ENBRIDGE

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VIA RESS and EMAIL

September 7, 2021

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

Dear Christine Long:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2021-0147
2022 Rates (Phase 1) – Interrogatory Responses and Corrected Exhibits

In accordance with Procedural Order No. 1 dated August 9, 2021, enclosed please find interrogatory responses from Enbridge Gas in the above noted proceeding.

In addition to the interrogatory responses, Enbridge Gas is also filing correction to the following exhibits:

Exhibit	Correction
Exhibit B, Tab 1, Schedule 1, page 3, Table 1	• Line 1 – changed 2022 Proposed in EB-2020-0095 to 2022 Proposed in EB-2021-0147 • Line 2 – changed 2021 Approved in EB-2019-0194 to 2021 Approved in EB-2020-0095
Exhibit B, Tab 1, Schedule 1, Appendix A	• Line 2 – Opening balance should be zero • Line 5 – Closing balance should be zero • Line 8 - Annual PDO Shift line 11 + line 17 +line 21 was corrected to Annual PDO Shift line 11 + line 18 +line 22

Please contact the undersigned if you have any questions.

Yours truly,

(Original Signed)

Rakesh Torul
Technical Manager, Regulatory Applications

cc: Intervenors (EB-2021-0147)
David Stevens, Aird and Berlis LLP

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, p. 8

Question(s):

As a result of declines in the forecast for Rate 145 between 2021 and 2022, the DSM unit rate for Rate 145 customers increases significantly when the 2022 DSM budget allocation to this rate classes is held constant to the 2021 level. The Company has experienced a gradual migration of customers and associated volumes from Rate 145 to Rate 110 and proposes to shift the related DSM budget of $0.450 million from Rate 145 to Rate 110 to recognize the customer movement and reduce the DSM unit rate burden that would otherwise be experienced by the remaining customers in the rate class.

a) Were alternatives other than holding the 2021 level considered? If so, please provide additional details.

b) What is the individual DSM unit rate burden that would otherwise be experienced by the remaining Rate 145 class customers if no shift of the related DSM budget were to take place?

c) Would shifting the associated DSM costs of migrating customers result in no DSM-related rate increases to remaining Rate 145 customers? Has Enbridge Gas conclusively determined that there is no risk of cross-subsidization as a result of allocating DSM costs from one rate class to another?

Response:

a) There were no other alternatives considered other than holding the total DSM budget in rates at the current approved level. This approach is consistent with the approach agreed to by parties in Union's 2016 Rates (EB-2015-0116) settlement agreement when the 2016 DSM plan was not approved at the time of the rates

application. On August 26, 2021, the OEB has approved the continuation of the legacy utility 2021 DSM plans for the duration of 2022. The approved 2022 DSM budget is unchanged from what has been included as proposed DSM cost Y-factor in the filing for this 2022 Rates proceeding. Also, see the response at Exhibit I.BOMA.2.

Despite holding to the 2021 DSM budget level in 2022 rates, the Company identified certain rate classes that faced significant increases as a result of changes in the forecast used to derive the DSM unit rates and proposed a modest DSM budget shift between rate classes to mitigate the increases.

b) Please see Table 1 comparing the DSM unit rates for Rate 145 without and with the budget shift. Without the budget shift, the DSM unit rate for Rate 145 would be 2.5851 ¢/m³ higher (Line 3, Column c).

Table 1

Line No.	Particulars	DSM Costs ($000)	Delivery Volumes ($10^6 m^3$)	Unit Rates (¢/m³)
		(a)	(b)	(c) = (a)/(b)
	Rate 145			
1	Without Budget Shift	1,597	17.4	9.1766
2	With Budget Shift	1,147	17.4	6.5915
3	Change	(450)	-	(2.5851)

c) With the budget shift, the 2022 DSM unit rate for the remaining Rate 145 customers is 6.5915 ¢/m³, which is 0.9094 ¢/m³ higher than the 2021 DSM unit rate of 5.6821 ¢/m³. Note that in the absence of the budget shift, the 2022 DSM unit rate would increase even higher at 9.1766 ¢/m³ for the remaining Rate 145 customers as shown in b). There is no risk of cross-subsidization due to changes in the DSM budget costs in rates because any difference between the 2022 forecast DSM costs in 2022 Rates and actual 2022 DSM costs will be captured in the Demand Side Management Variance Account (DSMVA) and cleared to customers at a later date. Between the DSM unit rates in 2022 Rates and any resulting DSMVA clearance unit rate, current Rate 145 customers will pay their appropriate allocation of the 2022 DSM actual spend.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, pp. 3-4

Question(s):

In Union Gas's 2014 rates proceeding (EB-2013-0365), parties agreed to as part of the Settlement Framework for Reduction of Parkway Delivery Obligation (PDO), to permanently shift the PDO of Union South direct purchase customers to Dawn over time and introduce the payment of a Parkway Delivery Commitment Incentive (PDCI) for any continuing obligated deliveries at Parkway. The intention of the PDO shift (when possible) and the PDCI payment was to remedy the inequity between large volume direct purchase customers and all users of the Dawn Parkway System. Enbridge Gas forecasts that no additional PDO shift will be available to Union South direct purchase customers for November 1, 2021 to November 1, 2022.

a) In Enbridge Gas's opinion, why is there no interest from large volume direct purchase customers to take advantage of the PDCI and shift additional PDO?

b) How does Enbridge Gas promote or inform eligible large volume direct purchase customers of the availability of PDCI to shift PDO?

Response:

a) Enbridge Gas would only require additional PDO obligations or offer additional PDCI when it has the need for additional capacity.

b) Once turnback has been identified, Enbridge Gas would communicate any availability to customers directly, through the Company's customer newsletter and/or at large volume customer meetings. Please also see Exhibit I.ED.2 g).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, pp. 4-7

Question(s):

In accordance with the commitment made in the EB-2020-0095 settlement proposal, Enbridge Gas assessed pipeline and market-based solutions in this application, to reduce or eliminate the PDO. Enbridge Gas assessed certain infrastructure alternatives as part of this exercise. Enbridge Gas considered two infrastructure options: the Kirkwall to Hamilton NPS 48 pipeline and the Dawn to Enniskillen NPS 48 pipeline. The evidence notes that the Kirkwall to Hamilton followed by the Dawn to Enniskillen project sequence provides the best cost per unit of capacity of potential Dawn Parkway system projects. As a result, Enbridge Gas did not review other Dawn-Parkway system projects as alternatives.

a) If Enbridge Gas did not review other alternatives, how did it determine that the two considered alternatives were the lowest cost options?

b) Did Enbridge Gas undertake a preliminary review of other possible options? If yes, please provide information on these preliminary options.

Response:

a) and b)

Enbridge Gas completed a preliminary assessment of infrastructure alternatives consistent with the document “Dawn to Parkway Transmission System – Review of System Design” filed as Exhibit A, Tab 7, Attachment 1 in EB-2019-0159. This document is filed as Attachment 1 to this interrogatory response. It provides additional detail on the criteria used to review the Dawn Parkway System to determine if the existing facilities are adequate from a capacity and reliability standpoint to service the

forecast design day demands of in-franchise and ex-franchise customers. As discussed in the document, a “Schedule of Facilities” is prepared which compares the cost per unit of capacity of the various infrastructure alternatives.

The following pipeline and compression infrastructure facilities (listed in no particular order) were included in the analysis:

- Lobo E Compression (44,500 ISO HP);
- Bright D Compression (44,500 ISO HP);
- Parkway E Compression (44,500 ISO HP);
- Dawn to Enniskillen NPS 48 Pipeline (17.1 km);
- Lobo to London North NPS 48 Pipeline (16.9 km);
- Bright to Owen Sound NPS 48 Pipeline (17.7 km);
- Kirkwall to Hamilton NPS 48 Pipeline (10.1 km);
- Milton to Parkway NPS 48 Pipeline (8.7 km).

For the purposes of the assessment in this application, to reduce or eliminate the PDO, Enbridge Gas evaluated the Additional Capacity, Capital Cost and Cost per Unit of Capacity of the above stated options. Each option was analyzed individually and the NPS 48 Kirkwall Hamilton project resulted in the least cost per unit of capacity and was selected as the first proposed facility. The NPS 48 Kirkwall Hamilton did not have sufficient capacity to fully replace the PDO, so additional options were considered. With the NPS 48 Kirkwall Hamilton project chosen, the capacity of the remaining options changes due to the system hydraulics. The remaining options cost per unit of capacity was recalculated and the NPS 48 Dawn Enniskillen had the lowest cost per unit of capacity of the remaining options. The combination of NPS 48 Kirkwall Hamilton and NPS 48 Dawn Enniskillen created sufficient capacity to fully reduce the PDO.

The 278 TJ/d of capacity created from the combined Kirkwall to Hamilton NPS 48 and Dawn to Enniskillen NPS 48 is sufficient to replace the current 2022 PDO of 275 TJ/d. The Company is not proposing to proceed with this facilities solution because the revenue requirement of this solution is higher than the PDO cost (See Exhibit B, Tab 1, Schedule 2, Table 2). If the Company did proceed with this facilities solution, it would then file a LTC application, which would include detailed analysis of alternatives to the proposed project.

Dawn Parkway Transmission System

Review of System Design

14 June 2019

Transmission Optimization & Engineering Department

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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.

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[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 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.

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3. Forecast of Design Day Demand

Enbridge Gas has a requirement to provide 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 2019. From this data, Enbridge Gas has found the likelihood of a 43.1DD 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 Union South Rate Zone customers can continue to be 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 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 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 Network Analysis 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 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)

The 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)

The 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.

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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 the 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 contract 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 Energy Services 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 Enbridge Gas 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 over 280 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 Pipeline L.P. ("Vector), Panhandle Eastern Pipeline Company L.P. ("Panhandle Eastern") via the Enbridge Gas Panhandle system, Great Lakes Gas Transmission Pipeline ("GLGT") via Great Lakes Pipeline Canada ("GLC"), DTE Energy ("DTE") via St. Clair Pipelines L.P. ("St. Clair Pipelines"), Bluewater Gas Storage, LLC ("BGS") via Bluewater Pipeline (St. Clair Pipelines L.P.), and ANR via Niagara Gas Transmission Limited LINK Pipeline ("Niagara Link").

Enbridge Gas can also receive gas into the Dawn 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 the 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 Chippawa 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 system supply is described in EB-2019-0137 Enbridge Gas Inc. – 5 Year Gas Supply Plan.

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[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.

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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-2014-0365). 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 customer 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-2014-0365). 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 a number of 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 that 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.
    - The 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.

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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.

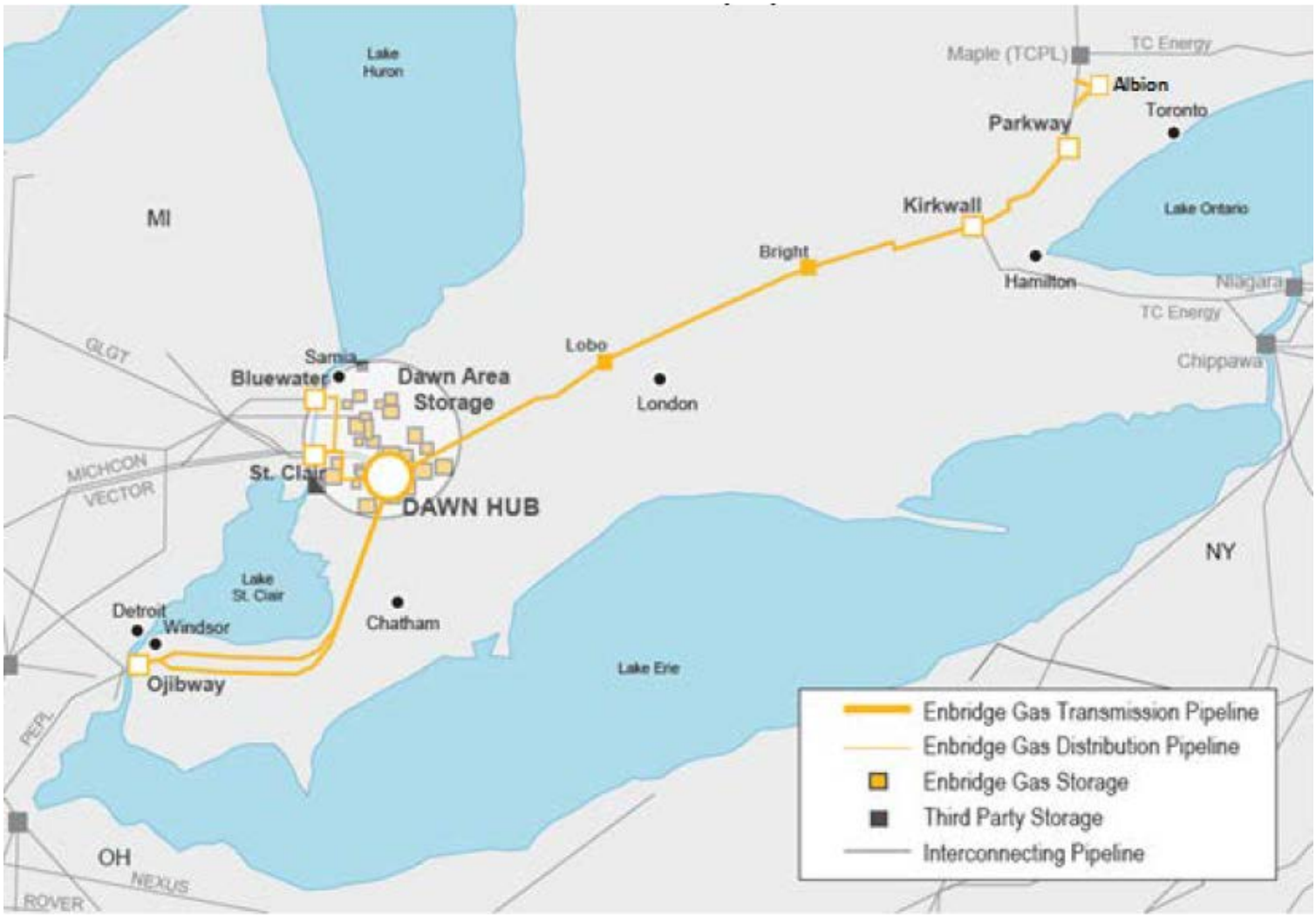
System
The transmission system including the pipelines, compressor stations and the metering and regulating facilities

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



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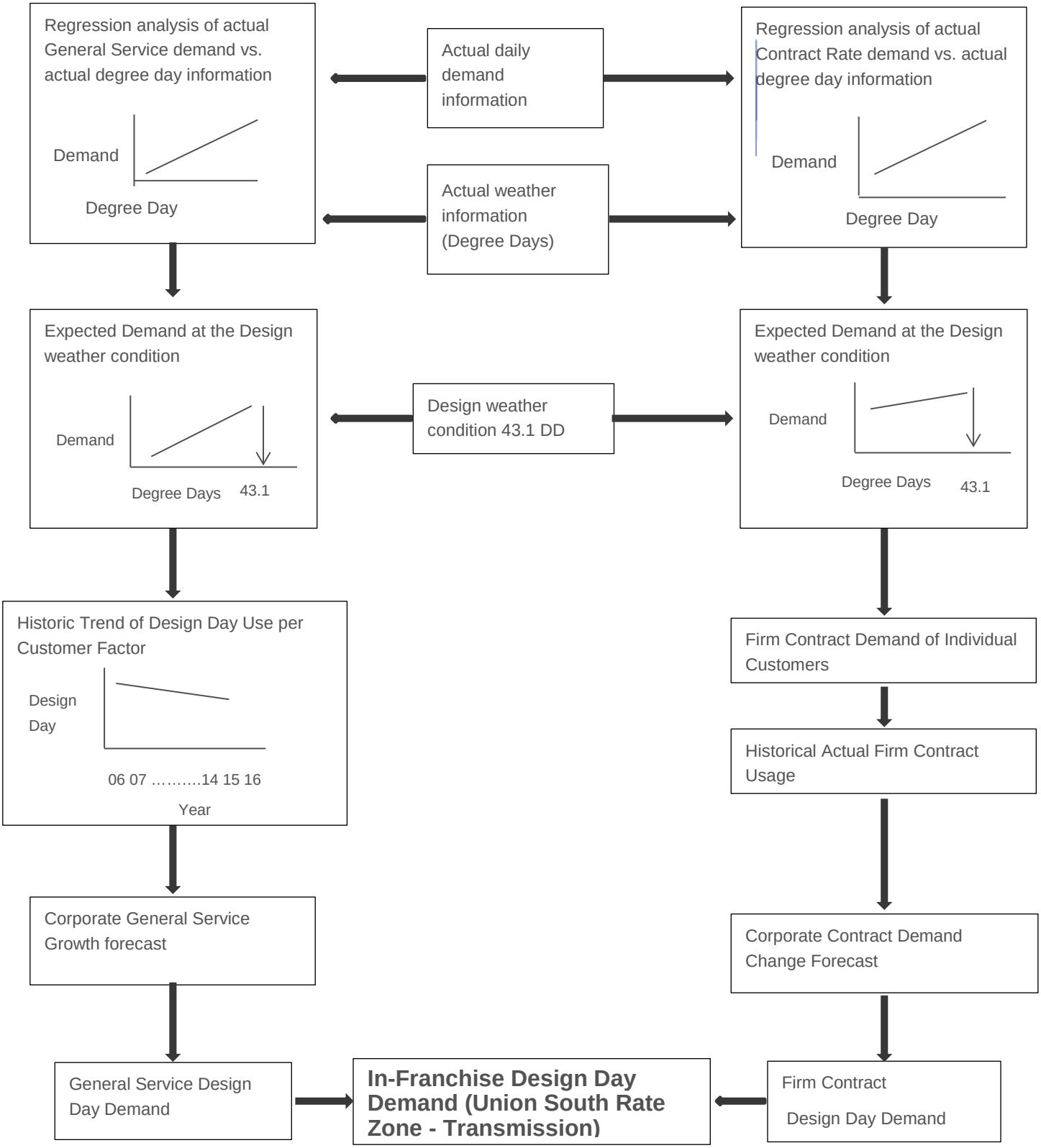
SCHEDULE 2 – UNION SOUTH RATE ZONE IN-FRANCHISE DESIGN DAY DEMAND DEVELOPMENT



Note: Forecasts provided by Demand Forecasting Department

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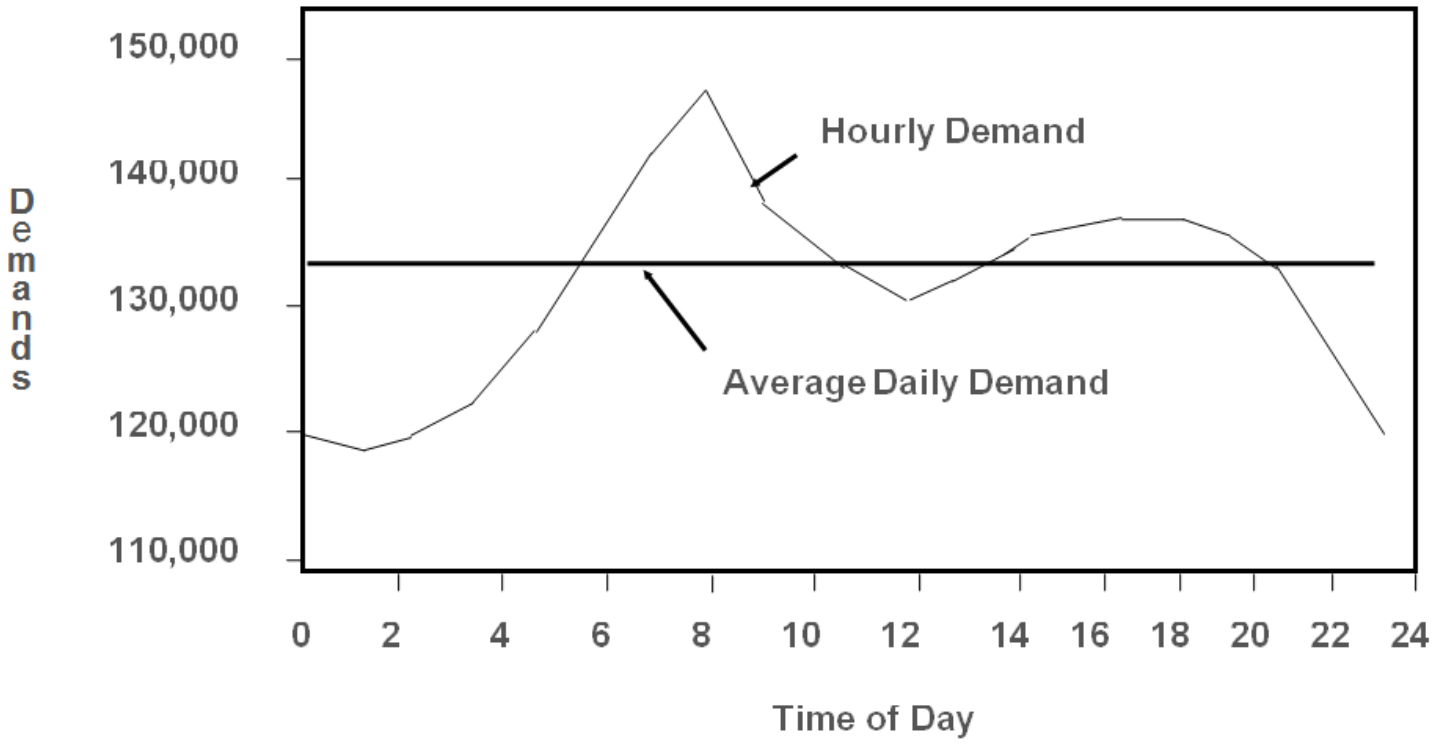
SCHEDULE 3 – SAMPLE DESIGN DAY DEMAND PROFILE (HOURLY PROFILE)



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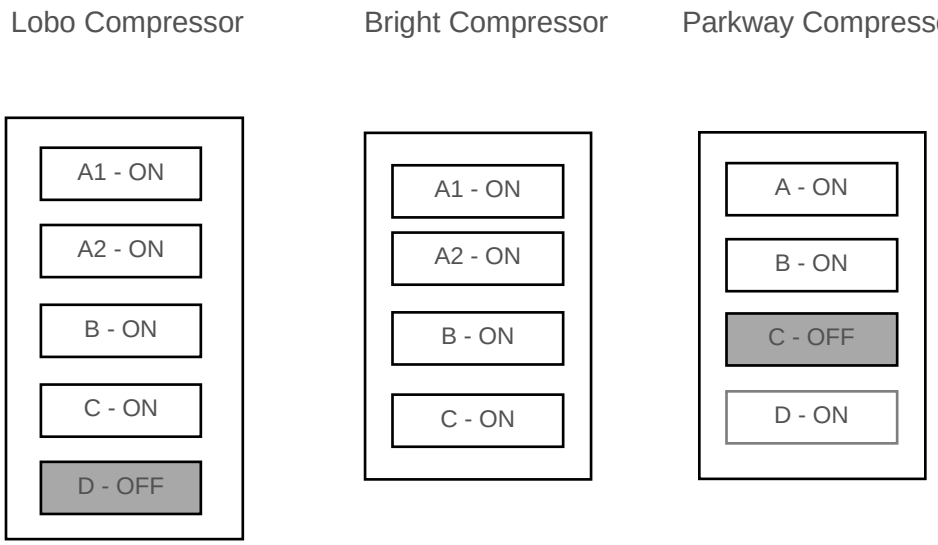
SCHEDULE 4 LOSS OF CRITICAL UNIT COVERAGE

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



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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:

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

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

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
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, pp. 7-9

Question(s):

In order to assess market-based alternatives to reduce or eliminate PDO, Enbridge Gas issued a Request for Proposal (RFP) to the market to determine market availability for a firm exchange service which the company may require between Dawn and Parkway. The evidence indicates that Enbridge Gas received limited interest (less than 50,000 GJ/day) in response to the RFP that could potentially be used to reduce the PDO.

a) Enbridge Gas indicated that it issued the RFP to the market. What type of customers or rate classes were informed of the RFP?

b) Based on the response to the RFP, does Enbridge Gas intend to enter into any agreement with interested parties to reduce the PDO? If no, why not?

c) Enbridge Gas has noted that in order to pursue the market-based alternatives, Enbridge Gas seeks direction from the OEB to secure the offered firm exchange capacity. In Enbridge Gas's opinion, does it require OEB approval to enter into an agreement for the firm exchange capacity? If not, what specific direction does Enbridge Gas require from the OEB?

