ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 7, Tab 0, p. 3

Question(s):

Enbridge Gas has proposed to harmonize the former EGD and Union rate zones into one rate zone. Enbridge Gas prepared the 2024 cost allocation study based on one rate zone for all costs and rate classes with the exception of transportation service options that provide regional transportation service.

a) Please provide the total cross-subsidy from Union South and EGD rate zone customers to Union North customers resulting from the proposed cost allocation study.

b) Please provide a revised 2024 cost allocation study and resulting rate design implications and bill impacts based on two rate zones: North (the former Union North rate zones) and South (Union South and EGD rate zone). Please also provide the assumptions underpinning the revised cost allocation study.

Response:

a) Enbridge Gas is not able to provide the shift in costs between the Union South, EGD and Union North rate zones resulting from the proposed cost allocation study at this time. A comparison of the bill impacts of the general service rate classes can serve as a proxy of the shift in costs between rate zones, but this comparison does not take into consideration amalgamation and other cost changes that have occurred since rates were last rebased for EGD and Union. To calculate the shift in costs, Enbridge Gas requires a new cost allocation study for the 2024 Test Year Forecast that allocates costs to each of the existing rate zones.

   Enbridge Gas will prepare analysis to determine the cost allocation impacts of rate zones for the 2024 Test Year. The cost allocation impacts will be based on the proposed cost allocation study, as provided at Exhibit 7, Tab 2, Schedule 1, compared to a cost allocation study to be prepared for the existing rate zones using the proposed cost allocation study methodologies, as provided at Exhibit 7, Tab 1, Schedule 2. Enbridge Gas will also provide impacts for gas supply and transmission costs for the service areas. Given the complexities and time requirement to prepare this analysis, Enbridge Gas will require more time. Enbridge Gas will file an updated response to this interrogatory, including the new cost allocation study, in advance of the settlement conference for this Application.

b) Please see part a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 7, Tab 0, Page 3

Question(s):

a) Are some areas of the province more expensive to serve than others both in terms of transmission and distribution, and also gas supply? If yes, please quantify the approximate percentage difference.

b) Enbridge proposes to harmonize the rate zones into a single rate zone. Presumably some rate zones are more expensive to serve than others. Please approximately quantify the impact on a typical residential customer's annual gas bill from the harmonization for (i) a customer in the rate zone that is the most expensive to serve and (ii) a customer in the rate zone that is the least expensive to serve.

c) Enbridge proposes to create a single rate zone. Presumably some areas are more expensive to serve than others. Please approximately quantify:

   i. How much a rural residential customer would be subsidized by other customers on a net annual bill impact basis (assuming rural customers are more expensive to serve); and

   ii. How much a customer in the area of the province that is most expensive to serve would be subsidized by other customers.

d) If Enbridge were to be directed to divide the province into 2 to 5 zones corresponding to cost of serving those customers, how would Enbridge do so? For instance, if it would do so based on geographic regions, please discuss which ones would be more and less expensive. If it would do so based on density (urban vs. rural), please explain.

<u>Response:</u>

a-d) Please see response at Exhibit I.7.0-STAFF-237. Enbridge Gas will file additional information on cost allocation impacts of rate zones for the 2024 Test Year in advance of the settlement conference for this Application.

As provided at Exhibit 8, Tab 2, Schedule 1, Section 1.4, pages 12 to 15, Enbridge Gas is not able to determine the costs for each geographic region based on limited available distribution cost detail. Enbridge Gas has identified alternate rate zones for gas supply and transmission costs, which are provided at Exhibit 8, Tab 2, Schedule 1, Section 1.5, pages 15- 23.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Preamble:

A working version of the cost allocation model for the current rate classes is requested, to better understand the development of internal allocators and linkages across spreadsheets.

Question(s):

Please provide an integrated working version of the complete cost allocation study for current rate classes in MS Excel electronic format with formulae intact. Please include the derivation of revenue-cost ratios for the current rate classes. Please include derivation of all internally developed functionalization, classification and allocation factors.

Response:

Please see Attachment 1 for the 2024 Cost Allocation Study, including the internal factors, filed in Excel. The derivation of the revenue to cost ratios for the current rate classes in Excel is provided at Exhibit 8, Tab 1, Schedule 3, Attachment 1.

This page is intentionally left blank. Due to size, this Attachment has not been included.

Please see Exhibit I.7.0-IGUA-72 Attachment 1.xlsx on the OEB’s RDS.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit 7

Question(s):

The rate zone harmonization allocates the costs of the transmission system facilities across all in-franchise customers, regardless of geographic location.

a) If the Board were to decide that EGI should create rate zones aligned with NAESB trading windows -i.e., North (GMIT NDA. Union EDA, Union NCDA) South-Central (Enbridge CDA, Union CDA, Parkway CDA) and Eastern (Enbridge EDA KPUC/Union EDA) - what type of adjustments would need to be made to the cost allocation study to accommodate this type of rate zone structure? Specifically address how such "supply based" rate zone might change gas supply, storage and transmission allocations.

b) If the Board were to approve the proposed cost allocation methodologies does this a single rate zone/harmonized rates? Would it remain fair and reasonable to over the long run apply the proposed cost allocation methodologies to the existing multiple rate zone rate design?

Response:

a) Please see response at Exhibit I.7.0-STAFF-237. Enbridge Gas will file additional information on cost allocation impacts of rate zones for the 2024 Test Year in advance of the settlement conference for this Application.

b) Please see response at Exhibit 7.1.1-STAFF-238.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit 7

Question(s):

a) Please provide all the live excel models that are used in the cost allocation outputs shown in attachments to Schedule 1.

Response:

a) Enbridge Gas has assumed this question relates to the attachments to Exhibit 7, Tab 2, Schedule 1. Please see response at Exhibit I.7-IGUA-72 where the 2024 Cost Allocation Study has been provided in Excel format.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 7, Tab 1, Schedule 1, pp. 5-6
Exhibit 8, Tab 2, Schedule 1, p. 9

Question(s):

The 2024 Cost Allocation Study is prepared based on one rate zone for all costs and rate classes with the exception of transportation service options that provide regional transportation service, such as ex-franchise transportation service options and transportation services for semi-unbundled and unbundled customers. The proposed allocation of costs to rate classes is based on the average embedded costs of the company's integrated system of gas supply, storage, transportation and distribution facilities to deliver gas to customers in different geographical regions of Ontario. This approach is consistent with the Cost Allocation Study of the legacy EGD rate zone, which used a unform system of rates throughout its franchise area.

a) Considering that the legacy Union rate zone is significantly larger and varies in customer density as compared to the former EGD rate zone, please explain how a single rate zone results in just and reasonable rates.

b) Considering that the costs to serve customers in the North are different from the costs to serve customers in the South, please explain how the proposed single rate zone aligns with the cost causation principle as noted in Exhibit 8, Tab 2, Schedule 1, para 20.

Response:

a-b) Enbridge Gas is proposing to harmonize the EGD and Union rate zones into one rate zone for in-franchise services as part of its rate harmonization proposal described at Exhibit 8, Tab 2, Schedule 1. A one rate zone approach to cost allocation and rate design allows the Company to align, simplify and enhance rates and services to meet all customers' needs regardless of geographical location. The rate harmonization plan, including the cost allocation and rate design proposals, recognizes the amalgamation of EGD and Union and responds to the OEB directive from the MAADs decision requiring Enbridge Gas to file a proposal for rate harmonization. The rate harmonization plan also meets the OEB's Filing Requirements[1] for utilities which have merged or amalgamated.

Enbridge Gas's total revenue requirement reflects the operational needs of one single utility functioning to serve all customers within the franchise area. With the amalgamation and integration of functional areas and systems, there are aspects of the revenue requirement that no longer represent the cost to serve the EGD or Union rate zones as stand-alone entities or rate zones. The Cost Allocation Study is prepared based on one rate zone and costs are allocated to rate classes based on usage, regardless of location. As a result, through the rate design proposed, customers will pay similar charges for similar services regardless of their location in the franchise area or the specific cost to serve their service area. This rate design ensures no one customer, industry or corporation has an advantage over others based on their location within the province.

Enbridge Gas's proposal for a single rate zone and postage stamp rates is consistent with the long-standing approach of setting common rates for all geographic regions that has been in place for over 40 years for the EGD rate zone (previously EGD). The OEB has approved with each of its EGD rate making decisions that postage stamp rate making is just and reasonable despite the Company providing service to two separate geographic areas. Customers in different areas of the EGD rate zone pay uniform rates for all services including gas supply, transmission, storage and distribution.

EGD's cost allocation methodologies, which were employed to functionalize, classify and allocate costs regardless of geographical location were based on cost causation principles and have been approved by the OEB for many years. The Company's proposed Cost Allocation Study reflecting one rate zone is also developed on cost causation principles. While the Company acknowledges that cost causation can be improved by identifying costs to serve a geographical area and designing rates to recover such costs, the Company also recognizes the additional benefits of one rate zone including a consistent customer experience and reduced administration. Setting postage stamp rates also allows for integrated operations and gas supply planning for the Company as a whole, as compared to maintaining and operating separate rate zones. The Cost Allocation Study balances the guiding principles provided at Exhibit 7, Tab 1, Schedule 1, page 5 which include cost causation, simplification, consistency, judgement and stability.

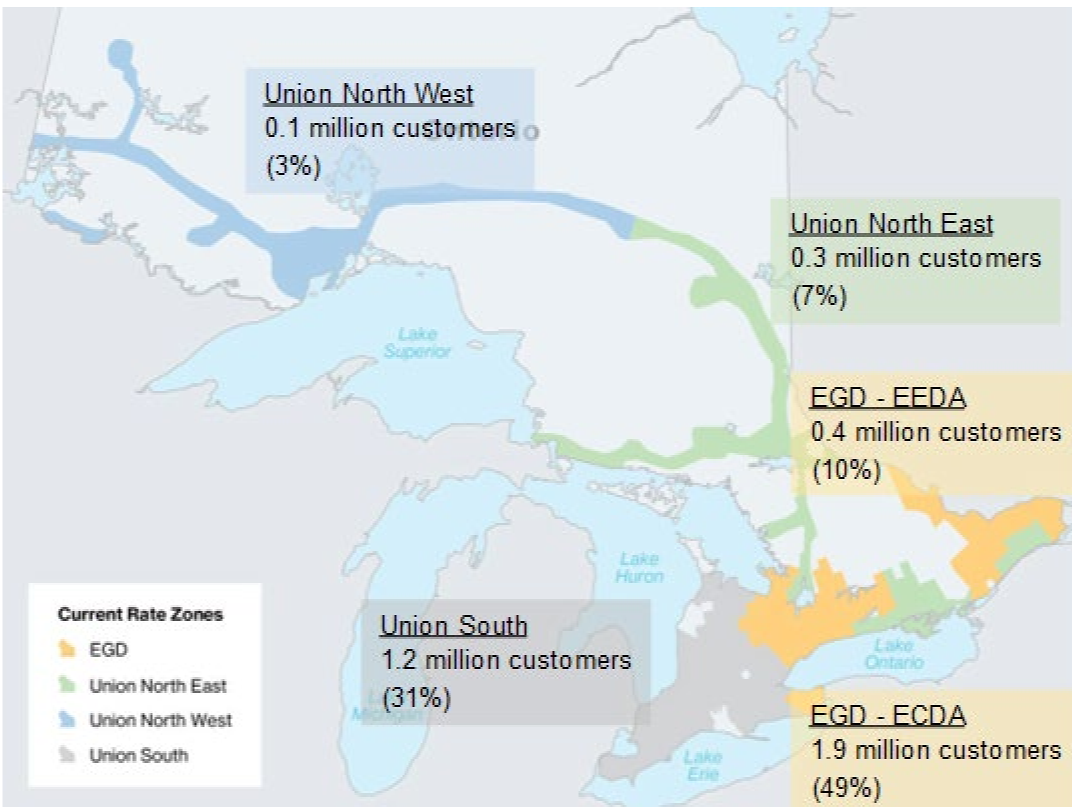
The use of common or postage-stamp rates is a widely accepted industry practice for setting utility rates, as it provides a consistent rate treatment across geographic regions or service areas and provides additional rate stability due to the larger base of customers. The rate design proposals reflecting one rate zone balance the guiding

[1] Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p.36.

principles provided at Exhibit 8, Tab 2, Schedule 1, pages 8 to 9 which include differences in cost of service, customer experience, customer bill impacts, availability of information, administrative simplicity and customer engagement feedback. The customer engagement results also provide general support for one rate zone, as provided at Exhibit 8, Tab 2, Schedule 1, Section 1.7, pages 22 to 23.

The map of the Enbridge Gas current rate zones for EGD (East and Central), Union North (West and East), and Union South from Exhibit 8, Tab 2, Schedule 1, Figure 1 is reproduced in Figure 1.

Figure 1: Map of Enbridge Gas Current Rate Zones



As depicted on the map, the geographic service area for Union North and Union South provides service to approximately 1.6 million customers (or 41%). EGD provides service to approximately 2.3 million (or 59%) customers although the geographical service area is smaller. Upon amalgamation in 2019, the Company has operated as one entity and has continued to provide safe and reliable service to all 3.9 million customers regardless of their geographic area or rate zone.

Union has had two separate rate zones since it amalgamated with Centra Gas in 1998. EGD has had one rate zone for over forty years despite also having a geographic separation between regions served by the Company. Union had the ability to have separate rate zones because rate base has been recorded separately for Union North and Union South. The rate base details between its separate geographic regions has not been recorded for EGD. While there may be cost differences to serve the Enbridge EDA separate from the Enbridge CDA, EGD had one rate zone for all customers and didn’t record costs separately. Without the underlying separation of costs, cost differences, if any, are not apparent.

The Union North rate zone had previously represented 25% of the total customers of Union. Upon the amalgamation of EGD and Union, the Union North rate zone now represents 10% of the total customers of Enbridge Gas, with the Union North East and Union North West rate zone representing 8% and 2%, respectively. While the cost differences for the Union North rate zone are known due to the historical record keeping, the Union North rate zone is a small component of the total amalgamated utility. The Union North East rate zone also serves a similar geographic area as the Enbridge EDA, with multiple adjacent boundaries, as shown on Figure 1. Maintaining the Union North East in a separate rate zone from the Enbridge EDA would result in customers in a similar geographic area in different rate zones. This result could lead to confusion for customers, particularly those who are captured by the rate zone with the higher rates.

Utilities, by the nature of the service provided, must pool costs at some level as costs to serve customers vary from one customer or geographic area to another. Maintaining a separate rate zone for Union North due to the cost differences that exist for this small subset of customers creates a significant amount of administration and prevents customers, the Company, and stakeholders from realizing further benefits of amalgamation.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 7, Tab 1, Schedule 2, p. 9

Question(s):

The 2024 Test Year revenue requirement includes the cost of regulated storage and excludes unregulated storage costs. Costs associated with land rights and wells and lines are incurred to provide both deliverability from storage on design day and to provide capacity to store gas. These costs are classified as 50% deliverability and 50% space. The storage space costs are further classified between storage space and operational contingency as Enbridge Gas manages the operational contingency storage space and its associated inventory to support the reliability and resilience of the Enbridge Gas system.

Please provide the basis for 50% allocation between deliverability and storage space. Please provide any calculations used to derive the allocation factor.

Response:

Enbridge Gas classifies[1] 50% of the costs of land rights, rents and wells and lines to storage deliverability and 50% to storage space. Storage space is further classified between space and operational contingency in proportion to 183.8 PJ and 15.6 PJ, respectively, of 199.4 PJ of regulated storage space. This classification methodology recognizes that the costs are incurred to support both deliverability from storage on design day and to provide capacity to store gas. The classification methodology simply splits the costs equally between storage deliverability and storage space and is not based on any further analysis. This approach is consistent with the methodology used by Union to classify land rights, rents and wells and lines between deliverability and space within Union's 2013 Cost Allocation Study.[2]

The derivation and support for the storage classification factor DEL_SPACE_OPCON is provided in Table 1.

[1] Based on storage classification factor DEL_SPACE_OPCON.
[2] EB-2011-0210, Exhibit G3, Tab 4, Schedule 3, p.1.

Table 1
DEL_SPACE_OPCON Classification Factor

Line No.	Particulars	DEL_SPACE_OPCON Classification Factor (1)
		(a)
1	Deliverability	50.00
2	Space (2)	46.09
3	Operational Contingency (3)	3.91
4	Total Classification Factor	100

Notes:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, page 5, line 15.
(2) Space allocation of 46.09 calculated as 50% x 183.8 PJ / 199.4 PJ x 100.
(3) Operational contingency of 3.91 calculated as 50% x 15.6 PJ / 199.4 PJ x 100.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 7, Tab 1, Schedule 3, Attachment 1, p. 6

Question(s):

The functional classification of “Distribution Customer-Services” is allocated to in-franchise rate classes in proportion to the average number of customers.

Please explain why the proposed allocation of “Distribution Customer-Services” is different from the allocation methodology of the former EGD, Union North and Union South zone.

Response:

When assessing allocation methodologies for the integrated Cost Allocation Study, Enbridge Gas encountered challenges in the availability of common information for both the EGD and Union rate zones in order to derive a harmonized allocation factor for distribution services. In EGD’s OEB-approved Cost Allocation Study, EGD had allocated the cost of distribution services in proportion to the historical investment in services by pipe diameter and pipe length. In Union’s OEB-approved Cost Allocation Study, Union allocated the costs based on an approach using the number of services, service length and number of customers for the Union North rate zone and based on service replacement costs for the Union South rate zone. Each one of these allocation methodologies is difficult to prepare on its own and the information to expand the methodology to the other rate zones was not available.

Enbridge Gas is proposing a simplified approach to allocate distribution services based on number of customers recognizing distribution services are a customer-related cost. The proposed allocation methodology using the number of customers provides simplification where the previous methodologies used by EGD and Union were complex and time-consuming to replicate.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 7, Tab 1, Schedule 4, pp. 18-20 & Attachment 1; EB-2021-0002, Decision and Order, November 15, 2022, Schedule A

Question(s):

Enbridge Gas is proposing to update the DSM budget allocation methodology for the current rate classes from the 2024 DSM budget allocation provided in the 2022 to 2027 DSM Plan proceeding.

a) Please confirm the DSM-related rate class impacts in Attachment 1 are fully aligned with approved 2024 DSM budget in Schedule A of the EB-2021-0002 decision. If not confirmed, please update Attachment 1 to align.

b) Please discuss the reasons for DSM-related changes to rate class impacts noted in Attachment 1 relative to the DSM budget allocation provided in the DSM Plan, particularly for those rate classes where costs have changed greater than +/- $250,000.

Response:

a) Confirmed. Exhibit 7, Tab 1, Schedule 4, Attachment 1, updated March 8, 2023 is aligned with the DSM Plan decision except for the budgetary inflation factor which has not yet been applied to 2024 and 2025. The Decision and Order in EB-2021-0002 approved an annual escalation factor to increase the approved DSM Program budgets, including program administration costs, by 3% plus inflation and all other portfolio related costs by inflation. The DSM Plan as approved used a 2% proxy for inflation, however the actual inflation factor is to be based on the CPI ("Consumer Price Index") index. Enbridge Gas has been conversing with OEB Staff to determine how and when the inflationary factor will be applied to 2024 and 2025, however at this time it has not yet been determined.

b) As provided at Exhibit 7, Tab 1, Schedule 4, Section 5, the DSM budget allocation provided in the DSM Plan was prepared to minimize rate impacts for years prior to rebasing (2022 and 2023) while Enbridge Gas was in a price cap rate-setting IR term. Enbridge Gas also recognized the appropriate application to request a change to the DSM budget allocation (for 2024 and later years) was in the context of a rebasing application rather than the DSM plan application.

Exhibit 7, Tab 1, Schedule 4, Attachment 1, updated March 23, 2023 demonstrates the impact in the change in DSM allocation method when applied to 2024. The methodology used up to and including 2023 uses as a base what was built into rates in the previous year. By way of example and looking at the program cost component only for simplicity, if the amount allocated to Rate 170 in 2023 rates represented 2% of the total allocated program spend (excluding low-income and administration costs), then 2% is applied to the entire 2024 program budget to derive the rate allocation for 2024. For 2024, the total program budget excluding administration and low-income program/offerings is $119,943,247. That means $2,398,865 ($119,943,247 x 2%) would be allocated to Rate 170 for program costs under the existing methodology even though Rate 170 will not participate or be eligible to participate in all programs.

Using the new proposed allocation methodology; considering historical participation as well as program design, Rate 170 participates in Commercial and Industrial Programs. Within Commercial, assume the 3-year historical average shows Rate 170 represents 1% of actual spending in the Commercial program (and compared only to rate classes that have historically participated in the Commercial program) and 1.5% of spending in Industrial. The Commercial program budget for Enbridge Gas is $15,332,964 and $5,676,733 for Industrial. Applying the allocations, the program budget allocated to Rate 170 under the new methodology is $238,481 ($15,332,964 x 1% + $5,676,733 x 1.5%). This is significantly less than what the old methodology would have yielded.

Actual spend has always been tracked and allocated by rate class and in consideration of the OEB-approved budgets by program. By not forecasting the spend based on the program, large balances can accumulate in the DSM variance account on an annual basis. Changing the methodology to consider historical participation as the basis of the forecast and then applying the allocation only to the program budgets the rate class participates in minimizes amounts that would otherwise be recorded in DSM deferral and variance account balances. Enbridge Gas is not proposing a change to the allocation of the DSM low-income program budget.

ENBRIDGE GAS INC.

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

Interrogatory

Question(s):

Please complete the following table:

Rate	Current Monthly Customer Charge	January 1, 2024 as proposed Monthly Customer Charge	April 1, 2026 Month Customer Charge (Harmonized Rates)	Current Demand Charge (cents/m3)	January 1, 2024 as proposed Demand Charge (cents/m3)	April 1, 2026 Demand Charge (cents/m3)	Current Total Bill for Large-volume customer (excluding commodity costs)	January 1, 2024 Total Bill for Large-volume customer (excluding commodity costs)	April 1, 2026 Total Bill for Large-volume customer (excluding commodity costs)
EGD 125			n/a			n/a			n/a
Union South T2			n/a			n/a			n/a
Harmonized E24	n/a	n/a		n/a	n/a		n/a	n/a	

Response:

Please see Attachment 1 for the requested information for Rate 125 of the EGD rate zone and Rate T2 of the Union South rate zone.

Evidence related to the harmonized rate classes, including Rate E24, will be addressed in Phase 2 of the proceeding in accordance with the OEB's Decision on Issues List dated January 27, 2023.

Rate 125 & Rate T2 Large Volume Parameters

Line No.	Rate Class	Current Monthly Customer Charge (1)	January 1, 2024 as proposed Monthly Customer Charge (2)	Current Demand Charge (cents/m^3) (1)	January 1, 2024 as proposed Demand Charge (cents/m^3) (2)	Current Total Bill for Large-volume customer (excluding commodity costs) (3)	January 1, 2024 Total Bill for Large-volume customer (excluding commodity costs) (3)
1	Rate 125	$546.97	$3,000.00	11.2127	10.6497	$3,135,864	$3,008,907
2	Rate T2	$6,803.81	$3,000.00	First 140,870 m^3: 33.1606 Over 140,870 m^3: 18.4774	First 140,870 m^3: 38.5289 Over 140,870 m^3: 21.7223	$3,156,032	$3,500,299

Notes:
(1) Rate 125 current rates per EB-2022-0133, Exhibit D, Tab 1, Appendix A.
Rate T2 current rates per EB-2022-0133, Exhibit D, Tab 2, Appendix A.
(2) Exhibit 8, Tab 2, Schedule 8, Attachment 2, column (h).
(3) For purposes of the total bill, Enbridge Gas also excluded the federal carbon charge and has provided the delivery charge total bill only.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit 7 Tab 1 Schedule 1 and Exhibit 7, Tab 1, Schedule 3

Preamble:

The cost allocation studies were based on sound cost allocation principles and long-standing methodologies that categorized and allocated costs based on EGD and Union's system operations and customer rate classes. Enbridge Gas has reviewed each of the methodologies and to the extent possible, incorporated those same principles and approaches into the integrated cost allocation study for the amalgamated utility. Please see Exhibit 7, Tab 1, Schedule 3 for a comparison of the EGD and Union OEB-approved cost allocation methodologies.

Question(s):

a) Please indicate for each of the categories in Exhibit 7, Tab 1, Schedule 3 where the new cost allocation has increased or decreased the total cost allocation for the different functional classifications for EGD 125 and Union South T2 customers.

b) Please provide any classifications where the new allocation increases/decreases cost allocation by 10% or greater.

Response:

a-b) As provided at Exhibit 7, Tab 1, Schedule 3, page 2, paragraph 5, due to the different allocation approaches and the availability of information for Enbridge Gas, the Company cannot provide a complete comparison of the proposed cost allocation methodologies to the OEB-approved cost allocation methodologies for the EGD and Union rate zones in aggregate. The Company was not able to recreate two stand-alone cost allocation studies for the EGD and Union rate zones in the same format that was approved in EGD's and Union's respective 2013 Cost of Service proceedings.

Similarly, Enbridge Gas cannot provide a comparison of the proposed methodologies to the OEB-approved methodologies for specific rate classes.

Please see response at Exhibit I.7.0-STAFF-237. Enbridge Gas will file additional information on cost allocation impacts of rate zones for the 2024 Test Year in advance of the settlement conference for this Application.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit 7 Tab 1 Schedule 1 Plus Attachment Page 12 of 12

Preamble:

Enbridge Gas is increasing the revenue deficiency by $0.7 million to update the market-based storage costs from $13.2 million as provided at Exhibit 4, Tab 2, Schedule 1, Attachment 1, page 4, line 14 to $13.9 million. The adjustment of $0.7 million is to include the market-based storage fuel costs in the total cost of market- based storage as the fuel costs were not included in the 2024 Test Year Forecast revenue requirement provided at Exhibit 6, Tab 1, Schedule 2.

Question(s):

a) Please explain the driver for the increase in fuel costs related to market-based storage.

Response:

a) As provided at Exhibit 7, Tab 1, Schedule 1, page 12, the market-based storage fuel costs were not included in the initial 2024 Test Year Forecast revenue requirement. The exclusion of the market-based storage fuel costs was identified through the cost allocation and rate design process after the 2024 Test Year Forecast revenue requirement for Exhibit 6 was finalized. In order to include the market-based fuel costs in the cost allocation process, Enbridge Gas adjusted the revenue requirement to include the $0.7 million of market-based storage fuel costs.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit 7 Tab 1 Schedule 3 Plus Attachment Page 2

Preamble:

Due to the different allocation approaches and the availability of information for Enbridge Gas, the Company cannot provide a complete comparison of the proposed cost allocation methodologies to the OEB-approved cost allocation methodologies for the EGD and Union rate zones in aggregate. The Company was not able to recreate two stand-alone cost allocation studies for the EGD and Union rate zones in the same format that was approved in EGD's and Union's respective 2013 Cost of Service proceedings. The proposed Cost Allocation Study and methodologies used provide an allocation of costs based on cost causation principles similar to the OEB-approved methodologies.

Question(s):

a) Can Enbridge confirm that it is unable to recreate a uniform cost allocation methodology for the EGD and Union rate zones on an individual basis.

b) If the answer to 1 is yes, please explain.

Response:

a-b) Please see response at Exhibit I.7.0-STAFF-237 and Exhibit I.7.1-VECC-62.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit 7 Tab 1 Schedule 3 Plus Attachment Page 6 of 6

Preamble:

Union's Cost Allocation Study allocates costs within a functional classification in various manners depending on the specific cost item. In some cases, costs within a functional classification may all be allocated using the same allocation factor while in other cases, costs within a functional classification may have multiple allocation factors depending on the cost item. This approach resulted in a high number of allocation factors relative to the EGD Cost Allocation Study, with over 100 allocation factors and almost 40 direct assignments in the Union Cost Allocation Study.

Enbridge Gas has prepared its 2024 Cost Allocation Study with one allocation factor reflective of the incurrence of costs for each functional classification category when possible. Where there were costs within a given functional classification that required a different allocation approach, Enbridge Gas has direct assigned certain costs. Given the varied nature of the costs in the distribution function, certain costs were classified as specific, as they required a distinct allocation specific to the cost item, such as bad debt and DSM. In total, there are 34 proposed allocation and direct assignment factors in the 2024 Cost Allocation Study. A detailed description of the proposed allocation methodology is provided at Exhibit 7, Tab 1, Schedule 2, Section 3. A list of the factor descriptions for functionalization, classification and allocation is provided at Exhibit 7, Tab 2, Schedule 1, Attachment 11.

Question(s):

a) Please provide functional classifications where the allocation factor was reduced to a single value.

Response:

a) The 2024 Cost Allocation Study and Union's Cost Allocation Study are not directly comparable for most functional classifications other than the storage and transmission functions. Of these functions, the following had more than one allocation factor in Union's Cost Allocation Study and use one factor in the 2024 Cost Allocation Study:

- Storage Demand - Deliverability;
- Storage Demand - Space[1];
- Storage Demand - Operational Contingency; and
- Transmission Demand - Dawn Parkway.

Distribution and gas supply functions are not directly comparable as they are divided into 16 functional classifications in the 2024 Cost Allocation Study, as compared to 5 in Union's Cost Allocation Study.

[1] In the 2024 Cost Allocation Study, the allocation of storage space demand costs includes a direct assignment factor and an allocation factor.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit 7 Tab 1 Schedule 4 Plus Attachment Page 6 of 20

Preamble:

The Panhandle System and St. Clair System are westerly peaking systems serving in-franchise demands on design day. To the extent ex-franchise Rate C1 and Rate M16 customers use contracted capacity on design day, the demands would flow easterly to Dawn (counter flow). Accordingly, the proposed cost allocation methodology does not allocate costs to ex-franchise rate classes but will instead recognize the use of the Panhandle System and St. Clair System to provide ex- franchise transportation under Rate C1 and Rate M16 through the rate design process. Enbridge Gas is proposing to calculate a cost-based demand and commodity rate for these rate classes in order to provide a contribution towards the recovery of the Panhandle System and St. Clair System related transmission costs. Please see Exhibit 8, Tab 2, Schedule 5, Section 2.1 for the proposed rate design for Rate C1 on the Panhandle System and St. Clair System.

Question(s):

a) Please provide the increase in costs allocated to ex franchise customers on Rate C1 and M16 as part of the move to a cost-based demand and commodity rate.

Response:

a) There is no increase in costs allocated to ex-franchise customers as part of the cost-based demand and commodity rate proposed for Rate C1 or Rate M16.

   The current approved cost allocation methodology allocates costs to Rate C1 and Rate M16 based on the average unit cost of the Panhandle and St. Clair system in the Cost Allocation Study. The current approved rate design methodology derives a rate based on the allocation of costs. While Enbridge Gas has not allocated costs to Rate C1 or Rate M16 in the 2024 Cost Allocation Study, Enbridge Gas is proposing to maintain the rate design methodology for the Rate C1 transportation paths where gas flows easterly, from Dawn to Ojibway, St. Clair and Bluewater. As a result, there is no impact to Rate C1 customers who use these paths. Please see Exhibit 8, Tab 2, Schedule 8, Attachment 13, updated March 8, 2023, for the calculation of the Rate C1 demand charge from Dawn of $6.677/GJ, which is based on the current approved rate design methodology.

Enbridge Gas is proposing a change to the current approved rate design methodology for the Rate C1 and Rate M16 transportation paths where the demands would flow easterly (counter flow). The proposed Rate C1 demand charge for these transportation paths is $1.829/GJ, which is a decrease from the current approved rate design methodology of $6.677/GJ. Please see Exhibit 8, Tab 2, Schedule 5, pages 9-11, Section 1.2 for the proposed rate design for Rate C1 firm transportation between St. Clair, Bluewater, Ojibway and Dawn. Please see Exhibit 8, Tab 2, Schedule 8, Attachment 13, updated March 8, 2023, for the calculation of the Rate C1 demand charge to Dawn of $1.829/GJ, which is based on the proposed rate design methodology.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit 7 Tab 1 Schedule 4 Plus Attachment Page 11 of 20

Preamble:

Enbridge Gas is proposing to change the classification of Dawn Parkway measuring and regulating costs, including plant and O&M costs, to Dawn Station demand and allocate the costs to rate classes based on bi-directional design day demands at Dawn without a distance weighting. This proposal recognizes that measuring and regulating costs are not affected by the distance gas is transported, and therefore the use of a distance weighted methodology does not best represent cost causality. This cost allocation methodology also ensures that similar transmission measuring and regulating costs on the Dawn Parkway System (Dawn, Kirkwall and Parkway) are allocated based on bi-directional design day demands without a distance weighting.

Question(s):

a) What is the impact of this change for EGD 125 and Union South T2 customers.

Response:

a) Please see Exhibit 7, Tab 1, Schedule 4, Attachment 1, column c), line 6 and line 26, updated March 8, 2023. There is no impact to Rate 125 and a decrease in the allocation of costs to Rate T2 of $0.255 million to the Dawn Station cost allocation proposal.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit 7 Tab 1 Schedule 4 Plus Attachment Page 14 of 20

Preamble:

Enbridge Gas is proposing to change the allocation of Dawn Parkway transmission demand costs to in-franchise rate classes by assuming all in-franchise design day demands are served from Dawn in the derivation of the distance weighted allocation factor. This change will increase the costs allocated to in-franchise rate classes, as the design day demands supplied from Dawn are transported over a longer distance than design day demands supplied from Parkway, which will increase the distance-weighting applied to the in-franchise design day demands. Enbridge Gas is proposing to allocate PDCI costs in proportion to the allocation of Dawn Parkway transmission demand costs, which includes an allocation of costs to both in-franchise and ex-franchise rate classes. The proposal to allocate PDCI costs to both in-franchise and ex-franchise rate classes will more than offset the increase to in-franchise rate classes from the change in the distance weighted allocation factor.

Question(s):

a) What does Enbridge mean when it says the change “will more than offset the increase to in-franchise rate classes”? Is the offset recovered from ex franchise customers and, if so, what is the impact of the change between in-franchise and ex franchise customers?

Response:

a) The statement “will more than offset the increase to in-franchise rate classes” refers to the fact that the benefit in-franchise rate classes receive from the proposal to allocate PDCI costs in proportion to the allocation of Dawn Parkway transmission demand costs of approximately $5.1 million is greater than the reduction in the benefit in-franchise rate classes currently receive through the removal of the distance weighted allocation factor of approximately $3.4 million, for a net decrease of $1.7 million. Please see Table 1 for the net impact of the Dawn Parkway cost allocation methodology proposals to in-franchise and ex-franchise rate classes.

Table 1
Net Impact of Dawn Parkway Cost Allocation Methodology Proposals

Line No.	Particulars ($000s)	PDCI Allocation Proposal: Current Methodology (1)	PDCI Allocation Proposal: Proposed Methodology (2)	PDCI Allocation Proposal: Impact	Distance-Weighted Allocation Proposal: Impact (3)	Net Impact
		(a)	(b)	(c) = (b-a)	(d)	(e) = (c+d)
1	In-franchise	17,612	12,509	(5,103)	3,369	(1,733)
2	Ex-franchise	-	5,103	5,103	(3,369)	1,733
3	Total	17,612	17,612	-	-	-

Notes:

(1) Current methodology allocates PDCI costs to Union South in-franchise rate classes. With the proposal for one rate zone, the PDCI costs would be allocated to all in-franchise rate classes.

(2) Proposed methodology to allocate PDCI costs is based on the Dawn Parkway demand allocation factor provided at Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 19.

(3) The impact of the distance-weighted allocation proposal is provided at Exhibit I.4.7-TCPL-2 part d).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit 7 Tab 1 Schedule 4 Plus Attachment Page 15 of 20

Preamble:

Enbridge Gas is also proposing to continue to pay the PDCI on all DCQ quantities obligated at Parkway, as required by the utility, to account for the additional costs incurred by the customer of the PDO. As part of this Application, Enbridge Gas is proposing to expand the PDO and PDCI offering to customers located in the EGD rate zone who currently are contractually obligated to deliver gas at the Enbridge CDA. As provided at Exhibit 8, Tab 2, Schedule 2, Enbridge Gas is proposing to harmonize the rate design for DP customers located in the Enbridge CDA and the Union South rate zone, such that they pay common transportation rates. To recognize the system benefit of delivering gas to Parkway, these customers will receive a PDCI payment as an offset to the gas supply transportation charges.

Question(s):

a) Will the PDCI payment fully offset all gas supply transportation charges? If not, please explain **and calculate the impact**.

Response:

a) No. The PDCI payment will offset approximately 76% of the common transportation component[1] of the gas supply transportation charge, as shown in Table 1. The common transportation component represents the incremental charge to EGD rate zone customers with an Enbridge CDA point of receipt, resulting from the proposal for common transportation rates.

   The PDCI payment is meant to offset the incremental cost of delivering gas to Parkway/Enbridge CDA over the cost of delivering to Dawn and is based on the daily Rate M12 Dawn to Parkway charge, including fuel and the facility carbon charge.

[1] Exhibit 8, Tab 2, Schedule 2, p.15, Table 3, line 9.

Table 1
Comparison of PDCI Payment & Transportation Charges

Line No.	Particulars	Unit Rate
		(a)
1	PDCI payment ($/GJ) (1)	(0.173)
2	Conversion to volume (GJ/10^3/m^3)	39.08
3	PDCI payment (cents/m^3) (line 1 x line 2 / 10)	(0.6761)
4	Common transportation charge (cents/m^3) (2)	0.8875
5	Difference (line 3 + line 4)	0.2114
6	Offset percentage (1 - line 3 / line 4)	76%

Notes:
(1) Exhibit 8, Tab 2, Schedule 8, Attachment 6.
(2) Exhibit 8, Tab 2, Schedule 2, page 15, Table 3, line 9.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit 7, Tab 1, Schedule 1 Plus Attachment, Page 8, Section 3.1
Reclassified Revenue and Cost Components, Paragraph 20

Preamble:

"Enbridge Gas reclassified revenue and cost components of the revenue requirement to align with the cost allocation and rate design process. These adjustments include:

- Reclassifying $25.3 million of customer supplied fuel (CSF) from cost of gas to distribution and transportation revenue;
- Reclassifying $15.3 million of gas supply optimization revenue from transportation revenue to other revenue; and
- Reclassifying $3.7 million of community expansion system expansion surcharge (SES) and temporary connection surcharge (TCS) revenue and renewable natural gas (RNG) station charge revenue from distribution and transportation revenue to other revenue."

Question(s):

a) Please explain from first principles why each of these costs were reclassified in the 2024 Cost allocation Model. For example, were these costs incorrectly classified in the legacy Union/EGD cost allocation Models or are new costs not previously classified.

b) Specifically, why would gas supply optimization not be a cost of gas commodity supply?

c) Specifically, why would renewable natural gas (RNG) station charge not be a cost of distribution?

<u>Response:</u>

a) The reclassification of the identified revenue and cost components in the preamble is required to ensure Enbridge Gas's revenue is equal to the revenue requirement. The adjustments are not incorrectly classified costs or new costs not previously identified. The adjustments are required to align the revenue and cost components of the revenue requirement with the requirements for the cost allocation and rate design process.

   The $25.3 million customer supplied fuel (CSF) adjustment is required because Exhibit 6 includes the compressor fuel netted with CSF in the cost of gas expense. The Cost Allocation Study does not net CSF revenue and compressor fuel costs in cost of gas expense in order to fully allocate the total cost of compressor fuel requirements. The value of CSF is reclassified to revenue to recognize that customers provide CSF to offset the allocation of fuel costs. The CSF adjustment is consistent with the adjustment made by Union in its 2013 Cost Allocation Study.[1]

   The adjustments for gas supply optimization, SES, TCS and RNG station charge revenue from distribution and transportation revenue to other revenue is required to ensure Enbridge Gas recognizes revenue is generated through charges that are not set through the rate design process. The revenue generated by these other charges offsets the revenue requirement recovered in base rates, which are set through the rate design process. The Cost Allocation Study nets the allocation of the revenue requirement with the updated other revenue amount. The rate design process uses the net revenue requirement in the derivation of rates.

b) Gas supply optimization revenue of $15.3 million is recorded as transportation revenue in Exhibit 6. Enbridge Gas enters into exchange transactions using upstream transportation assets that are part of the Gas Supply Plan to generate revenue when these assets are not fully required.[2] The revenue is not a cost of gas supply commodity because it is revenue generated through exchange transactions. 90% of the revenues earned from optimization activities are refunded to ratepayers in rates. To facilitate the refund of the optimization revenue to ratepayers as a reduction to rates, Enbridge Gas reclassifies the optimization revenue from transportation revenue in Exhibit 6 to other revenue as described in part a).

c) RNG station charge revenue of $3.0 million relates to the premium above the posted station charge paid by RNG producers to make the capital project required to attach to Enbridge Gas's system economically feasible. Enbridge Gas reclassifies this RNG station charge revenue from transportation revenue, as recorded in Exhibit 6, to other revenue as described in part a).

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[1] EB-2011-0210, Exhibit G3, Tab 1, Schedule 2, footnote 2.
[2] Exhibit 3, Tab 4, Schedule 1, p.7.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 2, pg. 7 & Ex. 4, Tab 2, Schedule 1, Attachment 3

Preamble:

Section 2.1 describes the proposed Gas Supply classification. Reconciling legacy EGD and Union approaches, while dealing with a merged utility and gas supply contracting, creates a lot of moving parts. As a starting point for clarification, we believe understanding the classification of Transportation between Gas Supply and Load Balancing is an important starting point.

Question(s):

Using the November 1, 2022, Upstream Transportation Contract Summary found at Ex. 4, Tab 2, Schedule 1, Attachment 3, please replace the Contract Expiry found in column (e) with a designation of whether the contract demand charges are considered Transportation Demand or Load Balancing Transport for the purposes of classification.

a) If a particular contract is used for both, please split the row into 2 rows showing the amounts classified to either Transportation Demand or Load Balancing Transport.

b) Please provide an Excel file for this developed table.

Response:

Please see response at Exhibit I.7.1-IGUA-75 part a).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 2, pg. 8

Preamble:

EGI evidence states: *Load balancing commodity includes gas supply load balancing costs to meet above average day demands. These costs are incurred by contracting for peaking services and purchasing incremental gas supply over the winter period to meet seasonal and design day demands for all customers.*

We would like to understand how these commodity costs are handled for the purposes of matching the revenue generated when selling the molecules.

Question(s):

Please describe how the commodity costs are allocated in the following scenario.

a) If the current WACOG is $5 and the peak season commodity is purchased at Dawn for $7, does load balancing commodity get allocated the full $7 cost?

   i. If so, how does the revenue generated from selling the molecule get properly allocated to recognize that the load balancing premium is, in our view, actually $2? Please explain fully.

   ii. If, however, the peak season commodity cost is split as $5 to Gas Supply and $2 to Load Balancing, we would like that confirmed.

Response:

a) In the scenario provided, the price variance between the peak season commodity cost of $7 at Dawn and the Dawn forecasted price (not the current WACOG) of $5 results in a difference of $2, which is proposed to be captured in the Load Balancing Variance Account. Please see Exhibit 4, Tab 2, Schedule 1, Attachment 1, page 5 for the detailed calculation of the 2024 load balancing costs.

Cost variances captured in the Load Balancing Variance Account will be recovered from in-franchise rate classes that require storage services as part of the QRAM process.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 2, pg. 9-10

Preamble:

EGI evidence states: *The 2024 Test Year revenue requirement includes the cost of regulated storage and excludes unregulated storage costs. Regulated storage costs are classified as storage demand and storage commodity…*
Market-based storage demand costs are incurred to meet the Utility's storage space and storage deliverability requirements. The market-based storage demand costs are classified in proportion to total utility storage space and deliverability net plant excluding base pressure gas and linepack.

Question(s):

Please clarify if unregulated storage costs refer to the non-utility storage whose prices are unregulated (market-based).

a) Please clarify how the demand and commodity costs for market-based storage contracts executed to meet in-franchise demand are treated. The referenced statement above seems to suggest it is asset-based when we would have expected the allocations to be contract-based. Please explain fully.

Response:

Confirmed.

a) Demand and commodity costs for market-based storage contracts are included in gas costs[1] based on contracted quantity and price. Market-based storage contracts are functionalized to storage and classified to deliverability and space as provided at Exhibit 7, Tab 2, Schedule 1, Attachment 5, line 68.

[1] Per Exhibit 4, Tab 2, Schedule 1, Attachment 1, p.2, line 26.

The assets for unregulated storage are not included in the 2024 Test Year rate base.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 2, pg. 18

Preamble:

EGI evidence states: *The operational contingency space of approximately 15.6 PJ allows Enbridge Gas to meet its operational needs. Operational contingency storage space costs are allocated to in-franchise and ex-franchise customers based on how operational contingency space is used. Please see Exhibit 4, Tab 2, Schedule 4 for a description of the operational contingency components.*

We would like to understand how these costs are allocated.

Question(s):

For the components listed in Ex.4, Tab 2, Schedule 4, please define the parameters used for the purposes of classification and the drivers to allocate the component costs.

a) Currently, are any operational contingency costs from the Union Dawn storage allocated to ex-franchise customers?

   i. If so, how? Please explain.
   ii. If not, why not?

Response:

Please see response at Exhibit I.7.1-IGUA-76, part d).

a) Yes. Operational contingency space is required to support the storage and transmission services provided to all customers, including in-franchise and ex-franchise customers.

   i. Please see response at Exhibit I.7.1-IGUA-76, Attachment 2 for the cost allocation details of operational contingency. A portion of the operational contingency costs are also recovered from the non-utility storage business, as provided at response at Exhibit I.4.2-FRPO-141.

      The allocation of operational contingency is consistent with Union's 2013 Cost Allocation Study that also had an allocation of operational contingency (system integrity) to ex-franchise rate classes. In addition to those identified in Table 2, Union included ex-franchise in the allocation of UFG forecast variances which is no longer a component of operational contingency in 2024.

   ii. Please see part a).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 2, pg. 18

Preamble:

EGI evidence states: *The operational contingency space of approximately 15.6 PJ allows Enbridge Gas to meet its operational needs. Operational contingency storage space costs are allocated to in-franchise and ex-franchise customers based on how operational contingency space is used. Please see Exhibit 4, Tab 2, Schedule 4 for a description of the operational contingency components.*

We would like to understand how these costs are allocated.

Question(s):

How are storage commodity costs allocated to the non-utility storage? Please explain fully.

