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Our File No. 176656

June 14, 2018

VIA RESS, EMAIL AND COURIER

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attention: Kirsten Walli,
Board Secretary

Dear Ms. Walli:

Re: EB-2017-0306/0307: Enbridge Gas Distribution Inc. and Union Gas Limited Application for Amalgamation and Rate-Setting Mechanism

Please find enclosed herewith BOMA's Final Argument.

Yours truly,

FOGLER, RUBINOFF LLP

Tom Brett per: [signature]

Thomas Brett
TB/dd
Encls.
cc: All Parties *(via email)*

EB-2017-0306
EB-2017-0307

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15 (Sched. B);

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. and Union Gas Limited, pursuant to section 43(1) of the *Ontario Energy Board Act, 1998,* for an order or orders granting leave to amalgamate as of January 1,2019;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. and Union Gas Limited, pursuant to section 36 of the *Ontario Energy Board Act, 1998,* for an order or orders approving a rate setting mechanism and associated parameters during the deferred rebasing period, effective January 1, 2019.

FINAL ARGUMENT OF

BUILDING OWNERS AND MANAGERS ASSOCIATION, GREATER TORONTO ("BOMA")

June 14, 2018

Tom Brett
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Counsel for BOMA

<u>"No Harm" Test</u>

1. ***Have the applicants appropriately applied the "No Harm" test in this case, including in consideration of the OEB's statutory objectives in relation to natural gas?***

2. ***Have the applicants met the test?***

BOMA is strongly of the view that the Board's merger policy for electricity distribution utilities, contained in the three documents, Rate-making Associated with Distributor Consolidation, Report of the Board ("2007 Report") and EB-2014-0138, Report of the Board, Rate-making Associated with Distributor Consolidation dated March 26, 2015 ("2015 Report"), and the Handbook to Electricity Distributor and Transmitter Consolidations dated January 19, 2016 (the "Handbook"), does not, and should not, apply to the natural gas sector and to the applicant's proposed amalgamation, for several reasons. First, these documents deal explicitly with the electricity sector. In the Introduction to the July 2007 Report, the Board stated:

> *"Earlier this year, the Board initiated a consultative process focusing on the regulatory treatment of certain rate-related issues <u>associated with consolidation in the electricity distribution sector</u>. The purpose of the consultation was to assist the Board in developing a policy framework on relevant rate-making issues and to provide greater predictability for distributors and other stakeholders in relation to those issues."* (our emphasis)

In the 2015 Report, in the Introduction, the Board stated (p4):

> *"After considering the <u>government's policy expectations</u>, the results of the consultations, and the OEB's own expectations that the distribution sector should continue to seek out efficiencies especially through consolidation, the OEB has concluded that it will proceed at this time with amendments to its <u>rate-making policy associated with electricity distributor consolidation.</u>"* (our emphasis)

and further stated (p3):

> *"The report of the Ontario Distribution Sector Review Panel, issued in December 2012, set out a vision for consolidation resulting in the less costly and more efficient delivery of electricity, with a predicted cost savings of $1.2 billion over the next ten years. When the Minister of Energy responded to the Panel's report, he indicated that he expected that the sector would find ways to achieve those savings through more efficient service delivery, including negotiated consolidations. This view was carried forward in the government's December 2013 Long Term Energy Plan ("LTEP"), where it is stated that the government expects electricity distributors to pursue innovative partnerships and transformative initiatives that will result in savings for electricity ratepayers. On March 31, 2014, the OEB issued a OEB staff Discussion Paper (the "Discussion Paper") providing background on the current policies, summarizing stakeholder input received in relation to those policies, and setting out questions for stakeholder comment with respect to potential changes to those policies. On November 13, 2014, the Advisory Council on Government Assets issued its findings which included the view that consolidation was needed to encourage modernization of the electricity distribution system."*

The Handbook, both in its title, its listing of the objectives of the Board in electricity, section 1.1 of the Act at p4, as part of its explanation of the no harm test, and the reference to the various government policy documents urging consolidation of the electricity distribution industry all confirm that the Handbook is meant to deal with electricity distributor and transmitter mergers.

These three documents are clear on their face that they apply only to the electricity sector.

As noted in the quotations from the Reports, the Board's electricity merger policy was developed in the context of several important facts, including the fact that at the time the restructuring of the electricity industry in 1998, there were more than 300 electricity distributors in Ontario, many of them very small. Second, Ontario Government policy, from that time onward, supported the consolidation of the electricity distribution industry into fewer larger utilities, and that policy continues to this day. The reports of both the Ontario Distribution Sector Review Panel in December 2012 and the Advisory Council on Government Assets on November 13, 2014 strongly supported electricity distribution utility consolidations, citing the potential economies of scale, lower financing costs, more capacity for innovation, among other factors.

In order to provide a strong incentive for electricity utilities to consolidate, the Board's 2007 Report allowed the merged entity to defer rebasing for ratemaking purposes for up to five years to offset the merging utilities' transactional costs and integration costs. In other words, the utilities were permitted to retain 100% of any savings due to efficiencies or productivity improvements they were able to achieve, as a result of the merger, for a five-year period following the merger.

