Volumes by Rate Zone
for the period 2011-2020

		EGD Rate Zone			Union South Rate Zone			Union North Rate Zone		
Line No.	Particulars ($10^6 m^3$)	General Service	Contract (2)	Total	General Service	Contract	Total	General Service	Contract	Total
		(a)	(b)	(c) = (a+b)	(d)	(e)	(f) = (d+e)	(g)	(h)	(i) = (g+h)
1	2011	9,338	2,082	11,420	4,091	6,142	10,233	1,274	2,695	3,969
2	2012	9,259	2,073	11,332	4,029	6,362	10,391	1,284	2,773	4,057
3	2013	9,469	2,023	11,491	4,063	6,203	10,266	1,279	2,793	4,072
4	2014	9,374	1,923	11,297	4,116	6,268	10,385	1,310	2,433	3,743
5	2015	9,392	1,914	11,306	4,078	6,235	10,313	1,283	2,083	3,366
6	2016	9,374	1,935	11,309	4,141	6,122	10,263	1,302	2,047	3,349
7	2017	9,853	1,911	11,764	4,318	5,746	10,064	1,342	1,638	2,979
8	2018	9,884	1,971	11,855	4,429	6,172	10,601	1,354	1,672	3,026
9	2019	9,982	1,904	11,886	4,501	6,251	10,752	1,382	1,663	3,045
10	2020 (1)									

Note:
(1) 2020 actual normalized annual throughput volumes are not yet available.
(2) There is no distribution volume for EGD Power Generation customers.

ENBRIDGE GAS INC.
Firm and Interruptible Design Day Demands by Rate Zone
for the period 2011-2020

		EGD Rate Zone			Union South Rate Zone			Union North Rate Zone		
Line No.	Particulars ($10^3m^3/d$)	General Service	Contract	Total	General Service	Contract	Total	General Service	Contract	Total
		(a)	(b)	(c) = (a+b)	(d)	(e)	(f) = (d+e)	(g)	(h)	(i) = (g+h)
1	W11/12	92,128	12,362	104,490	40,248	38,795	79,044	11,916	10,678	22,594
2	W12/13	92,925	15,580	108,506	39,043	38,781	77,824	11,559	11,123	22,682
3	W13/14	95,811	15,466	111,277	38,673	40,202	78,875	11,733	11,164	22,897
4	W14/15	99,247	15,708	114,956	40,977	41,165	82,142	11,873	10,822	22,695
5	W15/16	100,272	15,213	115,485	40,635	41,597	82,232	12,208	10,327	22,535
6	W16/17	100,471	15,819	116,290	40,509	41,861	82,370	12,016	9,470	21,486
7	W17/18	101,500	16,024	117,524	41,166	41,799	82,966	12,056	8,433	20,489
8	W18/19	100,239	15,008	115,246	42,034	41,672	83,706	12,143	12,108	24,250
9	W19/20	98,650	14,631	113,281	42,960	43,915	86,875	12,315	10,787	23,102
10	W20/21	100,920	14,664	115,584	42,744	43,441	86,185	11,803	11,781	23,584

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit C, page 26

Question:

With respect to the incremental funding for the pilot projects request that EGI expects to request following approval of an IRP framework for EGI, would EGI seek funding and/or participation from groups such as the federal government, the provincial government, municipal governments, the Heating, Refrigeration and Air Conditioning Institute of Canada, Ontario Geothermal Association, solar associations and companies, etc.? If not, please explain why not.

Response

Enbridge Gas will seek funding for IRP pilot projects from all available sources.

In addition to this funding, Enbridge Gas would scan for opportunities to work with any group interested in supporting or supplementing funding towards a successful IRP pilot project which may optimize value for customers.

Where additional funding for IRP pilot projects is required, Enbridge Gas proposes that the OEB approve the recording of the balance of IRP pilot-related costs in the IRP cost deferral account which Enbridge Gas requests to be established to record IRP costs not included in base rates (please also see the responses at Exhibit I.APPrO.6 and at Exhibit I.CCC.3).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers ("OGVG")

Interrogatory

Reference:

EB-2019-0159, Exhibit A, Tab 13, page 13.
EB-2020-0181, Exhibit C, Tab 1, Schedule 1, page 46 Figure 6.

Preamble:

EGI has filed Exhibit A, Tab 13 from its EB-2019-0159 application as the initial basis for its IRP proposal.

At page 13 of Exhibit A, Tab 13, the IRP Proposal makes the following reference:
The IRP study findings estimate that only 14-17% of reinforcements in the sample (which only included distribution reinforcements) could feasibly be replaced by an IRPA. The referenced IRP study was not included as an attachment to the IRP Proposal; the referenced IRP study was instead cited as appearing in EB-2018-0097 as Exhibit I.EGDI.SEC.1, Attachment 1, October 11, 2018. A review of the OEB filings for EGI dated October 11, 2018 reveals a set of interrogatory responses from EGI in EB-2018-0097, wherein there is an IRP study filed at Exhibit I.EGDI.SEC.1, Attachment 1. However, the referenced study does not have a page 138; the attached study is only 49 pages long.

Question:

a) Please file the IRP Study referred to by EGI at page 13 of Exhibit A, Tab 13 that resulted in the estimate that only 14-17% of sampled reinforcements could feasibly be replaced by an IRPA, including a reference for that estimate within the document.

b) With respect to the estimate that only 14-17% of sampled reinforcements could feasibly be replaced by an IRPA, please provide the analysis performed as part of the study that resulted in the estimate, to the extent that analysis is not included in the study itself.

c) Please comment on whether any changes in EGI's proposed approach to IRP since it filed Exhibit A have had a material impact on the estimate of how many reinforcements in the sample provided for the IRP study could feasibly be replaced by an IRPA; if there has been a material impact please produce a revised analysis demonstrating how the original 14-17% estimate has been affected.

d) Using the total proposed annual capital program spend for EGI over the 2021 to 2025 period as filed by EGI in EB-2020-0181 at Exhibit C, Tab 1, Schedule 1, page 46 Figure 6, please provide an additional line item which splits out the estimated spend on projects that, based on EGI's updated analysis, might feasibly be replaced by IRPAs (OGVG expects that this would be accomplished by splitting the planned system access spending into IRPA feasible and IRPA non-feasible sub-categories; if that is not appropriate please provide an alternate presentation). In providing the estimate OGVG recognizes that, particularly for the early years in the estimate, the answer will be entirely theoretical, setting out the level of capital programming that would have been IRPA feasible had there been an OEB approved IRP policy in place in advance of the proposed projects becoming known.

Response

a) See EB-2018-0097, Exhibit I.EGDI.STAFF.13, Attachment 1, Page 1 of 246; Filed: 2018-11-26, also filed as part of the current (EB-2020-0091) proceeding on July 22, 2020, and available at:
https://www.rds.oeb.ca/CMWebDrawer/Record/682322/File/document

The reference for the 14-17% of sampled reinforcements that could feasibly be replaced by an IRPA, can be found on page 138 of ICF's May 2018 report referenced in the link above.

b) Additional details on the analysis are included on pp. 137-138 of ICF's May 2018 report, which was filed by Enbridge Gas on July 22, 2020. Underlying data for the analysis has been provided as part of Exhibit I.GEC.19 b).

c) There has been no material change in the number of reinforcements indicated in ICF's May 2018 IRP Study that could feasibly be replaced by an IRPA due to changes in Enbridge Gas's IRP approach. Consideration of other costs and benefits (e.g. federal carbon charge) may have an impact on the shape of the cost/benefit curves but would not have an impact on the upper limit on the peak demand growth rate that can be deferred.

d) There are too many projects included this in Table for Enbridge Gas to provide a detailed analysis as requested. However, the following analysis may provide some insight:

System Reinforcement projects are reflected in the System Service Line Item. If the System Reinforcement Investments in the AMP are filtered to include projects with a 2021-2025 spend of more than $10 million, the totals for these investments are reflected in Table 1 below:

Table 1

Rate Zone	2021	2022	2023	2024	2025
UNION	36,737,174	234,938,602	107,566,278	133,497,832	107,936,285
EGD	3,848,319	23,439,568	10,018,348	26,764,391	63,913,865

Compression Stations Growth Projects are reflected in the System Access Line Item. Applying the same logic as above, only the Dawn De-hy project would qualify for IRP – the spend profile is reflected in Table 2 below.

Table 2

Investment ID	2021	2022	2023	2024	2025
101995	5,004,870	27,706,534	16,420,584	1,636,712	

As noted in the response at Exhibit I.STAFF.7, some DS-Gate, Feeder & A Station investments are partially driven by growth and could be assessed for IRPAs but where the investment is driven primarily by compliance or condition, there may not be time to assess the effectiveness of IRPAs. These investments are mapped to the System Renewal Line Item.

Please also see response at Exhibit I.STAFF.8 g) which describes which of the ICM-Eligible projects in Tables 6.1-2 and 6.1-3 of the AMP would be considered appropriate for IRP assessment purposes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers ("OGVG")

Interrogatory

Reference:

Exhibit B, page 18.

Preamble:

Consistent with the Guiding Principle of Cost Effectiveness, given that the least cost option is a central driver for selection of either a facility or non-facility solution, the recommended solution should be a lesser cost for customers on-the-whole. However, as pointed out in the IRP Study completed by ICF, this is an important approach that needs to be confirmed by the OEB as it will have a major impact on the development of an IRP framework for Enbridge Gas. For the purposes of this IRP Proposal the remainder of this evidence assumes that the Board will prioritize the most economic (lowest cost) alternative.

Question:

a) Please confirm that the intent of the IRP Framework is to continue to provide existing and potential customers the same level of access to incremental firm capacity as would be available under EGI's current status quo planning parameters, at the same or lower cost as would be the case had the incremental capacity been secured through a traditional facilities-based solution. If not confirmed, please explain how existing and potential customers may be negatively impacted as a result of the IRP Framework in terms of their access to incremental firm capacity and the cost to them of any incremental capacity.

Response

Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers ("OGVG")

Interrogatory

Reference:

Exhibit B, page 32.

Preamble:

Enbridge Gas will apply to the OEB for approval to recover the costs associated with investment in any IRPA. Enbridge Gas presumes that such an application would, similar to applications for LTC facility alternatives, include an explanation of the system constraint/need, a summary of stakeholder engagement input, rationale for investment in the IRPA, the estimated individual and overall costs of investment, proposed cost allocation and recovery methodologies, proposed ownership and operationalization arrangements and a commitment to ongoing annual monitoring and reporting on the relative effectiveness of the IRPA to relieve the identified constraint.

Question:

a) Please provide an overview of how EGI expects to allocate the costs associated with IRPAs; please discuss whether or not EGI's proposed allocation methodology has the potential to negatively impact customers accessing incremental firm capacity relative to the impact they would have experienced as a result of the implementation of a traditional facilities-based solution and allocation of costs.

