Aiken & Associates
578 McNaughton Ave. West
Chatham, Ontario, N7L 4J6
Phone: (519) 351-8624
E-mail: randy.aiken@sympatico.ca

July 10, 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 – Technical Conference Questions of the London Property Management Association for Enbridge Gas Inc. – Phase 3

Please find attached the technical conference questions of the London Property Management Association for Enbridge Gas Inc. in the above noted proceeding. To reduce time required in the technical conference, I have my questions. If Enbridge is willing to provide written answers through undertaking responses, I will not require any time at the technical conference, other than to possibly follow up on questions and responses from other participants.

If Enbridge is unable to provide written answers, my estimate of time is 90 minutes. I am unable to divide this time estimate between panels 3 and 4 because there is an overlap between the two panels on some of the questions. I do not require any time for panels 1, 2 or 5.

Yours very truly,

Randy Aiken

Digitally signed by Randy Aiken
Date: 2025.07.10 16:56:50 -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

TECHNICAL CONFERENCE QUESTIONS OF THE LONDON PROPERTY MANAGEMENT ASSOCIATION

1. Ref: Ex. I.8.2-CCC-23
Ph. 3 Ex. 8, Tab 2, Sch. 2, Att. 1
Ph. 3 Ex. 8, Tab 2, Sch. 5, pg. 3
Ph. 3 Ex. 8, Tab 2, Sch. 6, pgs. 8-9
Ex. I.8.2-VECC-11

The response to the CCC interrogatory shows an $8.6 million base rate reduction in costs recovered from rate E62. Attachment 1 of Exhibit 8, Tab 2, Schedule 2 shows that this cost is recovered primarily from rates E01, E02 and E10.

a) Please confirm the above.

b) Please confirm that the reduction of $8.6 million in costs recovered from rate E62 results in decreases in the increase in rates for Rate 200 from 13.9% to 0.5% and for Rate M9 from 26.6% to 3.1% as shown in Table 2 on page 8 of Exhibit 8, Tab 2, Schedule 6. If not confirmed, what is driving the decreases shown in Table 2.

c) Please confirm that in addition to the reduction of the $8.6 million there is a further adjustment proposed for customers within Rate E62 through Rider R and that this involves the phasing in of credits and debits over a 5 year period between the existing Rate 200 and M9 customers. If not confirmed, please explain.

d) Please confirm that the reduction of $8.6 million base rate reduction in costs is not included in Rider R and is a permanent reduction in costs recovered from rate E62, at least until the next cost allocation and rate design exercise is undertaken. If not confirmed, please explain.

e) As noted, Table 2 on page the impact including adjustment for Rate M9 under the proposed one rate zone is an increase of 3.1%. Please explain the difference between this figure and the 3.5% shown in column b on line 2 of Table 1 in Exhibit I.8.2-VECC-11.

f) Please confirm that the average total bill impacts for Rate E62 customer shown in Table 1 of Exhibit I.8.2-VECC-11 includes the reduction of $8.6 million costs recovered for Rate E62 as proposed by EGI. If not confirmed, please explain.

g) For the other lines in Table 1 of Exhibit I.8.2-VECC-11, please add a column to show the dollar reduction in the costs recovered from Rate E62 based on the other scenarios shown in the table.

h) Please explain how a gas distributor located in another province can be considered an in-franchise customer (Ex. I.8.2-VECC-11) while another gas distributor located within the province is served under rates that EGI labels as ex-franchise (M17 and proposed E60 & E70 (Exhibit 8, Tab 2, Schedule 5, Table 1).

2. Ref: Exhibit I.7.0-FRPO-33, pg. 3
Exhibit I.7.1-CCC-6, pg. 2

The second paragraph in the response part C in FRPO interrogatory indicates that gas supply administration costs are recovered as part of the delivery revenue rather than through gas cost revenue. The response to part C in the CCC interrogatory states that EGI is not allocating sales service related gas supply administration costs to direct purchase customers and that these costs to provide sales service are allocated in proportion to sales service volumes and recovered from sales service customers only. The response then goes on to state that EGI classifies the O&M costs for direct purchase and distributor consolidated billing service to the same gas supply admin functional classification which are then offset by other revenue associated with the DP admin charge and the DCB charge.

a) Do the DP admin and DCB charges cover 100% of the associated costs that are included in the gas supply admin? If not what percentage of the associated costs are recovered through these charges?

b) Please explain how the gas supply admin costs associated with providing sales service customers with gas are only recovered from system gas customers if these costs are recovered through delivery rates which are also recovered from direct purchase customers.

3. Ref: Ex. I.8.2-Staff-30

This interrogatory response deals with the potential movement between rates E02, E10 and E20. EGI has identified more than 800 customers that may have a financial incentive to switch rate classes upon implementation of the rate harmonization plan. Does EGI planning on informing each of these customers of the potential financial benefit of switching from one rate class to another upon the implementation of the rate harmonization plan? If not, why not?

