EB-2025-0155

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sch. B;

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an order or orders clearing certain commodity and non-commodity related deferral or variance accounts.

INTERROGATORIES OF CANADIAN MANUFACTURERS & EXPORTERS ("CME") TO ENBRIDGE GAS INC. ("EGI")

CME-1

Ref: Exhibit B, Tab 3, Schedule 1, p. 1, 3 of 4.
At page 1, EGI stated that "After removing 2024 severance from actual O&M, Enbridge Gas was relatively flat to 2024 OEB approved." EGI stated at page 3 that there was approximately $20 million in STIP and legislative benefits.

(a) Were there any other drivers of higher-than-expected O&M for the remaining workforce (after headcount reductions) other than STIP and legislative benefits?
(b) Please describe why EGI was required, or determined it was appropriate to provide 20 million in extra STIP and legislative benefits beyond what was forecast in rates.

CME-2

Ref: Exhibit B, Tab 3, Schedule 2, page 5 of 8.
At page 4, EGI stated "First is the reprioritization of investments based on funding the most urgent, near-term requirements of the system, and reducing scope of projects to focus on component and partial replacements. The second reason is the completion or re-pacing of several large customer-driven projects."

(a) Prior to the ordered reduction in capital spending, did EGI give consideration to component and partial replacements? If the answer is no, explain why not, if the answer is yes, explain how EGI has changed its approach to partial or component replacements as compared to the previous capital planning process before the capital reduction.
(b) Please provide a list of large customer driven projects that were re-paced, and the overall impact of the re-pacing on the capital budget.

CME-3

Ref: Exhibit C, Tab 2, Schedule 3, p. 2 of 6.
(a) Please confirm CME's understanding that the harmonization of UFG volumes for the Union rate zone therefore represents a timing difference of being affected by 2023 and 2024 adjustments simultaneously, and that now that it is on the harmonized

methodology, that increase will recur in the future. If that's not confirmed, please explain the reason why it would recur.

CME-4

Ref: Exhibit C, Tab 2, Schedule 3, p. 2 of 6.
At page 4, EGI stated that "The impact of the December 2023 unbilled and no-bill estimates (as was the previous practice) on 2024's UFGVVA was an increase in UFG recorded in the variance account of approximately 21,049 10^3 m^3. The impact of the December 2024 unbilled and no-bill estimates was an increase of 63,948 10^3 m^3."

(a) Has Enbridge investigated why the increase in UFG changed so drastically between 2023 (21K) and 2024 (63K) as a result of unbilled and no-billed estimates? What is the reason?

CME-5

Ref: Exhibit C, Tab 2, Schedule 3, p. 4 of 6.
At page 4, EGI stated "The new 2024 Benchmark Analysis, represented in Figure 2, recognizes the relative size of each utility within a comparator group by determining the groups weighted average UFG by volume of throughput."

(a) Was ScottMadden asked to opine on whether or not the analysis of UFG volumes should be weighted by volume of throughput? If so what was their response, if not, why not?

(b) Other than any consultations with ScottMadden, did EGI conduct any analysis to determine if throughput volume average weighting was appropriate in this circumstance?

(c) Figure 2 at page 5 shows sharp changes to year over year UFG amounts. UFG can be impacted by billing issues, such as when estimated reads underestimate the actual consumption. Has EGI ever conducted any analysis to correlate the UFG with increases or decreases in estimated meter reads?

CME-6

Ref: Exhibit C, Tab 2, Schedule 3, p. 5, Figure 2, page 6
Figure 2 demonstrates that at least to some degree, many of the utilities captured in the study experience similar trends year over year. At page 6 of 6, EGI stated that "common macroeconomic factors or national/continental weather trends" could be the reason for the industry-wide trends.

(a) What sort of macroeconomic factors or weather would cause changes to UFG? Is EGI's statement simply a matter referring to total throughout of gas (either due to colder/warmer weather and consumer purchasing volumes)? Or are there other impacts either of economic conditions or weather which might impact UFG (such as colder weather causing additional leaks in physical pipe infrastructure)?

CME-7

Ref: Exhibit C, Tab 2, Schedule 5, p. 1.
On Page 1, EGI stated: "Disposition variances result from Enbridge Gas's billing systems' inability to locate and apply deferral clearance unit rates to all intended customers and/or volumes. Due to customer moves and other account changes, deferral clearance unit rates derived utilizing historical customers and volumes are not able to be assessed against all historical customers and/or volumes at the time of disposition, resulting in the balances captured in the Deferral Clearing Variance Account."

(a) Will the amounts credited to ratepayers be allocated to the customer classes within which the original customers took service? Or will the amounts credited be allocated to rate classes in a different fashion? If the latter, please explain the allocation methodology.