Response

Enbridge Gas expects to propose to allocate the costs associated with IRPAs in the same manner as the capital investments they serve to defer, avoid or reduce. For example, if the IRPA replaces the reinforcement of a distribution system, Enbridge Gas would propose to allocate the IRPA costs in the same manner as the costs associated with a facility investment in the distribution system.

Enbridge Gas does not expect the proposed allocation methodology to negatively impact customers accessing incremental firm capacity compared to a facility alternative. Please also see the response at Exhibit I.STAFF.22 e).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers ("OGVG")

Interrogatory

Reference:

OEB Staff Evidence, The "Guidehouse report", page 9.

Preamble:

Due to significant delays and challenges with pipeline projects by regulatory agencies, both [New York based] utilities unilaterally enacted moratoria on new customer connections in specific parts of their service territory. Within the Supply / Demand Analysis in the Gas Planning Proceeding, Con Edison details the permitting challenges that have delayed or restricted the development of infrastructure projects over the last 5-10 years. The New York State Department of Environmental Conservation's denial of multiple water permit applications for the Northeast Supply Enhancement (NESE) project ultimately led the developer to abandon the project. This pipeline cancellation primarily affected National Grid but also impacted Con Edison's long-term supply outlook.

Question:

a) Please discuss the extent to which EGI has or has not experienced the level of significant delays and challenges by regulatory agencies that has, apparently, been experienced in New York State.

b) Does EGI expect that, in the regulatory landscape in Ontario as it relates to natural gas infrastructure, it may or would be necessary for EGI to implement moratoria on new customer connections without the implementation of IRPAs as a way to circumvent regulatory constraints on facility-based solutions?

Response

a) Enbridge Gas has not experienced the level of delays and challenges from regulatory agencies as seems to have been experienced by utilities in New York State.

b) In relation to the natural gas regulatory landscape in Ontario, Enbridge Gas does not see a need for moratoria on new customer connections at this time.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers ("OGVG")

Interrogatory

Reference:

Exhibit B page 24.

Preamble:

Both electric GSHPs and EASHPs provide a solution that could be deployed to mitigate the need to build new infrastructure or to reduce the amount of new infrastructure required. It should be noted that these solutions may also result in unintended and perhaps meaningful consequences to electrical transmission and/or distribution system(s) and their carbon intensity profiles.

Question:

a) Please explain how, when applicable, the impact of the electrification of gas end-uses on the relevant electricity distribution and transmission systems should be integrated into the IRP analysis. In particular, please explain the extent to which the participation by the potentially affected electricity distributors and transmitters are required in order to properly assess the viability and total cost impact of proposed electrification based IRPAs where the proposed alternative creates incremental electricity demand that may trigger the need for new electricity distribution and/or transmission infrastructure.

Response

Enbridge Gas believes that it is appropriate for any IRPA cost-benefit analysis to take increased natural gas or electric system costs that could result from investments in IRPAs into account.

In order to better understand the size and scale of potential increased electricity system costs and impacts that would result from investment in a particular IRPA, Enbridge Gas intends to advise the IESO and local LDCs of specific IRPAs that it has deemed to be cost effective and is considering for investment in order to better understand the potential impacts to electricity systems that may result. Information on whether the electricity system could support the additional capacity in a particular area and whether, if needed, the lead times required to create incremental electricity capacity would be necessary before Enbridge Gas could prudently pursue investment in an IRPA that converted some portion of natural gas demand to the electricity grid.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers ("OGVG")

Interrogatory

Reference:

Exhibit B page 20.

Preamble:

Customer-Specific Builds – If an identified need has been underpinned by a specific customer's clear determination for a facility option and either the choice to pay a Contribution in Aid of Construction ("CIAC"), or to contract for long-term firm services delivered by such facilities, then that project is not reasonable for an IRP analysis.

Question:

a) Does EGI intend this exception to include builds underpinned by more than one customer, where groups of customers are seeking firm capacity and, collectively, can supply a sufficient mix of CIACs or contracts for long-term firm services (i.e., through the use of EGI's Hourly Allocation Factor as approved in EB-2019-0094) to support a facilities-based solution?

Response

Yes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers ("OGVG")

Interrogatory

Reference:

Exhibit C page 9.

Preamble:

Enbridge Gas acknowledged in its Additional Evidence that,
Although cost/economics is the primary factor with respect to alternative selection, as set out in the Guiding Principles underpinning Enbridge Gas's IRP Proposal (discussed in Section 2.0), there are other factors that may be considered.

Accordingly, Enbridge Gas supports the assessment of well-known and clearly quantifiable impacts to both ratepayers and society. That being said, Enbridge Gas also recognizes the challenges in assigning quantitative values to societal factors that offer indirect benefits. Therefore, Enbridge Gas supports the OEB's consideration of other costs and benefits similar and in addition to those set out in E.B.O. 134 as part of its development of an IRP Framework for Enbridge Gas. When assessing the feasibility of natural gas facility (pipeline) infrastructure and comparing them to IRPAs, the Board should establish a staged economic evaluation standard for IRPAs through this proceeding that ultimately resembles a modified version of the OEB's E.B.O. 134 guidelines or a DCF+ test.

Question:

a) Please confirm that consideration of "societal factors" that offer indirect benefits in what EGI refers to as a DCF+ plus test may result, if approved, in the implementation of IRPAs that are more expensive from a rate-making perspective than the facilities-based options the IRPAs are deferring or replacing.

b) Assuming that a) is confirmed, please comment on the feasibility of splitting the allocation of the costs of an IRPA into two components:

    i. the cost of the facilities-based solution the IRPA is replacing, and

ii. the incremental costs beyond what would have been incurred to implement the facilities-based solution which are only being incurred as a result of going beyond the basic DCF analysis to consider societal factors, with the result that incremental costs incurred in recognition of societal factors are allocated to all of EGI's customers.

Response

a) Confirmed.

b) Enbridge Gas will be able to identify the two components of IRPA costs:

i. Enbridge Gas will have the estimated costs of both the preferred IRPA(s) and the comparable baseline facility alternatives in order to complete its economic assessment of any IRPA(s).

ii. Enbridge will be able to calculate the estimated incremental costs of the IRPA(s) compared to the baseline facility alternatives as part its economic assessment.

Enbridge Gas proposes to treat the entire IRPA cost in the same manner, even in a potential situation where an IRPA cost may be higher than a facilities-based cost as a result of societal factors.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Sustainable Energy Association (OSEA)

INTERROGATORY

Reference:

EGI Additional Evidence, Exhibit B, Page 13 and 14 of 46

Preamble:

Figure 2.1 of the Enbridge's Additional Evidence summarizes IRP Integration at Enbridge Gas

Question:

a) When comparing IRPAs to facility alternatives, will Enbridge Gas test reasonable sensitivities to planning assumptions (e.g., variations in demand growth rates, policy impacts, technology advances)? If yes, please provide a description of how Enbridge will incorporate sensitivity analysis into the planning process.

b) Enbridge Gas states that it incorporates DSM impacts into its annual demand forecast. OSEA supports the incorporation of DSM impacts early in the planning process. Please describe how the quantity and quality of DSM impacts are determined by Enbridge Gas. For example, does Enbridge Gas only assess committed (e.g., contracted) DSM impacts?

c) Please describe how IRPA(s) for identified system needs will be developed, and specify how costs will be estimated, quantity of network demand calculated, and viability of solutions tested.

Response

a) Enbridge Gas will not test sensitivities to the planning assumptions for the demand forecast during its facility and IRPA analysis as doing so for any number of potential factors would not be efficient or reasonable. Enbridge Gas uses the best information available when developing its demand forecasts and utilizes those forecasts to identify future system constraints/needs. Enbridge Gas will monitor identified system constraints as part of the Asset Management Plan process and will update the demand forecast should any of the planning assumptions change. Enbridge Gas will consider all IRPAs available to meet identified constraints as part of the IRP planning process.

Enbridge Gas will test reasonable sensitivities to planning assumptions for specific IRPAs. For example, any assumption associated with an IRPA that would require field validation could have a sensitivity assessment performed at the time of development to better understand the impact on an identified system constraint and any associated baseline facility alternative.

b) Enbridge Gas does not make any assumptions with respect to future changes in DSM program activity in the development of its annual demand forecast. The demand forecast includes currently approved DSM levels carried forward into future years beyond the OEB's current DSM Framework and OEB-approved multi-year plan period.

DSM volumes used in Enbridge Gas's annual demand forecast for the EGD and Union rate zones are determined based on the OEB-approved DSM Plans (EB-2015-0029, EB-2015-0049 and EB-2019-0271).[1]

c) For a high-level overview of how Enbridge Gas proposes that IRP be integrated into planning process, please see the response at Exhibit I.STAFF.2. Enbridge Gas is undertaking a review of its existing planning practices to integrate its IRP Proposal into those processes with more refinement. This review will include the entire IRP process from stakeholdering to implementation of the IRPAs and will include all impacted groups within Enbridge Gas. As part of this effort, Enbridge Gas will identify all of the processes required to assess and evaluate IRPAs including the timing and scope of each step. In addition, this review process will identify additional resources required within Enbridge Gas to adequately undertake IRP. Enbridge Gas expects that approval to proceed with IRP pilot projects will provide a further means to refine and update IRP process integration over time.

[1] EB-2019-0137, Enbridge Gas Inc. – 5 Year Gas Supply Plan, May 1, 2019, pp. 31-33 & 69-71.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Sustainable Energy Association (OSEA)

INTERROGATORY

Reference:

EDI Additional Evidence, Exhibit B, Page 21 to 30 of 46

Preamble:

In December 2020, the Federal Government of Canada announced the intent to raise the carbon price to $170/tonne by 2030.

Question:

a) Please describe how the federal carbon price announcement will influence Enbridge Gas' development of IRPA(s). Please comment specifically on the impact on the Innovative Technologies listed in Section 3 (Page 21 to 30 of 46) of Enbridge Gas' Additional Evidence.

Response

Because the federal carbon price increase is proposed but not yet adopted in legislation for implementation, it has not been incorporated into demand forecasts.

Enbridge Gas includes carbon pricing in the natural gas price variables used in its weather normalized average consumption per customer models. Naturally, demand has a negative response to changes in total prices. If the carbon price reaches $170 per tCO_2e by 2030, the resulting higher natural gas price driver variables used in the models will lead to a lower volume forecast for those years potentially impacting which IRPAs are reasonably considered in the evaluation and where specifically,[1] lower carbon or non-gas alternatives may be suitable to support the objectives of the new federal climate plan. This higher cost of natural gas (inclusive of carbon costs) would make the business case for increased blending of clean fuels such as RNG and hydrogen more attractive, and may increase throughput of natural gas and blended clean fuels for electricity production and compressed natural gas refueling stations.

[1] EB-2020-0181, Exhibit I.SEC.6, January 21, 2021, p. 3.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Sustainable Energy Association (OSEA)

INTERROGATORY

Reference:

ICF IRP Study, ES-43

Preamble:

The ICF IRP Study notes that changes in Ontario energy policy and utility regulatory structure necessary to facilitate the use of DSM to reduce infrastructure investments include “cost recovery guidelines for overlapping DSM and facilities planning and implementation costs, and criteria for addressing DSM impact risks.”