However, the electric utilities later complained that they did not still have enough incentive to merge, and in the 2015 Report, the Board extended the deferred rebasing period, during which the utilities could keep the savings, up to ten years, to offset transaction costs and integration costs. The utilities had only to request ten years, and they were given it (see, for example, the decision approving the merger that produced Alectra (EB-2017-0024). They did not have to demonstrate to the Board that they needed it. The policy did require an earnings sharing mechanism in years six to ten of the deferral period, but only in the event, and to the extent, that the utility's ROE exceeded a 3% deadband over allowed ROE, a highly unlikely eventuality, given the typical returns in the Ontario electricity distribution sector. That policy remains in place today.

The Rate Handbook applies to gas distributors rate submissions but not to gas companies' mergers. The Handbook is thirty pages long, with only about half a page dedicated to MAADs, which deal very briefly with gas rates filings following a merger.

The Handbook to Electricity Distribution and Transmission Consolidation ("Electricity Consolidation Handbook"), January 19, 2016 deals only with electricity utility mergers. It does not deal with gas utility mergers.

For example, that document states at p15:

> *"To encourage consolidation, the OEB has introduced policies that provide consolidating distributors with an opportunity to offset transaction costs with any achieved savings".*

In BOMA's view, there is clearly no need for such substantial incentives to encourage Enbridge Inc. ("Enbridge") to amalgamate its two large wholly owned Ontario natural gas utilities, Union Gas and EGD. Enbridge already has enough incentives to amalgamate the two corporations. Notably, it will be able to run the Amalco with one senior management team. It will also be able to allocate capital on a more efficient basis, that is over Amalco as a whole, rather than make such decisions only in respect of the two former utilities' silos, based on an integrated asset management program for Amalco as a whole. It will have the opportunity, if it so chooses, to integrate some of the IT systems and procedures and methods, which it forecasts should result in large savings over time (C.BOMA.16). It will be able to raise capital more efficiently, for a larger, more resilient company. Enbridge shareholders would undoubtedly eventually pressure it to amalgamate the two entities if Enbridge fails to do so on its own. Enbridge would require a compelling reason not to amalgamate.

EGD and Union are the only two large gas utilities in Ontario. They have been profitable for decades, with their actual returns (normalized returns for EGD) almost always exceeding their allowed ROEs. Amalco will own 99% of the Ontario gas distribution industry. Moreover, following Enbridge's February 2017 decision to acquire Spectra Inc., Enbridge now owns 100% of the common shares of companies which in turn own 100% of the shares of both Union and EGD. Enbridge made a commercial decision in 2016/2017 to acquire Houston-based, Spectra Inc. to add substantial gas transportation and processing assets to its existing oil transportation assets. One of the Spectra assets that Enbridge acquired was Union Gas.

Second, there is not, and has never been, any explicit Government policy to encourage the merger of EGD and Union into one company. In fact, regulators have flagged the advantages of having a few large gas distributors in Ontario.

The Rate Filing Requirements for Natural Gas Rate Applications dated February 16, 2017 provides detailed guidelines for the filing of gas distributors' rate submissions. These guidelines contain an introduction of four pages, and a forty-one page chapter, entitled "Cost of Service Applications".

The only reference to MAADs applications contained in the forty-five page document is in a three-line sentence, that states:

> *"In the first cost of service application following a consolidation, the applicant is expected to address any rate-making aspects of the MAADs transaction, including a rate harmonization plan and /or customer rate classifications post consolidation."*

To summarize, there is currently no MAADs policy for the merger of the province's two major gas utilities, nor any consideration of the appropriate rate treatment for the gas entity after the merger to ensure ratepayers are properly protected. That policy will, BOMA believes, be established by the Board in this proceeding.

If the "no harm" test remains the test for mergers, the question is whether the transaction harms the ratepayers. The answer to that question depends on the rate-making framework that will apply to Amalco after the amalgamation, as the rates proposal and the amalgamation proposal are linked, and must be considered together. As will be discussed below, BOMA has concluded that the rates framework proposal, in particular the ten year deferred rebasing period, during which the shareholders will take all the savings, is harmful to ratepayers. The onus is on the applicant to show that ratepayers will benefit, or at least will not be harmed, from the transaction. In BOMA's view, it has not done so.

Rebasing Deferral

3. Is deferral of rebasing appropriate in the context of this application?

BOMA is of the view that deferral of rebasing is not appropriate in the context of the application, for the following reasons.

First and most important, applying the electricity merger policy to the proposed gas company amalgamation would permit the amalgamated company to utilize a very generous rate-making policy framework, available under the electricity merger policy, including a ten year deferred rebasing period designed to provide a strong incentive for electricity utilities to merge, rather than the policy currently in place for gas utilities under IRM, which requires a cost of service rebasing and/or a new custom IR incentive rate-making proposal every five years. EGD's proposal would be much less favourable to utility ratepayers, and more favourable to utility shareholders than the existing policy and practice under RRFE for gas utilities.

Second, Amalco has proposed to allocate to the shareholders the very substantial savings that it has forecast will arise from its forecast "integration" expenditures. The company has forecast "integration" capital expenditures of $150 million over the years 2019 through 2023 (a five year period), and savings of $680 million over the proposed ten year period starting in 2019 and ending in 2028. EGD proposes that the company's shareholders will be responsible for the $150 million in capital expenditures and will receive the entire $680 million in savings (see Exhibit B, Tab 1, Attachment 12 (our emphasis).