CME-8

Ref: Exhibit C, Tab 2, Schedule 6, p. 1-3
At pages 1-3, EGI stated that it was "not able to shift any PDO in 2024". EGI also stated that "In 2025, Enbridge Gas will continue to consider practical market-based solution alternatives to PDO, and as part of that consideration Enbridge Gas will be issuing an RFP for an exchange from Parkway to Dawn or Kirkwall to Dawn."

(a) Was an RFP for an exchange from Parkway to Dawn or Kirkwall to Dawn implemented in 2024? If so, please explain if EGI thinks that it would be more successful in 2025.

(b) If an exchange was not implemented in 2024, please explain why not.

CME-9

Ref: Exhibit C, Tab 2, Schedule 7, p. 1 of 3; Exhibit C, Tab 2, Schedule 14.
CME would like to better understand the interactions of accounts 179-305 and 179-328. At Schedule 7, EGI stated "The forecast accrual reference amount that will be used to calculate the entries recorded assumes that the total gross accrual cost as determined by actuarial valuation is what is recorded in the Company's total operating and maintenance expense. The actual cash payments would include all cash payments the utility makes for its pension and OPEB obligations. The approved accrual amount in rates will not change or escalate during the IR term."
EGI stated at Schedule 14 that account 179-328 "records the difference, in excess of a $10 million deadband (debit or credit), between the revenue requirement impact of actual pension and other post-employment benefits (OPEB) costs (accrual and cash-based amounts) and the revenue requirement impact of pension and OPEB costs (accrual and cash-based amounts) included in rates.

(a) Please confirm whether the actuarial valuation of accrual costs corresponds to the accrual amount used to forecast the revenue requirement impact of accrual pension and OPEB costs in account 179-328 or not.

(b) If not confirmed, please explain what is used to forecast the accrual costs if not the actuarial valuation, and why it is appropriate to use two different forecasts.

(c) Would account 179-328 capture the variances described between the actuarial valuation and what is recorded in the Company's total operating and maintenance expense? Please explain fully.

(d) Are the credits/debits in account 179-305 ever trued up between the actuarial valuation and the actual recorded operating and maintenance expense?

CME-10

Ref: Exhibit C, Tab 2, Schedule 8, p. 4 of 5

At page 4, EGI stated: "Enbridge Gas still has the option to satisfy its 2024 EPS obligation by purchasing EPUs from other EPS participants. EPUs typically sell at a discount to the excess emissions charge, which would reduce Enbridge Gas's 2024 EPS compliance obligation."

EGI also stated that "EPP funding is equal to a facility's compliance payment made to the provincial government in the previous year."

We reviewed Staff-2 in EB-2024-0251 and have the following additional questions:

(a) Is the EPP funding available cumulative for each facility, or is it forfeited if not used in one year?

(b) To the extent that EPP funding is *not* cumulative, and disappears at the end of each year. Please provide the amount of money that was available through the EPP that was not used by EGI since the program started (2024) broken out by regulated facility.

(c) If EPUs are purchased in one year, and therefore reduce the EPP funding for the following year, is there any bar to EGI paying the compliance charge for more of its EPS compliance obligation, thereby increasing the funding available in future years after the initial reduction?

(d) How does EGI's planning department plan projects to coincide with compliance funding? For instance, will EGI specifically pay for more of its compliance charges rather than EPUs for certain facilities in preparation for using the EPP funding to pay for specific projects?

(e) Please provide an example of a facility where EGI has used EPP funding on emission reduction projects, the amount of emissions reduced as a result of the projects, and the reduction in compliance costs as a result.

(f) Is there any difference between purchasing EPU's or paying compliance obligations on behalf of the regulated or unregulated business? If so, please describe the differences.

CME-11

Ref: Exhibit C, Tab 2, Schedule 9, page 3 of 6
At page 6, EGI stated "The variances recorded are due to deliveries of renewable natural gas (RNG) and hydrogen to customers from 2022 to 2024, through the Company's OptUp program and Low Carbon Energy Project (LCEP), respectively".

(a) As CME understands it, the OptUp program is a voluntary program whereby customers choose to pay a premium to purchase low carbon energy. Please confirm that EGI is proposing to refund the credit for the overcharge of federal carbon amounts to all customers, rather than the specific customers who opted into the OptUp program and paid the premium for low carbon gas.

CME-12

Ref: Exhibit C, Tab 2, Schedule 18, p. 6 of 6.
At page 6, EGI stated "In 2021 and 2022, Enbridge Gas averaged $3.2 million in actual spend on VMS for high risk locates. Following the implementation of Bill 93, annual expenditures have risen to $8.3 million in 2023 and $9.3 million in 2024."

(a) Has EGI seen additional market entrants entering the locate market to take advantage of the increase in market prices?

(b) Has EGI explored any opportunities to complete this work in house to reduce the cost of locates? Why or why not?