Response:

a) The RFP was circulated to an established group of market participants through a non-binding but confidential RFP. Market participants included LDCs, Transmission Pipeline Companies, Marketers, Power Customers, Producers and Energy Management Companies.

b) and c)

Based on the bid received in the RFP Enbridge Gas would consider contracting with the bidders. Enbridge Gas is seeking OEB direction to move forward and requires guidance to establish a methodology to recover costs of the proposal.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit A, Tab 2, Page 5 of 6, Paragraph 16

Preamble:

Approval of the IRM rate adjustment set out in this Application will result in the following bill impacts:

- the net annual bill increase for a typical EGD residential customer consuming 2,400 m^3 per year will be approximately $7.76 per year for sales services customers and $7.74 per year for bundled direct purchase customers, each excluding any 2022 ICM impacts;
- the net annual bill increase for a typical Union South residential customer consuming 2,200 m^3 per year will be approximately $8.71 per year for sales services customers and $8.65 per year for bundled direct purchase customers, each excluding any 2022 ICM impacts; and
- the net annual bill increase for a typical Union North residential customer consuming 2,200 m^3 per year will be approximately $10.49 per year for sales services customers and $11.42 per year for bundled direct purchase customers, each excluding any 2022 ICM impacts.

Question(s):

(a) What are the anticipated 2022 ICM impacts for each of the typical residential customers? Please indicate what additional amounts, if any, are likely to be charged to typical residential customers for each of the different types of customers.

Response:

a) Matters related to 2022 ICM funding will be addressed in Phase 2 of the 2022 Rate application, which will be filed separately in October 2021, under docket number EB-2021-0148.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit B, Tab 1, Page 7 of 19, Paragraph 15

Preamble:

On May 5, 2021, Enbridge Gas filed its proposed 2022-2027 DSM plan (EB-2021-0002). The application is still in the early stages of the regulatory process and as a result Enbridge Gas proposes to maintain the 2021 DSM budget of $67.8 million for the EGD rate zone and $64.3 million for the Union rate zones in 2022 Rates.

Question(s):

(a) If a decision is released on application EB-2021-0002, prior to November 26, 2021, will the new DSM budget be implemented by Enbridge Gas for the rates beginning January 1, 2022, or will Enbridge Gas maintain the current 2021 DSM budgets for the rates beginning January 1, 2022?

Response:

On August 26, 2021, the OEB issued its Decision and Order on 2022 DSM activities[1] and has ordered that Enbridge Gas maintain the currently approved 2021 DSM budget for the duration of 2022. The approved budgets for the 2022 DSM programs are $67.8 million for the EGD rate zone and $64.3 million for the Union rate zones. The approved 2022 DSM budget is unchanged from what has been included as proposed DSM cost Y-factors in the filing for this 2022 Rates proceeding.

[1] EB-2021-0002, Decision and Order on 2022 DSM activities dated August 26, 2021, page 2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit B, Tab 1, Page 5 of 9, Paragraph 17

Preamble:

Any alternative to reduce or eliminate the PDO will reduce the cost of PDCI payments (due to a lower PDO) but will increase the cost associated with the PDO shift in Enbridge Gas's rates. As a result, the cost of alternatives to reduce or eliminate the PDO should be assessed against the current PDCI cost.

Question(s):

a) Can Enbridge Gas provide the assessment of the cost of alternatives to reduce or eliminate the PDO as compared to the current PDCI cost?

b) Further, can Enbridge Gas provide the assessment of cost of alternatives to reduce or eliminate the PDO as compared future estimated PDCI costs?

c) What would the anticipated long term savings be compared to the estimated short term costs of implementing each alternative?

Response:

a) The PDCI cost in 2022 Rates is $14.8 million for continued obligated deliveries at Parkway which is less than the approximate low end revenue requirement associated with a build required to eliminate the PDO.

   Please refer to Exhibit B, Tab 1, Schedule 2, Table 2, page 8.

b) There is no change expected for PDO in 2023. Please refer to Exhibit B, Tab 1, Schedule 2, Table 2, page 8.

c) Please refer to Exhibit B, Tab 1, Schedule 2, Table 2, page 8.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, Page 9

Preamble:

"In order to pursue the market based alternative Enbridge seeks direction from the OEB to secure the offered firm exchange capacity."

Question:

(a) Is Enbridge seeking direction from the OEB in this proceeding as to whether to secure the offered firm exchange capacity as described above?

(b) Is the question of whether to secure the offered firm exchange capacity as described above within the scope of what the OEB could direct in this proceeding as understood by Enbridge?

Response

a) and b)

Please see the response at Exhibit I.STAFF.4 c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2

Question:

(a) Please provide a table showing the PDO (TJ/day) from 2010 to today.

(b) Please provide a table showing the annual PDCI from its inception to today.

(c) Page 1 states: “Direct purchase customers in the Union South rate zone are obligated to deliver gas to Enbridge Gas at various receipt points upstream or on Enbridge Gas’s system, including the interconnect with TCPL at Parkway.” Does this mean that these customers are in effect required to purchase gas that is delivered through the TCPL mainline or other non-Dawn-Parkway routes? If not, please explain and quantify.

(d) Page 2 states: “As a result of the current obligated Parkway deliveries by direct purchase customers and sales service customers, Enbridge Gas’s Dawn-Parkway system is physically smaller than it otherwise would be.” Is that because the obligated Parkway deliveries take a different transmission pathway (e.g. the TCPL mainline)? If not, please explain.

(e) Do customers subject to the PDO subsidize other customers because they are required to use transmission pathways that are more expensive then the Dawn-Parkway pathway? If not, please explain.

(f) Is the PDCI meant to address inequities by compensating customers subject to the PDO for the benefits they provide to the system and/or the cost of providing those benefits? If not, please explain. If yes, please describe the degree to which the PDCI fully compensates those customers.

(g) As the PDO is reduced, how is this reduction allocated between customers who are subject to the PDO?

Response

a) Please see table below.

Schedule 1
Parkway Delivery Obligation (PDO) for 2010 - 2022
(TJ/day)

	Nov-10	Nov-11	Nov-12	Nov-13	Nov-14	Nov-15	Nov-16	Nov-17	Nov-18	Nov-19	Nov-20	Nov-21	Nov-22
PDO	698	658	633	672	352	345	369	376	298	228	239	249	264

b) The table below provides the forecast PDCI cost included as part of the annual rate application each year.

Annual PDCI Costs ($000s)

2016(1)	2017	2018	2019	2020	2021	2022
2,821	16,559	13,171	12,371	12,766	13,482	14,768

Notes:
(1) The PDCI became effective November 1, 2016. The forecast PDCI cost for 2016 was recovered through the Parkway Obligation Rate Variance deferral account.

c) Yes, confirmed.

d) Yes, confirmed with the exception of PDO customers who directly hold M12 Dawn-Parkway contracts or customers who contract for M12 Dawn-Parkway from another shipper.

e) No, customers with a PDO do not provide a benefit to all other customers because other transmission pathways are more expensive. The benefit provided to all customers by customers with a PDO is related to a Dawn Parkway System build that is avoided because of the PDO. The Dawn Parkway System is smaller than it otherwise would need to be without the PDO. The cost of a Dawn Parkway System build would be paid for by all customers.

f) Yes, the PDCI is intended to compensate customers with a PDO by providing the customer with a credit for the cost of transporting gas from Dawn to Parkway on Enbridge Gas's Dawn Parkway System. The actual cost to the customer may be different than the PDCI credit provided.

g) Enbridge Gas may propose to allocate the shift to Dawn between customers consistent with the approach described in the Settlement Framework for Reduction of Parkway Delivery Obligation (PDO Settlement).[1] Direct purchase (DP) customers with a PDO of 100 GJ/d or less would be provided the opportunity to shift their entire PDO to Dawn. A proportionate share of any remaining available capacity would be offered to all other DP customers with a PDO who do not hold M12 Dawn to Parkway capacity. Customers with a PDO holding M12 Dawn to Parkway capacity would be offered a similar proportionate share.

[1] EB-2013-0365, Settlement Framework for Reduction of Parkway Delivery Obligation, approved by the OEB on June 16, 2014.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2

Question:

(a) Once a customer's PDO has been reduced by Enbridge, please describe any barriers (contractual, regulatory, market, financial, etc.) to re-subjecting that customer to the PDO and the changes that would be necessary to overcome those barriers.

(b) If the PDO and PDCI are reduced, can they later be increased as an alternative to an infrastructure project intended to increase the Dawn-Parkway system capacity? If not, please describe all barriers and the changes that would be required to remove them.

(c) As the PDO is reduced, is available capacity to ship from Empress shifted to serve deliveries at Dawn, such that capacity to ship along the TCPL mainline to Parkway is reduced? If not, please explain.

(d) In other words, will the reduction of the PDO potentially reduce the ability to deliver to Parkway outside of the Dawn-Parkway system? If not, please explain.

Response

a) Per the posted Obligated Daily Contract Quantity (DCQ) – Union South policy, changes in DCQ as a result of changes in consumption for all direct purchase customers served via the Dawn to Parkway transmission system are allocated at Parkway - customers that experience growth must deliver their incremental DCQ at Parkway, even if their current DCQ was at Dawn, and will receive the PDCI credit on that incremental DCQ. PDO can only be imposed on new incremental customer volumes.

b) See response to a) above

c) The Dawn Hub is connected to several pipelines including TCPL, so Enbridge Gas is not able comment on what effect the PDO reduction would have on the TransCanada Main Line.

d) See part c) above.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2

Question:

(a) Please provide a map (or maps) of Ontario's gas transmission pipelines that shows the flows in and out of Ontario on each line before and after the efforts that Enbridge has made to reduce the PDO.

(b) Please provide a map (or maps) of Ontario's gas transmission pipelines that shows the available capacity (TJ/d) on each transmission line before and after the efforts that Enbridge has made to reduce the PDO.

Response

a) and b)

Direct purchase customers are solely responsible to manage their obligated deliveries through a variety of options, including: (i) procuring upstream or (ii) procuring supply directly from counterparties at the Dawn Hub or Parkway. Therefore, the impacts on available capacity of other transmission system pipelines are not known by Enbridge Gas. As a result, Enbridge Gas is unable to provide a map of Ontario's gas transmission pipelines that shows flows in and out of Ontario on each line before and after the efforts that Enbridge made to reduce the PDO.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2

Question:

(a) Has the PDO been reduced primarily through turnback? If not, please explain.

(b) How much of the turnback that has made PDO reductions possible has been from in-franchise versus ex-franchise customers (in TJ/d)?

(c) What is the total TJ/day of all contracts to ship gas to the northeastern United States through the Dawn-Parkway system?

(d) Could the PDO be reduced by not renewing contracts to ship gas to the northeastern United States through the Dawn-Parkway system? If not, please describe all barriers and the changes that would be required to remove them.

(e) Is the PDCI charged to ex-franchise customers?

(f) Could the PDCI be shifted to ex-franchise customers? If not, please describe all barriers and the changes that would be required to remove them.

Response

a) Confirmed. Past reduction of the PDO has been facilitated through excess Dawn Parkway System capacity that was made available through Dawn to Kirkwall turnback.

b) All Dawn Parkway System turnback used to facilitate a PDO reduction has been from ex-franchise shippers. In total, Dawn Parkway System capacity of 351 TJ/d was used to reduce direct purchase (DP) customers' PDO:

- 200 TJ/d to reduce the PDO for DP customers who do not hold M12 Dawn to Parkway capacity,
- 19 TJ/d to reduce the PDO for DP customers holding M12 Dawn to Parkway capacity, and
- 132 TJ/d to reduce the PDO for TCE.

Sales service deliveries at Parkway has been reduced by 92 TJ/d.

c) Currently, there are 643 TJ/d contracted to ship gas to northeastern United States through the Dawn-Parkway system.

d) The current Settlement Framework for Reduction of Parkway Delivery Obligation (PDO Settlement) requires the Company to use Dawn to Parkway capacity that is made available from M12 Dawn to Kirkwall turnback to reduce the PDO.

Enbridge Gas does not discriminate against shippers on the Dawn Parkway System based on their geographic location. The Dawn-Parkway system is an open access pipeline and Enbridge Gas cannot compel Shippers to turnback capacity that they currently hold. The Shipper has sole discretion to turnback or maintain capacity on the system.

e) No, the PDCI credit is only provided to direct purchase and sales service in-franchise customers who have a Parkway obligated delivery point. The PDCI cost is allocated and recovered from in-franchise rate classes consistent with the manner described in the PDO Settlement framework. The PDCI costs are not allocated to ex-franchise rate classes.

f) No, the PDCI could not be shifted to Enbridge Gas ex-franchise shippers. The Dawn Parkway System benefit provided by the PDO is a result of gas arriving at Parkway without being transported on the Dawn Parkway System. Ex-franchise shippers use Dawn Parkway System capacity for transport purposes and gas deliveries to Parkway on behalf of ex-franchise shippers use the Dawn Parkway System. The PDCI credit is provided to direct purchase and sales service customers as a result of the benefit their Parkway deliveries provide to the system. There would be no benefit to the system of Parkway deliveries by Enbridge Gas ex-franchise shippers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, Page 8

Question:

a) Please express the comparison of the options in Table 2 as a single NPV figure for each option. Please use a timeframe that Enbridge believes is appropriate (40 years?).

b) Please express the comparison of the options in Table 2 in cost/capacity for each option, both gross and NPV.

Response

a) Please find below in column (d), the 40-year NPV value for each option in Table 2 excluding the potential market solution. The market solution is excluded from the NPV summary as the potential variability in the rate and the uncertainty of renewal makes this calculation unfeasible.

b) Please find below in column (c) and (e), the cost/capacity for each option, both gross and NPV.

Line No.	Particulars	Capacity (TJ/d) (a)	Capital Costs ($ millions) (b)	Capital Costs ($/GJ) (c)	NPV (40 years) ($ millions) (d)	NPV (40 years) ($/GJ) (e)
1	Kirkwall to Hamilton NPS 48	85	191	2,243.1	255.7	3,002.9
2	Combined Kirkwall to Hamilton NPS 48 and Dawn to Enniskillen NPS 48	278	438	1,576.2	570.9	2,054.4
3	Potential Market Solution	37	n/a	n/a	n/a	n/a
4	Current 2022 PDO	275	n/a	n/a	282.6	1,028.3

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, Page 7

Question:

(a) Please explain the market based alternative in more detail.

(b) Please explain the financial rationale for the entity that bid for 37,000 Gj/d and the pathway that entity is likely to use to fulfill that obligation.

Response

a) The market based alternative is an exchange service between Dawn and Parkway that does not utilize increased Dawn-Parkway capacity.

   As part of the settlement agreement in EB-2020-0095, Enbridge Gas agreed to identify market-based alternatives that would in effect reduce the PDO similarly to a facility expansion. A Dawn to Parkway firm exchange is the optimal service to achieve this by allowing the gas to be received at Parkway and then delivered at Dawn without using the Dawn to Parkway system. To determine market availability for a firm exchange, Enbridge Gas issued a Request for Proposal and received limited interest.

b) EGI does not know the financial rationale of the bidding entity. The entity has indicated that they would utilize existing Kirkwall-Parkway capacity to fulfill the exchange service.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, Page 8

Question:

(a) Could the PDO be reduced by reducing demand on the Dawn-Parkway system through energy efficiency programs or fuel switching programs?

(b) Will Enbridge be considering methods to reduce PDO through demand side management? If yes, when will that occur?

Response

a) and b)

As per the OEB policy framework on Integrated Resource Planning (IRP), future system needs and constraints may be resolved using facility alternatives or IRP alternatives (IRPAs), including: the delivery of enhanced targeted energy efficiency programs; fuel switching programs; or additional market-based alternatives/arrangements similar to PDO. In other words, PDO is already a form of IRPA.

Increased enhanced targeted energy efficiency programming and/or fuel switching are potential IRPAs that could reduce peak period demand on the Dawn Parkway system in the future, which may reduce the PDO. However, such investments are more appropriately assessed as part of a future IRP Plan application made to the OEB which reflects the relative cost, risk and timing of IRPA investments relative to facility alternatives.

In accordance with the OEB's Decision and Order on Enbridge Gas's IRP Proposal, the Company will identify system constraints/needs as part of its annual Asset Management Planning process, up to ten years in advance in order to assess the viability of IRPAs relative to facility alternatives. At this time, Enbridge Gas does not have any plans to reduce or eliminate PDO (an IRPA itself) with other IRPAs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1Page 11 Plus Appendices; Exhibit D, Tab 1, Rate Order, Working Papers, Schedule 10; Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 13; EB-2020-0095 Exhibit I.EP.1 Page 1 -12.

Question(s):

a) Please provide updates to the tables and charts in EB-2020-0095 Exhibit I.EP.1 Page 1 -12 showing 2020 actuals 2021 E and 2022 forecast.

b) Please provide a discussion for each rate class
   i. Changes in 2020 actuals
   ii. 2021 YTD trends and Covid-19 impacts
   iii. 2022 forecast
   iv. Specifically the drivers for -1.4% AU decrease for EGD Rate 1 and -1.7 % for Union RZ M1. Is it due to price or other factors

Response:

EGD Rate Zone:

a) For its 2022 rate application, Enbridge Gas used the same average use models as in EGD's 2014 to 2021 rate applications (with addition of 2020 actual data to the estimation period). The key factor used to evaluate the accuracy of the General Service average use forecast is the percentage variance between normalized actual and normalized forecast average use per customer. As seen in the Actual to OEB Approved Percentage variance table (Table 1) below, the average percentage variance from forecast over the last 10 years is 0.6% for Rate 1 and 0.5% for Rate 6.

   Besides tracking historical accuracy through the percentage variances, the models Also have been subject to a battery of tests. Please see the models' estimation and test results for 2022 forecast in Tables 5 and 8 and the diagnostic test results in Tables 6 and 9 below. The results show that the models continued to have high

R-squared, and to generate small forecast errors while passing the key statistical specification tests. Based on the updated results there is no statistics that alert as 'out of norm'.