Question:

a) Cost recovery is a barrier to DSM adoption, and OSEA supports the investigation of cost recovery guidelines for DSM. Please provide further details on the cost recovery guidelines required. Please comment on the following:

    i. Cost recovery for expanded planning requirements

    ii. Regulatory framework and cost recovery on developing IRPA(s) including the potential and cost of non-pipeline solutions and demand response

    iii. Cost recovery and regulatory framework for comparing baseline facilities and IRPA(s) in meeting system needs cost-effectively

Response

a)

    i. Please see the responses at Exhibit I.APPrO.6 b) and Exhibit I.STAFF.22 a) regarding incremental IRP costs associated with evaluating and planning IRP/IRPAs.

ii. & iii.

As discussed in Enbridge Gas's Additional Evidence on page 32, the Company proposes an IRP Framework that would see "Like Treatment for Like Results". Specifically, Enbridge Gas proposes to treat the costs (both capital and O&M) associated with planning, implementing, administering, measuring and verifying the effectiveness of investments in IRPA(s) in the same manner as the costs for facility expansion/reinforcement projects (capitalized to rate base) that IRP will defer, avoid or reduce. Capitalizing IRPA costs to rate base ensures that ratepayers avoid rate volatility that could otherwise be caused by significant investment in geotargeted IRPAs that might occur if the full cost of the IRPA is charged to ratepayers at one point in time instead of being spread out over the period in which the benefits are being realized.

Enbridge Gas expects that it will include a proposal for cost recovery of each specific IRPA investment as part of its future applications to the Board for approval to invest in IRPA(s), and/or as part of subsequent applications to recover the costs associated with such investments.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Sustainable Energy Association (OSEA)

INTERROGATORY

Reference:

ICF IRP Study, ES-7 and ES-43; EGI Additional Evidence, Exhibit B, Page 36 and 43 of 46

Preamble:

The ICF IRP Study notes that approval to invest in Advanced Metering Infrastructure ("AMI") is needed to collect hourly data on the impacts of DSM programs and measures. The ICF IRP Study further notes that large customers can have a disproportionate impact on the demand on a network and the timing for additional capacity requirements.

In its Additional Evidence Enbridge Gas notes that "absent more granular consumption data that would be available from AMI implementation, more conservative derating factors will need to be applied towards consideration of a given alternative and, incremental evaluation policy and/or protocols may need to be designed and implemented at additional cost."

However, Enbridge Gas is not proposing to deploy AMI at this time.

Question:

a) Please explain Enbridge Gas' rationale for not deploying AMI at this time.

b) Please provide a high-level overview of what a deployment plan for AMI might include. OSEA is seeking to understand what Enbridge Gas envisions would be the major components of an AMI deployment plan.

c) Has Enbridge Gas considered targeted deployment of AMI? For example, has Enbridge Gas considered targeting large customers that have a disproportionate impact on network demand; or attempting to deploy AMI at downstream nodes within the pipeline network below the gate station level? OSEA is seeking to understand what Enbridge Gas' priorities are in the development of an AMI deployment plan.

Response

a) & b)
As stated in Enbridge Gas's Additional Evidence at Exhibit B, page 45:

> "Currently in Canada, the ultrasonic meters that would support AMI are being reviewed by Measurement Canada. Once approved, these meters would also need to undergo testing by Enbridge Gas's measurement experts before they can be proposed for deployment within Enbridge Gas's franchise area. Enbridge Gas anticipates that ultrasonic meters will receive Measurement Canada approval at some point in mid to late 2021, that Enbridge Gas will continue to assess the feasibility of an AMI implementation and that Enbridge Gas may be in a position to advance AMI-specific applications and a viable roll-out strategy to the Board as soon as 2022."

For additional detail regarding AMI and its potential deployment by Enbridge Gas please see the response at Exhibit I.VECC.11.

c) Enbridge Gas has considered targeted deployment of AMI and will continue to include both targeted and franchise-wide approaches in its analyses. An AMI deployment requires meters and a network to send hourly reads back to Enbridge Gas. The network aspect may not be effective if it is only used by a small portion of customers in its range. As Enbridge Gas determines the optimal AMI scenario, targeting of key geographic areas may be considered where future constraints have been identified and where AMI might be useful in evaluating IRPA(s)' effectiveness.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Sustainable Energy Association (OSEA)

INTERROGATORY

Reference:

EGI Additional Evidence, Exhibit B, Page 45 of 46

Preamble:

Enbridge Gas states that ultrasonic meters are expected to support AMI and are under review by Measurement Canada.

Question:

a) OSEA supports the deployment of AMI to support DSM program Measurement & Verification (M&V) and DSM program design. Please describe why ultrasonic meters were selected as Enbridge Gas' preferred AMI technology.

b) Are there other metering assets that have Measurement Canada support that are currently available for deployment by Enbridge Gas? OSEA is interested in understanding the benefit(s) of waiting for ultrasonic meter approval from Measurement Canada, as opposed to deploying existing alternatives.

Response

a) & b)
Ultrasonic meters are two-way communication natural gas meters whereas other metering technologies that currently have Measurement Canada's support are one-way feeds. This two-way communication allows ultrasonic meters to achieve additional programming functionality, and enables safety features that are not present in other one-way feed offerings, such as: remote gas shut-off abilities; pressure monitoring; meter health checks; high flow alarms; and temperature sensors. There are a number of different ultrasonic meter manufacturers and options can vary amongst them, meaning that not all functions may be available in each ultrasonic meter brand.

Ultrasonic meters may provide cost savings to the utility through a reduction in truck rolls as the remote shut-off function can be utilized in certain situations. Ultrasonic meters also eliminate the additional expense associated with attaching encoded receiver transmitters (“ERTs”) to meters in the field. Attaching ERTs to meters in the field can create additional costs as the meter and ERTs will have mismatched useful lives requiring the need for additional asset tracking and increased labour to repeatedly attach and detach the assets as one needs to be retired while the other remains useful. Enbridge Gas has also learned from its IRP pilot in Deep River that meter reading of ERTs can be inconsistent.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Sustainable Energy Association (OSEA)

INTERROGATORY

Reference:

EGI Additional Evidence, Exhibit B, Page 26 to 27 of 46

Preamble:

In its Additional Evidence, Enbridge Gas states that it will “keep a close eye on DR (demand response) pilots in the residential space.” .

Question:

a) Please describe how Enbridge Gas will “keep a close eye on DR pilots in the residential space.” Specifically, please describe what jurisdictions Enbridge Gas will be monitoring, and what information from the DR residential pilots Enbridge Gas will focus on.

Response

Enbridge Gas is in contact with program managers in key jurisdictions (namely Michigan, California and New York) to keep apprised of DR program progress, best practices and lessons learned, specifically related to customer enrollment, peak hour savings and snapback. Additionally, the Company is also reviewing publicly available reports as they become available.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Sustainable Energy Association (OSEA)

INTERROGATORY

Reference:

EGI Additional Evidence, Exhibit B, Page 27 of 46

Preamble:

Enbridge Gas states that "commercial and industrial customers have been moving away from interruptible rates for the natural gas volumes as they value certainty of supply over the cost reduction."

Question:

a) Please provide details (e.g., customer surveys) supporting the increase in customer value of certainty of supply over the cost of reduction.

b) Beyond value of certainty of supply, please identify other reasons why Commercial and Industrial customers may have moved away from interruptible rates. For example, OSEA's understanding is that a customer with interruptible rates requires a secondary fuel train at site to be eligible. The cost of maintaining a secondary fuel train at a site could be a determining factor in the shift to firm rates.

Response

a) & b)
As demonstrated by the changing mix of executed gas distribution contracts over time, Enbridge Gas has observed an increasing number of customers choosing firm over interruptible services. The number of customers choosing either a fully or a partially interruptible service to meet their energy needs have experienced a continued decline with customer indications that this preference is driven by the specifics of their operation but generally is reflective of key factors including: the on-going costs of owning and operating alternative fuel systems, the reliability and availability of alternative fuel sources during sustained curtailments, and the cost spread between firm and interruptible distribution rates.

Customers are not required to have an alternative fuel for eligibility under an interruptible rate contract. However, they must be able to demonstrate their ability to accommodate a full interruption of natural gas service for the interruptible portion of their demand.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Sustainable Energy Association (OSEA)

INTERROGATORY

Reference:

EGI Additional Evidence, Exhibit B, Page 25 to 27 of 46;

Preamble:

In Enbridge Gas' Additional Evidence, it is noted that Natural Gas DR programs are receiving more attention and sometimes replacing interruptible rates. DR programs may provide an opportunity for more acute targeting of interruptible demand aligned with the value of deferred capacity expansion.

Question:

a) Please provide a summary of DR program types that have been explored by Enbridge Gas to date. Please include a description of the DR program, the potential for the program to achieve demand reduction, an estimate of program cost, and a confidence range for the potential demand reduction and cost estimate.

Response

The information provided in the preamble is incorrect.

Enbridge Gas does not note in its evidence that DR programs are sometimes replacing interruptible rates, nor does the Company agree with the statement that DR programs provide an opportunity to more acutely target interruptible demand.

While Enbridge Gas has been keeping up to date with DR programs in Ontario and other key jurisdictions, (namely the states of Michigan, California and New York), the Company has not explored natural gas DR in a substantive way for use in Ontario beyond understanding potential best practices developed in other jurisdictions. Enbridge Gas has not developed any detailed estimates on savings or costs for a program in Ontario. Consistent with its IRP Proposal, Additional Evidence, Reply Evidence and the clarification provided through responses to interrogatories, Enbridge Gas will consider DR at such time that a system constraint is identified in the future and may bring forward an IRPA application to the Board for approval to invest in DR. At that time Enbridge Gas expects that its application may include additional supporting information regarding DR observed in other jurisdictions, its potential to resolve identified constraints/needs in Ontario, associated costs and risks.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Sustainable Energy Association (OSEA)

INTERROGATORY

Reference:

EGI Additional Evidence, Exhibit B, Page 25 to 27 of 46;

Preamble:

Enbridge Gas notes that ground source heat pumps and electric air source heat pumps "provide a solution that could be deployed to mitigate the need to build new infrastructure or to reduce the amount of new infrastructure required. It should be noted that these solutions may also result in unintended and perhaps meaningful consequences to electrical transmission and/or distribution system(s) and their carbon intensity profiles."

Question:

a) Please explain how Enbridge Gas intends to account for consequences to the carbon intensity profiles of electrical transmission and/or distribution system(s) in evaluating the suitability of IRPAs.

b) Please describe any efforts or activities where Enbridge Gas is coordinating with electricity system planners and stakeholders on IRPAs.

Response

a) As part of the evaluation of an IRPA, the resulting GHG emissions will be evaluated. This evaluation will take into consideration the efficiency of the proposed equipment and the marginal GHG emissions associated with the electricity consumed by such equipment. As part of the stakeholder model put forward by Enbridge Gas and discussed in Enbridge Gas's Additional Evidence under Component 1 of the Stakeholder Engagement Process,[1] local LDCs will be an important stakeholder in which to engage and seek feedback from regarding any potential IRPA solution.