Response:

Storage commodity costs include unaccounted for gas (UFG), compressor fuel and company use gas. Storage commodity costs allocated to the non-utility operations are not included in the utility revenue requirement. A description of the allocation of costs to non-utility is provided at Exhibit 1, Tab 13, Schedule 2. This evidence will be addressed in Phase 2 of the proceeding as noted in Enbridge Gas's February 1, 2023 letter.

Please see response at Exhibit I.4.2-FRPO-141 for the treatment of the operational contingency allocation to non-utility storage.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 2, pg. 19

Preamble:

EGI evidence states: *Kirkwall Station costs are allocated between in-franchise and ex-franchise rate classes in proportion to bi-directional design day demands at Kirkwall. In-franchise costs are allocated to in-franchise bundled rate classes using design day demands with the costs allocated to semi-unbundled and unbundled services based on the design day demands of the respective service area.*

Question(s):

Please provide the design day flows that underpin allocations for the Kirkwall station.

a) Please ensure the direction is clearly specified and what assumptions are made regarding the TCE contract from Kirkwall to Union CDA for 135,000 GJ/day.

Response:

The design day flows underpinning the Kirkwall Station transmission demand allocation factor are provided in Table 1.

Table 1
Derivation of Kirkwall Station Allocation Factor

Line No.	Particulars	Kirkwall Station Allocation Factor (GJ/d)	Kirkwall Station Allocation Factor (10^3m^3/d) (2)
		(a)	(b)
	Ex-franchise Demands		
1	Dawn to Kirkwall	49,500	1,267
2	Kirkwall to Parkway	407,610	10,430
3	Kirkwall to Dawn	63,328	1,620
4	Total Ex-franchise Demands	520,438	13,317
5	Total In-franchise Demands (Kirkwall Export)	91,996	2,354
6	Total (1)	612,434	15,671

Notes:
(1) Allocation factor in 10^3m^3 per Exhibit 7, Tab 2, Schedule 1, Attachment 12, page 12, line 29.
(2) Conversion to 10^3m^3 using heat value of 39.08 GJ/10^3m^3

a) Enbridge Gas did not include the demands associated with the 135,000 GJ/d Kirkwall to Union CDA contract in the derivation of the Kirkwall Station allocation factor. If Enbridge Gas had included the demands associated with this contract in the Kirkwall Station allocation factor, the costs allocated to in-franchise rate classes would increase by $0.214 million with a decrease in the costs allocated to ex-franchise rate classes by the same amount.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 2, pg. 19

Preamble:

EGI evidence states: *Kirkwall Station costs are allocated between in-franchise and ex-franchise rate classes in proportion to bi-directional design day demands at Kirkwall. In-franchise costs are allocated to in-franchise bundled rate classes using design day demands with the costs allocated to semi-unbundled and unbundled services based on the design day demands of the respective service area.*

Question(s):

Please explain more fully this concept that is repeated in this section that states: *using design day demands with the costs allocated to semi-unbundled and unbundled services based on the design day demands of the respective service area.*

a) If a semi-unbundled customer is situated in the eastern service area vs. the central service area, how are their design day demands treated differently? Please explain fully with the help of a numeric illustrative example.

Response:

Please see response at Exhibit I.7.1-IGUA-78, part a), part ii) for an explanation of the allocation of costs to semi-unbundled and unbundled services based on the design day demands of the respective service area.

a) Semi-unbundled service is not proposed to be offered to customers located in the eastern service area. The issue will be addressed in Phase 2 of the proceeding in accordance with the OEB’s Decision on Issues List dated January 27, 2023.

   Assuming for the purposes of this response, a semi-unbundled customer was located in the eastern service area, the allocation of costs to semi-unbundled services would be calculated as the semi-unbundled design day demands in the eastern service area divided by the total eastern design day demands multiplied by the cost of the eastern service area. The same calculation would apply to a customer in the central service area except the semi-unbundled demands, total demands and costs would be for the central service area. Please see response at Exhibit I.7.1-IGUA-78, Attachment 1, page 2, column (d), for an illustrative example showing the allocation to semi-unbundled and unbundled services in the derivation of the Dawn Parkway transmission demand allocation factor.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 2, pg. 19

Preamble:

EGI evidence states: *Panhandle/St. Clair System costs are allocated to in-franchise bundled rate classes in proportion to design day demands with the costs allocated to semi-unbundled and unbundled services based on the design day demands of the South service area.*

Question(s):

Does this mean that Panhandle/St. Clair System costs are allocated to all bundled customers of EGI and to semi- & unbundled customers in the South service area by their design day demand (i.e., proportional to their design day demand as a fraction of the total design day demand of the South service area)?

a) Alternatively, is the design day demand of these South service area semi- & unbundled customers in proportion to the design day demand of all EGI customers?

b) Please explain fully.

Response:

Yes. The Panhandle/St. Clair System allocation factor is based on the in-franchise design day demands of the South service area. The allocation to semi-unbundled rate classes is based on the design day demands for each semi-unbundled rate class in proportion to the total South service area design day demands. The remaining allocation is to in-franchise bundled rate classes in proportion to design day demands. Please see response at Exhibit I.7.1-IGUA-77, Attachment 2, for the derivation of the Panhandle/St. Clair transmission demand allocation factor.

a-b) No. The design day demands of semi-unbundled customers are not allocated in proportion to the design day demands of all Enbridge Gas customers. Please see response above.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 2, pg. 22

Question(s):

Please explain the distinction of greater than or less than NPS 4 for Distribution Demand High Pressure.

a) What functional difference does this sizing make?

Response:

a) The distinction of NPS 4 for distribution demand high pressure mains enables Enbridge Gas to differentiate the allocation of high pressure main costs. Large diameter, high pressure mains are used by the Company to provide service to all customers and as a result, all customers receive an allocation of the costs of these mains. Rate classes with larger customers, some of which are served solely by large diameter mains, are allocated an appropriate proportion of the cost of smaller diameter mains.

   In EGD's 2014 to 2018 Rate Application Decision with Reasons[1], in reference to the allocation of costs to Rate 125, the OEB found that Rate 125 customers, due to the rate class eligibility criteria, should not be allocated the costs of transmission pressure pipelines less than 6 inches in diameter. Customers eligible for Rate 125 would not be served by pipelines 4 inches in diameter or less. Accordingly, the EGD Cost Allocation Study split the classification of distribution mains into the categories of greater than 4 inches in diameter and less than or equal to 4 inches in diameter.

   In Union's Cost Allocation Study, distribution mains for Union North categorized as sole use or joint use consisted of pipelines 6 inches in diameter or greater. Sole use mains included assets serving specific large volume customers and the costs of these assets were allocated in proportion to the demands of sole use customers. Joint use mains, which support sole use assets not directly connected to the TransCanada Mainline as well as grid assets, classified as 4 inches in diameter or

[1] EB-2012-0459, Decision with Reasons, July 17, 2014.

less, were allocated to Union North customers in proportion to system peak and average day demands excluding customers who were entirely sole use. The grid use assets were allocated to general service rate classes only.

Enbridge Gas is proposing to maintain the 4 inch diameter split for high pressure main classification as part of the 2024 Cost Allocation Study. The proposed approach is consistent with methodologies previously approved by the OEB for both EGD and Union. The differentiation of 4 inch mains ensures that larger customers being served by larger diameter and larger pressure mains are allocated an appropriate proportion of the costs of smaller diameter mains.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 3, pg. 2 & Exhibit 8, Tab 2, Schedule 1, para. 34

Preamble:

EGI evidence states: *The Company was not able to recreate two stand-alone cost allocation studies for the EGD and Union rate zones in the same format that was approved in EGD's and Union's respective 2013 Cost of Service proceedings.*

While this statement may have merit when viewing integrated distribution rates, EGI should not have the same issue with Gas Supply rates by current Rate Zones (see para. 34 referenced above).

Question(s):

Please confirm that EGI could use the current information available to provide Gas Supply rates to the newly proposed service areas.

a) Please provide comparison rates to compare the One Rate Zone approach to individual Service Area rates for Gas Supply.

Response:

Confirmed. As provided at Exhibit 8, Tab 2, Schedule 1, Section 1.5, pages 15 to 22, Enbridge Gas identified alternative rate zones for gas supply and transmission costs.

a) Please see response at Exhibit I.7.0-STAFF-237. Enbridge Gas will file additional information on cost allocation impacts of rate zones for the 2024 Test Year in advance of the settlement conference for this Application.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 3, pg. 4

Question(s):

Please explain how Tecumseh Gas storage division costs are functionalized to transmission and compression or storage.

a) Please explain why this separation is warranted.

Response:

EGD's cost allocation methodology[1] functionalized Tecumseh storage costs primarily based on plant investment identified by the OEB's Uniform System of Accounts for Gas Utilities. Transmission and compression related costs represented the cost to move gas from the Tecumseh storage pool along the Tecumseh transmission lines to Dawn. Storage related costs represented the cost of the storage pool such as wells and field lines. Tecumseh operating costs for depreciation, taxes, return and operating and maintenance expense were functionalized according to plant investment or directly assigned.

a) The functionalization of Tecumseh storage costs to transmission, compression and storage was necessary to design rates and services for ex-franchise transmission and storage services under Rate 325 and Rate 330 for the EGD rate zone.

   As provided at Exhibit 8, Tab 1, Schedule 2, page 5, the Company is proposing to eliminate Rate 325 and Rate 330. Union was the only customer taking service under Rate 325 and Rate 330 had no customers taking service. Enbridge Gas is now operating as one integrated storage facility therefore the cost of the Tecumseh transmission, compression and storage is all functionalized to storage in the 2024 Cost Allocation Study. For rate design purposes, there is no longer a need to identify

[1] The 2018 EGD Cost Allocation Study relating to Tecumseh can be found at EB-2017-0086, Exhibit G2, Tab 7, Schedule 2, p.1.

these assets under the EGD functionalization categories because the EGD transmission lines are now part of the integrated Dawn storage facilities and not needed for transmission purposes.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 3, pg. 4

Preamble:

EGI evidence states: *Costs were directly assigned to the functional categories where possible, and the remaining indirect costs were functionalized based on analysis of use and the Company's knowledge of its operations. Union further divided the storage function into dehydrator and excluding dehydrator at the function level and divided the transmission function into Dawn Station, Dawn-Trafalgar Easterly, Dawn-Trafalgar Westerly, Other Transmission, and Ojibway/St. Clair at the function level.*

Question(s):

Please define the remaining indirect costs and what drivers or principles are used for their allocation from the company's knowledge.

Response:

Enbridge Gas has responded to the question based on the functionalization and classification of the indirect costs in the 2024 Cost Allocation Study. The approach to functionalizing and classifying indirect costs in the 2024 Cost Allocation Study is similar to the approach used by Union.

Costs are directly assigned to a specific function or classification when possible. Indirect costs are functionalized and classified based on the following methodologies for rate base and operating and maintenance expenses as follows:

Rate Base

- General plant – Functionalized and classified in proportion to a 50/50 weighting of functionalized and classified net plant and O&M expenses[1].

[1] Net plant costs exclude linepack and base pressure gas. O&M expenses exclude cost of gas, DSM program related costs, employee benefits, and administrative and general expenses.

- Working capital – Functionalized and classified in proportion to net plant.

Operating and Maintenance Expenses

- General operating and engineering expenses – Functionalized primarily based on an analysis of activities conducted by budget centre managers by department and classified in proportion to classified net plant.

- Employee benefit expenses – Functionalized and classified in proportion to the functionalized and classified labour expense.

- Administrative and general expenses – Functionalized and classified in proportion to functionalized and classified other O&M expenses[2].

[2] Other O&M expenses exclude cost of gas, DSM program related costs, uncollectible account costs, employee benefits, and administrative and general expenses.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 3, pg. 4

Preamble:

EGI evidence states: *Costs were directly assigned to the functional categories where possible, and the remaining indirect costs were functionalized based on analysis of use and the Company's knowledge of its operations. Union further divided the storage function into dehydrator and excluding dehydrator at the function level and divided the transmission function into Dawn Station, Dawn-Trafalgar Easterly, Dawn-Trafalgar Westerly, Other Transmission, and Ojibway/St. Clair at the function level.*

Question(s):

Please explain why the storage function was divided into dehydrator and excluding dehydrator at the functional level.

a) Is EGI continuing to use that division in its proposal? Please explain.

Response:

Union's Cost Allocation Study classified the storage function into dehydrator and excluding dehydrator demand to allow for an allocation of utility dehydrator costs to both in-franchise and ex-franchise rate classes. Union provided a dehydration service as part of Rate M12 that, as part of the NGEIR Decision[1], became an unregulated service. As such, an allocation of dehydration assets were assigned to the non-utility operation and the allocation to ex-franchise rate classes was no longer required. In Union's 2013 Cost Allocation Study, the storage dehydrator and storage excluding dehydrator classifications remained but the allocation factors were the same.

a) No, Enbridge Gas is not proposing to maintain the storage classification between storage dehydrator and excluding dehydrator demand costs in the 2024 Cost Allocation Study. The Company is no longer providing an ex-franchise dehydration

[1] EB-2005-0551.

service and as such, a separate classification and allocation of storage dehydrator costs is no longer needed.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 3, Attachment 1

Preamble:

Under the Gas Supply Comparison by Rate Zone, in Union North, *A portion of costs directly assigned to interruptible based on winter sales volumes.*

Question(s):

Are these costs assigned to Rate 25?

a) If so, how is the transfer price determined?
b) If not, to what are the costs assigned?
c) Is this service proposed to be discontinued or harmonized? Please explain.

Response:

Yes, the Union Cost Allocation Study direct assigned transportation demand and commodity costs to Union North Rate 25 based on winter sales volumes.

a) The transportation demand costs directly assigned to Rate 25 were calculated by multiplying the winter sales volumes by TCPL delivery area by the weighted transportation demand tolls for each TCPL delivery area. The transportation commodity costs directly assigned to Rate 25 were calculated by multiplying the winter sales volumes by TCPL delivery area by the weighted transportation fuel rates for each TCPL delivery area.

b) Please see above.

c) No. Enbridge Gas is not proposing to eliminate the Rate 25 rate class or service options effective January 1, 2024. Enbridge Gas's proposal for rate class and service harmonization will be addressed in Phase 2 of the proceeding, as noted in Enbridge Gas's February 1, 2023 letter.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 3, Attachment 1

Preamble:

Under the Methodology Comparison for Storage by Rate Zone, the distinction of including or excluding dehydrator comes up in many boxes.

Question(s):

Please explain the reasoning behind the methodology applications of dehydrator costs.

Response:

The storage dehydrator demand functional classification in Union's Cost Allocation Study included the costs associated with utility dehydration assets. The storage excluding dehydrator functional classification included the costs associated with storage deliverability, space and operational contingency, previously referred to as system integrity. Please see response at Exhibit I.7.1-FRPO-184, which describes the rationale for the classification between storage dehydrator and storage excluding dehydrator demand in Union's Cost Allocation Study.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 4, pg. 17

Preamble:

EGI evidence states: *In Union's Hagar Liquefaction Service Rate proceeding[22], the OEB approved a non-utility cross charge of $1.59/GJ. The charge was based on the forecast of customers at the time of the application. As there are no customers contracted for the liquefaction service, Enbridge Gas is not able to update the Cost Allocation Study or cross charge amount as part of this Application.*

Question(s):

Does this approach infer that if, for whatever reason, non-utility storage is not contracted, the cost should fall back to the utility customers until it is contracted? Please explain.

Response:

No. The non-utility cross charge in this reference is for a liquefaction service at the Hagar LNG facility. The costs for the Hagar LNG facility are regulated and recovered from in-franchise customers, as the facility is used to meet in-franchise design day demands. Should a customer contract for the unregulated liquefaction service at the Hagar LNG facility, the cross charge would be paid by the customer to the utility operations. Any incremental revenue from the cross charge would be recorded as utility earnings during the IR term, which may be subject to earnings sharing, and would be included as part of the forecast for the next rebasing proceeding to the benefit of utility customers.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 1, Schedule 4, Attachment 1

Question(s):

Please provide the evidence associated with the significant rate increase from DSM to Rate 6.

Response:

Exhibit 7, Tab 1, Schedule 4, Attachment 1, updated March 8, 2023 reflects the impact of the change to the DSM budget allocation to rate classes for the 2024 Test Year. Please see response at Exhibit I.7.1-STAFF-241, part b) for details on the rate class impacts.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

7.1.1 paragraph 12; 8.2.1 pages 12 to 15

Preamble:

IGUA would like to better understand the impact of inadequate or inconsistent information or record keeping on EGI's proposal for harmonized cost allocation for distribution assets.

Question(s):

a) Please explain how EGD tracks its distribution assets, and why it is impossible to geographically differentiate those assets.

b) Please explain the level of detail that is available for segregating distribution assets between EGD CDA and EGD EDA.

c) Please explain how Union tracks its North system distribution assets, and why it is impossible to differentiate costs between the North West and North East geographic zones.

d) Please explain the level of detail that is available for segregating distribution assets between Union North West and Union North East areas.

e) Can EGI identify its physical mains by geographic region using its GISs, such that there is a physical alternative allocation method to that advanced in paragraph 33 of 8.7.1? Please specify the level of physical detail that is available by geographic region.

Response:

a-b) For cost accounting purposes, EGD did not record its distribution assets by location. Information recorded for distribution mains consists of pipe size, material, date installed and length. As EGD had only one rate zone for rate-making purposes, the cost accounting detail has not been maintained based on location of the assets.

The Company does not have the asset information detail to separate the cost of distribution assets between the Enbridge CDA and Enbridge EDA without using an allocation methodology.

c-d) For cost accounting purposes, Union recorded its distribution assets by regional areas that consist of: Eastern, Northeast and Northwest. The Northeast detail contains the asset information of the Sudbury, North Bay, Orillia and Sault Ste. Marie areas. Distribution main assets are tracked by pipe size, material, date installed and length for each regional area.

From a rate-making perspective, Union had one rate zone for purposes of distribution costs but two rate zones for gas supply costs. Within the Northeast regional area, Sudbury, North Bay, and Orillia areas are in the Union North East gas supply rate zone but the Sault Ste. Marie area is in the Union North West gas supply rate zone.

As such, the Company does not have the asset information detail to separate the cost of distribution assets in the Northeast regional area without using an allocation methodology.

e) Yes, distribution mains can be identified by geographic region using the Company's Geographical Information Systems (GIS). The level of pertinent detail available for mains includes size, material, pressure, date installed, and length.

The level of effort involved to reconcile the GIS and cost information for purposes of splitting costs into new distribution rate zones would be significant. In addition, the changes to internal processes and information systems would be necessary to record and maintain the information.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Preamble:

Clarification regarding the classification and allocation of gas supply costs is requested.

Question(s):

a) Please detail how gas supply costs are classified into commodity, load balancing and transportation. Please include supporting workpapers for the development of the GASSUPPLY_CLASS classification factor, for the current rate classes.

b) Please provide supporting workpapers for the development of the following allocation factors, with a definition of the specific peak demands and average demands used for each, for the current rate classes. Please indicate whether the parameters apply to gas supply service, bundled DP service, semi-unbundled service or unbundled service.

   i. LOAD_BALANCING
   ii. TRANS_FUEL

c) For 2024 gas supply commodity costs, please specify forecast monthly volumes and costs by receipt point.

d) From 7.1.3 Attachment 1 page 1, it appears that administrative costs for gas supply were previously allocated to both sales and direct purchase customers. Please identify the administrative costs previously assigned to direct purchase customers, and explain where those costs are proposed to be recovered.

Response:

a) Enbridge Gas classifies[1] the cost of gas expense based on a detailed analysis of the 2024 Gas Supply Plan. Table 1 provides the derivation and support for the gas supply classification factor GASSUPPLY_CLASS.

[1] Based on gas supply classification factor GASSUPPLY_CLASS.

Table 1
GASSUPPLY_CLASS Classification Factor

Line No.	Particulars ($000s)	GASSUPPLY_CLASS Classification Factor (1)
		(a)
1	Gas Supply Commodity (2)	2,728,041
2	Load Balancing Transport (3)	175,236
3	Load Balancing Commodity (4)	23,591
4	Transportation Demand (3)	162,050
5	Transportation Commodity (3)	23,899
6	Total Cost of Gas Classification Factor	3,112,816

Notes:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, page 4, line 3.
(2) Table 2, line 4.
(3) Derivation provided at Exhibit I.7.1-IGUA-75, Attachment 2.
(4) Exhibit 4, Tab 2, Schedule 1, Attachment 1, page 5, column (m), line 8.

b) Enbridge Gas has provided the transportation demand, load balancing transportation demand and transportation commodity costs by service area in Attachment 1. The allocation factors for the following functional classifications are provided as follows:

- Attachment 2 provides the derivation of the allocation factor for transportation demand (TRANS_DEMAND);
- Attachment 3 provides the derivation of the allocation factor for load balancing transport (LOAD_BALANCING); and
- Attachment 4 provides the derivation of the allocation factor for transportation commodity (TRANS_FUEL).

Enbridge Gas classifies upstream transportation contracts to gas supply commodity, transportation demand, load balancing transport, and distribution demand depending on the nature of the contract. Upstream transportation fuel costs for transportation demand and load balancing transport functional classifications are classified as transportation commodity.

The gas supply commodity functional classification includes the cost of transportation contracts upstream of Dawn or Empress. Included in Table 1, line 1 is $178.1 million of demand and fuel costs associated with these contracts. The cost of these contracts is paid for by sales service customers only.

The transportation demand functional classification includes the cost of upstream transportation contracts required to transport gas to the various Enbridge Gas delivery areas to meet average annual demands for both sales service and bundled DP customers. Enbridge Gas assumes long-haul transportation contracts are used to serve average annual demands in each respective delivery area, with any remaining average annual demands met through the use of short haul transportation contracts. Average annual demands are calculated as the forecasted annual volume divided by 366.

The load balancing transport functional classification includes the cost of upstream transportation contracts that are required to meet design day demand and incremental to the transportation required to meet the average annual demands. Design day demand is the peak volume estimated to be consumed by each customer on an extreme cold weather day. The peak volumes for each customer are combined to determine the design day demand for the rate class.

For the transportation commodity allocation factor, total annual volumes are used to allocate costs of the functional classification. The total annual volume is the amount of gas forecast to be delivered to customers during the year. This includes system-supplied customers, bundled direct purchase customers, and semi-unbundled customers. Unbundled customers and volumes were excluded.

c) Please see Attachment 5 for the monthly forecast volumes and cost of commodity purchases by receipt point. Total commodity purchases include purchases made on behalf of sales service customers as well as for UFG, compressor fuel and company use, offset by customer supplied fuel. Table 2 provides a reconciliation of total commodity purchases.

Table 2
Reconciliation of Total Commodity Purchases

Line No.	Particulars	Commodity Purchases TJ	Commodity Purchases ($000s) (1)
		(a)	(b)
1	Total Commodity Purchases (2)	527,231	2,799,304
2	Storage Fluctuation (3)	858	7,383
3	Total	528,089	2,806,687
	Gas Supply Demand (4)		
4	Sales Service Commodity	513,276	2,728,041
5	UFG	11,825	62,783
6	Compressor Fuel	7,510	39,874
7	Company Use	774	4,108
8	Customer Supplied Fuel	(5,296)	(28,119)
9	Total	528,089	2,806,687

Notes:
(1) Cost calculated as the total volumes in column (a) multiplied by the weighted average reference price of $5.309/GJ per Exhibit 4, Tab 2, Schedule 2, Attachment 3.
(2) Attachment 3, column (m). Line 8 provides the purchases in PJ, line 24 provides the cost.
(3) Exhibit 4, Tab 2, Schedule 1, Attachment 1, page 4, line 2.
(4) Exhibit 4, Tab 2, Schedule 1, Attachment 1, page 6, column (a).

To clarify, gas supply administration costs were allocated to sales service customers only in both EGD and Union's previous cost allocation studies.

In the 2024 Cost Allocation Study, the gas supply admin functional classification includes the cost of gas supply administration and direct purchase administration. The costs of the direct purchase administration are offset by an allocation of the revenue from providing the service. Therefore, the remaining balance in the gas supply admin functional classification is only related to the gas supply administration costs and allocated using sales service volumes.

The costs of direct purchase administration and the distributor consolidated billing (DCB) Program are recovered through direct purchase service charges. The costs for these services are provided in Table 3. The revenue from the service charges offsets the costs in Table 3, is provided at Exhibit 7, Tab 2, Schedule 1, Attachment 4, page 4, lines 104-105.

Table 3
Direct Purchase Administrative Costs

Line No.	Particulars ($000s)	General Administration Costs (1) Direct Purchase Administration	DCB Program	Incremental Contract Service Administration Costs (2)
		(a)	(b)	(c)
1	Customer Accounting	606	690	413
2	System Operation & Engineering	660	-	394
3	Bad Debt	-	775	-
4	Administrative & General Expense	1,131	691	1,107
5	Employee Benefits	546	266	427
6	Total	2,943	2,422	2,342

Notes:

(1) The general direct purchase administration costs are offset by revenue in the gas supply admin functional classification at Exhibit 7, Tab 2, Schedule 1, Attachment 4, page 4, lines 104 and 105.

(2) The incremental cost of direct purchase administration for contract service rate classes is recovered in contract service delivery rates.

Transportation Demand & Load Balancing Transport and Transportation Commodity Costs By Service Area

Line No.	Particulars	Transportation Demand Costs ($000s)	Load Balancing Transport Costs ($000s)	Transportation Commodity Costs ($000s)
		(a)	(b)	(c)
1	EGD CDA	42,815	15,989	662
2	EGD EDA	89,806	110,847	18,670
3	Union North West	10,896	13,501	2,751
4	Union North East	17,062	34,900	1,618
5	Union South	1,472	-	198
6	Total	162,050	175,236	23,899

Derivation of the Transportation Demand Allocation Factor

Line No.	Particulars	Annual Volumes (1) (10^3m^3)	Allocation to Semi-Unbundled and Unbundled Services ($000s)	Remaining Allocation to Bundled Rate Classes (5) ($000s)	Western Transportation Volumes (10^3m^3)	Western Transportation Allocation (6) ($000s)	Western Transportation Adjustment (7) ($000s)	Transportation Demand Allocation Factor (8)
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (b+c+e+f)
	EGD Rate Zone							
1	Rate 1	5,001,027	-	41,492	15,031	280	(1,347)	40,425
2	Rate 6	4,795,693	-	39,788	177,308	3,301	(1,292)	41,798
3	Rate 100	27,429	-	228	-	-	(7)	220
4	Rate 110	1,068,281	-	8,863	11,179	208	(288)	8,784
5	Rate 115	381,873	-	3,168	-	-	(103)	3,065
6	Rate 125	-	-	-	-	-	-	-
7	Rate 135	52,646	-	437	-	-	(14)	423
8	Rate 145	15,714	-	130	-	-	(4)	126
9	Rate 170	323,254	-	2,682	-	-	(87)	2,595
10	Rate 200	188,852	-	1,567	2		(51)	1,516
11	Rate 300	-	-	-	-	-	-	-
12	Total EGD Rate Zone	11,854,769	-	98,355	203,520	3,789	(3,193)	98,952
	Union North Rate Zone							
13	Rate 01	989,005	-	8,205	12,798	238	(266)	8,177
14	Rate 10	324,093	-	2,689	35,299	657	(87)	3,259
15	Rate 20	135,325	248 (2)	1,123	29,227	544	(36)	1,878
16	Rate 25	5,703	-	47	-	-	(2)	46
17	Rate 100	-	-	-	-	-	-	-
18	Total Union North Rate Zone	1,454,125	248	12,064	77,324	1,440	(392)	13,360
	Union South Rate Zone							
19	Rate M1	3,255,132	-	27,007	-	-	(877)	26,130
20	Rate M2	1,319,376	-	10,946	-	-	(355)	10,591
21	Rate M4 (F)	593,661	-	4,925	-	-	(160)	4,766
22	Rate M4 (I)	238	-	2	-	-	()	2
23	Rate M5 (F)	4,406	-	37	-	-	(1)	35
24	Rate M5 (I)	55,087	-	457	-	-	(15)	442
25	Rate M7 (F)	713,738	-	5,922	-	-	(192)	5,729
26	Rate M7 (I)	75,999	-	631	-	-	(20)	610
27	Rate M9	90,073	-	747	-	-	(24)	723
28	Rate T1 (F)	393,754	49 (3)	-	-	-	-	49
29	Rate T1 (I)	37,536	5 (3)	-	-	-	-	5
30	Rate T2 (F)	4,963,881	619 (3)	-	-	-	-	619
31	Rate T2 (I)	41,762	5 (3)	-	-	-	-	5
32	Rate T3	249,200	31 (3)	-	-	-	-	31
33	Total Union South Rate Zone	11,793,844	709	50,674	-	-	(1,645)	49,738
34	Total	25,102,739	957	161,093 (4)	280,843	5,229	(5,229)	162,050

Notes:
(1) Annual throughput volumes excluding unbundled volumes.
(2) Direct assigned based on allocation of transportation demand costs for Rate 20 unbundled storage.
(3) Semi-unbundled allocation in proportion to Union South transportation demand costs per Attachment 1.
(4) Calculated as total classification cost of $162.050 million less semi-unbundled/unbundled cost of $0.957 million per column (b).
(5) Column (c), line 34 total of $161,093 million allocated in proportion to column (a), excluding semi-unbundled.
(6) Column (d) x Western Transportation Premium of 1.8620 cents/m^3.
(7) Western transportation adjustment allocated to all rate classes in proportion to column (c).
(8) Transportation demand allocation factor, TRANS_DEMAND, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 55, updated March 8, 2023.

Derivation of the Load Balancing Transport Allocation Factor

Line No.	Particulars	Total Firm Design Day Demands (1) (10³m³)	Average Day Demands (2) (10³m³/d)	Design Day Storage Requirements (3) (10³m³/d)	Allocation to Semi-Unbundled and Unbundled Services ($000s)	Remaining Allocation to Bundled Rate Classes (7) ($000s)	Load Balancing Transport Allocation Factor (8)
		(a)	(b)	(c) = (a-b)	(d)	(e)	(f) = (d+e)
	EGD Rate Zone						
1	Rate 1	52,737	13,664	39,073	-	55,261	55,261
2	Rate 6	47,062	13,103	33,959	-	48,029	48,029
3	Rate 100	166	75	91	-	129	129
4	Rate 110	5,400	2,919	2,481	-	3,509	3,509
5	Rate 115	1,135	1,043	92	-	129	129
6	Rate 125	-	-	-	-	-	-
7	Rate 135	19	144	-	-	-	-
8	Rate 145	-	-	-	-	-	-
9	Rate 170	-	-	-	-	-	-
10	Rate 200	1,252	516	736	-	1,041	1,041
11	Rate 300	-	-	-	-	-	-
12	Total EGD Rate Zone	107,772	31,464	76,433	-	108,099	108,099
	Union North Rate Zone						
13	Rate 01	9,708	2,702	7,006	-	9,908	9,908
14	Rate 10	2,866	886	1,981	-	2,801	2,801
15	Rate 20	650	370	280	1,799 (4)	396	2,195
16	Rate 25	-	-	-	-	-	-
17	Rate 100	-	-	-	-	-	-
18	Total Union North Rate Zone	13,224	3,957	9,267	1,799	13,106	14,904
	Union South Rate Zone						
19	Rate M1	31,063	8,894	22,169	-	31,354	31,354
20	Rate M2	11,510	3,605	7,905	-	11,180	11,180
21	Rate M4 (F)	4,097	1,622	2,475	-	3,501	3,501
22	Rate M4 (I)	-	-	-	-	-	-
23	Rate M5 (F)	36	12	24	-	34	34
24	Rate M5 (I)	-	-	-	-	-	-
25	Rate M7 (F)	6,060	1,950	4,110	-	5,813	5,813
26	Rate M7 (I)	-	6	-	-	-	-
27	Rate M9	495	246	249	-	352	352
28	Rate T1 (F)	-	-	-	- (5)	-	-
29	Rate T1 (I)	-	-	-	- (5)	-	-
30	Rate T2 (F)	-	-	-	- (5)	-	-
31	Rate T2 (I)	-	-	-	- (5)	-	-
32	Rate T3	-	-	-	- (5)	-	-
33	Total Union South Rate Zone	53,261	16,335	36,932	-	52,233	52,233
34	Total	174,257	51,756	122,631	1,799	173,438 (6)	175,236

Notes:
(1) Excludes semi-unbundled and unbundled firm design day demands.
(2) Firm annual volumes / 366, excluding semi-unbundled and unbundled firm annual volumes.
(3) Zero if negative.
(4) Direct assigned based on allocation of load balancing transport costs for Rate 20 unbundled storage.
(5) Semi-unbundled allocation in proportion to Union South load balancing transport costs per Attachment 1.
(6) Calculated as total classification cost of $175.236 million less semi-unbundled/unbundled cost of $1.799 million per column (d).
(7) Column (e), line 34 total of $173.438 million allocated in proportion to column (c).
(8) Load balancing transport allocation factor, LOAD_BALANCING, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 31, updated March 8, 2023.

Derivation of the Transportation Commodity Allocation Factor

Line No.	Particulars	Annual Volumes (1) (10^3m^3)	Allocation to Semi-Unbundled and Unbundled Services		Remaining Allocation to Bundled Rate Classes (5)		Transportation Commodity Allocation Factor (6)
		(a)	(b)		(c)		(d) = (b+c)
	EGD Rate Zone						
1	Rate 1	5,001,027	-		6,126		6,126
2	Rate 6	4,795,693	-		5,874		5,874
3	Rate 100	27,429	-		34		34
4	Rate 110	1,068,281	-		1,309		1,309
5	Rate 115	381,873	-		468		468
6	Rate 125	-	-		-		-
7	Rate 135	52,646	-		64		64
8	Rate 145	15,714	-		19		19
9	Rate 170	323,254	-		396		396
10	Rate 200	188,852	-		231		231
11	Rate 300	-	-		-		-
12	Total EGD Rate Zone	11,854,769	-		14,521		14,521
	Union North Rate Zone						
13	Rate 01	989,005	-		1,211		1,211
14	Rate 10	324,093	-		397		397
15	Rate 20	135,325	20	(2)	166		185
16	Rate 25	5,703	-		7		7
17	Rate 100	-	-		-		-
18	Total Union North Rate Zone	1,454,125	20		1,781		1,801
	Union South Rate Zone						
19	Rate M1	3,255,132	-		3,987		3,987
20	Rate M2	1,319,376	-		1,616		1,616
21	Rate M4 (F)	593,661	-		727		727
22	Rate M4 (I)	238	-				
23	Rate M5 (F)	4,406	-		5		5
24	Rate M5 (I)	55,087	-		67		67
25	Rate M7 (F)	713,738			874		874
26	Rate M7 (I)	75,999	-		93		93
27	Rate M9	90,073	-		110		110
28	Rate T1 (F)	393,754	7	(3)	-		7
29	Rate T1 (I)	37,536	1	(3)	-		1
30	Rate T2 (F)(1)	4,963,881	84	(3)	-		84
31	Rate T2 (I)	41,762	1	(3)	-		1
32	Rate T3	249,200	4	(3)	-		4
33	Total Union South Rate Zone	11,793,844	96		7,481		7,577
34	Total	25,102,739	115		23,783	(4)	23,899

Notes:
(1) Annual throughput volumes excluding unbundled volumes.
(2) Direct assigned based on allocation of transportation commodity costs for Rate 20 unbundled storage.
(3) Semi-unbundled allocation in proportion to Union South transportation commodity costs per Attachment 1.
(4) Calculated as total classification cost of $23.899 million less semi-unbundled/unbundled cost of $0.115 million per column (b).
(5) Column (c), line 34 total of $23.783 million allocated in proportion to column (a), excluding semi-unbundled.
(6) Transportation commodity allocation factor, TRANS_FUEL, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 57, updated March 8, 2023.

2024 Gas Supply Commodity & System Transportation Costs

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Commodity Purchases (PJ)													
1	Western Canadian Sedimentary Basin	10.5	9.9	10.3	10.4	9.5	10.3	9.3	9.3	9.0	9.7	9.8	10.6	118.7
2	Ontario / Dawn	20.3	23.6	0.0	2.1	4.1	13.3	7.7	0.1	10.9	10.5	10.1	24.2	126.7
3	Appalachia	8.5	8.0	8.5	8.2	8.5	8.2	8.5	8.5	8.2	8.5	8.2	8.5	100.4
4	Chicago	6.1	5.7	6.1	5.9	6.1	5.9	6.1	6.1	5.9	6.1	5.9	6.1	71.4
5	Niagara	6.9	6.4	6.9	6.6	6.9	6.6	6.9	6.9	6.6	6.9	6.6	6.9	80.9
6	U.S. Mid-Continent	1.9	1.7	1.9	1.8	1.9	1.8	1.9	1.9	1.8	1.9	1.8	1.9	22.0
7	Unsecured	2.5	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	7.1
8	Total Commodity Purchases (PJ)	56.6	57.5	33.6	35.0	36.8	46.1	40.3	32.6	42.4	43.5	42.4	60.4	527.2
	Commodity Purchases ($ millions)													
9	Western Canadian Sedimentary Basin	50.4	47.1	43.4	45.6	40.1	43.5	39.5	37.7	37.2	41.3	44.5	50.2	520.4
10	Ontario / Dawn	61.3	56.6	54.3	56.0	55.3	53.1	54.7	54.8	52.6	54.3	55.0	59.4	667.5
11	Appalachia	47.6	43.4	42.2	41.8	41.6	40.6	41.9	40.9	32.1	32.5	39.1	44.1	487.9
12	Chicago	40.0	36.2	31.9	30.2	30.7	29.9	31.1	31.2	29.9	31.2	32.1	36.6	391.1
13	Niagara	37.0	34.1	33.5	32.3	32.9	31.6	32.5	32.5	31.1	32.2	32.9	35.8	398.2
14	U.S. Mid-Continent	11.4	10.3	10.2	8.9	9.0	8.9	9.4	9.4	9.0	9.3	10.6	11.2	117.5
15	Unsecured	14.4	11.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.4	38.6
16	Total Commodity Purchases	262.1	239.5	215.5	214.9	209.7	207.5	209.1	206.4	191.9	201.0	214.0	249.7	2,621.2
	Transportation ($ millions)													
17	TCPL Niagara	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	15.2
18	Great Lakes	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	6.5
19	U.S. Mid-Continent	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	19.4
20	Nova	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	8.2
21	Vector	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	23.7
22	Nexus	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	105.0
23	Total Transportation	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	178.1
24	Total Commodity & Transportation Costs (1)	276.9	254.4	230.4	229.7	224.5	222.3	223.9	221.2	206.7	215.8	228.9	264.5	2,799.3

Note:

(1) Total commodity and transportation costs in column (m) per Exhibit 4, Tab 2, Schedule 1, Attachment 1, page 3, column (c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Preamble:

It is IGUA's understanding that the allocation of upstream transmission/ transportation costs on a volumetric basis is historically justified by a conceptual model in which the upstream transmission facilities are operated at or near 100 percent load factor on an annual basis. IGUA seeks to confirm that condition applies to 2024.

Question(s):

a) For each upstream transmission asset/contract, please define the pipeline, the receipt points, delivery points, capacity retained, annual volumes transmitted, annual load factor and annual cost. Please indicate how the cost for each contract is classified between demand, commodity and load balancing.

b) Please provide supporting workpapers for the derivation of the TRANS_DEMAND allocation factor, with an explanation for volumes included and excluded from the factor, for the current rate classes.

Response:

a) Please see Attachment 1 which provides contract parameters and cost information for all third-party transportation contracts. Attachment 2 provides the cost allocation approach to upstream transportation costs and assumed load factor.

   As provided at Attachment 2, transportation demand costs have been allocated based on average day demands of the specific delivery areas. For example, average day demand in the Union SSMDA is approximately 13 TJ/d[1], or 62% of the contracted capacity from Empress to Union SSMDA. Enbridge Gas has allocated approximately 62% of the total demand cost of the Empress to Union SSMDA contract to transportation and the remaining 38% to load balancing.

b) Please see response at Exhibit I.7.1-IGUA-74 part b) for the derivation of the transportation demand allocation factor, TRANS_DEMAND. Please see Attachment

[1] Attachment 2, column (d), row 4.

2, column (d) for the average day demand used in the derivation of transportation demand costs.

Upstream Transportation Contract Summary

Line No.	Upstream Pipeline / Transportation Service (1)	Primary Receipt Point	Primary Delivery Point	2024 Contract Quantity (GJ/d)	Less: T-Service assignments	2024 System/DP Contract Quantity (GJ/d)	2024 Forecast Unitized Demand Charge ($Cdn/GJ)	Total Demand Costs ($000s)	Total Fuel Costs ($000s)
		(a)	(b)	(c)	(d)	(e) = (c-d)	(f)	(g)	(h)
	TransCanada Pipeline								
	Long Haul								
1	Empress to Union NCDA FT	Empress	Union NCDA	1,412	412	1,000	1.264	462	64
2	Empress to Union EDA FT	Empress	Union EDA	5,089	89	5,000	1.477	2,703	353
3	Empress to Union NDA FT	Empress	Union NDA	4,056	1,971	2,085	1.004	766	123
4	Empress to Union WDA FT	Empress	Union WDA	54,603	-	54,603	0.645	12,881	1,259
5	Empress to Union SSMDA FT	Empress	Union SSMDA	21,643	700	20,943	0.895	6,858	1,037
6	Empress to Union MDA FT	Empress	Union MDA	5,565	-	5,565	0.459	934	49
7	Empress to Union ECDA FT	Empress	Union ECDA	3,000	-	3,000	1.340	1,472	198
8	Empress to Emerson 2 FT	Empress	Emerson 2	21,418	-	21,418	0.486	3,813	-
9	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	265,000	-	265,000	0.927	89,954	-
10	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	260,000	-	260,000	0.370	35,198	18,226
11	NBJ to Enbridge CDA	North Bay Junction	Enbridge CDA	5,000	-	5,000	0.340	622	346
12	Diversions								
13	Empress to Union MDA FT	Union MDA	Parkway	305	-	305	0.865	97	11
14	Empress to Union SSMDA FT	Union SSMDA	Parkway	8,376	-	8,376	0.428	1,312	115
15	Empress to Union WDA FT	Union WDA	Parkway	5,380	-	5,380	0.679	1,337	147
16	Total Long Haul							158,409	21,928
	Short Haul								
17	Parkway to Union EDA FT	Parkway	Union EDA	133,414	14,286	119,128	0.310	13,514	233
18	Parkway to Union EDA FT (EMB)	Parkway	Union EDA	25,000	-	25,000	0.340	3,107	68
19	Parkway to Union NCDA FT	Parkway	Union NCDA	11,783	1,987	9,796	0.227	813	26
20	Parkway to Union NDA FT	Parkway	Union NDA	126,629	16,629	110,000	0.474	19,087	655
21	Dawn to Union CDA FT	Dawn	Union ECDA	8,000	-	8,000	0.277	810	68
22	Niagara to Kirkwall FT	Niagara	Kirkwall	21,101	-	21,101	0.174	1,342	-
23	Kirkwall to Union CDA FT	Kirkwall	Union CDA	135,000	-	135,000	0.116	5,711	362
24	Dawn to CDA FT	Union Dawn	Enbridge CDA	149,818	-	149,818	0.308	16,909	4
25	Dawn to EDA FT	Union Dawn	Enbridge EDA	114,000	-	114,000	0.576	24,047	7
26	Dawn to Iroquois FT	Union Dawn	Iroquois	40,000	-	40,000	0.574	8,400	3
27	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	333,524	-	333,524	0.154	18,784	4
28	Parkway to CDA FT-SN	Union Parkway Belt	Victoria Square #2 CDA	85,000	-	85,000	0.154	4,803	1
29	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	214,114	-	214,114	0.415	32,511	394
30	Niagara Falls to CDA	Niagara Falls	Enbridge Parkway CDA	76,559	-	76,559	0.189	5,284	-
31	Chippawa to CDA	Chippawa	Enbridge Parkway CDA	123,441	-	123,441	0.190	8,592	-
32	Total Short Haul							163,715	1,824
	Storage and Transportation Service Firm Withdrawal/Injections								
33	NCDA	Parkway	Union NCDA	N/A	N/A	N/A	0.000	-	-
34	WDA	Parkway	Union WDA	N/A	N/A	N/A	0.848	978	114
35	SSMDA	Dawn	Union SSMDA	N/A	N/A	N/A	0.000	-	19
36	NDA	Parkway	Union NDA	N/A	N/A	N/A	0.474	8,520	44
37	EDA	Parkway	Union EDA	N/A	N/A	N/A	0.310	2,989	36
38	CDA	Parkway	Enbridge CDA	N/A	N/A	N/A	0.154	15,989	323
39	EDA	Kirkwall	Enbridge EDA	N/A	N/A	N/A	0.415	10,765	3
40	EDA	Parkway	Enbridge EDA	N/A	N/A	N/A	0.415	1,475	37
41	Total Storage and Transportation Service Firm Withdrawal/Injections							40,716	577
42	Total TransCanada Pipeline							362,839	24,329

Upstream Transportation Contract Summary

Line No.	Upstream Pipeline / Transportation Service	Primary Receipt Point	Primary Delivery Point	2024 Contract Quantity (GJ/d)	Less: T-Service assignments	2024 System/DP Contract Quantity (GJ/d)	2024 Forecast Unitized Demand Charge ($Cdn/GJ)	Total Demand Costs ($000s)	Total Fuel Costs ($000s)
		(a)	(b)	(c)	(d)	(e) = (c-d)	(f)	(g)	(h)
	Centra Transmission Holdings Inc.								
43	Centra Transmission Holdings Inc.	Spruce	Union MDA	5,813	-	5,813	0.536	1,141	-
44	Centra Pipelines Minnesota Inc.	Sprague	Baudette	5,813	-	5,813	0.125	266	-
45	Total							1,407	-
	NOVA Transmission								
46	NIT to Empress	NIT	Empress	125,000	-	125,000	0.180	8,222	-
	Panhandle Eastern Pipe Line Company L.P.								
47	PEPL FT	Panhandle Field Zone	Ojibway (Union)	60,138	-	60,138	0.816	17,966	1,455
	Vector Pipelines L.P.								
48	Vector US FT1	Chicago	Cdn/US Interconnect	105,505	-	105,505	0.211	8,129	75
49	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	126,606	-	126,606	0.006	278	-
50	Vector US FT1	Milford Junction	St. Clair	116,056	-	116,056	0.186	7,920	83
51	Vector Canada FT1	St. Clair	Dawn	184,635	-	184,635	0.006	405	-
52	Vector US FT1	Alliance	St. Clair	21,101	-	21,101	0.186	1,440	15
53	Vector US FT1	Northern Border	St. Clair	68,579	-	68,579	0.211	5,284	49
54	Total							23,456	222
	NEXUS Gas Transmission, LLC								
55	NEXUS - FT	Kensington	St. Clair (Union)	158,258	-	158,258	1.041	60,284	84
56	NEXUS - FT	Kensington	Milford Junction	58,028	-	58,028	0.959	20,373	31
57	NEXUS - FT	Clarington	Milford Junction	58,028	-	58,028	1.140	24,205	31
58	Total							104,863	145
	Great Lakes Gas Transmission								
53	GLGT	Emerson	St. Clair	21,101	-	21,101	0.324	2,500	100
	Great Lakes Pipeline Canada Ltd.								
54	Great Lakes Pipeline Canada Ltd.	St. Clair	Union SWDA	21,101	-	21,101	0.015	114	-
	St. Clair Pipelines L.P.								
55	St. Clair Pipelines L.P. (St. Clair Pipeline)	St. Clair/Intl Border	St. Clair/Intl Border	214,000	-	214,000	0.004	287	-
56	St. Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Intl Border	Bluewater/Intl Border	127,000	-	127,000	0.021	998	-
57	Total							1,286	-
	2193914 Canada Inc.								
58	2193914 Canada Inc.	Vaughan	Lisgar	244,265	-	244,265	0.011	2,581	-
59	Total							525,236	26,250

Notes:
(1) Conversion Factors:
DTH to GJ conversion rate: 1.055056 GJ/DTH
Enbridge North Heat Value: 38.86
Exchange rate: $1 USD = $1.274 CAD
(2) Column (c), line 4 has been adjusted to reflect new Empress to WDA capacity starting in November 2023 that was not included in Exhibit 4, Tab 2, Schedule 1, Attachment 3.
(3) Column (c), line 29 has been adjusted to reflect new Parkway to Enbridge EDA capacity starting in November 2022 that was not included in Exhibit 4, Tab 2, Schedule 1, Attachment 3.
(4) Column (c), lines 48 and 53 have been adjusted to reflect a misclassification of capacity between these contracts in Exhibit 4, Tab 2, Schedule 1, Attachment 3.

