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March 9, 2018

Delivered by Email, RESS & Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2701
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Enbridge Gas Distribution Inc. & Union Gas Limited
MAADs Application (EB-2017-0306)
Rate Application (EB-2017-0307)
Interrogatories from The Association of Power Producers of Ontario

Pursuant to Procedural Order No. 3, please find enclosed Interrogatories from the Association of Power Producers of Ontario.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Per:

Original signed by John A. D. Vellone

John A. D. Vellone

cc: Intervenors of record in EB-2017-0306 & EB-2017-0307
Dave Butters, APPrO
John Wolnik, Elenchus

EB-2017-0306 and EB-2017-0307

Interrogatories

To

Enbridge Gas Distribution Inc. AND Union Gas Limited

From

The Association of Power Producers of Ontario (APPrO)

March 9, 2018

QUESTIONS REGARDING MAADS APPLICATION ISSUES LIST

“No Harm” Test

1-APPrO-1

Reference: EB-2017-0306, Exhibit B, Tab 1, pg. 20

Preamble: APPrO would like to understand whether the ratepayer benefits identified directly from the proposed amalgamation, or from some other difference in underlying assumptions.

Questions:

a. What assumptions did the applicants use to forecast rates for Enbridge (line 1) and Union (line 2) over the 10 year period? Did you assume a continuation of the existing IR plans? Or did you apply the same price cap mechanism that is proposed for Amalco (line 3)?
b. What assumptions did the applicants use to forecast rates for Almalco (line 3) over the 10 year period? Did you include any amounts for ICM funding? If no, why not?
c. Please provide an updated version of Table 3 to compare on an apples-to-apples basis by using the same price cap rate setting mechanism that is proposed for Amalco (line 3) for each of Enbridge (line 1) and Union (line 2) for each year.
d. Using the table created in part (c), please add a new line beneath the Amalco line which provides an estimate of the revenue requirement impact of the expected ICM costs for each year over the 10 year period. Please add another new line that totals these costs with the forecasted Amalco costs for each year.
e. Please re-produce Figure 1 to show the cumulative ratepayer benefit (or loss) under the scenarios outlined in (d) above.

2-APPrO-2

Reference: EB-2017-0306, Exhibit B, Tab 1, Attachment 11, pgs. 2-4

Questions:

a. Please provide equivalent pro-forma statements for each year in the proposed 10-year deferral period.
b. Please provide a descriptive list of all the assumptions that went into creating this 10 year pro forma.
c. Please provide a description of the major year-over-year trends seen across this 10 year pro-forma.
d. Please provide a list of the uncertainties / contingencies that may affect the estimates outlined in this 10 year pro forma. If possible, please produce a sensitivity analysis that illustrates best case, worse case and expected case impacts on this pro forma.
e. Provide similar 10 year pro forma statements for each of Enbridge and Union (assuming the proposed merger does not occur). Include a descriptive list of all assumptions, major year-over-year trends, uncertainties/contingencies, and an equivalent sensitivity analysis. Please describe how the forecast accounted for utilities obligation to maximize continuous improvements in their productivity and cost performance, whenever possible, including taking advantage of opportunities arising from their common ownership.

Rebasing Deferral

3 & 4(a)-APPrO-3

Reference: EB-2017-0306, Exhibit B, Tab 1, Section 5.1 (pgs. 41-42)

The deferred rebasing period of 10 years is necessary to allow Amalco to integrate and have sufficient time to support making the capital and system investments necessary to generate integration synergies across the combined EGD and Union operations. The Applicants will use the 10 year deferred rebasing term to generate efficiencies through system and process integration as well as workforce alignment as described at a high level in Section 4.6; and

EB-2017-0306, Ex. B, Tab 1, Section 4.6 (pg. 25)

Opportunities to generate efficiencies and synergies over the deferred rebasing period through workforce restructuring and alignment, as well as system and process integration exist in the following areas:

- *Customer Care*
- *Distribution Work Management*
- *Utility Shared Services*
- *Storage and Transmission, Gas Supply and Gas Control*
- *Management Functions*
- *Other Functions*

[…]

The estimated capital investment required for the integration of systems and technology to support the amalgamation of EGD and Union is estimated to be between $50 million and $250 million to deliver potential cost synergies of between $350 million and $750 million over the 10 year deferred rebasing period.