As can be seen from the company's evidence, cited above, the savings over ten years are forecast to be over 400% higher than the capital expenditures ($680 million versus $150 million), an egregiously unfair arrangement for the ratepayers. The risks to the shareholders are relatively small, given the fact that Enbridge already controls both companies and has access to all the required information. In fact, the evidence is that Union and EGD senior executives met to develop the high level integration capital plan, and prepared C.BOMA.16 and Attachment 12 above. Their analysis of the shareholders' cash flow, displayed at Attachment 12, also shows that Amalco would be cash flow positive in year two of ten, and every year thereafter, and would have recovered its entire integration capital expenditure early in year five of the ten year proposed deferred period. It forecasts $70 million of net cash flow in each of years five, six, seven, eight, nine, and ten, with no offsetting capital expenditures. Amalco has no need for the extra five years.

In BOMA's view, ratepayers would be better served by taking responsibility for both the integration capital expenditures and receiving the benefit of the forecast savings. To achieve that result, BOMA suggests that the Board direct Amalco to file a cost of service rebasing application in 2020 to be effective no later than January 1, 2021. BOMA proposes that the Board extend 2018 rates for each utility to 2019 and 2020, by extending the current rates by two years, with adjustments discussed below. The rate adjustments would be implemented by the Board in Amalco's 2019 rate proceeding on the basis of Board's guidance in this case. Extension of the utilities' current IRM regimes for two years would give Amalco time, up to two and one half years, to prepare a full cost of service filing, including a comprehensive cost allocation study. It would also provide Amalco an opportunity to firm up and make more concrete the high level estimates in the application of its forecast integration capital expenditures and savings, both of which would become the responsibility of ratepayers.

Ratepayers will benefit from having a cost of service rebasing filing for several reasons. First, ratepayers and the Board would have a clear starting point for the determination of Amalco's future rates, based on current costs, and full information on how the "going in" rate base and rates were established. The evidence in this case does not provide a detailed, coherent, well-thought out plan, for the post-merger rates, "either base capital" or integration capital. The forecast integration investments and savings are merely a preliminary estimate and based on very large range of potential costs and savings (Exhibit B, Tab 1, p26). The lack of detailed forecasting of capital expenditures, the lack of a distribution system plan, and a detailed OM&A plan, makes the estimation of the "status quo option", which Amalco has characterized as two consecutive five year custom IR (four custom IR plans) for Union and EGD tentative and unreliable. Amalco admitted that "we are not in a position to file a custom IR for either company at this point" (Tr1, p17). That being the case, high level ten year estimates for two consecutive custom IRs for each company are completely unreliable as a tool to judge whether ratepayers are harmed or benefit from, the proposed deferred rebasing scheme rates framework. That, in turn, calls into question the alleged customer benefit of $410 million. Furthermore, the status quo option should not be the summation of EGD's and Union's hypothetical custom IRs over a ten year period. The companies will very likely be amalgamated, so a single Amalco IRM program should be the comparator. In addition, if the Board finds that the electricity utility MAADs policy does not apply, the status quo option would be a cost of service rebasing followed by an IRM program.

A 2020 cost of service rebasing will also enable Amalco to conduct a proper cost allocation study in order to refresh costs that will become the basis for its subsequent IRM plan. The company could then, following the cost of service rebasing year, propose either a five year price cap plan, following the previous Union plan, or a five year custom IR plan following the EGD model. They would have the data to support their preferred choice.

The companies have not done a comprehensive cost allocation study since 2012, and there is a need to have more current costs upon which to base Amalco's first IRM plan. Under the company's proposal, there would not be comprehensive cost allocation study until 2028, the end of the ten year deferral period, the time of the company's proposed rebasing. Fifteen years in the case of Union, and ten years in the case of EGD, is too long to go without reliable estimate of costs, whatever IRM Amalco selects. After that long a period of time, it is difficult to recreate the cost picture properly, to have an easily understandable and verifiable narrative of how costs have developed, with a company the size of Amalco. The Board and ratepayers will be disadvantaged. In BOMA's view, rates based on costs that outdated would not be just and reasonable rates. Amalco has also agreed, as a general principle, that it is difficult to do cost allocation for part of the company's cost, without considering the impact on the remainder of the company, while at the same time proposing that partial studies be done in 2019. A full cost of service filing will allow Amalco to deal with the Ojibway/St. Clair issue, and to allocate costs across Amalco as a whole.

Furthermore, working with long outdated costs causes distortions in other areas. For example, Amalco is proposing to use Union's 2013 rate base numbers to calculate the ICM threshold for the prior Union customers, and more current 2018 figures to calculate the ICM threshold for former EGD customers, notwithstanding that Union's budgeted 2018 rate base is $6,103.2 billion compared to $4,293.3 billion in 2013, a difference of $2,410 billion (C-BOMA-29, p2). By using the much lower 2013 rate base, Union is able to create an artificially low materiality criteria, and a larger ICM capacity, which does not accurately reflect Union's increased financial strength due to the large rate base additions during the IRM period. A full cost of service hearing would allow for a serious discussion of the appropriate materiality threshold for both Amalco and its ratepayers, prior to the approval of the very large proposed ICM programs, or the inclusion of comparable amounts in a custom IR program.