Upstream Transportation Cost Allocation

Line No.	Upstream Pipeline / Transportation Service (1)	2024 Forecast Unitized Demand Charge ($Cdn/GJ)	Total Demand Costs ($000s)	Total Fuel Costs ($000s)	Average Day Demand (TJ/d)	Load Factor	Demand Costs ($000s) Transportation	Demand Costs ($000s) Load Balancing	Demand Costs ($000s) Gas Supply Commodity	Demand Costs ($000s) Distribution	Fuel Costs ($000s) Transportation Commodity	Fuel Costs ($000s) Gas Supply Commodity	Fuel Costs ($000s) Distribution
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	TransCanada Pipeline												
	Long Haul												
1	Empress to Union NCDA FT	1.264	462	64	1.0	100%	462	-	-	-	64	-	-
2	Empress to Union EDA FT	1.477	2,703	353	2.2	45%	1,212	1,491	-	-	353	-	-
3	Empress to Union NDA FT	1.004	766	123	2.1	100%	766		-	-	123	-	-
4	Empress to Union WDA FT	0.645	12,881	1,259	27.1	50%	6,390	6,491	-	-	1,259	-	-
5	Empress to Union SSMDA FT	0.895	6,858	1,037	12.9	62%	4,234	2,624	-	-	1,037	-	-
6	Empress to Union MDA FT	0.459	934	49	1.6	29%	271	663	-	-	49	-	-
7	Empress to Union ECDA FT	1.340	1,472	198	3.0	100%	1,472	-	-	-	198	-	-
8	Empress to Emerson 2 FT	0.486	3,813	-	21.4	100%	-	-	3,813	-	-	-	-
9	Empress to NBJ FT - NBJ LTFP	0.927	89,954	-	194.1	73%	65,899	24,055	-	-	-	-	-
10	NBJ to Enbridge EDA	0.370	35,198	18,226	189.1	73%	25,605	9,594	-	-	18,226	-	-
11	NBJ to Enbridge CDA	0.340	622	346	5.0	100%	622	-	-	-	346	-	-
12	Diversions												
13	Empress to Union MDA FT	0.865	97	11	N/A	N/A	-	97	-	-	11	-	-
14	Empress to Union SSMDA FT	0.428	1,312	115	N/A	N/A	-	1,312	-	-	115	-	-
15	Empress to Union WDA FT	0.679	1,337	147	N/A	N/A	-	1,337	-	-	147	-	-
16	Total Long Haul		158,409	21,928			106,933	47,662	3,813	-	21,928	-	-
	Short Haul												
17	Parkway to Union EDA FT	0.310	13,514	233	52.1	44%	5,916	7,598	-	-	233	-	-
18	Parkway to Union EDA FT (EMB)	0.340	3,107	68	-	0%	-	3,107	-	-	68	-	-
19	Parkway to Union NCDA FT	0.227	813	26	9.8	100%	813	-	-	-	26	-	-
20	Parkway to Union NDA FT	0.474	19,087	655	45.5	41%	7,892	11,195	-	-	655	-	-
21	Dawn to Union CDA FT	0.277	810	68	N/A	N/A	-	-	-	810	-	-	68
22	Niagara to Kirkwall FT	0.174	1,342	-	21.1	100%	-	-	1,342	-	-	-	-
23	Kirkwall to Union CDA FT	0.116	5,711	362	N/A	N/A	-	-	-	5,711	-	-	362
24	Dawn to CDA FT	0.308	16,909	4	149.8	100%	16,909	-	-	-	4	-	-
25	Dawn to EDA FT	0.576	24,047	7	-	0%	-	24,047	-	-	7	-	-
26	Dawn to Iroquois FT	0.574	8,400	3	-	0%	-	8,400	-	-	3	-	-
27	Parkway to CDA FT	0.154	18,784	4	333.5	100%	18,784	-	-	-	4	-	-
28	Parkway to CDA FT-SN	0.154	4,803	1	85.0	100%	4,803	-	-	-	1	-	-
29	Parkway to EDA FT	0.415	32,511	394	-	0%	-	32,511	-	-	394	-	-
30	Niagara Falls to CDA	0.189	5,284	-	76.6	100%	-	-	5,284	-	-	-	-
31	Chippawa to CDA	0.190	8,592	-	123.4	100%	-	-	8,592	-	-	-	-
32	Total Short Haul		163,715	1,824			55,117	86,858	15,218	6,521	1,394	-	430
	Storage and Transportation Service Firm Withdrawal/Injections												
33	NCDA	-	-	-	N/A	N/A	-	-	-	-	-	-	-
34	WDA	0.848	978	114	N/A	N/A	-	978	-	-	114	-	-
35	SSMDA	-	-	19	N/A	N/A	-	-	-	-	19	-	-
36	NDA	0.474	8,520	44	N/A	N/A	-	8,520	-	-	44	-	-
37	EDA	0.310	2,989	36	N/A	N/A	-	2,989	-	-	36	-	-
38	CDA	0.154	15,989	323	N/A	N/A	-	15,989	-	-	323	-	-
39	EDA	0.415	10,765	3	N/A	N/A	-	10,765	-	-	3	-	-
40	EDA	0.415	1,475	37	N/A	N/A	-	1,475	-	-	37	-	-
41	Total Storage and Transportation Service Firm Withdrawal/Injections		40,716	577			-	40,716	-	-	577	-	-
42	Total TransCanada Pipeline		362,839	24,329			162,050	175,236	19,031	6,521	23,899	-	430

Upstream Transportation Cost Allocation

Line No.	Upstream Pipeline / Transportation Service	2024 Forecast Unitized Demand Charge ($Cdn/GJ)	Total Demand Costs ($000s)	Total Fuel Costs ($000s)	Average Day Demand (TJ/d)	Load Factor	Demand Costs ($000s) Transportation	Demand Costs ($000s) Load Balancing	Demand Costs ($000s) Gas Supply Commodity	Demand Costs ($000s) Distribution	Fuel Costs ($000s) Transportation Commodity	Fuel Costs ($000s) Gas Supply Commodity	Fuel Costs ($000s) Distribution
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Centra Transmission Holdings Inc.												
43	Centra Transmission Holdings Inc.	0.536	1,141	-	N/A	N/A	-	-	-	1,141	-	-	-
44	Centra Pipelines Minnesota Inc.	0.125	266	-	N/A	N/A	-	-	-	266	-	-	-
45	Total		1,407	-			-	-	-	1,407	-	-	-
	NOVA Transmission												
46	NIT to Empress	0.180	8,222	-	125.0	100%	-	-	8,222	-	-	-	-
	Panhandle Eastern Pipe Line Company L.P.												
47	PEPL FT	0.816	17,966	1,455	60.1	100%	-	-	17,966	-	-	1,455	-
	Vector Pipelines L.P.												
48	Vector US FT1	0.211	8,129	75	105.5	100%	-	-	8,129	-	-	75	-
49	Vector Canada FT1	0.006	278	-	126.6	100%	-	-	278	-	-	-	-
50	Vector US FT1	0.186	7,920	83	116.1	100%	-	-	7,920	-	-	83	-
51	Vector Canada FT1	0.006	405	-	184.6	100%	-	-	405	-	-	-	-
52	Vector US FT1	0.186	1,440	15	21.1	100%	-	-	1,440	-	-	15	-
53	Vector US FT1	0.211	5,284	49	68.6	100%	-	-	5,284	-	-	49	-
54	Total		23,456	222			-	-	23,456	-	-	222	-
	NEXUS Gas Transmission, LLC												
55	NEXUS - FT	1.041	60,284	84	158.3	100%	-	-	60,284	-	-	84	-
56	NEXUS - FT	0.959	20,373	31	58.2	100%	-	-	20,373	-	-	31	-
57	NEXUS - FT	1.140	24,205	31	58.2	100%	-	-	24,205	-	-	31	-
58	Total		104,863	145			-	-	104,863	-	-	145	-
	Great Lakes Gas Transmission												
53	GLGT	0.324	2,500	100	21.1	100%	-	-	2,500	-	-	100	-
	Great Lakes Pipeline Canada Ltd.												
54	Great Lakes Pipeline Canada Ltd.	0.015	114	-	21.1	100%	-	-	114	-	-	-	-
	St. Clair Pipelines L.P.												
55	St. Clair Pipelines L.P. (St. Clair Pipeline)	0.004	287	-	N/A	N/A	-	-	-	287	-	-	-
56	St. Clair Pipelines L.P. (Bluewater Pipeline)	0.021	998	-	N/A	N/A	-	-	-	998	-	-	-
57	Total		1,286	-			-	-	-	1,286	-	-	-
	2193914 Canada Inc.												
58	2193914 Canada Inc.	0.011	2,581	-	N/A	N/A	-	-	-	2,581	-	-	-
59	Total		525,236	26,250			162,050	175,236	176,154	11,795	23,899	1,922	430

Notes:
(1) Conversion Factors:
DTH to GJ conversion rate: 1.055056 GJ/DTH
Enbridge North Heat Value: 38.86
Exchange rate: $1 USD = $1.274 CAD

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

7.1.3 Attachment 1, 7.2.1 and 7.3.1, Attachments 5, 9, 10 and 12.

Preamble:

Additional detail regarding classification and allocation of storage costs is requested.

Question(s):

a) Please provide the rationale for derivation of the DEL_SPACE_OPCON classification factor, and provide supporting workpapers.

b) Please explain conceptually how storage costs are segregated between the gas cost revenue requirement and the delivery revenue requirement.

c) Please provide the allocation of operational contingency costs to each service area in the most recent previous cost allocation studies.

d) Please explain how the OP_CONTINGENCY allocation factor is derived, and provide supporting workpapers, for the current rate classes.

e) Re EGI storage demand deliverability at 7.1.3 Attachment 1 page 2, please define the term "design day demands less design day deliveries" for the purposes of allocating these costs.

f) Please provide supporting workpapers for the derivation of the NETFROMSTOR allocation factor, for the current rate classes.

g) Please explain why storage deliverability costs are not allocated based on the difference between design day demands and average day demands.

h) Please provide supporting workpapers for the derivation of the STORAGEEXCESS allocation factor, including monthly volumes by class, for the current rate classes.

i) Please provide workpapers for the development of the STORCOMM allocation factor.

Response:

a) Please see response at Exhibit I.7.1-STAFF-239.

b) Enbridge Gas considers costs from the Gas Supply Plan that are classified to the storage function as the gas cost revenue requirement. Specifically, the costs include unaccounted for gas (UFG), storage-related compressor fuel, company use gas and market-based storage demand and fuel costs. The components of the storage gas cost revenue requirement totaling $34.697 million is provided at Exhibit 7, Tab 2, Schedule 1, Attachment 5, lines 64-68 and line 70.

c) For EGD, the operational contingency requirements were managed operationally through injection and withdrawal targets rather than procuring incremental storage space for operational contingency purposes. As a result, the costs were not separately identified and allocated in EGD's Cost Allocation Study.

   For Union, operational contingency costs, previously referred to as system integrity costs, were separately identified in Union's Cost Allocation Study. Please see Attachment 1 for the allocation of system integrity costs to Union rate classes in 2013.

d) Please see Attachment 2 for the derivation of the operational contingency allocation factor OP_CONTINGENCY.

   Table 1 provides the allocation methodologies for operational contingency components used in the 2024 Cost Allocation Study. The allocation methodologies are consistent with those used by Union in its 2013 Cost Allocation Study[1] for operational contingency, previously referred to as system integrity.

[1] EB-2011-0210.

Table 1
Allocation Methodology of Operational Contingency Components

Line No.	Particulars	Operational Contingency Space (1) (PJ)	Allocation Methodology
		(a)	(b)
1	Forecast Weather Variances	7.9	General service winter volumes
2	System Linepack	1.3	Dawn Parkway distance-weighted design day demand allocator
3	Storage Pool Factors	4.8	1.3 PJ empty space - storage space requirements including operational contingency for in-franchise rate classes
			3.5 PJ filled space - storage space requirements including operational contingency for all rate classes
4	OBA/LBA Imbalances	1.6	Total throughput volumes
5	Total	15.6	

Note:
(1) Exhibit 4, Tab 2, Schedule 4, page 4.

e) The term “design day demands less design day deliveries” refers to the difference between the design day demands and the average day demands for a rate class. Average day demand is calculated by dividing annual throughput volume by numbers of days in a year (366 days in 2024) of a specific rate class. In essence, design day deliveries is the same as average day demands.

Withdrawals from storage are not needed to meet average day demand because gas deliveries arrive daily above ground and are sufficient to meet the average day demands. Withdrawals from storage, or storage deliverability, is required for the utility to meet any demands above the average day demand in excess of the daily gas deliveries.

f) Please see Attachment 3 for the derivation of the storage allocation factor NETFROMSTOR.

g) The allocation of storage deliverability costs to bundled rate classes is based on the difference between design day demands and average day demands. Please see part e). The allocation of storage deliverability costs to semi-unbundled rate classes is based on the forecast of contracted injection/withdrawal rights.

h) Please see Attachment 4 for the derivation of the storage allocation factor STORAGEXCESS.

i) Please see Attachment 5 for the derivation of the storage allocation factor STORCOMM.

Union's 2013 System Integrity Cost Allocation (1)

Line No.	Particulars ($000s)	Union's 2013 System Integrity Revenue Requirement (2)
		(a)
	Union North	
1	Rate 01	3,925
2	Rate 10	1,029
3	Rate 20	276
4	Rate 25	-
5	Rate 100	19
6	Total Union North	5,249
	Union South	
7	Rate M1	1,118
8	Rate M2	377
9	Rate M4	40
10	Rate M5 (F)	1
11	Rate M5 (I)	50
12	Rate M7 (F)	15
13	Rate M7 (I)	
14	Rate M9	6
15	Rate M10	
16	Rate T1 (F)	29
17	Rate T1 (I)	2
18	Rate T2 (F)	199
19	Rate T2 (I)	4
20	Rate T3	32
21	Total Union South	1,873
22	Total In-franchise (line 6 + line 21)	7,122
	Ex-franchise	
23	Excess Utility Storage Space	360
24	Rate C1 (F)	30
25	Rate C1 (I)	133
26	Rate M12	890
27	Rate M13	4
28	Rate M16	9
29	Total Ex-franchise	1,426
30	Total Union (line 22 + line 29)	8,548

Notes:
(1) In Union's Cost Allocation Study, operational contingency was referred to as system integrity.
(2) EB-2011-0210, Exhibit G3, Tab 5, Schedule 10, Updated for OEB Decision.

Operational Contingency Components

Line No.	Particulars	Total (1) (PJ)	Total (1) (10^3m^3) (3)	Filled Space (2) (PJ)	Filled Space (2) (10^3m^3) (3)
		(a)	(b)	(c)	(d)
1	Forecast Weather Variances	7.9	202,149	5.1	130,502
2	System Line Pack	1.3	33,265	1.3	33,265
3	OBA/LBA Imbalances	1.6	40,942	0.9	23,030
4	Storage Pool Factors	4.8	122,825	3.5	89,560
5	Total	15.6	399,181	10.8	276,356

Notes:
(1) Exhibit 4, Tab 2, Schedule 4, page 4.
(2) Filled space of 10.8 PJ per Exhibit 4, Tab 2, Schedule 4, page 7.
(3) Conversion based on heat value of 39.08 $GJ/10^3m^3$.

Derivation of the Operational Contingency Allocation Factor

		Allocator					Allocation					
					Storage Space							
Line No.	Particulars	General Service Winter Volume Allocator (10^3m^3)	Dawn Parkway Transmission Demand Allocation Factor (1)	Total Volume Allocator (10^3m^3)	Storage Space Demand Allocation Factor (2)	Including Operational Contingency Allocations	Forecast Weather Variances (3) (10^3m^3)	System Linepack (4) (10^3m^3)	OBA/LBA Imbalances (5) (10^3m^3)	Storage Pool Factors Empty Space (6) (10^3m^3)	Storage Pool Factors Filled Space (7) (10^3m^3)	Operational Contingency Allocation Factor (8)
		(a)	(b)	(c)	(d)	(e) = (d+f+g+h)	(f)	(g)	(h)	(i)	(j)	(k) = (f+g+h+i+j)
	EGD Rate Zone											
1	Rate 1	3,736,474	7,959	5,001,027	65,278	142,830	66,911	6,410	4,231	10,171	25,889	113,612
2	Rate 6	3,334,402	7,103	4,795,693	52,816	122,305	59,711	5,721	4,057	8,709	22,169	100,367
3	Rate 100	-	25	27,429	209	252	-	20	23	18	46	107
4	Rate 110	-	815	1,068,281	4,459	6,019	-	656	904	429	1,091	3,080
5	Rate 115	-	171	381,873	574	1,035	-	138	323	74	188	722
6	Rate 125	-	-	824,971	-	698	-	-	698	50	127	874
7	Rate 135	-	3	52,646	-	47	-	2	45	3	8	59
8	Rate 145	-	-	15,714	109	122	-	-	13	9	22	44
9	Rate 170	-	-	323,254	492	765	-	-	273	55	139	467
10	Rate 200	-	189	188,852	1,893	2,205	-	152	160	157	400	869
11	Rate 300	-	-	-	-	-	-	-	-	-	-	-
12	Total EGD Rate Zone	7,070,876	16,265	12,679,740	125,830	276,279	126,622	13,100	10,727	19,673	50,077	220,200
	Union North Rate Zone											
13	Rate 01	740,673	1,465	989,005	12,978	28,258	13,264	1,180	837	2,012	5,122	22,415
14	Rate 10	218,660	433	327,974	3,224	7,765	3,916	348	277	553	1,408	6,502
15	Rate 20	-	151	929,101	1,424	2,331	-	121	786	166	422	1,496
16	Rate 25	-	-	126,831	-	107	-	-	107	8	19	134
17	Rate 100	-	-	1,076,378	-	911	-	-	911	65	165	1,140
18	Total Union North Rate Zone	959,333	2,048	3,449,289	17,626	39,373	17,179	1,650	2,918	2,804	7,137	31,687
	Union South Rate Zone											
19	Rate M1	2,396,059	4,688	3,255,132	41,073	90,510	42,908	3,776	2,754	6,445	16,406	72,288
20	Rate M2	862,219	1,737	1,319,376	12,362	30,318	15,440	1,399	1,116	2,159	5,495	25,610
21	Rate M4 (F)	-	618	593,661	2,541	3,541	-	498	502	252	642	1,894
22	Rate M4 (I)	-	-	238	5	6	-	-			1	2
23	Rate M5 (F)	-	5	4,406	10	18	-	4	4	1	3	13
24	Rate M5 (I)	-	-	55,087	-	47	-	-	47	3	8	58
25	Rate M7 (F)	-	915	713,738	3,492	4,832	-	737	604	344	876	2,560
26	Rate M7 (I)	-	-	75,999	363	427	-	-	64	30	77	172
27	Rate M9	-	75	90,073	354	490	-	60	76	35	89	260
28	Rate T1 (F)	-	200	431,289	1,485	2,011	-	161	365	143	364	1,034
29	Rate T1 (I)	-	-	-	-	-	-	-	-	-	-	-
30	Rate T2 (F)	-	2,532	5,005,643	9,403	15,678	-	2,040	4,235	1,116	2,842	10,232
31	Rate T2 (I)	-	-	-	-	-	-	-	-	-	-	-
32	Rate T3	-	251	249,200	3,206	3,619	-	202	211	258	656	1,327
33	Total Union South Rate Zone	3,258,277	11,022	11,793,844	74,294	151,497	58,348	8,878	9,977	10,788	27,460	115,451
34	Total In-Franchise	11,288,487	29,336	27,922,873	217,749	467,149	202,149	23,627	23,622	33,265	84,674	367,338
	Ex-Franchise											
35	Rate 331	-	-	311,157	-	263	-	-	263	-	48	311
36	Rate 332	-	-	2,610,498	-	2,208	-	-	2,208	-	400	2,609
37	Rate C1 (F)	-	194	6,565,587	-	5,711	-	157	5,554	-	1,035	6,746
38	Rate C1 (I)	-	-	1,168,501	-	989	-	-	989	-	179	1,168
39	Rate M12	-	11,736	9,381,880	-	17,389	-	9,452	7,937	-	3,152	20,541
40	Rate M13	-	-	122,598	-	104	-	-	104	-	19	123
41	Rate M16	-	-	278,638	-	236	-	-	236	-	43	278
42	Rate M17	-	36	33,355	-	57	-	29	28	-	10	68
						-						
43	Total Ex-Franchise	-	11,966	20,472,213	-	26,957	-	9,638	17,319	-	4,886	31,843
44	Total	11,288,487	41,302	48,395,086	217,749	494,106	202,149	33,265	40,942	33,265	89,560	399,181

Notes:
(1) Dawn Parkway transmission demand allocator per Exhibit 7, Tab 2, Schedule 1, Attachment 12, page 11, updated March 8, 2023.
(2) Storage space demand allocator per Exhibit 7, Tab 2, Schedule 1, Attachment 12, page 14, updated March 8, 2023.
(3) Page 1, column (b), line 1, allocated in proportion to column (a).
(4) Page 1, column (b), line 2, allocated in proportion to column (b).
(5) Page 1, column (b), line 3, allocated in proportion to column (c).
(6) Page 1, column (b), line 4 minus, page 1, column (d), line 4, allocated in proportion to column (e) infranchise allocation.
(7) Page 1, column (d), line 4, allocated in proportion to column (e).
(8) Operational contingency allocation factor, OP_CONTINGENCY, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 39, updated March 8, 2023.

Derivation of Storage Deliverability Demand Allocation Factor

Line No.	Particulars	Total Firm Design Day Demands (1) ($10^3m^3/d$)	Average Day Demands ($10^3m^3/d$)	Design Day Storage Requirements (3) ($10^3m^3/d$)	Semi-Unbundled/ Unbundled Contracted Injection/Withdrawal Rights ($10^3m^3/d$)	Storage Demand Deliverability Allocation Factor ($10^3m^3/d$)	Storage Deliverability Demand Allocation Factor (TJ) (4)(5)
		(a)	(b)	(c) = (a - b)	(d)	(e) = (c + d)	(f) = (e) x HV
	EGD Rate Zone						
1	Rate 1	52,737	13,664	39,073	-	39,073	1,527
2	Rate 6	47,062	13,103	33,959	-	33,959	1,327
3	Rate 100	166	75	91	-	91	4
4	Rate 110	5,400	2,919	2,481	-	2,481	97
5	Rate 115	1,135	1,043	92	-	92	4
6	Rate 125	-	-	-	-	-	-
7	Rate 135	19	144	-	-	-	-
8	Rate 145	-	-	-	-	-	-
9	Rate 170	-	-	-	-	-	-
10	Rate 200	1,252	516	736	-	736	29
11	Rate 300	-	-	-	-	-	-
12	Total EGD Rate Zone	107,772	31,464	76,433	-	76,433	2,987
	Union North Rate Zone						
13	Rate 01	9,708	2,702	7,006	-	7,006	274
14	Rate 10	2,866	886	1,981	-	1,981	77
15	Rate 20	650	370	280	302	582	23
16	Rate 25	-	-	-	-	-	-
17	Rate 100	-	-	-	-	-	-
18	Total Union North Rate Zone	13,224	3,957	9,267	302	9,568	374
	Union South Rate Zone						
19	Rate M1	31,063	8,894	22,169	-	22,169	866
20	Rate M2	11,510	3,605	7,905	-	7,905	309
21	Rate M4 (F)	4,097	1,622	2,475	-	2,475	97
22	Rate M4 (I)	-	-	-	-	-	-
23	Rate M5 (F)	36	12	24	-	24	1
24	Rate M5 (I)	-	-	-	-	-	-
25	Rate M7 (F)	6,060	1,950	4,110	-	4,110	161
26	Rate M7 (I)	-	6	-	-	-	-
27	Rate M9	495	246	249	-	249	10
28	Rate T1 (F)	-	-	-	865	865	34
29	Rate T1 (I)	-	-	-	-	-	-
30	Rate T2 (F)	-	-	-	5,397	5,397	211
31	Rate T2 (I)	-	-	-	-	-	-
32	Rate T3	-	-	-	1,385	1,385	54
33	Total Union South Rate Zone	53,261	16,335	36,932	7,648	44,580	1,742
34	Total	174,257	51,756	122,631	7,949	130,581	5,103

Notes:
(1) Excludes semi-unbundled and unbundled firm design day demands.
(2) Excludes semi-unbundled and unbundled firm design day demands and interruptible volumes.
(3) Zero if negative.
(4) Conversion based on heat value of 39.08 GJ/10^3m^3.
(5) Storage deliverability demand allocation factor, NETFROMSTOR, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 37, updated March 8, 2023.

Derivation of the Storage Excess Allocation Factor

Line No.	Particulars	Total Winter Throughput Volumes (1) (10^3m^3)	Average Day Demands x 152 Days of Winter (2) (10^3m^3)	Semi-Unbundled/ Unbundled Contracted Storage Space (10^3m^3)	Storage Excess (3) (10^3m^3)	Storage Space Demand Allocation Factor (4) (5) (TJ)
		(a)	(b)	(c)	(d) = (a - b + c)	(e)
	EGD Rate Zone					
1	Rate 1	3,736,474	2,076,929	-	1,659,545	65,278
2	Rate 6	3,334,402	1,991,654	-	1,342,748	52,816
3	Rate 100	16,703	11,391	-	5,312	209
4	Rate 110	557,015	443,658	-	113,357	4,459
5	Rate 115	173,192	158,592	-	14,600	574
6	Rate 125	-	-	-	-	-
7	Rate 135	11,259	21,864	-	-	-
8	Rate 145	9,297	6,526	-	2,771	109
9	Rate 170	146,755	134,247	-	12,507	492
10	Rate 200	126,549	78,430	-	48,119	1,893
11	Rate 300	-	-	-	-	-
12	Total EGD Rate Zone	8,111,646	4,923,292	-	3,198,959	125,830
	Union North Rate Zone					
13	Rate 01	740,673	410,734	-	329,939	12,978
14	Rate 10	216,559	134,596	-	81,963	3,224
15	Rate 20	67,412	56,200	25,143	36,355	1,424
16	Rate 25	2,295	2,368	-	-	-
17	Rate 100	-	-	-	-	-
18	Total Union North Rate Zone	1,026,939	603,899	25,143	448,257	17,626
	Union South Rate Zone					
19	Rate M1	2,396,059	1,351,858	-	1,044,200	41,073
20	Rate M2	862,219	547,938	-	314,281	12,362
21	Rate M4 (F)	311,154	246,548	-	64,606	2,541
22	Rate M4 (I)	238	99	-	139	5
23	Rate M5 (F)	2,086	1,830	-	256	10
24	Rate M5 (I)	20,728	22,878	-	-	-
25	Rate M7 (F)	385,182	296,416	-	88,766	3,492
26	Rate M7 (I)	40,785	31,562	-	9,223	363
27	Rate M9	46,399	37,408	-	8,992	354
28	Rate T1 (F)	-	-	37,989	37,989	1,485
29	Rate T1 (I)	-	-	-	-	-
30	Rate T2 (F)	-	-	240,615	240,615	9,403
31	Rate T2 (I)	-	-	-	-	-
32	Rate T3	-	-	82,037	82,037	3,206
33	Total Union South Rate Zone	4,064,850	2,536,536	360,642	1,891,105	74,294
34	Total In-franchise	13,203,435	8,063,727	385,785	5,538,321	217,749

Notes:
(1) Excludes semi-unbundled and unbundled winter volumes.
(2) Annual throughput excluding semi-unbundled and unbundled / 366 days x 152 days of winter (February 2024 is a leap year).
(3) Zero if negative.
(4) Conversion based on heat value of 39.08 GJ/10^3m^3, adjusted to total storage of 217.7 PJ per Exhibit 4, Tab 2, Schedule 1, page 19, Table 4, column (b), line 10.
(5) Storage space demand allocation factor, STORAGEXCESS, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 47, updated March 8, 2023.

Derivation of Storage Commodity Allocation Factor

Line No.	Particulars	Annual Delivery Volumes (1) (10^3m^3)	Bundled Storage Activity (2) (10^3m^3)	Semi-Unbundled/ Unbundled Storage Activity (10^3m^3/d)	Total Storage Activity (10^3m^3/d)	Storage Commodity Allocation Factor (4) (5)	
		(a)	(b)	(c)	(d) = (b+c)	(e)	
	EGD Rate Zone						
1	Rate 1	5,001,027	2,922,778	-	2,922,778	2,858	
2	Rate 6	4,795,693	2,802,774	-	2,802,774	2,741	
3	Rate 100	27,429	16,031	-	16,031	16	
4	Rate 110	1,068,281	624,341	-	624,341	611	
5	Rate 115	381,873	223,180	-	223,180	218	
6	Rate 125	315,000	-	-	-	-	
7	Rate 135	52,646	30,768	-	30,768	30	
8	Rate 145	15,714	9,184	-	9,184	9	
9	Rate 170	323,254	188,921	-	188,921	185	
10	Rate 200	188,852	110,372	-	110,372	108	
11	Rate 300	-	-	-	-	-	
12	Total EGD Rate Zone	12,169,769	6,928,348	-	6,928,348	6,776	
	Union North Rate Zone (1)						
13	Rate 01	989,005	578,009	-	578,009	565	
14	Rate 10	324,093	189,412	-	189,412	185	
15	Rate 20	135,325	79,089	13,366	92,455	90	
16	Rate 25	5,703	3,333	-	3,333	3	
17	Rate 100	-	-	-	-	-	
18	Total Union North Rate Zone	1,454,125	849,843	13,366	863,209	844	
	Union South Rate Zone						
19	Rate M1	3,255,132	1,902,415	-	1,902,415	1,860	
20	Rate M2	1,319,376	771,090	-	771,090	754	
21	Rate M4 (F)	593,661	346,957	-	346,957	339	
22	Rate M4 (I)	238	139	-	139		
23	Rate M5 (F)	4,406	2,575	-	2,575	3	
24	Rate M5 (I)	55,087	32,195	-	32,195	31	
25	Rate M7 (F)	713,738	417,134	-	417,134	408	
26	Rate M7 (I)	75,999	44,417	-	44,417	43	
27	Rate M9	90,073	52,642	-	52,642	51	
28	Rate T1 (F)	-	-	76,502	76,502	75	
29	Rate T1 (I)	-	-	-	-	-	
30	Rate T2 (F)	-	-	798,320	798,320	781	
31	Rate T2 (I)	-	-	-	-	-	
32	Rate T3	-	-	164,618	164,618	161	
33	Total Union South Rate Zone	6,107,711	3,569,563	1,039,440	4,609,003	4,507	
34	Total	19,731,606	11,347,754	1,052,806	12,400,560	12,127	(3)

Notes:
(1) Excludes semi-unbundled and unbundled annual delivery volumes.
(2) Bundled storage activity of 11,347,754 10^3m^3 allocated in proportion to column (a).
(3) Total storage UFG cost of $12.127 million.
(4) Allocated in proportion to column (d).
(5) Storage commodity allocation factor, STORCOMM, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 49, updated March 8, 2023.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

7.1.4 Section 1.1 paragraphs 9-18; 7.2.1 Attachments; 7.3.1 Attachments

Preamble:

IGUA requests clarification of the proposed cost allocation treatment of the Panhandle transmission system and the St. Clair transmission system.

In previous proceedings EGI (and previously Union Gas) acknowledged an inequity in allocating significant Panhandle System expansion costs to customers served off of the St. Clair System and who do not derive any benefit from the Panhandle System. Previous Union gas proposed cost allocation changes to remedy this inequity, however consideration of those changes was deferred by the OEB to a review of EGI's entire cost allocation methodology. IGUA seeks to understand how EGI's proposal in this proceeding addresses this inequity.

Question(s):

a) Please explain why and how Panhandle/St. Clair costs are segregated between the gas cost revenue requirement and the delivery revenue requirement in 7.2.1 Attachments 9 and 10.

b) Is it generally correct that, under design conditions, the only customers who benefit from the Panhandle and St. Clair systems are those west of Dawn? Please explain your response.

c) Please provide design day demands for customers west of Dawn for each current rate class, split between those served from the Panhandle system and those served from the St. Clair system.

d) Please explain how EGI's proposal eliminates the inequity detailed in the preamble, namely that customers situated on the St. Clair pipeline are being allocated costs associated with the Panhandle System expansion. Please include a quantitative demonstration in your response of how the allocation of Panhandle System expansion costs will change under your proposal.

e) Paragraph 15 of 7.1.4 Section 1.1 appears to indicate that costs are allocated to all in-franchise bundled rate classes based on design day demands. Please explain how design day demands are derived for the bundled rate classes in the PAN-STCLAIR allocator. In particular, please explain why the design day demands in 7.2.1 Attachment 12 generally appear to be approximately 30 percent of class design day demands, except for Union North Rate 20 and Union South rates T1, T2 and T3.

f) Paragraph 14 of 7.1.4 Section 1.1 appears to indicate that the allocation method for Panhandle/St. Clair is based on a single rate zone model. Please reconcile this position with the proposed zone-specific transportation charges for harmonized rates, notably the South zone charge for Rate E24 and the eligibility restrictions for Rate E20.

g) Please provide a version of 7.2.1 Attachment 6 with costs for the Panhandle and St. Clair systems classified separately.

h) Please provide supporting calculations for the derivation of the values shown at 7.1.4 Attachment 1, column (a).

<u>Response:</u>

a) Enbridge Gas considers costs from the Gas Supply Plan that are classified to the Panhandle/St. Clair transmission demand functional classification as the gas cost revenue requirement. Specifically, the costs include the transportation costs associated with the St. Clair and Bluewater pipeline river crossings contracted with St. Clair Pipelines L.P. The costs of the transportation contracts are recovered in distribution rates along with the Panhandle/St. Clair transmission demand delivery revenue requirement. The components of the Panhandle/St. Clair gas cost revenue requirement totaling $1.285 million is provided at Exhibit 7, Tab 2, Schedule 1, Attachment 6, lines 64- 68 and line 70.

   All other utility costs of the Panhandle/St. Clair revenue requirement are considered the delivery revenue requirement. The gas cost revenue requirement is recovered in delivery rates along with the demand delivery revenue requirement.

b) Yes. Under design conditions, in-franchise customers located west of Dawn are served by the Panhandle and St. Clair Systems.

c) Please see Attachment 1. Enbridge Gas has included the westerly peaking in-franchise design day demands for the Panhandle System and St. Clair System. Ex-franchise easterly design day demands have not been included.

d) Enbridge Gas's proposed one rate zone approach to cost allocation eliminates the regional allocation that currently exist in the methodologies used by Union for costs within the same rate zone. Cost allocation methodologies based on regional systems and demands within the same rate zone create inequities. The inequities form between rate classes when investments are made to certain geographic areas within the rate zone depending on the mix of customer rate class demands in the region.

   Enbridge Gas's proposed cost allocation methodology for the Panhandle/St. Clair system allocates costs to all rate classes based on the one rate zone proposal with costs allocated to semi-unbundled and unbundled services based on the design day demands of the South service area. The proposed methodology considers the system wide benefit to customers accessing natural gas regardless of location and recognizes semi-unbundled and unbundled services are dependent upon the Union South transmission system for transportation needs. Allocating costs in the proposed manner also provides the benefit of minimizing rate volatility that could occur with a regional approach to cost allocation when significant investment is required in one region over another.

e) The Panhandle/St. Clair System allocation factor total is based on the design day demands of the South service area. Using the South service area design day demands as the total for the allocation factor allows for the allocation of costs to semi-unbundled services to be in proportion to the design day demands of each semi-unbundled rate class. The remaining factor is allocated to all in-franchise bundled rate classes in proportion to design day demands. Please see Attachment 2 for the derivation of the Panhandle/St. Clair transmission demand allocation factor PAN_STCLAIR.

f) Please see part e) regarding the approach to the allocation of Panhandle/St. Clair costs to semi-unbundled services. Evidence related to harmonized rate classes will be addressed in Phase 2 of the proceeding as noted in Enbridge Gas's February 1, 2023, letter.

g) Please see Attachment 3 for the separation of the Panhandle/St. Clair functional classification revenue requirement into costs related to the Panhandle System and St. Clair System.

h) Please see Attachment 4.

Panhandle System & St. Clair System Design Day Demands

Line No.	Particulars ($10^3m^3/d$)	Design Day Demands Panhandle System	St. Clair System	Total
		(a)	(b)	(c) = (a + b)
	EGD Rate Zone			
1	Rate 1	-	-	-
2	Rate 6	-	-	-
3	Rate 100	-	-	-
4	Rate 110	-	-	-
5	Rate 115	-	-	-
6	Rate 125	-	-	-
7	Rate 135	-	-	-
8	Rate 145	-	-	-
9	Rate 170	-	-	-
10	Rate 200	-	-	-
11	Rate 300	-	-	-
12	Total EGD Rate Zone	-	-	-
	Union North Rate Zone			
13	Rate 01	-	-	-
14	Rate 10	-	-	-
15	Rate 20	-	-	-
16	Rate 25	-	-	-
17	Rate 100	-	-	-
18	Total Union North Rate Zone	-	-	-
	Union South Rate Zone			
19	Rate M1	5,658	875	6,533
20	Rate M2	2,263	315	2,578
21	Rate M4 (F)	2,101	27	2,128
22	Rate M4 (I)	-	-	-
23	Rate M5 (F)	27	-	27
24	Rate M5 (I)	-	-	-
25	Rate M7 (F)	4,619	-	4,619
26	Rate M7 (I)	-	-	-
27	Rate M9	-	-	-
28	Rate T1 (F)	682	101	782
29	Rate T1 (I)	-	-	-
30	Rate T2 (F)	3,724	14,580	18,304
31	Rate T2 (I)	-	-	-
32	Rate T3	-	-	-
33	Total Union South Rate Zone	19,074	15,898	34,971
	Ex-Franchise			
34	Rate 331	-	-	-
35	Rate 332	-	-	-
36	Rate 401	-	-	-
37	Rate M12	-	-	-
38	Rate M13	-	-	-
39	Rate M16	-	-	-
40	Rate M17	-	-	-
41	Rate C1 (F)	-	-	-
42	Rate C1 (I)	-	-	-
43	Total Ex-Franchise	-	-	-
44	Total	19,074	15,898	34,971

Derivation of Panhandle/St.Clair Transmission Demand Allocation Factor

Line No.	Particulars	Total Firm Design Day Demands (1) ($10^3m^3/d$)	Applicable Semi-Unbundled and Unbundled Design Day Demands (2) ($10^3m^3/d$)	Remaining Allocation to Bundled Rate Classes (4) ($10^3m^3/d$)	Panhandle/St. Clair Transmission Demand Allocation Factor (5) ($10^3m^3/d$)
		(a)	(b)	(c)	(d) = (b + c)
	EGD Rate Zone				
1	Rate 1	52,737	-	16,119	16,119
2	Rate 6	47,062	-	14,385	14,385
3	Rate 100	166	-	51	51
4	Rate 110	5,400	-	1,651	1,651
5	Rate 115	1,135	-	347	347
6	Rate 125	-	-	-	-
7	Rate 135	19	-	6	6
8	Rate 145	-	-	-	-
9	Rate 170	-	-	-	-
10	Rate 200	1,252	-	383	383
11	Rate 300	-	-	-	-
12	Total EGD Rate Zone	107,772	-	32,940	32,940
	Union North Rate Zone				
13	Rate 01	9,708	-	2,967	2,967
14	Rate 10	2,866	-	876	876
15	Rate 20	650		199	199
16	Rate 25	-	-	-	-
17	Rate 100	-	-	-	-
18	Total Union North Rate Zone	13,224	-	4,042	4,042
	Union South Rate Zone				
19	Rate M1	31,063	-	9,494	9,494
20	Rate M2	11,510	-	3,518	3,518
21	Rate M4 (F)	4,097	-	1,252	1,252
22	Rate M4 (I)	-	-	-	-
23	Rate M5 (F)	36	-	11	11
24	Rate M5 (I)	-	-	-	-
25	Rate M7 (F)	6,060	-	1,852	1,852
26	Rate M7 (I)	-	-	-	-
27	Rate M9	495	-	151	151
28	Rate T1 (F)	-	2,077	-	2,077
29	Rate T1 (I)	-	-	-	-
30	Rate T2 (F)	-	26,229	-	26,229
31	Rate T2 (I)	-	-	-	-
32	Rate T3	-	2,601	-	2,601
33	Total Union South Rate Zone	53,261	30,906	16,279	47,186
34	Total In-franchise	174,257	30,906	53,261	84,168
	Ex-franchise				
35	Rate 331	-	-	-	-
36	Rate 332	-	-	-	-
37	Rate 401	-	-	-	-
38	Rate M12	-	-	-	-
39	Rate M13	-	-	-	-
40	Rate M16	-	-	-	-
41	Rate M17	-	-	-	-
42	Rate C1 (F)	-	-	-	-
43	Rate C1 (I)	-	-	-	-
44	Total Ex-Franchise	-	-	-	-
45	Total	174,257	30,906	53,261 (3)	84,168

Notes:
(1) Excludes semi-unbundled and unbundled firm design day demands.
(2) Applicable semi-unbundled and unbundled design day demands.
(3) Calculated as total allocation of 84,168 less semi-unbundled/unbundled allocation of 30,906.
(4) Column (c), line 45 total of 53,261 allocated in proportion to column (a).
(5) Panhandle/St. Clair transmission demand allocation factor, PAN_STCLAIR, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14 to 16, line 41, updated March 8, 2023.