Questions:

a. Please quantify the anticipated efficiencies or synergies associated with workforce restructuring and alignment. Please provide any internal documentation, including reports, memos, correspondence, etc., that forecasts or attempts to quantify the anticipated efficiencies or synergies associated with workforce restructuring and alignment. If the internal documentation differs from the applicant's current estimates, please explain the reasons for the differences.
b. To the extent there are incremental O&M costs associated with implementing any of these efficiency initiatives (the applicants mention the addition of temporary staff to facilitate new software system implementations as one example) please quantify on a year-over-year basis the incremental O&M costs for each such initiative.

c. The OEB expects utilities to demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives. Given the clear synergies projected for each of these initiatives, would the Applicants undertake these efficiency initiatives if the Board does not approve a 10 year deferral period? If no, why not?
d. Under the proposed 10 year deferral, when would ratepayers see the direct benefits from the O&M savings associated with the above noted efficiency investments in reduced rates?
e. Under the Applicant’s proposed ICM, would the Applicants be eligible to seek recovery of the capital investments associated with these efficiency improvements as part of the ICM?

4(b)-APPrO-4

Reference: EB-2017-0306, Exhibit B, Tab 1, Section 5.2, Pgs. 42-43

Preamble: The OEB determined in its Decision and Procedural Order No. 3 that:

The OEB does not agree with the arguments of the applicants and accepts the position of intervenors and OEB staff that all aspects of the MAADs Handbook do not automatically apply to natural gas. The MAADs Handbook does not specifically reference natural gas and there is no specific guidance in the Handbook as to how gas mergers should proceed. The OEB is of the view that issues such as the deferral period and earnings sharing mechanism are legitimate areas of inquiry and are not pre-determined in this case.

Question:

a. In light of the above Board's decision in PO3, do the applicants propose any changes to the ESM outlined in the Application?

Preamble: OEB Decision and Order dated July 17, 2014 in EB-2012-0459 states at pg. 15 that:

The Board finds that the dead band should be eliminated and that all over-earnings will be shared 50:50 between ratepayers and shareholders. The Board agrees that the central issue is that the sharing with ratepayers needs to be balanced with an incentive to find and retain efficiencies. The Board also agrees with CCC that a key consideration is the overall IR framework and the other parameters. The Board is approving a Custom IR for Enbridge, but must address the shortcomings of the plan. The lack of total cost benchmarking and the lack of independent budget assessments result in a greater risk that costs have been over-forecast. Therefore, the Board concludes that additional ratepayer protection is warranted. A 100 basis point dead band provides insufficient protection for ratepayers, and therefore the Board finds that the dead band should be eliminated for this Custom IR plan.

Question:

b. Enbridge's current ESM provides that all over-earnings would be shared 50:50 between ratepayers and shareholders (EB-2012-0459). Please explain how increasing the deadband to 300 basis points results in "no harm" to ratepayers?

Preamble: EB-2013-0202 Settlement at Exhibit A, Tab 1, page 37 states

If, in any calendar year, Union's actual utility ROE is more than 200 basis points over the 2013 Board approved ROE of 8.93%, then such earnings in excess of 200 basis points would be shared 90/10 between customers and Union (i.e., customers would be credited 90% and Union would be credited 10%).

Question:

c. Union's current ESM provides that all over-earnings more than 200 basis points would be shared 90:10 between ratepayers and shareholders (EB-2013-0202). Please explain how increasing the deadband to 300 basis points while decreasing ratepayers share from 90% to 50% results in "no harm" to ratepayers?

4(c)-APPrO-5

Reference: None

Question:

a. Are the applicants willing to propose any additional mechanisms to protect the interests of consumers pending rebasing?

5-APPrO-6

Reference: None

Questions:

a. For Enbridge, please provide a complete listing of any commitments to future action that were made at any time between 2013 to 2018. Please cite the source of each such commitment.
b. For Union, please provide a complete listing of any commitments to future action that were made at any time between 2013 to 2018. Please cite the source of each such commitment.
c. Please provide a description of when and how each of these commitments were already or are to be addressed.
d. Are the applicants willing to update Amalco’s cost allocation methodology in 2019 to ensure revenues and costs are appropriate, before embarking on an extended deferral period before the next rebasing? If no, why not?

<u>Impacts of the Merger</u>

6-APPrO-7

<u>Reference:</u> EB-2017-0306, Exhibit B, Tab 1, Pg. 9-10

As of Dec. 31, 2016:

- *Enbridge owned and operated storage facilities in Ontario, with 1 a total working capacity of approximately 3.2 billion cubic metres (115 billion cubic feet) of which 2.6 billion cubic metres (92 billion cubic feet) is available for utility customers at cost-based rates; and*
- *Union owned and operated approximately 4.6 billion cubic metres (162 billion cubic feet) of storage capacity in 23 underground facilities located in depleted gas fields, of which approximately 2.7 billion cubic metres (95 billion cubic feet) is reserved for utility customers at cost based rates.*

<u>Questions:</u>

a. Please explain, and quantify, the impact of the proposed merger on competition in gas storage in Ontario.
b. Please explain in detail any arrangements between Enbridge and Union related to the buying and selling of storage capacity. Please file any agreements associated with such arrangements.
c. For each such arrangement, please explain whether the prices paid for storage capacity are market based or cost based. Cite the relevant sections of the applicable agreement. If market based, please quantify on an annual basis the premium paid over cost based rates.
d. Please explain in detail any arrangements between Enbridge and Union related to the buying and selling of transmission or distribution capacity. Please file any agreements associated with such arrangements.
e. For each such arrangement, please explain whether the prices paid for transmission/distribution capacity are market based or cost based. Cite the relevant sections of the applicable agreement. If market based, please quantify on an annual basis the premium paid over cost based rates.
f. Please explain how the applicants propose to rebate to ratepayers any such premiums to ensure that ratepayers are not harmed as a result of the proposed merger.