[1] Additional Evidence, Exhibit B, p. 40.

b) In addition to the stakeholder engagement efforts described in the response at part a), please also see the responses at Exhibit I.STAFF.9 and at Exhibit I.STAFF.13.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Sustainable Energy Association (OSEA)

INTERROGATORY

Reference:

EGI Additional Evidence, Exhibit B, Page 31 and 33 of 46

Preamble:

For comparison of IRPAs to facility alternatives, Enbridge Gas suggests using a project horizon that aligns with the OEB-approved depreciable life of infrastructure asset(s) to which the IRPA is being compared. IRPAs may have a different depreciable life or have a contracted term (e.g., DR programs). Further, comparisons by project horizon require confidence in long-term demand forecasts which become less certain over the long-term.

Question:

a) Please describe how Enbridge Gas intends to compare different project horizons for facility alternatives and IRPAs.

b) Please describe how uncertainty in demand forecasts will be incorporated into the comparison of IRPAs to facility alternatives.

c) Please provide annual demand forecasts for the past 10 years and actual demand for the 10 years.

d) Please describe how the risk of stranded or under capacity assets will be managed through the planning process for solutions with longer project horizons. Put another way, please describe how the planning process will consider the risk of underutilized solutions.

e) Please describe how Enbridge Gas will consider scalability of solutions when comparing IRPAs to facility alternatives. For example, facility alternatives typically have fixed additional capacity to the system such as a new pipeline; whereas IRPAs could be tailors to specific system need (e.g., larger quantity of DR procured to meet growing system needs).

Response

a) Enbridge Gas expects the proposed DCF+ methodology will enable the Company to make a value comparison of different project horizons. Please see the response at Exhibit I.VECC.9 for more information on asset lives and project horizons. Enbridge Gas expects the AMP to provide detail on underlying identified system constraints. Please see the response at Exhibit I.STAFF.4 for more information.

b) Enbridge Gas recognizes and has noted in the past that long term forecasting has greater uncertainty than short term forecasting. One method that Enbridge Gas uses to minimize this risk is to refresh forecasts regularly in order to ensure that revised forecasts are incorporated into subsequent plans (such as the Gas Supply Plan or Asset Plan).

   Enbridge Gas also recognizes that deploying IRPAs significantly in advance of an identified system constraint/need carries more forecast uncertainty than simply serving incremental demand with facilities at a later date. Enbridge Gas intends to re-evaluate demand growth regularly in order to reallocate IRPA budgets and program objectives in response to changing system needs as appropriate. The result of this review will appear in subsequent AMP revisions. See Paragraph 80 on page 36 of Enbridge Gas's Additional Evidence for more information.

c) Please see Table 1 for Enbridge Gas's actual versus forecast volumes for the period of 2010-2019. Please note that actual and forecast volumes in the table have been normalized to the corresponding Board Approved degree days for the respective year.

Table 1

EGI Volumes (10^6m^3)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Actual	24,757	25,621	25,779	25,829	25,425	24,985	24,921	24,807	25,483	25,682
Forecast (Budget)	24,326	24,905	25,322	25,857	25,830	25,966	26,255	25,365	24,687	24,697

** There is no distribution volume for Enbridge Gas Power Generation customers*

d) As detailed in Enbridge Gas's Additional Evidence at page 36, a core part of the existing and proposed IRP planning process is the regular review and revision of system constraints/needs as inputs into various planning processes. Please also see the response at Exhibit I.PP.10.

e) As detailed above in the response at part b, Enbridge Gas intends to review and manage IRPA budgets to meet changing needs. If revised analysis of identified system constraints/needs concludes that an additional constraint exists and through the IRPA assessment process the Company determines that incremental IRPAs are the optimal solution, Enbridge Gas will determine which IRPA is best suited to serve the identified system constraint/need at the time while taking into account which IRPAs are already deployed in that region and what synergies can be leveraged there.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Sustainable Energy Association (OSEA)

INTERROGATORY

Reference:

EGI Additional Evidence, Exhibit B, Page 31 and 33 of 46

Preamble:

Enbridge Gas proposes to only proceed with an IRPA where the IRPA "can meet the demands of future system capacity, is more cost-effective than facility alternatives and meets the other important Guiding Principles…"

Enbridge Gas suggests that the Board consider incentivizing Enbridge Gas to prioritize investments in IRPAs by "adding an incentive for such successful investments, over-and-above the regulated rate of return earned (e.g., an incentive based on the net benefits achieved…)"

Question:

a) Is Enbridge Gas proposing that the Board only incentivize Enbridge Gas to successfully implement an IRPA that is more cost-effective than facility alternatives?

b) Would the incentive costs to customers be included in the assessment of facility alternatives to IRPAs?

c) Please describe how an incentive would be determined for successful investments in IRPAs. Would the incentive be pre-determined for all IRPA solutions or would it be specific to the comparison between facility alternatives and IRPAs?

d) Please provide examples from other jurisdictions where incentives have been used to support deployment of IRPAs

Response

a) Yes.

However, as discussed in its Additional Evidence at paragraph 67:

> “Although cost/economics is the primary factor with respect to alternative selection, as set out in the Guiding Principles underpinning Enbridge Gas’s IRP Proposal (discussed in Section 2.0), there are other factors that may be considered.”

Enbridge Gas recognizes that the Board may wish to consider additional factors than solely costs/economics when assessing and/or establishing any IRP related incentives which is why the Company went on in its Reply evidence at page 9 to state:

> “Accordingly, Enbridge Gas supports the assessment of well-known and clearly quantifiable impacts to both ratepayers and society. That being said, Enbridge Gas also recognizes the challenges in assigning quantitative values to societal factors that offer indirect benefits. Therefore, Enbridge Gas supports the OEB’s consideration of other costs and benefits similar and in addition to those set out in E.B.O. 134 as part of its development of an IRP Framework for Enbridge Gas. When assessing the feasibility of natural gas facility (pipeline) infrastructure and comparing them to IRPAs, the Board should establish a staged economic evaluation standard for IRPAs through this proceeding that ultimately resembles a modified version of the OEB’s E.B.O. 134 guidelines or a DCF+ test.”

b) Yes, the cost of any incentives provided to customers in an IRPA solution would need to be included in the assessment of an IRPA in comparison to a baseline facility alternative.

c) & d)
Incentives supporting ConEd’s deployment of non-pipeline solutions are discussed in ICF’s IRP Jurisdictional Review Report provided as part of Enbridge Gas’s Additional Evidence at Exhibit B, Appendix A, pages 26 to 32. For further discussion on the proposed incentives to encourage investments in IRP/IRPAs please see the response at Exhibit.I.Staff.25.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Question:

a) Does Enbridge (including EGD or Union Gas) currently have any policy, procedure or manual (including sections in other manuals) related to IRP? If yes, please provide a copy of all related materials.

b) Please identify which infrastructure project application (i.e. Leave to Construct) filed by Enbridge (including EGD or Union Gas) that does the best job of considering IRP considerations (e.g. DSM or other). Please provide the project name, a brief description and an explanation of what considerations make the project the best at considering IRP options.

c) When Enbridge considers cost savings related to decreased pipe size requirements due to IRP options (e.g. DSM or other), what cost per meter installed does Enbridge use to calculated those savings (e.g. comparing costs of NPS 4, 6, 12, 16, 20, etc.)?

d) Please explain how Enbridge ensures that the costs savings for decreasing pipe size (option analysis) is done on a consistent and defendable basis across all proposed projects. Please provide a table of installed costs by pipe size used if available.

e) Has Enbridge ever done a capacity assessment of its assets across its system? If yes, please provide a copy of that assessment. If no, how does Enbridge assess which pipelines are under-utilized or reaching capacity?

Response

a) No, Enbridge does not have policy, procedure or manual (including sections in other manuals) related to IRP.

b) Enbridge Gas conducted a numerical IRP analyses for the identified system constraint that resulted in the London Lines Project (EB-2020-0192). When comparing the baseline facilities alternative (LTC construct approximately 51.5 km of NPS 4 and 39km of NPS 6 pipeline from Dawn to Komoka to replace existing lines) to the optimal IRPA (ETEE), the facilities alternative was deemed preferable due to considerations of cost, timing and safety.

c) & d)
If Enbridge Gas were to consider cost savings related to decreased pipe size requirements resulting from investments in IRPA(s), each pipe size option would be considered individually as its own potential solution. The developed solutions would then be compared to one another to quantify potential cost savings. Enbridge Gas does not use cost per meter when developing costing options during the Project Design stage. However, a comparison of cost per meter for various pipeline sizes could potentially be back-calculated once total project costs are determined in the future and may become a useful comparison tool for future specific IRP/IRPA applications. At such time that Enbridge Gas seeks OEB approval to proceed with investments in IRPA(s) it expects that it would include an assessment of costs for comparable baseline facilities which could include such a comparison.

e) Yes. Enbridge Gas utilizes hydraulic models to perform ongoing capacity assessments of its systems. Resulting proposed projects to serve growth are compiled in the Asset Management Plan ("AMP") which is filed with the OEB on an ongoing basis. The latest copy of the AMP was filed as part of Phase 2 of Enbridge Gas's 2021 Rates proceeding (EB-2020-0181) at Exhibit C, Tab 2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Question:

Does Enbridge perform IRP-related screenings for any infrastructure projects. If yes,

a) Please provide a copy of the materials used in the IRP-related screening.

b) Please describe how the IRP-related screening process was developed and which department owns it.

c) Please describe how Enbridge currently decides which projects will be subject to an IRP-related screening.

d) Please provide a list of all infrastructure projects mitigated or reduced due to IRP considerations.

Response

a) & b)

The May 2018 ICF IRP Study (placed onto the record in this proceeding July 22, 2020) and the 2019 IESO/OEB Achievable Potential Study,[1] have been the basis for IRP/IRPA related assessments of identified system constraints underlying applications to the Board for leave-to-construct facilities to date.

The IRP/IRPA related assessment process was jointly developed by several departments within the Company. Currently no one single department "owns" the assessment/screening process in its entirety. Enbridge Gas intends to determine clear accountabilities for future IRP/IRPA assessments through process mapping exercises informed by the IRP Framework ultimately established by the Board for Enbridge Gas through this proceeding. Please also see the response at Exhibit I.OSEA.1 c).