Transmission Classification of Panhandle System and St. Clair System Costs

Line No.	Particulars ($000s)	Panhandle/ St. Clair (1)	Panhandle System	St. Clair System
		(a) = (b + c)	(b)	(c)
	Gross Plant			
1	Land	5,431	5,421	11
2	Land Rights	10,103	9,577	525
3	Structures & Improvements	5,042	5,012	30
4	Measuring & Regulating	142,576	139,206	3,370
5	Mains	641,249	633,051	8,198
6	Compressor Equipment	15,004	15,004	-
7	Gas Holders Storage and Equipment	-	-	-
8	Wells and Lines	-	-	-
9	Base Pressure Gas	-	-	-
10	Services	-	-	-
11	Meters & Regulators	-	-	-
12	Customer Stations	-	-	-
13	Linepack	610	582	28
14	Subtotal (sum lines 1 to 13)	820,017	807,854	12,163
15	General Plant	34,234	33,979	254
16	Total Gross Plant (lines 14 + 15)	854,250	384,834	12,417
	Accumulated Depreciation			
17	Land	-	-	-
18	Land Rights	(1,765)	(1,560)	(205)
19	Structures & Improvements	(2,901)	(2,879)	(23)
20	Measuring & Regulating	(30,690)	(28,385)	(2,304)
21	Mains	(82,960)	(77,079)	(5,881)
22	Compressor Equipment	(9,178)	(9,178)	-
23	Gas Holders Storage and Equipment	-	-	-
24	Wells and Lines	-	-	-
25	Base Pressure Gas	-	-	-
26	Services	-	-	-
27	Meters & Regulators	-	-	-
28	Customer Stations	-	-	-
29	Linepack	-	-	-
30	Subtotal (sum line 17 to 29)	(127,495)	(119,082)	(8,412)
31	General Plant	(17,963)	(17,830)	(133)
32	Total Accumulated Depreciation (lines 30 + 31)	(145,458)	(136,912)	(8,546)

Transmission Classification of Panhandle System and St. Clair System Costs (Continued)

Line No.	Particulars ($000s)	Panhandle/ St. Clair (1)	Panhandle System	St. Clair System
		(a) = (b+c)	(b)	(c)
	Net Plant			
33	Land	5,431	5,421	11
34	Land Rights	8,337	8,017	320
35	Structures & Improvements	2,141	2,133	7
36	Measuring & Regulating	111,887	110,821	1,066
37	Mains	558,290	555,972	2,317
38	Compressor Equipment	5,826	5,826	-
39	Gas Holders Storage and Equipment	-	-	-
40	Wells and Lines	-	-	-
41	Base Pressure Gas	-	-	-
42	Services	-	-	-
43	Meters & Regulators	-	-	-
44	Customer Stations	-	-	-
45	Linepack	610	582	28
46	Subtotal (sum lines 33 to 45)	692,522	688,772	3,750
47	General Plant	16,270	16,149	121
48	Total Net Plant (lines 46+47)	708,792	704,921	3,871
	Working Capital			
49	Materials and Supplies	4,842	4,816	26
50	DCB Receivable/(Payable)	(230)	(229)	(1)
51	Customer Security Deposits	(2,724)	(2,709)	(15)
52	Gas in Storage	-	-	-
53	Working Cash Allowance	(6,025)	(5,992)	(33)
54	Subtotal (sum lines 49 to 53)	(4,137)	(4,114)	(22)
55	Total Rate Base (lines 48+54)	704,655	700,807	3,848
56	Percent Return on Rate Base	5.87%	5.87%	5.87%
57	Return on Rate Base (line 55 x line 56)	41,364	41,138	226
	Depreciation Expense			
58	Storage, Transmission, and Distribution	16,402	16,147	255
59	General Plant	3,967	3,938	29
60	Total Depreciation Expense	20,369	20,085	284
	Income & Property Taxes			
61	Income Taxes	5,270	5,241	29
62	Property Taxes	3,474	3,360	114
63	Total Taxes	8,743	8,600	143

Transmission Classification of Panhandle System and St. Clair System Costs (Continued)

Line No.	Particulars ($000s)	Panhandle/ St. Clair (1)	Panhandle System	St. Clair System
		(a) = (b+c)	(b)	(c)
	Operating & Maintenance (O&M) Expenses			
	Cost of Gas			
64	Gas Supply Commodity	-	-	-
65	Compressor Fuel	-	-	-
66	Unaccounted For Gas	-	-	-
67	Company Use Gas	-	-	-
68	Market Based Storage	-	-	-
69	Parkway Delivery Commitment Incentive	-	-	-
70	Other Transportation	1,285	-	1,285
	Storage			
71	Local Storage	-	-	-
72	Supervision	468	468	-
73	Storage Wells & Lines	-	-	-
74	Compressor	361	361	-
75	Measuring & Regulating	-	-	-
76	Dehydration	-	-	-
77	Rents	-	-	-
78	Other Storage	-	-	-
	Transmission			
79	Supervision	598	585	13
80	Lines	51	50	1
81	Compressor	62	62	-
82	Measuring & Regulating	1,215	1,186	29
	Distribution			
83	Supervision	-	-	-
84	Meter & Regulator	-	-	-
85	Service & Equipment on Customer Premise	-	-	-
86	Mains & Services	-	-	-
87	Measuring & Regulating	-	-	-
88	Other Distribution	-	-	-
	General Operating & Engineering			
89	System Operation & Engineering	4,264	4,241	23
	Sales Promotion & Merchandise			
90	Sales Promotion & Supervision	-	-	-
91	Demand Side Management - Program	-	-	-
92	Demand Side Management - Administration	-	-	-
	Distribution Customer Accounting			
93	Supervision	-	-	-
94	Customer Contracts & Orders	-	-	-
95	Meter Reading	-	-	-
96	Customer Billing, Accounting and Bill Delivery	-	-	-
97	Large Volume Customer Care	-	-	-
98	Credit & Collection	-	-	-
99	Uncollectible Accounts	-	-	-
	Administrative & General Expense			
100	Employee Benefits	2,695	2,669	26
101	Administrative & General	3,156	3,126	30
102	Total O&M Expenses (sum lines 64 to 101)	14,155	12,748	1,407
103	Total Revenue Requirement (lines 57+60+63+102)	84,632	82,572	2,060

Transmission Classification of Panhandle System and St. Clair System Costs (Continued)

Line No.	Particulars ($000s)	Panhandle/ St. Clair (1)	Panhandle System	St. Clair System
		(a) = (b+c)	(b)	(c)
	Other Revenue			
104	Direct Purchase Administration	-	-	-
105	DCB/ABC Fee	-	-	-
106	Gas Supply Optimization	-	-	-
107	Late Payment Penalties	-	-	-
108	Customer Accounting Charge	-	-	-
109	Other Income	-	-	-
110	Other Revenue Surcharges	-	-	-
111	Total Other Revenue (sum lines 104 to 110)	-	-	-
112	Total Revenue Requirement Less Other Revenue (line 103 - line 111)	84,632	82,572	2,060

Note:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 6, page 4, column (k), updated March 8, 2023.

Rate Class Impacts of Panhandle/St. Clair Proposed Cost Allocation Methodology

Line No.	Particulars	Current Approved Cost Allocation Methodology: Allocator (1)	Current Approved Cost Allocation Methodology: Allocation ($000s) (2)	Proposed Cost Allocation Methodology: PAN_STCLAIR Allocator (3)	Proposed Cost Allocation Methodology: Allocation ($000s) (4)	Variance
		(a)	(b)	(c)	(d)	(e) = (d - b)
	EGD Rate Zone					
1	Rate 1	4,959	15,529	16,119	16,208	679
2	Rate 6	4,426	13,858	14,385	14,464	606
3	Rate 100	16	49	51	51	2
4	Rate 110	508	1,590	1,651	1,660	70
5	Rate 115	107	334	347	349	15
6	Rate 125	-	-	-	-	-
7	Rate 135	2	6	6	6	
8	Rate 145	-	-	-	-	-
9	Rate 170	-	-	-	-	-
10	Rate 200	118	369	383	385	16
11	Rate 300	-	-	-	-	-
12	Total EGD Rate Zone	10,134	31,734	32,940	33,122	1,388
	Union North Rate Zone					
13	Rate 01	913	2,859	2,967	2,984	125
14	Rate 10	270	844	876	881	37
15	Rate 20	61	191	199	200	8
16	Rate 25	-	-	-	-	-
17	Rate 100	-	-	-	-	-
18	Total Union North Rate Zone	1,244	3,894	4,042	4,064	170
	Union South Rate Zone					
19	Rate M1	2,921	9,147	9,494	9,547	400
20	Rate M2	1,082	3,389	3,518	3,537	148
21	Rate M4 (F)	385	1,206	1,252	1,259	53
22	Rate M4 (I)	-	-	-	-	-
23	Rate M5 (F)	3	11	11	11	
24	Rate M5 (I)	-	-	-	-	-
25	Rate M7 (F)	570	1,785	1,852	1,863	78
26	Rate M7 (I)	-	-	-	-	-
27	Rate M9	47	146	151	152	6
28	Rate T1 (F)	639	2,001	2,077	2,088	87
29	Rate T1 (I)	-	-	-	-	-
30	Rate T2 (F)	8,069	25,268	26,229	26,373	1,105
31	Rate T2 (I)	-	-	-	-	-
32	Rate T3	800	2,506	2,601	2,616	110
33	Total Union South Rate Zone	14,517	45,458	47,186	47,446	1,988
	Ex-Franchise					
34	Rate 331	-	-	-	-	-
35	Rate 332	-	-	-	-	-
36	Rate 401	-	-	-	-	-
37	Rate M12	-	-	-	-	-
38	Rate M13	-	-	-	-	-
39	Rate M16	188	588	-	-	(588)
40	Rate M17	-	-	-	-	-
41	Rate C1 (F)	945	2,959	-	-	(2,959)
42	Rate C1 (I)	-	-	-	-	-
43	Total Ex-Franchise	1,133	3,546	-	-	(3,546)
44	Total	27,027	84,632	84,168	84,632	-

Notes:
(1) Panhandle and St. Clair maximum design capacity, includes direct assignment to ex-franchise.
(2) Allocated using column (a).
(3) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 41, updated March 8, 2023.
(4) Allocated using column (c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

7.1.4 Section 1.4; 7.2.1 Attachments; 7.3.1 Attachments

Preamble:

Clarification regarding the proposed changes to the allocation of the Dawn-Parkway costs is requested.

Question(s):

a) Please describe the specific rationale for the nature of the D-PTRANS allocator and provide supporting calculations for its development. As part of your response:

   i. For bundled in-franchise customers, please specify which customers' demands are and are not included in the allocator.

   ii. For semi-unbundled and unbundled customers, please explain what is meant by the respective service area and indicate which customers' demands are and are not included in the allocator.

b) Please explain why a distance-weighted allocator is appropriate for these costs, in the harmonized cost allocation/rate design framework posited in this application.

c) Please provide supporting calculations for the derivation of the values shown at 7.1.4 Attachment 1, column (d).

Response:

a) Dawn Parkway transmission demand costs are allocated between in-franchise and ex-franchise rate classes in proportion to distance-weighted design day demands, which is also referred to as commodity-kilometres. This cost allocation methodology recognizes that the Dawn Parkway System is designed to meet easterly design day requirements and that the use of the Dawn Parkway System depends on the design day demands and the distance those design day demands are required to be transported on the Dawn Parkway System.

Please see Attachment 1 for the derivation of the Dawn Parkway transmission demand allocation factor D-PTRANS.

i. The Dawn Parkway transmission demand allocation factor includes all bundled in-franchise firm design day demands. The allocation factor excludes the design day demands for bundled in-franchise interruptible and unbundled services.

ii. The allocation to semi-unbundled and unbundled services is determined using the semi-unbundled and unbundled demands in the respective service area in proportion to the total demands of the respective service area. For example, Rate T1 semi-unbundled customers in the Union South service area would get an allocation of costs based on the Rate T1 design day demands in the South service area as a proportion of the total South service area design day demands. The design day demands for semi-unbundled rate classes do not include interruptible design day demands consistent with the bundled in-franchise rate classes. Please see Attachment 1, page 2, column (d) for an illustrative example showing the allocation to semi-unbundled and unbundled services in the derivation of the Dawn Parkway transmission demand allocation factor.

b) The distance weighting component of the Dawn Parkway transmission demand allocation factor is used to determine the in-franchise and ex-franchise allocation of demands using the Dawn Parkway transmission system on design day. The allocation of Dawn Parkway transmission demand costs to in-franchise rate classes is based on design day demands without regard to distance. The distance weighting component to the allocator continues to be an appropriate methodology because it ensures that the ex-franchise rate classes are allocated costs in proportion to their use of the Dawn Parkway System. The ex-franchise rate design also follows the distance weighting allocation so that the rate of each Dawn Parkway service option reflects costs related to the distance traveled on the system, such as Kirkwall to Parkway and Dawn to Parkway service options.

c) Please see Attachment 2.

Calculation of Dawn Parkway Distance-Weighted Design Day Demands

Line No.	Particulars	Design Day Demands ($10^6m^3/d$)	Average Kilometre Post (km)	Distance Weighted Design Day Demands ($(10^6m^3/d)*km$)	
		(a)	(b)	(c) = (a x b)	
1	EGD	82.678	228.056	18,855	
2	Union North	10.280	228.940	2,354	
3	Union South	48.711	166.835	8,127	
4	Total In-franchise	141.670		29,336	
5	Rate M12	60.080	195.337	11,736	
6	Rate C1	0.849	228.940	194	
7	Rate M17	0.227	159.390	36	
8	Total Ex-franchise	61.156		11,966	
9	Total	202.826		41,302	(1)

Note:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, page 11, column (a), line 19, updated March 8, 2023.

Calculation of Dawn Parkway Transmission Demand Allocation Factor

Line No.	Particulars	Total Firm Design Day Demands (1) ($10^3m^3/d$)	Applicable Semi-Unbundled and Unbundled Design Day Demands (2) ($10^3m^3/d$)	Total Design Day Demands ($10^3m^3/d$)	Allocation to Semi-Unbundled and Unbundled Services (($10^3m^3/d$)*km)		Remaining Allocation to Bundled Rate Classes (7) (($10^3m^3/d$)*km)	Dawn Parkway Transmission Demand Allocation Factor (8) (($10^3m^3/d$)*km)	
		(a)	(b)	(c) = (a+b)	(d)		(e)	(f) = (d+e)	
	EGD Rate Zone								
1	Rate 1	52,737	-	52,737	-		7,959	7,959	
2	Rate 6	47,062	-	47,062	-		7,103	7,103	
3	Rate 100	166	-	166	-		25	25	
4	Rate 110	5,400	-	5,400	-		815	815	
5	Rate 115	1,135	-	1,135	-		171	171	
6	Rate 125	-	-	-	-		-	-	
7	Rate 135	19	-	19	-		3	3	
8	Rate 145	-	-	-	-		-	-	
9	Rate 170	-	-	-	-		-	-	
10	Rate 200	1,252	-	1,252	-		189	189	
11	Rate 300	-	-	-	-		-	-	
12	Total EGD Rate Zone	107,772	-	107,772	-		16,265	16,265	
	Union North Rate Zone								
13	Rate 01	9,708	-	9,708	-		1,465	1,465	
14	Rate 10	2,866	-	2,866	-		433	433	
15	Rate 20	650	302	952	53	(3)	98	151	
16	Rate 25	-	-	-	-		-	-	
17	Rate 100	-	-	-	-		-	-	
18	Total Union North Rate Zone	13,224	302	13,526	53		1,996	2,048	
	Union South Rate Zone								
19	Rate M1	31,063	-	31,063	-		4,688	4,688	
20	Rate M2	11,510	-	11,510	-		1,737	1,737	
21	Rate M4 (F)	4,097	-	4,097	-		618	618	
22	Rate M4 (I)	-	-	-	-		-	-	
23	Rate M5 (F)	36	-	36	-		5	5	
24	Rate M5 (I)	-	-	-	-		-	-	
25	Rate M7 (F)	6,060	-	6,060	-		915	915	
26	Rate M7 (I)	-	-	-	-		-	-	
27	Rate M9	495	-	495	-		75	75	
28	Rate T1 (F)	-	2,077	2,077	200	(4)	-	200	
29	Rate T1 (I)	-	-	-	-		-	-	
30	Rate T2 (F)	-	26,229	26,229	2,532	(5)	-	2,532	
31	Rate T2 (I)	-	-	-	-		-	-	
32	Rate T3	-	2,601	2,601	251	(6)	-	251	
33	Total Union South Rate Zone	53,261	30,906	84,168	2,984		8,038	11,022	
34	Total In-franchise	174,257	31,208	205,465	3,037		26,299	29,336	
	Ex-franchise								
35	Rate 331	-	-	-	-		-	-	
36	Rate 332	-	-	-	-		-	-	
37	Rate 401	-	-	-	-		-	-	
38	Rate M12	-	-	-	-		-	11,736	(9)
39	Rate M13	-	-	-	-		-	-	
40	Rate M16	-	-	-	-		-	-	
41	Rate M17	-	-	-	-		-	36	(10)
42	Rate C1 (F)	-	-	-	-		-	194	(11)
43	Rate C1 (I)	-	-	-	-		-	-	
44	Total Ex-Franchise	-	-	-	-		-	11,966	
45	Total	174,257	31,208	205,465	3,037		26,299	41,302	

Notes:
(1) Excludes semi-unbundled and unbundled firm design day demands.
(2) Applicable semi-unbundled and unbundled design day demands for the use of the Dawn Parkway System.
(3) Calculated as (column (b), line 15) / (column (c), line 18) x (page 1, column (c), line 2).
(4) Calculated as (column (b), line 28) / (column (c), line 33) x (page 1, column (c), line 3).
(5) Calculated as (column (b), line 30) / (column (c), line 33) x (page 1, column (c), line 3).
(6) Calculated as (column (b), line 32) / (column (c), line 33) x (page 1, column (c), line 3).
(7) Calculated as (page 1, column (c), line 4) - (column (d), line 45). Allocated using column (a).
(8) Dawn Parkway transmission demand allocation factor, DPTRANS, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11 to 13, line 19, updated March 8, 2023.
(9) Direct assignment from page 1, column (c), line 5.
(10) Direct assignment from page 1, column (c), line 6.
(11) Direct assignment from page 1, column (c), line 5.

Rate Class Impacts of Dawn Parkway Proposed Cost Allocation Methodology

		Allocators			Current Approved Cost Allocation Methodology					
Line No.	Particulars	Dawn Parkway Allocator (1)	Dawn Station Allocator (2)	Parkway Station Allocator (3)	Dawn Parkway Allocation ($000s) (4)	Dawn Station Allocation ($000s) (5)	Parkway Station Allocation ($000s) (6)	PDCI Allocation ($000s) (7)	Operational Contingency ($000s) (8)	Total Allocation ($000s)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i) = (d+e+f+g+h)
	EGD Rate Zone									
1	Rate 1	7,597	35,692	15	43,301	2,089	6,866	4,848	2,045	59,149
2	Rate 6	6,779	31,851	13	38,642	1,864	6,127	4,326	1,807	52,766
3	Rate 100	24	112		136	7	22	15	2	182
4	Rate 110	778	3,655	1	4,434	214	703	496	55	5,903
5	Rate 115	163	768		932	45	148	104	13	1,242
6	Rate 125	-	-	-	-	-	-	-	16	16
7	Rate 135	3	13		15	1	2	2	1	21
8	Rate 145	-	-	-	-	-	-	-	1	1
9	Rate 170	-	-	-	-	-	-	-	8	8
10	Rate 200	180	847		1,028	50	163	115	16	1,371
11	Rate 300	-	-	-	-	-	-	-	-	-
12	Total EGD Rate Zone	15,524	72,938	30	88,489	4,268	14,032	9,907	3,964	120,659
	Union North Rate Zone									
13	Rate 01	1,398	6,570	3	7,971	384	1,264	892	404	10,915
14	Rate 10	413	1,940	1	2,353	114	373	263	117	3,220
15	Rate 20	146	669		833	39	174	93	27	1,166
16	Rate 25	-	-	-	-	-	-	-	2	2
17	Rate 100	-	-	-	-	-	-	-	21	21
18	Total Union North Rate Zone	1,957	9,179	4	11,157	537	1,811	1,249	570	15,325
	Union South Rate Zone									
19	Rate M1	4,475	21,023	9	25,505	1,230	4,044	2,855	1,301	34,937
20	Rate M2	1,658	7,790	3	9,450	456	1,499	1,058	461	12,924
21	Rate M4 (F)	590	2,773	1	3,364	162	533	377	34	4,470
22	Rate M4 (I)	-	-	-	-	-	-	-		
23	Rate M5 (F)	5	24		30	1	5	3		39
24	Rate M5 (I)	-	-	-	-	-	-	-	1	1
25	Rate M7 (F)	873	4,102	2	4,976	240	789	557	46	6,608
26	Rate M7 (I)	-	-	-	-	-	-	-	3	3
27	Rate M9	71	335		406	20	64	45	5	540
28	Rate T1 (F)	164	1,029		936	60	7	105	18	1,126
29	Rate T1 (I)	-	-	-	-	-	-	-	-	-
30	Rate T2 (F)	2,075	12,991		11,829	760	83	1,324	178	14,174
31	Rate T2 (I)	-	-	-	-	-	-	-	-	-
32	Rate T3	206	1,288		1,173	75	8	131	23	1,411
33	Total Union South Rate Zone	10,117	51,354	15	57,670	3,005	7,032	6,456	2,070	76,234
	Ex-Franchise									
34	Rate 331	-	-	-	-	-	-	-	6	6
35	Rate 332	-	-	-	-	-	-	-	47	47
36	Rate 401	-	-	-	-	-	-	-	-	-
37	Rate M12	11,736	79,461	51	66,895	4,650	24,059	-	379	95,982
38	Rate M13	-	-	-	-	-	-	-	2	2
39	Rate M16	-	-	-	-	-	-	-	5	5
40	Rate M17	36	227	-	206	13	-	-	1	221
41	Rate C1 (F)	194	849	1	1,108	50	331	-	122	1,611
42	Rate C1 (I)	-	-	-	-	-	-	-	21	21
43	Total Ex-Franchise	11,966	80,537	52	68,209	4,713	24,390	-	582	97,894
44	Total	39,565	214,008	100	225,525	12,524	47,265	17,612	7,187	310,112

Notes:
(1) Dawn Parkway transmission demand allocation factor, adjusted to exclude design day demands served from Parkway Station.
(2) Dawn Station transmission demand allocation factor, adjusted to exclude design day demands served from Parkway Station.
(3) Parkway Station transmission demand allocation factor, adjusted to include design day demands served from Parkway Station.
(4) Exhibit 7, Tab 2, Schedule 1, Attachment 6, page 3, column (i), line 103 - line 69, updated March 8, 2023. Allocated using column (a).
(5) Exhibit 7, Tab 2, Schedule 1, Attachment 6, page 3, column (f), line 103, updated March 8, 2023. Allocated using column (b).
(6) Exhibit 7, Tab 2, Schedule 1, Attachment 6, page 3, column (h), line 103, updated March 8, 2023. Allocated using column (c).
(7) Exhibit 7, Tab 2, Schedule 1, Attachment 6, page 3, column (i), line 69, updated March 8, 2023. Allocated to in-franchise rate classes only using column (a).
(8) Any adjustments to the Dawn Parkway allocation factor impact the Dawn Parkway portion of the Operational Contingency allocation factor and subsequent allocation.

Rate Class Impacts of Dawn Parkway Proposed Cost Allocation Methodology

		Allocators			Proposed Cost Allocation Methodology						
Line No.	Particulars	Dawn Parkway Allocator (1)	Dawn Station Allocator (2)	Parkway Station Allocator (3)	Dawn Parkway Allocation ($000s) (4)	Dawn Station Allocation ($000s) (5)	Parkway Station Allocation ($000s) (6)	PDCI Allocation ($000s) (7)	Operational Contingency ($000s) (8)	Total Allocation ($000s)	Impact ($000s) (9)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i) = (d+e+f+g+h)	(j)
	EGD Rate Zone										
1	Rate 1	7,959	37,289	14.66	43,460	2,107	6,928	3,394	2,046	57,934	(1,215)
2	Rate 6	7,103	33,277	13.08	38,783	1,880	6,182	3,029	1,807	51,682	(1,084)
3	Rate 100	25	117	0.05	137	7	22	11	2	178	(4)
4	Rate 110	815	3,818	1.50	4,450	216	709	348	55	5,778	(124)
5	Rate 115	171	802	0.32	935	45	149	73	13	1,216	(26)
6	Rate 125	-	-	-	-	-	-	-	16	16	(0)
7	Rate 135	3	13	0.01	16	1	2	1	1	21	(0)
8	Rate 145	-	-	-	-	-	-	-	1	1	(0)
9	Rate 170	-	-	-	-	-	-	-	8	8	(0)
10	Rate 200	189	885	0.35	1,032	50	164	81	16	1,343	(29)
11	Rate 300	-	-	-	-	-	-	-	-	-	-
12	Total EGD Rate Zone	16,265	76,202	29.95	88,813	4,305	14,158	6,936	3,965	118,176	(2,483)
	Union North Rate Zone										
13	Rate 01	1,465	6,864	2.70	8,000	388	1,275	625	404	10,692	(224)
14	Rate 10	433	2,026	0.80	2,362	114	376	184	117	3,154	(66)
15	Rate 20	151	689	0.37	822	39	174	64	27	1,126	(40)
16	Rate 25	-	-	-	-	-	-	-	2	2	(0)
17	Rate 100	-	-	-	-	-	-	-	21	21	(0)
18	Total Union North Rate Zone	2,048	9,580	3.86	11,184	541	1,826	873	571	14,996	(329)
	Union South Rate Zone										
19	Rate M1	4,688	21,964	8.63	25,599	1,241	4,081	1,999	1,302	34,221	(716)
20	Rate M2	1,737	8,138	3.20	9,485	460	1,512	741	461	12,659	(265)
21	Rate M4 (F)	618	2,897	1.14	3,376	164	538	264	34	4,376	(94)
22	Rate M4 (I)	-	-	-	-	-	-	-	0	0	(0)
23	Rate M5 (F)	5	25	0.01	30	1	5	2	0	38	(1)
24	Rate M5 (I)	-	-	-	-	-	-	-	1	1	(0)
25	Rate M7 (F)	915	4,285	1.68	4,994	242	796	390	46	6,469	(140)
26	Rate M7 (I)	-	-	-	-	-	-	-	3	3	(0)
27	Rate M9	75	350	0.14	408	20	65	32	5	529	(11)
28	Rate T1 (F)	200	1,188	-	1,095	67	-	85	19	1,266	140
29	Rate T1 (I)	-	-	-	-	-	-	-	-	-	-
30	Rate T2 (F)	2,532	15,011	-	13,828	848	-	1,080	184	15,941	1,767
31	Rate T2 (I)	-	-	-	-	-	-	-	-	-	-
32	Rate T3	251	1,489	-	1,371	84	-	107	24	1,587	175
33	Total Union South Rate Zone	11,022	55,348	14.80	60,186	3,127	6,997	4,700	2,079	77,089	855
	Ex-Franchise										
34	Rate 331	-	-	-	-	-	-	-	6	6	-
35	Rate 332	-	-	-	-	-	-	-	47	47	-
36	Rate 401	-	-	-	-	-	-	-	-	-	-
37	Rate M12	11,736	79,461	50.68	64,082	4,489	23,956	5,004	370	97,901	1,919
38	Rate M13	-	-	-	-	-	-	-	2	2	-
39	Rate M16	-	-	-	-	-	-	-	5	5	-
40	Rate M17	36	227	-	197	13	-	15	1	227	6
41	Rate C1 (F)	194	849	0.70	1,062	48	329	83	121	1,643	32
42	Rate C1 (I)	-	-	-	-	-	-	-	21	21	-
43	Total Ex-Franchise	11,966	80,537	51.38	65,341	4,550	24,284	5,103	573	99,852	1,957
44	Total	41,302	221,667	100	225,525	12,524	47,265	17,612	17,612	310,112	-

Notes:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 19, updated March 8, 2023.
(2) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 15, updated March 8, 2023.
(3) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 43, updated March 8, 2023.
(4) Allocated using column (a). Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 16, updated March 8, 2023. Sum of column (d) and column (g).
(5) Allocated using column (b). Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 13, updated March 8, 2023.
(6) Allocated using column (c). Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 15, updated March 8, 2023.
(7) Allocated using column (a). Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 16, updated March 8, 2023. Sum of column (d) and column (g).
(8) Any adjustments to the Dawn Parkway allocation factor impact the Dawn Parkway portion of the Operational Contingency allocation factor and subsequent allocation.
(9) Exhibit 7, Tab 1, Schedule 4, Attachment 1, column (d), updated March 8, 2023.

Transmission Classification of Parkway Measurement and Parkway Compression Costs

Line No.	Particulars ($000s)	Parkway Demand (1)	Parkway Measurement	Parkway Compression
		(a) = (b+c)	(b)	(c)
	Gross Plant			
1	Land	30,938	4,960	25,978
2	Land Rights	428	69	359
3	Structures & Improvements	79,367	12,724	66,643
4	Measuring & Regulating	58,892	58,892	-
5	Mains	8,228	1,319	6,909
6	Compressor Equipment	308,461	-	308,461
7	Gas Holders Storage and Equipment	-	-	-
8	Wells and Lines	-	-	-
9	Base Pressure Gas	-	-	-
10	Services	-	-	-
11	Meters & Regulators	-	-	-
12	Customer Stations	-	-	-
13	Linepack	41	7	34
14	Subtotal (sum lines 1 to 13)	486,356	77,970	408,386
15	General Plant	18,324	3,882	14,442
16	Total Gross Plant (lines 14+15)	504,680	81,852	422,828
	Accumulated Depreciation			
17	Land	-	-	-
18	Land Rights	(81)	(10)	(70)
19	Structures & Improvements	(24,564)	(3,182)	(21,382)
20	Measuring & Regulating	(18,616)	(18,616)	-
21	Mains	(1,785)	(231)	(1,554)
22	Compressor Equipment	(125,107)	-	(125,107)
23	Gas Holders Storage and Equipment	-	-	-
24	Wells and Lines	-	-	-
25	Base Pressure Gas	-	-	-
26	Services	-	-	-
27	Meters & Regulators	-	-	-
28	Customer Stations	-	-	-
29	Linepack	-	-	-
30	Subtotal (sum line 17 to 29)	(170,152)	(22,039)	(148,113)
31	General Plant	(9,615)	(2,037)	(7,578)
32	Total Accumulated Depreciation (lines 30+31)	(179,768)	(24,076)	(155,692)

Transmission Classification of Parkway Measurement and Parkway Compression Costs (Continued)

Line No.	Particulars ($000s)	Parkway Demand (1)	Parkway Measurement	Parkway Compression
		(a) = (b+c)	(b)	(c)
	Net Plant			
33	Land	30,938	4,960	25,978
34	Land Rights	347	58	289
35	Structures & Improvements	54,803	9,542	45,261
36	Measuring & Regulating	40,276	40,276	-
37	Mains	6,443	1,088	5,355
38	Compressor Equipment	183,354	-	183,354
39	Gas Holders Storage and Equipment	-	-	-
40	Wells and Lines	-	-	-
41	Base Pressure Gas	-	-	-
42	Services	-	-	-
43	Meters & Regulators	-	-	-
44	Customer Stations	-	-	-
45	Linepack	41	7	34
46	Subtotal (sum lines 33 to 45)	316,203	55,931	260,272
47	General Plant	8,709	1,845	6,864
48	Total Net Plant (lines 46+47)	324,912	57,776	267,136
	Working Capital			
49	Materials and Supplies	2,221	395	1,826
50	DCB Receivable/(Payable)	(105)	(19)	(87)
51	Customer Security Deposits	(1,250)	(222)	(1,027)
52	Gas in Storage	-	-	-
53	Working Cash Allowance	(2,764)	(491)	(2,272)
54	Subtotal (sum lines 49 to 53)	(1,898)	(337)	(1,560)
55	Total Rate Base (lines 48+54)	323,014	57,439	265,576
56	Percent Return on Rate Base	5.87%	5.87%	5.87%
57	Return on Rate Base (line 55 x line 56)	18,961	3,372	15,590
	Depreciation Expense			
58	Storage, Transmission, and Distribution	14,596	2,071	12,525
59	General Plant	2,124	450	1,674
60	Total Depreciation Expense	16,720	2,521	14,199
	Income & Property Taxes			
61	Income Taxes	2,416	430	1,986
62	Property Taxes	1,096	168	928
63	Total Taxes	3,512	597	2,915

Transmission Classification of Parkway Measurement and Parkway Compression Costs (Continued)

Line No.	Particulars ($000s)	Parkway Demand (1)	Parkway Measurement	Parkway Compression
		(a) = (b+c)	(b)	(c)
	Operating & Maintenance (O&M) Expenses			
	Cost of Gas			
64	Gas Supply Commodity	-	-	-
65	Compressor Fuel	-	-	-
66	Unaccounted For Gas	-	-	-
67	Company Use Gas	-	-	-
68	Market Based Storage	-	-	-
69	Parkway Delivery Commitment Incentive	-	-	-
70	Other Transportation	-	-	-
	Storage			
71	Local Storage	-	-	-
72	Supervision	-	-	-
73	Storage Wells & Lines	-	-	-
74	Compressor	-	-	-
75	Measuring & Regulating	-	-	-
76	Dehydration	-	-	-
77	Rents	-	-	-
78	Other Storage	-	-	-
	Transmission			
79	Supervision	800	226	573
80	Lines	1		1
81	Compressor	1,271	-	1,271
82	Measuring & Regulating	502	502	-
	Distribution			
83	Supervision	-	-	-
84	Meter & Regulator	-	-	-
85	Service & Equipment on Customer Premise	-	-	-
86	Mains & Services	-	-	-
87	Measuring & Regulating	-	-	-
88	Other Distribution	-	-	-
	General Operating & Engineering			
89	System Operation & Engineering	1,956	348	1,608
	Sales Promotion & Merchandise			
90	Sales Promotion & Supervision	-	-	-
91	Demand Side Management - Program	-	-	-
92	Demand Side Management - Administration	-	-	-
	Distribution Customer Accounting			
93	Supervision	-	-	-
94	Customer Contracts & Orders	-	-	-
95	Meter Reading	-	-	-
96	Customer Billing, Accounting and Bill Delivery	-	-	-
97	Large Volume Customer Care	-	-	-
98	Credit & Collection	-	-	-
99	Uncollectible Accounts	-	-	-
	Administrative & General Expense			
100	Employee Benefits	1,563	428	1,135
101	Administrative & General	1,979	489	1,491
102	Total O&M Expenses (sum lines 64 to 101)	8,072	1,992	6,080
103	Total Revenue Requirement (lines 57+60+63+102)	47,265	8,482	38,782

Transmission Classification of Parkway Measurement and Parkway Compression Costs (Continued)

Line No.	Particulars ($000s)	Parkway Demand (1) (a) = (b+c)	Parkway Measurement (b)	Parkway Compression (c)
	Other Revenue			
104	Direct Purchase Administration	-	-	-
105	DCB/ABC Fee	-	-	-
106	Gas Supply Optimization	-	-	-
107	Late Payment Penalties	-	-	-
108	Customer Accounting Charge	-	-	-
109	Other Income	-	-	-
110	Other Revenue Surcharges	-	-	-
111	Total Other Revenue (sum lines 104 to 110)	-	-	-
112	Total Revenue Requirement Less Other Revenue (line 103 - line 111)	47,265	8,482	38,782

Note:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 6, page 1, column (h), updated March 8, 2023.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

7.1.4, Section 1.2.

Preamble:

Additional information regarding the allocation of Parkway station costs is requested.

Question(s):

a) Please explain why Parkway station costs for measurement and compression are not separately classified and allocated. Please provide the costs for each function.

b) Please provide supporting calculations for the PKWY_DEMAND allocator, the current rate classes.

c) Are Parkway compression costs allocated to all in-franchise customers based on design day demands, including those west of Parkway? Please explain your response.

d) Please explain how bi-directional design day demands are derived for each rate class, and provide supporting workpapers. Please also explain how demands in opposite directions can both contribute to cost causation on a design day at the Parkway station.

e) Please provide supporting calculations for the derivation of the values shown at 7.1.4, Attachment 1, column (b).

Response:

a) Please see Attachment 1 for the separation of the Parkway Station transmission demand functional classification revenue requirement into costs related to Parkway Station measurement and Parkway Station compression.

Enbridge Gas has not separately classified Parkway Station measurement and compression costs because the proposed allocation factor incorporates both the measurement and compression and provides a reasonable allocation of the two activities at Parkway Station.

b) Please see Attachment 2 for the derivation of the Parkway Station transmission demand allocation factor PKWY_DEMAND.

c) No. Parkway Station compression costs are allocated to all bundled in-franchise rate classes based on design day demands, including the demands west of Parkway consistent with the allocation of costs for one rate zone. Parkway Station compression costs are not allocated to semi-unbundled or unbundled services in the South service area as the South service area does not require the use of Parkway Station.

d) Bi-directional design day demands are derived based on design day inflows and outflows at the Parkway Station. In-franchise demands are based on gas outflows at Parkway from transportation on the Dawn Parkway System. Ex-franchise demands are based on easterly and westerly Dawn Parkway System paths that require Parkway Station. Please see Attachment 2, page 1, column a) for the bi-directional design day demands.

   The use of bi-directional demands to allocate measuring and regulating costs is consistent with the use of the measuring and regulating facilities to meter gas inflows and outflows of the station on design day. The proposal to use bi-directional design day demands for the allocation of Parkway Station measuring and regulating costs is consistent with the OEB Decision on Kirkwall Station measuring and regulating costs in Union's 2014 Rates proceeding[1].

e) Please see Attachment 3.

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[1] EB-2013-0365.

Parkway Station Measuring and Regulating and Compression
Design Day Demands and Gross Plant Costs

Line No.	Particulars (10^3m^3)	Measuring & Regulating (a)	Compression (b)
	In-franchise Design Day Demands		
1	EGD	80,864	45,195
2	Union North	10,280	10,280
3	Union South	-	-
4	Total In-franchise Design Day Demands	91,144	55,475
	Ex-franchise - Easterly Design Day Demands		
5	Kirkwall to Parkway	10,430	10,430
6	Dawn to Parkway (Rate M12)	48,383	48,383
7	Dawn to Parkway (Rate C1)	849	849
8	Total Ex-franchise Easterly Design Day Demands	59,662	59,662
	Ex-franchise - Westerly Design Day Demands		
9	Parkway to Dawn	28,191	-
10	Total Ex-franchise Westerly Design Day Demands	28,191	-
11	Total Ex-franchise Design Day Demands (line 8 + line 10)	87,853	59,662
12	Total Parkway Station Design Day Demands (line 4 + line 11)	178,998	115,137
	Gross Plant Costs ($000s)		
13	Gross Plant Costs (1)	58,892	308,461
14	Percentage (based on line 13)	16.0%	84.0%

Note:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 6, page 1, column (h), line 4 and 6, updated March 8, 2023.

Derivation of Parkway Station Transmission Demand Allocation Factor

Line No.	Particulars	Total Firm Design Day Demands (1) ($10^3m^3/d$)	Applicable Semi-Unbundled and Unbundled Design Day Demands ($10^3m^3/d$)	Total Design Day Demands ($10^3m^3/d$)	Parkway Station Measuring and Regulating: Allocation to Semi-Unbundled Unbundled Bundled Storage	Parkway Station Measuring and Regulating: Remaining Allocation to Bundled Rate Classes (3)	Parkway Station Measuring and Regulating: Parkway Station Measuring & Regulating Allocation Factor (6)	Parkway Station Compression: Allocation to Semi-Unbundled Unbundled Bundled Storage	Parkway Station Compression: Remaining Allocation to Bundled Rate Classes (8)	Parkway Station Compression: Parkway Station Compression Allocation Factor (11)	Parkway Station Transmission Demand Allocation Factor (12)(13)
		(a)	(b)	(c) = (a+b)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	EGD Rate Zone										
1	Rate 1	52,737	-	52,737	-	27,515	15.4%	-	16,720	14.5%	14.66
2	Rate 6	47,062	-	47,062	-	24,554	13.7%	-	14,920	13.0%	13.08
3	Rate 100	166	-	166	-	87	0.0%	-	53	0.0%	.05
4	Rate 110	5,400	-	5,400	-	2,817	1.6%	-	1,712	1.5%	1.50
5	Rate 115	1,135	-	1,135	-	592	0.3%	-	360	0.3%	.32
6	Rate 125	-	-	-	-	-	0.0%	-	-	0.0%	-
7	Rate 135	19	-	19	-	10	0.0%	-	6	0.0%	.01
8	Rate 145	-	-	-	-	-	0.0%	-	-	0.0%	-
9	Rate 170	-	-	-	-	-	0.0%	-	-	0.0%	-
10	Rate 200	1,252	-	1,252	-	653	0.4%	-	397	0.3%	.35
11	Rate 300	-	-	-	-	-	0.0%	-	-	0.0%	-
12	Total EGD Rate Zone	107,772	-	107,772	-	56,228	31.4%	-	34,168	29.7%	29.95
	Union North Rate Zone										
13	Rate 01	9,708	-	9,708	-	5,065	2.8%	-	3,078	2.7%	2.70
14	Rate 10	2,866	-	2,866	-	1,495	0.8%	-	909	0.8%	.80
15	Rate 20	650	302	952	229 (2)	339	0.3%	229 (7)	206	0.4%	.37
16	Rate 25	-	-	-	-	-	0.0%	-	-	0.0%	-
17	Rate 100	-	-	-	-	-	0.0%	-	-	0.0%	-
18	Total Union North Rate Zone	13,224	302	13,526	229	6,899	4.0%	229	4,192	3.8%	3.86
	Union South Rate Zone										
19	Rate M1	31,063	-	31,063	-	16,207	9.1%	-	9,848	8.6%	8.63
20	Rate M2	11,510	-	11,510	-	6,005	3.4%	-	3,649	3.2%	3.20
21	Rate M4 (F)	4,097	-	4,097	-	2,138	1.2%	-	1,299	1.1%	1.14
22	Rate M4 (I)	-	-	-	-	-	0.0%	-	-	0.0%	-
23	Rate M5 (F)	36	-	36	-	19	0.0%	-	11	0.0%	.01
24	Rate M5 (I)	-	-	-	-	-	0.0%	-	-	0.0%	-
25	Rate M7 (F)	6,060	-	6,060	-	3,162	1.8%	-	1,921	1.7%	1.68
26	Rate M7 (I)	-	-	-	-	-	0.0%	-	-	0.0%	-
27	Rate M9	495	-	495	-	258	0.1%	-	157	0.1%	.14
28	Rate T1 (F)	-	2,077	2,077	-	-	0.0%	-	-	0.0%	-
29	Rate T1 (I)	-	-	-	-	-	0.0%	-	-	0.0%	-
30	Rate T2 (F)	-	26,229	26,229	-	-	0.0%	-	-	0.0%	-
31	Rate T2 (I)	-	-	-	-	-	0.0%	-	-	0.0%	-
32	Rate T3	-	2,601	2,601	-	-	0.0%	-	-	0.0%	-
33	Total Union South Rate Zone	53,261	30,906	84,168	-	27,788	15.5%	-	16,886	14.7%	14.80
34	Total In-franchise	174,257	31,208	205,465	229	90,915	50.9%	229	55,246	48.2%	48.62
	Ex-franchise										
35	Rate 331	-	-	-	-	-	0.0%	-	-	0.0%	-
36	Rate 332	-	-	-	-	-	0.0%	-	-	0.0%	-
37	Rate 401	-	-	-	-	-	0.0%	-	-	0.0%	-
38	Rate M12	-	-	-	-	87,004 (4)	48.6%	-	58,813 (9)	51.1%	50.68
39	Rate M13	-	-	-	-	-	0.0%	-	-	0.0%	-
40	Rate M16	-	-	-	-	-	0.0%	-	-	0.0%	-
41	Rate M17	-	-	-	-	-	0.0%	-	-	0.0%	-
42	Rate C1 (F)	-	-	-	-	849 (5)	0.5%	-	849 (10)	0.7%	.70
43	Rate C1 (I)	-	-	-	-	-	0.0%	-	-	0.0%	-
44	Total Ex-Franchise	-	-	-	-	87,853	49.1%	-	59,662	51.8%	51.38
45	Total	174,257	31,208	205,465	229	178,768	100.0%	229	114,908	100.0%	100

Notes:
(1) Excludes semi-unbundled and unbundled firm design day demands.
(2) Calculated as (column (b), line 15) / (column (c), line 18) x (page 1, column (a), line 2).
(3) Direct assignment to ex-franchise. In-franchise allocation calculated as (page 1, column (a), line 4) minus (column (d), line 34), allocated in proportion to column (a).
(4) Direct assignment from page 1, column (a), line 5 + line 6 + line 9.
(5) Direct assignment from page 1, column (a), line 7.
(6) Percentage calculated based on allocated totals in columns (d) and (e).
(7) Calculated as (column (b), line 15) / (column (c), line 18) x (page 1, column (b), line 2).
(8) Direct assignment to ex-franchise. In-franchise allocation calculated as (page 1, column (b), line 4) minus (column (g), line 34), allocated in proportion to column (a).
(9) Direct assignment from page 1, column (b), line 5 + line 6 + line 9.
(10) Direct assignment from page 1, column (b), line 7.
(11) Percentage calculated based on allocated totals in columns (g) and (h).
(12) Calculated as (column (f) x page 1, column (a), line 14) + (column (i) x page 1, column (b), line 14).
(13) Parkway Station transmission demand allocation factor, PKWY DEMAND, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 43, updated March 8, 2023.

Rate Class Impacts of Parkway Station Proposed Cost Allocation Methodology

Line No.	Particulars	Current Approved Cost Allocation Methodology Allocator (1)	Current Approved Cost Allocation Methodology Allocation ($000s) (2)	Proposed Cost Allocation Methodology PKWY_DEMAND Allocator (3)	Proposed Cost Allocation Methodology Allocation ($000s) (4)	Variance
		(a)	(b)	(c)	(d)	(e) = (d - b)
	EGD Rate Zone					
1	Rate 1	7,597	9,075	15	6,928	(2,147)
2	Rate 6	6,779	8,098	13	6,182	(1,916)
3	Rate 100	24	29		22	(7)
4	Rate 110	778	929	2	709	(220)
5	Rate 115	163	195		149	(46)
6	Rate 125	-	-	-	-	-
7	Rate 135	3	3		2	(1)
8	Rate 145	-	-	-	-	-
9	Rate 170	-	-	-	-	-
10	Rate 200	180	215		164	(51)
11	Rate 300	-	-	-	-	-
12	Total EGD Rate Zone	15,524	18,545	30	14,158	(4,388)
	Union North Rate Zone					
13	Rate 01	1,398	1,671	3	1,275	(395)
14	Rate 10	413	493	1	376	(117)
15	Rate 20	146	175		174	()
16	Rate 25	-	-	-	-	-
17	Rate 100	-	-	-	-	-
18	Total Union North Rate Zone	1,957	2,338	4	1,826	(512)
	Union South Rate Zone					
19	Rate M1	4,475	5,345	9	4,081	(1,265)
20	Rate M2	1,658	1,981	3	1,512	(469)
21	Rate M4 (F)	590	705	1	538	(167)
22	Rate M4 (I)	-	-	-	-	-
23	Rate M5 (F)	5	6		5	(1)
24	Rate M5 (I)	-	-	-	-	-
25	Rate M7 (F)	873	1,043	2	796	(247)
26	Rate M7 (I)	-	-	-	-	-
27	Rate M9	71	85		65	(20)
28	Rate T1 (F)	164	196	-	-	(196)
29	Rate T1 (I)	-	-	-	-	-
30	Rate T2 (F)	2,075	2,479	-	-	(2,479)
31	Rate T2 (I)	-	-	-	-	-
32	Rate T3	206	246	-	-	(246)
33	Total Union South Rate Zone	10,117	12,086	15	6,997	(5,089)
	Ex-Franchise					
34	Rate 331	-	-	-	-	-
35	Rate 332	-	-	-	-	-
36	Rate 401	-	-	-	-	-
37	Rate M12	11,736	14,020	51	23,956	9,936
38	Rate M13	-	-	-	-	-
39	Rate M16	-	-	-	-	-
40	Rate M17	36	43	-	-	(43)
41	Rate C1 (F)	194	232	1	329	96
42	Rate C1 (I)	-	-	-	-	-
43	Total Ex-Franchise	11,966	14,295	51	24,284	9,989
44	Total	39,565	47,265	100	47,265	-

Notes:
(1) Dawn Parkway demand transmission allocation, adjusted to include distance credit for volumes obligated at Parkway.
(2) Allocated using column (a).
(3) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 43, updated March 8, 2023.
(4) Allocated using column (c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

7.1.4, Section 1.3.

Preamble:

Clarification regarding allocation of costs for Dawn station is requested.

Question(s):

a) Please explain whether EGI incurs compression costs at Dawn associated with westerly flows under design conditions. If so, please explain why Dawn compression costs are assigned to Dawn Parkway.

b) Please identify the customer demands that are included in the DAWN_DEMAND allocation factor and provide supporting workpapers for the development of the allocator.

c) Please explain why the bi-directional design day demands in the DAWN_DEMAND allocator are about 71 percent of distribution design day demands, except for Union North Rate 20 and Union South rates T1, T2 and T3.

d) Please provide supporting calculations for the derivation of the values shown at 7.1.4 Attachment 1, column (c).

