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June 5, 2025

Mr. Ritchie Murray
Acting Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Mr. Murray

RE: EB-2025-0064 – Interrogatories of the London Property Management Association for Enbridge Gas Inc. – Phase 3

Please find attached the interrogatories of the London Property Management Association for Enbridge Gas Inc. in the above noted proceeding.

Yours very truly,

Randy Aiken

Digitally signed by Randy Aiken
Date: 2025.06.05 08:23:51 -04'00'

Randy Aiken
Aiken & Associates

c.c. EGI, Regulatory Affairs
Intervenors

Enbridge Gas Inc.

Application to change its natural gas rates and other charges beginning January 1, 2024

Phase 3

<u>INTERROGATORIES OF THE LONDON PROPERTY MANAGEMENT ASSOCIATION</u>

<u>1.3-LPMA-1</u>

Ref: Ph. 3, Ex. 1, Tab 3, Sch. 1

a) Please provide an updated version of the total bill impacts for a typical residential and small commercial sales service customer shown in Table 1 that is based on current 2025 rates and the most recent approved QRAM figures. Please exclude the rate mitigation rider in the calculation and set the federal carbon charge to $0.

b) Please provide a version of Table 1 that shows the total bill impacts for a typical residential and small commercial direct purchase customer using the same assumptions as above but excluding the gas commodity cost.

<u>1.3-LPMA-2</u>

Ref: Ph. 3, Ex. 1, Tab 3, Sch. 1, Att. 3

Please provide an updated version of the Evidence Mapping in Attachment 3 that reflects the OEB's approved issues list as set out in Procedural Order No. 2, dated May 16, 2025.

<u>1.6-LPMA-3</u>

Ref: Ph. 3, Ex. 1, Tab 6, Sch. 1

The customer engagement noted in the evidence took place in 2021 and early 2022 and is now more than 3 years out of date.

a) Has EGI undertaken and/or completed any new customer engagement since that noted in the evidence? If yes, please provide a comprehensive report of the results of that engagement.

b) Has EGI undertaken any customer engagement following the setting of the carbon charge to $\$0/m^3$ and the threat of tariffs on Canadian exports to the United States and retaliatory tariffs on American exports to Canada? If yes, please provide the results of that engagement.

4.2-LPMA-4

Ref: Ph. 3, Ex. 4, Tab 2, Sch. 2

a) Please provide a version of Table 1 that excludes the costs for the EGD rate zone as noted in paragraph 32.

b) Are there similar or other costs for the other rate zones that would not be included in the WARP calculation? If yes, please reflect these changes in the version of Table 1 requested above and explain what costs have been removed.

4.2-LPMA-5

Ref: Ph. 3, Ex. 4, Tab 2, Sch. 2

Please quantify the cost associated with the "additional administrative complexities" of having more than one rate zone for WARP purposes noted in paragraph 36.

4.2-LPMA-6

Ref: Ph. 3, Ex. 4, Tab 2, Sch. 2

Attachment 1 shows transportation costs of approximately $277 million that has been included in the EGD reference price calculation and that, as noted in paragraph 32, these costs will not be included in the WARP calculation.

a) Will this cost of approximately $277 million be recovered through distribution and/or transmission rates? If not, please explain fully where these costs will be recovered.

b) Under the one rate zone proposal, will these costs be spread over all customers in all of the existing rate zones? If not, please explain fully the existing customer classes and rate zones that will pay this cost.

c) Please provide an estimate of the cost increase or decrease associated with the removal of these costs from the WARP calculation for each of the existing rate zones.

d) Please provide the estimated per customer dollar impact in each rate zone for each rate class in that zone related to the removal of the $277 million from the WARP calculation.

4.2-LPMA-7

Ref: Ph. 3, Ex. 4, Tab 2, Sch. 2

Attachment 3 shows a heat value of 39.08 $GJ/10^3m^3$.

a) Please confirm that this figure is updated on an annual basis by EGI. If not confirmed, how often can this figure be updated?

b) Is this figure applied to all gas purchases regardless of supply source?

c) Please explain fully how the heat value is calculated, including all sources of information used.

d) Given the range of supply sources and the potential for the amount from each source to change relative to other sources, has EGI considered using different heat values from each supply source? If not, why not?

7.0-LPMA-8

Ref: Ph. 3, Ex. 7, Tab 0, Sch. 1

Figure 2 shows the Union North East rate zone having 0.3 million customers or 7% of the total number of EGI customers. Table 5 breaks the Union North East into North and East service areas. Please provide the number of customers and the resulting percentage of EGIU customers for each of the North and East service areas shown in Table 5.

7.0-LPMA-9

Ref: Ph. 3, Ex. 7, Tab 0, Sch. 1

a) Do the percent change in total revenues shown in Table 4 and in the delivery revenues and/or gas cost revenues shown in Table 5 include the federal carbon charge?

b) If yes, please provide versions of Tables 4 and 5 that exclude the federal carbon charge.