TABLE 1
GENERAL SERVICE AVERAGE USE

	Test Year	Rate Classes	Col. 1 Actual Normalized Average Use (m^3)	Col. 2 Board Approved Normalized Average Use (m^3)	Col. 3 Variance Normalized Average Use (1-2)	Col. 4 %Variance Normalized Average Use (3/2)*100
FISCAL YEAR	2004*	Rate 1	2,843	2,857	(14)	-0.5%
		Rate 6	21,472	21,612	(140)	-0.6%
	2005	Rate 1	2,890	2,953	(63)	-2.1%
		Rate 6	22,241	22,507	(266)	-1.2%
	2006	Rate 1	2,796	2,850	(54)	-1.9%
		Rate 6	22,272	21,999	273	1.2%
	2007	Rate 1	2,726	2,687	39	1.5%
		Rate 6	22,783	21,010	1,773	8.4%
	2008	Rate 1	2,636	2,647	(11)	-0.4%
		Rate 6	24,869	24,204	665	2.7%
	2009	Rate 1	2,604	2,637	(33)	-1.3%
		Rate 6	27,281	28,165	(884)	-3.1%
	2010	Rate 1	2,579	2,622	(43)	-1.6%
		Rate 6	29,106	27,949	1,157	4.1%
	2011	Rate 1	2,594	2,643	(49)	-1.8%
		Rate 6	29,471	28,029	1,442	5.1%
	2012	Rate 1	2,529	2,510	18	0.7%
		Rate 6	28,941	30,122	(1,182)	-3.9%
YEAR	2013	Rate 1	2,547	2,568	(22)	-0.8%
		Rate 6	29,878	29,878	(0)	0.0%
	2014	Rate 1	2,475	2,433	41	1.7%
		Rate 6	28,634	28,383	251	0.9%
	2015	Rate 1	2,427	2,419	9	0.4%
		Rate 6	28,600	28,341	259	0.9%
	2016	Rate 1	2,401	2,480	(79)	-3.2%
		Rate 6	28,203	28,753	(550)	-1.9%
	2017	Rate 1	2,485	2,472	13	0.5%
		Rate 6	29,462	29,058	404	1.4%
	2018	Rate 1	2,456	2,358	98	4.2%
		Rate 6	29,377	28,656	721	2.5%
	2019	Rate 1	2,463	2,412	51	2.1%
		Rate 6	29,348	29,154	194	0.7%
	2020	Rate 1	2,445	2,383	62	2.6%
		Rate 6	28,409	28,610	(202)	-0.7%
		Rate 1	Average % variance		2004-2020	0.0%
		Rate 1	Average % variance		2011-2020	0.6%
		Rate 6	Average % variance		2004-2020	1.0%
		Rate 6	Average % variance		2011-2020	0.5%

TABLE 5 - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Metro Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.64	6.54	0.00
LOG(CDD)	0.70	13.74	0.00
LOG(REALCRCRPG)	-0.03	-1.24	0.23
LOG(MET20VINT)	0.66	7.53	0.00
DUM2008	0.01	0.42	0.68
DUM2010	-0.02	-0.68	0.50
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.02		
F-statistic	275.19		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.20	0.85
DLOG(CDD)	0.75	20.54	0.00
DLOG(MET20VINT)	0.81	2.39	0.02
DUM2008	0.00	0.21	0.83
ECM_MET20(-1)	-0.91	-5.00	0.00
R-squared	0.94		
Adjusted R-squared	0.93		
S.E. of regression	0.02		
F-statistic	109.88		0.00

Western Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.21	1.69	0.10
LOG(CDD)	0.64	11.05	0.00
LOG(REALCRCRPG)	-0.07	-2.06	0.05
LOG(WES20VINT)	0.55	2.47	0.02
LOG(CENTEMP)	0.09	0.56	0.58
DUM2008	-0.02	-1.01	0.32
DUM2010	-0.05	-1.90	0.07
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.03		
F-statistic	139.82		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-1.05	0.30
DLOG(CDD)	0.71	17.25	0.00
DLOG(REALCRCRPG)	-0.02	-0.50	0.62
DUM2008	0.00	0.03	0.98
ECM_WES20(-1)	-0.96	-5.32	0.00
R-squared	0.91		
Adjusted R-squared	0.90		
S.E. of regression	0.02		
F-statistic	78.92		0.000

Central Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.269	1.89	0.07
LOG(CDD)	0.648	9.78	0.00
LOG(REALCRCRPG)	-0.001	-0.02	0.99
LOG(CEN20VINT)	0.789	4.03	0.00
LOG(CENTEMP)	0.077	0.58	0.57
DUM2008	-0.051	-2.21	0.03
R-squared	0.96		
Adjusted R-squared	0.96		
S.E. of regression	0.03		
F-statistic	158.93		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.01	0.51	0.61
DLOG(CDD)	0.70	14.55	0.00
DLOG(REALCRCRPG)	0.03	0.55	0.59
DUM2008	-0.01	-0.54	0.59
DLOG(CEN20VINT)	1.05	1.49	0.15
ECM_CEN20(-1)	-0.91	-5.05	0.00
R-squared	0.89		
Adjusted R-squared	0.87		
S.E. of regression	0.03		
F-statistic	47.60		0.000

TABLE 5 CONTINUED - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Northern Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	3.13	2.40	0.02
LOG(CDD)	0.63	9.71	0.00
LOG(REALCRCRPG)	-0.04	-1.03	0.31
LOG(NOR20VINT)	0.67	3.17	0.00
LOG(CENTEMP)	-0.01	-0.04	0.97
DUM2009	-0.07	-2.65	0.01
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.03		
F-statistic	189.93		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.15	0.88
DLOG(CDD)	0.69	14.97	0.00
DLOG(REALCRCRPG)	0.01	0.19	0.85
DLOG(NOR20VINT)	0.84	1.48	0.15
ECM_NOR20(-1)	-0.94	-5.34	0.00
R-squared	0.89		
Adjusted R-squared	0.88		
S.E. of regression	0.03		
F-statistic	61.53		0.000

Eastern Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.37	3.84	0.00
LOG(EDD)	0.69	9.14	0.00
LOG(REALERCRPG)	-0.02	-0.48	0.64
LOG(ERC20VINT)	0.76	8.05	0.00
DUM2008	-0.03	-1.10	0.28
DUM2010	-0.06	-2.35	0.03
R-squared	0.97		
Adjusted R-squared	0.97		
S.E. of regression	0.03		
F-statistic	197.33		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.57	0.57
DLOG(EDD)	0.79	13.94	0.00
DLOG(ERC20VINT)	0.56	0.99	0.33
ECM_ERC20(-1)	-0.98	-2.43	0.02
AR(1)	-0.07	-0.16	0.87
R-squared	0.89		
Adjusted R-squared	0.87		
S.E. of regression	0.03		
F-statistic	56.97		0.000

Niagara Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.50	3.97	0.00
LOG(NDD)	0.68	8.61	0.00
LOG(REALNRCRPG)	-0.07	-1.78	0.09
LOG(NRC20VINT)	0.88	5.73	0.00
DUM2008	0.01	0.22	0.83
DUM2010	-0.03	-0.75	0.46
R-squared	0.96		
Adjusted R-squared	0.95		
S.E. of regression	0.04		
F-statistic	135.20		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-1.95	0.06
DLOG(NDD)	0.74	13.77	0.00
ECM_NRC20(-1)	-0.61	-3.59	0.00
R-squared	0.86		
Adjusted R-squared	0.85		
S.E. of regression	0.03		
F-statistic	99.74		0.000

TABLE 6 - RATE 1

Model Diagnostic Tests

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Test		Metro Region	Western Region	Central Region	Northern Region	Eastern Weather Zone	Niagara Weather Zone
Breusch-Godfrey Serial Correlation LM Test	Test Statistic	1.48	0.33	0.01	0.04	3.96	1.09
	P Value	0.22	0.57	0.91	0.84	0.06	0.30
ARCH Test	Test Statistic	2.54	0.66	0.23	0.88	1.99	0.01
	P Value	0.11	0.42	0.63	0.35	0.16	0.94
Chow Forecast Test	Test Statistic	0.28	0.18	0.71	1.17	1.29	0.09
	P Value	0.60	0.68	0.41	0.29	0.27	0.76
Ramsey RESET Test	Test Statistic	0.17	0.09	0.07	0.00	0.87	1.52
	P Value	0.68	0.77	0.79	1.00	0.36	0.23

TABLE 8 - RATE 6 REVENUE CLASS 12 REGRESSION EQUATIONS

Central Revenue Class 12 (Apartment)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	1.79	0.97	0.34
LOG(CDD)	0.53	4.06	0.00
LOG(CENTEMP)	0.69	4.09	0.00
DUM1996	-0.11	-2.78	0.01
DUM2008	0.22	3.45	0.00
AR(1)	0.41	2.31	0.03
R-squared	0.94		
Adjusted R-squared	0.93		
S.E. of regression	0.06		
F-statistic	95.547		0.000

Eastern Revenue Class 12 (Apartment)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	4.79	2.62	0.01
LOG(EDD)	0.46	4.81	0.00
LOG(TIME)	-0.05	-2.53	0.02
DUMERC12	0.26	7.22	0.00
DUM2011	-0.13	-3.36	0.00
LOG(REALERCCPG)	-0.12	-2.06	0.05
LOG(EASTEMP)	0.37	1.52	0.14
DUM2014	0.11	4.55	0.00
R-squared	0.95		
Adjusted R-squared	0.94		
S.E. of regression	0.03		
F-statistic	77.94		0.000

Niagara Revenue Class 12 (Apartment)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	6.02	4.43	0.00
LOG(NDD)	0.47	5.80	0.00
LOG(TIME)	-0.02	-1.38	0.18
LOG(NIAGEMP)	0.19	0.96	0.35
LOG(REALNRCCPG)	-0.03	-0.68	0.50
DUMNRC12	-0.05	-2.07	0.05
DUM2011	-0.07	-2.33	0.03
AR(1)	0.03	0.17	0.87
R-squared	0.85		
Adjusted R-squared	0.81		
S.E. of regression	0.03		
F-statistic	21.14		0.000

TABLE 8 CONTINUED - RATE 6 REVENUE CLASS 48 REGRESSION EQUATIONS

Central Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-3.83	-2.24	0.03
LOG(CDD)	0.75	8.55	0.00
LOG(TIME)	-0.19	-7.25	0.00
LOG(CRCCOMVAC)	-0.03	-0.98	0.34
LOG(ONTGDP)	0.61	5.20	0.00
LOG(REALCRCCPG)	-0.11	-3.10	0.00
DUM2008	0.07	2.76	0.01
R-squared	0.88		
Adjusted R-squared	0.86		
S.E. of regression	0.04		
F-statistic	37.06		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.01	1.00	0.33
DLOG(CDD)	0.83	14.08	0.00
DLOG(TIME)	-0.09	-2.02	0.05
DLOG(CRCCOMVAC)	-0.07	-2.11	0.04
DLOG(REALCRCCPG)	-0.05	-1.00	0.32
ECM_CRC48(-1)	-0.89	-4.76	0.00
R-squared	0.88		
Adjusted R-squared	0.86		
S.E. of regression	0.03		
F-statistic	41.82		0.000

Eastern Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-3.50	-1.92	0.06
LOG(EDD)	0.69	5.93	0.00
LOG(TIME)	-0.23	-9.13	0.00
LOG(ONTGDP)	0.62	5.33	0.00
LOG(REALERCCPG)	-0.16	-3.97	0.00
DUM2008	0.12	4.09	0.00
R-squared	0.88		
Adjusted R-squared	0.86		
S.E. of regression	0.04		
F-statistic	44.21		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.01	1.05	0.30
DLOG(EDD)	0.75	8.76	0.00
DLOG(TIME)	-0.14	-2.47	0.02
DLOG(REALERCCPG)	-0.06	-1.02	0.32
ECM_ERC48(-1)	-0.76	-3.97	0.00
R-squared	0.76		
Adjusted R-squared	0.72		
S.E. of regression	0.04		
F-statistic	23.41		0.000

Niagara Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.60	-0.34	0.74
LOG(NDD)	0.71	7.98	0.00
LOG(TIME)	-0.09	-3.50	0.00
LOG(REALNRCCPG)	-0.14	-3.34	0.00
LOG(ONTGDP)	0.36	3.05	0.00
DUM2009	0.04	1.38	0.18
R-squared	0.81		
Adjusted R-squared	0.77		
S.E. of regression	0.04		
F-statistic	25.05		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.19	0.85
DLOG(NDD)	0.78	11.64	0.00
DLOG(REALNRCCPG)	-0.08	-1.36	0.18
ECM_NRC48(-1)	-0.84	-4.21	0.00
R-squared	0.83		
Adjusted R-squared	0.82		
S.E. of regression	0.04		
F-statistic	52.17		0.000

TABLE 8 CONTINUED - RATE 6 REVENUE CLASS 73 REGRESSION EQUATIONS

Central Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.96	0.35	0.73
LOG(CDD)	0.50	2.94	0.01
LOG(TIME)	-0.15	-3.95	0.00
LOG(ONTGDP)	0.48	3.00	0.01
DUM2008	0.52	12.60	0.00
R-squared	0.92		
Adjusted R-squared	0.91		
S.E. of regression	0.08		
F-statistic	94.29		0.000

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.04	-3.26	0.00
DLOG(CDD)	0.60	8.35	0.00
DLOG(ONTGDP)	1.34	4.16	0.00
DUM2008	0.26	5.66	0.00
DUM2009	-0.21	-4.67	0.00
ECM_CRC73(-1)	-0.72	-6.20	0.00
R-squared	0.83		
Adjusted R-squared	0.80		
S.E. of regression	0.04		
F-statistic	28.94		0.000

Eastern Revenue Class 73 (Industrial)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	-83,372	-0.52	0.61
EDD	24	0.93	0.36
DUM2003	60,947	1.73	0.09
DUM2004	-170,733	-3.69	0.00
DUM2009	143,943	6.67	0.00
EASTEMP	209	0.80	0.43
TIME	-975	-0.47	0.64
R-squared	0.87		
Adjusted R-squared	0.85		
S.E. of regression	32,312.76		
F-statistic	33.66		0.000

Niagara Revenue Class 73 (Industrial)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	-1.14	-0.36	0.72
LOG(NDD)	0.74	3.92	0.00
DUM2002	-0.37	-4.43	0.00
DUM2007	0.49	4.96	0.00
DUM2010	0.41	3.98	0.00
LOG(NIAGEMP)	1.27	2.64	0.01
AR(1)	0.71	4.77	0.00
R-squared	0.97		
Adjusted R-squared	0.97		
S.E. of regression	0.10		
F-statistic	174.69		0.000

TABLE 9-RATE 6
Model Diagnostic Tests

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.	Col 9.	Col 10.	Col 11.
		Revenue Class 12 (Apartment) Model Diagnostic Tests			**Revenue Class 48 (Commercial) Model Diagnostic Tests**			**Revenue Class 73 (Industrial) Model Diagnostic Tests**		
Test		Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone	Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone	Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone
Breusch-Godfrey Serial Correlation LM Test	Test Statistic	0.00	0.16	0.15	0.06	0.16	0.72	0.26	3.95	2.13
	P Value	0.97	0.69	0.70	0.81	0.69	0.40	0.61	0.06	0.14
ARCH Test	Test Statistic	0.03	0.70	3.50	0.24	0.35	0.27	0.70	0.45	2.95
	P Value	0.87	0.40	0.06	0.62	0.55	0.60	0.40	0.50	0.09
Chow Forecast Test	Test Statistic	1.33	0.27	0.05	1.48	2.40	2.12	2.72	2.35	0.09
	P Value	0.26	0.60	0.82	0.23	0.13	0.16	0.11	0.14	0.76
Ramsey RESET Test	Test Statistic	0.27	2.22	0.16	1.34	0.40	0.42	1.61	1.45	3.12
	P Value	0.61	0.15	0.69	0.26	0.53	0.52	0.21	0.24	0.09

b) i., ii., iii., iv.

The 1.4% decrease in average use for Rate 1 customers represents the percentage change in average use from the 2021 OEB Approved forecast to 2022 Forecast.

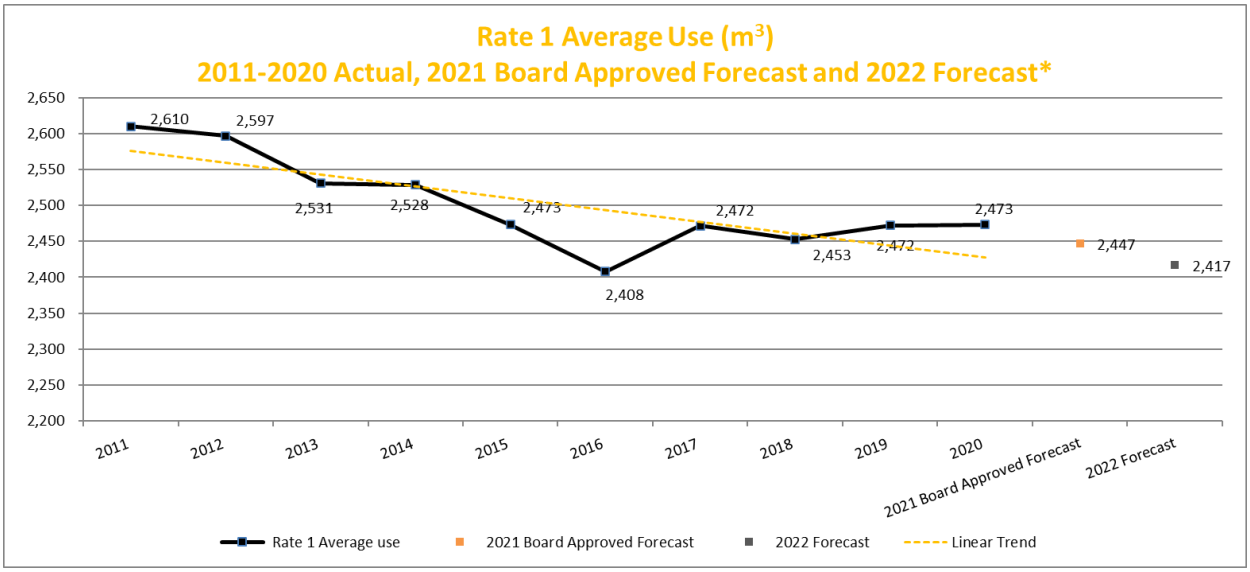
The 2021 OEB Approved forecast was developed in an earlier proceeding using the actuals to 2019 and the assumptions from the 2020 Spring Economic Outlook while the 2022 forecast has been developed using the actuals to 2020 and the

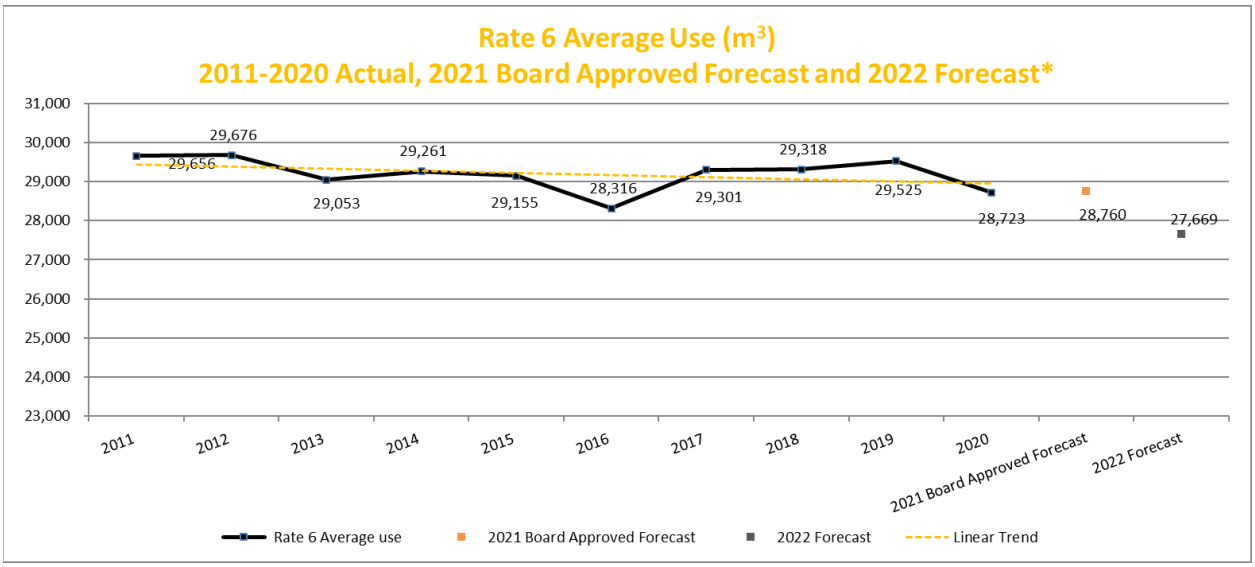
assumptions from 2021 Spring Economic Outlook. As a result, 1.4% decrease in Rate 1 average use is not reflective of the actual average use trend.

The following table illustrates actual average use trend for Rate 1 and 6 for the last 10 years[1], 2021 OEB Approved forecast and the forecast for 2022. These figures have all been normalized to 2022 Budget degree days for comparability. The average annual decline in actual average use for the last 10 years is 0.6% for Rate 1. Over the same period, Rate 6 shows an average annual increase of 0.07% which is relatively flat except during the pandemic period.

Rate 1 normalized average use in 2020 has been higher than expected but the 2022 forecast aligns with the last 10 years trend. Rate 6 normalized average use in 2020 showed almost 3% decline in 2020 from the year before. Rate 6 customers and their consumption patterns are heavily impacted by the economic conditions under the pandemic, and production levels that are often difficult to predict. In 2022, Rate 6 average use is expected slightly decline due to the economic conditions created by the pandemic have not been fully recovered yet. Year to date, 2021 normalized Rate 1 average use has been approximately 3.5% lower than budgeted average use while normalized Rate 6 average use has been almost 5% lower than budgeted use. 2022 forecast average use for both Rate 1 and Rate 6 look reasonable when current average consumption has been considered, but the length of the pandemic can be a risk for a forecast and might impact forecast accuracy for 2021 and 2022.

[1] Please note that 10 years trend line has been provided for representation purpose only. The forecast has been developed using longer historical data and regression methodology (not trend model) which driven by driver variables in the model and the long-term trend.