Response:

a) Yes, Enbridge Gas incurs compression costs at Dawn associated with westerly flows under design conditions.

   The transmission compression costs at Dawn that support westerly design day demands are classified to Panhandle/St. Clair transmission demand.

   The transmission compression costs at Dawn that support easterly design day demands are classified to Dawn Parkway transmission demand as proposed in this Application. The classification to Dawn Parkway aligns all the compression related costs for the Dawn Parkway System (Dawn, Lobo, and Bright) and recognizes the cost of compression is necessary to support gas flowing from Dawn using the Dawn Parkway System. Dawn Parkway transmission demand costs are allocated in proportion to the distance weighted design day demands of the Dawn Parkway System and compression costs at Dawn support the distance the gas needs to travel.

b) Please see Attachment 1 for the derivation of the Dawn Station transmission demand allocation factor DAWN_DEMAND. Page 1 summarizes the bi-directional design day demands using the Dawn Station. The design day demands used in the derivation of the allocation factor for in-franchise rate classes are presented on page 2, column (c). The ex-franchise design day demands used in the derivation of the allocation factor for ex-franchise rate classes are presented on page 1, lines 5-13.

c) The Dawn Station transmission demand allocation factor does not represent the bi-directional in-franchise design day demands using the Dawn Station by rate class.

   The summary of the Dawn Station bi-directional in-franchise design day demands by rate zone is provided at Attachment 1, page 1, lines 1-3. The allocation of the Dawn Station design day demands to semi-unbundled and unbundled services is based on the proportion of the total design day demands of the semi-unbundled and unbundled services compared to the South service area. Please see Attachment 1, page 2, column (d). The remaining in-franchise design day demands using Dawn Station are allocated in proportion to total design day demands of the remaining bundled in-franchise rate classes. This results in a common ratio of Dawn Station allocation to total design day demands for bundled rate classes. Please see Attachment 1, page 2, column (e).

d) Please see Attachment 2.

Dawn Station Design Day Demands

Line No.	Particulars (10^3m^3/day)	Dawn Station Design Day Demands
		(a)
	In-franchise	
1	EGD	82,678
2	Union North	10,280
3	Union South	48,171
4	Total In-franchise	141,130
	Ex-franchise - Easterly	
5	Dawn to Kirkwall	1,267
6	Dawn to Parkway (Rate M12)	48,383
7	Dawn to Parkway (Rate C1)	849
8	Rate M17	227
9	Total Ex-franchise - Easterly	50,726
	Ex-Franchise - Westerly	
10	Kirkwall to Dawn	1,620
11	Parkway to Dawn	28,191
12	Total Ex-franchise - Westerly	29,811
13	Total Ex-franchise (line 9 + line 12)	80,537
14	Total (line 4 + line 13)	221,667 (1)

Note:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, page 11, column (a), line 15, updated March 8, 2023.

Calculation of Dawn Station Transmission Demand Allocation Factor

Line No.	Particulars ($10^3m^3/d$)	Total Firm Design Day Demands (1)	Applicable Semi-Unbundled and Unbundled Design Day Demands (2)	Total Design Day Demands	Allocation to Semi-Unbundled and Unbundled Services		Remaining Allocation to Bundled Rate Classes (7)	Dawn Station Transmission Demand Allocation Factor (8)	
		(a)	(b)	(c) = (a+b)	(d)		(e)	(f) = (d + e)	
	EGD Rate Zone								
1	Rate 1	52,737	-	52,737	-		37,289	37,289	
2	Rate 6	47,062	-	47,062	-		33,277	33,277	
3	Rate 100	166	-	166	-		117	117	
4	Rate 110	5,400	-	5,400	-		3,818	3,818	
5	Rate 115	1,135	-	1,135	-		802	802	
6	Rate 125	-	-	-	-		-	-	
7	Rate 135	19	-	19	-		13	13	
8	Rate 145	-	-	-	-		-	-	
9	Rate 170	-	-	-	-		-	-	
10	Rate 200	1,252	-	1,252	-		885	885	
11	Rate 300	-	-	-	-		-	-	
12	Total EGD Rate Zone	107,772	-	107,772	-		76,202	76,202	
	Union North Rate Zone								
13	Rate 01	9,708	-	9,708	-		6,864	6,864	
14	Rate 10	2,866	-	2,866	-		2,026	2,026	
15	Rate 20	650	302	952	229	(3)	459	689	
16	Rate 25	-	-	-	-		-	-	
17	Rate 100	-	-	-	-		-	-	
18	Total Union North Rate Zone	13,224	302	13,526	229		9,350	9,580	
	Union South Rate Zone								
19	Rate M1	31,063	-	31,063	-		21,964	21,964	
20	Rate M2	11,510	-	11,510	-		8,138	8,138	
21	Rate M4 (F)	4,097	-	4,097	-		2,897	2,897	
22	Rate M4 (I)	-	-	-	-		-	-	
23	Rate M5 (F)	36	-	36	-		25	25	
24	Rate M5 (I)	-	-	-	-		-	-	
25	Rate M7 (F)	6,060	-	6,060	-		4,285	4,285	
26	Rate M7 (I)	-	-	-	-		-	-	
27	Rate M9	495	-	495	-		350	350	
28	Rate T1 (F)	-	2,077	2,077	1,188	(4)	-	1,188	
29	Rate T1 (I)	-	-	-	-		-	-	
30	Rate T2 (F)	-	26,229	26,229	15,011	(5)	-	15,011	
31	Rate T2 (I)	-	-	-	-		-	-	
32	Rate T3	-	2,601	2,601	1,489	(6)	-	1,489	
33	Total Union South Rate Zone	53,261	30,906	84,168	17,689		37,659	55,348	
34	Total In-franchise	174,257	31,208	205,465	17,918		123,212	141,130	
	Ex-franchise								
35	Rate 331	-	-	-	-		-	-	
36	Rate 332	-	-	-	-		-	-	
37	Rate 401	-	-	-	-		-	-	
38	Rate M12	-	-	-	-		-	79,461	(9)
39	Rate M13	-	-	-	-		-	-	
40	Rate M16	-	-	-	-		-	-	
41	Rate M17	-	-	-	-		-	227	(10)
42	Rate C1 (F)	-	-	-	-		-	849	(11)
43	Rate C1 (I)	-	-	-	-		-	-	
44	Total Ex-Franchise	-	-	-	-		-	80,537	
45	Total	174,257	31,208	205,465	17,918		123,212	221,667	

Notes:
(1) Excludes semi-unbundled and unbundled design day demands.
(2) Applicable semi-unbundled and unbundled design day demands for the use of the Dawn Station.
(3) Calculated as (column (b), line 15) / (column (c), line 16) x (page 1, column (a), line 2).
(4) Calculated as (column (b), line 28) / (column (c), line 33) x (page 1, column (a), line 3).
(5) Calculated as (column (b), line 30) / (column (c), line 33) x (page 1, column (a), line 3).
(6) Calculated as (column (b), line 32) / (column (c), line 33) x (page 1, column (a), line 3).
(7) Calculated as (page 1, column (a), line 4) - (column (d), line 45). Allocated using column (a).
(8) Dawn Station transmission demand allocation factor, DAWN_DEMAND, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11 to 13, line 15, updated March 8, 2
(9) Direct assignment from page 1, column (c), line 5 + line 6 + line 10 + line 11.
(10) Direct assignment from page 1, column (c), line 8.
(11) Direct assignment from page 1, column (c), line 7.

Rate Class Impacts of Dawn Station Proposed Cost Allocation Methodology

Line No.	Particulars	Allocator		Current Approved Cost Allocation Methodology			Proposed Cost Allocation Methodology			
		DAWN_DEMAND Allocator (1)	DPTRANS Allocator (2)	Dawn Station Allocation ($000s) (3)(5)	Dawn Parkway Allocation ($000s) (4)(5)	Total Allocation	Dawn Station Allocation ($000s) (3)(6)	Dawn Parkway Allocation ($000s) (4)(7)	Total Allocation	Variance (8)
		(a)	(b)	(c)	(d)	(e) = (c + d)	(f)	(g)	(h) = (f + g)	(i) = (h - e)
	EGD Rate Zone									
1	Rate 1	37,289	7,959	8,817	39,167	47,984	2,107	46,854	48,961	977
2	Rate 6	33,277	7,103	7,868	34,953	42,821	1,880	41,812	43,692	872
3	Rate 100	117	25	28	123	151	7	147	154	3
4	Rate 110	3,818	815	903	4,011	4,913	216	4,798	5,013	100
5	Rate 115	802	171	190	843	1,033	45	1,008	1,054	21
6	Rate 125	-	-	-	-	-	-	-	-	-
7	Rate 135	13	3	3	14	17	1	17	17	
8	Rate 145	-	-	-	-	-	-	-	-	-
9	Rate 170	-	-	-	-	-	-	-	-	-
10	Rate 200	885	189	209	930	1,139	50	1,112	1,162	23
11	Rate 300	-	-	-	-	-	-	-	-	-
12	Total EGD Rate Zone	76,202	16,265	18,018	80,041	98,058	4,305	95,749	100,054	1,996
	Union North Rate Zone									
13	Rate 01	6,864	1,465	1,623	7,210	8,833	388	8,625	9,013	180
14	Rate 10	2,026	433	479	2,129	2,608	114	2,546	2,661	53
15	Rate 20	689	151	163	741	904	39	886	925	21
16	Rate 25	-	-	-	-	-	-	-	-	-
17	Rate 100	-	-	-	-	-	-	-	-	-
18	Total Union North Rate Zone	9,580	2,048	2,265	10,080	12,345	541	12,058	12,599	254
	Union South Rate Zone									
19	Rate M1	21,964	4,688	5,193	23,070	28,263	1,241	27,598	28,839	575
20	Rate M2	8,138	1,737	1,924	8,548	10,472	460	10,226	10,686	213
21	Rate M4 (F)	2,897	618	685	3,043	3,728	164	3,640	3,804	76
22	Rate M4 (I)	-	-	-	-	-	-	-	-	-
23	Rate M5 (F)	25	5	6	27	33	1	32	33	1
24	Rate M5 (I)	-	-	-	-	-	-	-	-	-
25	Rate M7 (F)	4,285	915	1,013	4,501	5,514	242	5,384	5,626	112
26	Rate M7 (I)	-	-	-	-	-	-	-	-	-
27	Rate M9	350	75	83	367	450	20	440	459	9
28	Rate T1 (F)	1,188	200	281	987	1,268	67	1,180	1,247	(20)
29	Rate T1 (I)	-	-	-	-	-	-	-	-	-
30	Rate T2 (F)	15,011	2,532	3,549	12,462	16,012	848	14,908	15,756	(255)
31	Rate T2 (I)	-	-	-	-	-	-	-	-	-
32	Rate T3	1,489	251	352	1,236	1,588	84	1,479	1,563	(25)
33	Total Union South Rate Zone	55,348	11,022	13,087	54,241	67,328	3,127	64,887	68,014	685
	Ex-Franchise									
34	Rate 331	-	-	-	-	-	-	-	-	-
35	Rate 332	-	-	-	-	-	-	-	-	-
36	Rate 401	-	-	-	-	-	-	-	-	-
37	Rate M12	79,461	11,736	18,788	57,752	76,540	4,489	69,086	73,576	(2,965)
38	Rate M13	-	-	-	-	-	-	-	-	-
39	Rate M16	-	-	-	-	-	-	-	-	-
40	Rate M17	227	36	54	178	232	13	213	226	(6)
41	Rate C1 (F)	849	194	201	957	1,158	48	1,145	1,193	35
42	Rate C1 (I)	-	-	-	-	-	-	-	-	-
43	Total Ex-Franchise	80,537	11,966	19,043	58,887	77,930	4,550	70,444	74,994	(2,936)
44	Total	221,667	41,302	52,412	203,249	255,661	12,524	243,137	255,661	-

Notes:

(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 15, updated March 8, 2023.
(2) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 19, updated March 8, 2023.
(3) Allocated using column (a).
(4) Allocated using column (b).
(5) Totals excludes shift of Dawn Station related compressor costs to Dawn Parkway and Dawn Parkway related measuring and regulating costs to Dawn Station.
(6) Total per Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 13, updated March 8, 2023.
(7) Total per Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 16, updated March 8, 2023.
(8) Exhibit 7, Tab 1, Schedule 4, Attachment 1, page 1, column (c), updated March 8, 2023.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

7.1.3 Attachment 1, Distribution Demand, Line No. 1; 7.2.1 Attachments; 7.3.1 Attachments

Preamble:

Costs for high pressure mains over 4” represent a significant cost to IGUA’s members in the proposed cost allocation studies. EGI’s proposed method for allocating these costs appears to be based on design day demands for customers taking service at distribution pressure. No attempt appears to be made to directly assign these costs to large customers who are sole use or who rely only on relatively short mains.

Question(s):

a) For the most recent cost allocation study for Union North, please provide the net book cost for mains over 4” split between sole use, joint use and grid categories. Please also provide the mains cost allocation details.

b) For the most recent cost allocation study for Union South, please provide the net book cost for mains over 4” categorized as other transmission and distribution. Please also provide the allocation of the costs for these mains to Union South customers.

c) For each of the current rate classes, please provide the number of customers and design day demand for customers taking service directly from high pressure mains over 4” for each class.

d) Please provide supporting detail and workpapers for deriving the ZERO_INT classification factor at 7.2.1 Attachment 7 and 7.3.1 Attachment 7.

e) Please provide supporting detail for the derivation of the HIGHPRESS>4 allocator, at 7.2.1 Attachment 12 and at 7.3.1 Attachment 12.

f) For each customer that will be eligible to take service under harmonized rate E20, E22 or E24, please provide the mains distance in metres/kilometres between the customer’s location and the transmission gate station.

g) Please also provide total kilometres of high-pressure mains over 4” for each current service area.

h) Reference 7.1.3 Attachment 1. Please explain whether the allocation of mains costs to sole use customers in the Union North zone represented all mains costs for those customers, or whether those customers’ loads were included in the allocation factor for joint use mains. Please also explain why that approach was not retained and expanded to other zones in the proposed cost allocation study.

Response:

a) Please see Attachment 1 for the allocation to Union North rate classes of the rate base for Union North sole use and joint use mains greater than 4” in diameter from Union’s 2013 Cost Allocation Study. Union’s 2013 rate base for sole use and joint use mains was $20.5 million and $75.4 million, respectively. There were no grid use mains greater than 4” in diameter in Union’s 2013 Rate Base.

b) Please see Attachment 2 for the allocation to Union South rate classes of the rate base for Union South distribution and other transmission mains greater than 4” in diameter from Union’s 2013 Cost Allocation Study. Union’s 2013 Rate Base for distribution and transmission mains was $191.7 million and $143.0 million, respectively. For purposes of this response, Enbridge Gas has included all mains classified as distribution demand and other transmission demand because the diameter size detail from 2013 was not used in the Cost Allocation Study and would be difficult to recreate at this time.

c) Please see Attachment 3.

d) Please see Attachment 4.

e) The high pressure >4” main allocation factor represents total in-franchise design day demands. Please see response at Exhibit I.7.1-IGUA-82 part e).

f) This evidence will be addressed in Phase 2 of the proceeding as noted in Enbridge Gas’s February 1, 2023 letter.

g) Please see Table 1.

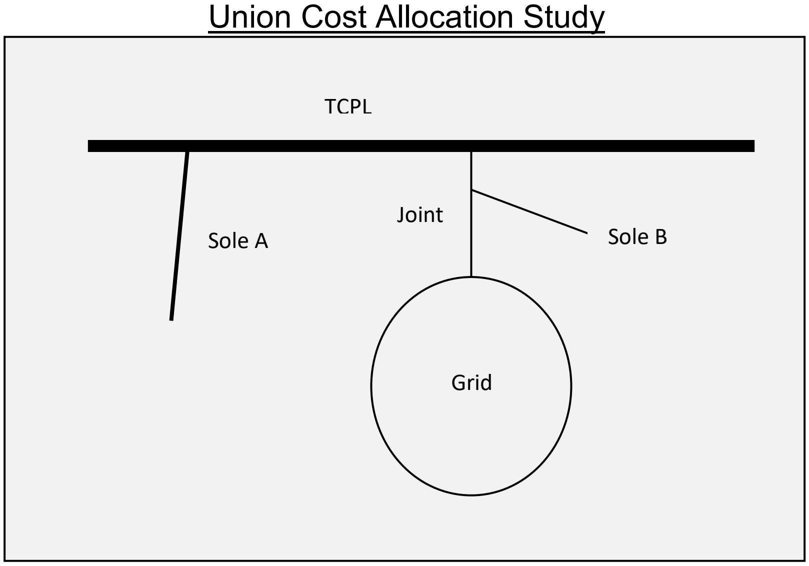
Table 1
Kilometres of High Pressure Distribution Mains >4”

Line No.	Rate Zone	High Pressure Mains >4” (km)
		(a)
1	EGD	1,903
2	Union North	745
3	Union South	956
4	Total	3,604

h) Union’s allocation methodology for distribution mains for Union North did include certain joint use mains costs in allocation to sole use mains customers.

The Union Cost Allocation Study consisted of three categories of distribution mains in Union North, specifically sole use, joint use and grid use. Please see Figure 1.

Figure 1: Categories of Union North Distribution Mains
Union Cost Allocation Study



The sole use category of distribution mains was broken down into two types of sole use mains. The first type of sole use main included assets directly off the TransCanada mainline used to serve a specific customer (Sole A in Figure 1). The second type of sole use main included assets used to serve a specific customer through joint use mains directly off the TransCanada mainline (Sole B in Figure 1). The allocation factor for sole use mains allocated the costs of sole use mains to Union North rate classes in proportion to the demands of sole use customers.

The joint use category of distribution mains included assets served directly off the TransCanada Mainline that support both grid use mains and sole use mains not directly connected to the TransCanada Mainline (Sole B in Figure 1). The allocation factor for joint use mains allocated the costs of joint use mains to Union North rate classes in proportion to system peak and average day demands excluding customers who are entirely sole use.

In the 2024 Cost Allocation Study, Enbridge Gas is proposing to classify distribution mains into three categories: high pressure > 4” in diameter, high pressure <= 4” in diameter and low pressure mains. The allocation factors for these three categories are based on the design day demands that utilize each category of distribution main. Rate classes with large volume customers who are served by large diameter, high pressure distribution mains will get an allocation of costs related to high pressure, high diameter mains and less proportion of low pressure mains relative to the mix of customers in the rate class. The proposed methodology is similar to the Union’s approach for Union North in that it allocates costs based on use of the assets. Please also see response at Exhibit I.7.1-FRPO-180.

Allocation of Rate Base for Union North Sole Use and Joint Use Mains > 4" in Diameter
Union 2013 Cost Allocation Study

		Sole Use Mains > 4"		Joint Use Mains > 4"			
Line No.	Particulars	Allocation Factor (1) (%)	Rate Base Allocation (2) ($000s)	Allocation Factor (3) (%)	Rate Base Allocation (4) ($000s)	Allocation of Mains > 4" in Diameter ($000s)	Percent Allocation (%)
		(a)	(b)	(c)	(d)	(e) = (b+d)	(f)
	Union North Rate Zone						
1	Rate 01	0.0%	-	37.3%	28,109	28,109	29.3%
2	Rate 10	0.0%	-	11.9%	8,970	8,970	9.4%
3	Rate 20	56.2%	11,564	20.6%	15,509	27,073	28.2%
4	Rate 25	20.0%	4,112	5.2%	3,920	8,033	8.4%
5	Rate 100	23.8%	4,897	25.0%	18,842	23,739	24.7%
6	Total Union North Rate Zone	100.0%	20,573	100.0%	75,350	95,923	100.0%

Notes:
(1) EB-2011-0210, Exhibit G3, Tab 5, Schedule 21, page 18, MAINS-SOLE%, updated for Board Decision.
(2) Allocated in proportion to column (a).
(3) EB-2011-0210, Exhibit G3, Tab 5, Schedule 21, page 18, PK&AVG-SOLE%, updated for Board Decision.
(4) Allocated in proportion to column (c).

Allocation of Rate Base for Union South Distribution and Other Transmission Mains > 4" in Diameter
Union 2013 Cost Allocation Study

Line No.	Particulars	Distribution Mains > 4" Allocation Factor (1) (%)	Distribution Mains > 4" Rate Base Allocation (2) ($000s)	Other Transmission Mains > 4" Allocation Factor (3) (%)	Other Transmission Mains > 4" Rate Base Allocation (4) ($000s)	Allocation of Mains > 4" in Diameter ($000s)	Percent Allocation (%)
		(a)	(b)	(c)	(d)	(e) = (b+d)	(f)
	Union South Rate Zone						
1	Rate M1	58.2%	111,662	42.4%	60,638	172,300	51.5%
2	Rate M2	19.6%	37,514	14.2%	20,372	57,886	17.3%
3	Rate M4	5.5%	10,602	4.6%	6,572	17,174	5.1%
4	Rate M5	7.7%	14,793	0.1%	107	14,899	4.5%
5	Rate M7	1.2%	2,275	1.7%	2,381	4,655	1.4%
6	Rate M9	0.0%	-	0.5%	765	765	0.2%
7	Rate M10	0.0%	-	0.0%	23	23	0.0%
8	Rate T1	3.8%	7,213	3.9%	5,603	12,817	3.8%
9	Rate T2	4.0%	7,666	28.8%	41,252	48,917	14.6%
10	Rate T3	0.0%	-	3.7%	5,300	5,300	1.6%
11	Total Union South Rate Zone	100.0%	191,724	100.0%	143,013	334,737	100.0%

Notes:
(1) EB-2011-0210, Exhibit G3, Tab 5, Schedule 21, pages 10-11, DISTDEMAND%, updated for Board Decision.
(2) Allocated in proportion to column (a).
(3) EB-2011-0210, Exhibit G3, Tab 5, Schedule 21, pages 10-11, OTHERTRANS%, updated for Board Decision.
(4) Allocated in proportion to column (c).

Contract Customers Directly Connected to
High Pressure Distribution Mains >4"

Line No.	Particulars	Number of Customers	Design Day Demand (10^3m^3/day)
		(a)	(b)
	EGD Rate Zone		
1	Rate 100	3	13
2	Rate 110	93	2,120
3	Rate 115	14	1,016
4	Rate 125	4	9,260
5	Rate 135	14	6
6	Rate 145 (1)	-	-
7	Rate 170 (1)	-	-
8	Rate 200	1	1,252
9	Rate 300	-	-
10	Total EGD Rate Zone	129	13,667
	Union North Rate Zone		
11	Rate 20	31	6,829
12	Rate 25 (1)		-
13	Rate 100	11	3,267
14	Total Union North Rate Zone	42	10,095
	Union South Rate Zone		
15	Rate M4 (1)	36	849
16	Rate M5 (1)	-	-
17	Rate M7 (1)	28	2,905
18	Rate M9	2	279
19	Rate T1 (1)	10	650
20	Rate T2 (1)	22	25,780
21	Rate T3	1	2,601
22	Total Union South Rate Zone	99	33,065
23	Rate M17	1	227
24	Total	541	113,882

Note:
(1) Excludes customer count and design day demands of interruptible customers.

Average Cost per Metre by Pipe Diameter
as at December 31, 2021

Line No.	Pipe Diametre (inches)	Average Cost Per Metre ($)
	(a)	(b)
1	0.50	55.97
2	0.75	38.21
3	1.00	11.88
4	1.25	40.61
5	1.50	35.72
6	2.00	49.44
7	3.00	31.92
8	4.00	105.92
9	6.00	174.07
10	8.00	208.04
11	10.00	241.93
12	12.00	420.38
13	14.00	364.44
14	16.00	199.03
15	20.00	168.47

Zero-Intercept Classification Factor
as at December 31, 2021

Line No.	Particulars	Cost
		(a)
1	Zero-intercept value ($/metre) (1)	44.798
2	Low pressure distribution mains length (km)	65,371
3	Total customer-related mains cost ($000s)	2,928,488
	Zero-Intercept Classification Factor	
	Distribution Demand Mains ($000s)	
4	High-Pressure > 4"	1,775,393
5	High-Pressure <= 4"	339,570
6	Low Pressure (2)	3,465,983
7	Distribution Customer Mains ($000s) (line 3)	2,928,488
8	Total ($000s)	8,509,433

Notes:

(1) The pipe diametre and average cost per metre information from Attachment 1, page 1 results in the following best fit line regression equation:
$y = 14.741x + 44.798$; $R^2 = 0.5447$.
where 44.798 is the cost per metre at the y intercept.

(2) Cost of low pressure distribution mains is classified between distribution demand low pressure and distribution customer mains.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Preamble:

A significant share of distribution and transmission costs are allocated using some measure of design day demand. IGUA requests a primer on how those demand allocators are derived, and when the methods were approved by the Board.

Question(s):

a) Please detail the methodology used to develop design day demands in each of the current service areas, and when those methods were approved by the Board. Please distinguish between general service and contract service.

b) Please specify any differences in defining design day demands across the current service areas and explain how they were reconciled in the current proposal.

c) Please indicate how design day demand conditions are derived, how frequently they are updated, and when they were approved by the Board.

d) Where design day demands for interruptible customers are included in allocation factors, please specify how those demands are derived and the basis for that approach.

e) Please provide supporting workpapers for the development of each design day demand allocator, including but not limited to ALBIONTRANS, DAWN_DEMAND, HIGHPRESS>4, HIGHPRESS<4, KIRKWALL_DEMAND, LOWPRESS, PAN_STCLAIR, and PKWY_DEMAND.

Response:

a) The proposed method to determine design day demand is provided at Exhibit 4, Tab 2, Schedule 3, Section 4.3, paragraphs 50 to 57. The design day demand process is summarized in paragraph 51 and includes details related to general service and contract rate customers in items g) and h). This method can provide design day demand for each contract rate customer. Exhibit 4, Tab 2, Schedule 3, paragraph 52 explains the benefits of using the previous winter's data. Using the previous winter's data ensures the most recent information is being incorporated into the design day demand. Recent trends, which would include energy transition, IRPAs and DSM activity, will be included in the design day calculation. Exhibit 4, Tab 2, Schedule 3, paragraph 53 explains that the design day demand methodology has been used by Union successfully for more than 40 years.

Exhibit 4, Tab 2, Schedule 3, Figures 2 to 5 show how well the existing methodology can predict the forecast winter's demand as stated in Exhibit 4, Tab 2, Schedule 3, paragraph 56.

> Of note, the results from Winter 2018/2019 are shown in Figures 2 and 4. January 30, 2019, was a 43.0 HDDw (the third highest recorded) compared to the existing design day HDDw of 43.1 for London weather station. The actual consumption on that day was 59,125 10^3m^3/day compared to the forecast design day demand of 59,020 10^3m^3/day. The design day demand on that day was 102% of the forecast demand. This method is used to develop the design day demands for the South and North rate zones for the transmission system, storage system and gas supply plan.

As stated in Exhibit 4, Tab 2, Schedule 3, paragraph 9.

> The proposed methods for determining design criteria and design demands have been accepted by the OEB in prior applications. The set temperature method has been used in the Union North rate zone for over 40 years and has been used in the Union South rate zone since 2013.

In Exhibit 4, Tab 2, Schedule 3, paragraph 28.

> In its 2012 ESM proceeding, Union responded to an OEB-directive to provide an expert and independent review of its Gas Supply Plan, its gas supply planning process, and gas supply planning methodology. As part of meeting that directive Union filed a report authored by Sussex Energy Advisors (Sussex Report) which addressed Union's Gas Supply Plan and the processes and methodologies (including the design criteria and design demands) used to develop the Gas Supply Plan. The Sussex Report found that the set temperature approach was appropriate and similar to the design criteria used by other gas distribution utilities. The Sussex Report recommended minor changes to Union's design criteria. The OEB indicated that it was appropriate for Union to adopt the recommendations made in the Sussex Report.

The EGD and Union distribution systems currently use near identical methodologies to determine the design hour demand. The proposed method to determine design hour demand is detailed in Exhibit 4, Tab 2, Schedule 3, Section 4.3, paragraphs 58 to 61.

> The existing EGD and Union methods for design hour are almost identical to each other and, as such, there is very little to harmonize. The Union method has two additional steps incorporated into the harmonized method above as items (g) and (h), of paragraph 59, that refine the results and are included in the proposed harmonized method. The proposed design hour demand method is harmonized with the design day demand method as the design hour demand is adjusted to align with the design day demand in step (g). This step results in the distribution, transmission, storage and Gas Supply Plan being aligned and harmonized.

As stated in Exhibit 4, Tab 2, Schedule 3, paragraph 6.

> The EGD method was specifically designed for gas supply planning functions, which was to support contracting for space on upstream transportation systems. EGD did not have transmission systems to transport its gas commodity to the utility and as such the risk was placed on the supply points where spot gas could be acquired to mitigate shortfalls on the one in five-year recurrence level. To prevent distribution system failures, a condition that is unacceptable to its customers, EGD also included engineering assumptions that further reduced the risk of not meeting the design day demand. As an amalgamated utility, this approach is not appropriate for integrated transmission, distribution, and storage assets. Design demands need to be granular and aligned to actual observed customer behaviour and very cold weather.

The EGD method is detailed in the 5 Year Gas Supply Plan[1] from page 36 and 37. This method was OEB-approved as part of EGD's 2013 Cost of Service Application[2].

Enbridge Gas's upstream gas supply, storage, transmission, and distribution systems are integrated and interdependent. Due to the integrated nature of these facilities, the underlying processes to estimate the design demand used to design the gas supply, storage, transmission, and distribution assets also need to be harmonized. The design criteria and design demand process needs to consider not only the design conditions but also the impact on day-to-day system operations when evaluating potential changes in approach. The processes must be able to estimate demand for the planning cycle which extends over the entire year as well as at the design condition. The goal of the proposed design methodology is to harmonize all planning functions and provide granular and detailed data for use across a wide variety of functions including future energy planning analysis (i.e., IRPAs, energy transition, hydrogen, CCUS, etc.).

b) The design day method for Union was already harmonized as the Gas Supply Plan and the transmission and storage systems used the exact same method. The design hour method for the distribution system was harmonized, as it adjusted demand to match the design day demand.

The EGD distribution system uses the same design hour method as Union except for the adjustment to match the design day demand and a method to convert daily to hourly demand.

Fundamentally Union's transmission, storage, distribution systems and gas supply plan, and EGD's distribution system are aligned and currently harmonized across the design demand processes. The design criteria method to develop the design day heating degree day is different, in that the Union method uses the coldest day on record while the EGD method uses a 1:5 recurrence interval.

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[1] EB-2019-0137.
[2] EB-2011-0354.

The EGD design day demand method was developed specifically for the gas supply plan and does not align to the systems as detailed above. The EGD method is not an appropriate method to adopt for distribution, transmission and storage asset planning and is not aligned to the methods currently in use for all other planning functions. Please see response at Exhibit.I.4.2-FRPO-118 for additional details on the EGD rate zone design demand methodology.

c) The design day demand conditions are referred to as the design criteria and are derived as detailed at Exhibit 4, Tab 2, Schedule 3, Section 3, paragraphs 32 to 42. Union currently uses the coldest observed on record (set temperature) methodology in the North and South rate zones. This method incorporates the impact of wind speed on the HDD. As stated in Exhibit 4, Tab 2, Schedule 3, paragraph 9.

> The proposed methods for determining design criteria and design demands have been accepted by the OEB in prior applications. The set temperature method has been used in the Union North rate zone for over 40 years and has been used in the Union South rate zone since 2013.

In Exhibit 4, Tab 2, Schedule 3, paragraph 28.

> The Sussex Report found that the set temperature approach was appropriate and similar to the design criteria used by other gas distribution utilities. The Sussex Report recommended minor changes to Union's design criteria. The OEB indicated that it was appropriate for Union to adopt the recommendations made in the Sussex Report.

EGD rate zone currently uses a probabilistic method with a 1 in 5-year recurrence interval which means that the design criteria is anticipated to be exceeded once every 5 years. Please see response at Exhibit I.4.2-FRPO-118 for additional details on the EGD rate zone design demand methodology.

The EGD method is detailed in the 5 Year Gas Supply Plan[3] from pages 34 to 37. This method was OEB approved as part of EGD's 2013 Cost of Service Application[4].

As stated in Exhibit 4, Tab 2, Schedule 3, paragraph 6.

> The EGD method was specifically designed for gas supply planning functions, which was to support contracting for space on upstream transportation systems. EGD did not have transmission systems to transport its gas commodity to the utility and as such the risk was placed on the supply points where spot gas could be acquired to mitigate shortfalls on the one in five-year recurrence level. To prevent distribution system failures, a condition that is unacceptable to its customers, EGD also included engineering assumptions that further reduced the risk of not meeting the design day demand. As an amalgamated utility, this approach is not appropriate for integrated transmission, distribution, and storage assets. Design demands need to be granular and aligned to actual observed customer behaviour and very cold weather.

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[3] EB-2019-0137.
[4] EB-2011-0354.

d) The design day demands for firm or interruptible customers is completed as follows.

1. Linear regression analyses are completed by rate class and by individual customer for each delivery area using:

    i. Customer actual daily measured volumetric demand.
    ii. Prior winter data.
    iii. Weather data in the form of HDDw from geographically associated weather stations.
    iv. Weekends and holidays and outliers are removed from the analysis.

2. Resulting regression line is extrapolated to the design day HDDw.

3. Existing contract rate demand data details include:

    i. If the customer is 100% firm an engineering assessment is made between the results from the linear regression (due to heat sensitivity), their maximum usage (due to process load), or a demand reservation (large, intermittent use or other) based on the customers firm contract demand (CD).

    ii. If the customer is 100% interruptible an engineering assessment is made between the results from the linear regression, their maximum usage, or a demand reservation based on the customers interruptible CD.

    iii. If the customer has both firm and interruptible CD an engineering assessment is made between the results from the linear regression, maximum usage, or a demand reservation.
        a. If the engineering assessment's choice is the linear regression, because the customer is heat sensitive, and
            i. The resultant design day demand is greater than the firm CD then the interruptible design day demand will be the amount exceeding the firm CD.
            ii. If the resultant design day demand is less than the firm CD the interruptible design day demand will be set to zero.
        b. If the engineering assessment's choice is their maximum demand, as the customer is process, and
            i. The resultant design day demand is greater than the firm CD then the interruptible design day demand will be the amount exceeding the firm CD.
            ii. If the resultant design day demand is less than the firm CD the interruptible design day demand will be set to zero.
        c. If the choice is the demand reservation, due to large size or intermittent usage or other reason, then the interruptible design day

demand will be the interruptible CD.

4. The individual customers analysis results are adjusted to align with the linear regression results by rate class to consider demand diversity or non-coincident usage. This step assumes not all customers are using their design demand at the same moment.

5. Some interruptible customers who do not use gas during the winter, such as asphalt plants, will have their interruptible design day demand set to zero.

6. Company's demand forecasts for new and existing customers are added to the existing customers design day demand to become the estimated forecast design day demand.

7. Interruptible demand is curtailed on design day.

Enbridge Gas used the design day demands of interruptible customers, as described above, in the derivation of the allocation factor for low pressure distribution mains. The derivation of the low pressure distribution mains allocation factor (LOWPRESS) is provided in part e). Interruptible demands are considered curtailed on design day and the distribution system is not generally designed to serve these demands. The inclusion of interruptible demands in the allocation of low-pressure distribution mains provides for a contribution to the recovery of distribution mains costs by interruptible customers to the benefit of firm customers.

e) The derivation of the requested allocation factors is provided as follows:

i. ALBIONTRANS – Please see Attachment 1.
ii. KIRKWALL_DEMAND – Please see Attachment 2.
iii. PAN_STCLAIR – Please see Exhibit I.7.1-IGUA-77, Attachment 2.
iv. D-PTRANS – Please see Exhibit I.7.1-IGUA-78, Attachment 1.
v. PKWY_DEMAND – Please see Exhibit I.7.1-IGUA-79, Attachment 2.
vi. DAWN_DEMAND – Please see Exhibit I.7.1-IGUA-80, Attachment 1.
vii. HIGHPRESS>4 – Please see Attachment 3.
viii. HIGHPRESS<=4 – Please see Attachment 3.
ix. LOWPRESS – Please see Attachment 4.

Derivation of Albion Transmission Demand Allocation Factor

Line No.	Particulars	Total Firm Design Day Demands (1) ($10^3m^3/d$)	Allocation to In-Franchise (3)		Allocation to Ex-Franchise		Albion Transmission Demand Allocation Factor (5)
		(a)	(b)		(c)		(d) = (b+c)
	EGD Rate Zone						
1	Rate 1	52,737	12		-		12
2	Rate 6	47,062	11		-		11
3	Rate 100	166	0		-		0
4	Rate 110	5,400	1		-		1
5	Rate 115	1,135	0		-		0
6	Rate 125	-	-		-		-
7	Rate 135	19	0		-		0
8	Rate 145	-	-		-		-
9	Rate 170	-	-		-		-
10	Rate 200	1,252	0		-		0
11	Rate 300	-	-		-		-
12	Total EGD Rate Zone	107,772	25		-		25
	Union North Rate Zone						
13	Rate 01	9,708	2		-		2
14	Rate 10	2,866	1		-		1
15	Rate 20	650	0		-		0
16	Rate 25	-	-		-		-
17	Rate 100	-	-		-		-
18	Total Union North Rate Zone	13,224	3		-		3
	Union South Rate Zone						
19	Rate M1	31,063	7		-		7
20	Rate M2	11,510	3		-		3
21	Rate M4 (F)	4,097	1		-		1
22	Rate M4 (I)	-	-		-		-
23	Rate M5 (F)	36	0		-		0
24	Rate M5 (I)	-	-		-		-
25	Rate M7 (F)	6,060	1		-		1
26	Rate M7 (I)	-	-		-		-
27	Rate M9	495	0		-		0
28	Rate T1 (F)	-	-		-		-
29	Rate T1 (I)	-	-		-		-
30	Rate T2 (F)	-	-		-		-
31	Rate T2 (I)	-	-		-		-
32	Rate T3	-	-		-		-
33	Total Union South Rate Zone	53,261	12		-		12
34	Total In-franchise	174,257	40	(2)	-		40
	Ex-franchise						
35	Rate 331	-	-		-		-
36	Rate 332	-	-		60	(4)	60
37	Rate 401	-	-		-		-
38	Rate M12	-	-		-		-
39	Rate M13	-	-		-		-
40	Rate M16	-	-		-		-
41	Rate M17	-	-		-		-
42	Rate C1 (F)	-	-		-		-
43	Rate C1 (I)	-	-		-		-
44	Total Ex-Franchise	-	-		60		60
45	Total	174,257	40		60		100

Notes:
(1) Excludes semi-unbundled and unbundled firm design day demands.
(2) 40% of Albion line is allocated to bundled rate classes.
(3) 40% allocated in proportion to column (a).
(4) 60% of Albion line is direct assigned to Rate 332.
(5) Albion transmission demand allocation factor, ALBIONTRANS, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 9, updated March 8, 2023.

Bi-Directional Design Day Demands at Kirkwall Station

Line No.	Particulars	Kirkwall Station Design Day Demands ($10^6m^3/d$)
		(a)
	In-franchise	
1	EGD	1,814
2	Union North	-
3	Union South	540
4	Total In-franchise	2,354
	Ex-franchise	
5	Rate M12	13,317
6	Rate C1	-
7	Rate M17	-
8	Total Ex-franchise	13,317
9	Total	15,671

Derivation of Kirkwall Station Transmission Demand Allocation Factor

Line No.	Particulars	Total Firm Design Day Demands (1) ($10^3m^3/d$)	Applicable Semi-Unbundled Design Day Demands ($10^3m^3/d$)	Total Design Day Demands ($10^3m^3/d$)	Allocation to Semi-Unbundled Services (2) ($10^3m^3/d$)	Remaining Allocation to Bundled Rate Classes (3) ($10^3m^3/d$)	Transmission Demand Allocation Factor (6) ($10^3m^3/d$)	
		(a)	(b)	(c) = (a+b)	(d)	(e)	(f) = (d+e)	
	EGD Rate Zone							
1	Rate 1	52,737	-	52,737	-	652	652	
2	Rate 6	47,062	-	47,062	-	582	582	
3	Rate 100	166	-	166	-	2	2	
4	Rate 110	5,400	-	5,400	-	67	67	
5	Rate 115	1,135	-	1,135	-	14	14	
6	Rate 125	-	-	-	-	-	-	
7	Rate 135	19	-	19	-	0	0	
8	Rate 145	-	-	-	-	-	-	
9	Rate 170	-	-	-	-	-	-	
10	Rate 200	1,252	-	1,252	-	15	15	
11	Rate 300	-	-	-	-	-	-	
12	Total EGD Rate Zone	107,772	-	107,772	-	1,333	1,333	
	Union North Rate Zone							
13	Rate 01	9,708	-	9,708	-	120	120	
14	Rate 10	2,866	-	2,866	-	35	35	
15	Rate 20	650	-	650	-	8	8	
16	Rate 25	-	-	-	-	-	-	
17	Rate 100	-	-	-	-	-	-	
18	Total Union North Rate Zone	13,224	-	13,224	-	164	164	
	Union South Rate Zone							
19	Rate M1	31,063	-	31,063	-	384	384	
20	Rate M2	11,510	-	11,510	-	142	142	
21	Rate M4 (F)	4,097	-	4,097	-	51	51	
22	Rate M4 (I)	-	-	-	-	-	-	
23	Rate M5 (F)	36	-	36	-	0	0	
24	Rate M5 (I)	-	-	-	-	-	-	
25	Rate M7 (F)	6,060	-	6,060	-	75	75	
26	Rate M7 (I)	-	-	-	-	-	-	
27	Rate M9	495	-	495	-	6	6	
28	Rate T1 (F)	-	2,077	2,077	13	-	13	
29	Rate T1 (I)	-	-	-	-	-	-	
30	Rate T2 (F)	-	26,229	26,229	168	-	168	
31	Rate T2 (I)	-	-	-	-	-	-	
32	Rate T3	-	2,601	2,601	17	-	17	
33	Total Union South Rate Zone	53,261	30,906	84,168	198	659	857	
34	Total In-franchise	174,257	30,906	205,163	198	2,156 (4)	2,354	
	Ex-franchise							
35	Rate 331	-	-	-	-	-	-	
36	Rate 332	-	-	-	-	-	-	
37	Rate 401	-	-	-	-	-	-	
38	Rate M12	-	-	-	-	-	13,317	(5)
39	Rate M13	-	-	-	-	-	-	
40	Rate M16	-	-	-	-	-	-	
41	Rate M17	-	-	-	-	-	-	
42	Rate C1 (F)	-	-	-	-	-	-	
43	Rate C1 (I)	-	-	-	-	-	-	
44	Total Ex-franchise	-	-	-	-	-	13,317	
45	Total	174,257	30,906	205,163	198	2,156	15,671	

Notes:
(1) Excludes semi-unbundled and unbundled firm design day demands.
(2) Calculated as (page 1, column (a), line 3 x column (c) / column (c), line 33).
(3) Calculated as (column (e), line 34 x column (e) / column (a), line 34).
(4) Calculated as (page 1, column (a), line 4 - column (d), line 34).
(5) Ex-franchise bi-directional design day demands direct assigned to M12.
(6) Kirkwall Station transmission demand allocation factor, KIRKWALL_DEMAND, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 29, updated March 8, 2023.

Calculation of High Pressure Main Allocation Factors

Line No.	Particulars	High Pressure Mains >4" Allocation Factor (1) (2) (10^3m^3/day)	Demands Served by Mains Greater than 4" (3) (10^3m^3/day)	High Pressure Mains <=4" Allocation Factor (4) (10^3m^3/day)
		(a)	(b)	(c) = (a - b)
	EGD Rate Zone			
1	Rate 1	52,737	-	52,737
2	Rate 6	47,062	-	47,062
3	Rate 100	166	13	153
4	Rate 110	5,400	2,120	3,280
5	Rate 115	1,135	1,016	119
6	Rate 125	9,260	9,260	-
7	Rate 135	19	6	13
8	Rate 145	-	-	-
9	Rate 170	-	-	-
10	Rate 200	1,252	1,252	-
11	Rate 300	-	-	-
12	Total EGD Rate Zone	117,032	13,667	103,365
	Union North Rate Zone			
13	Rate 01	9,708	-	9,708
14	Rate 10	2,896	-	2,896
15	Rate 20	7,610	6,829	781
16	Rate 25	-	-	-
17	Rate 100	3,398	3,267	131
18	Total Union North Rate Zone	23,612	10,095	13,517
	Union South Rate Zone			
19	Rate M1	31,063	-	31,063
20	Rate M2	11,510	-	11,510
21	Rate M4 (F)	4,097	849	3,248
22	Rate M4 (I)	-	-	-
23	Rate M5 (F)	36	-	36
24	Rate M5 (I)	-	-	-
25	Rate M7 (F)	6,060	2,905	3,155
26	Rate M7 (I)	-	-	-
27	Rate M9	495	279	216
28	Rate T1 (F)	2,077	650	1,426
29	Rate T1 (I)	-	-	-
30	Rate T2 (F)	26,229	25,780	448
31	Rate T2 (I)	-	-	-
32	Rate T3	2,601	2,601	-
33	Total Union South Rate Zone	84,168	33,065	51,102
34	Total In-franchise	224,812	56,828	167,984
	Ex-franchise			
35	Rate 331	-	-	-
36	Rate 332	-	-	-
37	Rate 401	-	-	-
38	Rate M12	-	-	-
39	Rate M13	-	-	-
40	Rate M16	-	-	-
41	Rate M17	227	227	-
42	Rate C1 (F)	-	-	-
43	Rate C1 (I)	-	-	-
44	Total Ex-franchise	227	227	-
45	Total	225,038	57,054	167,984

Notes:
(1) Total firm in-franchise design day demands plus design day demands of Rate M17.
(2) High pressure mains greater than 4 inch allocation factor, HIGHPRESS>4 , per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 27, updated March 8, 2023.
(3) Firm design day demands served by high pressures mains greater than 4 inches.
(4) High pressure mains less than 4 inch allocation factor, HIGHPRESS<=4 , per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 25, updated March 8, 2023.

