ONTARIO ENERGY BOARD

STAFF SUBMISSION ON
ENBRIDGE GAS DISTRIBUTION AND UNION GAS LIMITED AMALGAMATION AND RATE-SETTING FRAMEWORK APPLICATIONS
EB-2017-0306 / EB-2017-0307

June 15, 2018

Background

Enbridge Gas Distribution Inc. (Enbridge Gas) and Union Gas Limited (Union Gas), jointly referred to as the applicants, filed an application dated November 2, 2017 with the Ontario Energy Board (OEB) under section 43(1) of the *Ontario Energy Board Act, 1998* (the Act), for approval to effect the amalgamation of Enbridge Gas and Union Gas into a single company referred to as Amalco. On November 23, 2017, the applicants filed another application with the OEB under section 36 of the Act for approval of a rate setting mechanism and associated parameters, effective January 1, 2019.

Enbridge Gas is a major Canadian rate-regulated gas distribution, storage and transmission company serving over 2.1 million residential, commercial and industrial customers in 121 franchise areas of central and eastern Ontario, including the Greater Toronto Area (GTA) and the Niagara Peninsula, Ottawa, Brockville, Peterborough and Barrie. Its head office is in the City of Toronto and it has approximately 2,100 employees. Enbridge Gas currently operates under a five-year Custom Incentive Regulation (IR) framework approved by the OEB in EB-2012-0459 and ending in 2018.

Union Gas is a major rate-regulated natural gas storage, transmission and distribution company serving about 1.5 million residential, commercial and industrial customers in over 400 communities across northern, southwestern and eastern Ontario. Its head office is in the Municipality of Chatham-Kent and it has approximately 2,300 employees. Union Gas currently operates under a five-year price cap Incentive Ratemaking Mechanism (IRM) approved by the OEB in EB-2013-0202 and ending in 2018.

The applicants have been under common ownership since February 27, 2017 when Enbridge Inc. merged with Spectra Energy Corp. Both companies (Enbridge Gas and Union Gas) were expected to file rebasing applications for 2019 rates. However, the companies have proposed to merge and defer rebasing until 2029.

In preparing the merger application,[1] the applicants followed the OEB's *Handbook to Electricity Distributor and Transmitter Consolidations* (MAADs Handbook), which provides guidance on applications for mergers, acquisitions, amalgamations and divestitures (MAADs). Accordingly, the applicants adopted all of the policy directions from the MAADs Handbook in their application. This includes election of a ten-year deferred rebasing period, application of the "no harm" test, use of a price-cap index to set rates during the deferred rebasing period, earnings sharing from year six of the deferred rebasing period and availability of an Incremental Capital Module (ICM).

[1] EB-2017-0306.

In their submissions on the issues list, OEB staff and intervenors argued that not all elements of the MAADs Handbook applied to the gas distributors, considering that the policy was essentially drafted to incentivize consolidation within the electricity sector in Ontario. The OEB in its decision[2] on the issues list agreed with the intervenors and OEB staff, noting that there is no reference to the gas distributors in the MAADs Handbook and it would therefore not restrict the ability of parties to question the applicability of the policies within the electricity MAADs policy framework. The OEB however determined that it would continue to use the "no harm" test for assessing the amalgamation. The OEB also combined the two proceedings (amalgamation and rate-setting framework) and approved an issues list in the decision. The decision further outlined procedural steps including a discovery process and scheduled an oral hearing.

Prior to the oral hearing, the OEB in Procedural Order No. 5, required that all parties who wished to cross-examine at the oral hearing file their initial positions on certain key matters in advance of the oral hearing. OEB staff provided their initial submissions on April 30, 2018. OEB staff's position on certain matters has changed as a result of the testimony at the oral hearing and undertaking responses. A detailed description and rationale of staff's position on specific areas is discussed below.

Summary of OEB Staff Positions

OEB staff supports the proposed amalgamation between Enbridge Gas and Union Gas. As noted earlier, the parents of the two utilities have already merged. OEB staff is of the opinion that the proposed merger will lead to synergies and benefits to ratepayers in terms of cost and quality of service over the long-term in addition to regulatory efficiency. However, OEB staff is of the view that the rate-setting framework should be revised from that proposed in order to better protect customers during the deferral period. These elements are discussed in the following sections.

A summary of key OEB staff positions is summarized below:

- Approval to amalgamate under section 43 of the OEB Act should be granted.
- Track the estimated net savings during the deferred rebasing period as part of the scorecard.
- Deferred rebasing period of six years.
- Asymmetrical earnings sharing mechanism (ESM) – if in any year Amalco's actual ROE is more than 100 basis points over the OEB-approved ROE (last rebasing), then excess earnings starting at 101 basis point to 200 basis points to be shared 50/50 and over 200 basis points to be shared 90/10 between

[2] Decision and Procedural Order No. 3, March 1, 2018.

ratepayers and Amalco. ESM should start in year four of the six-year deferred rebasing period.

- OEB staff prefer a two-factor IPI for inflation that uses labour and non-labour inflation.
- Base productivity factor of 0% and stretch factor of 0.3%.
- Z-factor materiality threshold should be $7.5 million.
- For the Incremental Capital Module (ICM), the applicants should use OEB-approved cost of capital parameters from most recent rebasing application and the review of ICM including the incremental revenue requirement and rate riders should be addressed in the annual rate application, not the leave to construct.
- No discrete adjustments to selected assets in the absence of a full cost allocation study.
- Excess utility storage space of Union Gas should be available for all in-franchise customers of Amalco.
- OEB staff has no concerns with the nature of the condition proposed to ensure Amalco maintains a significant presence in the Municipality of Chatham-Kent but OEB staff questions whether this needs to be a condition of any leave to amalgamate.

No Harm Test

The OEB has already determined that it will apply the “no harm” test in this proceeding to determine if the applicants’ leave to amalgamate should be granted.[3]

The “no harm” test considers whether the proposed transaction will have an adverse effect on the attainment of the OEB’s statutory objectives in relation to gas, as set out in section 2 of the OEB Act. As the OEB noted in a recent decision, “If the proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application.”[4]

Section 2 of the OEB Act states that the OEB, in carrying out its statutory responsibilities in relation to gas, shall be guided by the following objectives:

1. To facilitate competition in the sale of gas to users.
2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.
3. To facilitate rational expansion of transmission and distribution systems.