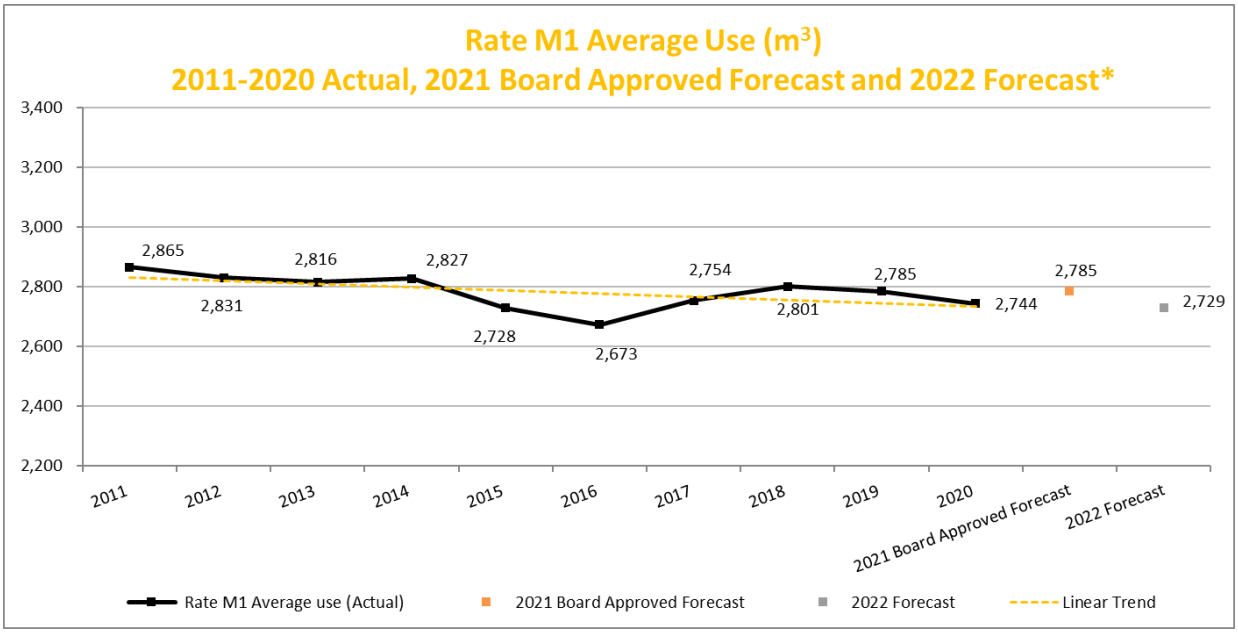


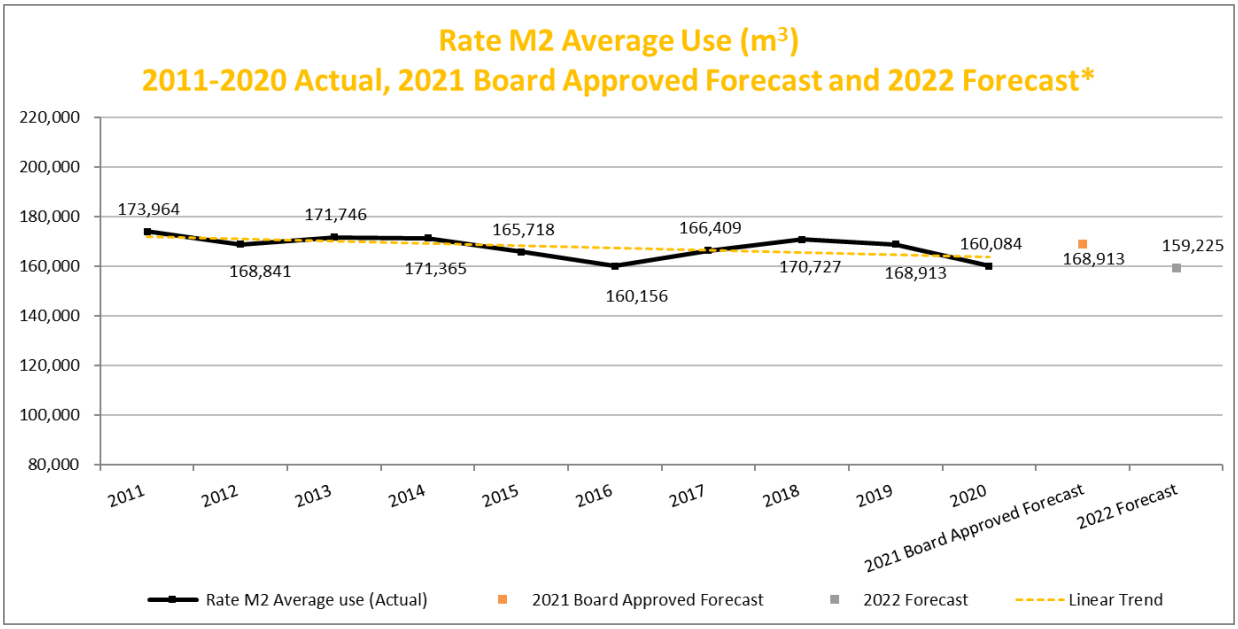


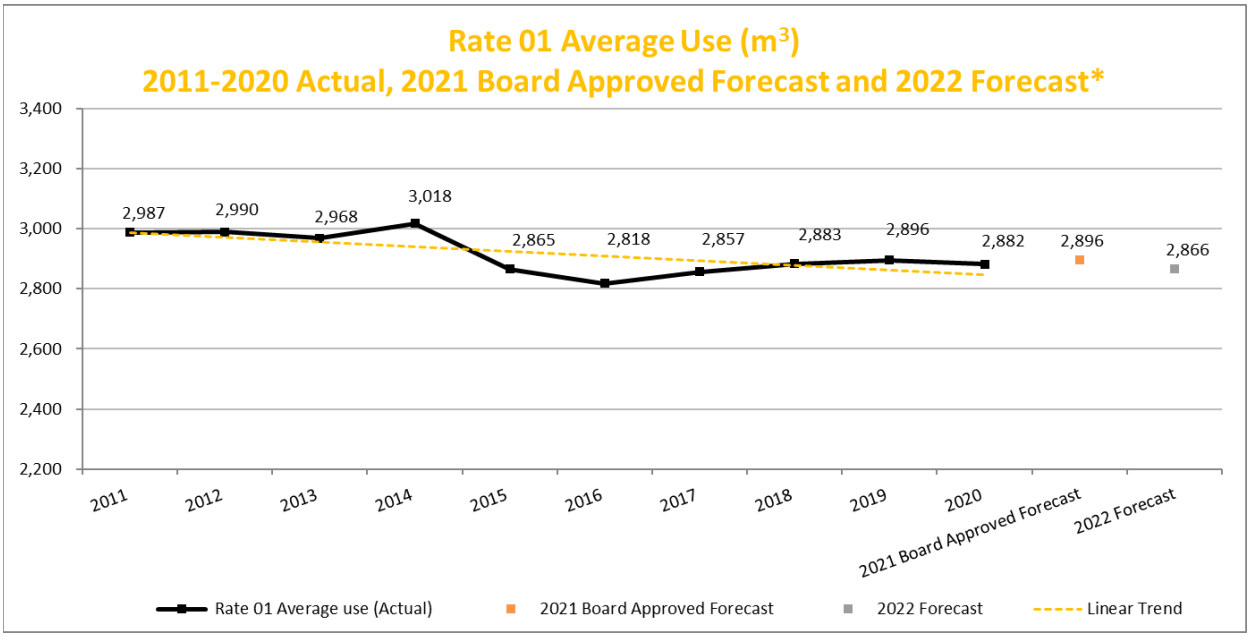
*All normalized to 2022 forecast degree days (using OEB approved methodology)

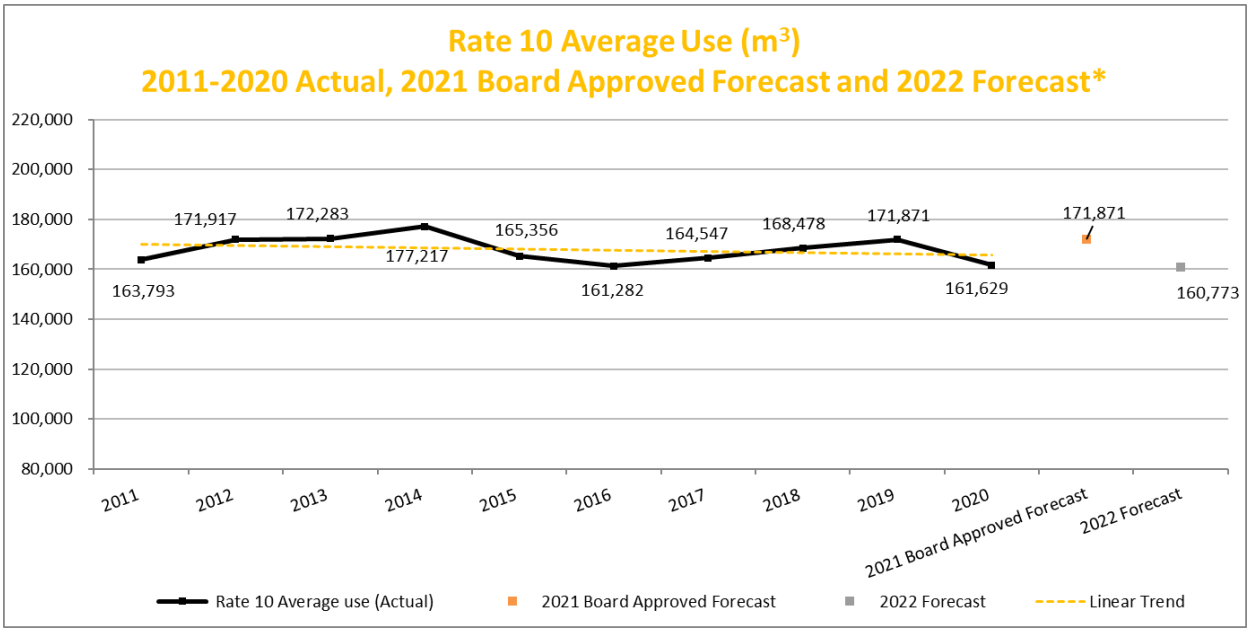
Union Rate Zones:

a) The charts and tables for the actual Normalized Average Consumption (NAC) at 2022 Normal Degree Day and target NAC for 2021 and 2022 for Rate M1, Rate M2, Rate 01 and Rate 10 are shown below:


Rate M1 Average Use (m3)
2011-2020 Actual, 2021 Board Approved Forecast and 2022 Forecast*
3,400
3,200
3,000
2,800
2,600
2,400
2,200
2,865
2,831
2,816
2,827
2,728
2,673
2,754
2,801
2,785
2,744
2,785
2,729
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021 Board Approved Forecast
2022 Forecast
Rate M1 Average use (Actual)
2021 Board Approved Forecast
2022 Forecast
Linear Trend


Rate M2 Average Use (m3)
2011-2020 Actual, 2021 Board Approved Forecast and 2022 Forecast*
220,000
200,000
180,000
160,000
140,000
120,000
100,000
80,000
173,964
168,841
171,746
171,365
165,718
160,156
166,409
170,727
168,913
160,084
168,913
159,225
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021 Board Approved Forecast
2022 Forecast
Rate M2 Average use (Actual)
2021 Board Approved Forecast
2022 Forecast
Linear Trend





*All normalized to 2022 forecast degree days (using OEB approved methodology)

Year	Rate M1		Actual vs Target	Rate M2		Actual vs Target
	Actual	Target	% variance	Actual	Target	% variance
2013	2,768	2,778	-0.4%	169,422	143,867	17.8%
2014	2,748	2,751	-0.1%	167,537	165,085	1.5%
2015	2,676	2,761	-3.1%	163,129	169,121	-3.5%
2016	2,667	2,852	-6.5%	159,933	172,694	-7.4%
2017	2,764	2,738	0.9%	166,969	166,297	0.4%
2018	2,810	2,654	5.9%	171,248	159,319	7.5%
2019	2,780	2,767	0.5%	168,624	167,039	0.9%
2020	2,746	2,817	-2.5%	160,140	171,679	-6.7%
Average			-0.7%			1.3%

Year	Rate 01		Actual vs Target	Rate 10		Actual vs Target
	Actual	Target	% variance	Actual	Target	% variance
2013	2,900	2,765	4.9%	168,975	157,381	7.4%
2014	2,923	2,898	0.9%	172,516	167,443	3.0%
2015	2,799	2,901	-3.5%	162,078	169,025	-4.1%
2016	2,788	3,015	-7.5%	159,855	177,214	-9.8%
2017	2,835	2,844	-0.3%	163,483	164,329	-0.5%
2018	2,864	2,771	3.3%	167,467	158,894	5.4%
2019	2,880	2,853	1.0%	171,056	164,301	4.1%
2020	2,875	2,893	-0.6%	161,276	168,964	-4.6%
Average			-0.2%			0.1%

b) i)

Target NAC for 2020 is the actual 2019 use weather normalized at the 2020 normal weather. The 2020 actual NAC was below the target NAC for all Union rate classes, ranging from -0.6% to -6.7%. The average percentage variance since 2013 is close to zero percent in Rate 01 and Rate 10, only -0.7% for Rate M1 and 1.3% in Rate M2.

For comparison purposes, the actual NAC shown in the charts are at the 2022 weather normal. A simple trend line placed over the last ten years indicates that the NAC for all rate classes is declining since 2011, at the average annual rates of -0.5% in Rate M1, -0.9% in Rate M2, -0.4% for Rate 01 and -0.1% in Rate 10.

b) ii)

For the past 7 months, actual NAC occurred lower relative to the target NAC (2021 target NAC is the 2019 actual use at the 2021 weather normal).

YTD July 2021 - Percentage Variance Actual to Target NAC

Rate Class	% variance
Rate M1	-6%
Rate M2	-11%
Rate 01	-5%
Rate 10	-15%

b) iii)

Based on the OEB-approved methodology, the 2022 Target NAC for Rate M1, Rate M2, Rate 01 and Rate 10 are the actual 2020 NAC weather normalized using the 2022 normal weather. Visual inspection suggests that target NAC is line with the historical trend

b) iv)

The -1.7% represents the change from the 2021 target NAC to the 2022 target NAC which is based on the 2019 to 2020 actual NAC calculated at the 2021 and the 2022 OEB-approved weather normal, respectively.

Based on OEB-approved methodology, Enbridge Gas uses the latest available NAC (2020) as 2022 forecast in the Union rate zones. There are no regression equations or regression statistics as a result, and no ‘out of norm’ comment can be made.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1 Page 11 para 29 and 30; Exhibit D, Tab 1, Rate Order, Working Papers, Schedule 10; Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 13; EB-2020-0095 Exhibit I.EP.2 Attachment 1 Pages 1 – 10.

Question(s):

a) Please update EB-2020-0095 Exhibit I.EP.2 Attachment 1 Pages 1 - 10 to show the derivation of the 2022 forecast Budget Degree Days for each of the 3 DD Zones.

b) Discuss if each of the Preferred DD Methodologies still produce the best result compared to the other options.

Response:

a) Please see Attachment 1 for the updated 'Budget Degree Days' evidence.

b) During its IR terms (including deferred rebasing), the Company continues to use the previously approved degree day (DD) forecasting methodologies for each rate zone. The Company evaluates the rankings and performance of DD forecasting methodologies only in its rebasing applications and continues to use the OEB approved methodologies during the related IR (or deferred rebasing) period. As stated in the 2020 rate application (EB-2019-0194, Exhibit JT1.5), the Company will present evidence about the appropriate DD forecasting methodologies to be used on a go-forward basis in its next rebasing application.

2022 BUDGET DEGREE DAYS

1. The purpose of this evidence is to provide the forecast of degree days for the 2022 test year.

2. The 2022 degree day forecasts were prepared in accordance with the Ontario Energy Board's (OEB) EB-2012-0459 Decision with Reasons dated July 17, 2014. The OEB has approved the use of the 50:50 Hybrid method for the Central weather zone, the de Bever with Trend method for the Eastern weather zone and the 10-year moving average method for the Niagara weather zone. Table 1 displays the 2022 degree day forecasts that were generated according to the approved methodologies for each weather zone within the franchise using Environment Canada degree days. Conversions to Gas Supply degree days are depicted in the latter part of this evidence.

Table 1
Forecast of 2022 Environment Canada Degree Days

Region	*Methodology*	*Forecast*
Central	50:50 Hybrid	3,673
Eastern	De Bever with Trend	4,383
Niagara	10-year moving average	3,399

Degree Day Forecast Methodology

3. The degree day forecast for the Central weather zone was prepared using the 50:50 Hybrid method which is an average of the 10-year Moving Average and the 20-year Trend forecast. Table 2 provides the actual Environment Canada degree day data for the Central weather zone and the resultant 10-year moving average, 20-year Trend, and 50:50 Hybrid forecast. The 10-year moving average is calculated using

data covering the period 2011 to 2020[1], while 20-year Trend model is estimated for the period 2001 to 2020. The 20-year Trend model results are provided in Table 3.

Table 2
Environment Canada Degree Day Forecast – Central

Col. 1	*Col. 2*
Calendar Year	Actual[1]
2000	3,826
2001	3,420
2002	3,630
2003	3,982
2004	3,798
2005	3,797
2006	3,378
2007	3,722
2008	3,837
2009	3,836
2010	3,501
2011	3,648
2012	3,215
2013	3,775
2014	4,103
2015	3,766
2016	3,462
2017	3,502
2018	3,758
2019	3,927
2020	3,512
2022 Forecast (10-year Moving average)	3,667
2022 Forecast (20-year Trend)[2]	3,679
2022 Forecast (50:50 Hybrid)[3]	3,673

[1]Environment Canada heating degree day observations from Pearson Int't Airport until June 2013. Effective June 13th, 2013 Environment Canada is no longer able to provide degree day data for Pearson Int'l Airport. Data from June 12th, 2013 and thereafter are obtained from the Toronto Int'l A station.

[2]Calculated using the 20-year Trend regression equation from Table 3.

[3]Average of 10-year Moving average and 20-year Trend forecasts.

[1] The 10 year moving average for year *t* is calculated as (DD_{t-2}+DD_{t-3}+ … +DD_{t-10}+DD_{t-11})/10 where DD is the actual degree day value.

Table 3
Model Results & Test Statistics: Central_20-year Trend Methodology

Sample: 2001 2020 Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	3,677.9	114.55	32.11	0.000
TREND	0.0336	8.90	0.00	0.997
R-squared	0.000	F-statistic	0.00	
		F-prob	0.997	

Environment Canada Central Degree Day= 3,677.9+0.336*TREND
The trend variable takes the values of 1 through 20 for each of the years from 2001 to 2020. The value of 22 is used for 2022 to generate 2022 degree day forecast.

4. The degree day forecast for the Eastern weather zone was prepared using the de Bever with Trend method. This method regresses actual Environment Canada degree days on a constant, a 5-year weighted average of Environment Canada degree days[2] and a trend. The 5-year weighted averages are lagged two years. Table 4 displays the actual Environment Canada degree day data for the Eastern weather zone, the 5-year weighted averages used to estimate the model, and the resultant degree day forecast for 2022. The model is estimated over the period 1950 to 2020 for a total of 71 years which is determined by the cycle length with smallest variance. Estimation results are provided in Table 5.

[2] The five-year weighted average for year *t* is calculated as $(5*DD_{t-2}+4*DD_{t-3}+3*DD_{t-4}+2*DD_{t-5}+DD_{t-6})/15$ where DD is the actual degree day value.

Table 4
Environment Canada Degree Day Forecast – Eastern

Col. 1	*Col. 2*	*Col.3*
Calendar Year	Actual[1]	5-year Weighted MA[2]
1950	4,824	4,665
1951	4,587	4,594
1952	4,404	4,661
1953	4,059	4,641
1954	4,707	4,556
1955	4,689	4,385
1956	4,799	4,465
1957	4,405	4,523
1958	4,736	4,626
1959	4,718	4,584
1960	4,451	4,652
1961	4,586	4,669
1962	4,826	4,596
1963	4,921	4,584
1964	4,569	4,667
1965	4,810	4,753
1966	4,683	4,709
1967	4,882	4,755
1968	4,780	4,735
1969	4,698	4,775
1970	4,899	4,778
1971	4,797	4,762
1972	5,014	4,805
1973	4,420	4,808
1974	4,725	4,876
1975	4,514	4,736
1976	5,008	4,723
1977	4,597	4,637
1978	4,939	4,741
1979	4,589	4,695
1980	4,920	4,790
1981	4,438	4,735
1982	4,647	4,798
1983	4,536	4,674
1984	4,535	4,658
1985	4,659	4,601
1986	4,501	4,570
1987	4,328	4,585
1988	4,640	4,564
1989	4,931	4,482
1990	4,250	4,524
1991	4,303	4,657
1992	4,861	4,537
1993	4,780	4,461
1994	4,730	4,585
1995	4,585	4,646
1996	4,603	4,681
1997	4,786	4,680
1998	3,828	4,664
1999	4,137	4,689
2000	4,543	4,399
2001	4,115	4,276
2002	4,381	4,328
2003	4,715	4,240
2004	4,637	4,273
2005	4,421	4,444
2006	4,037	4,531
2007	4,447	4,511
2008	4,488	4,373
2009	4,534	4,376
2010	3,973	4,388
2011	4,144	4,430
2012	4,055	4,293
2013	4,402	4,242
2014	4,632	4,155
2015	4,486	4,209
2016	4,322	4,346
2017	4,378	4,428
2018	4,547	4,421
2019	4,777	4,420
2020	4,231	4,454
2022 Forecast (de Bever with Trend)[3]	4,383	4,466

[1]Environment Canada heating degree day observations from MacDonald-Cartier Airport until December 2011. Effective December 15th, 2011, Environment Canada is no longer able to provide degree day data for MacDonald-Cartier Airport. Data from December 15th, 2011 and thereafter are obtained from the Ottawa Int'l A station.

[2]5-year weighted average lagged 2 years.

[3]Calculated using the de Bever with Trend regression equation from Table 5.

Table 5
Model Results & Test Statistics: Eastern_De Bever with Trend Methodology

Sample: 1950 2020 Included observations: 71

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	3,877.93	1,036.34	3.74	0.00
ECEDD5WA	0.1839	0.22	0.84	0.40
DBWT_TREND	-4.3377	1.79	-2.43	0.02
R-squared	0.18	F-statistic	7.46	
		F-prob	0.00	

Environment Canada Eastern Degree Day= 3,877.93+0.1839*ECEDD5WA-4.3377*TREND
5-year weighted average of 4,465.5 is used for 2022 to generate 2022 degree day forecast.
Trend variables takes the values from 1 to 71 for the period of 1950-2020. 73 is used for 2022 to generate 2022 degree day forecast.

5. The degree day forecast for the Niagara weather zone was prepared using the 10-year Moving Average method. Table 6 displays the actual Environment Canada degree day data for the Niagara weather zone and the resultant degree day forecast which is calculated using data covering the period 2011 to 2020[3].

[3] The 10 year moving average for year *t* is calculated as (DD_{t-2}+DD_{t-3}+ … +DD_{t-10}+DD_{t-11})/10 where DD is the actual degree day value.

Table 6
Environment Canada Degree Day Forecast – Niagara

Col. 1	*Col. 2*
Calendar Year	Actual[1]
2011	3,458
2012	3,021
2013	3,527
2014	3,832
2015	3,450
2016	3,100
2017	3,258
2018	3,488
2019	3,649
2020	3,205
2022 Forecast (10-yr Moving average)	3,399

[1]Environment Canada heating degree day observations from St. Catherines Airport until August 2008. Effective September 2008 Environment Canada is no longer able to provide degree day data for St.Catherines Airport. Data from September 2008 and thereafter are obtained from the Vineland Climate Station.

Gas Supply Degree Day Conversion

6. The final step in the degree day forecast involves the conversion of Environment Canada degree days to Gas Supply degree days. Environment Canada degree days are calculated as the average of degree days related to the daily minimum and maximum temperatures within a 24-hour period. On the other hand, Gas Supply degree days are determined relative to average hourly temperatures within a 24-hour period. The latter is used by EGD's Gas Control as it is perceived to be more representative of temperature variations within a given day. Although there are differences between the two measurements, the data sets are highly correlated.

7. The conversion leverages the correlation between both series and is carried out by regressing actual Gas Supply degree days onto actual Environment Canada degree days. The resultant equation (one for each weather zone) is used to convert the Environment Canada degree day forecast to the Gas Supply degree day forecast. Tables 7, 8 and 9 display actual Environment Canada degree days, actual Gas Supply degree days and the resultant Gas Supply degree day forecasts for the 2022 test year for each of the Central, Eastern, and Niagara regions, respectively. Each conversion model uses a sample that is consistent with the prescribed approved methodology to generate the forecasts. The sample for the Eastern region utilizes all the historical data available for Gas Supply degree days.