QUESTIONS REGARDING RATE-SETTING MECHANISM ISSUES LIST

Rate Framework

1(b)-APPrO-8

Reference: EB-2017-0307, Exhibit B, Tab 2

Questions:

a. Please provide the retainer letter between Mr. Makholm (the expert) and the applicants together with any supplemental instructions provided to Mr. Makholm by the applicants or their counsel.
b. Please provide a timeline that specifies the date Mr. Makholm was first approached by the applicants to provide evidence, the delivery of instructions to Mr. Makholm, the delivery of any drafts of the evidence (regardless of name) by Mr. Makholm, and the delivery of any feedback (whether written or oral) to Mr. Makholm on the drafts, and the ultimate finalization of the report that was filed in evidence at Exhibit B, Tab 2.
c. Please provide copies of all prior drafts of the report provided at Exhibit B, Tab 2 of the evidence.

1(b)-APPrO-9

Reference: EB-2017-0307, Exhibit B, Tab 2, pgs 24-31

Question:

a. Why are the date ranges for the trending of TFP data for Union (2001-2016) and Enbridge (1993-2016) different?
b. Please explain what other methods are available to analyze TFP trends other than a simplistic “visual” inspection. Please provide the results of such other methods.
c. Has the author of this study conducted an inquiry into all of the efficiencies and cost savings that may arise as a result of the proposed merger of Enbridge and Union requested in EB-2017-0306?
d. How does the author’s methodology account for known efficiencies that are to occur in the future as a result of the proposed merger, which are by their very nature not going to be reflected in a historical TFP analysis?

1(b)-APPrO-10

Reference: EB-2017-0307, Exhibit B, Tab 1, Section 2.2, pgs. 8-9

The Applicants propose a productivity factor based on the Total Factor Productivity Analysis and associated recommendations prepared by Jeff Makholm of National Economic Research Associates Inc. ("NERA"), who was engaged by the Applicants. Based on his analysis, Dr. Makholm recommends an X factor of zero and further recommends that a stretch factor would not be appropriate; and

EB-2017-0307, Exhibit B, Tab 2, pg. 30

Based on my TFP growth study for the large group of US distribution companies, supported by my comparable analysis of TFP growth for both EGD and Union, I do not recommend an X-factor for EGD or Union for their upcoming 10-year rebasing periods.

Question:

a. On its face, Mr. Makholm's x-factor recommendation applies to Enbridge and Union as separate and distinct entities. On what basis are the applicant's extending this recommendation to Amalco?

1(e)-APPrO-11

Reference: Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors dated July 14, 2008 at pg. 35.

"The Board has determined that the eligibility criteria are sufficient to limit Z factors to events genuinely external to the regulatory regime ***and beyond the control of management*** *and the Board.";* and

EB-2017-0307, Exhibit B, Tab 1, pg. 11

Causation – the change in cost, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine event and must be clearly outside of the base upon which rates were derived

[…]

Management Control - the cause of the change in cost must be: (a) not reasonably within the control of utility management; and (b) a cause that utility management could not reasonably control or prevent through the exercise of due diligence.

Questions:

a. Please confirm that the proposed z-factor relates only to events that are genuinely external to the regulatory regime and beyond the control of management.
b. Does the introduction of the word "reasonably" serve to expand the scope of z-factor events to matters that are otherwise within management's control? For example, would it be unreasonable to factor in a decision by management not to pursue a particular maintenance activity decades ago if it results in a major disaster today?

1(g)-APPrO-12

Reference: EB-2017-0307, Exhibit B, Tab 1, pg. 12-13; and

Handbook to Electricity Distributor and Transmitter Consolidations dated January 19, 2016 at pg. 17:

The Incremental Capital Module (ICM) is an additional rate-setting mechanism under the Price Cap IR option to allow adjustment to rates for discrete capital projects.

Questions:

a. Please confirm the applicant’s proposed ICM would only apply to discrete capital projects that exceed the materiality threshold.
b. If not confirmed, please explain why non-discrete capital projects should be eligible for ICM funding under a 10 year deferred rebasing period.