[3] Ibid, page 8.
[4] Decision and Order, EB-2016-0276 (denying application by Hydro One to acquire Orillia Power), April 12, 2018, page 5.

4. To facilitate rational development and safe operation of gas storage.
5. To promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry and the education of consumers.

In applying the no harm test, the OEB has focused on the objectives that are "of most direct relevance to the impact of the proposed transaction."[5] In the gas context, those are "price, reliability and quality of gas service, and financial viability."[6]

During the hearing, few concerns were raised about the reliability and quality of gas service, or about the financial viability of Amalco or the gas sector as a whole. The main issue is price.

In OEB staff's view, the merger will result in synergy-related savings. The applicants' "underlying cost structures", to use the terminology of the MAADs Handbook, will decrease substantially as they complete the process of amalgamation. The applicants expect that they will achieve net positive savings (net of integration investments) in year three (2021) and total net cumulative savings of $530 million over the proposed ten-year deferred rebasing period.[7] Although these estimates are "high level", OEB staff submits that even if actual savings achieved are less than forecast (or the integration investments higher), it stands to reason that the underlying cost structures of the consolidating utilities will change for the better as synergies are achieved. OEB staff supports the merger, as it will likely decrease the underlying cost structures. Approval under section 43 of the OEB Act should therefore be granted.

[5] *Ibid.*, pages 5-6; Decision and Order, EB-2016-0351 (approving sale of Natural Resource Gas Limited distribution system to EPCOR Natural Gas Limited Partnership), August 3, 2017, page 4.
[6] Decision and Order, EB-2016-0351, page 4.
[7] Pre-filed Evidence, Exhibit B, Tab 1, Attachment 12, $680-$150=$530 million. This calculation is based on a cash flow basis and as the applicants explained in Undertaking J2.4, if the applicants include their allowed ROE for each of deferred rebasing years, the total estimated net savings during the deferred rebasing period is reduced to $120 million: Ontario Greenhouse Vegetable Growers IR response #7(a), $530-$410=$120 million.

Just and Reasonable Rates Test

Overview

OEB staff has concerns with several aspects of the rate-setting framework proposed by the applicants. Although the applicants' proposals for a ten-year deferred rebasing period and an earnings sharing mechanism were included in the applicants' section 43 merger application OEB staff deals with them here as aspects of the rate framework. The deferral period and the elements of the rate setting framework are closely linked. For example, the applicants' rate framework proposals are premised on a ten-year deferral period. The two components of the application have to be considered together. In OEB staff's view, in this case it makes more sense conceptually to consider the application as a whole and the length of the deferral period and the design of the earnings sharing mechanism in terms of whether they would support "just and reasonable" rates under s. 36.

The applicants have noted that the proposed amalgamation will provide an estimated net savings of $530 million over the 10-year deferred rebasing period. However, ratepayers will not share these savings under the rate-setting approach proposed by the applicants. Ratepayers will in fact see an increase in rates during each year of the deferred rebasing period. OEB staff submits that there should be some mechanism to track the savings achieved during the deferred rebasing years. This will allow the OEB and parties to determine at rebasing, how the utility performed with respect to the forecasted savings and to what extent the savings will be reflected in future rates. OEB staff in the scorecard section of this submission, have suggested tracking the annual savings as part of the scorecard proposed by the applicants.

In Decision and Procedural Order No. 3, the OEB noted that in the Rate Handbook, two rate-setting options were available to gas distributors: Custom IR and the Price Cap IR. The Rate Handbook characterized the Custom IR option as a rebasing application, given its consideration of costs. The OEB agreed with OEB staff that the only option available to the gas utilities if a deferred rebasing is approved is Price Cap IR. However, the features and parameters of the Price Cap IR framework were open to argument[8].

The applicants have requested a Price Cap Index (PCI) during the deferred rebasing period. The annual rate change would use a price cap index, where PCI growth is driven by an inflation factor, less a productivity factor of zero and no stretch factor.

[8] Decision and Procedural Order No. 3, Page 10, March 1, 2018.

The proposed framework includes Y factor adjustments that are passed through to customers without any annual escalation. These include pass-through gas commodity and upstream transportation costs, demand side management cost changes that occur in separate applications, lost revenue adjustment mechanism changes for the contract market, normalized average consumption/average use, and Cap-and-Trade costs.

Consistent with the OEB-established policy on the ICM under mergers and acquisitions for electricity utilities, the applicants have proposed that, during the deferred rebasing period, they could apply for rate adjustments to recover costs associated with qualifying incremental capital investment beyond what is normally funded through approved rates.

The OEB's Price Cap formula includes a Z factor mechanism to address material changes in costs associated with unforeseen events outside of the control of management. The applicants propose using a materiality threshold of $1.0 million for Amalco during the deferred rebasing period. This is consistent with the threshold for electric distributors with revenue requirements in excess of $200 million.[9]

The Price Cap IR mechanism would be calculated as $PCI = I – X \pm Y \pm Z$. OEB staff is not opposed to the use of a Price Cap Index mechanism. However, it does not agree with some of the elements of the Price Cap Index proposed by the applicants.
OEB staff is of the opinion that a number of the elements of the rate-setting framework generally such as earnings sharing and stretch factor, and the request for a ten-year deferred rebasing period, do not provide adequate customer protection. As proposed, the rate framework does not, in OEB staff's view, do enough to ensure that the potential savings from the merger flow through to customers.

OEB staff in the following sections makes several recommendations to ensure that customer interests are protected while the utility is given the opportunity to achieve efficiencies through amalgamation and earn the OEB-approved return on equity – in other words, to ensure that rates for Amalco prior to rebasing are just and reasonable.