Table 7
Determination of Gas Supply Equivalent Degree Days - Central

Col. 1	*Col. 2*	*Col. 3*
Calendar Year	Actual Environment Canada Degree Days	Actual Gas Supply Degree Days
2001	3,420	3,400
2002	3,630	3,597
2003	3,982	3,949
2004	3,798	3,766
2005	3,797	3,750
2006	3,378	3,355
2007	3,722	3,659
2008	3,837	3,801
2009	3,836	3,767
2010	3,501	3,466
2011	3,215	3,597
2012	3,775	3,194
2013	4,103	3,746
2014	4,103	4,044
2015	3,766	3,710
2016	3,462	3,412
2017	3,502	3,499
2018	3,758	3,728
2019	3,927	3,887
2020	3,512	3,459
2022 Forecast (10-year Moving average)[1]		3,628
2022 Forecast (20-year Trend)[2]		3,640
2022 Forecast (50:50 Hybrid)[3]		3,634

[1]2022 forecast (10-year Moving average) is calculated using the following regression equation:
Gas Supply degree day =73.9356+0.9692*(Environment Canada degree day)
R-squared=0.9957, Adjusted R-squared=0.9952, F-statistic=1869.25, Prob(F-statistic)=0.000000

[2]2022 forecast (20-year Trend) is calculated using the following regression equation:
Gas Supply degree day =83.0979+0.9668*(Environment Canada degree day)
R-squared=0.9954, Adjusted R-squared=0.9951, F-statistic=3,863.02, Prob(F-statistic)=0.000000

[3]2022 forecast (50:50 Hybrid) is an average of 10-year Moving average and 20-year Trend.

Table 8
Determination of Gas Supply Equivalent Degree Days - Eastern

Col. 1	*Col. 2*	*Col. 3*
Calendar Year	Actual Environment Canada Degree Days	Actual Gas Supply Degree Days
1970	4,899	5,018
1971	4,797	4,584
1972	5,014	4,816
1973	4,420	4,480
1974	4,725	4,858
1975	4,514	4,229
1976	5,008	4,901
1977	4,597	4,604
1978	4,939	4,920
1979	4,589	4,550
1980	4,920	4,853
1981	4,438	4,361
1982	4,647	4,617
1983	4,536	4,515
1984	4,535	4,504
1985	4,659	4,648
1986	4,501	4,507
1987	4,328	4,268
1988	4,640	4,601
1989	4,931	4,883
1990	4,250	4,225
1991	4,303	4,270
1992	4,861	4,746
1993	4,780	4,715
1994	4,730	4,700
1995	4,585	4,530
1996	4,603	4,561
1997	4,786	4,711
1998	3,828	3,802
1999	4,137	4,112
2000	4,543	4,506
2001	4,115	4,071
2002	4,381	4,317
2003	4,715	4,663
2004	4,637	4,598
2005	4,421	4,397
2006	4,037	4,012
2007	4,447	4,411
2008	4,488	4,431
2009	4,534	4,472
2010	3,973	3,947
2011	4,144	4,108
2012	4,055	4,048
2013	4,402	4,484
2014	4,632	4,552
2015	4,486	4,397
2016	4,322	4,231
2017	4,378	4,318
2018	4,547	4,459
2019	4,777	4,682
2020	4,231	4,682
2022 Forecast[1]		4,343

[1]2022 forecast is calculated using the following regression equation:
Gas Supply degree days = 161.8064+0.954*(Environment Canada degree days)
R-squared=0.9395, Adjusted R-squared=0.9383, F-statistic=760.77, Prob(F-statistic)=0.000000

Table 9
Determination of Gas Supply Equivalent Degree Days - Niagara

Col. 1	*Col. 2*	*Col. 3*
Calendar Year	Actual Environment Canada Degree Days	Actual Gas Supply Degree Days
2011	3,458	3,334
2012	3,021	3,013
2013	3,527	3,537
2014	3,832	3,814
2015	3,450	3,548
2016	3,100	3,233
2017	3,258	3,282
2018	3,488	3,537
2019	3,649	3,670
2020	3,205	3,224
2022 Forecast[1]		3,419

[1]2022 forecast is calculated using the following regression equation:
Gas Supply degree days = 276.1498+0.9239*(Environment Canada degree days)
R-squared=0.9249, Adjusted R-squared=0.9155, F-statistic=98.56, Prob(F-statistic)=0.0000

2022 Degree Day Forecasts:

Table 10
Summary of 2022 Degree Days Forecast

Region	***Environment Canada Degree Days***	***Gas Supply Degree Days***
Central	3,673	3,634
Eastern	4,383	4,343
Niagara	3,399	3,419

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1 Plus Appendices Page 3 Table 1 and paragraphs 53 and 54; Exhibit D, Tab 2, Rate Order, Working Papers Schedule 1 Page 1; Exhibit D, Tab 2 Rate Order Working Papers Schedule 5. EB-2020-0095, Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 5, column (j).

Preamble:

We would like to better understand the increase in Revenue Requirement and resulting increases in residential rates and bill impacts for Union North and Union South (~2200 m^3)

Question(s):

a) Please confirm from comparison of Revenue Requirement increases that the major difference between EGD and Union Rate Zones are the 2021 Capital Pass-Through and the PDO Charge.

b) Please provide a schedule or schedules for Rates R01, and M1 that shows how the $2.956 million and $8.008 million overall increase in the 2021 RR for these classes is derived/allocated and results in the rate increases in excess of $10.42 and $8.71 per year respectively.

Response:

The docket numbers referenced in Line 1 and Line 2 of Table 1 at Exhibit B, Tab 1, Schedule 1 are incorrect. Enbridge Gas will file a correction to this exhibit with the interrogatory response.

a) Not confirmed. The rate increase to the Union rate zones relative to the EGD rate zone is driven in part by the increase to the 2022 capital pass-through and PDO rate adjustments. The rate increases are also driven by impacts of the price cap index,

average use/NAC adjustments and DSM unit rate impacts. Please see the response to part b) below for a detailed breakdown of the bill impacts for each zone.

b) The total proposed revenue change for EGD rate zone Rate 1 and Union rate zones Rate M1 and Rate 01 for 2022 rate-setting purposes is provided in Table 1.

Table 1
Breakdown of Revenue Changes for 2022 Rate-Setting

Line No.	Particulars ($000s)	Rate 1 EGD	Rate M1 Union South	Rate 01 Union North
		(a)	(b)	(c)
1	Price Cap Index	11,465	5,736	2,304
2	Capital Pass-through	-	1,412	653
3	Parkway Delivery Obligation	-	860	-
4	Average Use/Normalized Average Consumption	-	-	-
5	Demand Side Management	-	-	-
6	Total Revenue Change for 2022 Rate-Setting	11,465	8,008	2,956

The calculation of the price cap index for the EGD rate zone is provided at Exhibit D, Tab 1, Rate Order, Working Papers, Schedule 5 and for the Union rate zones is provided at Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 5.

The allocation of the Union rate zones 2022 capital pass-through cost adjustment is provided at Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 14.

The allocation of the Union rate zones 2022 PDO cost adjustment is provided at Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 11.

The total residential bill impact is affected by proposed 2022 revenue changes for rate-setting as well as average use/NAC and DSM unit rate impacts. Please see Table 2 for the breakdown of the net increase in total bill impacts for typical residential customers in EGD rate zone Rate 1 and Union rate zones Rate M1 and Rate 01.

Table 2
Breakdown of 2022 Rates Residential Total Bill Impact

Line No.	Particulars ($)	Rate 1 EGD	Rate M1 Union South	Rate 01 Union North West	Rate 01 Union North East
		(a)	(b)	(c)	(d)
1	Price Cap Index	5.64	4.98	6.57	6.79
2	Capital Pass-through	-	1.28	2.02	2.01
3	Parkway Delivery Obligation	-	0.61	-	-
4	Average Use/Normalized Average Consumption	2.07	1.81	1.99	2.65
5	Demand Side Management	0.05	0.02	(0.03)	(0.03)
6	Total Bill Impact (1)	7.76	8.71	10.55	11.42

Note:
(1) EGD rate zone bill impact based on a typical residential customer consuming 2,400 m^3 per year per Exhibit D, Tab 1, Rate Order, Working Papers, Schedule 3.1, Page 2, Col. 7, Line 2.6. Union rate zone bill impacts based on a typical residential customer consuming 2,200 m^3 per year per Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 3, Line 11.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, Page 8, plus Attachment

Preamble:

"Enbridge Gas has assessed the alternatives to reduce or eliminate the PDO as described above in response to the 2021 Rates settlement proposal. Infrastructure alternatives are more costly than the current PDCI cost. Market-based alternatives are slightly less costly than the current PDCI alternative but does not provide sufficient capacity to provide a full reduction of the PDO. ***At this time, Enbridge Gas has not acted on or reflected the lower cost market-based alternative in this application.*** In order to pursue the market based alternative Enbridge seeks direction from the OEB to secure the offered firm exchange capacity."

Question(s):

a) Please confirm that EGI has rejected market-based solutions in previous proceedings. Why has EGI decided to pursue these at this time?

b) Please provide a listing of the responses to the RFP with names omitted. Include volumes, price and other conditions such as term etc.

c) When must EGI accept/reject the offers for November 2022 implementation?

d) Why has EGI not proceeded expeditiously to get OEB approval before now?

e) Based on accepting the full 37,000 Gj/d, what would be the expected annual reductions in the PDO and PDCI over the 5 year term? November 2022 –November 2027?

f) Will EGI extend the term of the Exchange(s) and if so, under what circumstances?

Response:

a) As explained in its 2014 rates application[1], legacy Union Gas evaluated a Winter Peaking Service (WPS) option where Union Gas would purchase a WPS from a third party to provide the required delivery of gas at Parkway during the winter months if required. It was determined that a WPS service to reduce the PDO would come at an uncertain cost and might not be available for the entire direct purchase Parkway Delivery Obligation.

   Enbridge Gas agreed to investigate market-based solutions as directed in the 2021 rates proceeding settlement agreement[2].

b) There was one bidder into the market RFP, the bid was 36,751 GJ/d for 5 years starting November 1, 2022. The demand charge was $0.11 CAD/GJ.

c) EGI must accept or reject the offer by April 1, 2022.

d) Please see the response at Exhibit I.STAFF.4 b).

e) Please see table below:

	2022	**2023**	**2024**	**2025**	**2026**	**2027**
PDO Reductions (TJ/d)	37.0	37.0	37.0	37.0	37.0	37.0
PDCI Reductions ($ millions)	0.1	0.5	0.5	0.5	0.5	0.4

f) At this time Enbridge Gas is unable to determine if the exchange would be extended by either party due to changing market conditions and volatility.

[1] EB-2013-0365, Exhibit A, Tab 4, pp 14-20

[2] EB-2020-0095, Decision on Settlement Proposal and Interim Rate Order, dated November 6, 2020, p.6

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Page 12, and Exhibit D, Tab 2, Rate Order Working Papers, Schedule 14, Page 1

Preamble:

"Enbridge Gas has updated the capital pass-through projects to reflect the 2022 revenue requirement of each project consistent with the rate treatment in past years."

Question(s):

a) Please explain how Enbridge updated the capital pass-through projects that resulted in the increase in the revenue requirement.

b) Please file a table showing the calculation of the 2022 revenue requirement of each capital pass-through project.

Response:

a) As part of the 2022 Rates application, Enbridge Gas removed the forecast 2021 capital pass-through revenue requirement of $130.519 million[1] from base rates revenue and added back the forecast 2022 capital pass-through revenue requirement of $131.952 million to base rates revenue. The difference of $1.434 million is the net impact to 2022 base rates. Please see Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 5, columns (e) and (j) for the base rate adjustments related to the 2021 and 2022 capital pass-through projects, respectively. Any variances between the actual revenue requirement and the revenue requirement included in rates for each capital pass-through project is recovered/refunded to customers as part of the annual deferral disposition and earnings sharing application.

[1] The 2021 capital pass-through revenue requirement of $130.519 million was included in 2021 Board-approved base rates.

b) The 2022 forecast revenue requirement included in rates for each capital pass through project is provided at Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 14, pages 4-10, column (d).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, pages 1-2

Preamble:

EGI evidence states: "*Direct purchase customers in the Union South rate zone are obligated to deliver gas to Enbridge Gas at various receipt points upstream or on Enbridge Gas's system, including the interconnect with TCPL at Parkway.*"

Question(s):

We would like to understand better the management and opportunities of the Delivery Obligation and Commitment Incentive.

Please provide a table showing all points of receipt of delivery of Direct Purchase on the Union South system. For each point of delivery, please provide:

a) Total firm daily receipts (TJ/day)
b) Total firm daily receipts that are obligated (TJ/day)
c) Unit rate of Commitment Incentive paid ($/GJ)

Response:

a) and b)

Please see the table below.

Union South

	Dawn	Parkway
Total Obligated (TJ/d)	446	264
Non-Obligated	387	-
Total (TJ/d)	833	264

c) The current PDCI unit rate is $(0.148)/GJ. The proposed PDCI unit rate in the 2022 rate application is $(0.152)/GJ.[1]

[1] EB-2021-0147, Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 8, page 3.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, pages 1-2

Preamble:

EGI evidence states: "*Direct purchase customers in the Union South rate zone are obligated to deliver gas to Enbridge Gas at various receipt points upstream or on Enbridge Gas's system, including the interconnect with TCPL at Parkway.*"

Question(s):

We would like to understand better the management and opportunities of the Delivery Obligation and Commitment Incentive.

Please confirm that firm daily obligated receipts at Kirkwall provide a system benefit to the Dawn-Parkway system similar to firm daily obligated receipts at Parkway.

a) Please confirm that firm obligated deliveries at Kirkwall provide a supply-side IRPA alternative.
b) Please provide the current ratio of flow capability created by receipts at Kirkwall versus receipts at Parkway.
c) Does EGI offer a Commitment Incentive at Kirkwall?
    i. Has a Direct Purchase customer inquired about the possibility?
    ii. Please provide EGI's rationale as to why it would not provide a Commitment Incentive at Kirkwall to allow other DP customers to move their point of obligation back to Dawn and/or reduce PDO/PDCI costs.

Response:

a) Not confirmed. In some instances, firm daily obligated deliveries at Kirkwall may be considered an IRPA depending on the specific need. As with any proposed infrastructure facility project, a detailed analysis of the proposed project and the

alternatives to the proposed project will be completed as part of the Leave to Construct application.

However, firm daily obligated deliveries at Kirkwall do not provide the equivalent hydraulic benefit of firm daily obligated deliveries through a Parkway Delivery Obligation. Firm daily obligated deliveries at Kirkwall and Parkway are similar only in that they are delivered on the Dawn Parkway System at a location other than Dawn and therefore each impact the system differently.

The Dawn Parkway System is constrained between Kirkwall and Parkway due to the lack of pipeline facilities in this section. To be effective in reducing the constraint at Parkway, the Kirkwall deliveries need to be transported to Parkway, which increases the flow between Kirkwall and Parkway. Increasing flow between Kirkwall and Parkway increases the pressure drop in the constrained Kirkwall to Parkway section making the Kirkwall deliveries much less efficient.

Please also see response to part b).

b) The current ratio of Parkway deliveries vs Kirkwall deliveries is 0.35. This means that for every 100 TJ/d of deliveries at Kirkwall only 35 TJ/d of capacity at Parkway is created. Said another way, to reduce 264 TJ/d of PDO, 755 TJ/d of Kirkwall deliveries would be required.

   To operationalize this alternative, if DP customers were to be Kirkwall obligated, they would have to deliver approximately 3 molecules for each one they burn. Since this over delivery is not reasonable, their transfer to Kirkwall would be only a third as effective meaning additional facilities or non-facility alternatives would be required to make up the difference in capacity at Parkway.

c) No Kirkwall is not an obligated receipt point for direct purchase customers.

   i) No customers have inquired about having Kirkwall as an obligated receipt point.
   ii) Please see response to part a) and b).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Section 3,
Exhibit D, Tab 2, Rate Order Working Papers Schedule 11 and
EB-2019-0194 Exhibit JT1.7

Preamble:

We would like to understand better the evolution of the Dawn-Parkway system, the impact of PDO and capital builds and the resulting impact on rates.”

Question(s):

Please update to current and provide the attachments provided in EB-2019-0194 Exhibit JT1.7

Response:

Please see Attachments 1 to 4.

UNION RATE ZONES
Derivation of the Capital Pass-through Project Allocators - Parkway Projects

Line No.	Particulars	Union North In-Franchise (a)	Union South In-Franchise (b)	Ex-Franchise (c)	Total (d) = (a+b+c)
	Dawn-Parkway Distance Weighted Design Day Demands				
	2013 Board-Approved per EB-2011-0210				
1	Design Day Demands ($10^6m^3/d$)	7	44	124	175
2	Weighted Average Distance (km)	229	82	214	182
3	Distance Weighted Demands ($10^6m^3/d$ x km) (1)	1,592	3,588	26,557	31,737
4	Distance Weighted Demands (%)	5.0%	11.3%	83.7%	100.0%
	Parkway Projects (per EB-2012-0433 / EB-2013-0074)				
5	Project Demands ($10^6m^3/d$)	2	-	10	11
6	Weighted Average Distance (km)	229	-	229	229
7	Project Distance Weighted Demands ($10^6m^3/d$ x km) (line 5 x line 6) (2)	425	-	2,201	2,626
	Parkway Projects Allocator (per EB-2012-0433 / EB-2013-0074)				
8	Design Day Demands ($10^6m^3/d$) (line 1 + line 5)	9	44	134	186
9	Weighted Average Distance (km)	229	82	215	185
10	Project Distance Weighted Demands ($10^6m^3/d$ x km) (line 8 x line 9)	2,017	3,588	28,758	34,363
11	Distance Weighted Demands (%)	5.9%	10.4%	83.7%	100.0%
	Design Day Demands requiring Dawn Compression				
	2013 Board-Approved per EB-2011-0210				
12	Design Day Demands requiring Dawn Compression ($10^6m^3/d$) (3)	7	26	116	149
13	Dawn Compression Demands (%)	4.6%	17.4%	77.9%	100.0%
	Parkway Projects (per EB-2012-0433 / EB-2013-0074)				
14	Project Demands requiring Dawn Compression ($10^6m^3/d$)	2	-	10	11
	Parkway Projects Allocator (per EB-2012-0433 / EB-2013-0074)				
15	Design Day Demands requiring Dawn Compression ($10^6m^3/d$) (line 12 + line 14	9	26	126	161
16	Dawn Compression Demands (%)	5.5%	16.2%	78.4%	100.0%

Notes:
(1) EB-2011-0210, Exhibit G3, Tab 5, Schedule 23, Updated, pages 7-8, line 5.
(2) EB-2012-0451/EB-2012-0433/EB-2013-0074, Exhibit I.A3.UGL.FRPO.28, Attachment 1, column (c).
(3) EB-2011-0210, Exhibit G3, Tab 5, Schedule 23, Updated, pages 7-8, line 11.

UNION RATE ZONES
Derivation of the Capital Pass-through Project Allocators - 2016 Dawn-Parkway Expansion

Line No.	Particulars	Union North In-Franchise (a)	Union South In-Franchise (b)	Ex-Franchise (c)	Total (d) = (a+b+c)
	Dawn-Parkway Distance Weighted Design Day Demands				
	2013 Board-Approved per EB-2011-0210				
1	Design Day Demands ($10^6m^3/d$)	7	44	124	175
2	Weighted Average Distance (km)	229	82	214	182
3	Distance Weighted Demands ($10^6m^3/d$ x km) (1)	1,592	3,588	26,557	31,737
4	Distance Weighted Demands (%)	5.0%	11.3%	83.7%	100.0%
	2016 Dawn-Parkway Expansion (per EB-2014-0261)				
5	Project Demands ($10^6m^3/d$)	1	2	9	13
6	Weighted Average Distance (km)	229	209	209	211
7	Project Distance Weighted Demands ($10^6m^3/d$ x km) (line 5 x line 6) (2)	285	509	1,857	2,651
	2016 Dawn-Parkway Expansion Allocator (per EB-2014-0261)				
8	Design Day Demands ($10^6m^3/d$) (line 1 + line 5)	8	46	133	187
9	Weighted Average Distance (km)	229	89	214	184
10	Project Distance Weighted Demands ($10^6m^3/d$ x km) (line 8 x line 9)	1,878	4,097	28,414	34,388
11	Distance Weighted Demands (%)	5.5%	11.9%	82.6%	100.0%
	Design Day Demands requiring Dawn Compression				
	2013 Board-Approved per EB-2011-0210				
12	Design Day Demands requiring Dawn Compression ($10^6m^3/d$) (3)	7	26	116	149
13	Dawn Compression Demands (%)	4.6%	17.4%	77.9%	100.0%
	2016 Dawn-Parkway Expansion (per EB-2014-0261)				
14	Project Demands requiring Dawn Compression ($10^6m^3/d$)	1	2	8	12
	2016 Dawn-Parkway Expansion Allocator (per EB-2014-0261)				
15	Design Day Demands requiring Dawn Compression ($10^6m^3/d$) (line 12 + line 1	8	28	124	161
16	Dawn Compression Demands (%)	5.1%	17.7%	77.2%	100.0%

Notes:
(1) EB-2011-0210, Exhibit G3, Tab 5, Schedule 23, Updated, pages 7-8, line 5.
(2) EB-2014-0261, Exhibit A, Tab 10, Table 10-1, line 5. Union North T-service incremental Dawn-Parkway demands of 0.771 $10^6m^3/d$ included in Ex-franchise.
(3) EB-2011-0210, Exhibit G3, Tab 5, Schedule 23, Updated, pages 7-8, line 11.