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[1] https://www.ieso.ca/2019-conservation-achievable-potential-study

c) IRPA(s) (or non-pipeline alternatives) are increasingly being assessed for most major identified system constraints in direct response to the Board's encouragement discussed in Enbridge Gas's Additional Evidence at pages 3 to 12. Following the establishment of an IRP Framework for Enbridge Gas, the Company intends to apply the guidance provided therein by the Board to assess identified system constraints as appropriate going forward. Please also see the responses at Exhibit I.STAFF.2 and at Exhibit I.OSEA.1 c), for discussion of the integration of IRP with existing planning processes.

d) It is likely that most recent facility projects initiated by Enbridge Gas have been delayed, mitigated or reduced to some degree since Enbridge Gas initiated interruptible services and demand side management ("DSM"). Quantifying the peak period impact of these actions would be difficult due to the lack of granular metering and tracking of DSM effects over time. AMI would support the quantification of these impacts in the future. Please see the response at Exhibit I.STAFF.4 f), for more information on the potential benefits of AMI. It is not reasonably possible to provide an account of all recent projects mitigated by such actions to date. Further, the goal of this proceeding is to establish an IRP Framework for Enbridge Gas to support its consideration of natural gas IRP going forward, not to scrutinize Enbridge Gas in hindsight for prudent investments deemed by the OEB to be in the best interests of ratepayers at the time.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Question:

a) Please provide a summary of all external stakeholder feedback received by Enbridge on its IRP Proposal prior to it being filed and explain how the feedback was incorporated into the IRP Proposal.

Response

Enbridge Gas did not seek direct external stakeholder feedback on its IRP Proposal prior to it being filed with the Board. However, Enbridge Gas's IRP Proposal was informed by Natural Gas IRP practices in other jurisdictions, Ontario developments and by the IRP Studies that Enbridge Gas has commissioned ICF to conduct.

The May 2018 IRP Study conducted by ICF was informed by external stakeholder feedback. A summary of the external stakeholder feedback received for the May 2018 IRP Study can be found in EGD's January 15, 2018 DSM Mid-Term Review (EB-2017-0127/EB-2017-0128) Submission at paragraphs 119 to 129.[1]

[1] https://www.rds.oeb.ca/CMWebDrawer/Record/596649/File/document

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

References:

[Exhibit B]

[PollutionProbe_IR_Appendix A-Toronto Plan_20210112]

[PollutionProbe_IR_Appendix B-Ottawa Plan_20210112]

[PollutionProbe_IR_Appendix H-Ontario MEP Guideline_20210112]

Question:

a) Please describe what steps Enbridge takes to coordinate with municipal energy and emissions plans when considering infrastructure projects.

b) Please explain how ICF believes that the IRP Framework and planning assumptions should be aligned with community/municipal energy and emissions plans.

c) Please provide a copy of the RFP and scope of work for the IRP related studies that ICF has conducted for Enbridge (including EGD and Union Gas).

d) Please explain how Enbridge integrates Ontario municipal energy and emissions plans into its planning assumption for infrastructure planning [MEP links?]

Response

a) b) & d)
Enbridge Gas engages government agencies, municipalities, indigenous groups and landowners early in its assessment of potential facility projects, consistent with the Board's guidance for applications for Leave to Construct (and Environmental Guidelines for Hydrocarbon Pipelines and Facilities in Ontario). Enbridge Gas is also continuously gaining insight from the municipalities within its franchise area.

Generally, Municipal Energy Plans (“MEP”) and Community Energy Plans (“CEP”) take a broader perspective, including: all fuels, such as gasoline and diesel for transportation, natural gas and electricity; and outlining GHG reduction targets achieved through varying methods including conservation, efficiency improvements and fuel type optimization. CEPs are often aspirational in nature, with little budgetary backing or implementation plans. Enbridge Gas’s Municipal Energy Solutions team is often engaged with municipalities in their MEP efforts, not only providing aggregated consumption data allowing them to understand their historical consumption by sector to inform their CEP processes, but also offering tangible conservation and low carbon opportunities and collaborations. Once municipalities develop and initiate concrete operational plans with adequate budgets to take steps towards meeting their MEP/CEP goals and a pattern of achieved results is developed, Enbridge Gas expects that it will be in a better position to reflect these results in its facility planning forecasts. Coordination between a municipality’s Energy Planning team and Enbridge Gas planning processes can also benefit IRP plans by incorporating local input on opportunities to develop community-based solutions. Please also see the response at Exhibit.I.VECC.1.

c) Please see the response to interrogatories in Enbridge Gas’s 2017/2018 Demand Side Management Deferral and Variance Account Disposition Application proceeding (EB-2020-0067) at Exhibit I.SEC.8 Attachment 1, filed October 7, 2020, for the RFP and Scope of Work for the May 2018 ICF IRP Study.

The Scope of Work for the Updated Jurisdictional review can be found at Attachment 1 to this response. Personal information as well as the hourly rates set out within Attachment 1 have been redacted. Enbridge Gas will file a separate unredacted copy of Attachment 1 under separate cover with the Board and Board Staff. This is consistent with the approach taken in EB-2020-0067 for the disclosure of the RFP and Scope of Work for the May 2018 ICF IRP Study.

PROPOSAL

To: [redacted] and [redacted], Enbridge Gas

From: [redacted] and [redacted], ICF Canada

Date: June 10, 2020

Re: IRP Analysis – Dawn to Parkway Expansion

Background

In 2018, ICF completed an Integrated Resource Planning study for Enbridge Gas Inc. (EGI) focused on assessing the viability of employing targeted energy efficiency as an alternative to natural gas infrastructure projects.[1] This study included a jurisdictional review and consultations to determine what progress has been made on this topic by other North American utilities. The majority of the research for this jurisdictional scan was completed in 2017. Since this time, gas utilities have continued to study energy efficiency as a non-pipe option.

EGI has requested that ICF complete an updated jurisdictional scan to assess recent developments in the use of energy efficiency as a gas infrastructure alternative. EGI would also like ICF to provide regulatory support during the IRP proceeding on an as needed basis. As part of this work, ICF will leverage work completed for EGI as part of the 2018 IRP Study, as well as work in other jurisdictions including New York State.

Proposed Scope of Work

The scope of the proposed work will include the following tasks:

1. **IRP Jurisdictional Scan Update:** ICF will update the jurisdictional review from the IRP Study with a specific focus on New York State. This will include the following tasks:
    - **Review of recent developments in natural gas IRP:** Recognizing that there have been changes with natural gas IRPs since the IRP Study, ICF will complete targeted research and a limited number of consultations to assess recent developments. Research and consultations will be focused on leading jurisdictions that were identified as being at the forefront of natural gas IRP developments during the IRP study. This includes NW Natural, FortisBC, and ConEd.

      In addition, ICF will leverage our involvement with the procurement process for

[1] ICF, “Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment – Final Report”, completed on behalf of Enbridge Gas Distribution and Union Gas Limited, pp. 154-155, May 18, 2018.

non-pipe solutions in ConEd's service territory, as well as our review of New York and New York City natural gas markets for other clients to:

- Provide a summary of the ongoing ConEd Smart Solutions for Natural Gas Customers Program, including intervenor positions, oppositions to the proposal, issues, and outcomes.
- Review the history and status of ConEd and National Grid non-pipeline solution efforts, including a review of the current long-term supply plan review underway at the NY PSC.
- Summarize the status of the New York Public Service gas supply planning proceeding.

- **Comparison of New York and Ontario:** ICF will leverage staff expertise and targeted research to compare and assess structural differences in the following aspects between New York and Ontario. This research will leverage staff specializing in gas markets, electricity markets, and energy efficiency policy. Where appropriate, we will consider differences in service territories, customer types, and nature of rate classes (e.g. firm vs. interruptible).
  - **Legislative mandates and regulatory regimes:** ICF will provide a high-level analysis of the differences between the legislative mandates and regulatory regimes in New York and Ontario, such as differences in the regulatory and rule-making structure, carbon pricing mechanisms and targets, emission reduction policies, clean energy standard programs and specific targets for resource specific procurement targets to support mandates and emission reduction targets, such as offshore wind or energy storage procurement targets. This will also include a brief overview of the legislative changes and regulatory direction in each jurisdiction that have led to present conditions, such as the support for natural gas community expansion and moving customers off of fuel oil in each region.
  - **Electricity markets and systems:** ICF's review will describe and explain key differences between the electricity markets and systems in Ontario and NY, highlighting the most important implications on system planning processes. In addition to a summary on past, current and projected capacity mixes and system constraints, the analysis will outline key market structures such as energy and capacity market structures, processes for resource procurements and the interplay between policies and planning. ICF will also provide a high-level overview of the DER policies in each region and how this has impacted the development of policies and frameworks related to non-wire alternatives (NWA).
  - **Natural gas markets and systems:** ICF will describe and explain key differences between the natural gas markets and systems in Ontario and NY, highlighting the most important implications on system planning processes. In addition to insights regarding pipeline infrastructure in each jurisdiction, this will include an assessment of supply and demand sources and constraints, winter peak supply constraints on supply/transmission, availability of storage, and the viability of different types of non-pipeline solutions such as CNG, LNG, and biogas. ICF will also discuss the relative proportion of energy demand taken up by natural gas in each region and the relative energy prices for average costumers compared to electricity.

    - **Energy efficiency markets and systems:** ICF will identify and explain implications of key differences between the energy efficiency markets and systems in Ontario and New York. This will include the process to set energy efficiency targets, the role of utilities in each jurisdiction, and a review of how NYSERDA impacts the planning and delivery of energy efficiency in New York. We will also provide a high-level overview of the history of natural gas DSM programs in each jurisdiction, discussing when these programs originated, recent trends, current and historical spending on a $ per customer basis, and the level of integration between electric and natural gas-related EE programming. Finally, ICF will provide an overview of achievable potential study results in each region, highlighting differences.

  - **Reporting:** The results of our targeted research and consultations will be compiled in a Draft Report for the EGI team's review and feedback.

2. **IRP Regulatory Support:** As requested by EGI staff, ICF will provide support throughout the IRP Regulatory process. This will include reviewing supplementary evidence put forth by other parties and supporting as a witness in related regulatory processes, which are anticipated to last at least till the end of 2020. ICF may also work with another third-party consultant currently conducting analysis for EGI where required, to coordinate information and/or provide comment. Support may include but not be limited to responding to interrogatories, supporting submissions, and testifying in technical conferences and/or oral hearings.

Proposed Budget

ICF is proposing a fixed fee budget of [redacted] for the completion of this project. This does not include any applicable taxes or expenses. Although we do not anticipate any expenses at this stage, any related expenses will be approved by EGI and will be invoiced at cost. Hourly rates are based on the Amending Agreement dated July 24, 2018 (amendment to Master Services Agreement (MSA)). We have also added hourly rates for the Managing Director and Subject Matter Expert categories, which is consistent with other work of this nature. Details on the anticipated level of effort and the staff involved in the execution of this work are provided below.