A rebasing shortly after the merger would also be consistent with the practice employed in other North American energy regulators, when reviewing gas and electric mergers. In their study of twenty-nine approved mergers in the United States and Canada, Messrs. Ladanyi and Brady found that in most cases, the deferred rebasing (or rate freeze, in many US cases) was two or three years, with a few as long as five years; the longest, seven years (Tr3, pp 77 - 79).

Finally, a rebasing soon after the merger would also both give Amalco the time, and encouragement, to integrate their asset management plans, prepare a distribution system plan that is consistent with OEB guidelines, explain how the plan, going forward, will be consistent with the Board's RRFE, finalize the integration plans, and enable the company to allocate capital on an Amalco-wide basis, unconstrained by the EGD and Union "silos". It will allow time to integrate storage service, and gas supply plans, and conduct a serious analysis of rate harmonization. Amalco will then comply with the Amended Filing Requirements for Natural Gas Rate Applications issued February 16, 2017, which require utilities that have merged or amalgamated their service areas since the last cost of service or custom IR application to file a rate harmonization plan subject to established cost allocation and rates design principles for the natural gas sector (p36).

As noted above, an early 2020-2021 rebasing would establish a clear baseline for Amalco's proposed incentive regulation plan. The evidence in the proceeding as to what is the appropriate starting point is confusing, with arguments around productivity initiatives, costs from earlier periods brought forward, apples to oranges comparisons, for example, comparing the inclusion of the $182 million EGD overspend on the GTA project in 2029 rate base with its earlier inclusion in Amalco rates in the status quo, and most important, the mixing of cost numbers and other numbers, such as the $410 million alleged benefit in revenue Amalco needs to earn over and above what it gets from the price cap model to reach its allowed ROE 20 basis points target return each year, in establishing the alleged net "benefit" to ratepayers from using the applicant's ten year deferred rebasing plan (see Tr6, p111), while not offsetting against that "benefit", the fact that shareholders, not ratepayers, would reap the $430 million in excess savings over the same period.

The onus was on the company to demonstrate clearly the benefits to ratepayers. It has not done so. Moreover, much of the explanation was provided only very late in the proceeding, when intervenors had little time left for a thorough examination. The prefiled evidence contains no detailed information to demonstrate how the ratepayers would benefit from the proposal.

A 2020-2021 rebasing proposal would put both the IRM options on a stronger base, with an agreed starting point and fulsome information.

Moreover, with a 2020-2021 rebasing, the Board and ratepayers would be able to monitor the progress of the integration capital expenditures, and OM&A savings resulting from those expenditures. Under Amalco's proposal, it would be much more difficult to do that. The company would also have a firmer grasp on both its integration expenditures and its savings, and would not have to resort to overly complicated methods of demonstrating what it "requires" to earn its allowed return. It would have the opportunity to recover its prudently incurred integration and transaction costs for rates, and provide ratepayers the savings in OM&A costs, and capital costs, also through rates. And given the asymmetry of information that always exists among the company, the Board, and ratepayers' representatives, determination of the new cost base as soon as possible is fairer to both parties.

What is the appropriate deferral period in the event the Board were inclined to provide one? As noted above, BOMA believes there should be no deferred rebasing period in the sense of a period during which the shareholders were earning savings as a result of the shareholders' much smaller costs. But if the Board wished to approve a deferral period, it should be no longer than five years, and be in an amount just sufficient for the company to recover its documented implementation costs.

As noted above, the company's evidence shows that the company recovers its "integration" and transactional costs, the latter of which the company states to be de minimus, by early in the fifth year of the proposed ten year rebasing period.

In the event the Board were to have a deferred rebasing period, an earnings sharing mechanism, which applies from the outset of the IRM, should be applied and be on a 50/50 basis with no deadband, increasing to 75/25 in favour of the ratepayers if overearnings exceed 100 basis points, similar to the schemes used by Union and EGD in their current programs. The proposed 300 basis point deadband is far too large since utility overearnings have almost never exceeded 300 basis points above allowed ROE.

The Board should in no event approve the additional 20 basis points over allowed ROE being built into rates structure and/or the rates framework. The company's proposal for a 0% stretch factor underpins the 20 basis point premium of approximately $12 million per year, over ten years. The company has provided no justification in its evidence for why it should receive an additional 20 basis points in ROE, above the Board allowed level, over the ten year period.

Amalco is, after all, the party seeking approval for the "amalgamation", even though the rate structure, as proposed, results in a merger more in form than in substance. Amalco argues that merging the two businesses should allow them to generate savings for ratepayers over a period of time. Their risks are limited since they already own both businesses. They could have deferred the application for six months to study the cost increases more closely. It is not appropriate to propose a structure that will provide them with a 20 basis point increase over allowed ROEs, especially when ratepayers need to wait for ten years to gain the promised savings.

5. What commitments to future action have the utilities made during their respective 2013-2018 rate plan terms, what other rate setting issues merit attention now (including cost allocation issues), and when and how are these commitments and issues to be addressed?