Deferred Rebasing Period

The applicants have requested a ten-year deferred rebasing period in line with the policy direction in the MAADs Handbook. The OEB has already determined that the MAADs

[9] Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (page 36, July 14, 2008) sets a materiality threshold of $1 million for a distributor with a distribution revenue requirement of more than $200 million.

policy does not apply in its entirety to gas and parties are free to argue the elements of the MAADs policy framework apart from the "no harm" test.[10]

In its initial position document, OEB staff considered the possibility of supporting a 10-year deferred rebasing period provided that it is accompanied by a robust protection mechanism for ratepayers. However, the concerns expressed at the oral hearing have persuaded OEB staff that a shorter deferred rebasing period is warranted. A full review of the costs of Union Gas and Enbridge Gas was last undertaken in 2012 and 2013 respectively and important elements of rate setting such as load forecasts, rate base, cost allocation and rate design have not been reviewed since then. Decoupling revenues from costs for 15 years, as proposed, would be unprecedented since the OEB introduced incentive regulation.

Kitchener Utilities raised the issue of cost allocation that impacts the rates that Union Gas charges Kitchener.[11] The concern was with respect to how costs were allocated for some recent capital projects. The OEB, in the specific leave to construct proceedings, determined that cost allocation issues should be dealt with in a cost of service proceeding.[12] The Industrial Gas Users Association (IGUA) similarly raised a concern in Union Gas' 2017 IRM rates proceeding related to the Panhandle Reinforcement Project cost allocation. The OEB in that decision determined that changes to cost allocation should be supported through a full cost allocation study that is more appropriate in a cost of service proceeding.[13] These issues seem to indicate that if cost allocation is not examined for the next ten years, there may be significant imbalances in how costs are allocated to the different rate classes.

Average use or average consumption is another area where significant shortcomings were revealed. The applicants have stated that they will examine average use only at rebasing. At the same time, Enbridge Gas acknowledged that a structural break had occurred in some of the average use models in 2016[14]. However, at the oral hearing it noted that such issues would only be examined at rebasing.[15]

In light of the above arguments, staff submits that the deferral period should not be ten years. A review of the applicants' evidence indicates that a deferral period of six years would be appropriate and seems to strike a good balance between the needs of the applicants to complete integration and benefit from the savings, and the need for a full

[10] Decision and Procedural Order No. 3, Page 4.
[11] Oral Hearing Transcript, Volume 3, pages 158-159, May 14, 2018.
[12] Oral Hearing Transcript, Volume 3, page 159.
[13] Decision and Order, EB-2017-0087, January 18, 2018.
[14] EB-2017-0102, Energy Probe IR#7e.
[15] Oral Hearing Transcript, Volume 3, pages 134-135.

examination of the amalgamated utilities' cost at the earliest opportunity. Furthermore, the applicants noted that at the five-year mark of the deferred rebasing period, they will be prepared to file a harmonization study including a review of existing cost allocation methodologies.[16] In other words, the applicants will have all the necessary information to file a rebasing application for the amalgamated utility by year five.

The applicants have indicated that all integration will be completed by 2024, with the exception of management, under the low/moderate scenario and 2022 under the aggressive scenario.[17] OEB staff is not convinced that management integration will take longer than 5 years considering that certain functions such as Human Resources and Finance are already being integrated at the executive level. Further, the evidence indicates that by 2024, most of the integration will be complete and the utility will have a net benefit of $190 million as shown in Table 1 below.[18] The $190 million benefit shown in 2024 refers to cumulative benefits over the six year period and is calculated on a cash flow basis.

Table 1

(Amount in $ million)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Investments	$ 11	$ 47	$ 100	$ 137	$ 150	$ 150	$ 150	$ 150	$ 150	$ 150
Savings	$ 3	$ 41	$ 104	$ 174	$ 255	$ 340	$ 425	$ 510	$ 595	$ 680
Net Savings	$ (8)	$ (6)	$ 4	$ 37	$ 105	$ 190	$ 275	$ 360	$ 445	$ 530

Based on the arguments presented above, OEB staff is of the opinion that a six year deferral period is appropriate and Amalco should rebase for 2025 rates.

Earnings Sharing Mechanism

The applicants have proposed an earning sharing mechanism (ESM) that will start in year six (2024). If in any calendar year from 2024 to 2028, the actual utility ROE is greater than 300 basis points above the allowed ROE as set out under the OEB's policy, the excess earnings above 300 basis points will be shared 50/50 between the ratepayers and the shareholders. For the purposes of the ESM, the utility earnings will be calculated using generally accepted accounting principles (GAAP).

[16] Oral Hearing Transcript, Volume 5, page 13.
[17] Interrogatory Response, BOMA.16, Attachment 1, page 19.
[18] EB-2017-0306, Exhibit B, Tab 1, Attachment 12.

Given the high threshold to trigger sharing, OEB staff believes that under the ESM approach proposed by the applicants, ratepayers are not likely to share in any of the benefits achieved by the applicants as a result of amalgamation during the deferred rebasing period. As noted earlier, the applicants' expected ROE over the ten-year period is likely to range between 0 and 30 basis points.[19]

OEB staff submits that Amalco's proposal does not achieve the objective of adequately protecting customer interests. Furthermore, as noted by the applicants in the argument-in-chief, the ESM policy as noted in the Rate Handbook is for electricity distributors.[20] In their argument-in-chief the applicants state:

> On the contrary, the third sentence of this section of Appendix 3 (on the subject of ESM) starts with the words "For electricity distributors", which makes clear that, where the Board intended to limit the guidance in this section of Appendix 3 to a particular sector, it used specific words to do so.[21]

As is evident from the above statement, the applicants agree that the ESM policy was intended to apply to electricity distributors. Over the course of this proceeding, the applicants have not supplemented their original arguments as to why or on what basis they are requesting an ESM which they themselves acknowledge as applying only to electricity (beyond the fact that the ESM is a feature of the MAADs Handbook).

Having established that the applicants cannot rely on the ESM as outlined in the MAADs handbook as default feature of any deferral period, OEB staff recommends a customized ESM that aligns with the specific deferral period proposed in this submission.

Given the six-year deferral period proposed, OEB staff is of the view that there should be an asymmetrical ESM and that the ESM should be similar to the one approved in Union Gas' 2014-2018 IRM application that was underpinned by a complete settlement. OEB staff proposes that the following ESM should be effective commencing with the fourth deferral year (2022).