Exhibit 1: Proposed Fixed Budget for Jurisdictional Scan

TASK DESCRIPTION	STAFF AND LABOUR ESTIMATES																Total Labour Cost	TOTALS
	Project Manager		*Gas Markets Expert*		*Strategic Support*		*Electricity Markets Expert*		*NWA and DERs Expert*		*EE Policy Expert*		*Gas Markets Support*		*Lead Researcher*			
	[redacted]		[redacted]		[redacted]		[redacted]		[redacted]		[redacted]		[redacted]		[redacted]			
	hrs	[redacted]	hrs	[redacted]	hrs	[redacted]	hrs	[redacted]	hrs	[redacted]	hrs	[redacted]	hrs	[redacted]	hrs	[redacted]		
Project Initiation and PM																	[redacted]	
Client Meetings and Ongoing PM	[redacted]	[redacted]																
Review of Recent Developments in Natural Gas IRP																	[redacted]	
Targeted research	[redacted]	[redacted]																
Consultations																		
Comparison of New York and Ontario																	[redacted]	
Legislative mandates and regulatory regimes	[redacted]	[redacted]																
Electricity markets and systems																		
Natural gas markets and systems																		
Energy efficiency markets and systems																		
Reporting																	[redacted]	
Draft reporting	[redacted]	[redacted]																
Final reporting																		
TOTALS	[redacted]	[redacted]																

In addition, due to the undefined nature of the necessary IRP Regulatory Support, ICF is proposing to complete this work on a time and materials basis based on the same hourly rates, as summarized in the table below.

Exhibit 2: Proposed Hourly Rates for IRP Regulatory Support

ICF Staff	Rate Category	Hourly Rate ($/h)
[redacted]	Managing Director	[redacted]
[redacted]	Senior Subject Matter Expert	[redacted]
[redacted]	Vice President	[redacted]
[redacted]	Subject Matter Expert	[redacted]
[redacted]	Senior Manager	[redacted]
[redacted]	Associate	[redacted]

Project Schedule

Assuming that this project kicks off during the week of June 15, 2020, ICF will deliver a draft report by July 22, 2020. The report will be finalized based on feedback from the EGI team.

ENBRIDGE GAS INC.

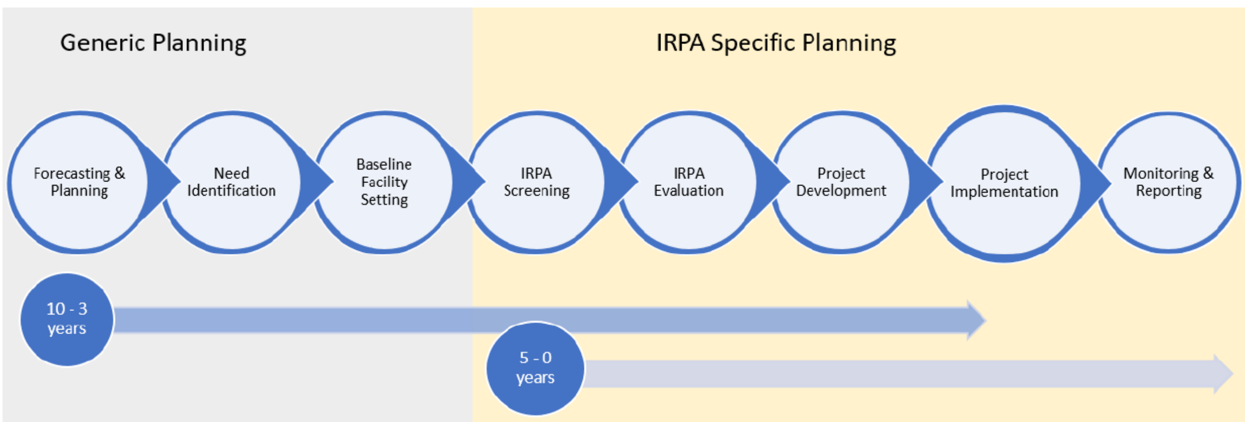
Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

References:

[Exhibit B]

Figure 2.1



Question:

a) Recently, many Leave to Construct projects have been submitted to the OEB within 3 years of the proposed construction date. Please explain what would change from the status quo if the approach outlined in Figure 2.1 was leveraged.

b) Does Enbridge have a long-term demand forecast and plan that identifies specific needs across its system and required infrastructure? If yes, please provide a copy.

c) Please explain how the long-term demand forecast and infrastructure plan relates to Enbridge's 5 Year Gas Supply Plan.

Response

a) For facility alternatives that are determined to be required following IRP assessment/screening, it is likely Enbridge Gas would still have filed the LTC applications within three years of the proposed construction date. Where an IRPA(s) is identified as the preferred alternative to meet an identified system constraint in the future, Enbridge Gas expects that it will file an IRPA application for approval more than three years in advance of the date when a comparable facilities alternative would have to be constructed to resolve the constraint.

b) Yes, Enbridge Gas filed its Asset Management Plan as part of its 2021 Rates proceeding (EB-2020-0181) which identifies the long-term needs across its system. Please see EB-2020-0181, Exhibit C, Tab 2 for the Asset Management Plan.

c) Please see the response at Exhibit I.STAFF.2 for a discussion of the demand forecasting and planning processes for Enbridge Gas's 5-Year Gas Supply Plan and Asset Management Plan.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

References:

[Exhibit B, Page 4]

"And while DSM – appropriately underpinned by its own distinct framework - has evolved as experience has been gained, it is anticipated to continue to be essential in continuing to reduce the natural gas usage and energy bills of Enbridge Gas customers for years to come while also continuing to passively mitigate infrastructure needs over time through reduction in annual demand"

Question:

a) Please explain why DSM would only passively mitigate infrastructure needs over time, rather than being used as an active tool to contribute to infrastructure cost mitigation and consumer energy cost savings.

b) Does the statement above suggest that Enbridge does not believe that DSM is an effective IRP tool? Please explain the answer.

c) Please provide the amount of DSM annual savings targeted in the Enbridge 2021 DSM Plan, and compare that as a percentage of the 2019 OEB/IESO DSM Potential Study. Please include the calculations.

Response

a) & b)
Please see the response at Exhibit I.STAFF.11.

c) A response to this question was provided in Enbridge Gas's response to Interrogatories submitted by Pollution Probe in the 2021 DSM plans proceeding.[1] Enbridge Gas has inserted the response below:

[1] EB-2019-0271, Enbridge Gas Responses to Interrogatories, Exhibit I.PP.2

Regarding questions that involve interpreting the 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study ("2019 APS"), Enbridge Gas would like to ensure that the appropriate contextual lens is applied when considering its responses. Enbridge Gas stresses that any responses derived from analyzing the 2019 APS must be considered in conjunction with the underlying assumptions used in the study and the corresponding uncertainty associated with those assumptions.

Regarding uncertainty, Navigant, the author of the 2019 APS states,

> "The analysis and outputs of this study depend on a large number of inputs, all of which are estimates of one form or another: estimates of measure savings, forecasts of future consumption, assumptions regarding future inflation rates, etc… However, all estimates are, by definition, uncertain, which necessarily means that estimated outputs must also be uncertain."[2]

While the 2019 APS represents the most recent study of its kind for Ontario, due to the uncertainty associated with the assumptions and estimates used and the resulting uncertainty of the possible outcomes, Enbridge Gas believes the 2019 APS is only <u>one</u> of <u>many</u> inputs that could be used to inform the stated 2019 APS objectives which include: (i) the development of future conservation policy and/or frameworks; and (ii) program design, implementation and evaluations.

While Enbridge Gas will endeavor to be responsive where possible in the answers it provides, these answers should be considered as accurate as the underlying assumptions and estimates upon which the 2019 APS potential is based.

A few key items to note when considering the constraints in trying to compare 2019 APS forecasts and budgets with those generated by Enbridge Gas:

- The 2019 APS is a self-identified net study, and as such did contemplate free-ridership when developing its forecasted potential.

  The 2019 APS, Section 7.2.4.2 <u>Net Savings Study</u> states:[3]

  > "…most programs will have at least some free riders, the program administrator incurs additional incentive and administrative costs to deliver to these customers without achieving any additional energy efficiency potential beyond what would happen naturally…"

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[2] 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study, pp. 2-3.

[3] 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study, Navigant Consulting Ltd., Updated December 10, 2019, p. 106

The 2019 APS further clarifies:

> "Program design, delivery, and assessment of free ridership are beyond the scope of this potential study."

As a result, the underlying net-to-gross assumption(s) that would need to be understood to make comparisons of gross (actual) budgets relative to the budgets shown in the 2019 APS are not specified.

- Another limiting factor to comparing the potential put forward by the 2019 APS study to Enbridge Gas's forecasted targets for 2020 and 2021 is exclusion of an overhead budget that would invariably be needed to support the achievement of the potential being put forward by the 2019 APS.

- Finally, Enbridge Gas targets have been traditionally set as Lifetime m^3 or CCM targets, the 2019 APS deal with annual m^3 forecasted potential. In order to align any comparative analysis an assumed measure life would need to have been stipulated.

The above items represent some of the concerns Enbridge Gas has with making comparisons or drawing conclusions for future potential based solely on the 2019 APS… In an effort to be as responsive as possible, Enbridge Gas is providing the following information to allow others to draw their own conclusions, but reiterates the limitations inherent to the 2019 APS, as discussed above.

The 2019 APS suggests that ~$113.3 million annual m^3 can be achieved based on a budget of ~80 million which was not fully costed in the 2019 APS.[4]

As outlined in the response at Exhibit I.PP.7 Attachment 1, Enbridge Gas's 2021 forecast results based on achievement of 100% OEB-approved targets is approximately $1.94 billion lifetime m^3 based on a total budget of ~$132 million.

It should be apparent that these two data points cannot reasonably be compared without the application of assumptions. For example, the application of an assumed 15-year measure life to Enbridge Gas's lifetime savings target would amount to ~$130 million annual m^3 or ~115% of the potential in the 2019 APS.

[4] 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study, p. 116.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

References:

[Exhibit B, Page 13]

"Optimized Scoping - Recognizing that reviewing IRPAs for every forecasted infrastructure project would be extremely time intensive, binary screening should be undertaken to confirm which forecast need(s) should undergo an IRP assessment"

Question:

a) Please provide a list of IRPA activities and related costs estimates for a typical small (below the threshold Enbridge proposes), medium (at the threshold Enbridge proposes) and large project (above the threshold Enbridge proposes).

b) Please provide a copy of the assessment criteria and any tools Enbridge proposes for the binary screening of projects.

c) Is there a cost, size or length threshold Enbridge is proposing to use to decide which projects should have an IRPA done.

d) For projects where an IRPA will not be done, is there any IRP-related assessment proposed?

Response

a) Enbridge Gas cannot reasonably provide specific cost estimates for assessments of projects of various sizes at this time as the number of potential IRPA(s) applicable to each is too large. However, it is likely that assessments for small projects could have as many potential IRPAs and be as time consuming as for larger projects. Please see the response at Exhibit I.GEC.6, for further discussion regarding the costs of assessing IRPA(s).

b) Please see Enbridge Gas's Additional Evidence at Exhibit B, pages 15 through 21 which outlines the IRP assessment approach and binary screening tools proposed.

c) No. Enbridge Gas is not proposing to impose specific thresholds for cost, size or length of a potential comparable facility project at this time. However, those are factors which would inform the analysis of and related viability of specific IRPAs considered to avoid, defer or reduce investments in facility alternatives.

d) No. Optimized Scoping as a Guiding Principle is suggested to mitigate unnecessary costs for ratepayers of unproductive and inefficient analyses.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

References:

[Exhibit B, Page 35]

"It takes approximately three to five (3 - 5) years to put a facility expansion/reinforcement project into service, including: project selection, preparation of an application to the OEB for LTC and subsequent approval, procurement of land rights, completion of relevant environmental studies and resulting impact mitigation efforts, to obtain all necessary permits, to order materials and to construct the facilities."