In its most recent IRM proceeding (EB-2012-0459), EGD proposed a five year custom incentive rate-setting plan ("custom IR") to begin January 1, 2014. The proposed revenue requirement for 2014 was $1.009 billion, increasing to $1.292 billion in 2018. The RRFE provides that for a custom IR plan at the end of its term, as EGD is in 2018, "the incurred rate base will be adjusted prospectively (subject to prudency review) to reflect actual spend" [over the years of the plan] (our addition) before it commences its new rate setting cycle. In EB-2012-0459, EGD committed to file a full cost of service application in 2019, in the following exchange, which occurred on the first day of that proceeding:

> *"Mr. Shepherd: Finally, on p34, that deals with rebasing in 2019, and, if I understand what you are proposing, it is essentially the same as Union. You are agreeing that you will file, regardless of whether you are rebasing, a full cost of service application in 2019?*
>
> *Mr. Culbert: That is correct."*

In EB-2013-0202, the Board approved a Settlement Agreement that for a multi-year price cap IRM that was used to set Union's rates over the 2014 to 2018 period. The Settlement Agreement provided for a full cost of service rebasing for 2019, regardless of whether or not it will be used for ratemaking. In EB-2013-0202, Tab 1, pp 44-45, which has been reproduced below, the relevant part of the Settlement Agreement states:

> *"11.0 Rebasing*
>
> *Union would (subject to any subsequent agreement of all parties to extend the IRM term) prepare a full cost-of-service filing at the time of rebasing, regardless of whether Union applies to set rates for 2019 on a cost-of-service basis or not.*
>
> *At the time of rebasing, Union would provide 2013-2017 actual, 2018 bridge and 2019 forecast information. In addition, Union would provide historical plant continuity information for 2012, 2013, 2014, 2015 and 2016 similar to the information provided in the EB-2011-0210 proceeding at Exhibits B6/T1 & T2/S 1 – 5"."*

This provision is consistent with the RRFE (Regulatory Framework for Electricity Distributors, A Performance Based Approach), which states that for fourth generation IR (price cap), the "going in" rates are determined in a single forward test year cost of service review (RRFE, p13).

BOMA believes that the utilities should honour these commitments by having Amalco file a rebasing proposal to be effective January 1, 2021, at the latest. The Board should allow them to defer the commitments they made in 2013 to rebase in 2019 to 2021.

Amalco will have the option of proposing a five year price cap plan, or a custom IR plan with a term of five years, to be determined in its cost of service rebasing filing, which would be filed no later than January 1, 2020. In either case, the Board could extend the "Union" and "EGD" 2018 rate into 2019 and 2020. Amalco would track all implementation costs and savings therefrom in a separate account which would be reflected in rate base and OM&A for the cost of service rebasing year. The recent history of overearnings should allow the rates to remain constant or nearly the same, as 2018 rates, subject to the adjustments which are the subject of EB-2017-0307 issues 8, 9, 10, and 11, assuming those adjustments are approved by the Board.

In BOMA's view, the fact that Enbridge has decided, for commercial reasons, to amalgamate its wholly owned utility subsidiaries, Union Gas and EGD, is not a sufficient reason to depart from the Settlement Agreement in EB-2013-0202 (Union Gas) or from the commitment by EGD during the EB-2012-0459 proceeding that EGD would file a full cost of service case in 2020-2021, prior to commencing a new IRM cycle, as set out in the RRFE.

Union and EGD also made commitments with respect to cost allocation in EB-2013-0202 and EB-2012-0459. As noted above, in the EB-2013-0202 Settlement Agreement, Union agreed to file a full cost of service filing in 2019, regardless of whether there is not to be used for rate setting, unless the parties agreed otherwise to extend the IRM term. A full cost of service filing would, of course, include a comprehensive cost allocation study. However, in this case, Amalco is not proposing to do a full cost of service study until proposed its 2028 rebasing submission ten years from now. However, Amalco is proposing to re-examine the cost allocation of the capital costs of the Ojibway expansion, in its proposed 2019 rate application.

BOMA notes that in EB-2012-0459 (p72), EGD rejected a proposal by APPrO to make specific cost allocation changes related to pipeline capacity. It stated that:

> *"it would not be appropriate to make one change [in cost allocation] in isolation of a broader examination of cost allocation".*

And, at Tr5, p43, in the current proceeding, the following exchange took place:

> *"MR. SHEPHERD: ...Ms. Mikhaila, you said the other day that you can't really properly do cost allocation, except in the context of a cost-of-service application because that's when you have all your costs set out in detail, right?*
>
> *MS. MIKHAILA: Sorry, you lost me on the last part. That's when you have your cost all?*
>
> *MR. SHEPHERD: All broken down in detail. So that's when you can do a cost allocation study effectively, right, when you have a full set of costs.*
>
> *MS. MIKHAILA: Yes."*

In light of the positions taken by Union and EGD, BOMA submits that Amalco should, in the event the Board approves the amalgamation, undertake a full cost allocation study as early as possible, as part of their proposed full cost of service submission. They will have time to complete the study before filing a cost of service style rebasing in 2020. They will be able to properly allocate costs for any integration capital and OM&A that they are proposing.