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[19] FRPO ir#1, Attachment 1, Page 23.
[20] Handbook for Utility Rate Applications, October 13, 2016 – the Handbook provides guidance to utilities and stakeholders on applications to the OEB for approval of rates.
[21] Argument-in-Chief, Page 12, Para 35

If in any calendar year, the actual ROE is more than 100 basis points over the OEB-approved ROE from each of the legacy utilities' most recent cost-based (rebasing) application, then excess earnings starting at 101 basis points to 200 basis points would be shared 50/50 between customers and Amalco. If in any calendar year, Amalco's actual utility ROE is more than 200 basis points above the 2018 OEB approved ROE, then such earnings in excess of 200 basis points would be shared 90/10 between customers and Amalco (i.e., customers would be credited 90% and Amalco would be credited 10%).

Enbridge Gas in its current Custom IR also has an ESM. The ESM essentially shares earnings over the OEB allowed ROE 50:50 on a weather normalized basis[22]. OEB staff prefers the Union Gas ESM as it provides the utility with a better incentive to achieve savings and a better opportunity to earn over the allowed ROE, while at the same time protects ratepayers from excessive overearnings.

OEB staff further submits that the earnings sharing should be implemented at the commencement of year four (2022) which is the point at which Amalco will have recovered all its integration investments through savings as confirmed in Table 1 above. Year 4 is also the mid-point of the six-year recommended deferral period which aligns with the intent of the MAADs policy that provides for earnings sharing from year six of a 10-year deferred rebasing period.

For the purposes of the ESM, Amalco would calculate its earnings using the regulatory rules prescribed by the OEB from time to time, and would not make any material changes in accounting practices that have the effect of either reducing or increasing utility earnings. All revenues that would be included in revenues in a cost-of-service application would be included in the earnings calculation, and only those expenses (whether operating or capital) that would be allowable as deductions from earnings in a cost-of-service application would be included in the earnings calculation. Should Amalco decide to include any changes (accounting, capitalization, depreciation rates etc.) during the deferred rebasing period, then staff submits that parties should be free to argue whether the impact of such changes should be included/excluded from the earnings sharing calculation.

[22] Response to OEB Staff IR#7.

Inflation Factor

The applicants propose to use the quarterly Gross Domestic Product Implicit Price Index Final Domestic Demand (GDP IPI FDD) Canada index as the inflation factor. The OEB currently uses the GDP-IPI FDD as a non-labour (materials and capital equipment) indicator for electricity. GDP-IPI (FDD) has been used in the past for natural gas rate adjustment plans for Union Gas and Enbridge Gas, as well as in some earlier generations of electricity distribution IRM. In addition, Union Gas' current IRM framework, ending December 31, 2018, uses this measure.

The OEB moved to a two-factor IPI for the electricity sector that uses labour in addition to non-labour components commencing in 2014. The Average Weekly Earnings (AWE) (Ontario – all businesses except unclassified) is the labour component currently used by the OEB.

OEB staff is not opposed to the use of the inflation factor proposed by the applicants but would prefer a two-factor IPI that uses labour and non-labour inflation, and which are weighted by their contribution to costs. Adoption of a two-factor IPI would ensure more consistency between natural gas and electricity sectors. In an undertaking response[23], the applicants provided a comparison of the inflation factor using GDP IPI FDD and using both GDP IPI FDD and AWE (70/30 weighted). The comparison of the last 10 years (2007-2016) shows that the difference between the two methodologies is not material.

If the OEB permits Amalco to use the GDP-IPI FDD as the sole inflation measure, OEB staff would suggest that the manner in which the inflation change is measured be based on calendar year-over-year change, rather than the mid-year calculation currently used by natural gas distributors.[24] This would make calculation and verification against Statistics Canada numbers easier.

If there was a change to the two-factor IPI, calendar year alignment would make transitioning easier if some or all components are calendar year statistics (like AWE). In

[23] Undertaking Response J5.2.

[24] Natural gas distributors calculate inflation by going from Q3 of one year to Q2 of the following, for the most recent actual published statistics, and comparing to the same periods (Q3 to Q2) for the immediately preceding year. (See Exhibit C/LPMA-16) Also, OEB staff understands that the year-over-year changes are calculated on a quarter-by-quarter basis (Q2 to Q2 of the preceding year, Q1 to Q1 of the preceding year, etc.). This is not how Statistics Canada calculates annual changes, or how the OEB calculates its GDP-IPI or IPI changes; quarterly statistics are averaged into annual values, and the year-over-year change is based on these annual (12-month or 4-quarter) values. The difference is an occasional rounding difference of ±0.1%.

the absence of better information, OEB staff suggests the use of a 70/30 weighting in accordance with that used for electricity distributors in Ontario.

Base Productivity Factor

In support of their proposal with respect to the productivity and stretch factor, the applicants submitted a report prepared by Dr. Jeff D. Makholm of National Economic Research Associates Inc. (NERA). OEB staff filed evidence of Dr. Mark Lowry of Pacific Economics Group Research LLC (PEG) titled “IRM Framework for the Proposed Merger of Enbridge and Union Gas[25]”. The study examined the nature of productivity research and its role in IRM design. The study also critiqued NERA’s productivity research and provided an alternate productivity and stretch factor.

Based on the results of the PEG study, OEB staff submits that the base productivity factor, or X-Factor, should be zero.

The expert reports filed by the applicants’ expert, and by OEB staff’s expert, both recommend an X-Factor of zero. OEB staff has no cause to disagree with this analysis.

OEB staff shares Dr. Lowry’s reservations about the methodology employed by Dr. Makholm in his research, and the potential precedential effect this could have on future *OEB cases. As the applicants observe* in their argument-in-chief, it may not be necessary for the OEB to make detailed findings on the relevant merits of Dr. Lowry and Dr. Makholm’s analysis in this regard, as they both came to the same ultimate conclusion.

To the extent that the OEB opines on the relative merits of the experts’ analysis, OEB staff submits that Dr. Lowry’s evidence should be preferred.

Dr. Makholm uses a One Hoss Shay approach, which assumes that there is no depreciation (deterioration) of productive capability until the end of the life of the asset. The OEB has previously not accepted this as being a reasonable assumption regarding large and complex infrastructure such as electricity networks and hydroelectric generators, which do require both maintenance and replacement/refurbishment expenditures to maintain production as designed to end-of-life.[26] OEB staff submits that sophisticated gas networks for transmission, distribution and storage and ancillary

[25] OEB Staff Evidence, April 11, 2018.
[26] Exhibit K4.1, Transcript Vol. 3 (May 15, 2018), pp. 48-57.

systems owned and operated by Enbridge Gas and Union Gas would similarly not exhibit "One Hoss Shay" characteristics.