4. Ref: Ex. I.7.1-FRPO-51, Att. 1

a) Are the average cost per metre figures shown on page 1 of the attachment the gross average costs or net average costs (i.e. reflecting accumulated depreciation)?

b) Please explain the factors that result in the average cost per metre of a 0.5 inch pipe diameter being nearly 5 times more than that of a 1.0 inch diameter pipe.

c) Please explain the factors that result in the average cost per metre of the 1.5 and 3 inch pipes being significantly less than the 1.25 and 2 inch pipes, respectively.

d) Please explain why the average cost per metre of the 16 and 20 inch pipes are significantly less than that of 12 and 14 inch diameter pipes.

e) Are the pipe diameters shown as 0.8 and 1.3 actually 0.75 and 1.25 inches, respectively?

f) Please explain why data from December 31, 2021 was used for the average cost per metre and the classification factor.

g) Please update the information on page 1 to reflect data as of the end of December, 2024, or the most recent information available if December, 2024 data is not available.

h) Please update the information on page 2 to reflect data as of the end of December, 2024, or the most recent information available if December, 2024 data is not available.

i) Please confirm that the figure of 1,801,039 shown on line 6 on page 2 is simply the difference between total low pressure distribution mains and distribution low pressure customer mains. If this is not the case, please explain how the 1,801,039 is calculated.

j) If the total customer-related mains cost shown at line 3 on page 2 was reduced by $100 million to $2,828,488 and with a corresponding increase in the demand-related mains, please confirm that this would result in the allocation of more costs to be recovered through demand charges and less costs to be recovered through customer charges. If not, please explain why not.

k) Please confirm that under the above scenario, the impact on individual rate classes would be determined by both the allocation of customer-related costs and demand-related costs to each of the rate classes. If not confirmed, please explain.

l) Based on the above scenario in the proposed one rate zone scenario, please show the change in customer-related costs and in demand-related costs for each rate class.

m) In the regression equation shown in note 1 on page 2, is the intercept value of 44.798 statistically significantly different from zero at a 95% confidence level; at an 80% confidence level?

5. Ref: Ex. I.8.2-LPMA-15
Ph. 3 Ex.8, Tab 2, Sch. 3, Att. 7, pg. 28

a) Please confirm that when the federal carbon charge was included in the calculation, about 63,000 customers or 1.6% of total general service customers would see bill impacts of a 10% or more increase.

b) Please confirm that when the federal carbon charge is removed from the calculation, about 288,000 customers or 7.3% of total general service customers would see bill impacts of a 10% or more increase.

c) Based on the no federal carbon charge calculation, please confirm that only about 42,000 customers or 1.1% of total general service customers would see bill impacts of a 10% or more increase.

d) Did EGI consider a rate design with three parts for general service customers of a fixed charge, a demand charge and a volumetric charge where a portion of the demand-related costs were recovered through a demand charge and the remainder of the demand-related costs were recovered through a volumetric charge as a form of rate mitigation? If not, why not?

6. Ref: Ex. I.8.2-LPMA-18
Ph. 3 Ex. 8, Tab 2, Sch. 9, Att. 2, g. 1

In the response to part a of the LPMA interrogatory, EGI states that design day demands are allocated to the harmonized rate classes proportionally by CAEC based on their analysis of individual customers historical consumption, but CAEC states that the sum of the individual 2018 and 2019 demands will not match the general service 2024 total forecast design day demand.

For cost allocation and billing demand purposes, EGI has used 1,087,127 103 m3/d for Rate E01 and 772,599 103 m3/d for Rate E02, resulting in delivery demand rates of 61.4250 cents/m3 and 63.5355 cents/m3 respectively.

a) Please confirm that the billing demand figures noted above are not related to the sum of the design day estimates using the CAEC regression methodology based on 2018 an/or 2019 data or any other period.

b) Does EGI and/or CAEC have the aggregate sum of all customers under each of Rate E01 and E02 based on the CAEC regression methodology? If yes, please provide the two figures.

7. Ref: Ex. I.8.2-LPMA-18
Ph. 3 Ex. 8, Tab 2, Sch. 9, Att. 2, pg. 1

In the response to part d of the LPMA interrogatory, EGI indicated that it does not plan on requesting a variance account to track the difference in delivery demand charge revenues noting that the annual update is intended to capture changes in demand requirements specific to each customer under design day conditions. However this does not take into account the difference in the design day billing units used to calculate the delivery demand rates which appear to be based on a different methodology that the aggregate of all customers in the rate classes based on the CAEC methodology that will be used for billing purposes beginning in 2027.

a) If the billing units from the CAEC methodology derived from 2018/2019 data or any period prior to the end of 2024 are higher than the figures used to derive the delivery demand rates, will this not result in higher revenues to EGI because the delivery demand rate is higher than it should be based on the lower forecast of delivery demand forecasts?

b) If the billing units from the CAEC methodology derived from 2018/2019 data or any period prior to the end of 2024 are lower than the figures used to derive the delivery demand rates, will this not result in lower revenues to EGI because the delivery demand rate is lower than it should be based on the higher forecast of delivery demand forecasts?

8. Ref: Ex. I.8.2-CCC-15

Please calculate the design day demand shown in line 4 of the table on page 2 based on the consumption, days and heating degree days shown in the response to part a, with the following changes to that data:

a) No consumption in July through October in each of 2018 and 2019;

b) If the design day demand increases, please explain why this is reasonable.

c) If the design day demand decreases, please explain why this is reasonable.