Impacts of the Merger

6. ***Would the proposed merger impact any other OEB policies, rules or orders (e.g. regulation of new storage, Storage and Transmission Access Rule (STAR)? If so, what are those impacts and how should the OEB address them?***

If the merger is approved, there are no longer any Union customers or EGD customers; just Amalco customers. In those circumstances, it is not right for different Amalco customers to be paying different prices for the same storage service. The principal reason they are paying different prices is because EGD, on behalf of its bundled customers, must acquire about 25 PJs of a total required storage service of 124 PJs from the unregulated market at a price about twice that, the regulated cost based price of that storage EGD owns in its Tecumseh storage pools. EGD purchases 19 PJs of that 25 PJs from Union's unregulated storage (our emphasis). On the other hand, Union's former customers are paying the lower cost based price for storage service because Union owns sufficient regulated storage resources to supply its own bundled customers and have an excess amount of 7 PJs, which it sells into the market as short term storage or related services. Therefore, Amalco's customers that are formerly Union customers are paying less for storage than Amalco customers who are former EGD customers. Given that all customers are now Amalco customers, that is not right.

In the NGEIR proceeding in 2005, in which the Board decided, inter alia, that storage service was not a monopoly service and that it should therefore be unregulated, the Board "assigned" Union Gas 100 PJs of regulated storage, and "assigned" EGD the current level of its regulated service.

Several intervenors in this case, including Board staff, have questioned why, given that both former Union and EGD ratepayers are all Amalco customers, the Union 7 PJs excess storage should not be shared with former EGD customers. Exhibit JT2.12 shows that over the last five year period, the former Union ratepayers would have lost less than the gain to the former EGD ratepayers, had Union's 7 PJs excess of regulated storage been applied to all Amalco ratepayers (Tr3, p23).

In the same NGEIR proceeding, the Board decided that EGD, which did not have enough regulated storage to supply its bundled customer base, was directed to continue to contract for the balance of the storage it required from the market.

The applicant's answer is that they will consider this problem as part of any rates harmonization effort that they may undertake. BOMA believes that this answer is a further reason why the Board should order a rebasing in 2020, or at the very latest 2021, which would provide Amalco an opportunity to rationalize its storage. BOMA would suggest that the Board signal at this time, in this case, as a condition of granting the merger, that Amalco address this in its 2020-2021 rebasing application. BOMA also suggests that the Board direct Amalco to commission an independent expert study, the terms of reference to be agreed between Amalco and intervenors, to assess the options and make recommendations to rationalize gas storage and transportation for Amalco, such review to include an assessment of the NGEIR decision. That decision was made in 2005, over thirteen years ago, and it needs to be reconsidered in light of the merger and the passage of time.

7. ***If leave is granted, what conditions should be attached?***

If the Board grants EGD and Union leave to amalgamate, it should be subject to the condition that there be no deferred rebasing period. Amalco should be directed to file a full cost of service rebasing in 2020, effective on January 1, 2021.

8. ***What is the status of the Undertakings to the Lieutenant Governor in Council of Ontario?***

9. ***To the extent that the Undertakings are impacted by this application, should any of the provisions of the Undertakings be replaced by a condition of any OEB approval?***

10. ***If so, what should the content of the condition be?***

BOMA has no submissions on Issues 8, 9, and 10.

Monitoring and Reporting

The Board should require Amalco to report annually to the Board and to intervenors, as part of an annual rate adjustment proceeding, a comprehensive statement of progress of whatever ICM plan it has chosen post-rebasing, using the rebasing year forecast numbers, buttressed by actual numbers when available as a starting point. The information should include, as well as detailed information on capital and OM&A costs (including integration costs), achieved savings, capital costs and costs of approved ICM projects, "rate base" continuity schedules, including schedules for depreciation taxes and returns which allow parties to have a clear picture of utility spending and income to assist with establishing a fair base year in the next rebasing. The report should also indicate the calculation of claimed rate base/depreciation drag in the event a price cap plan is implemented.

Finally, annual productivity initiatives, both capital and OM&A with attached savings, should be detailed, and operating costs on a disaggregated basis shown so that the Board and parties can track the changes in such costs, both reductions and additions on the same disaggregate basis over the IRM period, including costs for services provided by affiliated companies, and revenues for services rendered to affiliate companies.

Finally, the actual return (and normalized return) should be shown for each year, with the causes of any changes in actual returns delineated. Only with this information can the Board ensure that the eventual rebasing is based on solid data and is fair to all parties.

<u>Rate-Setting Mechanism Issues List</u>

<u>Rate Framework</u>

1. ***If the OEB grants the Applicants' request for approval of the amalgamation and deferral of rebasing, what should be the features of a Price Cap IR mechanism during the deferral period, including?***

   (a) What is the appropriate inflation factor?

   Amalco has proposed to use the GDPIPIFDD. BOMA supports that choice.

   (b) What is the appropriate productivity factor?

   BOMA agrees that the productivity factor growth should be 0%, as recommended by Dr. Lowry, based on total factor productivity trend. The stretch factor should be 0.3% (see below), for an X-factor of 0.3%.

   (c) Should a stretch factor apply, and, if so, what is an appropriate stretch factor?