Dr. Lowry, in his evidence and testimony, also notes that the assumed end-of-life of assets can have material impact on Total Factor Productivity (TFP) results using a One Hoss Shay economic depreciation; this is less of a concern for geometric decay as the error introduced is smaller. The limitation faced in such studies is that, with a limited population of very long-lived assets like electricity and natural gas networks and hydroelectric generators, there is limited information on actual lives. Dr. Makholm has assumed 33 years for Enbridge Gas and Union Gas, consistent with the US electric utilities in his study.[27] This is actually different from the 37 or so average life for Enbridge Gas' and Union Gas' capital assets from their historical records [28].

Dr. Lowry, in contrast, assumes a geometric decay approach in his TFP analysis. The OEB is familiar with and has accepted this approach in the past, for both the natural gas and electricity sectors, as the X-factor in electricity and gas Performance Based Regulation (PBR)/IRM plans have been based on TFP studies by PEG and other economists using a geometric decay approach.[29]

Dr. Makholm's TFP study was based on a group of U.S. utilities, most of which were electricity only with some gas-and-electric utilities. Furthermore, the TFP analysis only dealt with electricity operations of these utilities. While OEB staff concedes that there are many similarities in business environment characteristics, the capital-intensive nature of the businesses, and on the operations of electric and gas utilities, there are also differences. Dr. Lowry also included in his evidence a TFP analysis of a sample of US gas distributors – a sample that would obviously be more comparable to Enbridge Gas and Union Gas.

For these reasons, and others outlined by Dr. Lowry,[30] OEB staff submits that PEG's analysis is more credible to that of NERA in the context of this application. However,

[27] Exhibit C/Staff-43
[28] Transcript, Vol. 4 (May 15, 2018), p.62/l.25 to p. 64/l. 28
[29] e.g.,*Productivity And Price Performance For Electric Distributors In Ontario,* Prepared for Ontario Energy Board Staff By F.J. Cronin, M. King and E. Colleran, PHB Hagler Bailly Consulting, July 6, 1999 (for the RP-1999-0034 process to develop the first Generation Electricity Distribution Rate Handbook), *Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks: A Concept Paper* Report To The Ontario Energy Board, Dr. L. Kaufmann, PEG, April 2011 (EB-2010-0673), *Price Cap Index Design for Ontario's Natural Gas Utilities*, M.N. Lowry, D. Hovde, L. Getachew and L. Kaufmann, March 30, 2007 (EB-2006-0209), *IRM Design for Ontario Power Generation*, M.N. Lowry and D. Hovde, November 23, 2016, EB-2016-0152.
[30] Exhibit M1 (May 4, 2018) UPDATED, pp. 24-35, and Transcript, Vol. 4 (May 15, 2018), pp.143-150

OEB staff agrees with the applicants, and both the experts, that the X-factor should be zero.

Stretch Factor

OEB staff submits that the OEB should apply a stretch factor of 0.3% to Amalco's price cap plan.

The OEB has been approving IRM plans in one form or another for the gas utilities and electricity utilities since the early 2000s.[31] It has been both the OEB's practice and policy, currently and historically, to employ a stretch factor in the majority of these plans.

The Electricity Experience

A review of the OEB's practices and policy statements for the electricity sector is instructive. The OEB has commonly used stretch factors since the outset of PBR/IRM regulation for electricity distributors, including the current framework. The rationale for this policy has been set out many times in a number of OEB policy documents. The Supplemental Report of the Board for 3rd Generation IRM described the rationale as follows:

> It is important to note that stretch factors are consumer benefits. They are somewhat analogous to earnings sharing mechanisms, although stretch factors take effect immediately with the application of the formula and are not dependent on the realization of any productivity gains or excess earnings, as would be the case with an earnings sharing mechanism.[32]

The OEB has also been clear that stretch factors are not intended to be used only in the transition from cost of service to PBR/IRM:

> 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 their expected sector productivity trend. Consequently, stretch factors

[31] Transcript, Vol. 4 (May 15, 2018), p. 26/l. 27 to p. 27/l. 8. Enbridge Gas' first plan was about 15 years ago, while that for Union Gas was about 13 years ago, according to Amalco's witnesses. Electricity distributors had their first PBR rate adjustment in 2002 under the First Generation Rate Handbook (RP-1999-0034 and RP-2000-0069).
[32] EB-2007-0673, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, September 17, 2008, pp. 19-20.

> continue to have an important role in IR plans after distributors move from cost of service regulation.[33]

Dr. Makholm argues that the OEB's stretch policies are appropriate for the electricity sector, but not for the gas sector. He believes that the large number of electricity distributors (which is not typical in other jurisdictions) makes a stretch factor useful for encouraging strong performance amongst the utilities. However, he argues that this is not a factor for the gas utilities, and that typically stretch factors are only appropriate in transitioning from cost of service to PBR/IRM, to reflect the greater efficiencies that should be available to utilities at this time. Dr. Makholm further argues that what the OEB refers to as a "stretch factor" for electricity distributors is different from what other jurisdictions refer to as a stretch factor.

OEB staff does not agree with Dr. Makholm's analysis in this regard. None of the statements made by the OEB in prior decisions and reports supporting a stretch factor appear to be dependent on the number of distributors, or to be specific to just the electricity sector. The OEB has also been clear that stretch factors are not just for the initial transition from cost of service to IRM. Although there may be variations on the definition of a "stretch factor" across different jurisdictions, OEB staff does not accept that the OEB's stretch factor is not a "real" stretch factor. But even if this were so (which is not conceded), that does not argue against imposing the OEB stretch factor on gas utilities. The OEB has been clear and consistent on what it thinks a stretch factor is, and all of its reasoning applies equally to gas and electricity. If other jurisdictions mean something different when they talk about a stretch factor, that does not mean that the OEB should not use its version of a stretch factor here.