Question:

a) If Enbridge knows that an expansion/reinforcement project is needed in advance, please explain why Enbridge does not identify projects in its OEB filings 3-5 years in advance.

b) Please provide an illustrative timeline for a project that requires 5 years to put into service using the categories listed above.

Response

a) Enbridge Gas identifies projects as part of its Asset Management Plan filing which provides a 10-year plan of future projects. This was done, by exception, within a five-year timeframe in the AMP filed in the 2021 Rates proceeding (Phase 2), please also see the response at Exhibit I.STAFF.6.

b) The timeline included at Figure 2.1 of Exhibit B is for illustrative purposes only. The timing of projects, including both traditional facility projects and IRPAs, will vary depending on the size of the project, the timing of the need, the approvals required and timelines for construction and implementation of the IRPA/facilities. In an effort to be as responsive as reasonably possible Enbridge Gas provides an illustrative example of the timeline for a large LTC project in Table 1 below.

Table 1

Timing*	**Activity**
5 years	Project selection
3-5 years	Preparation of LTC application including environmental studies, land rights procurement
2-0 years	Acquire necessary permits, purchase materials, construction
0 years	Implementation

*number of years prior to the facility being required.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

References:

[Exhibit C, Page 4]

"Enbridge Gas supports striving for consistency between future IRPA applications and leave-to-construct ("LTC") applications and their underlying policy frameworks, to the extent reasonably possible"

Question:

a) What scope of assets does Enbridge believe IRP should be applied to (e.g. all current and future assets, or just current assets, future assets only, transmission, distribution)? Please explain.

Response

Enbridge Gas has outlined proposed criteria for completing a binary screening for whether an IRP analysis should be considered in its Additional Evidence at Exhibit B, pages 19-20 under the section titled "Where should IRP be considered". Further insight on this topic might be aided by the completion of the pilot projects.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

References:

[Exhibit C, Page 25]

"In terms of the broader natural gas system, all indications in the foreseeable future are that Enbridge Gas's natural gas infrastructure in Ontario will remain used and useful …"

Question:

a) Please provide a copy of all analysis and materials that were used to develop the statement above.

b) Please define what was intended by the term "foreseeable future".

Response

a) & b)
Enbridge Gas has not conducted specific analysis to support the statement referenced as part of this proceeding. Enbridge Gas's conclusions are based on continued annual in-franchise demand growth realized by the Company, continued support for expansion into new communities across Ontario, and continued interest in ex-franchise services from customers in Ontario, Quebec and in markets downstream. Further, the forecast for natural gas commodity prices in Ontario is anticipated to remain competitive compared to electricity and other fossil fuels. By the term "foreseeable future", Enbridge Gas is referring to the 10 year time horizon contemplated within its Asset Management Plan and based upon the most recent government policies (e.g., stated intent of the Federal government to apply an escalating cost of carbon emissions beginning in 2023 to 2030 culminating at a cost of \$170/tonne CO_2e). Enbridge Gas does not speculate on the effects of potential future government policies. Rather, the Company develops planning processes with consideration for OEB-approved methodologies and policies that are in place where impacts are known and quantifiable. Please also see the response at Exhibit.I.VECC.1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

References:

[Exhibit C]

Appendix C of Enbridge's Reply Evidence (Exhibit C) contains an executed Form A for Expert Witnesses from ICF.

Question:

a) Please provide a complete list of the evidence that the Form A's from ICF pertain to.

b) Other than the ICF experts identified in the Form A's, does Enbridge have other (internal or external) experts it is putting forward to defend any evidence currently filed? If yes, please provide a list of which experts own which pieces of evidence.

Response

a) Form A from ICF pertains to the 2018 IRP Study filed with the Board as part of this proceeding on July 22, 2020 and the IRP Jurisdictional Review Report filed with Enbridge Gas's Additional Evidence on October 15, 2020 as Appendix A.

b) No, Enbridge Gas is not putting forward other independent experts in this proceeding.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (“PP”)

INTERROGATORY

References:

[ICF IRP Report, Section 2.1] - “Based on a review of the state of the industry, there is no relevant precedent for, or evidence of natural gas utilities consideration of the impact of broad-based DSM, geo-targeted DSM or dedicated DR programs impact on facilities planning. Further, while electric utilities have used DSM and DR programs to reduce the need for new generating capacity and transmission capacity for many years, there is only relatively limited experience deferring distribution system infrastructure.”

[PollutionProbe_IR_Appendix C-BCUC Guidelines_20210112]

[PollutionProbe_IR_Appendix D-ConEd Interim BCA Handbook_20210112]

Question:

a) Recent IESO auctions included energy efficiency and other Distributed Energy Resources (DERs) to enable a greater range of IRP solutions. For example, the York Region auction alone exceeded the desired response by 340% (34MW vs. 10MW target). Does ICF agree that these types of examples show capacity to meet Ontario’s energy needs through non-traditional IRP solutions? If not, why not.

b) Pollution Probe has provided two illustrative examples above of specific natural gas IRP related initiatives. One from BCUC started almost 20 years ago and has been matured through regulatory process and effort of the Canadian gas utility (Fortis). The second example indicates an interim gas utility handbook that was developed in 2017 and updated based on stakeholder feedback. Were these examples identified during the ICF industry review? If yes, why were they not included?

Response

a) ICF Canada cannot draw any conclusions with respect to natural gas IRP from these examples because they apply to the electricity sector rather than the natural gas sector.

Furthermore, ICF Canada cannot draw any conclusions from these examples with respect to the use of electric energy efficiency, demand response, or any other forms of electric distributed energy resources to defer distribution system infrastructure investments as opposed to utility-scale generation (i.e., transmission-connected) capacity and transmission capacity.

b) The term IRP in the context of the ICF's May 2018 report is similar to IRPA (also referred to as non-pipe alternatives (NPA)). Traditional natural gas IRP, which is the focus of the BCUC Guidelines and the IRP process employed by many other gas utilities for decades, does not specifically consider IRPA. As such, the BCUC Guidelines are not directly relevant to this proceeding.

The ConEd Interim BCA Handbook was published in 2018,[1] based on work performed in 2017. Similarly, most of the consultations in ICF's May 2018 report were completed in 2016 and 2017. While ConEd may have had the intention of conducting future work on "broad-based DSM, geo-targeted DSM or dedicated DR programs impact on facilities planning" and their 2017 work would go on to match the definition of IRP in ICF's May 2018 IRP report, ConEd did not reveal any details on this as part of preliminary consultations and did not give permission to ICF to reveal any details publicly in a published report.

[1] Consolidated Edison. (2018). Interim Benefit Cost Analysis Handbook for Non-Pipeline Solutions. New York, NY, USA.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

References:

[PollutionProbe_IR_Appendix F-IESO Engagement_20210112]

Question:

Does ICF agree that the IESO Engagement Principles used to coordinate their planning represent best practices? If not, what changes would you recommend?

Response

ICF does not believe that the IESO Engagement Principles used to coordinate planning would necessarily be applicable to natural gas, nor should they be considered to be "best" practice for natural gas network planning.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

INTERROGATORY

Reference:

Ex B P13

Question:

Enbridge Gas's IRP Proposal are underpinned by four Guiding Principles. With respect to Public Policy, Enbridge Gas indicates the IRP will be considered in a manner to ensure that it is supportive of and aligned with public policy, where appropriate.

Please specify the existing public policy that Enbridge Gas is most focused on in considering IRPAs.

Response

In considering natural gas IRP and investment in IRPAs, Enbridge Gas will consider public policy where there is existing legislation, Board directives or Company policies in place that may impact IRP. This includes public policy related to federal, provincial and municipal climate policies, indigenous policies, and community expansion policies. Specifically, the following policies are currently in place and will be considered:

- Greenhouse Gas Pollution Pricing Act, including the associated regulations;[1]
- Final Guidelines for Potential Projects to Expand Access to Natural Gas Distribution;[2] and
- Enbridge Inc.'s ("Enbridge") Indigenous Peoples Policy.[3]

Other regulations that are implemented in the future arising from the Made in Ontario Environment Plan and the federal Pan-Canadian Framework on Clean Growth and Climate Change will also be considered as they are enacted in legislation.

[1] https://laws-lois.justice.gc.ca/eng/acts/G-11.55/
[2] https://www.oeb.ca/sites/default/files/ltr-final-guidelines-gas-expansion-20200305.pdf
[3] https://www.enbridge.com/~/media/Enb/Documents/About%20Us/indigenous_peoples_policy.pdf?la=en

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

INTERROGATORY

Reference:

Ex B P13

Question:

The evidence states "…Enbridge Gas proposes an IRP process plan that takes into account its existing forecasting and system planning processes which provide critical input to the development of a fulsome Asset Management Plan ("AMP") designed to meet the forecasted firm contracted peak period demands of customers. As set out in Figure 2.1, following OEB approval of an IRP framework, Enbridge Gas will incorporate its IRP Proposal into its existing planning processes and review qualifying facility needs for potential IRPAs."

a) Does Enbridge Gas foresee the need for any significant changes to the design and execution of its existing planning processes as a result of incorporating an IRP Proposal into its existing planning processes? Please discuss.

b) Does Enbridge Gas foresee the need for new recruits as a result of incorporating an IRP Proposal into its existing planning processes? Please discuss.

c) Does Enbridge Gas foresee the need for additional staff/executive training as a result of incorporating an IRP Proposal into its existing planning processes? Please discuss.

d) Does Enbridge Gas consider incorporating its IRP Proposal into its existing planning processes as a cultural shift within the organization? Please discuss.

e) Please discuss any potential obstacles with respect to incorporating its IRP Proposal into its existing planning processes and the impact of these obstacles.

<u>Response</u>

a) c) & e)
Please see the response at Exhibit I.OSEA.1 c). Enbridge Gas is currently undergoing a review of its existing planning practices to integrate its IRP Proposal into those processes. At this time, as that review is ongoing and in the absence of an IRP Framework, it is unknown what additional employee training and/or unique obstacles to integration, if any, will be required and experienced respectively.

b) Please see the response at Exhibit I.GEC.6.

d) Yes, incorporating IRP into Enbridge Gas's planning processes has the potential to result in a cultural shift. While Enbridge Gas's historic focus on safely and reliably serving the firm contractual demands of its customers on a peak design basis will remain, the Company expects that the establishment of an IRP Framework aligned with its IRP Proposal, Additional Evidence and Reply Evidence will be transformative to its traditional planning processes, will require extensive new work to administer/manage and operationalize and could have far-reaching implications in terms of how the Company continues to grow and earn revenues, and how it interacts with its customers and communities in which it operates.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

INTERROGATORY

Reference:

Ex B P19

Question:

In Enbridge Gas's 2019 IRP Policy Proposal, there was a table (Table 3.1) that summarized project attributes supporting the relevance of IRPAs. Since the time of that filing, and through its continued learnings about IRP, Enbridge Gas has evolved its thinking around the criteria that would constitute a binary screening for IRP assessment.