UNION RATE ZONES
Derivation of the Capital Pass-through Project Allocators - 2017 Dawn-Parkway Expansion

Line No.	Particulars	Union North In-Franchise (a)	Union South In-Franchise (b)	Ex-Franchise (c)	Total (d) = (a+b+c)
	Dawn-Parkway Distance Weighted Design Day Demands				
	2013 Board-Approved per EB-2011-0210				
1	Design Day Demands ($10^6m^3/d$)	7	44	124	175
2	Weighted Average Distance (km)	229	82	214	182
3	Distance Weighted Demands ($10^6m^3/d$ x km) (1)	1,592	3,588	26,557	31,737
4	Distance Weighted Demands (%)	5.0%	11.3%	83.7%	100.0%
	2017 Dawn-Parkway Expansion (per EB-2015-0200)				
5	Project Demands ($10^6m^3/d$)	-	-	12	12
6	Weighted Average Distance (km)	-	-	194	194
7	Project Distance Weighted Demands ($10^6m^3/d$ x km) (line 5 x line 6) (2)	-	-	2,323	2,323
	2017 Dawn-Parkway Expansion Allocator (per EB-2015-0200)				
8	Design Day Demands ($10^6m^3/d$) (line 1 + line 5)	7	44	136	187
9	Weighted Average Distance (km)	229	82	212	182
10	Project Distance Weighted Demands ($10^6m^3/d$ x km) (line 8 x line 9)	1,592	3,588	28,879	34,060
11	Distance Weighted Demands (%)	4.7%	10.5%	84.8%	100.0%
	Design Day Demands requiring Dawn Compression				
	2013 Board-Approved per EB-2011-0210				
12	Design Day Demands requiring Dawn Compression ($10^6m^3/d$) (3)	7	26	116	149
13	Dawn Compression Demands (%)	4.6%	17.4%	77.9%	100.0%
	2017 Dawn-Parkway Expansion (per EB-2015-0200)				
14	Project Demands requiring Dawn Compression ($10^6m^3/d$) (4)	-	-	10	10
	2017 Dawn-Parkway Expansion Allocator (per EB-2015-0200)				
15	Design Day Demands requiring Dawn Compression ($10^6m^3/d$) (line 12 + line 14)	7	26	126	159
16	Dawn Compression Demands (%)	4.3%	16.4%	79.3%	100.0%

Notes:
(1) EB-2011-0210, Exhibit G3, Tab 5, Schedule 23, Updated, pages 7-8, line 5.
(2) EB-2015-0200, Exhibit A, Tab 10, Table 10-1, line 5.
(3) EB-2011-0210, Exhibit G3, Tab 5, Schedule 23, Updated, pages 7-8, line 11.
(4) EB-2015-0200, Exhibit A, Tab 10, Table 10-2, line 5.

UNION RATE ZONES

Derivation of the Capital Pass-through Project Allocators - Panhandle Reinforcement Project

Line No.	Particulars ($10^3m^3/d$)	Capacity	M1	M2	M4	M5	M7	T1	T2	Total In-Franchise	C1	M16	Total Ex-Franchise	Total	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i) = (sum b-h)	(j)	(k)	(l) = (j+k)	(m) = (i+l)	
	2013 Board-Approved per EB-2011-0210														
1	Ojibway/St. Clair Design Maximum Capacity	15,188													
2	Less: C1 Transportation - Ojibway/St. Clair Firm Demand	(2,264)													
3	Less: M16 Firm Demand (West of Dawn)	(473)													
4	Remaining Pipe Capacity to be Allocated to In-Franchise	12,452 (2)													
5	2013 Panhandle Firm Design Day Demands		5,567	1,870	929	30	131	524	3,051	12,102	-	-	-	12,102	
6	2013 Sarnia Industrial Line Firm Design Day Demands		764	257	12	-	-	1,047	9,541	11,620	-	-	-	11,620	
7	Total Firm Design Day Demands		6,331	2,127	941	30	131	1,570	12,592	23,722	-	-	-	23,722	
8	2013 Board-Approved Allocation Methodology		3,323	1,116	494	16	69	824	6,610	12,452	2,264	473	2,737	15,188	(1)
			22%	7%	3%	0%	0%	5%	44%	82%	15%	3%	18%	100%	
	2013 Board-Approved Allocation Methodology Updated for Project														
9	2013 Approved Ojibway/St. Clair Demand Allocator	15,188													
10	Less: C1 Transportation - Ojibway/St. Clair Firm Demand	(2,264)													
11	Less: M16 Firm Demand (West of Dawn)	(473)													
12	Add: Incremental Capacity related to the Project	2,739 (3)													
13	Remaining Pipe Capacity to be Allocated to In-Franchise	15,191													
14	2013 Panhandle Firm Design Day Demands		5,567	1,870	929	30	131	524	3,051	12,102	-	-	-	12,102	
15	2013 Sarnia Industrial Line Firm Design Day Demands		764	257	12	-	-	1,047	9,541	11,620	-	-	-	11,620	
16	2017 Incremental Firm Design Day Demands for the Project		28	24	696	-	439	154	151	1,492	-	-	-	1,492	
17	2018 Incremental Firm Design Day Demands for the Project		28	21	343	-	-	-	-	392	-	-	-	392	
18	2019 Incremental Firm Design Day Demands for the Project		28	43	259	-	-	-	-	330	-	-	-	330	
19	2020 Incremental Firm Design Day Demands for the Project		28	33	182	-	-	-	-	242	-	-	-	242	
20	2021 Incremental Firm Design Day Demands for the Project (5)		28	70	185	-	-	-	-	283	-	-	-	283	
21	Total Firm Design Day Demands		6,471	2,318	2,605	30	570	1,725	12,743	26,461	-	-	-	26,461	
22	2013 Board-Approved Allocator Updated for Panhandle Reinforcement Project		3,715	1,330	1,496	17	327	990	7,316	15,191	2,264	473	2,737	17,927	(4)
			21%	7%	8%	0%	2%	6%	41%	85%	13%	3%	15%	100%	

Notes:

(1) EB-2011-0210, Exhibit G3, Tab 5, Schedule 23, Updated, pages 7-8, line 5.

(2) In-franchise capacity (Line 4) allocated using total Panhandle and St. Clair Design Day Demands (Line 7) to in-franchise rate classes. Rate C1 demand (Line 2) and Rate M16 demand (Line 3) added to total in-franchise allocation.

(3) Incremental capacity of 2,739 $10^3m^3/d$ equal to 106 TJ/d based on a heat value of 38.55 $GJ/10^3m^3$.

(4) In-franchise capacity (Line 13) allocated using total Panhandle, St. Clair, and Incremental Project Design Day Demands (Line 20) to in-franchise rate classes. Rate C1 demand (Line 10) plus Rate M16 demand (Line 11) added to total in-franchise allocation.

(5) The incremental capacity created by the Panhandle Reinforcement Project was forecast to be utilized by incremental firm design day demands by 2021.

UNION RATE ZONES

Recovery of Allocated Rate M12 and Rate C1 Capital Pass-through Costs by Transportation Path for 2022

Line No.	Particulars ($000's)	Parkway Projects	BOP	2016 D-P Expansion	2017 D-P Expansion	Panhandle Reinforcement	Sudbury Replacement	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = sum(a - f)
	Rate M12/C1							
1	Dawn to Parkway	26,402	(112)	17,072	36,573	(164)	(138)	79,634
2	Dawn to Kirkwall	3,444	(15)	2,220	5,174	(22)	(18)	10,783
3	Kirkwall to Parkway	242	(1)	159	203	(1)	(1)	600
4	M12-X	2,870	(12)	1,861	3,637	(17)	(15)	8,325
5	Parkway to Dawn	570	(2)	374	477	(3)	(3)	1,414
6	Rate C1 Dawn-Parkway	202	(1)	131	280	(1)	(1)	610
7	Total Rate M12/C1 (1)	33,730	(142)	21,817	46,344	(208)	(176)	101,365
	Rate C1							
8	St.Clair & Dawn / Ojibway & Dawn	(10)	(0)	1,013	(27)	1,304	(0)	2,278
9	Short-term Transportation	(19)	(1)	(8)	(19)	155	(1)	107
10	Total Rate C1 (2)	(29.397)	(1)	1,004	(46)	1,459	(1)	2,386

Notes:

(1) Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 14, p. 3, line 19.

(2) Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 14, p. 3, line 23.

UNION RATE ZONES
Dawn to Parkway System Capacity and Demand, PDO Shift Details, and PDO Demand Revenue Difference

Line No.	Particulars (TJ/d)	2013 Forecast W13/14 (a)	W14/15 (b)	W15/16 (c)	W16/17 (d)	W17/18 (e)	W18/19 (f)	W19/20 (g)	W20/21 (h)	W21/22 (i)	W22/23 (j)
	Dawn-Parkway System										
	Included in Rates										
1	2013 Cost of Service (EB-2011-0210) Capacity	6,803	6,803	6,803	6,803	6,803	6,803	6,803	6,803	6,803	6,803
2	Incremental Dawn-Parkway Capacity (1)	-	-	433	876	1,332	1,332	1,332	1,332	1,332	1,332
3	Total	6,803	6,803	7,236	7,678	8,135	8,135	8,135	8,135	8,135	8,135
	Other Changes (No Impact to Rates)										
4	Other Dawn-Parkway Capacity Changes	-	(2)	(222)	(170)	(246)	(262)	(256)	(219)	(186)	(176)
	Annual Forecast										
5	Total Forecasted Dawn-Parkway Capacity (line 3 + line 4)	6,803	6,801	7,014	7,508	7,889	7,873	7,878	7,915	7,949	7,959
6	Total Forecasted Dawn-Parkway Demands	6,593	6,643	7,049	7,443	7,783	7,759	7,905	7,911	8,055	8,005
7	Forecast Dawn-Parkway Excess/(Shortfall) (line 5 - line 6) (2)	210 (3)	158	(35)	65	106 (4)	114	(27)	4	(106)	(47)

Notes:

(1) W15/16 - Incremental capacity resulting from the Brantford-Kirkwall / Parkway D Project of 433 TJ/d.
W16/17 - Incremental capacity resulting from the Dawn Parkway 2016 System Expansion Project of 443 TJ/d.
W17/18 - Incremental capacity resulting from the 2017 Dawn Parkway Project of 457 TJ/d.

(2) The PDO shift was reflected in Dawn-Parkway excess/(shortfall) beginning W15/16.

(3) The W13/14 forecast filed in Union's 2013 Cost of Service proceeding (EB-2010-0210) included 210 TJ/d of excess Dawn-Parkway capacity. In the EB-2011-0210 Decision, the Board accepted Union's forecast and regulatory treatment.
Union's 2013 cost allocation study allocates Dawn-Parkway demand costs in proportion to distance weighted design day demands. The 2013 allocation resulted in approximately 84% of costs allocated to Union's ex-franchise rate classes and 16% to Union's in-franchise rate classes.

(4) As part of the 2017 Dawn-Parkway Project (EB-2015-0200), Union had forecast a surplus of 30,393 GJ/d on the Dawn-Parkway System following the completion of the project. As part of the EB-2015-0200 Settlement Agreement, Union agreed to market the surplus capacity in accordance with the Storage and Transportation Access Rule (“STAR”) and credit the revenues to the project deferral account.

UNION RATE ZONES
Forecast Usage for Rate-Setting

Line No.	Particulars (GJ)	EGD Rate Zone (a)	Other Ex-Franchise (b)	Total (c)	EGD as % of Total (d) = (a/c)
	2013 Forecast Usage (1)				
	Rate M12/C1				
1	Dawn to Parkway	23,486,076	19,566,524	43,052,600	54.6%
2	Dawn to Kirkwall	-	8,708,176	8,708,176	0.0%
3	Kirkwall to Parkway	-	1,411,468	1,411,468	0.0%
4	M12-X	2,400,000	2,292,132	4,692,132	51.1%
5	Parkway to Dawn	2,839,032	1,492,491	4,331,523	65.5%
6	Rate C1 Dawn-Parkway	-	84,780	84,780	0.0%
	Capital Pass-through Projects				
	Rate M12/C1				
7	Dawn to Parkway	6,650,319	5,299,461	11,949,780	55.7%
8	Dawn to Kirkwall	-	-	-	-
9	Kirkwall to Parkway	-	1,453,860	1,453,860	0.0%
10	M12-X	-	-	-	-
11	Parkway to Dawn	-	-	-	-
12	Rate C1 Dawn-Parkway	-	421,080	421,080	0.0%
	2022 Forecast Usage for Rate-Setting (2)				
	Rate M12/C1				
13	Dawn to Parkway	30,136,395	24,865,985	55,002,380	54.8%
14	Dawn to Kirkwall	-	8,708,176	8,708,176	0.0%
15	Kirkwall to Parkway	-	2,865,328	2,865,328	0.0%
16	M12-X	2,400,000	2,292,132	4,692,132	51.1%
17	Parkway to Dawn	2,839,032	1,492,491	4,331,523	65.5%
18	Rate C1 Dawn-Parkway	-	505,860	505,860	0.0%

Notes:
(1) Total forecast usage per EB-2011-0210, Rate Order, Working Papers, Schedule 14, p. 11, column (a) expressed in GJ.
(2) Total forecast usage per Exhibit D, Tab 2, Rate Order, Working Papers, Scheudule 5, column (n) annualized.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Section 3,
Exhibit D, Tab 2, Rate Order Working Papers Schedule 11 and
EB-2019-0194 Exhibit JT1.7

Preamble:

EGI evidence states: "*In effect, Union South in-franchise customers receive a 'distance credit' as a result of the obligated deliveries at Parkway, which recognizes that design day demands supplied from Parkway are transported over a shorter distance than design day demands supplied from Dawn. Since Dawn-Parkway costs are allocated to Union South in-franchise rate classes on the basis of Dawn-Parkway design day demands, the primary beneficiary of the "distance credit" are Union South general service rate classes (Rate M1 and Rate M2).*"

We would like to understand better the application of the distance credit as applied to PDO.

Question(s):

Please describe specifically how the daily deliveries at Parkway are applied to in-franchise design day demands.

a) Specifically, are the in-franchise design demands reduced proportionally along the Dawn-Parkway system or
b) Are the obligated Parkway deliveries netted against the most easterly in-franchise lateral demands or
c) Assumed to "move" from Parkway to the lateral(s) incurring fuel gas or
d) Describe specifically the approach used.

Response:

a) to d)

Obligated Parkway deliveries are netted against the in-franchise demands utilizing laterals at the eastern end of the Dawn-Parkway transmission system starting at Parkway and moving westerly towards Dawn until the Parkway Delivery Obligation is fully netted off.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Section 3,
Exhibit D, Tab 2, Rate Order Working Papers Schedule 11 and
EB-2019-0194 Exhibit JT1.7

Preamble:

EGI evidence states: "*In effect, Union South in-franchise customers receive a 'distance credit' as a result of the obligated deliveries at Parkway, which recognizes that design day demands supplied from Parkway are transported over a shorter distance than design day demands supplied from Dawn. Since Dawn-Parkway costs are allocated to Union South in-franchise rate classes on the basis of Dawn-Parkway design day demands, the primary beneficiary of the "distance credit" are Union South general service rate classes (Rate M1 and Rate M2).*"

We would like to understand better the application of the distance credit as applied to PDO.

Question(s):

Please provide the resulting design day simulation results for this applications Dawn-Parkway system assuming that Parkway deliveries moved to Dawn as a result of the PDO settlement agreement:

a) Were moved
b) Were not moved (i.e., before and after application of existing PDO to show effect)

Response:

a) and b)

Firm obligated deliveries at Parkway increase the Dawn Parkway System capacity by an equivalent amount. Assuming that firm obligated Parkway deliveries were shifted to Dawn, the Dawn Parkway System capacity would decrease by approximately 244 TJ/d in winter 2021/2022. The 244 TJ/d is equal to the PDO by direct purchase customers without M12 service provided at Exhibit B, Tab 1, Schedule 1, Appendix A, page 1, column (g), row 13.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Section 3,
Exhibit D, Tab 2, Rate Order Working Papers Schedule 11 and
EB-2019-0194 Exhibit JT1.7

Preamble:

EGI evidence states: "*In effect, Union South in-franchise customers receive a 'distance credit' as a result of the obligated deliveries at Parkway, which recognizes that design day demands supplied from Parkway are transported over a shorter distance than design day demands supplied from Dawn. Since Dawn-Parkway costs are allocated to Union South in-franchise rate classes on the basis of Dawn-Parkway design day demands, the primary beneficiary of the "distance credit" are Union South general service rate classes (Rate M1 and Rate M2).*"

We would like to understand better the application of the distance credit as applied to PDO.

Question(s):

For the purposes of Schedule 11 of the Working Papers, is the approach in IR #5 used to calculate the fuel impact?

a) Please describe in full including how the EB-2011-0210 allocations are developed including simulation results and flows assumed in those simulations.

b) Using the description, please provide a verbal description along with numeric support that justifies an almost doubling of fuel gas allocated to Union South in-franchise versus an approximately 10% increase in total fuel gas shown on page 5 of Schedule 11.

Response:

a) The allocation of forecast compressor fuel along the Dawn Parkway system is completed in accordance with the OEB Approved M12 Rate Schedule[1]. The allocations are completed monthly, by compressor station based on forecast activity.

b) The movement of obligated deliveries from Parkway to Dawn increase in-franchise easterly activity on the system. The ability to allow customers to shift their obligated deliveries results from M12 turnback capacity which reduces M12 activity on the Dawn Parkway system. The resulting impact is an increased share of the compressor fuel because in-franchise activity increases and M12 activity decreases. As an example, please see Attachment 1 for the allocation of compressor fuel at the Bright compressor station for the month of January.

[1] M12 Rate Schedule, page 3

UNION GAS LIMITED
Estimated Fuel Impact of the Parkway Delivery Obligated Reduction at the Bright Compressor

Line No.	Particulars (GJ)	Allocation of Fuel (Updated for PDO)			Allocation of Fuel (as filed in EB-2011-0210)			Difference
		Fuel	Activity	%	Fuel	Activity	%	
		(a)	(b)		(f)	(g)		(p) = (e - j)
1	M12 Easterly	188,275	93,040,713	67%	175,274	93,620,072	71%	13,001
2	M12 Westerly	-	-		-	-		-
3	C1 LT Easterly	443	219,015	0%	410	219,015	0%	33
4	C1 ST Easterly	40,457	19,992,825	14%	37,430	19,992,825	15%	3,027
5	C1 LT Westerly	-	-		-	-		-
6	C1 ST Westerly	-	-		-	-		-
7	M16 to Pool	-	-		-	-		-
8	Infranchise - North	8,930	4,413,198	3%	8,262	4,413,198	3%	668
9	Infranchise - South	42,016	20,763,361	15%	25,057	13,383,548	10%	16,960
10	Total	280,122	138,429,112	100%	246,434	131,628,657	100%	33,689

Notes:
(1) Sales of Dawn to Parkway transportation services were reduced by 84 TJ per day.
(2) Compressor throughput was adjusted to account for a shift of 219 TJ of delivered supply from Parkway to Dawn and 84 TJ/d of M12 turnback.
(3) Compressor fuel costs increased to reflect the change in flows outlined in note (2).
(4) Based on contract quantities from 2013 Rates filing.
(5) Allocation of fuel is consistent with YCR formula in the current M12 Rate Schedule.
(6) The total fuel excludes C1 Dawn to Dawn-Vector and C1 Dawn to Dawn-TCPL fuel of 31,960 GJ.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2 and
EB-2020-0091 FRPO_OEB_IRP_PRESENT_20210219 pages 11-17

Preamble:

We would like to understand better the market-base alternatives considered and potential additional market-based alternatives.

Question(s):

The RFP produced in the Appendix specifies a Dawn receipt and Parkway delivery.

a) Please confirm that a similar long-term exchange agreement that would use a Dawn receipt and Kirkwall delivery could provide additional flow capability to Reduce PDO/PDCI costs similar to Dawn-Parkway.
b) Did EGI consider requesting proposal that could include Dawn receipt and Kirkwall delivery?
    i) If not, why not?
    ii) If so, why was that option not included in the RFP.

Response:

a) Please see the response at Exhibit I.FRPO.2.

b) No, Enbridge Gas did not specifically consider a Kirkwall delivery within the RFP. Please see the response at Exhibit I.FRPO.2.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2 and

EB-2020-0091 FRPO_OEB_IRP_PRESENT_20210219 pages 11-17

Preamble:

We would like to understand better the market-base alternatives considered and potential additional market-based alternatives.

Question(s):

Did EGI consider contracting for long-term obligated deliveries to Parkway deliveries as a means of providing for required demands and reducing PDO/PDCI costs?

a) If not, why not?
b) If so, why was that option not included in the RFP.

Response:

a) and b)

Enbridge Gas did not specifically consider long term obligated deliveries to Parkway to reduce PDO. However, the RFP did provide bidders the opportunity to include any alternative solutions that met the needs identified. No bids that included alternative solutions were received.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2 and
EB-2020-0091 FRPO_OEB_IRP_PRESENT_20210219 pages 11-17

Preamble:

We would like to understand better the market-base alternatives considered and potential additional market-based alternatives.

Question(s):

Did EGI consider contracting for long-term obligated deliveries to Kirkwall deliveries as a means of providing for required demands and reducing PDO/PDCI costs?

a) If not, why not?
b) If so, why was that option not included in the RFP.

Response:

a) and b)

Please see the response at Exhibit I.FRPO.8.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2 and
EB-2020-0091 FRPO_OEB_IRP_PRESENT_20210219 pages 11-17

Preamble:

We would like to understand better the market-base alternatives considered and potential additional market-based alternatives.

Question(s):

In EB-2020-0091, FRPO presented the opportunity to consider using Dawn LTFP deliveries committed by suppliers and facilitated by TCPL to Parkway as a means of using displacement to meet Dawn-Parkway demand.

a) Has EGI consider the potential for employing displacement at Parkway in conjunction with TCPL as a means of meeting Dawn-Parkway demand?
    i. If so, please provide all relevant communication with TCPL on the possibility including summaries of conversations.
    ii. If not, why not? Please ensure the response includes any physical, commercial, or other reasons why this approach could not be used to satisfy a Dawn-Parkway demands even as a bridging solution to a longer term approach.

Response:

a) Enbridge Gas has not considered FRPO's referenced non-facility supply side alternative to incremental pipeline infrastructure. Enbridge Gas will consider specific non-facility supply side alternatives as required in future LTC applications. Enbridge Gas further notes that TCPL received the Company's RFP seeking solutions for additional Parkway deliveries and TCPL did not provide any bid or response.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2 and
EB-2020-0091 FRPO_OEB_IRP_PRESENT_20210219 pages 11-17

Preamble:

We would like to understand better the market-base alternatives considered and potential additional market-based alternatives.

Question(s):

In November of 2020, EGI launched an Open Season to determine Dawn-Parkway demand starting as early as 2023. The deadline for response was January of 2021.

Please provide:

a) The demand bid for and the starting dates requested
b) The bids accepted
c) The impact on the forecasted Dawn-Parkway capability
d) The need for a Leave to Construct
e) The foreseen schedule for the application

Response:

The requested information is not relevant to the relief being sought in this application.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit D, Tab 1, Rate Order, Appendix B, Page 51

Preamble:

We would like to understand better the utilization of Segment A from Parkway to Albion and its impact on rates.