Dr. Makholm's evidence relies heavily on a 2012 decision of the Alberta Utilities Commission (AUC), which dealt with the move from cost of service regulation to Performance Based Regulation (PBR, which for the purposes of this discussion is equivalent to IRM) for gas and electricity utilities in Alberta. Both Dr. Makholm and OEB Staff's witness Dr. Lowry were witnesses in that proceeding. Dr. Makholm argues that this decision demonstrates that it is essentially agreed to amongst experts that stretch factors, to the extent they are warranted at all, should only be used when transitioning from cost of service to PBR/IRM.

OEB staff does not agree with Dr. Makholm's opinion in this regard. Most importantly, although the AUC decision is interesting, it is in no way binding in Ontario, and should

[33] EB-2010-0379, *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, November 21, 2013 (corrected December 4, 2013), pp. 18-19.

not supersede the OEB's own in depth analysis on the purpose of a stretch factor that it has developed over many years. Second, the fact that Dr. Lowry disagrees with Dr. Makholm's position shows that there is not unanimous agreement amongst the expert community on this issue. Finally, it should be noted that in the next case before the AUC on this issue, the AUC retained a stretch factor for its second generation PBR framework. The AUC felt that this was appropriate because the original plan included a number of cost of service elements that were not part of the second generation plan. However, this is exactly the same as the situation for Enbridge Gas, who's current rate setting plan is a custom IR which includes both cost of service elements and IR elements.

The Gas Experience

The OEB's policies and practices on the electricity side are instructive, but of course it is policies and practices on the gas side that are even more relevant to the current application. Here too the OEB has been clear that a stretch factor is appropriate.

Both Union Gas and Enbridge Gas have been operating under one form of IRM or another for many years. Historically, most gas and electric utilities' IRM plans have included stretch factors.[34] Both utilities' current IRM plans also include a stretch factor.

Union Gas' current Price Cap IR framework (which is still in effect) was the result of a settlement that was reached by all parties, and approved by the OEB in 2014. The productivity factor under that agreement was not a standard fixed X-factor. Instead the parties agreed that the productivity factor would be expressed as a percentage of inflation: rates would increase annually by 40% of GDP-IPI-FDD. The parties were clear that the X-factor they settled on included a stretch factor: "Together, the Upfront Productivity Commitment described in section 1.2.2 and the X factor are inclusive of a stretch factor."[35] As a party to the settlement, Union therefore proposed, and the OEB accepted, that its current IRM plan should have a stretch factor.

Enbridge Gas' current IRM framework, which was approved by the OEB after holding a hearing in 2014, also includes at minimum an implicit stretch factor. Enbridge Gas' application included various measures that it argued constituted a productivity factor; for example they argued that keeping full time equivalent employee levels flat over the term of the plan was a type of productivity factor. Enbridge Gas submitted that its proposed productivity factor included a stretch factor.[36] The OEB ultimately approved the

[34] See, for example, the OEB's decision in the first PBR (as it was then called) decision, RP-1999-0034, January 2000, pp. 40-41.
[35] EB-2013-0202, Settlement Agreement, p. 12.
[36] EB-2012-0459, Decision with Reasons, July 17, 2014, p. 47.

application, but modified some of the “built-in” productivity factors proposed by the utility. Irrespective of the OEB’s adjustments, Enbridge Gas proposed a productivity factor that included a stretch factor, and the productivity factor finally approved by the OEB did not alter this situation.

The OEB’s policy guidance for gas also states that a stretch factor is appropriate. The OEB’s Rate Handbook applies to both electricity and gas. The Rate Handbook was developed based on the principles of the Renewed Regulatory Framework (RRF).[37]

The Rate Handbook clearly indicates that rate proposals from gas utilities should include a stretch factor. Under the section entitled “the OEB’s review of the key components of rate applications”, the Rate Handbook states:

> In reviewing a utility’s proposed outcomes and performance metrics, the OEB’s key considerations are:
>
> - […]
> - Performance metrics which will accurately measure whether outcomes are being achieved, and which include stretch goals to demonstrate enhanced effectiveness and continuous improvement.[38]

The Rate Handbook repeats the expectation that a Price Cap IRM plan (which is what the applicants are seeking in this application) will include a stretch factor, whether it is for the electricity or natural gas sector:

> The Price Cap Incentive Rate-setting (Price Cap IR) is the standard formulaic method by which distribution rates are annually adjusted during the incentive rate-setting period between cost of service applications. The formula adjusts current rates for the following year by inflation in input prices (costs of production or service) less expected productivity improvements including a stretch factor (or consumer productivity dividend).[39]

Conclusion

OEB staff submits that it is clear that a stretch factor should be applied to Amalco’s rate framework. The applicants have filed a price cap IR plan. As described in more detail above, all of the OEB’s rationale for a stretch factor, all of the OEB’s practice (for both gas and electricity), and all of the OEB’s policy guidance (again for both gas and

[37] Handbook for Utility Rate Applications, October 13, 2016, p. 1.
[38] *Ibid.,* p. 16.
[39] *Ibid.,* Appendix 2, p. vi.

electricity), state that a stretch factor is appropriate. The OEB has consistently held that a stretch factor is not only appropriate for the transition from COS to PBR/IRM, but plays a role in subsequent IRM plans. None of the arguments raised in the application, including the report and testimony of Dr. Makholm, provide a convincing rationale why a stretch factor should not apply.

It should be noted that, despite having a stretch factor, both utilities have managed to over-earn in every year of their current Custom IR and IRM plans, as well as in most years even in previous plans.[40] They have been able to find efficiencies above and beyond their productivity and stretch factor, despite the fact that they have both been under some form of incentive rate-setting for several years.

What should the stretch factor be?

The question that remains, therefore, is what level of stretch factor is appropriate? A preferable method for determining an appropriate stretch factor, as established through the RRF, is through total cost benchmarking evaluations.[41] On the electricity side this benchmarking is used to rank the relative performance of the utilities and to slot them into one of several stretch factor cohorts that range from 0% to 0.6%. The “middle” cohort is 0.3% under the current electricity distribution IRM plan.

The applicants have not prepared any total cost benchmarking evidence for this proceeding. OEB staff recognizes that, unlike in the electricity distribution sector, there are not dozens of gas utilities in Ontario against which benchmarking can be performed. However, this would not prevent the utilities from benchmarking themselves against other North American gas distributors. OEB staff notes that Ontario Power Generation (OPG), for example, conducts extensive total cost benchmarking against other North American nuclear and hydroelectric operators, and files studies in its applications to assist the OEB in setting OPG’s payment amounts. Like the applicants, OPG operates multiple businesses, some of which are regulated and some of which are not. OEB staff cannot see any reason why similar benchmarking could not have been conducted for the applicants.