Derivation of Low Pressure Mains Allocation Factor for Interruptible Rate Classes

Line No.	Particulars	Firm Demands Served by Low Pressure Mains (10^3m^3/d)	Total Interruptible Design Day Demands (10^3m^3/d)	Interruptible Design Day Demands Served by High Pressure Mains < 4 inches (10^3m^3/d)	Interruptible Demands Served by Low Pressure Mains (10^3m^3/d)	Allocation of Interruptible Demands to Low Pressure Mains Allocation Factor (1)	Low Pressure Mains Allocation Factor (2)
		(a)	(b)	(c)	(b)	(e)	(f) = (a + e)
	EGD Rate Zone						
1	Rate 1	52,737	-	-	-	-	52,737
2	Rate 6	47,062	-	-	-	-	47,062
3	Rate 100	111	-	-	-	-	111
4	Rate 110	2,714	-	-	-	-	2,714
5	Rate 115	107	-	-	-	-	107
6	Rate 125	-	-	-	-	-	-
7	Rate 135	8	-	-	-	-	8
8	Rate 145	-	439	230	209	17	17
9	Rate 170	-	2,184	1,775	409	83	83
10	Rate 200	-	-	-	-	-	-
11	Rate 300	-	-	-	-	-	-
12	Total EGD Rate Zone	102,739	2,623	2,005	618	100	102,839
	Union North Rate Zone						
13	Rate 01	9,708	-	-	-	-	9,708
14	Rate 10	2,896	-	-	-	-	2,896
15	Rate 20	105	-	-	-	-	105
16	Rate 25	-	22,800	22,722	78	867	867
17	Rate 100	-	-	-	-	-	-
18	Total Union North Rate Zone	12,710	22,800	22,722	78	867	13,576
	Union South Rate Zone						
19	Rate M1	31,063	-	-	-	-	31,063
20	Rate M2	11,510	-	-	-	-	11,510
21	Rate M4 (F)	2,538	-	-	-	-	2,538
22	Rate M4 (I)	-	23	-	23	1	1
23	Rate M5 (F)	28	-	-	-	-	28
24	Rate M5 (I)	-	426	189	238	16	16
25	Rate M7 (F)	2,111	-	-	-	-	2,111
26	Rate M7 (I)	-	803	590	213	31	31
27	Rate M9	-	-	-	-	-	-
28	Rate T1 (F)	807	-	-	-	-	807
29	Rate T1 (I)	-	153	153	-	6	6
30	Rate T2 (F)	263	-	-	-	-	263
31	Rate T2 (I)	-	4,733	4,703	30	180	180
32	Rate T3	-	-	-	-	-	-
33	Total Union South Rate Zone	48,321	6,137	5,634	503	233	48,554
34	Total In-franchise	163,769	31,561	30,361	1,200	1,200	164,969

Notes:
(1) Low pressure mains interruptible demands allocated in proportion to total interruptible design day demands, column (b).
(2) Low pressure distribution mains allocation factor, LOWPRESS, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 33, updated March 8, 2023.

Five-Year Budget and Actual DSM Costs by Rate Class (1)

			2021		2020		2019		2018		2017	
Line No.	Rate Zone	Rate Class	Budget	Spend	Budget	Spend	Budget	Spend	Budget	Spend	Budget	Spend
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	EGD	Rate 1	$ 39,405,864	$ 49,668,794	$ 39,405,864	$ 45,470,316	$ 38,629,963	$ 50,335,534	$ 38,085,214	$ 47,205,761	$ 33,682,557	$ 42,752,501
2	EGD	Rate 6	$ 21,074,060	$ 17,428,618	$ 21,074,060	$ 16,295,553	$ 20,658,237	$ 19,743,557	$ 21,848,933	$ 16,615,780	$ 21,652,885	$ 16,889,095
3	EGD	Rate 9	$ 2,935	$ 2,367	$ 2,935	$ 2,206	$ 2,878	$ 2,429	$ 2,838	$ 2,776	$ 2,685	$ 2,207
4	EGD	Rate 100	$ -	$ 128,094	$ -	$ 68,078	$ -	$ 339,027	$ -	$ -	$ -	$ -
5	EGD	Rate 110	$ 1,752,037	$ 996,416	$ 1,752,037	$ 1,313,420	$ 1,717,402	$ 847,906	$ 1,833,430	$ 863,910	$ 1,827,592	$ 1,410,964
6	EGD	Rate 115	$ 1,319,025	$ 580,245	$ 1,319,025	$ 423,678	$ 1,292,940	$ 843,596	$ 1,382,857	$ 258,002	$ 1,380,036	$ 568,175
7	EGD	Rate 125	$ 110,076	$ 88,745	$ 110,076	$ 82,728	$ 107,934	$ 91,070	$ 106,436	$ 104,091	$ 100,674	$ 82,773
8	EGD	Rate 135	$ 255,246	$ 441,221	$ 255,246	$ 536,485	$ 250,196	$ 265,562	$ 268,087	$ 381,017	$ 267,843	$ 366,917
9	EGD	Rate 145	$ 1,597,384	$ 96,410	$ 1,597,384	$ 69,491	$ 1,565,792	$ 76,499	$ 1,675,301	$ 514,299	$ 1,672,264	$ 86,692
10	EGD	Rate 170	$ 2,195,251	$ 152,188	$ 2,195,251	$ 252,005	$ 2,151,818	$ 260,617	$ 2,306,995	$ 165,805	$ 2,305,696	$ 169,902
11	EGD	Rate 200	$ 38,160	$ 30,765	$ 38,160	$ 28,679	$ 37,417	$ 31,571	$ 36,898	$ 36,085	$ 34,900	$ 28,695
12	EGD	Rate 300	$ 7,338	$ 5,916	$ 7,338	$ 5,515	$ 7,196	$ 6,071	$ 7,096	$ 6,939	$ 6,712	$ 5,518
13		EGD Total	$ 67,757,376	$ 69,619,780	$ 67,757,376	$ 64,548,153	$ 66,421,773	$ 72,843,440	$ 67,554,087	$ 66,154,466	$ 62,933,844	$ 62,363,439
14	Union	M1	$ 27,446,431	$ 25,015,801	$ 27,446,431	$ 27,556,384	$ 27,163,647	$ 34,435,959	$ 24,375,225	$ 38,116,865	$ 21,549,844	$ 34,094,527
15	Union	M2	$ 10,658,120	$ 6,929,577	$ 10,658,120	$ 5,738,806	$ 10,601,605	$ 7,566,654	$ 10,442,453	$ 7,129,898	$ 9,991,833	$ 7,393,524
16	Union	M4	$ 3,092,957	$ 3,104,864	$ 3,092,957	$ 4,379,962	$ 3,150,206	$ 5,022,808	$ 3,077,422	$ 5,991,549	$ 3,027,897	$ 5,278,690
17	Union	M5	$ 2,171,433	$ 397,130	$ 2,171,433	$ 268,421	$ 1,977,091	$ 527,741	$ 2,210,140	$ 621,172	$ 2,168,304	$ 1,317,497
18	Union	M7	$ 2,034,347	$ 6,573,146	$ 2,034,347	$ 4,827,535	$ 2,129,549	$ 3,797,378	$ 2,055,472	$ 2,446,479	$ 2,028,397	$ 1,143,215
19	Union	T1	$ 1,568,951	$ 319,951	$ 1,568,951	$ 852,427	$ 1,505,371	$ 778,967	$ 1,572,627	$ 1,789,310	$ 1,532,088	$ 2,356,129
20	Union	T2	$ 4,725,369	$ 3,484,723	$ 4,725,369	$ 3,535,748	$ 4,612,216	$ 4,004,466	$ 3,653,491	$ 3,373,617	$ 3,604,840	$ 3,003,539
21	Union	Rate 01	$ 6,624,724	$ 4,539,016	$ 6,624,724	$ 4,210,937	$ 6,344,581	$ 6,010,726	$ 9,124,247	$ 6,855,310	$ 8,100,073	$ 5,777,036
22	Union	Rate 10	$ 3,126,779	$ 1,327,240	$ 3,126,779	$ 1,195,422	$ 3,001,617	$ 1,651,804	$ 3,093,087	$ 1,685,783	$ 2,950,718	$ 1,979,183
23	Union	Rate 20	$ 1,753,140	$ 533,408	$ 1,753,140	$ 726,388	$ 1,671,732	$ 1,101,630	$ 1,773,457	$ 293,574	$ 1,734,284	$ 1,430,636
24	Union	Rate 100	$ 1,147,290	$ 752,069	$ 1,147,290	$ 1,196,554	$ 1,111,159	$ 706,172	$ 1,894,685	$ 819,365	$ 1,881,795	$ 807,133
25		Union Total	$ 64,349,541	$ 52,976,924	$ 64,349,541	$ 54,488,582	$ 63,268,773	$ 65,604,306	$ 63,272,305	$ 69,122,921	$ 58,570,073	$ 64,581,110
26		Grand Total	$ 132,106,917	$ 122,596,705	$ 132,106,917	$ 119,036,736	$ 129,690,546	$ 138,447,745	$ 130,826,392	$ 135,277,388	$ 121,503,917	$ 126,944,549

Note:
(1) Spend only. Does not include LRAM or DSMI since there is no corresponding budget for those items.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

7.2.1 Attachments; 7.1.4 Section 5 and Attachment 1; 7.2.3 paragraph 75.

Preamble:

IGUA seeks clarification regarding the treatment of DSM costs.

Question(s):

a) Please provide a five-year history of budget and actual DSM costs by rate class, based both on the current class definitions.

b) Are variances in the DSM budgets tracked and recouped/refunded on a class-specific basis? Please explain as necessary.

c) Please reconcile the DSM administration costs between 7.2.1 Attachment 7 ($30,707) and 7.2.1 Attachment 8 ($62,581).

d) Please provide a copy or reference to the Company's DSM plan that supports budget values used for the development of the DSM_PRO and DSM_ADM allocators, as discussed at 7.1.4 section 5.

e) Is it correct that the rate impacts in 7.1.4 Attachment 1 related to DSM result from a change in budgets by class, and not a methodological change? Please explain any negative response.

f) Please indicate where and how the low-income customer DSM costs are allocated, as reported at 7.1.2 paragraph 75.

Response:

a) Please see Attachment 1 for the 2017-2021 DSM budget and actual costs (2022 is still being finalized). Since the request includes budget, the actual costs included are only DSM Plan spend and do not include LRAM or DSMI since there is no corresponding budget for those items.

b) The Demand Side Management Variance Account ("DSMVA") is used to track the variance between actual DSM spending by rate class versus the budgeted amount included in rates by rate class for each program year. The Company files an application to dispose of balances in certain deferral and variance accounts related to the delivery of the DSM program, including the DSMVA, for each program year to seek approval from the OEB to recoup/dispose of variances by rate class accordingly.

c) Please see Table 1. The total DSM Admin costs of $65.422 million used in the allocation to rate classes in the 2024 Cost Allocation Study includes an allocation of indirect administrative costs.

Table 1
DSM Admin Costs

Line No.	Particulars ($000s)	Total
1	Direct DSM Admin per DSM Plan decision (1)	30,707
	Indirect Administrative Costs (2)	
2	Return (3)	1,068
3	Depreciation expense	3,014
4	Income taxes	136
5	Operating & maintenance costs (4)	30,498
6	Total indirect administrative costs	34,715
7	Total DSM Admin (line 1 + line 7) (5)	65,422

Notes:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 7, line 92, updated March 8, 2023.
(2) Exhibit 7, Tab 2, Schedule 1, Attachment 7, column (i), updated March 8, 2023.
(3) Return based on $18.190 million of allocated general plant rate base.
(4) Operating and maintenance costs include employee benefits and administrative and general costs.
(5) Exhibit 717, Tab 2, Schedule 1, Attachment 8, line 25, updated March 8, 2023.

d) Budget values used for the development of the DSM_PRO and DSM_ADM allocation factors are from the 2022-2027 Multi-Year DSM Plan[1].

- Approved Program Subtotal for 2024 = $156,327,067, including program level admin

- Approved Program Level Admin = $11,979,496

- Approved Total Program Costs (DSM_PRO) = $144,347,571 ($156,327,067 - $11,979,496)

- Approved Total Admin Costs (DSM_ADM) = $30,706,696 ($11,979,496 program admin + $18,727,200 portfolio admin)

e) Not correct. The rate class impact provided at Exhibit 7, Tab .1, Schedule .4 Attachment 1 related to the DSM budget do reflect the proposed cost allocation methodology changes. Please also see response at Exhibit I.7.1-STAFF-241, part b).

f) The Low Income DSM program budget of $21.9 million for 2024 is included in the total DSM program costs provided at Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 24, updated March 8, 2023

As provided at Exhibit 7, Tab 1, Schedule 1, page 19, the DSM low-income budget is allocated to rate classes in proportion to forecast distribution revenues less the DSM budget costs. Enbridge Gas is not proposing a change to the allocation of DSM low-income budget costs as part of this Application.

The allocation of the DSM low-income budget results in all in-franchise rate classes contributing to the recovery of the DSM low-income budget, including rate classes that are not eligible to participate in DSM programs (i.e. Rates 9, 125, 200, and 300 for the EGD rate zone and Rates M9, M10, T3, and 25 for the Union rate zones). This allocation methodology is consistent with the electricity conservation and demand management framework, as well as the OEB’s Low-Income Energy Assistance Program (“LEAP”).

[1] EB-2021-0002, Application for Multi-Year Natural Gas Demand Side Management Plan (2022-2027), Decision and Order, Schedule A.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

7.1.2 and 7.1.3 Attachment 1.

Preamble:

IGUA requests additional detail regarding allocated meters costs.

Question(s):

a) Please provide supporting workpapers for the allocation of meters costs based on replacement cost, as indicated at 7.1.2 paragraph 79, for the current rate classes.

b) Please provide results from the most recent full cost of service study for each of the three current service territories for meters allocation by rate class, as discussed at 7.1.3 Attachment 1 page 6.

Response:

a) Please see Attachment 1 for the derivation of the distribution meters allocation factor METERREPLCOSTS.

b) Please see Attachment 2 for a summary of the allocation of distribution meter costs by rate class from the most recent OEB-approved Cost Allocation Study for EGD[1] and Union[2].

[1] EB-2017-0086.
[2] EB-2011-0210.

Derivation of Distribution Meters Demand Allocation Factor

Line No.	Particulars	Total Number of Meters	Average Meter Replacement Cost ($)	Total Meter Replacement Cost ($) (2)
		(a)	(b)	(c)
	EGD Rate Zone			
1	Rate 1	2,158,512	282	607,972,130
2	Rate 6	172,843	1,261	218,009,367
3	Rate 100	14	28,055	392,767
4	Rate 110	416	11,510	4,788,244
5	Rate 115	22	36,906	811,934
6	Rate 125	4	52,409	209,635
7	Rate 135	41	33,229	1,362,403
8	Rate 145	5	24,127	120,634
9	Rate 170	11	48,840	537,236
10	Rate 200 (1)	-	-	-
11	Rate 300	-	-	-
12	Total EGD Rate Zone	2,331,868		834,204,350
	Union North Rate Zone			
13	Rate 01	369,169	319	117,598,867
14	Rate 10	2,204	3,346	7,374,061
15	Rate 20	62	21,895	1,357,464
16	Rate 25	4	13,362	53,449
17	Rate 100	12	72,192	866,304
18	Total Union North Rate Zone	371,451		127,250,144
	Union South Rate Zone			
19	Rate M1	1,202,887	322	387,833,146
20	Rate M2	8,069	4,180	33,725,229
21	Rate M4 (F)	225	20,153	4,534,474
22	Rate M4 (I)	-	-	-
23	Rate M5 (F)	7	26,271	183,899
24	Rate M5 (I)	30	26,271	788,139
25	Rate M7 (F)	57	48,988	2,792,337
26	Rate M7 (I)	4	52,426	195,953
27	Rate M9	4	27,026	108,105
28	Rate T1 (F)	46	39,600	1,821,597
29	Rate T1 (I)	-	-	-
30	Rate T2 (F)	41	86,742	3,556,429
31	Rate T2 (I)	-	-	-
32	Rate T3	2	52,409	104,818
33	Total Union South Rate Zone	1,211,372		435,644,127
34	Total	3,914,691		1,397,098,622

Notes:
(1) Gate station at interconnect with Rate 200 customer owned by customer.
(2) Distribution meters demand allocation factor, METERREPLCOST, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14 to 16, line 35, updated March 8, 2023.

Allocation of Distribution Meter Revenue Requirement by Rate Class
2018 EGD Cost Allocation Study / 2013 Union Cost Allocation Study

Line No.	Particulars	2018/2013 Meter Revenue Requirement Allocation ($000s)
		(a)
	2018 EGD Cost Allocation Study (1)	
1	Rate 1	32,590
2	Rate 6	24,378
3	Rate 100	
4	Rate 110	577
5	Rate 115	59
6	Rate 125	238
7	Rate 135	92
8	Rate 145	69
9	Rate 170	54
10	Rate 200	-
11	Rate 300	-
12	Total EGD	58,057
	2013 Union Cost Allocation Study	
	Union North Rate Zone (2)	
13	Rate 01	20,896
14	Rate 10	2,378
15	Rate 20	392
16	Rate 25	370
17	Rate 100	135
18	Total Union North Rate Zone	24,171
	Union South Rate Zone (2)	
19	Rate M1	54,445
20	Rate M2	2,146
21	Rate M4 (F)	445
22	Rate M4 (I)	-
23	Rate M5 (F)	29
24	Rate M5 (I)	467
25	Rate M7 (F)	164
26	Rate M7 (I)	28
27	Rate M9	27
28	Rate M10	7
29	Rate T1 (F)	203
30	Rate T1 (I)	83
31	Rate T2 (F)	981
32	Rate T2 (I)	243
33	Rate T3	103
34	Total Union South Rate Zone	59,371
35	Total Union	83,541

Notes:
(1) EB-2017-0086, Exhibit G2, Tab 5, Schedule 3, page 1, item 5.1.
(2) Revenue requirement for meters, as per EB-2011-0210, Exhibit G3, Tab 5, Schedule 20, updated for OEB Decision.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

7.1.3 Attachment 1 and 7.2.1

Preamble:

IGUA requests detail regarding how station costs are identified and allocated.

Question(s):

a) Reference 7.1.3 Attachment 1 page 6: Please provide the allocation of station costs by current rate class from the most recent cost allocation study for the three existing rate areas.

b) Please provide supporting workpapers for the development of the STATIONREPLCOST allocator, for the current rate classes.

c) Reference 7.2.1 Attachment 7: Please explain how the station costs were identified within the M&R detail and explain why those costs are not recorded in the customer stations account.

d) Please provide book net plant for customer stations by current rate class, including costs recorded in both the measuring and regulating and the customer stations accounts.

Response:

a) Please see Attachment 1 for a summary of the allocation of distribution station costs by rate class from the most recent OEB-approved Cost Allocation Study for EGD[1] and Union[2].

b) Please see Attachment 2 for the derivation of the distribution stations allocation factor STATIONREPLCOST.

[1] EB-2017-0086.
[2] EB-2011-0210.

c) The distribution classification measuring and regulating plant costs include an amount that is direct assigned to distribution station functional classification. The direct assignment is required because EGD customer station plant costs are recorded in the same plant asset class as EGD measuring and regulating plant costs. The 2024 Cost Allocation Study methodology separately classifies customer station plant costs and measuring and regulating plant costs. Accordingly, the EGD customer stations plant was identified in the measuring and regulating plant asset class through a sub account code and classified to the distribution stations functional classification.

   The distribution classification measuring and regulating O&M costs include an amount that is direct assigned to the distribution stations functional classification because the customer station O&M expenses are included in measuring and regulating expense cost centres.

d) Please see Attachment 3.

Allocation of Distribution Station Revenue Requirement by Rate Class
2018 EGD Cost Allocation Study / 2013 Union Cost Allocation Study

Line No.	Particulars ($000s)	2018/2013 Station Revenue Requirement Allocation ($000s)
		(a)
	2018 EGD Cost Allocation Study (1)	
1	Rate 1	905
2	Rate 6	10,249
3	Rate 100	-
4	Rate 110	422
5	Rate 115	82
6	Rate 125	-
7	Rate 135	172
8	Rate 145	116
9	Rate 170	147
10	Rate 200	-
11	Rate 300	8
12	Total EGD	12,101
	2013 Union Cost Allocation Study	
	Union North Rate Zone (2)	
13	Rate 01	5,345
14	Rate 10	2,170
15	Rate 20	667
16	Rate 25	202
17	Rate 100	203
18	Total Union North Rate Zone	8,586
	Union South Rate Zone (2)	
19	Rate M1	16,482
20	Rate M2	575
21	Rate M4 (F)	110
22	Rate M4 (I)	-
23	Rate M5 (F)	11
24	Rate M5 (I)	111
25	Rate M7 (F)	34
26	Rate M7 (I)	7
27	Rate M9	6
28	Rate M10	2
29	Rate T1 (F)	49
30	Rate T1 (I)	20
31	Rate T2 (F)	212
32	Rate T2 (I)	61
33	Rate T3	21
34	Total Union South Rate Zone	17,700
35	Total Union	26,286

Notes:
(1) EB-2017-0086, Exhibit G2, Tab 5, Schedule 3, page 1, Item, 5.2.
(2) Revenue requirement for stations, as per EB-2011-0210, Exhibit G3, Tab 5, Schedule 20, updated for OEB Decision.

Derivation of Distribution Stations Demand Allocation Factor

Line No.	Particulars	Total Number of Stations	Average Station Replacement Cost ($)	Total Station Replacement Cost ($) (2)
		(a)	(b)	(c)
	EGD Rate Zone			
1	Rate 1	-	-	-
2	Rate 6	4,820	30,183	145,480,281
3	Rate 100	11	35,326	388,582
4	Rate 110	473	33,164	15,686,622
5	Rate 115	44	44,894	1,975,321
6	Rate 125	3	1,733,333	5,200,000
7	Rate 135	54	42,109	2,273,903
8	Rate 145	47	32,417	1,523,620
9	Rate 170	12	49,905	598,866
10	Rate 200 (1)	-	-	-
11	Rate 300	-	-	-
12	Total EGD Rate Zone	5,464		173,127,195
	Union North Rate Zone			
13	Rate 01	1,187	14,189	16,841,754
14	Rate 10	867	27,673	23,992,920
15	Rate 20	62	120,476	7,469,541
16	Rate 25	4	24,576	98,302
17	Rate 100	12	229,484	2,753,802
18	Total Union North Rate Zone	2,132		51,156,320
	Union South Rate Zone			
19	Rate M1	6,155	15,713	96,713,961
20	Rate M2	4,258	28,965	123,334,171
21	Rate M4 (F)	225	35,273	7,936,401
22	Rate M4 (I)	-	-	-
23	Rate M5 (F)	7	56,853	397,972
24	Rate M5 (I)	30	56,853	1,705,595
25	Rate M7 (F)	57	340,282	19,396,072
26	Rate M7 (I)	4	340,282	1,361,128
27	Rate M9	4	192,281	769,125
28	Rate T1 (F)	46	117,482	5,404,160
29	Rate T1 (I)	-	-	-
30	Rate T2 (F)	41	989,340	40,562,930
31	Rate T2 (I)	-	-	-
32	Rate T3	2	1,747,439	3,494,879
33	Total Union South Rate Zone	10,829		301,076,395
34	Total	18,425		525,359,911

Notes:
(1) Gate station at interconnect with Rate 200 customer owned by customer.
(2) Distribution stations demand allocation factor, STATIONREPLCOST, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 45, updated March 8, 2023.

Allocation of Distribution Station Net Plant

Line No.	Particulars	Station Replacement Costs Allocator (1)	Measuring and Regulating Distribution Station Net Plant (2)		Distribution Station Net Plant (2)(3)		Total Distribution Station Net Plant (4)
		(a)	(b)		(c)		(d) = (b + c)
	EGD Rate Zone						
1	Rate 1	-	-		-		-
2	Rate 6	145,480,281	50,744		36,299		87,043
3	Rate 100	388,582	136		97		232
4	Rate 110	15,686,622	5,471		3,914		9,386
5	Rate 115	1,975,321	689		493		1,182
6	Rate 125	5,200,000	1,814		1,297		3,111
7	Rate 135	2,273,903	793		567		1,361
8	Rate 145	1,523,620	531		380		912
9	Rate 170	598,866	209		149		358
10	Rate 200	-	-		-		-
11	Rate 300	-	-		-		-
12	Total EGD Rate Zone	173,127,195	60,387		43,198		103,585
	Union North Rate Zone						
13	Rate 01	16,841,754	5,874		4,202		10,077
14	Rate 10	23,992,920	8,369		5,987		14,355
15	Rate 20	7,469,541	2,605		1,864		4,469
16	Rate 25	98,302	34		25		59
17	Rate 100	2,753,802	961		687		1,648
18	Total Union North Rate Zone	51,156,320	17,843		12,764		30,608
	Union South Rate Zone						
19	Rate M1	96,713,961	33,734		24,132		57,865
20	Rate M2	123,334,171	43,019		30,774		73,793
21	Rate M4 (F)	7,936,401	2,768		1,980		4,748
22	Rate M4 (I)	-	-		-		-
23	Rate M5 (F)	397,972	139		99		238
24	Rate M5 (I)	1,705,595	595		426		1,020
25	Rate M7 (F)	19,396,072	6,765		4,840		11,605
26	Rate M7 (I)	1,361,128	475		340		814
27	Rate M9	769,125	268		192		460
28	Rate T1 (F)	5,404,160	1,885		1,348		3,233
29	Rate T1 (I)	-	-		-		-
30	Rate T2 (F)	40,562,930	14,148		10,121		24,269
31	Rate T2 (I)	-	-		-		-
32	Rate T3	3,494,879	1,219		872		2,091
33	Total Union South Rate Zone	301,076,395	105,016		75,123		180,139
34	Total	525,359,911	183,246	(5)	131,085	(6)	314,331

Notes:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 45, updated March 8, 2023.
(2) Allocation in proportion to column (a).
(3) Includes compressor equipment net plant classified to distribution stations.
(4) Total distribution station net plant excluding general plant.
(5) Exhibit 7 , Tab 2, Schedule 1, Attachment 7, page 2, column (m), line 36, updated March 8, 2023.
(6) Exhibit 7 , Tab 2, Schedule 1, Attachment 7, page 2, column (m), line 44, updated March 8, 2023.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

7.1.3 Attachment 1 page 6, 7.2.1 Attachment 9.

Preamble:

EGI forecasts some $11.1 million in costs associated with the Large Volume Customer Care account. IGUA requests detail regarding the nature of costs associated with that account, and the basis for the allocation of those costs.

Question(s):

a) Please provide a listing of the specific services provided to customers that are associated with the Large Volume Customer Care account.

b) Please provide a history of the number of employees engaged in providing those services for each operating area over the past five years, and as forecast for 2024.

c) In the most recent cost allocation study for the individual service areas, please provide the allocation of these costs.

d) Please discuss whether employees are assigned to individual customers. If so, please provide the number of employees assigned to customers in each rate class.

Response:

a) The Large Volume Customer Care functional classification includes costs of $11.7 million[1] in the 2024 Cost Allocation Study. Included in this total are $3.4 million of direct customer care costs reflecting the cost of contracting, billing and customer / vendor support services. In addition, there are $1.9 million[2] of direct administration costs associated with other departments supporting large volume direct purchase

[1] Exhibit 7, Tab 2, Schedule 1, Attachment 9, page 1, updated March 8, 2023.
[2] Exhibit I.7.1-IGUA-74, Table 3, column (c), excluding line 1 of $0.4 million which is captured in the direct customer care costs of $3.4 million.

customers. The remaining costs are related to indirect overheads, and include costs such as employee benefits, general operating and administration expenses.

b) The number of employees providing the services described in part a) above for Enbridge Gas are as follows:

2019 Actual: 55
2020 Actual: 54
2021 Actual: 58
2022 Actual: 54
2023 Estimate: 61
2024 Test Year: 57

c) Please see Attachment 1. The large volume customer care costs provided at Attachment 1 exclude an allocation of indirect costs.

d) The employees identified in part b) are not assigned by rate class. Resources are allocated by activity (e.g., contracting, billing, etc.). Customer service representatives are assigned to specific gas vendors for the direct purchase market.

Allocation of Large Volume Customers Care Costs by Rate Class
2018 EGD Cost Allocation Study / 2013 Union Cost Allocation Study

Line No.	Particulars ($000s)	Large Volume Customer Care Costs ($000s)
		(a)
	2018 EGD Cost Allocation Study (1)	
1	Rate 1	-
2	Rate 6	2,576
3	Rate 100	-
4	Rate 110	4
5	Rate 115	0
6	Rate 125	0
7	Rate 135	1
8	Rate 145	1
9	Rate 170	0
10	Rate 200	0
11	Rate 300	0
12	Total EGD	2,582
	2013 Union Cost Allocation Study	
	Union North Rate Zone (2)	
13	Rate 01	-
14	Rate 10	117
15	Rate 20	234
16	Rate 25	230
17	Rate 100	67
18	Total Union North Rate Zone	649
	Union South Rate Zone (2)	
19	Rate M1	4
20	Rate M2	332
21	Rate M4 (F)	432
22	Rate M4 (I)	-
23	Rate M5 (F)	116
24	Rate M5 (I)	422
25	Rate M7 (F)	8
26	Rate M7 (I)	8
27	Rate M9	11
28	Rate M10	7
29	Rate T1 (F)	121
30	Rate T1 (I)	26
31	Rate T2 (F)	19
32	Rate T2 (I)	57
33	Rate T3	4
34	Total Union South Rate Zone	1,564
35	Total Union	2,213

Notes:
(1) EB-2017-0086, Exhibit G2, Tab 5, Schedule 3, Page 1, Item 5.11, excluding indirect costs.
(2) EB-2011-0210, Exhibit G3, Tab 5, Schedule 20, updated for OEB for OEB Decision, excluding indirect costs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

Interrogatory

Reference:

7.1.2, 7.2.1 Attachments

Preamble:

Clarification regarding allocation of UFG and company-use gas costs is requested.

Question(s):

a) Reference 7.1.2 paragraph 12: Please explain how UFG and company-use gas costs are functionalized.

b) Please identify the specific uses for company-use gas, the volumes associated with each use (as available), and the locations for the consumption (as available).

c) To the extent available, please provide functionalized UFG rates (UFG volumes per total volume) and costs by current operating area and in total.

d) Please provide supporting workpapers for the derivation of the STORCOMM allocator, including an explanation for how injection and withdrawal volumes for the bundled in-franchised classes are determined.

e) Please provide supporting workpapers for the derivation of the TRANSCOMM allocator. Please include an explanation for the reference to “delivery and transportation volumes” at 7.2.1 Attachment 11 page 14. Please also explain why costs associated with this allocator are not assigned to unbundled customers.

f) Are any customers interconnected directly to the transmission system? If so, are volumes associated with those customers excluded from the DISTCOMM allocator? Please explain as necessary.

g) Please provide supporting workpapers for the derivation of the DISTCOMM allocator.

h) Are customers taking service directly from the high pressure distribution system assigned the same UFG rate as those customers who rely on both the high pressure and low pressure distribution systems? If so, please explain.

Response:

a) The forecast regulated cost of UFG is functionalized to storage, transmission and distribution based on forecast volumes for each activity.

The forecast regulated cost for company use gas is functionalized to storage, transmission and distribution based on the nature of the company use gas.

The functionalization of UFG and company use gas is provided at Exhibit 7, Tab 2, Schedule 1, Attachment 3, line 66 and 67.

b) Please see Table 1 for company use gas forecast components and functionalization.

Table 1
2024 Company Use Volumes by Function

Line No.	Particulars (10^3m^3)	Function			Total
		Storage	Transmission	Distribution	
		(a)	(b)	(c)	(d) = (a+b+c)
1	Vehicles (1)	40	157	623	820
2	Buildings (1)	104	408	1,623	2,135
3	Distribution Operations	-	-	9,790	9,790
4	Station Heating (2)	797	3,118	-	3,915
5	Storage & Transmission Operations (2)	419	1,640	-	2,060
6	Total	1,361	5,322	12,037	18,720
7	Revenue Requirement ($000s) (3)	282	1,104	2,498	3,884

Notes:
(1) Functionalized in proportion to storage, transmission and distribution net plant.
(2) Functionalized in proportion to storage and transmission net plant.
(3) Based on weighted average reference price of $207.493/10^3m^3$.

c) Please see Table 2 for the UFG functionalization broken out by rate zone. The UFG ratio of 0.471% is applied to applicable storage, transmission and distribution activity to allocate costs to rate zones.

Table 2
2024 UFG Volumes by Function

Line No.	Particulars	UFG Volumes (10^3m^3)	Total Activity (10^3m^3)	UFG Revenue Requirement ($000s) (1)
		(a)	(b)	(c)
	Storage			
1	EGD	32,718	6,941,715	6,789
3	Union North	4,006	849,843	831
2	Union South	21,723	4,609,003	4,507
4	Ex-franchise	-	-	-
5	Total Storage	58,447	12,400,560	12,127
	Transmission			
6	EGD	-	-	-
7	Union North	-	-	-
8	Union South	-	-	-
9	Ex-franchise	82,720	17,550,559	17,164
10	Total Transmission	82,720	17,550,559	17,164
	Distribution			
11	EGD	57,359	12,169,769	11,902
12	Union North	16,257	3,449,289	3,373
13	Union South	55,587	11,793,844	11,534
14	Ex-franchise	-	-	-
15	Total Distribution	129,203	27,412,902	26,809
16	Total (2)(3)	270,370	57,364,020	56,100

Notes:
(1) Based on weighted average reference price of $207.493/10^3m^3$.
(2) UFG ratio for cost allocation purposes =
270,370 10^3m^3 (UFG volumes) / 57,364,020 10^3m^3 (Total activity) = 0.471%.
(3) UFG volumes of 270,370 10^3m^3 per Exhibit 4, Tab 3, Schedule 1, page 10, Table 3, line 3.

d) Please see response at Exhibit I.7.1-IGUA-76, Attachment 5 for the storage commodity allocation factor STORCOMM.

Injection and withdrawal volumes for bundled in-franchise rate classes are determined as the difference between the opening balance of regulated storage at the beginning of the month and the closing balance at the end of the month. The absolute value of the difference for each month is summed to estimate the injection and withdrawal volumes for the year.

e) Please see Attachment 1 for the derivation of the transmission commodity allocation factor TRANSCOMM. The transmission commodity allocation factor is a blended allocator incorporating both transmission related UFG and company use gas.

The reference “delivery and transportation volumes” at Exhibit 7, Tab 2, Schedule 1, Attachment 11, page 14 refers to in-franchise delivery volumes used for the allocation of transmission related company use gas and ex-franchise transportation volumes used for the allocation of both transmission related UFG and company use gas.

Enbridge Gas has not included unbundled volumes in the allocation of transmission related company use gas because unbundled services do not use Enbridge Gas’s transmission facilities.

f) No, Enbridge Gas does not have any customers directly connected to transmission mains. There are some customers who have a service line that is connected to a transmission main, however, the service line is recorded and classified as a distribution main. For purposes of cost allocation, transmission mains include the Dawn Parkway System, Panhandle System, St. Clair System and Albion Line.

Enbridge Gas does have three Rate 125 unbundled customers who have a dedicated service connection to a TransCanada transmission main. The volumes for these customers have been excluded from the distribution commodity allocation factor, DISTCOMM, which allocates distribution related UFG and company use gas.

g) Please see Attachment 2 for the derivation of the distribution commodity allocation factor DISTCOMM.

h) Yes. Enbridge Gas has not considered the facilities customers are connected to in the allocation of distribution related UFG costs, which is consistent with the approach used to allocate UFG by EGD and Union. Enbridge Gas does not have the ability to identify and measure UFG by the customers connection to the distribution system.

Calculation of Transmission Commodity Allocation Factor

Line No.	Particulars	Annual Volumes (1) (10^3m^3)	Transmission UFG Costs (2) ($000s)		Transmission Company Use Gas Costs (4) ($000s)		Transmission Commodity Allocation Factor (6)
		(a)	(b)		(c)		(d) = (b + c)
	EGD Rate Zone						
1	Rate 1	5,001,027	0		129		129
2	Rate 6	4,795,693	0		124		124
3	Rate 100	27,429	0		1		1
4	Rate 110	1,068,281	0		28		28
5	Rate 115	381,873	0		10		10
6	Rate 125	0	0		0		0
7	Rate 135	52,646	0		1		1
8	Rate 145	15,714	0		0		0
9	Rate 170	323,254	0		8		8
10	Rate 200	188,852	0		5		5
11	Rate 300	0	0		0		0
12	Total EGD Rate Zone	11,854,769	0		307		307
	Union North Rate Zone						
13	Rate 01	989,005	0		26		26
14	Rate 10	324,093	0		8		8
15	Rate 20	148,691	0		4		4
16	Rate 25	5,703	0		0		0
17	Rate 100	0	0		0		0
18	Total Union North Rate Zone	1,467,492	0		38		38
	Union South Rate Zone						
19	Rate M1	3,255,132	0		84		84
20	Rate M2	1,319,376	0		34		34
21	Rate M4 (F)	593,661	0		15		15
22	Rate M4 (I)	238	0		0		0
23	Rate M5 (F)	4,406	0		0		0
24	Rate M5 (I)	55,087	0		1		1
25	Rate M7 (F)	713,738	0		18		18
26	Rate M7 (I)	75,999	0		2		2
27	Rate M9	90,073	0		2		2
28	Rate T1 (F)	393,754	0		10		10
29	Rate T1 (I)	37,536	0		1		1
30	Rate T2 (F)	4,963,881	0		128		128
31	Rate T2 (I)	41,762	0		1		1
32	Rate T3	249,200	0		6		6
33	Total Union South Rate Zone	11,793,844	0		305		305
	Ex-franchise						
34	Rate 331	0	0		0		0
35	Rate 332	0	0		0		0
36	Rate 401	0	0		0		0
37	Rate M12	9,381,880	9,175		243		9,418
38	Rate M13	122,598	120		3		123
39	Rate M16	278,638	272		7		280
40	Rate M17	33,355	33		1		33
41	Rate C1 (F)	6,565,587	6,421		170		6,591
42	Rate C1 (I)	1,168,501	1,143		30		1,173
43	Total Ex-franchise	17,550,559	17,164		454		17,618
44	Total	42,666,664	17,164	(3)	1,104	(5)	18,268

Notes:
(1) Excluding unbundled volumes.
(2) Allocation in proportion to column (a), excluding in-franchise volumes.
(3) Total transmission UFG costs of $17.164 million per Exhibit 7, Tab 2, Schedule 1, Attachment 6, line 66. Allocation to ex-franchise rate classes only. In-franchise allocation of UFG included in the distribution commodity allocation factor.
(4) Allocated in proportion to column (a).
(5) Total transmission company use gas costs of $1.104 million per Exhibit 7, Tab 2, Schedule 1, Attachment 6, line 67.
(6) Transmission commodity allocation factor, TRANSCOMM, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14 to 16, line 59, updated March 8, 2023.

Calculation of Distribution Commodity Allocation Factor

Line No.	Particulars	Annual Volumes (1) (10^3m^3)	Distribution Commodity Allocation Factor (2)(3)	
		(a)	(b)	
	EGD Rate Zone			
1	Rate 1	5,001,027	4,891	
2	Rate 6	4,795,693	4,690	
3	Rate 100	27,429	27	
4	Rate 110	1,068,281	1,045	
5	Rate 115	381,873	373	
6	Rate 125	315,000	308	
7	Rate 135	52,646	51	
8	Rate 145	15,714	15	
9	Rate 170	323,254	316	
10	Rate 200	188,852	185	
11	Rate 300	0	0	
12	Total EGD Rate Zone	12,169,769	11,902	
	Union North Rate Zone			
13	Rate 01	989,005	967	
14	Rate 10	327,974	321	
15	Rate 20	929,101	909	
16	Rate 25	126,831	124	
17	Rate 100	1,076,378	1,053	
18	Total Union North Rate Zone	3,449,289	3,373	
	Union South Rate Zone			
19	Rate M1	3,255,132	3,183	
20	Rate M2	1,319,376	1,290	
21	Rate M4 (F)	593,661	581	
22	Rate M4 (I)	238	0	
23	Rate M5 (F)	4,406	4	
24	Rate M5 (I)	55,087	54	
25	Rate M7 (F)	713,738	698	
26	Rate M7 (I)	75,999	74	
27	Rate M9	90,073	88	
28	Rate T1 (F)	393,754	385	
29	Rate T1 (I)	37,536	37	
30	Rate T2 (F)	4,963,881	4,854	
31	Rate T2 (I)	41,762	41	
32	Rate T3	249,200	244	
33	Total Union South Rate Zone	11,793,844	11,534	
34	Total	27,412,902	26,809	(3)

Notes:
(1) Allocated in proportion to column (a).
(2) Distribution commodity allocation factor, DISTCOMM, per Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11 to 13, line 17, updated March 8, 2023.
(3) Total distribution UFG costs of $26.809 million per Exhibit 7, Tab 2, Schedule 1, Attachment 7, line 67.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers (OGVG)

Interrogatory

Reference:

Exhibit 7 Tab 1 Schedule 1 Page 5

Question(s):

The 2024 Cost Allocation Study is prepared based on one rate zone for all costs and rate classes with the exception of transportation service options that provide regional transportation service, such as ex-franchise transportation service options and transportation services for semi-unbundled and unbundled customers. A one rate zone approach to the Cost Allocation Study allows for consistent pricing of like services across rate classes and geographic regions.

a) Please comment on the impact, if any, that EGI's one zone proposal will have on rate stability if fully implemented both at the cost allocation phase and the rate design phase.

b) Please explain what impact, if any, the proposal to implement one rate zone for both cost allocation and rate design purposes has on the recovery of costs associated with stranded assets.

Response:

a) Rate stability is an objective for Enbridge Gas's cost allocation and rate design process whereby the year-over-year change in costs and rates at a rate class level is stable and predictable. Enbridge Gas's proposal for one rate zone cost allocation and resulting rate design can provide additional rate stability for delivery costs. The one rate zone methodologies for cost allocation eliminates variations that can occur in rates between rate zones when the proportion of investments made on behalf of a subset of customers in one rate zone is different than another.

   In cost-of-service ratemaking year-over-year increases or decreases in delivery costs will be allocated and recovered from a greater number of customers. Rate stability can also occur in an IRM model where rates are adjusted based on a price cap formula, as is proposed by Enbridge Gas for 2025 to 2028. Although rates are decoupled from costs during the IR term, one rate zone can provide stability in the transition from an IRM ratemaking framework to a cost-of-service.

Gas supply rates will continue to be pass-through costs based on market prices adjusted each quarter in the QRAM process.

b) Please see response at Exhibit I.1.10-OGVG-2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

7-1-1, p.10

Question(s):

Please explain why the listed Exhibit 7 adjustments are being undertaken as part of the cost allocation process and not adjustments to the base revenue requirement.

Response:

The adjustments to the revenue deficiency were identified through the cost allocation and rate design process after the 2024 Test Year Forecast revenue requirement for Exhibit 6 was finalized. In order to include the adjustments in the cost allocation process, Enbridge Gas adjusted the revenue requirement in Exhibit 7.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

7-1-2, 7-2-1

Question(s):

Please provide a copy of the live spreadsheet/model that underlies the 2024 Cost Allocation Study.

Response:

Please see response at Exhibit I.7-IGUA-72 where the 2024 Cost Allocation Study has been provided in Excel.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

7-1-2, p.5

Question(s):

Enbridge notes that third-party contracts that provide a system benefit all customers, and are required to serve in-franchise demands, are considered distribution costs for cost allocation purposes:

a) Please provide the total amount of 2024 costs that are captured under the referenced functionalization.

b) Please confirm that if instead of transportation contracts, the demand (and the benefits) were served by Enbridge transportation assets, those costs would be functionalized as transportation costs for cost allocation purposes.

c) If (b) is confirmed, please explain why the differing functionalization approach is appropriate.

Response:

a) The 2024 forecast cost of third-party transportation contracts functionalized to distribution that provide a system benefit to all customers is $10.9 million. Please see Exhibit 7, Tab 2, Schedule 1, Attachment 3, page 3, column (i), line 70, updated March 8, 2023.

b) Not confirmed. For the purposes of the Cost Allocation Study, transmission costs are limited to those that provide cross franchise transportation service and include the Dawn Parkway, Albion, Panhandle and St. Clair transmission systems.

   Costs necessary to meet sales service and direct purchase in-franchise demands on the distribution system would be functionalized to distribution regardless of whether the costs were third-party transportation contracts or Enbridge Gas owned transportation assets.

c) Please see response to part b).

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

7-1-2, p.13

Question(s):

Please provide a more detailed explanation of the zero-intercept methodology.

Response:

The zero-intercept methodology is a cost allocation approach used to estimate the cost of distribution infrastructure necessary to provide customers access to natural gas service regardless of the amount of gas used or the peak demand the customer places on the distribution system. The zero-intercept methodology recognizes a linear relationship between the unit cost of a metre of pipeline and its diameter. From this linear relationship, the unit cost of a zero diameter pipeline is determined by the y-intercept. The zero diameter unit cost is applied to the total of all metres of pipeline. The resulting calculation is considered to be the minimum system cost necessary to provide customers access to natural gas service.

Enbridge Gas has applied the zero-intercept methodology to low pressure distribution main costs to determine the minimum system cost deemed to be the customer-related component of distribution mains. The methodology proposed by Enbridge Gas in the 2024 Cost Allocation Study is consistent with the OEB-approved methodology previously used by EGD.

Please see Exhibit I.7.1-IGUA-81 part d) for the derivation of the zero-intercept classification factor used in the 2024 Cost Allocation Study.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

7-1-2, p.14-24

Question(s):

For each category/classification where the allocation is based on demand, please explain why Enbridge has used the specific demand allocator (e.g. design, average day).

Response:

Please see Table 1 for a summary and description of the demand allocators included in the 2024 Cost Allocation Study. Demand costs, also known as capacity-related costs, are costs that vary with the usage of the system on design day. For each functional classification that allocates costs using demands, the allocator is designed using the specific demands that are reflective of cost incurrence.