7.0-LPMA-10

Ref: Ph. 3, Ex. 7, Tab 0, Sch. 1

a) Paragraph 78 states that Attachment 3 shows the average total bill impacts for natural gas service, including the gas commodity and the federal carbon charge. Please provide an updated version of Attachment 3 that reflects the current 2025 rates – including a federal carbon charge of $\$0/m^3$ – and the latest approved QRAM rates.

b) Please provide a corresponding updated version of Attachment 4 for direct purchase customers that also reflects the current 2025 rates and no federal carbon charge.

7.0-LPMA-11

Ref: Ph. 3, Ex. 7, Tab 0, Sch. 1

Are the dollar changes shown in Tables 7 – 9 incremental to the changes shown in Table 6? For example, Table 6 shows an increase in the Union South Rate Zone of $60.9 million based on current rate zones and Table 7 shows an increase for the Union South Rate Zone of $113.2 million for the proposed one rate zone alternative. Does this imply that the total net impact on the Union South Rate Zone an incremental revenue of $174.1 million?

7.3-LPMA-12

Ref: Ph. 3, Ex. 7, Tab 3, Sch. 1, Att. 12 & Ph. 3, Ex. 7, Tab 3, Sch. 2, Att. 12

a) Please confirm that there no changes in the functionalization factors shown in Attachment 12 between Schedule 2 (No Regional Adjustments) and Schedule 1 (Proposed). If not confirmed, please indicate which factors have changed.

b) Please confirm that there no changes in the classification factors shown in Attachment 12 between Schedule 2 (No Regional Adjustments) and Schedule 1 (Proposed). If not confirmed, please indicate which factors have changed.

c) Please confirm that the significant changes in the allocation factors are for PAN_STCLAIR, TRANS_DEMAND, TRANSPT_DEM_OPT, with smaller changes for a number of other allocation factors. If not confirmed, please indicate which other allocation factors exhibit significant changes.

7.3-LPMA-13

Ref: Ph. 3, Ex. 7, Tab 3, Sch. 1, Att. 9 & Ph. 3, Ex. 7, Tab 3, Sch. 2, Att. 9

The total delivery revenue requirement shown in Attachment 9 of Schedules 1 and 2 reflects an increase of $2.749 million for Rate E01 under the No Regional Adjustments option. Please confirm that this increase is driven by a larger allocation of Transmission Demand for Panhandle & St. Clair, partially offset by reductions for Transmission Demand for Dawn Station, Kirkwall Station, Parkway Station Albion and Dawn to Parkway allocations. If not confirmed, what are the major factors driving the increases and decreases in allocated costs?

7.3-LPMA-14

Ref: Ph. 3, Ex. 7, Tab 3, Sch. 1, Att. 10 & Ph. 3, Ex. 7, Tab 3, Sch. 2, Att. 10

The total gas cost revenue requirement shown in Attachment 10 of Schedules 1 and 2 reflects a decrease of $19.0 million for Rate E01 under the No Regional Adjustments option. Please confirm that this decrease is driven by a smaller allocation of Load Balancing -Transportation, Transportation Demand and Transportation Commodity. If not confirmed, what are the major drivers of the decreases in allocated costs?

8.2-LPMA-15

Ref: Ph. 3, Ex. 8, Tab 2, Sch. 3

Part (b) of paragraph 58 states that only about 63,000 customers or 1.6% of total general service customers would see bill impacts greater than a 10% increase.

a) Does the bill impact noted above include the federal carbon charge and the HST?

b) If the bill impact does include the federal carbon charge, what is the impact on the number of customers that would see bill impacts of greater than a 10% increase when the federal carbon charge is removed from the bills?

8.2-LPMA-16

Ref: Ph. 3, Ex. 8, Tab 2, Sch. 3, Att. 5

Please provide the underlying data used in Figure 10. In particular, please provide the billing data associated with each data point including the volume consumed in the billing period and the number of days in the billing period, along with the heating degree days that correspond to the billing period. Please also show and explain any adjustments made to the data in calculating the consumption in cubic meters per day and heating degree days/day variables.

8.2-LPMA-17

Ref: Ph. 3, Ex. 8, Tab 2, Sch. 9, Att. 2

For each rate class shown in Attachment 2, please indicate how the delivery demand charge units have been forecasted. Please explain the difference in methodology between general service and contract rate classes.

8.2-LPMA-18

Ref: Ph. 3, Ex. 8, Tab 2, Sch. 9, Att. 2

For Rate E01, the delivery demand charge forecast units is shown as 1,087,127 10^3 m^3/d and for Rate E02, the delivery demand charge forecast units is shown as 772,599 10^3 m^3/d.

a) How are these forecasts related to the regression analysis methodology proposed to be used by EGI to calculate delivery demand figures for each individual customer?

b) If the sum of the individual customer delivery demand figures is not equal to the figures shown for each of Rates E01 and E02, please provide the corresponding figures for the sum of the individual customers that would have been used for 2024 for each of Rate E01 and Rate E02.

c) Does EGI plan on re-calculating the delivery demand charge rate for 2027 based on the proposed methodology for calculating the delivery demand charge units that would be applicable for 2027? If not, why not?

d) Given that the sum of the individual customer delivery demand charge units is likely to be higher or lower than the current EGI forecast, does EGI plan on requesting a variance account to track the difference delivery demand charge revenues, similar to the tracking of delivery revenue volume variances due to changes in average use per customer and weather? If not, please explain why not.