In the absence of benchmarking data, it is difficult to say with certainty how efficient the applicants are relative to their peers. The data available suggest that Enbridge Gas may be a bit less productive than average, and Union Gas a bit more productive.[42] Under

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[40] Transcript volume 4, pp. 31-32.

[41] EB-2010-0379, *Draft Report of the Board on Empirical Research to Support Incentive Rate-setting for Ontario’s Electricity Distributors*, September 6, 2013, p. 26.

[42] Exhibit M1 (Revised May 4, 2018), p. 36/Tables 4A and 4B, and p. 41/Table 6-REVISED. The US gas distributor sample had a long-run TFP growth trend of -0.23%, compared to +0.66% for Union but in the

these circumstances OEB staff suggests that Amalco be assigned the stretch factor for the “middle” cohort of 0.3%, as the OEB has also accepted as “normal” performance for electricity distribution and for hydroelectric generation.

OEB staff accepts that there could be other ways to set the stretch factor. As described above, the stretch factor contained in Union Gas and Enbridge Gas’ current IRM plans were established using different methods. However, in the current case the applicants have not made any proposals at all. Under these circumstances OEB staff submits that the precedent from the electricity sector is most appropriate, and that the stretch factor should be 0.3%.

Y-Factors

The applicants have proposed a set of Y factors that are similar to Union’s 2014-2018 IRM framework. OEB staff has no concerns with the use of the Y factors proposed by the applicants. Most of the proposed Y factors are either related to pass through commodity amounts or are related to amounts approved in previous applications and that are to be disposed in the annual rates case.

However, OEB staff is concerned with the only Y-Factor proposed that is in relation to a true up. The applicants propose to continue to adjust rates annually to reflect the declining trend in average use. As noted earlier, in the last Enbridge Gas deferral and variance accounts proceeding, the utility acknowledged that the average use model was updated with the 2016 actual value and a diagnostic test indicated that a structural break occurred in 2016 for some models.[43] In other words, the average use model is not reliable and will not be corrected until the next rebasing. OEB staff understands that the load is weather normalized and the deferral account essentially captures decline in average use not related to weather.[44] However, OEB staff notes that the average use and load forecasting model have not been revised or reviewed since 2012 for both Enbridge Gas and Union Gas. Nevertheless, OEB staff accepts the continuation of the normalized average consumption/average use (NAC/AU) deferral account for now on the assumption that the deferral period is six years. Should the deferral period be longer than six years, OEB staff submits that the utilities should assume some risk of decline in average use considering that the utilities have not opted to revise their average use models and volume risks are a normal business risk for which utilities are compensated through the allowed ROE. OEB staff further submits that at the next rebasing, Amalco

range of -1.70% to -2.30% for Enbridge, per PEG’s analysis. See also Transcript, Day 4 (May 15, 2018), pp. 161-164.

[43] Response to Energy Probe IR#7, EB-2017-0102, January 14, 2017.

[44] Oral Hearing Transcript, Volume 5, pages 21-24, May 18, 2018.

should be required to file a proposed approach to discontinue the NAC/AU deferral and variance account.

Z-Factors

The applicants propose using a materiality threshold of $1.0 million for Amalco during the deferred rebasing period. Z factors are currently in place for both utilities (Enbridge Gas – $1.5 million and Union Gas – $4 million both on a revenue requirement basis) under their current rate setting plans. OEB staff notes that both utilities are at the end of their respective rate-setting plans and have been able to manage within their respective thresholds. In this application, Amalco has requested a threshold of $1.0 million which is in line with the current threshold for electricity distributors.

Amalco has not provided any specific reason for the $1.0 million threshold except that it is consistent with the threshold for electricity distributors.[45] OEB staff is not convinced that a utility that will have a rate base exceeding $10 billion and operating revenues exceeding $2 billion cannot manage a Z-factor related risk of over $1.0 million. In fact, the cumulative current threshold for the two utilities is $5.5 million. The applicants' argument that the Z-factor should be in line with other electricity distributors seems to be weak.

A recent proceeding where the OEB has set a Z-factor materiality threshold and that is comparable in terms of revenue requirement to Amalco is OPG. The Z-factor threshold for OPG's payment amounts application[46] for the period January 2017 to December 2021 is $10 million. The 2017 rate base for OPG's nuclear facilities is $3.4 billion and the operating revenue is approximately $3.0 billion.[47] The 2017 OPG rate base financed by capital structure is estimate to be $10.8 billion.[48] This compares to Amalco's rate base for 2016 of $10.7 billion and an operating revenue of approximately $2.186 billion. The revenue requirement of Amalco is approximately 75% of OPG's. Accordingly, OEB staff submits that Amalco's Z-factor materiality threshold should be $7.5 million on a revenue requirement basis (75% of 10 million).

Z-factor Treatment for Interest Costs

Z-factor treatment is applicable to costs that are non-routine, prudently incurred and costs that are outside the control of management. In this application, the applicants have referred to a rise in future interest rates as a factor that should be eligible for Z-

[45] Exhibit B, Tab 1, Page 12, Pre-filed Evidence, EB-2017-0307.
[46] EB-2016-0152
[47] Draft Payment Amounts Order, Revenue Requirement - $2.97 billion, Appendix A, Table 1, EB-2016-0152.
[48] EB-2016-0152, Exhibit C1, Tab 1, Schedule 1.

factor treatment. At the oral hearing, the applicants clarified that the reference to interest rates did not specifically refer to a general rise in interest rates but to the refinancing of the current debt of Enbridge Gas and Union Gas under Amalco.[49] The applicants further noted that Amalco would work to manage any increase in borrowing costs and would apply for recovery only under extraordinary circumstances.