Table 1
Summary of Demand Allocators

Line No.	Functional Classification (a)	Demand Allocator (b)	Description (c)
1	Load Balancing Transportation	Peak day demand over annual average demand	Incremental transportation cost in excess of transportation costs to meet the average annual demand is classified as load balancing transportation. The cost is incurred to meet peak design day demand above average day.
2	Load Balancing Commodity	Firm design day demands over design day deliveries	The incremental cost of commodity purchases for load balancing are required to meet design day demand that is greater than the gas deliveries arriving daily.
3	Transportation Demand	Average day demand	Transportation costs are required to meet average annual demand.
4	Storage Deliverability	Firm design day demands over design day deliveries	Withdrawals from storage are required to meet design day demand that is greater than the gas deliveries arriving daily.
5	Dawn Station	Bi-directional firm design day demands at Dawn	The Dawn Station is designed to meet the firm design day demands that require Dawn.
6	Kirkwall Station	Bi-directional firm design day demands at Kirkwall	The Kirkwall Station is designed to meet the firm design day demands that require Kirkwall.
7	Parkway Station	Firm design day demands at Parkway	The Parkway Station is designed to meet the firm design day demands that require Parkway.
8	Dawn Parkway	In-franchise and ex-franchise split based on distance-weighted design day demands. In-franchise allocation based on firm design day demands.	The Dawn Parkway System is designed to meet the firm transportation design day demands of both in-franchise and ex-franchise rate classes.
9	Albion	Firm design day demands	The Albion pipeline is designed to meet the firm transportation design day demands of both in-franchise and ex-franchise rate classes using the Albion pipeline.
10	Panhandle/ St. Clair	In-franchise firm design day demands	The Panhandle and St. Clair systems are designed to meet the firm transportation in-franchise design day demands.
11	Distribution High Pressure > 4”	In-franchise firm design day demands	High pressure mains are designed to meet firm in-franchise design day demands.
12	Distribution High Pressure <= 4”	In-franchise firm design day demands excluding customers directly connected to high pressure mains > 4” in diameter	High pressure mains less than or equal to 4” in diameter are designed to meet firm in-franchise design day demands excluding design day demands of customers who are connected to high pressure mains greater than 4” in diameter.
13	Distribution Low Pressure	In-franchise design day demands excluding customers directly connected to high pressure mains	Low pressure mains are designed to meet in-franchise design day demands except design day demands of customers who are connected to high pressure mains.

ENBRIDGE GAS INC.

Answer to Interrogatory from
TransCanada PipeLines Limited (TCPL)

Interrogatory

Reference:

1) EB-2019-0194, EGI's Response to TCPL Interrogatory Exhibit I.TCPL.1, b) – Attachment 1.
2) EB-2019-0194, EGI's Response to TCPL Interrogatory Exhibit I.TCPL.2, b) – Attachment 1.
3) Exhibit 7, Tab 1, Schedule 4, Attachment 1
4) Exhibit 7, Tab 2, Schedule 1, Attachment 6

Preamble:

Reference 1) provides a table as Attachment 1 *titled M12/M12-X/C1 Transportation Demand Charges Impacts of Cost Allocation Methodologies* produced by EGI as a response to a TCPL Interrogatory about EGI's 2019 Cost Allocation Study. The table provides the unit rate impacts ($/GJ) for M12, M12-X and C1 rate classes by transportation path for each of the proposed cost allocation changes (Panhandle/St. Clair, Parkway Station, Dawn Station). The impact of the cost allocation proposals was displayed by providing the unit rates under the current Board-approved methodology, the unit rates under the proposed methodology, and the resulting net impacts between the cases, with EGI specifying all assumptions relied on in providing these impacts.

Reference 2) provides a table titled *Rate Class Breakdown of Parkway Station Demand Costs – Measuring & Regulating Costs, Compression Costs, and All Other Costs* produced by EGI as a response to a TCPL Interrogatory about EGI's 2019 Cost Allocation Study.

Reference 3) shows the total rate class impacts from the proposed cost allocation methodology changes in total dollars, incremental to EGI's proposal to harmonize the EGD and Union rate zones into one rate zone. Under column (b) Parkway Station, the total impact to Ex-Franchise rate classes is an increase of $9.935 million with $9.882 million of that impact being allocated to M12 rate classes. There is an equal off-setting decrease in impact to the EGD Rate Zone, Union North Rate Zone, and Union South Rate Zone in aggregate.

Reference 4) shows the costs under the Transmission Classification and how the costs are allocated into the various Transmission Demand categories.

Question(s):

a) Please provide a table similar to the one in Reference 1) showing all of the unit rate impacts ($/GJ) for M12, M12-X and C1 rate classes by transportation path for each of the proposed cost allocation changes in the Cost Allocation Study (Panhandle/St. Clair, Parkway Station, Dawn Station, Dawn Parkway, DSM Budget). To display the impact, please provide the applicable unit rates under the current Board-approved methodology, the unit rates under the proposed methodology, and the resulting net impacts between the cases. Please explain and provide all assumptions relied on in calculating the impacts.

b) Please compile six tables similar to the table provided in Reference 2) showing a breakdown of Measuring & Regulating Costs, Compression Costs, and all other costs under the applicable Transmission Demand categories shown in Reference 4) and specified below. Please include all in-franchise and ex-franchise rate classes in these tables and provide the allocation units used to allocate these costs to the rate classes:

   i. for Parkway Station under the current Board-approved cost allocation methodology;
   ii. for Parkway Station under the proposed cost allocation methodology;
   iii. for Dawn Station under the current Board-approved cost allocation methodology;
   iv. for Dawn Station under the proposed cost allocation methodology;
   v. for Dawn Parkway under the current Board-approved cost allocation methodology; and
   vi. for Dawn Parkway under the proposed cost allocation methodology.

c) Please provide an excel file showing the data and derivation behind Reference 3).

Response:

a) Please see Attachment 1. For the purposes of this response, Enbridge Gas prepared Rate M12/C1 Dawn Parkway unit rates, assuming the cost allocation variances provided at Exhibit 7, Tab 1, Schedule 4, Attachment 1 for M12 and C1 were adjusted in rates.

b) Please see Attachment 2.

c) The derivation of the rate class impacts of the proposed cost allocation methodology changes have been provided as follows:

- Parkway Station – Please see response at Exhibit I.7.1-IGUA-79, Attachment 3.
- Dawn Station – Please see response at Exhibit I.7.1-IGUA-80, Attachment 2.
- Dawn Parkway – Please see response at Exhibit I.7.1-IGUA-78, Attachment 2.

The referenced attachments have been filed in Excel as Attachment 3.

Rate M12/M12-X/C1 Transportation Demand Charges Impacts of Proposed Cost Allocation Methodology Changes

		Demand Charge						Impact of 2024 Cost Allocation Proposals (Column (d))(1)			
Line No.	Particulars ($/GJ/mo)	2023 Rates Approved EB-2022-0133	Rate Impact of 2024 Rebasing	2024 Rates Approved Cost Allocation (2)	Rate Impact of Cost Allocation Proposals	2024 Rates Proposed Cost Allocation	Total Rate Impact	Parkway Station	Dawn Station	Dawn Parkway	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j) = (g + h + i)
1	M12/C1 Dawn to Kirkwall	3.190	(0.215)	2.975	(0.546)	2.429	(0.761)	(0.415)	(0.190)	0.059	(0.546)
2	M12/C1 Dawn to Parkway	3.760	(0.560)	3.200	0.223	3.423	(0.337)	0.273	(0.119)	0.069	0.223
3	M12/C1 Kirkwall to Parkway	0.570	0.092	0.662	0.769	1.431	0.861	0.688	0.071	0.010	0.769
4	C1 Parkway to Dawn/Kirkwall	0.888	(0.011)	0.877	0.061	0.938	0.050	0.074	(0.032)	0.019	0.061
5	C1 Kirkwall to Dawn	1.567	(0.040)	1.527	(0.155)	1.372	(0.195)	(0.243)	0.052	0.036	(0.155)
6	M12-X	4.648	(0.572)	4.076	0.285	4.361	(0.287)	0.348	(0.151)	0.088	0.285

Notes:
(1) The Panhandle/St. Clair and DSM budget proposed cost allocation methodology changes have no impact on Rate M12/C1 Dawn Parkway rates.
(2) Includes the impact of the proposed Dawn Parkway rate design proposal for 2024.

Parkway Station Demand - Allocation of Measuring and Regulating, Compression Costs and All Other Costs using Current Approved Cost Allocation Methodology

Line No.	Particulars ($000s)	Allocator (1)	Measuring and Regulating Costs (2)	Compression Costs (2)	All Other Costs (2)	Parkway Station Demand Costs
		(a)	(b)	(c)	(d)	(e) = (b + c + d)
	EGD Rate Zone					
1	Rate 1	7,597	886	4,388	3,801	9,075
2	Rate 6	6,779	790	3,916	3,392	8,098
3	Rate 100	24	3	14	12	29
4	Rate 110	778	91	449	389	929
5	Rate 115	163	19	94	82	195
6	Rate 125	-	-	-	-	-
7	Rate 135	3		2	1	3
8	Rate 145	-	-	-	-	-
9	Rate 170	-	-	-	-	-
10	Rate 200	180	21	104	90	215
11	Rate 300	-	-	-	-	-
12	Total EGD Rate Zone	15,524	1,810	8,968	7,767	18,545
	Union North Rate Zone					
13	Rate 01	1,398	163	808	700	1,671
14	Rate 10	413	48	238	207	493
15	Rate 20	146	17	84	73	175
16	Rate 25	-	-	-	-	-
17	Rate 100	-	-	-	-	-
18	Total Union North Rate Zone	1,957	228	1,131	979	2,338
	Union South Rate Zone					
19	Rate M1	4,475	522	2,585	2,239	5,345
20	Rate M2	1,658	193	958	830	1,981
21	Rate M4 (F)	590	69	341	295	705
22	Rate M4 (I)	-	-	-	-	-
23	Rate M5 (F)	5	1	3	3	6
24	Rate M5 (I)	-	-	-	-	-
25	Rate M7 (F)	873	102	504	437	1,043
26	Rate M7 (I)	-	-	-	-	-
27	Rate M9	71	8	41	36	85
28	Rate T1 (F)	164	19	95	82	196
29	Rate T1 (I)	-	-	-	-	-
30	Rate T2 (F)	2,075	242	1,199	1,038	2,479
31	Rate T2 (I)	-	-	-	-	-
32	Rate T3	206	24	119	103	246
33	Total Union South Rate Zone	10,117	1,179	5,845	5,062	12,086
34	Total In-franchise	27,599	3,217	15,944	13,809	32,970
	Ex-franchise					
35	Rate 331	-	-	-	-	-
36	Rate 332	-	-	-	-	-
37	Rate 401	-	-	-	-	-
38	Rate M12	11,736	1,368	6,780	5,872	14,020
39	Rate M13	-	-	-	-	-
40	Rate M16	-	-	-	-	-
41	Rate M17	36	4	21	18	43
42	Rate C1 (F)	194	23	112	97	232
43	Rate C1 (I)	-	-	-	-	-
44	Total Ex-franchise	11,966	1,395	6,913	5,987	14,295
45	Total	39,565	4,612	22,856	19,796	47,265

Notes:
(1) Dawn Parkway demand transmission allocation, adjusted to include distance credit for volumes obligated at Parkway.
(2) Allocation in proportion to column (a).

Parkway Station Demand - Allocation of Measuring and Regulating, Compression Costs and All Other Costs using Proposed Cost Allocation Methodology

Line No.	Particulars ($000s)	PKWY_DEMAND Allocator (1)	Measuring and Regulating Costs (2)	Compression Costs (2)	All Other Costs (2)	Parkway Station Demand Costs (3)
		(a)	(b)	(c)	(d)	(e) = (b + c + d)
	EGD Rate Zone					
1	Rate 1	14.66	676	3,350	2,902	6,928
2	Rate 6	13.08	603	2,990	2,589	6,182
3	Rate 100	0.05	2	11	9	22
4	Rate 110	1.50	69	343	297	709
5	Rate 115	0.32	15	72	62	149
6	Rate 125	-	-	-	-	-
7	Rate 135	0.01		1	1	2
8	Rate 145	-	-	-	-	-
9	Rate 170	-	-	-	-	-
10	Rate 200	0.35	16	80	69	164
11	Rate 300	-	-	-	-	-
12	Total EGD Rate Zone	29.95	1,381	6,846	5,930	14,158
	Union North Rate Zone					
13	Rate 01	2.70	124	617	534	1,275
14	Rate 10	0.80	37	182	158	376
15	Rate 20	0.37	17	84	73	174
16	Rate 25	-	-	-	-	-
17	Rate 100	-	-	-	-	-
18	Total Union North Rate Zone	3.86	178	883	765	1,826
	Union South Rate Zone					
19	Rate M1	8.63	398	1,973	1,709	4,081
20	Rate M2	3.20	148	731	633	1,512
21	Rate M4 (F)	1.14	53	260	225	538
22	Rate M4 (I)	-	-	-	-	-
23	Rate M5 (F)	0.01		2	2	5
24	Rate M5 (I)	-	-	-	-	-
25	Rate M7 (F)	1.68	78	385	333	796
26	Rate M7 (I)	-	-	-	-	-
27	Rate M9	0.14	6	31	27	65
28	Rate T1 (F)	-	-	-	-	-
29	Rate T1 (I)	-	-	-	-	-
30	Rate T2 (F)	-	-	-	-	-
31	Rate T2 (I)	-	-	-	-	-
32	Rate T3	-	-	-	-	-
33	Total Union South Rate Zone	14.80	683	3,384	2,930	6,997
34	Total In-franchise	48.62	2,242	11,113	9,625	22,980
	Ex-franchise					
35	Rate 331	-	-	-	-	-
36	Rate 332	-	-	-	-	-
37	Rate 401	-	-	-	-	-
38	Rate M12	50.68	2,338	11,585	10,034	23,956
39	Rate M13	-	-	-	-	-
40	Rate M16	-	-	-	-	-
41	Rate M17	-	-	-	-	-
42	Rate C1 (F)	0.70	32	159	138	329
43	Rate C1 (I)	-	-	-	-	-
44	Total Ex-franchise	51.38	2,370	11,744	10,171	24,284
45	Total	100	4,612	22,856	19,796	47,265

Notes:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 43, updated March 8, 2023.
(2) Allocation in proportion to column (a).
(3) Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 15, updated March 8, 2023.

Dawn Station Demand - Allocation of Measuring and Regulating, Compression Costs
and All Other Costs using Current Approved Cost Allocation Methodology

Line No.	Particulars ($000s)	DAWN_DEMAND Allocator (1)	Measuring and Regulating Costs (2)	Compression Costs (2)	All Other Costs (2)	Dawn Station Demand Costs
		(a)	(b)	(c)	(d)	(e) = (b + c + d)
	EGD Rate Zone					
1	Rate 1	37,289	370	4,825	3,621	8,817
2	Rate 6	33,277	330	4,306	3,232	7,868
3	Rate 100	117	1	15	11	28
4	Rate 110	3,818	38	494	371	903
5	Rate 115	802	8	104	78	190
6	Rate 125	-	-	-	-	-
7	Rate 135	13		2	1	3
8	Rate 145	-	-	-	-	-
9	Rate 170	-	-	-	-	-
10	Rate 200	885	9	115	86	209
11	Rate 300	-	-	-	-	-
12	Total EGD Rate Zone	76,202	757	9,861	7,400	18,018
	Union North Rate Zone					
13	Rate 01	6,864	68	888	667	1,623
14	Rate 10	2,026	20	262	197	479
15	Rate 20	689	7	89	67	163
16	Rate 25	-	-	-	-	-
17	Rate 100	-	-	-	-	-
18	Total Union North Rate Zone	9,580	95	1,240	930	2,265
	Union South Rate Zone					
19	Rate M1	21,964	218	2,842	2,133	5,193
20	Rate M2	8,138	81	1,053	790	1,924
21	Rate M4 (F)	2,897	29	375	281	685
22	Rate M4 (I)	-	-	-	-	-
23	Rate M5 (F)	25		3	2	6
24	Rate M5 (I)	-	-	-	-	-
25	Rate M7 (F)	4,285	43	555	416	1,013
26	Rate M7 (I)	-	-	-	-	-
27	Rate M9	350	3	45	34	83
28	Rate T1 (F)	1,188	12	154	115	281
29	Rate T1 (I)	-	-	-	-	-
30	Rate T2 (F)	15,011	149	1,943	1,458	3,549
31	Rate T2 (I)	-	-	-	-	-
32	Rate T3	1,489	15	193	145	352
33	Total Union South Rate Zone	55,348	550	7,162	5,375	13,087
34	Total In-franchise	141,130	1,402	18,263	13,705	33,369
	Ex-franchise					
35	Rate 331	-	-	-	-	-
36	Rate 332	-	-	-	-	-
37	Rate 401	-	-	-	-	-
38	Rate M12	79,461	789	10,282	7,717	18,788
39	Rate M13	-	-	-	-	-
40	Rate M16	-	-	-	-	-
41	Rate M17	227	2	29	22	54
42	Rate C1 (F)	849	8	110	82	201
43	Rate C1 (I)	-	-	-	-	-
44	Total Ex-franchise	80,537	800	10,422	7,821	19,043
45	Total	221,667	2,201	28,684	21,526	52,412

Notes:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 15, updated March 8, 2023.
(2) Allocation in proportion to column (a).

Dawn Station Demand - Allocation of Measuring and Regulating, Compression Costs
and All Other Costs using Proposed Cost Allocation Methodology

Line No.	Particulars ($000s)	DAWN_DEMAND Allocator (1)	Measuring and Regulating Costs (2)	Compression Costs (2)	All Other Costs (2)	Dawn Station Demand Costs (1)
		(a)	(b)	(c)	(d)	(e) = (b + c + d)
	EGD Rate Zone					
1	Rate 1	37,289	872	-	1,234	2,107
2	Rate 6	33,277	778	-	1,102	1,880
3	Rate 100	117	3	-	4	7
4	Rate 110	3,818	89	-	126	216
5	Rate 115	802	19	-	27	45
6	Rate 125	-	-	-	-	-
7	Rate 135	13		-		1
8	Rate 145	-	-	-	-	-
9	Rate 170	-	-	-	-	-
10	Rate 200	885	21	-	29	50
11	Rate 300	-	-	-	-	-
12	Total EGD Rate Zone	76,202	1,783	-	2,523	4,305
	Union North Rate Zone					
13	Rate 01	6,864	161	-	227	388
14	Rate 10	2,026	47	-	67	114
15	Rate 20	689	16	-	23	39
16	Rate 25	-	-	-	-	-
17	Rate 100	-	-	-	-	-
18	Total Union North Rate Zone	9,580	224	-	317	541
	Union South Rate Zone					
19	Rate M1	21,964	514	-	727	1,241
20	Rate M2	8,138	190	-	269	460
21	Rate M4 (F)	2,897	68	-	96	164
22	Rate M4 (I)	-	-	-	-	-
23	Rate M5 (F)	25	1	-	1	1
24	Rate M5 (I)	-	-	-	-	-
25	Rate M7 (F)	4,285	100	-	142	242
26	Rate M7 (I)	-	-	-	-	-
27	Rate M9	350	8	-	12	20
28	Rate T1 (F)	1,188	28	-	39	67
29	Rate T1 (I)	-	-	-	-	-
30	Rate T2 (F)	15,011	351	-	497	848
31	Rate T2 (I)	-	-	-	-	-
32	Rate T3	1,489	35	-	49	84
33	Total Union South Rate Zone	55,348	1,295	-	1,832	3,127
34	Total In-franchise	141,130	3,301	-	4,672	7,974
	Ex-franchise					
35	Rate 331	-	-	-	-	-
36	Rate 332	-	-	-	-	-
37	Rate 401	-	-	-	-	-
38	Rate M12	79,461	1,859	-	2,631	4,489
39	Rate M13	-	-	-	-	-
40	Rate M16	-	-	-	-	-
41	Rate M17	227	5	-	8	13
42	Rate C1 (F)	849	20	-	28	48
43	Rate C1 (I)	-	-	-	-	-
44	Total Ex-franchise	80,537	1,884	-	2,666	4,550
45	Total	221,667	5,185	-	7,338	12,524

Notes:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 15, updated March 8, 2023.
(2) Allocation in proportion to column (a).
(3) Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 13, updated March 8, 2023.

Dawn Parkway Demand - Allocation of Measuring and Regulating, Compression Costs and All Other Costs using Current Approved Cost Allocation Methodology

Line No.	Particulars ($000s)	Allocator (1)	Measuring and Regulating Costs (2)	Compression Costs (2)	All Other Costs (2)	Dawn Parkway Demand Costs
		(a)	(b)	(c)	(d)	(e) = (b + c + d)
	EGD Rate Zone					
1	Rate 1	7,597	-	15,431	32,718	48,149
2	Rate 6	6,779	-	13,770	29,198	42,968
3	Rate 100	24	-	49	103	152
4	Rate 110	778	-	1,580	3,350	4,930
5	Rate 115	163	-	332	704	1,036
6	Rate 125	-	-	-	-	-
7	Rate 135	3	-	6	12	17
8	Rate 145	-	-	-	-	-
9	Rate 170	-	-	-	-	-
10	Rate 200	180	-	366	777	1,143
11	Rate 300	-	-	-	-	-
12	Total EGD Rate Zone	15,524	-	31,534	66,862	98,396
	Union North Rate Zone					
13	Rate 01	1,398	-	2,841	6,023	8,864
14	Rate 10	413	-	839	1,778	2,617
15	Rate 20	146	-	297	629	926
16	Rate 25	-	-	-	-	-
17	Rate 100	-	-	-	-	-
18	Total Union North Rate Zone	1,957	-	3,976	8,430	12,406
	Union South Rate Zone					
19	Rate M1	4,475	-	9,089	19,272	28,361
20	Rate M2	1,658	-	3,368	7,141	10,508
21	Rate M4 (F)	590	-	1,199	2,542	3,741
22	Rate M4 (I)	-	-	-	-	-
23	Rate M5 (F)	5	-	11	22	33
24	Rate M5 (I)	-	-	-	-	-
25	Rate M7 (F)	873	-	1,773	3,760	5,533
26	Rate M7 (I)	-	-	-	-	-
27	Rate M9	71	-	145	307	452
28	Rate T1 (F)	164	-	334	708	1,041
29	Rate T1 (I)	-	-	-	-	-
30	Rate T2 (F)	2,075	-	4,215	8,938	13,153
31	Rate T2 (I)	-	-	-	-	-
32	Rate T3	206	-	418	886	1,304
33	Total Union South Rate Zone	10,117	-	20,551	43,575	64,126
34	Total In-franchise	27,599	-	56,061	118,867	174,928
	Ex-franchise					
35	Rate 331	-	-	-	-	-
36	Rate 332	-	-	-	-	-
37	Rate 401	-	-	-	-	-
38	Rate M12	11,736	-	23,839	43,056	66,895
39	Rate M13	-	-	-	-	-
40	Rate M16	-	-	-	-	-
41	Rate M17	36	-	73	133	206
42	Rate C1 (F)	194	-	395	713	1,108
43	Rate C1 (I)	-	-	-	-	-
44	Total Ex-franchise	11,966	-	24,307	43,902	68,209
45	Total	39,565	-	80,368	162,769	243,137

Notes:
(1) Dawn Parkway demand transmission allocation, adjusted to include distance credit for volumes obligated at Parkway.
(2) Allocation in proportion to column (a).

Dawn Parkway Demand - Allocation of Measuring and Regulating, Compression Costs and All Other Costs using Proposed Cost Allocation Methodology

Line No.	Particulars ($000s)	D-PTRANS Allocator (1)	Measuring and Regulating Costs (2)	Compression Costs (2)	All Other Costs (2)	Dawn Parkway Demand Costs (1)
		(a)	(b)	(c)	(d)	(e) = (b + c + d)
	EGD Rate Zone					
1	Rate 1	7,959	-	15,487	31,367	46,854
2	Rate 6	7,103	-	13,821	27,991	41,812
3	Rate 100	25	-	49	99	147
4	Rate 110	815	-	1,586	3,212	4,798
5	Rate 115	171	-	333	675	1,008
6	Rate 125	-	-	-	-	-
7	Rate 135	3	-	6	11	17
8	Rate 145	-	-	-	-	-
9	Rate 170	-	-	-	-	-
10	Rate 200	189	-	368	745	1,112
11	Rate 300	-	-	-	-	-
12	Total EGD Rate Zone	16,265	-	31,649	64,099	95,749
	Union North Rate Zone					
13	Rate 01	1,465	-	2,851	5,774	8,625
14	Rate 10	433	-	842	1,705	2,546
15	Rate 20	151	-	293	593	886
16	Rate 25	-	-	-	-	-
17	Rate 100	-	-	-	-	-
18	Total Union North Rate Zone	2,048	-	3,986	8,072	12,058
	Union South Rate Zone					
19	Rate M1	4,688	-	9,122	18,475	27,598
20	Rate M2	1,737	-	3,380	6,846	10,226
21	Rate M4 (F)	618	-	1,203	2,437	3,640
22	Rate M4 (I)	-	-	-	-	-
23	Rate M5 (F)	5	-	11	21	32
24	Rate M5 (I)	-	-	-	-	-
25	Rate M7 (F)	915	-	1,780	3,605	5,384
26	Rate M7 (I)	-	-	-	-	-
27	Rate M9	75	-	145	294	440
28	Rate T1 (F)	200	-	390	790	1,180
29	Rate T1 (I)	-	-	-	-	-
30	Rate T2 (F)	2,532	-	4,928	9,980	14,908
31	Rate T2 (I)	-	-	-	-	-
32	Rate T3	251	-	489	990	1,479
33	Total Union South Rate Zone	11,022	-	21,448	43,438	64,887
34	Total In-franchise	29,336	-	57,083	115,610	172,693
	Ex-franchise					
35	Rate 331	-	-	-	-	-
36	Rate 332	-	-	-	-	-
37	Rate 401	-	-	-	-	-
38	Rate M12	11,736	-	22,836	46,250	69,086
39	Rate M13	-	-	-	-	-
40	Rate M16	-	-	-	-	-
41	Rate M17	36	-	70	142	213
42	Rate C1 (F)	194	-	378	766	1,145
43	Rate C1 (I)	-	-	-	-	-
44	Total Ex-franchise	11,966	-	23,285	47,159	70,444
45	Total	41,302	-	80,368	162,769	243,137

Notes:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 19, updated March 8, 2023.
(2) Allocation in proportion to column (a).
(3) Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 16, updated March 8, 2023.

Rate Class Impacts of Parkway Station Proposed Cost Allocation Methodology

		Current Approved Cost Allocation Methodology		Proposed Cost Allocation Methodology		
Line No.	Particulars	Allocator (1)	Allocation ($000s) (2)	PKWY_DEMAND Allocator (3)	Allocation ($000s) (4)	Variance
		(a)	(b)	(c)	(d)	(e) = (d - b)
	EGD Rate Zone					
1	Rate 1	7,597	9,075	15	6,928	(2,147)
2	Rate 6	6,779	8,098	13	6,182	(1,916)
3	Rate 100	24	29		22	(7)
4	Rate 110	778	929	2	709	(220)
5	Rate 115	163	195		149	(46)
6	Rate 125	-	-	-	-	-
7	Rate 135	3	3		2	(1)
8	Rate 145	-	-	-	-	-
9	Rate 170	-	-	-	-	-
10	Rate 200	180	215		164	(51)
11	Rate 300	-	-	-	-	-
12	Total EGD Rate Zone	15,524	18,545	30	14,158	(4,388)
	Union North Rate Zone					
13	Rate 01	1,398	1,671	3	1,275	(395)
14	Rate 10	413	493	1	376	(117)
15	Rate 20	146	175		174	()
16	Rate 25	-	-	-	-	-
17	Rate 100	-	-	-	-	-
18	Total Union North Rate Zone	1,957	2,338	4	1,826	(512)
	Union South Rate Zone					
19	Rate M1	4,475	5,345	9	4,081	(1,265)
20	Rate M2	1,658	1,981	3	1,512	(469)
21	Rate M4 (F)	590	705	1	538	(167)
22	Rate M4 (I)	-	-	-	-	-
23	Rate M5 (F)	5	6		5	(1)
24	Rate M5 (I)	-	-	-	-	-
25	Rate M7 (F)	873	1,043	2	796	(247)
26	Rate M7 (I)	-	-	-	-	-
27	Rate M9	71	85		65	(20)
28	Rate T1 (F)	164	196	-	-	(196)
29	Rate T1 (I)	-	-	-	-	-
30	Rate T2 (F)	2,075	2,479	-	-	(2,479)
31	Rate T2 (I)	-	-	-	-	-
32	Rate T3	206	246	-	-	(246)
33	Total Union South Rate Zone	10,117	12,086	15	6,997	(5,089)
	Ex-Franchise					
34	Rate 331	-	-	-	-	-
35	Rate 332	-	-	-	-	-
36	Rate 401	-	-	-	-	-
37	Rate M12	11,736	14,020	51	23,956	9,936
38	Rate M13	-	-	-	-	-
39	Rate M16	-	-	-	-	-
40	Rate M17	36	43	-	-	(43)
41	Rate C1 (F)	194	232	1	329	96
42	Rate C1 (I)	-	-	-	-	-
43	Total Ex-Franchise	11,966	14,295	51	24,284	9,989
44	Total	39,565	47,265	100	47,265	-

Notes:
(1) Dawn Parkway demand transmission allocation, adjusted to include distance credit for volumes obligated at Parkway.
(2) Allocated using column (a).
(3) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 43, updated March 8, 2023.
(4) Allocated using column (c).

Rate Class Impacts of Dawn Station Proposed Cost Allocation Methodology

		Allocator		Current Approved Cost Allocation Methodology			Proposed Cost Allocation Methodology			
Line No.	Particulars	DAWN_DEMAND Allocator (1)	DPTRANS Allocator (2)	Dawn Station Allocation ($000s) (3)(5)	Dawn Parkway Allocation ($000s) (4)(5)	Total Allocation	Dawn Station Allocation ($000s) (3)(6)	Dawn Parkway Allocation ($000s) (4)(7)	Total Allocation	Variance (8)
		(a)	(b)	(c)	(d)	(e) = (c + d)	(f)	(g)	(h) = (f + g)	(i) = (h - e)
	EGD Rate Zone									
1	Rate 1	37,289	7,959	8,817	39,167	47,984	2,107	46,854	48,961	977
2	Rate 6	33,277	7,103	7,868	34,953	42,821	1,880	41,812	43,692	872
3	Rate 100	117	25	28	123	151	7	147	154	3
4	Rate 110	3,818	815	903	4,011	4,913	216	4,798	5,013	100
5	Rate 115	802	171	190	843	1,033	45	1,008	1,054	21
6	Rate 125	-	-	-	-	-	-	-	-	-
7	Rate 135	13	3	3	14	17	1	17	17	
8	Rate 145	-	-	-	-	-	-	-	-	-
9	Rate 170	-	-	-	-	-	-	-	-	-
10	Rate 200	885	189	209	930	1,139	50	1,112	1,162	23
11	Rate 300	-	-	-	-	-	-	-	-	-
12	Total EGD Rate Zone	76,202	16,265	18,018	80,041	98,058	4,305	95,749	100,054	1,996
	Union North Rate Zone									
13	Rate 01	6,864	1,465	1,623	7,210	8,833	388	8,625	9,013	180
14	Rate 10	2,026	433	479	2,129	2,608	114	2,546	2,661	53
15	Rate 20	689	151	163	741	904	39	886	925	21
16	Rate 25	-	-	-	-	-	-	-	-	-
17	Rate 100	-	-	-	-	-	-	-	-	-
18	Total Union North Rate Zone	9,580	2,048	2,265	10,080	12,345	541	12,058	12,599	254
	Union South Rate Zone									
19	Rate M1	21,964	4,688	5,193	23,070	28,263	1,241	27,598	28,839	575
20	Rate M2	8,138	1,737	1,924	8,548	10,472	460	10,226	10,686	213
21	Rate M4 (F)	2,897	618	685	3,043	3,728	164	3,640	3,804	76
22	Rate M4 (I)	-	-	-	-	-	-	-	-	-
23	Rate M5 (F)	25	5	6	27	33	1	32	33	1
24	Rate M5 (I)	-	-	-	-	-	-	-	-	-
25	Rate M7 (F)	4,285	915	1,013	4,501	5,514	242	5,384	5,626	112
26	Rate M7 (I)	-	-	-	-	-	-	-	-	-
27	Rate M9	350	75	83	367	450	20	440	459	9
28	Rate T1 (F)	1,188	200	281	987	1,268	67	1,180	1,247	(20)
29	Rate T1 (I)	-	-	-	-	-	-	-	-	-
30	Rate T2 (F)	15,011	2,532	3,549	12,462	16,012	848	14,908	15,756	(255)
31	Rate T2 (I)	-	-	-	-	-	-	-	-	-
32	Rate T3	1,489	251	352	1,236	1,588	84	1,479	1,563	(25)
33	Total Union South Rate Zone	55,348	11,022	13,087	54,241	67,328	3,127	64,887	68,014	685
	Ex-Franchise									
34	Rate 331	-	-	-	-	-	-	-	-	-
35	Rate 332	-	-	-	-	-	-	-	-	-
36	Rate 401	-	-	-	-	-	-	-	-	-
37	Rate M12	79,461	11,736	18,788	57,752	76,540	4,489	69,086	73,576	(2,965)
38	Rate M13	-	-	-	-	-	-	-	-	-
39	Rate M16	-	-	-	-	-	-	-	-	-
40	Rate M17	227	36	54	178	232	13	213	226	(6)
41	Rate C1 (F)	849	194	201	957	1,158	48	1,145	1,193	35
42	Rate C1 (I)	-	-	-	-	-	-	-	-	-
43	Total Ex-Franchise	80,537	11,966	19,043	58,887	77,930	4,550	70,444	74,994	(2,936)
44	Total	221,667	41,302	52,412	203,249	255,661	12,524	243,137	255,661	-

Notes:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 15, updated March 8, 2023.
(2) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 19, updated March 8, 2023.
(3) Allocated using column (a).
(4) Allocated using column (c).
(5) Totals excludes shift of Dawn Station related compressor costs to Dawn Parkway and Dawn Parkway related measuring and regulating costs to Dawn Station.
(6) Total per Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 13, updated March 8, 2023.
(7) Total per Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 16, updated March 8, 2023.
(8) Any adjustments to the Dawn Parkway allocation factor impact the Dawn Parkway portion of the Operational Contingency allocation factor and subsequent allocation.

Rate Class Impacts of Dawn Parkway Proposed Cost Allocation Methodology

		Allocators			Current Approved Cost Allocation Methodology					
Line No.	Particulars	Dawn Parkway Allocator (1)	Dawn Station Allocator (2)	Parkway Station Allocator (3)	Dawn Parkway Allocation ($000s) (4)	Dawn Station Allocation ($000s) (5)	Parkway Station Allocation ($000s) (6)	PDCI Allocation ($000s) (7)	Operational Contingency ($000s) (8)	Total Allocation ($000s)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i) = (d+e+f+g+h)
	EGD Rate Zone									
1	Rate 1	7,597	35,692	15	43,301	2,089	6,866	4,848	2,045	59,149
2	Rate 6	6,779	31,851	13	38,642	1,864	6,127	4,326	1,807	52,766
3	Rate 100	24	112		136	7	22	15	2	182
4	Rate 110	778	3,655	1	4,434	214	703	496	55	5,903
5	Rate 115	163	768		932	45	148	104	13	1,242
6	Rate 125	-	-	-	-	-	-	-	16	16
7	Rate 135	3	13		15	1	2	2	1	21
8	Rate 145	-	-	-	-	-	-	-	1	1
9	Rate 170	-	-	-	-	-	-	-	8	8
10	Rate 200	180	847		1,028	50	163	115	16	1,371
11	Rate 300	-	-	-	-	-	-	-	-	-
12	Total EGD Rate Zone	15,524	72,938	30	88,489	4,268	14,032	9,907	3,964	120,659
	Union North Rate Zone									
13	Rate 01	1,398	6,570	3	7,971	384	1,264	892	404	10,915
14	Rate 10	413	1,940	1	2,353	114	373	263	117	3,220
15	Rate 20	146	669		833	39	174	93	27	1,166
16	Rate 25	-	-	-	-	-	-	-	2	2
17	Rate 100	-	-	-	-	-	-	-	21	21
18	Total Union North Rate Zone	1,957	9,179	4	11,157	537	1,811	1,249	570	15,325
	Union South Rate Zone									
19	Rate M1	4,475	21,023	9	25,505	1,230	4,044	2,855	1,301	34,937
20	Rate M2	1,658	7,790	3	9,450	456	1,499	1,058	461	12,924
21	Rate M4 (F)	590	2,773	1	3,364	162	533	377	34	4,470
22	Rate M4 (I)	-	-	-	-	-	-	-		
23	Rate M5 (F)	5	24		30	1	5	3		39
24	Rate M5 (I)	-	-	-	-	-	-	-	1	1
25	Rate M7 (F)	873	4,102	2	4,976	240	789	557	46	6,608
26	Rate M7 (I)	-	-	-	-	-	-	-	3	3
27	Rate M9	71	335		406	20	64	45	5	540
28	Rate T1 (F)	164	1,029		936	60	7	105	18	1,126
29	Rate T1 (I)	-	-	-	-	-	-	-	-	-
30	Rate T2 (F)	2,075	12,991		11,829	760	83	1,324	178	14,174
31	Rate T2 (I)	-	-	-	-	-	-	-	-	-
32	Rate T3	206	1,288		1,173	75	8	131	23	1,411
33	Total Union South Rate Zone	10,117	51,354	15	57,670	3,005	7,032	6,456	2,070	76,234
	Ex-Franchise									
34	Rate 331	-	-	-	-	-	-	-	6	6
35	Rate 332	-	-	-	-	-	-	-	47	47
36	Rate 401	-	-	-	-	-	-	-	-	-
37	Rate M12	11,736	79,461	51	66,895	4,650	24,059	-	379	95,982
38	Rate M13	-	-	-	-	-	-	-	2	2
39	Rate M16	-	-	-	-	-	-	-	5	5
40	Rate M17	36	227	-	206	13	-	-	1	221
41	Rate C1 (F)	194	849	1	1,108	50	331	-	122	1,611
42	Rate C1 (I)	-	-	-	-	-	-	-	21	21
43	Total Ex-Franchise	11,966	80,537	52	68,209	4,713	24,390	-	582	97,894
44	Total	39,565	214,008	100	225,525	12,524	47,265	17,612	7,187	310,112

Notes:
(1) Dawn Parkway transmission demand allocation factor, adjusted to exclude design day demands served from Parkway Station.
(2) Dawn Station transmission demand allocation factor, adjusted to exclude design day demands served from Parkway Station.
(3) Parkway Station transmission demand allocation factor, adjusted to include design day demands served from Parkway Station.
(4) Exhibit 7, Tab 2, Schedule 1, Attachment 6, page 3, column (i), line 103 - line 69, updated March 8, 2023. Allocated using column (a).
(5) Exhibit 7, Tab 2, Schedule 1, Attachment 6, page 3, column (f), line 103, updated March 8, 2023. Allocated using column (b).
(6) Exhibit 7, Tab 2, Schedule 1, Attachment 6, page 3, column (h), line 103, updated March 8, 2023. Allocated using column (c).
(7) Exhibit 7, Tab 2, Schedule 1, Attachment 6, page 3, column (i), line 69, updated March 8, 2023. Allocated to in-franchise rate classes only using column (a).
(8) Any adjustments to the Dawn Parkway allocation factor impact the Dawn Parkway portion of the Operational Contingency allocation factor and subsequent allocation.

Rate Class Impacts of Dawn Parkway Proposed Cost Allocation Methodology

		Allocators			Proposed Cost Allocation Methodology						
Line No.	Particulars	Dawn Parkway Allocator (1)	Dawn Station Allocator (2)	Parkway Station Allocator (3)	Dawn Parkway Allocation ($000s) (4)	Dawn Station Allocation ($000s) (5)	Parkway Station Allocation ($000s) (6)	PDCI Allocation ($000s) (7)	Operational Contingency ($000s) (8)	Total Allocation ($000s)	Impact ($000s) (9)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i) = (d+e+f+g+h)	(j)
	EGD Rate Zone										
1	Rate 1	7,959	37,289	15	43,460	2,107	6,928	3,394	2,046	57,934	(1,215)
2	Rate 6	7,103	33,277	13	38,783	1,880	6,182	3,029	1,807	51,682	(1,084)
3	Rate 100	25	117		137	7	22	11	2	178	(4)
4	Rate 110	815	3,818	2	4,450	216	709	348	55	5,778	(124)
5	Rate 115	171	802		935	45	149	73	13	1,216	(26)
6	Rate 125	-	-	-	-	-	-	-	16	16	()
7	Rate 135	3	13		16	1	2	1	1	21	()
8	Rate 145	-	-	-	-	-	-	-	1	1	()
9	Rate 170	-	-	-	-	-	-	-	8	8	()
10	Rate 200	189	885		1,032	50	164	81	16	1,343	(29)
11	Rate 300	-	-	-	-	-	-	-	-	-	-
12	Total EGD Rate Zone	16,265	76,202	30	88,813	4,305	14,158	6,936	3,965	118,176	(2,483)
	Union North Rate Zone										
13	Rate 01	1,465	6,864	3	8,000	388	1,275	625	404	10,692	(224)
14	Rate 10	433	2,026	1	2,362	114	376	184	117	3,154	(66)
15	Rate 20	151	689		822	39	174	64	27	1,126	(40)
16	Rate 25	-	-	-	-	-	-	-	2	2	()
17	Rate 100	-	-	-	-	-	-	-	21	21	()
18	Total Union North Rate Zone	2,048	9,580	4	11,184	541	1,826	873	571	14,996	(329)
	Union South Rate Zone										
19	Rate M1	4,688	21,964	9	25,599	1,241	4,081	1,999	1,302	34,221	(716)
20	Rate M2	1,737	8,138	3	9,485	460	1,512	741	461	12,659	(265)
21	Rate M4 (F)	618	2,897	1	3,376	164	538	264	34	4,376	(94)
22	Rate M4 (I)	-	-	-	-	-	-	-			()
23	Rate M5 (F)	5	25		30	1	5	2		38	(1)
24	Rate M5 (I)	-	-	-	-	-	-	-	1	1	()
25	Rate M7 (F)	915	4,285	2	4,994	242	796	390	46	6,469	(140)
26	Rate M7 (I)	-	-	-	-	-	-	-	3	3	()
27	Rate M9	75	350		408	20	65	32	5	529	(11)
28	Rate T1 (F)	200	1,188	-	1,095	67	-	85	19	1,266	140
29	Rate T1 (I)	-	-	-	-	-	-	-	-	-	-
30	Rate T2 (F)	2,532	15,011	-	13,828	848	-	1,080	184	15,941	1,767
31	Rate T2 (I)	-	-	-	-	-	-	-	-	-	-
32	Rate T3	251	1,489	-	1,371	84	-	107	24	1,587	175
33	Total Union South Rate Zone	11,022	55,348	15	60,186	3,127	6,997	4,700	2,079	77,089	855
	Ex-Franchise										
34	Rate 331	-	-	-	-	-	-	-	6	6	-
35	Rate 332	-	-	-	-	-	-	-	47	47	-
36	Rate 401	-	-	-	-	-	-	-	-	-	-
37	Rate M12	11,736	79,461	51	64,082	4,489	23,956	5,004	370	97,901	1,919
38	Rate M13	-	-	-	-	-	-	-	2	2	-
39	Rate M16	-	-	-	-	-	-	-	5	5	-
40	Rate M17	36	227	-	197	13	-	15	1	227	6
41	Rate C1 (F)	194	849	1	1,062	48	329	83	121	1,643	32
42	Rate C1 (I)	-	-	-	-	-	-	-	21	21	-
43	Total Ex-Franchise	11,966	80,537	51	65,341	4,550	24,284	5,103	573	99,852	1,957
44	Total	41,302	221,667	100	225,525	12,524	47,265	17,612	17,612	310,112	-

Notes:
(1) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 19, updated March 8, 2023.
(2) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 11-13, line 15, updated March 8, 2023.
(3) Exhibit 7, Tab 2, Schedule 1, Attachment 12, pages 14-16, line 43, updated March 8, 2023.
(4) Allocated using column (a). Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 16, updated March 8, 2023. Sum of column (d) and column (g).
(5) Allocated using column (b). Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 13, updated March 8, 2023.
(6) Allocated using column (c). Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 15, updated March 8, 2023.
(7) Allocated using column (a). Exhibit 7, Tab 2, Schedule 1, Attachment 8, line 16, updated March 8, 2023. Sum of column (d) and column (g).
(8) Any adjustments to the Dawn Parkway allocation factor impact the Dawn Parkway portion of the Operational Contingency allocation factor and subsequent allocation.
(9) Exhibit 7, Tab 1, Schedule 4, Attachment 1, column (d), updated March 8, 2023.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit 7, Tab 1, Schedule 1, 3

Question(s):

The EGD and Union cost allocation studies were underpinned with customer information, system operations detail, and financial data from different IT systems. At times, Enbridge Gas was limited in proposing cost allocation methodologies based on information that was common and available for the amalgamated utility.

The Company was not able to recreate two stand-alone cost allocation studies for the EGD and Union rate zones in the same format that was approved in EGD's and Union's respective 2013 Cost of Service proceedings.

a) Given that the data appears to be from two separate IT systems please provide specific reasons why the prior approved cost allocation methodologies/ studies for EGD and Union could not be used to determine 2024 rates.

b) Please provide the last utilized excel models that were used for last Board approved EGD and Union rate zone cost allocations.

Response:

a) The OEB required[1] Enbridge Gas to file a proposal for rate harmonization with the current Application. The Cost Allocation Study underpinning proposed rates was prepared to support the proposal for rate harmonization. The rate harmonization plan is an important next step to move forward and continue planning for further integration as an amalgamated utility with a consistent customer experience.

   Enbridge Gas has continued to maintain asset detail and rate base information by rate zone through its IT systems, however, operating and maintenance costs are no longer prepared on the basis of current rate zones. Since amalgamation, the Company has integrated its operations and does not budget annual operating

[1] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, p.43.

expenses by current rate zones because the current rate zones are not aligned with how Enbridge Gas operates as an amalgamated utility to serve customers. For example, internal departments such as gas supply, regulatory, customer care and public affairs, among others, have integrated and provide support to the utility as a whole.

Enbridge Gas recognizes that cost allocation methodologies could be used to allocate operating and maintenance costs that are not available by the current rate zones in order to create the two separate cost studies. In order to prepare the two separate cost studies, Enbridge Gas would also need to recreate the current approved cost allocation factors for EGD and Union, many of which have not been maintained or prepared for purposes of this Application. The current approved methodologies could create an inconsistent allocation of costs across rate zones for similar cost types. The additional allocation methodologies to separate O&M costs as well as the separate allocation methodologies for each rate zone, are time consuming to prepare and do not recognize the amalgamation of EGD and Union.

Creating two separate cost studies is not aligned with the OEB's direction to file a proposal for a rate harmonization plan and would create inconsistencies in the treatment and recovery of like cost items across rate zones. Two separate cost studies would result in customers on the boundary point of adjacent rate zones with different rates and rate structures which no longer reflect the current operations of the Company. The challenges with maintaining the current rate zones are provided at Exhibit 8, Tab 2, Schedule 1, page 17.