Question(s):

Please confirm that TCPL pays for 1200 TJ/day demand capacity under Rate 332.

a) If not confirmed, how much is allocated and paid for by TCPL.

Response:

a) Confirmed.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit D, Tab 1, Rate Order, Appendix B, Page 51

Preamble:

We would like to understand better the utilization of Segment A from Parkway to Albion and its impact on rates.

Question(s):

What is the current design day demand of EGI's GTA system that is served by Segment A for the winter of 2021/22?

a) Has EGI explored or implemented any initiatives to mitigate the cost of the remaining capacity?
    i. If so, please describe the initiatives and the expected impact on rates 2022.
    ii. What was the impact of these initiatives in 2020 and how were the revenues allocated?

Response:

The current design day demand and capacity of Enbridge Gas's Segment A Albion Line for the winter 2021/22 is 2,019 TJ/d.

a) There is no excess capacity on Segment A.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, page 14

Question:

Please confirm that in the EB-2020-0091 Decision and Order dated July 22, 2021, the Ontario Energy Board approved the creation of two IRP related accounts, one for operating and maintenance costs and one for capital costs for the 2021 through 2023 period. If not confirmed, please explain fully.

Response

The Company confirms that as part of the EB-2020-0091 Decision and Order, dated July 22, 2021, the OEB approved the establishment of an IRP Operating Costs Deferral Account and an IRP Capital Costs Deferral Account for the 2021 through 2023 period. On August 12th, 2021 in accordance with the EB-2020-0091 Decision and Order, the Company filed draft accounting orders for the above mentioned accounts.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Appendix A

Question(s):

Line 8, Annual PDO Shift, is shown as line 11 + line 17 + line 21 and has no figures on the line. However, line 17 has non-zero figures. Should line 17 and line 21 be lines 18 and 22? If not, please provide an explanation for line 8.

Response

Yes, line 8 should be shown as Annual PDO Shift line 11 + line 18 + line 22. Enbridge Gas will file a correction to Appendix A with the interrogatory response.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Appendix C

Question(s):

a) Does the wording in Appendix C for the COVID-19 Emergency Deferral Account impact 2021 only or does it also impact 2020?

b) Does the wording impact the amount included in the account as noted in the EB-2021-0149 application and evidence? If yes, please provide the updated amount and an explanation for the change in the amount.

Response

a) The proposed wording of the accounting order for the Impacts Arising from the COVID-19 Emergency Deferral Account, included at Exhibit B, Tab 1, Schedule 1, Appendix C, would be applicable for the duration of the account. This would include 2020, as the effective date for the account was March 24, 2020.

b) The proposed wording does not impact the 2020 balance recorded in the account, as reflected in the EB-2021-0149 application and evidence.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, page 9

Question:

What “direction” is EGI seeking from the OEB related to securing the offered firm exchange capacity and please explain why EGI believes it requires this direction.

Response

Please see the response at Exhibit I.STAFF.4 b).

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit D, Tab 2, Rate Order, Appendix B

Question:

Please provide a copy of the M1 rate schedule that includes all the figures for the various components of the rates.

Response

Please see Attachment 1.

ENBRIDGE GAS INC.
UNION SOUTH
SMALL VOLUME GENERAL SERVICE RATE

(A) Availability

Available to customers in Union's Southern Delivery Zone.

(B) Applicability

To general service customers whose total consumption is equal to or less than 50,000 m^3 per year.

(C) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated which may be higher than the identified rates. (1)

a) Monthly Charge			$23.18	
b) Delivery Charge				
First	100 m^3		5.9896	¢ per m^3
Next	150 m^3		5.6947	¢ per m^3
All Over	250 m^3		4.9331	¢ per m^3
Delivery - Price Adjustment (All Volumes)		(2)	4.9085	¢ per m^3
c) Carbon Charges				
Federal Carbon Charge (if applicable)		(3)	7.8300	¢ per m^3
Facility Carbon Charge (in addition to Delivery Charge)			0.0127	¢ per m^3
Federal Carbon Charge - Price Adjustment (if applicable)			-	¢ per m^3
d) Storage Charge (if applicable)			0.8339	¢ per m^3
Storage - Price Adjustment (All Volumes)			-	¢ per m^3

Applicable to all bundled customers (sales and bundled transportation service).

e) Gas Supply Charge (if applicable)

The gas supply charge is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A".

f) System Expansion Surcharge ("SES") and Temporary Connection Surcharge ("TCS") (if applicable) (4)

The SES is applicable to a customer who receives gas distribution services from the Company as part of a Community Expansion Project listed below. The SES is applied to all volumes consumed by customers in the approved Community Expansion Project areas. The Company may apply the SES for a term of up to 40 years, to be determined in accordance with the Company's feasibility policy.

The TCS is applicable to a customer who receives gas distribution services from the Company as part of a Small Main Extension or Customer Attachment Project in lieu of paying a Contribution in Aid of Construction (CIAC). The TCS is applied to all volumes consumed, if applicable. The Company may require payment of a CIAC or apply the TCS for a term of up to 40 years, to be determined in accordance with the Company's feasibility policy.

System Expansion Surcharge (SES):	23.0000	¢ per m^3
Temporary Connection Surcharge (TCS):	23.0000	¢ per m^3

Community Expansion Project	In-service Date	SES Term
Kettle and Stony Point First Nation and Lambton Shores	2017	12 years
Milverton, Rostock and Wartburg	2017	15 years
Delaware Nation of Moraviantown First Nation	2018	40 years
Chippewas of the Thames First Nation	2019	40 years
Saugeen First Nation	2020	40 years

Notes:
(1) During any month in which a customer terminates service or begins service, the fixed charge for the month will be prorated to such customer.
(2) Approved in EB-2020-0067 (2017 & 2018 DSM Deferral and Variance Accounts), includes a temporary charge of 4.9085 cents/m^3 effective April 1, 2021 to September 30, 2021.
(3) The Federal Carbon Charge for on-reserve First Nations customers are interim, per the Board's Decision and Order in EB-2019-0247.
(4) Additional conditions and defined terms applicable to the SES and TCS are set out in the Company's Distribution New Business Guidelines as approved by the OEB in its EB-2020-0094 decision.

(D) Supplemental Service to Commercial and Industrial Customers Under Group Meters

Combination of readings from several meters may be authorized by the Company and the Company will not reasonably withhold authorization in cases where meters are located on contiguous pieces of property of the same owner not divided by a public right-of-way.

(E) Delayed Payment

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

(F) Direct Purchase

Unless otherwise authorized by Union, customers who are delivering gas to Union under direct purchase arrangements must obligate to deliver at a point(s) specified by Union, and must acquire and maintain firm transportation on all upstream pipeline systems. Customers initiating direct purchase arrangements, who previously received Gas Supply service, must also accept, unless otherwise authorized by Union, an assignment from Union of transportation capacity on upstream pipeline systems.

(G) Overrun Charge

In the event that a direct purchase customer fails to deliver its contracted volumes to Union, and Union has the capability to continue to supply the customer, Union will do so. The customer may pay for the identified delivery charge plus facility carbon charge and if applicable, the identified federal carbon charge and the total gas supply charge for utility sales provided in Schedule "A" per m^3, plus 7¢ per m^3.

Overrun Delivery Charge	6.8235	¢ per m^3
Federal Carbon Charge (if applicable)	7.8300	¢ per m^3
Facility Carbon Charge (in addition to Overrun Delivery Charge)	0.0127	¢ per m^3

(H) Bundled Direct Purchase Delivery

Where a customer elects transportation service under this rate schedule, the customer must enter into a Bundled T Gas Contract with Union for delivery of gas to Union. Bundled T Gas Contract Rates and Gas Purchase Contract Rates are described in rate schedule R1.

(I) Company Policy Relating to Terms of Service

a. Customers who temporarily discontinue service during any twelve consecutive months without payment of the monthly fixed charge for the months in which the gas is temporarily disconnected shall pay for disconnection and reconnection.

b. When gas is delivered at an absolute pressure in excess of 101.325 kilopascals, then for purposes of measurement, hereunder, such volume of gas shall be corrected to an absolute pressure of 101.325 kilopascals. Atmospheric pressure is assumed to be the levels shown below in kilopascals (absolute) regardless of the actual atmospheric pressure at which the gas is measured and delivered.

Zone	Assumed Atmospheric Pressure kPa	Zone	Assumed Atmospheric Pressure kPa
1	100.148	7	97.582
2	99.494	8	97.065
3	98.874	9	96.721
4	98.564	10	100.561
5	98.185	11	99.321
6	97.754	12	98.883

Effective January 1, 2022
Implemented January 1, 2022
O.E.B. Order # EB-2021-0147

Supersedes EB-2020-0181 Rate Schedule effective July 1, 2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit D, Tab 2, Rate Order, Appendix A, page 9 & Exhibit D, Tab 2, Working Papers, Schedule 5, pages 13-14

Question(s):

a) The rate changes for most rate classes in Union South are shown as increases in Appendix A. However, there are decreases shown for the M7 rate class. Please explain and highlight why the M7 rates are decreasing.

b) Schedule 5 in the Working Papers shows rate increases for the M7 rates. Please reconcile this increase with the decrease shown in Appendix A.

c) What is the difference in the M7 rates shown in Appendix A versus those shown in Schedule 5 of the Working Papers?

Response

Appendix A provides the total proposed rates and rate changes for each rate class and agrees with the rate schedules. Total rates are the sum of base rates and Y factor rates.

Base rates are derived through the approved price cap mechanism and include adjustments such as PCI, capital pass-through adjustment changes, and NAC and LRAM volume adjustments. Base rates for the Union rate zone are calculated at Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 5. Specifically, Rate M7 is calculated at pages 13 and 14.

Y factor rates are derived for Demand Side Management (DSM) costs and Parkway Delivery Obligation (PDO) costs. Y factor rates are designed to pass through the allocated costs to customers using the test year forecast. The DSM unit rate derivation for Rate M7 is found at Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 10, page 4 and the PDO unit rate derivation for Rate M7 is found at Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 11, page 9.

a) In Appendix A, Rate M7 unit rates are decreasing as a result of the decrease in Rate M7 DSM and PDO unit rates resulting from a higher test year demand and volume forecast for 2022 compared to 2021.

b) Schedule 5 provides the detailed derivation of base rates. Base rates for Rate M7 are increasing in 2022.

c) The difference in Rate M7 rates shown in Appendix A and those shown in Schedule 5 is the Y factor rates. Exhibit D, Tab 1, Rate Order, Working Papers, Schedule 6 provides continuity between Schedule 5 and Appendix A for Union rate zone rate classes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. A, T2, Sch. 1

Question(s):

a) Please provide a list of which Ontario municipalities served by Enbridge were consulted prior to filing the 2022 Rates application.

b) For each municipality consulted, please provide a summary of their input and how it was considered or included.

Response

a) and b)

As per the letter of direction, dated July 16, 2021 in this proceeding, the municipalities were served the OEB Notice and the Application. No municipalities served by Enbridge Gas were consulted prior to filing the 2022 Rates application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. B, T1, Sch.1

Question(s):

Enbridge Gas proposes to maintain the 2021 DSM budget of $67.8 million for the EGD rate zone and $64.3 million for the Union rate zones in 2022 rates. The aggregate of these two amounts is $132.1 million.

a) Please explain why Enbridge choose to rollover the 2021 DSM budget as a placeholder in the 2022 Rates application rather than use its proposed 2022 DSM budget.

b) Please confirm that the 2022 DSM budget of $132 million is merely a placeholder and that the actual 2022 DSM budget determined by the OEB will be the final 2022 DSM budget.

c) Please describe the approach proposed to true up between the 2022 DSM budget amount in this application and the actual 2022 DSM budget amount determined by the OEB.

d) Please identify any approvals requested in the 2022 Rate proceeding would set a precedent for any decision in the EB-2021-0002 (DSM) proceeding.

Response

a) to d)

Please see the response at Exhibit I.BOMA.2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. B, T1, Sch.1

Question(s):

LRAM volumetric adjustments include the expected natural gas savings that are partially effective in the 2022 program year.

a) Please provide a table by rate class of the fully allocated and partially allocated DSM volumes saving assumptions have been applied to 2022 rates in this application.

Response

a) The LRAM volume adjustment by rate class for the EGD rate zone can be found at Exhibit D, Tab 1, Rate Order, Working Papers, Schedule 11.

   The LRAM volume adjustment by rate class for the Union rate zones can be found at Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 15.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. B, T1, Sch.1

Question(s):

a) Please provide a list of 2022 requirements from the EB-2020-0091 (IRP) Decision that Enbridge will need to implement.

b) For each item referenced above, please provide an estimate completion date and cost.

Response

a) and b)

The Company is currently evaluating the IRP Decision[1] and is not in a position to provide details of IRP projects, programs and associated costs at this point in time. Enbridge Gas will include details about IRP implementation in its annual IRP report, following the direction in the IRP Decision (pages 83-84).

[1] EB-2020-0091, Decision and Order, dated July 22, 2021

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. B, T1, Sch.1, Appendix C

Question(s):

a) Please provide a summary of the costs proposed to be included in the COVID-19 Emergency Deferral Account.

b) Please provide a summary of the savings (activity and amount) that Enbridge was able to achieve to offset incremental costs to be claimed in the COVID-19 Emergency Deferral Account.

Response

a) In recognition of the guidance provided in the OEB's June 17th, 2021 Report: *Regulatory Treatment of Impacts Arising from the COVID-19 Emergency*, Enbridge Gas has and at present only expects to record its incremental costs necessary to comply with government or OEB initiated customer relief programs (Exceptional Pool costs - which are eligible for 100% recovery, subject to an approved ROE plus 300 basis point means test) within the Impacts Arising from the COVID-19 Emergency Deferral Account. To date, those costs include incremental 2020 LEAP EFA funding, and incremental CEAP and CEAP small business administration costs totaling $1.378 million.

b) As Enbridge Gas has only recorded and only expects to seek recovery of incremental costs necessary to comply with government or OEB initiated customer relief programs (Exceptional Pool costs), which are eligible for 100% recovery, and presently does not expect to seek recovery for other incremental COVID-19 related impacts, no savings have been recorded in the account.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. B, T1, Sch.2

Question(s):

Enbridge Gas has assessed the alternatives to reduce or eliminate the PDO as described above in response to the 2021 Rates settlement proposal . Infrastructure alternatives are more costly than the current PDCI cost. Market-based alternatives are slightly less costly than the current PDCI alternative but does not provide sufficient capacity to provide a full reduction of the PDO. At this time, Enbridge Gas has not acted on or reflected the lower cost market-based alternative in this application. In order to pursue the market based alternative Enbridge seeks direction from the OEB to secure the offered firm exchange capacity.

a) Please explain why Enbridge did not assess the full set of IRP options when assessing the options of PDO vs. infrastructure alternatives.

b) With the issuance of the OEB Decision for EB-2020-0091 (IRP), please provide a list of potential IRP options that Enbridge believes could be considered in the future.

c) Is it possible that other IRP alternatives could be more cost effective? If not, please explain.

Response

a) to c)

Please see the response at Exhibit I.PP.4.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

PollutionProbe_IR_AppendixA_TorontoRNG_20210818

Question(s):

a) Please explain if the RNG project described in Appendix A will paid for from the voluntary RNG program approved by the OEB.

b) What impacts (if any) will the RNG project described in Appendix A have on 2022 rates?

c) Please describe how the City of Toronto receives compensation for RNG injected in to the Enbridge natural gas grid.

d) Will the RNG from the City of Toronto project be used to serve Ontario natural gas customers. Please explain.

Response

a) The RNG project described in Appendix A has no interdependencies with the voluntary RNG program approved by the OEB.

b) The RNG project described in Appendix A will not impact 2022 Rates.

c) The City of Toronto will not be receiving compensation for injecting its RNG into the Enbridge natural gas grid.

d) The RNG from the City of Toronto project will not be used to serve Ontario natural gas customers, other than the City of Toronto. The City will allocate volumes of RNG from the City's producer account to the City's consumer accounts. The City will use this RNG to reduce GHG emissions from refuse trucks and buildings.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

B-1-2, p.8-9

With respect to alternatives to reduce or eliminate the PDO, Enbridge states: "At this time, Enbridge Gas has not acted on or reflected the lower cost market-based alternative in this application. In order to pursue the market based alternative Enbridge seeks direction from the OEB to secure the offered firm exchange capacity." [emphasis added]

Question(s):

a. Is Enbridge seeking direction from the OEB in this proceeding? If not, please explain why and what proceeding it will seek direction from the OEB.

b. What approvals are required by the OEB to implement the lower cost-market based alternative for a reduction (as opposed to elimination) of the PDO?

c. Please confirm that based on the table provided, implementation of a market-based solutions for 37 TJ/d would result in a savings to customers of $13.3M (14.7-1.5 from Table 2)

Response:

a) and b)

Please see the response at Exhibit I.STAFF.4 c).

c) If a market-based solution for 37 TJ/d is implemented this would not result in a savings of $13.3 M. The market-based solution does not eliminate all of the PDO volumes. The savings if a market-based solution of 37 TJ/d is implemented is $0.5 M (please see chart below).

	Capacity (TJ/d)	Revenue Requirement ($ millions)	Revenue Requirement ($/GJ)
Market Solution (from Table 2)	37	1.5	40.2
PDO (from Table 2)	275	14.8	53.7
Reduced PDO	238	12.8	53.7
Market Solution	37	1.5	40.2
PDO & Market Solution	275	14.3	51.9
Savings		0.5	1.9

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

D-2-13, P.1

Question(s):

Please explain your assumption that the Normalized Average Consumption ("NAC") Adjustment trend from 2019 to 2020 would be comparable to the change from 2021 to 2022 and the descending trend of NAC would continue.

Response:

The percentage changes listed at Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 13, page 1, represent the actual NAC changes from 2019 to 2020, as well as an update from the 2021 OEB-approved weather normal to the 2022 OEB-approved weather normal for Union rate zone classes (OEB approved methodology for the Union Gas zone rates).

Please refer to EB-2021-0147, Exhibit I.EP.1, pages 9-10, for the charts that illustrate historical NAC changes for each rate class over the past 10 years, calculated using the 2022 weather normal. A linear trend line in each chart indicates that a declining trend continues to present in the actual NAC for all Union Zone rate classes.

The average annual decline in actual NAC is 0.5% for Rate M1 and 0.9% for Rate M2, 0.4% for Rate 01 and 0.1% for Rate 10. The year-over-year actual average consumption fluctuation around the trend line is attributable to price, economic drivers, efficiency levels, and the customer's comfort level given weather fluctuations.

ENBRIDGE GAS INC. 2022 RATE APPLICATION
RATE SETTING MECHANISM

1. On August 30, 2018, in the MAADs Decision (EB-2017-0306/0307), the OEB approved a rate setting mechanism (Price Cap IR) for Enbridge Gas, which sets out a multi-year incentive rate-setting mechanism ("IRM") for the calendar year term of 2019 to 2023 (the "five year term"). The MAADs Decision confirmed that during the five year term, distribution rates will be set separately for the Enbridge Gas Distribution ("EGD") and Union Gas ("Union") rate zones.

2. The MAADs Decision approved the specific treatment of various elements in the IRM including the availability of an Incremental Capital Module ("ICM"). This 2022 Rate Application is the fourth annual rate adjustment application under the IRM approved in the MAADs Decision.

3. The purpose of this evidence is to describe the proposed changes to Enbridge Gas's base rates for regulated transportation, storage and distribution for each of its three rate zones (EGD, Union North and Union South) effective January 1, 2022, where changes to the base rates are determined in accordance with the IRM as follows:
    - Annual rate escalation, as determined by a price cap index ("PCI"), where PCI growth is driven by an inflation factor using GDP IPI FDD, less a productivity factor of zero and a stretch factor of 0.30%.
    - Pass-through of routine gas commodity and upstream transportation costs, demand side management cost changes, lost revenue adjustment mechanism changes for the contract market and average use/normalized average consumption.

- Updates to capital pass-thoughs and Parkway Delivery Obligation ("PDO") costs in the Union rate zones.

4. As set out in the Application and cover letter, Enbridge Gas is seeking approval of the changes to rates resulting from the IRM rate adjustment including approval of the Rate Order[1] by November 25, 2021, so that the resulting rates can be implemented on an interim basis effective January 1, 2022.

5. Enbridge Gas will submit an ICM funding request through a separate application to the OEB. Evidence supporting request(s) for ICM funding will be filed in Phase 2 of the 2022 Rate application in EB-2021-0148.

6. For reference, Table 1 outlines changes to Enbridge Gas's 2022 revenue for the EGD and Union rate zones.

[1] To be updated for October 2021 QRAM.

Table 1
Proposed Changes in Revenue by Rate Zone
Effective January 1, 2022

Line No.	Particulars	EGD Rate Zone ($000's)	Union Rate Zones ($000's)	
	Summary Change in Revenue:			
1	2022 Proposed in EB-2021-0147	1,293,067	1,346,489	/c
2	2021 Approved in EB-2020-0095 (1)	1,276,136	1,329,977	/c
3	Net Change (line 1 - line 2)	16,931	16,512	
	Detailed Change in Revenue:			
4	2022 Price Cap Index (1.4%)	16,931	13,673	
5	2022 DSM Budget Change	-	-	
6	2022 Capital Pass-through Change	-	1,434	
7	2022 Parkway Delivery Obligation Change	-	1,405	
8	Total Excluding Incremental Capital Module ("ICM") Funding (lines 4 through 7)	16,931	16,512	
9	2022 ICM Funding	Note (2)	Note (2)	
10	Total (line 8 + line 9)	16,931	16,512	

Notes:
(1) EGD rate zone per Exhibit D, Tab 1, Rate Order, Working Papers, Schedule 7.
Union rate zones per Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 9.
(2) 2022 ICM funding request(s) and supporting evidence will be filed as a separate application in EB-2021-0148.

7. This section of evidence is organized as follows:
    1. Price Cap Index Adjustment
    2. Deferral and Variance Account Requests
    3. PDO Reporting
    4. Commitments and Directives
    5. Bill Impacts
    6. Implementation

1. PRICE CAP INDEX ADJUSTMENT

8. Enbridge Gas has applied the Price Cap incentive rate-setting ("IR") mechanism using a PCI to adjust rates for 2022. PCI is calculated as PCI = I – X ± Y ± Z, where Enbridge Gas's PCI rate changes are a function of:
    - An inflation factor ("I factor");
    - A productivity and stretch factor ("X factor");
    - Certain predetermined pass-through adjustments ("Y factors");
    - Certain non-routine adjustments ("Z factors");
    - Capital pass-throughs; and
    - PDO Rate Adjustment.