   BOMA agrees with PEG's recommendation of a 0.3% stretch factor. PEG recommended a stretch factor of 0.3%, based on the fact that Amalco submitted no benchmarking evidence to support another factor, and that in the fourth generation IRM, 0.3% is the standard stretch factor for Ontario power distributors with average cost performance. PEG also noted, at p48 of their evidence that in EB-2016-0152, OPG proposed, and the OEB approved, a 0.3% stretch factor for the hydroelectric generation payment amount price cap plan, on the basis of cost benchmarking evidence.

Amalco's expert, Dr. Malkom, proposed a 0% stretch factor based on his argument that stretch factors are only appropriate in a utility's first IRM term, after switching from a cost of service rate setting regime.

However, the Board has rejected this concept of the stretch factor on several occasions, notably, in the 2013 (EB-2010-0379) Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario Electricity Distributors, issued November 21, 2013, as corrected on December 4, 2013, pp 18-19, where it stated that:

> *"The Board believes that stretch factors continue to be required and is not persuaded by arguments that stretch factors are only warranted immediately after distributors switch from years of cost of service regulation to IR. Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation".*

Both the Alberta and British Columbia regulators have recently included stretch factors in their approvals of gas and electric utilities IRM plans. The AUC-2012-0237 Rate Regulation Initiative Distribution Performance Based Regulation, issued September 12, 2012, set an X-factor of 1.16%, inclusive of a stretch factor of 0.2% (p27).

The Commissioners stated, at paragraph 515:

> *"Furthermore, as set out in section 6.5 of this decision, the Commissioner determined that a stretch factor of 0.2 percent will apply to the companies' PBR plans for the duration of the PBR term. Accordingly, the Commissioner finds that the total X-factor for the electric and gas distribution companies, inclusive of a stretch factor, will be 1.16 percent".*

In a more recent AUC decision, 20414-DOI-2016, dated December 16, 2016, 2018-2022 Performance Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, the Board mandated the continued use of a stretch factor. At p45, para 169, the Commissioners found as follows:

> *"The Commissioner finds that a reasonable X-factor for the next generation for PBR plans for electric and gas distribution utilities in Alberta, inclusive of a stretch factor will be 0.3 percent".*

Finally, the British Columbia Utilities Commission, after several generations of IRM plans, in its Decision of September 15, 2014, in which it established a Multi-year Performance Based Rate Making Plan for 2014 through 2018, for Fortis Energy, a large British Columbia gas distributor, in which it considered both the Alberta and Ontario stretch factor practices, established stretch factors for Fortis Energy Inc. and Fortis BC (a smaller Vancouver Island gas distribution company) of 0.2% and 0.1%, respectively.

(d) Should there be a pass through Y-factor for costs, such as:

i. Gas commodity and upstream transportation costs?

Whether the Board grants the request for amalgamation or not, or grants the amalgamation but does not accept a material deferral rebasing period, a number of Y-factors have been an established part of gas utility regulation in Ontario, and should be adopted as part of Amalco's rate regime. These include:

- Gas commodity and upstream transportation costs are passed through to ratepayers, assuming they were prudently incurred.

- ***ii. Demand side management (DSM) costs*** up to Board approval amounts are passed through to ratepayers.
- ***iii. A lost revenue adjustment mechanism (LRAM)*** which holds the utility harmless whole from a decline in volumes due to natural gas volume reduction, resulting from DSM measures.
- ***iv. Cap and trade costs*** are, by law, collected by the gas utilities from ratepayers through a specific cap and trade levy.
- ***v. Changes to normalized average consumption/average use***

(e) Should there be a Z factor, and if so what are the appropriate parameters and materiality threshold?

There should be Z-factor, as defined as in EGD's EB-2012-0459. It is symmetric.

The applicant has proposed a Z-factor of $1 million, which is less than Union's existing Z-factor of $4 million and EGD's existing Z-factor of $1.5 million, and much lower than what is appropriate for Amalco, given its very large size. In the recent 2015 OPG case (EB-2016-0152), the Board set a Z-factor materiality factor of $10 million. That amount is also appropriate for Amalco, as its revenue requirement is larger than that of OPG.

(f) Should there be an earnings sharing mechanism and if so what are the appropriate parameters?

There should be an earning sharing mechanism with parameters similar to those in the EGD price cap IRM (EB-2012-0459), namely 50/50 sharing of overearnings without a dead band for the first 100 basis points and 75%-25% in favour of ratepayers for overearnings in excess of 100 basis points. That ratio protects consumers to some extent, yet leaves an incentive for utilities to reduce costs. The 300 basis point dead zone earnings sharing included in the MAADs guidelines is much too wide, and will result in inadequate protection for ratepayers during an IRM period.

(g) ***Is the proposal for calculating the cost recovery treatment of qualifying capital investments consistent with the OEB's policy for Incremental Capital Modules, and if not are any deviations appropriate?***

In BOMA's view, the applicant's proposed incremental capital module is deficient in several respects. First, it does not contain a project specific materiality factor, which is necessary to ensure that the plan is consistent with the Board's CDM policy. The policy, as applied very clearly in the recent Alectra rate case (EB-2017-0024, p25), states, inter alia, that utilities, especially very large ones, ought to be able to manage smaller capital projects without recourse to ICM financing, that the proposed projects must be shown to have a significant influence on the operation of the utility, and not be simply a part of the annual tranche of an ongoing utility program, and that the relevant entity that set the project materiality threshold is the utility corporation, not one of its rate zones (EB-2017-0024, p23). For Amalco, a project specific materiality threshold amount of $5 million would be appropriate.