Enbridge Gas will prepare and file a cost allocation study for the existing rate zones using the proposed Cost Allocation Study structure and cost allocation methodologies prepared for this Application but applied to the existing rate zones. The cost allocation methodologies are provided at Exhibit 7, Tab 1, Schedule 2. Enbridge Gas will file the Cost Allocation Study for the existing rate zones in advance of the settlement conference for this Application. Please see response at Exhibit I.7.0-STAFF-237.

b) Please see Attachment 1 and 2 for the Excel, for the last OEB-approved Cost Allocation Study for EGD and Union, respectively.

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Please see Exhibit I.7.1-VECC-62 Attachment 1.xlsx on the OEB's RDS.

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Please see Exhibit I.7.1-VECC-62 Attachment 2.xls on the OEB's RDS.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit 7, Tab 1, Schedule 4

Question(s):

The Panhandle System and St. Clair System are westerly peaking systems serving in-franchise demands on design day.

a) Does gas ever physically flow westerly on either the Panhandle or St. Clair System?

Response:

a) Yes. The term "westerly" means that the system is located west of Dawn thus gas flows west from Dawn for design day.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit 7, Tab 2, Schedule 1, Attachment 8, *Cost Allocation Existing Rate Zones*

Question(s):

a) Please confirm the following 2024 Cost Allocations to legacy Rate Zones:

   i. Revenue Requirement allocated to EGD Rate 1 $2,305,139
   ii. EGD Rate 6 $1,210,677,
   iii. Revenue Requirement allocated to Union South Rate M1 $1,397,566; Rate M2 $282,434.

b) Please provide the percentage allocations.

c) Please provide a Table with the comparable historic revenue requirement allocations from 2018-2022.

d) Please comment on any shift in allocations over the period 2018-2024.

Response:

a) Not confirmed. Enbridge Gas has updated the net revenue requirement allocated to EGD Rate 1 and Rate 6 and Union South Rate M1 and M2, as provided at Table 1. Please see Exhibit 7, Tab 2, Schedule 1, Attachment 8, updated March 8, 2023.

Table 1
Revenue Requirement by Rate Class

Line No.	Rate Class	2024 Cost Allocation Study ($000s)	2024 Cost Allocation Study (%)	2018/2013 Cost Allocation Study (1) ($000s)
		(a)	(b)	(c)
1	Rate 1	2,322,283	36.8%	1,778,564
2	Rate 6	1,211,058	19.2%	1,066,538
3	Rate M1	1,408,048	22.3%	821,233
4	Rate M2	281,908	4.5%	120,819
5	Total	6,312,905		

Note:
(1) The EGD and Union cost allocation studies were previously approved in 2018[1] and 2013[2], respectively.

b) The percentage allocation for each rate class of the total net revenue requirement is provided in Table 1, column (b).

c) EGD's Cost Allocation Study was last approved by the OEB in 2018.[3] Union's Cost Allocation Study was last approved by the OEB in 2013.[4] The allocated revenue requirement from the last approved Cost Allocation Study for the requested rate classes is provided in Table 1.

Enbridge Gas's rates have been set through a Price Cap IR Framework since 2019 for the EGD rate zone and 2014 for the Union rate zones. As such, the Company has not received OEB approval for a Cost Allocation Study since 2018 for EGD and 2013 for Union and is therefore not able to provide the requested revenue requirement allocation for any years subsequent to the last approved Cost Allocation Study.

d) The allocation of costs from the last approved Cost Allocation Study is impacted by a number of factors including, but not limited to differences in the cost allocation methodologies utilized by EGD and Union compared to the proposed harmonized

[1] EB-2017-0086.
[2] EB-2011-0210.
[3] EB-2017-0086.
[4] EB-2011-0210.

methodologies, changes in customer forecasts, and changes in cost elements including the market price of gas.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 2, Schedule 1, Attachment 1, pg. 2, line 8

Question(s):

Please provide allocation basis for the costs in Line 8.

a) Please provide an Excel copy of the working papers to show the allocation.

Response:

Please see response at Exhibit I.7.1-IGUA-74, part a).

a) Please see Attachment 1 for the Excel, for support for the derivation of the gas supply commodity classification factor.

Cost of Gas Classification Factor

Line No.	Particulars ($000s)	Cost of Gas Classification Factor
		(a)
1	Gas Supply Commodity (1)	2,728,041
2	Load Balancing Transport (2)	175,236
3	Load Balancing Commodity (3)	23,591
4	Transportation Demand (4)	162,050
5	Transportation Commodity (5)	23,899
6	Total	3,112,816

Notes:

(1) Page 2, column (a), line 3.
(2) Page 4, column (f), line 65.
(3) Page 5, column (m), line 8. Filed as Exhibit 4, Tab 2, Schedule 1, Attachment 1, page 5.
(4) Page 4, column (e), line 65.
(5) Page 4, column (i), line 65.

Derivation of Gas Supply Costs for Sales Service Customers

Line No.	Particulars	Sales Total Cost ($000s) (a)
1	Sales service forecast (10^3m^3) (1)	13,147,613
2	Weighted average reference price ($/$10^3m^3$) (2)	207.493
3	Total gas supply cost for sales service customers (line 1 x line 2)	2,728,041

Notes:
(1) Exhibit 4, Tab 2, Schedule 1, Attachment 1, page 6, column (b), line 4.
(2) Exhibit 4, Tab 2, Schedule 2, Attachment 3, page 1, column (e), line 16.

Upstream Transportation Cost Allocation

Line No.	Upstream Pipeline / Transportation Service (1)	2024 Forecast Unitized Demand Charge ($Cdn/GJ)	Total Demand Costs ($000s)	Total Fuel Costs ($000s)	Average Day Demand (TJ/d)	Demand Costs ($000s)				Fuel Costs ($000s)		
						Transportation	Load Balancing	Gas Supply Commodity	Distribution	Transportation Commodity	Gas Supply Commodity	Distribution
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	TransCanada Pipeline											
	Long Haul											
1	Empress to Union NCDA FT	1.264	462	64	1.0	462	-	-	-	64	-	-
2	Empress to Union EDA FT	1.477	2,703	353	2.2	1,212	1,491	-	-	353	-	-
3	Empress to Union NDA FT	1.004	766	123	2.1	766	-	-	-	123	-	-
4	Empress to Union WDA FT	0.645	12,881	1,259	27.1	6,390	6,491	-	-	1,259	-	-
5	Empress to Union SSMDA FT	0.895	6,858	1,037	12.9	4,234	2,624	-	-	1,037	-	-
6	Empress to Union MDA FT	0.459	934	49	1.6	271	663	-	-	49	-	-
7	Empress to Union ECDA FT	1.340	1,472	198	3.0	1,472	-	-	-	198	-	-
8	Empress to Emerson 2 FT	0.486	3,813	-	-	-	-	3,813	-	-	-	-
9	Empress to NBJ FT - NBJ LTFP	0.927	89,954	-	194.1	65,899	24,055	-	-	-	-	-
10	NBJ to Enbridge EDA	0.370	35,198	18,226	189.1	25,605	9,594	-	-	18,226	-	-
11	NBJ to Enbridge CDA	0.340	622	346	5.0	622	-	-	-	346	-	-
12	Diversions											
13	Empress to Union MDA FT	0.865	97	11	-	-	97	-	-	11	-	-
14	Empress to Union SSMDA FT	0.428	1,312	115	-	-	1,312	-	-	115	-	-
15	Empress to Union WDA FT	0.679	1,337	147	-	-	1,337	-	-	147	-	-
16	Total Long Haul		158,409	21,928		106,933	47,662	3,813	-	21,928	-	-
	Short Haul											
17	Parkway to Union EDA FT	0.310	13,514	233	52.1	5,916	7,598	-	-	233	-	-
18	Parkway to Union EDA FT (EMB)	0.340	3,107	68	-	-	3,107	-	-	68	-	-
19	Parkway to Union NCDA FT	0.227	813	26	9.8	813	-	-	-	26	-	-
20	Parkway to Union NDA FT	0.474	19,087	655	45.5	7,892	11,195	-	-	655	-	-
21	Dawn to Union CDA FT	0.277	810	68	-	-	-	-	810	-	-	68
22	Niagara to Kirkwall FT	0.174	1,342	-	-	-	-	1,342	-	-	-	-
23	Kirkwall to Union CDA FT	0.116	5,711	362	-	-	-	-	5,711	-	-	362
24	Dawn to CDA FT	0.308	16,909	4	149.8	16,909	-	-	-	4	-	-
25	Dawn to EDA FT	0.576	24,047	7	-	-	24,047	-	-	7	-	-
26	Dawn to Iroquois FT	0.574	8,400	3	-	-	8,400	-	-	3	-	-
27	Parkway to CDA FT	0.154	18,784	4	333.5	18,784	-	-	-	4	-	-
28	Parkway to CDA FT-SN	0.154	4,803	1	85.0	4,803	-	-	-	1	-	-
29	Parkway to EDA FT	0.415	32,511	394	-	-	32,511	-	-	394	-	-
30	Niagara Falls to CDA	0.189	5,284	-	-	-	-	5,284	-	-	-	-
31	Chippawa to CDA	0.190	8,592	-	-	-	-	8,592	-	-	-	-
32	Total Short Haul		163,715	1,824		55,117	86,858	15,218	6,521	1,394	-	430
	Storage and Transportation Service Firm Withdrawal/Injections											
33	NCDA		-	-	-	-	-	-	-	-	-	-
34	WDA	0.848	978	114	-	-	978	-	-	114	-	-
35	SSMDA		-	19	-	-		-	-	19	-	-
36	NDA	0.474	8,520	44	-	-	8,520	-	-	44	-	-
37	EDA	0.310	2,989	36	-	-	2,989	-	-	36	-	-
38	CDA	0.154	15,989	323	-	-	15,989	-	-	323	-	-
39	EDA	0.415	10,765	3	-	-	10,765	-	-	3	-	-
40	EDA	0.415	1,475	37		-	1,475	-	-	37	-	-
41	Total Storage and Transportation Service Firm Withdrawal/Injections		40,716	577		-	40,716	-	-	577	-	-
42	Total TransCanada Pipeline		362,839	24,329		162,050	175,236	19,031	6,521	23,899	-	430

Upstream Transportation Cost Allocation

Line No.	Upstream Pipeline / Transportation Service	2024 Forecast Unitized Demand Charge ($Cdn/GJ)	Total Demand Costs ($000s)	Total Fuel Costs ($000s)	Average Day Demand (TJ/d)	Demand Costs ($000s) Transportation	Demand Costs ($000s) Load Balancing	Demand Costs ($000s) Gas Supply Commodity	Demand Costs ($000s) Distribution	Fuel Costs ($000s) Transportation Commodity	Fuel Costs ($000s) Gas Supply Commodity	Fuel Costs ($000s) Distribution
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Centra Transmission Holdings Inc.											
43	Centra Transmission Holdings Inc.	0.536	1,141	-	-	-	-	-	1,141	-	-	-
44	Centra Pipelines Minnesota Inc.	0.125	266	-	-	-	-	-	266	-	-	-
45	Total		1,407	-		-	-	-	1,407	-	-	-
	NOVA Transmission											
46	NIT to Empress	0.180	8,222	-	-	-	-	8,222	-	-	-	-
	Panhandle Eastern Pipe Line Company L.P.											
47	PEPL FT	0.816	17,966	1,455	-	-	-	17,966	-	-	1,455	-
	Vector Pipelines L.P.											
48	Vector US FT1	0.211	8,129	75	-	-	-	8,129	-	-	75	-
49	Vector Canada FT1	0.006	278	-	-	-	-	278	-	-	-	-
50	Vector US FT1	0.186	7,920	83	-	-	-	7,920	-	-	83	-
51	Vector Canada FT1	0.006	405	-	-	-	-	405	-	-	-	-
52	Vector US FT1	0.186	1,440	15	-	-	-	1,440	-	-	15	-
53	Vector US FT1	0.211	5,284	49	-	-	-	5,284	-	-	49	-
54	Total		23,456	222		-	-	23,456	-	-	222	-
	NEXUS Gas Transmission, LLC											
55	NEXUS - FT	1.041	60,284	84	-	-	-	60,284	-	-	84	-
56	NEXUS - FT	0.959	20,373	31	-	-	-	20,373	-	-	31	-
57	NEXUS - FT	1.140	24,205	31	-	-	-	24,205	-	-	31	-
58	Total		104,863	145		-	-	104,863	-	-	145	-
	Great Lakes Gas Transmission											
59	GLGT	0.324	2,500	100	-	-	-	2,500	-	-	100	-
	Great Lakes Pipeline Canada Ltd.											
60	Great Lakes Pipeline Canada Ltd.	0.015	114	-	-	-	-	114	-	-	-	-
	St. Clair Pipelines L.P.											
61	St. Clair Pipelines L.P. (St. Clair Pipeline)	0.004	287	-	-	-	-	-	287	-	-	-
62	St. Clair Pipelines L.P. (Bluewater Pipeline)	0.021	998	-	-	-	-	-	998	-	-	-
63	Total		1,286	-		-	-	-	1,286	-	-	-
	2193914 Canada Inc.											
64	2193914 Canada Inc.	0.011	2,581	-	-	-	-	-	2,581	-	-	-
65	Total		525,236	26,250		162,050	175,236	176,154	11,795	23,899	1,922	430

Note:
(1) Conversion Factors:
DTH to GJ conversion rate: 1.055056 GJ/DTH
Enbridge North Heat Value: 38.86
Exchange rate: $1 USD = $1.274 CAD

2024 Load Balancing Calculations

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Days in Month	31	29	30	31	31	30	31	31	30	31	30	31	365
2	Supplies (TJ)	20,379	23,600	0	2,012	4,000	13,200	7,686	0	10,823	10,440	10,024	24,150	126,314
3	Average Day Demand Per Month (TJ)	10,699	10,008	10,354	10,699	10,699	10,354	10,699	10,699	10,354	10,699	10,354	10,699	126,314
4	Average Purchases Variance (TJ)	9,680	13,592	(10,354)	(8,687)	(6,699)	2,846	(3,012)	(10,699)	469	(259)	(330)	13,451	0
5	Dawn Forecasted Price ($/GJ)	5.742	5.662	5.234	5.211	5.136	5.098	5.085	5.091	5.047	5.050	5.294	5.551	
6	Price Variance - Load Balancing ($000s) (1)	55,588	76,949	(54,190)	(45,265)	(34,408)	14,511	(15,318)	(54,463)	2,367	(1,306)	(1,745)	74,669	17,390
7	Demand Cost - Load Balancing ($000s)	524	524	524	513	513	513	513	513	513	513	513	524	6,201
8	Total Load Balancing Costs ($000s) (2)	56,112	77,472	(53,666)	(44,751)	(33,894)	15,024	(14,805)	(53,949)	2,881	(793)	(1,232)	75,192	23,591

Notes:
(1) Line 4 x line 5.
(2) Line 6 + line 7.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 2, Schedule 1, Attachment 1, pg. 3, line 9

Question(s):

Please provide allocation basis for the costs in Line 9.

a) Please provide an Excel copy of the working papers to show the allocation.

Response:

Please see Exhibit 7, Tab 2, Schedule 1, Attachment 5, page 3, lines 71- 78, updated March 8, 2023, which provides the detailed allocation of storage O&M expense. A description of the allocation of each O&M expense is as follows:

- Local storage costs are associated with the Hagar LNG facility, which is used to meet the design day demand of the Union North rate zone and is classified to storage deliverability.

- Supervision costs are not directly identifiable and are classified in proportion to storage O&M costs.

- Compressor, measuring and regulating and dehydration costs are incurred to serve the deliverability needs of the Company and are classified to storage deliverability.

Storage wells and lines, rent and other storage costs are classified as 50% storage deliverability and 50% storage space to recognize these costs are incurred to meet both deliverability and storage requirements of its storage operation. Storage space is further classified between storage space and operational contingency space. Please see response at Exhibit I.7.1-STAFF-239.

a) Please see response at Exhibit I.7.0-IGUA-72 for the 2024 Cost Allocation Study filed in Excel.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 7, Tab 3, Schedule 1, Attachment 12, pg. 11-14

Question(s):

Please provide detailed workpapers to show how the “Total” and “Rate E70” allocation factors were calculated for “D-PTRANS”.

Response:

This evidence will be addressed in Phase 2 of the proceeding as noted in Enbridge Gas’s February 1, 2023 letter.

ENBRIDGE GAS INC.

Answer to Interrogatory from
City of Kitchener (Kitchener)

Interrogatory

Reference:

Exhibit 7 Tab 2 Schedule 1 Attachment 12 Page 13 of 16, line 27
Allocation factors – Union South Rate Zone – Rate T3
“HIGHPRESS>4 Rate T3 – 2,601

Question(s):

a) Please provide the details of weather normalisation model that is used to calculate T3 customers design day demand along with all input data that is used in creating the model (historical consumption and HDD).

b) Based on response to Interrogatory # 3.2 -Kitchener-1-d, please provide forecasted design day demand for T3 rate class based updated Kitchener’s HDD?

c) Based on updated design day demand for T3 rate class, please provide impact on cost allocation factor and revenue requirement and T3 rates, which uses design day demand data?

Response:

a) The details of the weather normalization model that is used to calculate the Rate T3 customers design day demand is the same method currently in use in the Union South rate zone.

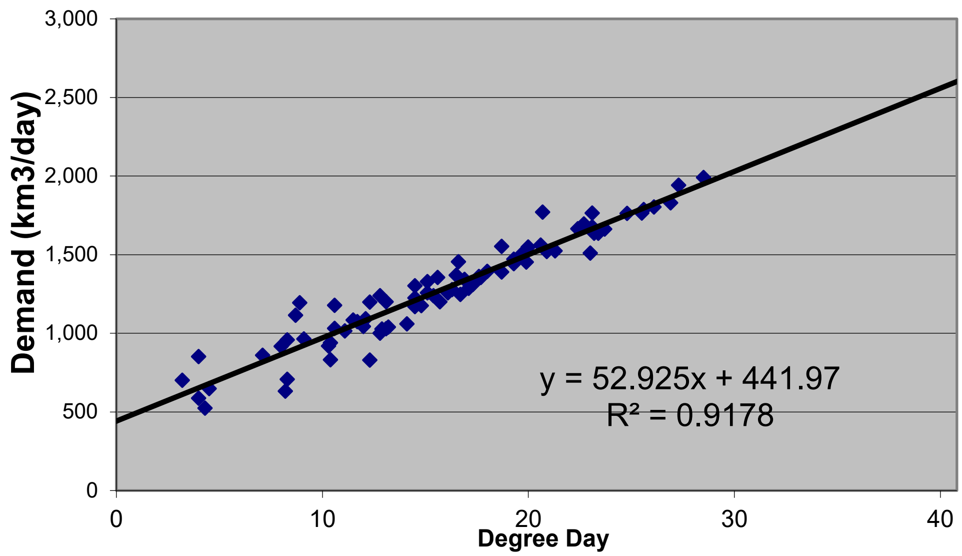
The design day demand process method is provided in detail at Exhibit 4, Tab 2, Schedule 3, paragraph 51. Specifically, for Rate T3 and other contract rate classes, is provided in detail in response at Exhibit I.7.1-IGUA-82 part d). The single customer in Rate T3 has a 100% firm contract. The geographically associated weather station for the design day demand is London.

The HDDw will be calculated as provided at Exhibit 4, Tab 2, Schedule 3, paragraphs 32 to 42.

The design day demand for the Rate T3 customer in this Application is 2,601.297 $10^3m^3/d$ and was derived as shown in Figure 1. This design day was based on the

Winter 2021/2022 actuals and there was no forecast demand growth. The data used in the analysis is shown in Table 1.

Figure 1: Design Day Demand Analysis for Rate T3 customer for Winter 2023/2024



Trend
40.8DD = 2601.297

Actual Data
MAX = 1991.14

Table 1: Data for Design Day Analysis of T3 Customer
based on London HDDw15

Line No.	Date	Day of Week	HDDw15	Demand (km^3/day)
1	1-Nov-21	Monday	10.40	831.78
2	2-Nov-21	Tuesday	12.30	830.45
3	4-Nov-21	Thursday	13.10	1029.87
4	8-Nov-21	Monday	4.30	523.36
5	9-Nov-21	Tuesday	8.20	631.89
6	10-Nov-21	Wednesday	8.30	708.10
7	11-Nov-21	Thursday	4.50	647.33
8	15-Nov-21	Monday	14.10	1060.07
9	16-Nov-21	Tuesday	12.00	1043.09
10	17-Nov-21	Wednesday	3.20	700.88
11	18-Nov-21	Thursday	13.20	1039.54
12	22-Nov-21	Monday	16.70	1248.00

13	23-Nov-21	Tuesday	15.40	1238.11
14	24-Nov-21	Wednesday	8.30	957.75
15	25-Nov-21	Thursday	12.90	1027.53
16	29-Nov-21	Monday	16.10	1256.53
17	30-Nov-21	Tuesday	14.50	1170.46
18	1-Dec-21	Wednesday	10.60	1030.49
19	2-Dec-21	Thursday	11.50	1083.49
20	6-Dec-21	Monday	16.30	1278.45
21	7-Dec-21	Tuesday	21.30	1523.37
22	8-Dec-21	Wednesday	19.30	1443.55
23	9-Dec-21	Thursday	15.10	1328.21
24	13-Dec-21	Monday	12.80	1001.28
25	14-Dec-21	Tuesday	11.10	1015.31
26	15-Dec-21	Wednesday	4.00	852.23
27	16-Dec-21	Thursday	7.10	860.38
28	3-Jan-22	Monday	22.40	1665.31
29	4-Jan-22	Tuesday	14.50	1302.74
30	5-Jan-22	Wednesday	20.90	1520.38
31	6-Jan-22	Thursday	23.20	1635.42
32	10-Jan-22	Monday	28.50	1991.14
33	11-Jan-22	Tuesday	20.70	1770.59
34	12-Jan-22	Wednesday	15.60	1356.04
35	13-Jan-22	Thursday	17.60	1361.31
36	17-Jan-22	Monday	18.70	1553.49
37	18-Jan-22	Tuesday	16.60	1455.89
38	19-Jan-22	Wednesday	20.60	1560.70
39	20-Jan-22	Thursday	27.30	1941.61
40	24-Jan-22	Monday	22.70	1695.74
41	25-Jan-22	Tuesday	25.50	1765.27
42	26-Jan-22	Wednesday	26.90	1829.22
43	27-Jan-22	Thursday	23.10	1764.20
44	31-Jan-22	Monday	23.00	1510.29
45	1-Feb-22	Tuesday	12.80	1238.73
46	2-Feb-22	Wednesday	18.70	1389.32
47	3-Feb-22	Thursday	25.60	1786.77
48	7-Feb-22	Monday	18.00	1393.60
49	8-Feb-22	Tuesday	19.30	1472.20
50	9-Feb-22	Wednesday	13.10	1201.23
51	10-Feb-22	Thursday	16.50	1368.50
52	14-Feb-22	Monday	26.10	1804.12

53	15-Feb-22	Tuesday	20.00	1548.78
54	16-Feb-22	Wednesday	8.70	1114.14
55	17-Feb-22	Thursday	19.90	1453.83
56	22-Feb-22	Tuesday	12.30	1197.23
57	23-Feb-22	Wednesday	24.80	1761.92
58	24-Feb-22	Thursday	23.10	1677.65
59	28-Feb-22	Monday	19.70	1505.93
60	1-Mar-22	Tuesday	15.10	1257.07
61	2-Mar-22	Wednesday	17.70	1354.97
62	3-Mar-22	Thursday	23.70	1662.38
63	7-Mar-22	Monday	16.90	1343.48
64	8-Mar-22	Tuesday	17.10	1285.61
65	9-Mar-22	Wednesday	14.80	1175.36
66	10-Mar-22	Thursday	15.70	1199.45
67	14-Mar-22	Monday	11.70	1073.68
68	15-Mar-22	Tuesday	14.50	1223.79
69	16-Mar-22	Wednesday	8.00	917.80
70	17-Mar-22	Thursday	4.00	586.84
71	21-Mar-22	Monday	10.30	920.08
72	22-Mar-22	Tuesday	12.10	1092.08
73	23-Mar-22	Wednesday	10.60	1177.73
74	24-Mar-22	Thursday	9.10	963.47
75	28-Mar-22	Monday	23.40	1636.66
76	29-Mar-22	Tuesday	17.30	1310.71
77	30-Mar-22	Wednesday	8.90	1194.58
78	31-Mar-22	Thursday	10.40	938.81

b) The closest weather station is located at the Waterloo airport (CYKF). Unfortunately, there is a lack of data at this airport to develop a reliable design day HDDw. Due to the daytime only operation at this airport and manual recording of temperature, there is a lack of overnight temperature data.

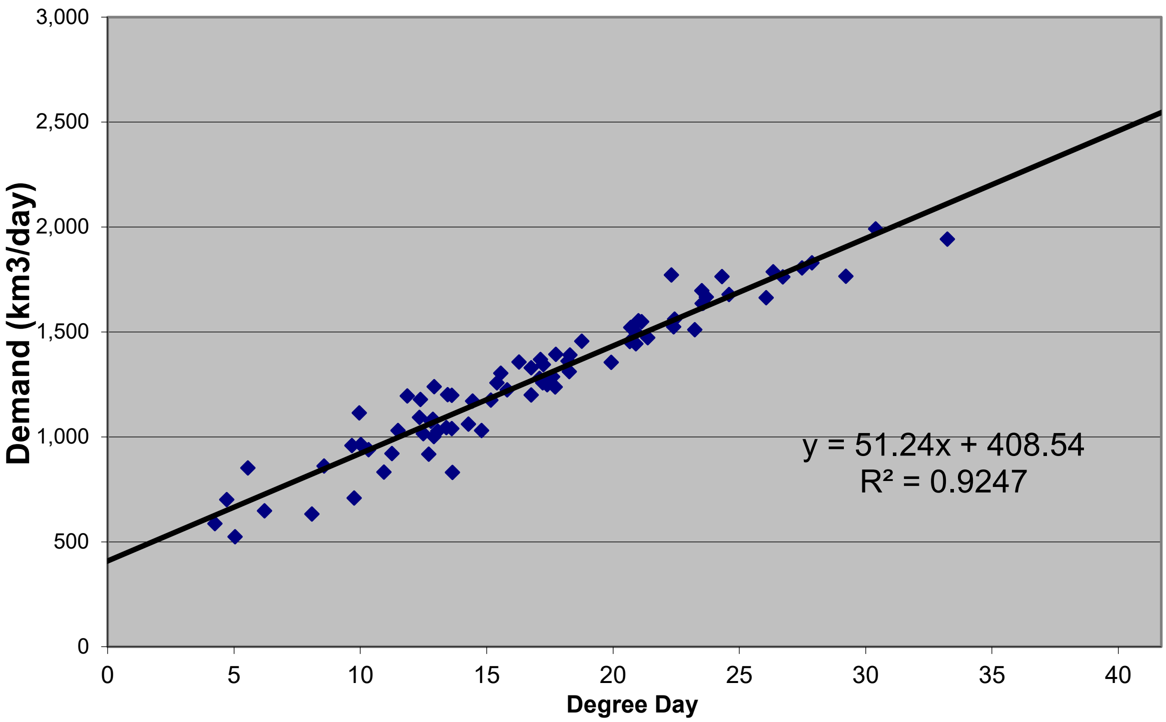
To be responsive, an incremental HDDw was calculated for Waterloo compared to London, which was estimated by taking the difference in cumulative HDDw between London and Waterloo, averaging the 4 data years and dividing by the number of days of the winter and is provided in Table 2.

Table 2

	Cumulative HDDw Winter Season (Waterloo)			
Year	Gas Day	Calendar Day	Gas Day	Calendar Day
	HDDw18	HDDw18	HDDw15	HDDw15
2019	3336	3331	2776	2772
2020	3037	3039	2474	2475
2021	2964	2961	2401	2396
2022	3218	3219	2651	2653
	Cumulative HDDw Winter Season (London)			
	Gas Day	Calendar Day	Gas Day	Calendar Day
	HDDw18	HDDw18	HDDw15	HDDw15
2019	3221	3218	2677	2673
2020	2877	2879	2332	2332
2021	2816	2811	2268	2263
2022	3047	3050	2494	2498
Incremental HDDw for Waterloo compared to London	0.98	0.98	0.88	0.88

The forecast design day demand using the Waterloo weather station is 2,545.261 10^3m^3/day compared to the 2,601.297 10^3m^3/day using the London weather station.

Figure 2: Design Day Demand Analysis for Rate T3 Customer
for Winter 2023/2024 using Waterloo Weather Station



Trend
41.7DD = 2545.261 km3/day

Actual Data
MAX = 1991.14 km3/day

Table 3: Data for Design Day Analysis of Rate T3 Customer
based on Waterloo HDDw15

Line No.	Date	Day of Week	HDDw15	Demand (km^3/day)
1	1-Nov-21	Monday	10.93	831.78
2	2-Nov-21	Tuesday	13.64	830.45
3	4-Nov-21	Thursday	14.79	1029.87
4	8-Nov-21	Monday	5.04	523.36
5	9-Nov-21	Tuesday	8.09	631.89
6	10-Nov-21	Wednesday	9.75	708.10
7	11-Nov-21	Thursday	6.21	647.33
8	15-Nov-21	Monday	14.28	1060.07

9	16-Nov-21	Tuesday	13.41	1043.09
10	17-Nov-21	Wednesday	4.71	700.88
11	18-Nov-21	Thursday	13.62	1039.54
12	22-Nov-21	Monday	17.39	1248.00
13	23-Nov-21	Tuesday	17.72	1238.11
14	24-Nov-21	Wednesday	9.66	957.75
15	25-Nov-21	Thursday	13.06	1027.53
16	29-Nov-21	Monday	17.22	1256.53
17	30-Nov-21	Tuesday	14.44	1170.46
18	1-Dec-21	Wednesday	11.50	1030.49
19	2-Dec-21	Thursday	12.88	1083.49
20	6-Dec-21	Monday	17.10	1278.45
21	7-Dec-21	Tuesday	22.40	1523.37
22	8-Dec-21	Wednesday	20.90	1443.55
23	9-Dec-21	Thursday	16.76	1328.21
24	13-Dec-21	Monday	12.92	1001.28
25	14-Dec-21	Tuesday	12.49	1015.31
26	15-Dec-21	Wednesday	5.55	852.23
27	16-Dec-21	Thursday	8.57	860.38
28	3-Jan-22	Monday	23.70	1665.31
29	4-Jan-22	Tuesday	15.56	1302.74
30	5-Jan-22	Wednesday	20.71	1520.38
31	6-Jan-22	Thursday	23.53	1635.42
32	10-Jan-22	Monday	30.39	1991.14
33	11-Jan-22	Tuesday	22.31	1770.59
34	12-Jan-22	Wednesday	16.28	1356.04
35	13-Jan-22	Thursday	18.23	1361.31
36	17-Jan-22	Monday	21.01	1553.49
37	18-Jan-22	Tuesday	18.77	1455.89
38	19-Jan-22	Wednesday	22.43	1560.70
39	20-Jan-22	Thursday	33.23	1941.61
40	24-Jan-22	Monday	23.52	1695.74
41	25-Jan-22	Tuesday	29.22	1765.27
42	26-Jan-22	Wednesday	27.88	1829.22
43	27-Jan-22	Thursday	24.32	1764.20
44	31-Jan-22	Monday	23.24	1510.29
45	1-Feb-22	Tuesday	12.93	1238.73
46	2-Feb-22	Wednesday	18.30	1389.32
47	3-Feb-22	Thursday	26.34	1786.77
48	7-Feb-22	Monday	17.74	1393.60

49	8-Feb-22	Tuesday	21.37	1472.20
50	9-Feb-22	Wednesday	13.46	1201.23
51	10-Feb-22	Thursday	17.13	1368.50
52	14-Feb-22	Monday	27.48	1804.12
53	15-Feb-22	Tuesday	21.14	1548.78
54	16-Feb-22	Wednesday	9.96	1114.14
55	17-Feb-22	Thursday	20.67	1453.83
56	22-Feb-22	Tuesday	13.62	1197.23
57	23-Feb-22	Wednesday	26.72	1761.92
58	24-Feb-22	Thursday	24.59	1677.65
59	28-Feb-22	Monday	20.84	1505.93
60	1-Mar-22	Tuesday	15.41	1257.07
61	2-Mar-22	Wednesday	19.93	1354.97
62	3-Mar-22	Thursday	26.06	1662.38
63	7-Mar-22	Monday	17.25	1343.48
64	8-Mar-22	Tuesday	17.61	1285.61
65	9-Mar-22	Wednesday	15.17	1175.36
66	10-Mar-22	Thursday	16.76	1199.45
67	14-Mar-22	Monday	12.79	1073.68
68	15-Mar-22	Tuesday	15.81	1223.79
69	16-Mar-22	Wednesday	12.71	917.80
70	17-Mar-22	Thursday	4.25	586.84
71	21-Mar-22	Monday	11.25	920.08
72	22-Mar-22	Tuesday	12.34	1092.08
73	23-Mar-22	Wednesday	12.38	1177.73
74	24-Mar-22	Thursday	10.03	963.47
75	28-Mar-22	Monday	23.58	1636.66
76	29-Mar-22	Tuesday	18.27	1310.71
77	30-Mar-22	Wednesday	11.86	1194.58
78	31-Mar-22	Thursday	10.33	938.81

c) Table 4 provides a summary of the cost allocation factor impacts for Rate T3 using the forecast design day demand of 2,545.261 10^3m^3/day as provided at part b) compared to the filed forecast demand of 2,601.397 10^3m^3/day.

Table 4
Rate T3 Allocation Factor Variances

Line No.	Allocation Factor	Rate T3 Allocation Factor: As Filed Demand of 2,601.297 10^3m^3/day	Updated Demand of 2,545.261 10^3m^3/day	Variance
		(a)	(b)	(c) = (b-a)
	Storage			
1	OP_CONTINGENCY	1,327	1,321	(6)
	Transmission			
2	DAWN_DEMAND	1,489	1,456	(33)
3	KIRKWALL_DEMAND	17	16	(0)
4	D-PTRANS	251	246	(6)
5	PAN_STCLAIR	2,601	2,545	(56)
	Distribution			
6	HIGHPRESS>4	2,601	2,545	(56)

The use of design day demands of 2,545.261 10^3m^3/day also results in a decrease to the revenue requirement of $0.149 million and a decrease to transportation demand charge of 0.5273 cents/m^3, from 25.4243 cents/m^3 to 24.8970 cents/m^3. Please see Attachment 1 for a summary of the revenue requirement and rate impact resulting from the cost allocation factor variances provided in Table 3.

Rate T3 Revenue Requirement and Rates Variances Based on Cost Allocation Study Update

Line No.	Particulars	As Filed Revenue Requirement (1) ($000s)	As Filed Rates (2) (cents / m³)	Updated per Exhibit I.7.2-Kitchener-2 (3) Revenue Requirement ($000s)	Updated per Exhibit I.7.2-Kitchener-2 (3) Rates (cents / m³)	Variance Revenue Requirement ($000s)	Variance Rates (cents / m³)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (d - b)
	Rate T3						
1	Monthly Customer Charge	371	$30,900.76	371	$30,900.76	-	-
	Transportation (cents/m³)						
2	Demand	7,170	25.4243	7,021	24.8970	(149)	(0.5273)
3	Commodity - Customer Provides Fuel	-	-	-	-	-	-
4	Customer Supplied Fuel - Transportation	415		415		-	
5	Total Transportation	7,955		7,807		(149)	
	Storage		($/GJ)		($/GJ)		
	Monthly Demand Charges:						
6	Firm Space	637	0.0166	637	0.0166	-	-
	Firm Injection/Withdrawal Right						
7	Union provides deliverability inventory	-	2.4871	-	2.4871	-	-
8	Customer provides deliverability inventory	1,453	2.2372	1,453	2.2372	-	-
9	Firm incremental injection	-	2.2372	-	2.2372	-	-
10	Interruptible withdrawal	-	2.2372	-	2.2372	-	-
	Commodity:						
11	Commodity (Customer Provides)	-	-	-	-	-	-
12	Customer Supplied Fuel - Storage	285		285			
13	Total Storage	2,375		2,375			
14	Total Rate T3	10,330		10,182		(149)	

Notes:
(1) Updated Exhibit 8, Tab 2, Schedule 8, Attachment 2, page 12, column (e) + (f).
(2) Updated Exhibit 8, Tab 2, Schedule 8, Attachment 2, page 12, column (h).
(3) Updated cost allocation study to reflect a design day demand of 2,535.261 10^3m^3/day for Rate T3.

ENBRIDGE GAS INC.

Answer to Interrogatory from
City of Kitchener (Kitchener)

Interrogatory

Reference:

Exhibit 7 Tab 2 Schedule 1 Attachment 8 Page 3 of 4, line 29
Distribution Customer – Stations: $346K cost allocated to T3 rate class

Question(s):

a) Please provide cost of replacement of Kitchener Gate Station (KGS) and Plains Road Station?

b) Please provide the details of last upgrade at KGS and Plains Road Station?

c) What are the designed and remaining life spans of the KGS and the Plains Road Station serving the gas distribution utility of Kitchener?

d) When is the next rebuild of the KGS and the Plains Road Station scheduled to occur?

e) Please provide design parameters / maximum capacity at KGS and Plains Road Station?

Response:

a) The following estimates are based upon existing design parameters for Kitchener Gate Station (KGS) and Plains Road Station. Replacement costs will vary dependent upon the actual cost of materials, fabrication, and installation at the time of replacement, as well as delivery pressure and flow requirements.

- Estimated replacement cost of KGS is $12 million
- Estimated replacement cost of Plains Road Station is $7 million

These costs provide the total estimated fully allocated replacement cost, including the cost of demolition and provisions to continue to supply gas to the downstream system during fabrication of the new station. As such, these estimated replacement costs are higher than the replacement costs used for cost allocation. Please see response at IGUA-85, part b) for the cost allocation details of distribution stations.

b) KGS had its last maintenance upgrade in 2020. Plains Road Station had its last maintenance upgrade in 2019. The former natural gas line heaters were replaced at both sites due to age and condition.

c) The design and remaining life spans for these stations are indefinite until load changes. Regular maintenance is performed at these sites.

d) There are no scheduled rebuilds in the present forecast. The next rebuild will occur when load is added by contract, as requested by the customer.

e) Please see Table 1.

Table 1
Design Parameters and Maximum Capacities

Line No.	Particulars	Unit of Measure	Kitchener Gate Station – Outlet #1	Kitchener Gate Station – Outlet #2	Plains Road Station
1	Maximum Hourly Volume	m^3/hour	104,384		16,000
2	Minimum Delivery Pressure	kPa	1207	207	1207

ENBRIDGE GAS INC.

Answer to Interrogatory from
City of Kitchener (Kitchener)

Interrogatory

Reference:

Exhibit 7 Tab 2 Schedule 1 Attachment 11 Page 12 of 14, line 10

Question(s):

a) Please provide details of calculation used for distance-weighted design day demand used in allocation factor D-PTRANS?

Response:

a) Please see response at Exhibit I.7.1-IGUA-78, Attachment 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
TransCanada PipeLines Limited (TCPL)

Interrogatory

Reference:

1) Exhibit 7, Tab 2, Schedule 1, Attachment 2, Page 3 of 3.
2) Exhibit 7, Tab 2, Schedule 1, Attachment 8.
3) Exhibit 8, Tab 1, Schedule 2, Attachment 2.
4) Exhibit 8, Tab 2, Schedule 8, Attachment 1, Page 1 of 3.

Preamble:

The table in Reference 1) shows a summary of the revenue requirement by rate class under the 2024 Cost Allocation Study. Column (ag) shows the revenue requirement for Rate 332 of $21.668 million.

Reference 2) is a table showing the Total Allocation to current rate classes from the 2024 Cost Allocation Study. Line 17 shows the Transmission Demand - Albion Revenue Requirement of $36.035 million which is allocated to rate classes using the "ALBIONTRANS" allocation factor which allocates 60% of these costs to ex-franchise (Rate 332), and the remaining 40% of costs to bundled in-franchise rate classes in proportion to firm design day demands.

Reference 3) lists all of the 2024 Rate Design Proposals contained in Exhibit 8.

The table in Reference 4) shows proposed revenue changes by rate class. Line 31 shows the approved revenue, revenue deficiency, proposed revenue requirement and proposed revenue for Rate 332.

Question(s):

a) Please provide a table showing the proposed in-franchise revenue requirement for Albion Pipeline in the same form as presented in Reference 1) column (ag).

b) Are there any new costs or cost categories being included in the Transmission Demand – Albion Revenue Requirement for 2024 that were costs associated with the Dawn Parkway System or any of the Stations on the Dawn Parkway System prior to 2024? If so, please describe and quantify these new costs.

c) Do any of the proposed cost allocation changes described in Exhibit 7 impact the total costs allocated to the Albion Pipeline (Transmission Demand – Albion Revenue Requirement) or Rate 332? If so, please explain and quantify any such impacts.

d) Do any of the proposed 2024 Rate Design Proposals shown in Reference 3) impact the rate for Rate 332, apart from the recovery of the revenue deficiency identified in Reference 4), column (b). If so, please explain and quantify any such Rate Design Proposal impacts.

Response:

a) Please see Attachment 1. In addition to the allocation of $21.71 million of Albion transmission demand revenue requirement, Rate 332 is also allocated $0.047 million of operational contingency costs.

b) No, there are no costs associated with Dawn Parkway System, including stations, included in the Albion transmission demand revenue requirement for 2024. The Albion transmission demand revenue requirement includes the direct costs of the Albion transmission line based on the utility's plant investment, related depreciation, and operating costs and an allocation of related indirect costs.

c) No, the proposed cost allocation methodology changes provided at Exhibit 7, Tab 1, Schedule 4 do not impact the costs classified to the Albion transmission demand functional classification. Please see Exhibit 7, Tab 1, Schedule 4, Attachment 1, line 30, updated March 8, 2023, which confirms that there are no impacts to Rate 332 resulting from the proposed cost allocation methodology changes.

   Rate 332 is subject to common cost allocation methodologies for related indirect costs that may be different to methodologies previously used by EGD to allocate similar costs. It is not possible to produce the impact of those changes because the Company has not prepared a stand-alone cost allocation study for the EGD rate zone.

d) No, there are no specific rate design proposals impacting Rate 332. The only proposal that indirectly impacts Rate 332 is the general proposal to recover the revenue deficiency through rates, which is provided at Exhibit 8, Tab 1, Schedule 2, Attachment 2, line 1.

Proposed In-franchise Revenue Requirement for Albion Pipeline

Line No.	Particulars ($000s)	Total Revenue Requirement	Rate 332	In-Franchise Rate Classes
		(a)	(b)	(c)
	Return on Rate Base			
1	Rate Base	341,317	204,790	136,527
2	Rate of Return on Rate Base	5.870%	5.870%	5.870%
3	Total Return on Rate Base	20,036	12,021	8,014
4	Depreciation Expense	8,572	5,143	3,429
	Taxes			
5	Income Tax	2,552	1,531	1,021
6	Property Tax	1,055	633	422
7	Total Taxes	3,607	2,164	1,443
	Operating & Maintenance Expenses			
8	Cost of Gas	-	-	-
9	Storage	-	-	-
10	Transmission	85	51	34
11	Distribution	-	-	-
12	General Operating & Engineering	2,066	1,240	827
13	Sales Promotion & Merchandise	-	-	-
14	Distribution Customer Accounting	-	-	-
	Administrative & General Expense			
15	Employee Benefits	844	506	338
16	Administrative & General	973	584	389
17	Total Operating & Maintenance Expenses	3,969	2,381	1,587
18	Total Revenue Requirement	36,184	21,710	14,473
19	Other Revenue	-	-	-
20	Total Revenue Requirement Less Other Revenue	36,184	21,710	14,473

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit 7, Tab 3, Schedule 1, Attachment 1, *Cost Allocation Harmonized Rate Classes*

Preamble:

Rate E1 Allocation $2,033,997 Rate E2 $999,234. Energy Probe wishes to understand the Parameters of the harmonized residential Rate Classes relative to legacy classes.

Question(s):

a) Please provide a tabular comparison of the parameters of the legacy and harmonized rate classes in terms of unit volumes, consumption, customer charge and demand charge.

b) Are small business ratepayers now in Rate E01? If so, please indicate how many customers have shifted and the associated change in allocated revenue requirement.

c) Please show how much revenue EGI will be collecting from each of the residential legacy and harmonized rate classes in 2025.

Response:

a-c) Evidence related to harmonized rate classes will be addressed in Phase 2 of the proceeding as noted in Enbridge Gas's February 1, 2023 letter.

The forecast parameters for current general service rate classes are provided in Table 1. The current rate classes are defined by type of customer in the EGD rate zone (Rate 1 residential and Rate 6 non-residential) and by size of customer in the Union rate zones. As such, the small volume general service rate classes (Rate 01 and Rate M1) in the Union rate zones are a mix of residential and non-residential customers.

Table 1
Current General Service Rate Class Parameters

Line No.	Particulars ($)	2024 Volume Forecast (10^3m^3) (1)	Current Rates (2) Customer Charges	Current Rates (2) Demand Charges	Proposed Rates (3) Customer Charges	Proposed Rates (3) Demand Charges
		(a)	(b)	(c)	(d)	(e)
	EGD Rate Zone					
1	Rate 1	5,001,027	21.88	-	23.00	-
2	Rate 6	4,795,693	76.58	-	80.00	-
3	Total EGD Rate Zone	9,796,720				
	Union North Rate Zone					
4	Rate 01	989,005	22.98	-	23.00	-
5	Rate 10	327,974	76.58	-	80.00	-
6	Total Union North Rate Zone	1,316,979				
	Union South Rate Zone					
7	Rate M1	3,255,132	22.98	-	23.00	-
8	Rate M2	1,319,376	76.58	-	80.00	-
9	Total Union South Rate Zone	4,574,509				
10	Total General Service	15,688,207				

Notes:
(1) Exhibit 8, Tab 2, Schedule 8, Attachment 2, column (a).
(2) EB-2022-0133, Exhibit D, Tab 2, Appendix A.
(3) Exhibit 8, Tab 2, Schedule 8, Attachment 2, column (h).

The forecasted 2024 revenue for each current rate class is provided at Exhibit 8, Tab 2, Schedule 8, Attachment 1, column (h). Enbridge Gas does not have an equivalent calculation for 2025 as this is outside the scope of the 2024 Rebasing proceeding.