As a result of reviewing the expert evidence filed by OEB Staff and GEC/ED, how has Enbridge Gas evolved its current thinking around the criteria that would constitute a binary screening for IRP assessment?

Response

Enbridge Gas evolved its thinking on binary screening related to IRP assessment in the period between filing its original IRP Proposal in 2019 and its Additional Evidence on October 15, 2020. Enbridge Gas considered in more depth what factors should constitute a more definitive screening and which items, although insightful, might not absolutely preclude the possible viability of an IRPA such as load growth rate, or project cost, especially when the Company broadened its definition of potential IRPAs to include activities beyond incremental amounts of traditional DSM programming.

Please see the response at Exhibit I.STAFF.8, for further detail on Enbridge Gas's proposed IRPA Screening process.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

INTERROGATORY

Reference:

Ex B P20

Question:

The evidence states….."The urgent timing and nature associated with most safety-related projects (e.g., requiring replacement of short pipeline segments), including integrity projects, does not allow for the lead times necessary for developing IRPA solutions."

Please confirm Enbridge Gas' latest thinking regarding the lead time threshold necessary for developing IRPA solutions.

Response

Enbridge Gas anticipates that an IRPA will take between 3 and 5 years to be designed and deployed with enough time to verify that it is performing as anticipated to resolve underlying identified system constraints. Of course, there are many factors that could influence this estimate such as the time needed to design, conduct, award RFPs, and negotiate contracts with third-party IRPA service providers. This is consistent with Guidehouse's Report regarding Con Ed's planning (i.e., a 36 – 60-month timeline for projects over $2 million[1]), and with Con Ed's own claim that,

> "Implementing alternative solutions takes longer than a traditional project because [Con Edison] must engage customers and the market, where applicable, and prove sufficient time for installation, verification and operation of alternative solutions."[2]

[1] EB-2020-0091,Guidehouse, Natural Gas Integrated Resource Planning in New York State and Ontario. November 12, 2020, p. 30.
[2] Ibid.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

INTERROGATORY

Reference:

Ex B P20

Question:

With respect to the Community Expansion & Economic Development criterion, Enbridge Gas indicates if a project has been driven by policy and related funding to explicitly deliver natural gas into communities to help bring heating costs down, then it is not reasonable to conduct an IRP analysis.

Is Enbridge Gas aware of any community expansion projects in other jurisdictions where an IRP analysis was conducted to help bring costs down and potentially defer, avoid or reduce new facility infrastructure? Please discuss.

Response

No, Enbridge Gas is not aware of any community expansion projects in other jurisdictions where an IRP analysis was conducted by a natural gas utility.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

INTERROGATORY

Reference:

Ex B P21-25 Gas and Non-Gas Alternatives Paragraphs 40-51

Question:

Enbridge Gas notes that RNG may be cost prohibitive especially as it compares to new natural gas infrastructure.

a) Does Enbridge Gas currently consider any other innovative technologies to be cost prohibitive?

b) Please explain how Enbridge Gas plans to prioritize and optimize innovative technologies in the context of IRPAs.

Response

a) & b)
Enbridge Gas is agnostic to the technologies that the Company would consider as viable IRPAs for investment to relieve identified system capacity constraints. IRPAs must satisfy Enbridge Gas's proposed IRP Guiding Principles as set out in paragraph 22 of the Company's Additional Evidence. The listing of technologies put forth to date should not be considered static. Enbridge Gas intends to continually consider new technologies and solutions as they become available. Enbridge Gas does not intend to apply any generic prioritization to the technologies being considered for application as IRPAs.

In terms of specific IRPAs cited by Enbridge Gas in its Additional Evidence and Reply Evidence, it is premature to draw conclusions regarding their cost-effectiveness until the Board establishes a cost-effectiveness assessment mechanism as part of its IRP Framework for Enbridge Gas and until such time that Enbridge Gas identifies a specific system constraint. Therefore, Enbridge Gas does not currently consider any technology to be entirely cost prohibitive at this time.

The Company intends to maintain a listing of innovative technologies that can be analyzed and considered as an IRPA (or part of an IRPA) consistent with its proposal set out in paragraph 29 of its Additional Evidence. At such time that Enbridge Gas identifies system constraints, it will assess any IRPAs with the potential to resolve those constraints and depending upon the unique circumstances of each may conclude that certain IRPA(s) are viable non-facility alternatives. Enbridge Gas expects that, consistent with its Additional Evidence,[1] it would next seek OEB approval to proceed with investment in such IRPA(s) and, as part of that application in support of receiving a determination of the Board that the proposed preferred alternative is prudent and should be approved, Enbridge Gas would include assessments of other IRPAs and facility/non-facility alternatives in terms of their cost-effectiveness and their relative alignment with the Guiding Principles.

[1] Exhibit B, Additional Evidence, pp. 17 & 32.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (“VECC”)

INTERROGATORY

Reference:

Ex B P26

Question:

Enbridge Gas indicates it will keep a close eye on DR pilots in the residential space.

Please discuss the current potential for low income DR pilots in the residential space.

Response

Please see the responses at Exhibit.I.OSEA.6 and at Exhibit I.OSEA.8.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

INTERROGATORY

Reference:

Ex B P26

Question:

Enbridge Gas indicates "Ultimately, cost/economic evaluation together with consideration of system reliability, safety and sustainability and broadly protecting the interests of customers will enable Enbridge Gas and the Board to determine whether it is preferable to proceed with investment in an IRPA."

Please provide Enbridge Gas' definition of sustainability in this context.

Response

The statement quoted by VECC can be found at Exhibit B, pages 30 to 31.

Sustainability can cover a broad range of topics, including environmental, social and governance. Simply put, sustainability means meeting the energy needs of current customers, without compromising the ability of future generations to meet their own needs.

Enbridge Inc. and Enbridge Gas broadly define sustainability as: (i) conducting our business in an ethical and socially responsible manner; (ii) protecting the environment and the safety of people; and (iii) engaging, learning from, respecting and supporting the communities and cultures with which we work.[1]

[1] Enbridge Inc. 2019 Sustainability Report (Resilient. Reliable. Responsible), p. 15;
https://www.enbridge.com/~/media/Enb/Documents/Reports/CSR_2019_FULL-1009.pdf?la=en

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

INTERROGATORY

Reference:

Ex B P31

Question:

The project horizon will be set to align with the OEB-approved depreciable life of the infrastructure asset(s) to which the IRPA is being compared.

Please discuss if any other options were considered to set the project horizon.

Response

For IRPAs to be evaluated on a comparable basis relative to traditional facilities investments, it is important to ensure that the time horizon under both alternatives are consistent when evaluating costs and benefits. In this way, Enbridge Gas can make a determination on the most cost-effective option, given that time horizons are the same for both alternatives. For example, if a traditional infrastructure project uses a 40 year time horizon for purposes of the economic feasibility, and an IRPA has an expected useful life of 20 years, the IRPA economic feasibility must consider two rounds of investment to provide 40 years of equivalent demand relief. In this way, economic feasibility can be compared on equal terms.

Setting the timeframe of the IRPA to align with the time horizon of traditional facility investment is appropriate because the IRPA is being evaluated as an alternative to a facility investment. Other options for project horizon would require a review of OEB policies regarding the economic feasibility of traditional facility investments. For that reason, Enbridge Gas has not considered other options for the project horizon.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

INTERROGATORY

Reference:

Ex B P39-42

Question:

Stakeholder engagement for IRP will include three engagement components.

Please discuss Enbridge Gas' current thinking with respect to reaching low income customers to provide input on IRP-related matters and whether any enhancements to current practices are needed and being considered.

Response

Please see the response at Exhibit I.STAFF.9.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

INTERROGATORY

Reference:

Ex B P42-46

Question:

Enbridge Gas indicates the deployment of an AMI system, including ultrasonic meters, allows for the collection of frequent interval data that Enbridge Gas requires to effectively target IRPAs and to monitor and verify their effectiveness to ensure that the IRPAs are performing as expected and to ensure peak period demand reductions are materializing. However, Enbridge Gas is not proposing to deploy AMI at this time.

a) Please provide an overview of Enbridge Gas' current state with respect to AMI.

b) Please provide the work activities, costs and timelines needed to fill this gap and effectively deploy an AMI system in order to target IRPAs and monitor and verify their effectiveness.

c) Please explain further why Enbridge Gas is not proposing to deploy AMI at this time.

d) Please discuss the optimal time for Enbridge Gas to deploy an AMI system.

Response

a) & d)
Enbridge Gas is currently forming a project team to further investigate deployment of AMI and the associated timing of deployment. Enbridge Gas expects to address AMI in its 2024 rebasing application.

b) Enbridge Gas sees the major components of an AMI deployment plan as including choosing the proper meter, network, and software applications in addition to ensuring compatibility between assets, as not all meters and networks can communicate with each other. There is significant work required to understand the impacts of AMI deployment on the utility to ensure that all functions that are affected will be able to function smoothly with AMI. At this time Enbridge Gas is not able to provide a timeline to deploy an AMI system as that estimate will come out of the work described in part a. For an estimated cost please see the response at Exhibit I.AAPrO.2 d) iii).

c) As described in the response to parts a) and b), Enbridge Gas is currently completing preliminary investigations into the deployment of AMI. With respect to meters, ultrasonic meters are pending Measurement Canada approval and once approved will need to undergo testing by the Enbridge Gas measurement experts before they can be deployed within the Enbridge Gas franchise area. It is anticipated the ultrasonic meters will receive Measurement Canada approval in early to mid-2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

INTERROGATORY

Reference:

Ex C P6

Question:

Regarding Value of Pilot Projects, Enbridge Gas supports EFG's recommendation that two pilot projects be developed by Enbridge Gas in 2021 and launched in 2022 to gain further experience and insights around planning, implementing and tracking IRPAs.

a) Please discuss Enbridge Gas' current thinking with respect to two potential candidates for pilot projects.

b) Please provide more details on the formal process needed to identify, scope and select candidate pilot projects and the potential cost and time implications.

Response

a) & b)
Please see the response at Exhibit I.STAFF.12, for discussion of Enbridge Gas's current thinking with respect to potential IRP pilot projects.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

INTERROGATORY

Reference:

Ex C P25, P

Question:

At Page 26, Enbridge Gas proposes that the pilot projects be selected and implemented following the development and issuance of an IRP Framework for Enbridge Gas.
At Page 25, Enbridge Gas indicates it could then apply the learnings from those pilot projects to future IRPAs.

Please discuss how Enbridge Gas' proposed IRPP Framework incorporates a mechanism for continuous improvement so that learnings from those pilot projects can be applied to future IRPAs.

Response

Please see the response at Exhibit I.STAFF.12.