Second, as noted above, Amalco appears to be calculating the overall materiality threshold using a different method than that provided for in the Board's policy, or at least not applying that policy in a fair manner, given the particular circumstances of this case. The applicant calculates the threshold based in part on Union's 2013 rate base, and in part on EGD's 2018 rate base. However, Union's forecast 2018 rate base, adjusted as a result of the inclusion of the large pass-through investments over the last several years, is $6,152.8 billion, and should be used in the calculation rather than the 2013 actual rate base of $3,783.9 billion (C.BOMA.29, p2), in order to obtain a proper measurement of Amalco's existing financial capacity to undertake capital expenditures without recourse to ICM funding. The increasing cash flow and financial strength flowing from the large Dawn-Trafalgar capital project should be recognized.

BOMA also suggests the Board provide the same detailed scrutiny of future Amalco ICM project requests as it did to Alectra's ICM proposals in EB-2017-0024, and that, as in that case, Amalco be required to carefully distinguish between base capital and ICM capital.

2. ***How should the framework address the four objectives in the Renewed Regulatory Framework of customer focus, operational effectiveness, public policy responsiveness, and financial performance?***

Customer Focus - There appears to have been no consultation with customers on the issue of whether to amalgamate the two companies or the proposed post-merger rates framework proposal, including that part of the proposal under which Amalco makes capital expenditure of $150 million to earn savings of $680 million over a ten year period. There was no lack of time to consult with customers, given that over 7 months elapsed between the Enbridge acquisition of Spectra, and the filing of the amalgamation and rate framework proposals, which were filed on the same day. Nor was it essential that Amalco file its proposal in calendar year 2017.

With respect to the other objectives of the Renewed Regulatory Framework, operational effectiveness, public policy responsiveness, and financial performance, Amalco did not explicitly address these objectives in any detailed manner. On financial performance, as noted earlier, it did not demonstrate a need for an annual return premium of 20 basis points over OEB allowed ROE levels. It did not discuss public policy responsiveness in any detail. The decision to defer the integration of asset management plans until the fifth year, to allocate capital mostly separately for each of the former Union and EGD systems, and the decision not to file a distribution system plan until 2021, and then file only a skeletal plan will likely diminish operational effectiveness, and does not demonstrate continuous improvement, at least in the short to medium term.

3. What changes to rates, regulated services, cost allocation or rate design should be permitted or required during the deferred rebasing period and what process should be required for such changes to be made?

The applicant has suggested that it may seek higher rates during the deferred rebasing period if interest rates were to rise to a level that would put the company in financial jeopardy. BOMA is of the view that the increase in rates could only be sought in an emergency situation, and then only if the increase in rates was a result of a general increase in interest rates in Canada to levels much higher than anticipated. It is common knowledge that Moody's downgraded Enbridge's debt in 2017 to one level above junk status. That rating decline will likely affect the Amalco's cost of capital at some point going forward. Absent some action from the Board to "ring fence" Amalco from any increase in debt costs, due to an increase in debt costs of the parent due to parent company excessive debt levels and profitability and/or liquidity concerns, BOMA suggests that the Board make clear, as a condition of approving the amalgamation, any increased interest costs due to problems at Enbridge should be the responsibility of the shareholders. BOMA believes that the utility shareholders should bear increases in debt costs flowing from the downgrade. Rates may also increase due to economy wide rate increases, but those rates are currently not expected to increase substantially. Amalco should be able to manage those increases.

4. What should the annual rate adjustment process be?

There should be a comprehensive annual adjustment process that is similar to what was conducted under the existing Union and EGD IRM plans, whether there is deferred rebasing of any kind, or not.

The process should be fulsome.

5, 6, 7 What deferral and variance accounts should continue, not continue? What additional (new) deferral accounts are appropriate?

BOMA has no comments on this issue.

8. Is the proposed adjustment to reflect the full amortization of Union Gas' accumulated deferred tax balance at the end of 2018 appropriate?

Yes, the proposed adjustment at the end of 2018 is appropriate.

9. Is the proposed adjustment to unwind smoothing of costs related to Enbridge Gas' Customer Information System and customer care forecast costs appropriate?

Yes, the proposed adjustment is appropriate.

10. Is the proposed adjustment to Enbridge Gas' Pension and OPEB costs appropriate?

Yes, the proposed adjustment to EGD's pension and OPEB costs is appropriate.

11. ***Is the proposed adjustment to reflect the removal of Enbridge Gas' tax deduction associated with the discontinued SRC refund appropriate?***

Yes, the proposed adjustment is appropriate.

12. ***Are the provisions of the MAADs Handbook related to harmonization applicable?***

No, because the MAADs Handbook is not applicable to this merger transaction, the provisions in the handbook that relate to harmonization should not apply to this transaction. Harmonization of rates and utility practices generally should be reviewed as part of the normal rebasing, as provided for in the Handbook for Utility Rate Applications.

All of which is respectfully submitted, June 14, 2018.

Tom Brett per

Tom Brett
Counsel for BOMA

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