9. PCI growth is driven by an inflation factor using GDP IPI FDD, less a productivity factor of zero and a stretch factor of 0.30%. For 2022, the inflation factor is 1.7% and the X factor is 0.3% resulting in a PCI of 1.4%, as shown in Table 2.

Table 2
Calculation of Price Cap Index
Effective January 1, 2022

Line No.		2022 Price Cap Index (a)
1	Inflation Factor	1.7%
2	Less: Productivity Factor (1)	0.0%
3	Less: Stretch Factor (2)	0.3%
4	2022 Price Cap Index	1.4%

Notes:
(1) EB-2017-0306/EB-2017-0307, Decision and Order, p. 25.
(2) EB-2017-0306/EB-2017-0307, Decision and Order, p. 27.

10. Each of these components is discussed further below.

1.1 INFLATION FACTOR

11. The MAADs Decision approved an inflation factor calculated as the calendar year-over-year percentage change in the annualized average of four quarters of Statistics Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand ("GDP IPI FDD").[2] The inflation factor is adjusted annually on this basis with no restatement for adjustments by Statistics Canada. For 2022 rates, the inflation factor of 1.7% is based on the average annual change in the GDP IPI FDD for Q1 to Q4 in 2020. The calculation is provided in Table 3.

[2] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp. 24-25.

Table 3
Annual % Change in GDP IPI FDD
Effective January 1, 2022

Line No.	Particulars	Annual % Change in GDP IPI FDD (1) (a)
1	January - March 2020	1.89%
2	April - June 2020	1.52%
3	July - September 2020	1.78%
4	October - December 2020	1.68%
5	Inflation Factor (Average % Change)	1.72%
6	Inflation Factor (Average % Change), rounded to one decimal place[3]	1.7%

Notes:
(1) Gross Domestic Product Implicit Price Index Final Domestic Demand, sourced from Statistics Canada CanSim Table 36-10-0106-01 (formerly CANSIM 380-0066). Data published on June 1, 2021.

1.2 PRODUCTIVITY AND STRETCH FACTORS

12. The X factor is the sum of the productivity and stretch factors, which are determined based on the OEB's expectations of efficiency and productivity gains. The MAADs Decision approved a productivity factor of 0% and a stretch factor of 0.30% for each year of the deferred rebasing period. The X factor is 0.30%, which is reflected in the PCI calculation in Table 2.

[3] In EB-2019-0194, Decision on Settlement Proposal and Interim Rate Order, Exhibit N1, Tab 1, Schedule 1, December 5, 2019, p. 9, all parties agreed that in future years, Enbridge Gas will use an inflation factor that has only one decimal place.

1.3 Y FACTORS

13. Y factors are costs associated with specific items that are subject to deferral account treatment and passed through to customers without any price cap adjustment. The MAADs Decision approved the following costs as Y factors:

- Cost of gas and upstream transportation;
- Demand Side Management ("DSM") costs as determined in EB-2015-0029/EB-2015-0049 and any subsequent proceeding;
- Lost Revenue Adjustment Mechanism ("LRAM") for the contract market; and
- Average Use and Normalized Average Consumption.

Cost of Gas and Upstream Transportation

14. Cost of gas supply and upstream transportation costs are passed through to customers through the Quarterly Rate Adjustment Mechanism ("QRAM"), and through the disposition of gas supply related deferral accounts for each rate zone. No changes to cost of gas supply and upstream transportation costs are proposed as part of this Application.

Demand Side Management ("DSM") and Lost Revenue Adjustment Mechanism ("LRAM")

15. On May 5, 2021 Enbridge Gas filed its proposed 2022-2027 DSM Plan (EB-2021-0002). The application is still in the early stages of the regulatory process and as a result Enbridge Gas proposes to maintain the 2021 DSM budget of $67.8 million for the EGD rate zone and $64.3 million for the Union rate zones in 2022 Rates.

16. The LRAM exists for the contract rate classes in both the EGD and Union rate zones. As part of annual rate setting, Enbridge Gas adjusts volumes and calculates rates to capture the volume impacts of DSM programs. Annual verification and audit of DSM program results will be conducted and any variance between the forecasted and the audited actual volume saving will be trued up in the respective LRAM Variance Accounts.

17. As discussed in the sections below, Enbridge Gas has calculated the rate impacts of the DSM budget and LRAM for each rate zone consistent with 2021 Rates.

DSM Budget and LRAM - EGD Rate Zone

18. Enbridge Gas has set the 2022 DSM budget costs and rate class allocation equal to the 2021 DSM budget costs and allocation in 2021 Rates with the exception of a proposed DSM budget shift of $0.456 million in total affecting Rate 110, Rate 145 and Rate 300. As a Y-Factor, 2022 DSM unit rates are derived from the allocated DSM budget costs and the 2022 forecast.

19. As a result of declines in the forecast for Rate 145 between 2021 and 2022, the DSM unit rate for Rate 145 customers increases significantly when the 2022 DSM budget allocation to this rate classes is held constant to the 2021 level. The Company has experienced a gradual migration of customers and associated volumes from Rate 145 to Rate 110 and proposes to shift the related DSM budget of $0.450 million from Rate 145 to Rate 110 to recognize the customer movement and reduce the DSM unit rate burden that would otherwise be experienced by the remaining customers in the rate class.

20. Additionally, the forecast for Rate 300 is also experiencing decline between 2021 and 2022 which significantly increases the 2022 DSM unit rate. Rate 300 does not participate in DSM programs but is allocated a cost associated with the DSM low income program. The Company proposes to shift approximately $0.006 million from Rate 300 to Rate 110 to recognize the decline in the Rate 300 forecast and the increase in the Rate 110 forecast.

21. The DSM volumetric adjustment for the EGD rate zone represents (1) the expected natural gas savings that are partially effective in the 2022 program year and will form the basis for LRAM calculations of 2022 DSM results, and (2) the balance of 2021 DSM volumes not captured in 2021 base rate volumes.

22. To account for fully effective DSM volumes from the 2021 program year to which 2022 DSM volumes will incrementally apply, volumes are adjusted by the difference between the partially effective volumes reflected in 2021 Base volumes and the fully effective 2021 DSM volumes, and the incremental 2022 partially effective DSM volumes. Mathematically, it is calculated as:

    2022 DSM Volumetric Adjustment = 2021 Fully-Effective DSM Volume – 2021 Partially-Effective DSM Volume + 2022 Partially-Effective Volume

23. Consistent with the approach in prior years in the EGD rate zone, the 2022 LRAM will be measured against the 2022 Partially Effective DSM Volume.

24. The allocation of the 2022 DSM budget to rate classes for the EGD rate zone can be found at Exhibit D, Tab 1, Rate Order, Working Papers, Schedule 8 and the LRAM volume adjustment for the EGD rate zone can be found at Exhibit D, Tab 1, Rate Order, Working Papers, Schedule 11.

DSM Budget and LRAM - Union Rate Zones

25. Similar to the EGD rate zone, Enbridge Gas has set the 2022 DSM budget costs and rate class allocation for the Union rate zones equal to the 2021 DSM budget costs and allocation in 2021 Rates. Further, to address customer transitions from Rate M5 to Rate M4, Enbridge Gas has continued to pool the Rate M4 and Rate M5 DSM costs and reallocate the pooled costs in proportion to 2022 forecast volumes.

26. Enbridge Gas has updated the base rates forecast usage in 2022 Rates to reflect final 2019 audited LRAM volumes consistent with the final 2019 annual verification and audit results. The difference between actual 2022 margin reductions related to the Union 2020-2022 DSM plans and the margin reduction included in 2022 rates will be recorded in the LRAM Deferral Account for 2022.

27. The allocation of the 2022 DSM budget to rate classes for the Union rate zones can be found at Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 10 and the LRAM volume adjustment for the Union rate zones can be found at Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 15.

<u>Average Use/Normalized Average Consumption Adjustment</u>

28. The MAADs Decision accepted an annual adjustment to rates to reflect the declining trend in use. Enbridge Gas has applied existing OEB-Approved methodologies for the EGD and Union rate zones to adjust rates to account for changes in average use/normalized average consumption.

Average Use Consumption Adjustment – EGD Rate Zone

29. The EGD rate zone average use adjustment reflects the existing OEB-Approved methodology to forecast the year-over year change in 2022 average use consumption for Rate 1 and Rate 6 customers. The methodology relies on regression equations to estimate the underlying historical trend of average use. Driver variables have remained unchanged and coefficients of existing models are re-estimated to include the most recent year of actual data. Rate 1 and Rate 6 average uses include the incremental impact of planned DSM for 2022, and have been normalized to the 2022 forecast degree days for each region as determined by OEB-Approved degree day methodologies. Exhibit D, Tab 1, Rate Order, Working Papers, Schedule 10 shows the 2022 forecast for Rate 1 and Rate 6, respectively.

Normalized Average Consumption ("NAC") Adjustment – Union Rate Zones

30. The Union rate zones general service storage and delivery rates have been adjusted to reflect the 2020 actual NAC, using the 2022 OEB-approved weather normal methodology blend of 50:50 (30-year average and 20-year declining trend). For 2022, the NAC adjustment is the variance between 2019 actual NAC and 2020 actual NAC, as shown at Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 13.

1.4 Z FACTOR ADJUSTMENT

31. To address material changes in costs associated with unforeseen events outside of the control of management the OEB's Price Cap formula includes a Z factor

mechanism. The OEB approved the inclusion of a Z factor mechanism in Enbridge Gas's rate-setting framework for costs that meet the Z factor criteria.[4]

32. Enbridge Gas does not have a Z factor proposal for 2022 Rates.

1.5 CAPITAL PASS-THROUGH PROJECTS

33. Enbridge Gas has updated the capital pass-through projects to reflect the 2022 revenue requirement of each project consistent with the rate treatment in past years. Any variance between the actual project costs and the amounts included in 2022 rates will be recorded in the respective deferral accounts.

34. Please see Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 14 for the capital pass-through rate adjustment by rate class for the Union rate zones.

1.6 PDO RATE ADJUSTMENT

35. Enbridge Gas has updated the PDO and Parkway Delivery Commitment Incentive ("PDCI") costs included in 2022 Rates for the Union rate zones to reflect the 2022 Rate M12 Dawn-Parkway toll. The PDO and PDCI fuel costs will be updated for October 1, 2021 QRAM as part of the final rate order. The update to the PDO and PDCI costs in 2022 Rates is in accordance with the PDO Settlement framework approved by the OEB as part of Union's 2014 Rates (EB-2013-0365) Decision and Order.

36. Please see Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 11 for the PDO and PDCI rate adjustment by rate class for the Union rate zones.

[4] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, 2018, p. 37.

1.7 OTHER

Retail Service Charges

37. Enbridge Gas has updated the Retail Service Charges for both the EGD and Union rate zones to reflect an inflation factor of 1.7%[5] as required by the OEB's Report on Energy Retailer Service Charges (EB-2015-0304).

Hydrogen Gas Rider M

38. As outlined in EB-2019-0294 Decision and Order, Enbridge Gas is to review the hydrogen gas rate rider annually and request an update if there is a material change in the price of natural gas.[6] The OEB noted the definition of "material" is in relation to the change in the commodity cost of natural gas as an increase or decrease of 25% or more. Enbridge Gas has reviewed the hydrogen gas rate rider calculation based on the most recent approved rates for Rate 1 and Rate 6 and confirms the change in the rate rider does not exceed 25%.

2. DEFERRAL AND VARIANCE ACCOUNTS

39. In accordance with previous OEB decisions, Enbridge Gas maintains a number of deferral and variance accounts. Most accounts continue on from one year to the next, but at times, accounts need to be opened, adjusted or closed. The evidence below discusses in more detail, changes to deferral and variance accounts requested for 2022 as part of this Application, as compared to the ongoing accounts which have been approved in prior proceedings.

[5] Per Table 2.
[6] EB-2019-0294, Decision and Order, October 29, 2020, p. 2.

2.1 NEW DEFERRAL ACCOUNTS

40. Enbridge Gas is not requesting the establishment of any new deferral or variance accounts as part of this proceeding. However, as was noted in Enbridge Gas' 2021 Rate Application, EB-2020-0095, through an accounting order dated March 25, 2020, titled "*Accounting Order for the Establishment of Deferral Accounts to Record Impacts Arising from the COVID-19 Emergency*", and subsequent accounting orders dated August 6, 2020 and August 14, 2020, the OEB established a deferral account, including a number of sub-accounts, in order to track incremental costs and lost revenues related to the COVID-19 pandemic. The effective date of the account was March 24, 2020. By letter dated May 14, 2020, the OEB initiated a stakeholder consultation (EB-2020-0133) to assist the OEB in the development of new accounting guidance and filing requirements related to the account, which where appropriate, would support the review and disposition of the account. On June 17, 2021 the consultation was concluded through the issuance of the Board's report titled *"Report of the Ontario Energy Board – Regulatory Treatment of Impacts Arising from the COVID-19 Emergency."* The report articulates the OEB's guidance with regards to the rules and operation of the account (including sub-accounts to be maintained), and disposition considerations. The Company has provided an accounting order for Enbridge Gas's Impacts Arising from the COVID-19 Emergency Deferral Account, at Exhibit B, Tab 1, Schedule 1, Appendix C, which reflects the OEB's guidance contained in the report.

41. The Company also notes that it has requested the establishment of an Integrated Resource Planning ("IRP") Costs Deferral Account, to track all incremental IRP-related costs not included in base rates, as part of its EB-2020-0091 Integrated Resource Planning Proposal application. An accounting order for the IRP Costs

Deferral Account will be provided as part of that proceeding, in accordance with any guidance included in the Board's pending decision.

2.2 ADJUSTMENT TO EXISTING DEFERRAL ACCOUNTS

42. Enbridge Gas is not requesting any adjustments to previously established deferral or variance accounts as part of this proceeding.

2.3 DEFERRAL ACCOUNT CLOSURE REQUESTS

43. Enbridge Gas is not requesting the closure of any previously established deferral or variance accounts as part of this proceeding. The Company notes, however, that as per the OEB's EB-2020-0134 Decision On Settlement Proposal, dated January 25, 2021, which approved the settlement proposal in the Company's application for the disposition of amounts recorded in certain 2019 deferral and variance accounts, and approved of the 2019 earnings sharing amount, that the EGD rate zone's 2019 Gas Supply Plan Cost Consequences Deferral Account was to be closed for periods beyond 2019.

3. PDO REPORTING

44. As directed in the MAADs Decision, Enbridge Gas will track the actual costs and the amounts recovered through rates related to PDO during the deferred rebasing for review at the time of rebasing. The purpose of this section of evidence is to continue to report on the PDO of Union South direct purchase ("DP") customers as agreed to in the PDO Settlement Framework approved by the OEB on June 16, 2014. The PDO Settlement Framework proposed to permanently shift the PDO of its Union South DP customers from Parkway to Dawn over time.

45. Under the PDO Settlement Framework, Union is required to report annually on: capacity that could be made available in the two years commencing with the test year to further reduce the PDO at a lower cost than the cost of the Parkway Delivery Commitment Incentive ("PDCI"); forecasted PDO quantities for the two years commencing with the test year; measures used by the Company to manage the initial Parkway shortfall; and, actual transmission compressor fuel on the Dawn to Parkway system in the prior year.

46. This evidence is organized to track those requirements similarly and as follows:

    3.1 Capacity Available to Reduce PDO

    3.2 Forecasted PDO Quantities

    3.3 Management of the Initial Parkway Shortfall

    3.4 Dawn to Parkway Transmission Compressor Fuel

47. In accordance with the commitment made in the Settlement Agreement in EB-2020-0095, Enbridge Gas is also filing evidence in this proceeding identifying pipeline, non-pipeline and market-based alternatives that the Company has considered to determine whether it is cost effective to eliminate or reduce the PDO and/or PDCI for 2022 and future years. That evidence is found at Exhibit B, Tab 1, Schedule 2.

3.1 CAPACITY AVAILABLE TO REDUCE PDO

48. In April 2014, Union offered Union South DP customers 146 TJ/day of temporarily available excess Dawn to Parkway capacity to shift a portion of their PDO volume to Dawn. This temporary capacity was no longer available as of October 31, 2015. However, Union agreed to manage the Parkway shortfall in-

order to maintain the 146 TJ/day of PDO shift beyond October 31, 2015, until sufficient Dawn to Kirkwall capacity was turned back by other M12 shippers to facilitate a permanent PDO shift.

49. Effective November 1, 2017, Union received sufficient Dawn to Kirkwall M12 turnback to replace the temporarily available capacity noted above (146 TJ/day). Union forecasts that no additional PDO reductions will be available to Union South DP customers for November 1, 2021 or November 1, 2022. Please see Appendix A in this exhibit, for an updated table illustrating the capacity available for PDO shift, and the current and forecasted PDO reductions.

3.2 FORECASTED PDO QUANTITIES

50. As Union did not receive any M12 Dawn to Kirkwall turnback effective November 1, 2021 or November 1, 2022, there will not be any incremental PDO relief for DP customers in 2022 or 2023.

51. The forecasted PDO for sales service customers is shown at Appendix A in this exhibit.

3.3 MANAGEMENT OF THE INITIAL PARKWAY SHORTFALL

52. As of November 1, 2017 the initial Parkway shortfall has been fully eliminated as a result of Dawn to Kirkwall turnback, and therefore Union did not need to take action to manage the shortfall.

3.4 DAWN TO PARKWAY TRANSMISSION COMPRESSOR FUEL

53. Dawn to Parkway transmission compressor fuel will be included with the schedules filed in the annual earnings sharing and deferral account disposition proceeding.

54. Please see Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 11 for details of the PDO and PDCI costs included in rates by rate class. The PDCI is paid monthly to DP customers for any continued obligated Daily Contract Quantity deliveries at Parkway.

4. COMMITMENTS AND DIRECTIVES

55. The outstanding commitments and directives for Enbridge Gas, including the EGD and Union rate zones, are shown in Appendix B in this exhibit. The listing includes the commitments and directives from the MAADs proceeding and other prior proceedings.

5. BILL IMPACTS

56. For typical Rate 1 residential customers in EGD rate zone with annual consumption of 2,400 m^3, the bill impact is a net increase of $7.76 per year for sales service customers and a net increase of $7.74 for bundled direct purchase customers, each excluding any 2022 ICM impacts.[7]

57. For typical Rate M1 residential customers in Union South with annual consumption of 2,200 m^3, the bill impact is a net increase of $8.71 per year for

[7] 2,400 m^3 used in accordance with the typical residential consumption in the EGD rate zone.

sales service customers and $8.65 for bundled direct purchase customers, excluding any 2022 ICM impacts.

58. For typical Rate 01 residential customers in Union North West with annual consumption of 2,200 m^3, the bill impact is a net increase of $10.55 per year for sales service customers and $10.49 for bundled direct purchase customers, excluding any 2022 ICM impacts.[8] For Rate 01 residential customers in Union North East with annual consumption of 2,200 m^3, the bill impact is a net increase of $11.42 per year for sales service customers and $11.38 for bundled direct purchase customers, excluding any 2022 ICM impacts.

6. IMPLEMENTATION

59. Enbridge Gas is requesting that the OEB review and approve the IRM rate adjustments, including the Rate Order[9] by November 25, 2021, so that the rates can be implemented on an interim basis in conjunction with the January 1, 2022 QRAM application.

[8] 2,200 m^3 used in accordance with the typical residential consumption in the Union rate zones.
[9] To be updated for October 2021 QRAM.

Parkway Delivery Obligation (PDO) for 2020 - 2022
(TJ/day)

Line No.	Particulars	2020 Rates As Filed (EB-2019-0194) Nov-19 (a)	Nov-20 (b)	Nov-21 (c)	2021 Rates As Filed (EB-2020-0095) Nov-20 (d)	Nov-21 (e)	Nov-22 (f)	2022 Rates As Filed (EB-2021-0147) Nov-21 (g)	Nov-22 (h)	Nov-23 (i)	
	CAPACITY AVAILABLE FOR PDO SHIFT										
1	Ex-Franchise M12 Dawn to Kirkwall Turnback	-	-	-	-	-	-	-	-	-	
	Allocation of Capacity Available (turnback):										
2	Opening Balance	-	-	-	-	-	-	-	-	-	/c
3	Temporary Capacity Provided	-	-	-	-	-	-	-	-	-	
4	Replacement of Temporary Capacity	-	-	-	-	-	-	-	-	-	
5	Closing Balance	-	-	-	-	-	-	-	-	-	/c
6	Available for PDO Shift	-	-	-	-	-	-	-	-	-	
	TOTAL DIRECT PURCHASE PDO										
7	Beginning PDO	239	239	239	249	249	249	264	264	264	
8	Annual PDO Shift *line 11 + line 18 + line 22*	-	-	-	-	-	-	-	-	-	/c
9	Remaining PDO	239	239	239	249	249	249	264	264	264	
	DIRECT PURCHASE PDO DETAIL BY CUSTOMER GROUP										
	PDO for Customers without M12 Service:										
10	Beginning PDO	208	208	208	218	218	218	244	244	244	
11	PDO Shift	-	-	-	-	-	-	-	-	-	
12	Surplus Required	-	-	-	-	-	-	-	-	-	
13	Remaining PDO	208	208	208	218	218	218	244	244	244	
14	Annual PDO Shift	-	-	-	-	-	-	-	-	-	
15	Allocation to those with PO < 100 GJ/day	-	-	-	-	-	-	-	-	-	
16	Percentage Reduction for those with PO > 99 GJ/day	-	-	-	-	-	-	-	-	-	
	PDO for Customers with M12 Service (except TCE):										
17	Beginning PDO	31	31	31	31	31	31	20	20	20	
18	In-Franchise M12 Dawn to Parkway Turnback *line 15 * line 16*	-	-	-	-	-	-	-	-	-	
19	Remaining PDO	31	31	31	31	31	31	20	20	20	
20	Annual PDO Shift	-	-	-	-	-	-	-	-	-	
	PDO for TCE Halton Hills:										
21	Beginning PDO	-	-	-	-	-	-	-	-	-	
22	In-Franchise M12 Dawn to Parkway turnback *line 15 * line 20*	-	-	-	-	-	-	-	-	-	
23	Remaining PDO	-	-	-	-	-	-	-	-	-	
24	Annual PDO Shift	-	-	-	-	-	-	-	-	-	
25	**PDO for Sales Service**	11	11	11	11	11	11	11	11	11	