OEB staff understands that the treasury function of Amalco resides in Enbridge Inc.[50] and the cost of borrowing for Amalco would be impacted by the credit rating of Enbridge Inc. OEB staff further notes that the credit rating of Enbridge Inc. has recently been downgraded by Moody's Investor Service Inc. The concern is over Enbridge Inc.'s total long term debt that currently exceeds $60 billion.[51] If there is any further downgrade in Enbridge Inc.'s credit rating, the cost of borrowing could increase significantly and this could adversely impact the ratepayers of Amalco. OEB staff submits that Amalco ratepayers should not have to pay for increases in the cost of borrowing, especially if they are related to deterioration in the credit profile of Enbridge Inc. Such increases are clearly within the control of management and do not qualify to be a Z-factor. Essentially, increases in the cost of borrowing are not Z-factors, according to OEB staff.

Incremental Capital Module

The applicants have requested an ICM for the proposed ten-year Price Cap IR deferred rebasing period as allowed for in the MAADs Handbook. The ICM is a regulatory tool that allows for recovery of the revenue requirement for qualifying material and incremental capital additions, beyond what is funded through approved rates (including considerations of the cumulative and combined impacts of price cap adjustments and demand growth since the last cost of service rebasing). Recovery is provided for through rate riders, which allow base rates to continue to be adjusted through the approved I – X price cap formula.

The ICM policy and mechanism was first developed for the 3rd Generation IRM for electricity distributors[52]. Based on experience with ICM applications from 2010 to early 2014, the OEB directed staff to review the policy in 2014. Reviews in 2014 and 2015 resulted in an evolution of the policy through two OEB reports:

- *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219)*, September 18, 2014

[49] Oral Hearing Transcript, Volume 5, page 20, May 18, 2018.
[50] Technical Conference Transcript, pages 12-13, April 3, 2018.
[51] Globe and Mail Article, "Moody's downgrades Enbridge Debt despite new financial plan", December 21, 2017.
[52] EB-2007-0673

- *[Report of the OEB: New Policy Options for the Funding of Capital Investments - Supplemental Report (EB-2014-0219)]*, January 22, 2014

The applicants have stated that they propose to comply with the OEB's ICM policy with one exception – they propose to use current long term debt and the current OEB issued ROE for determining the revenue requirement of any approved qualifying ICM policy, instead of the current approved debt and ROE rates from the last rebasing.[53]

It has become apparent through the interrogatory and technical conference process, and through cross-examination, that the applicants' proposal deviates from existing OEB ICM policy in other ways as well. These are discussed below.

Cost of Capital

In its initial position submission filed on April 30, 2018, OEB staff opposed Amalco's proposed cost of capital treatment.[54] OEB staff's position has not changed.

Enbridge Gas and Union Gas submit that they will be redeeming the existing preferred shares of each utility, and that these are not used for funding capital projects. They argue also that short-term debt is for funding working capital and not investment in capital assets.[55]

It is not clear that Amalco will not be issuing preferred shares to replace the existing preferred shares of Enbridge Gas and Union Gas. OEB staff notes that the stand-alone and amalgamated scenarios modelled in the interrogatory response FRPO 11 are based on the existing deemed capital structures, with short-term debt and preference shares, in addition to long-term debt and common equity, shown throughout the proposed deferred rebasing period of 2019 to 2028.

A change in the mix of preferred and common shares will change the cost of capital if the updated capital structure is used for purposes of the ICM. The applicants' proposal will effectively make the revenue requirement impact of future ICM projects more expensive for ratepayers. Amalco's proposal would increase the percentage of long-term debt and common equity on the rate base, thus raising the weighted average cost of capital. Rate base additions (represented by ICM projects) would add to these components, and the short-term debt and preference share proportions of the capital structure would decrease correspondingly. In effect, the applicants' proposal would change the deemed capital structure from what the OEB has determined as appropriate for each of Enbridge Gas and Union Gas. However, the applicants have not proposed a change in the deemed capital structure nor have they brought any evidence forward to

53 EB-2017-0307, Exhibit B/Tab 1/pp.15-16.
54 OEB Staff Initial Position, p. 3, April 30, 2018.
55 Exhibit C/Staff-15

support a change due to increased business risk (which is traditionally aligned with an increase to WACC).

The OEB's policy[56] to use the OEB-approved capital structure and cost of capital parameters from the utility's most recent rebasing application is to ensure consistent treatment between existing assets, and new assets funded through base distribution rates adjusted by the IRM formula, and new assets funded through ICM and Advanced Capital Module (ACM) rate riders. OEB staff also notes that the ICM materiality threshold calculation is in effect a cash flow test that compares a utility's ability to fund new capital investments through the price cap adjusted rates assuming an element of growth. Using an updated cost of capital structure is counter to this policy. OEB staff submits that this policy should apply to Amalco, just as it applies to electricity distributors or to OPG's hydroelectric generation.

Review of ICMs in Leave-to-Construct applications

The applicants have proposed that ICM projects be reviewed for approval in Leave-to-Construct (LtC) applications.[57] In its initial position submission, OEB staff also stated that it was opposed to the applicants' proposal that ICMs be reviewed and approved in Leave-to-Construct (LtC) applications. OEB staff's position has not changed.

OEB staff notes that determination of the amount of qualifying ICM capital for a project depends not just on the dollar value of that project, but also on the total capital budget in the rate year, and on what is funded through proposed base rates, including the cumulative and combined impact of I – X rate adjustments and growth in demand (customers and m^3 of gas deliveries); these numbers may not be known – with any certainty – at the time of the LtC application.

However, OEB staff submits that Amalco could identify in the earlier LtC application that it is its belief that the project could qualify for ICM treatment. The OEB, in that application, could test and determine the need for, prioritization and pacing of the project if it is aligned with a recently filed Utility System Plan. OEB staff notes that the applicants plan to each file a Utility System Plan (USP) as part of their 2019 rates application under the new rate-setting framework[58]. This would be similar to the testing of a capital project for ACM treatment as part of the Distribution System Plan in a cost of

[56] Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219), September 18, 2014, p. 24: **7.1.3 Cost of Capital -**

… A distributor filing for ACM or ICM rate riders shall use the cost of capital parameters approved by the Board in the distributor's most recent cost of service application when calculating the revenue requirement associated with the incremental funding.

[57] EB-2017-0307/Exhibit B/Tab 1/p. 15, Exhibit C/Staff-26.

[58] Transcript, Vol. 1, (May 3, 2018) REDACTED, p.95.

service application (or, in Alectra Inc.'s example, in an IRM application) for a project that would occur during the subsequent Price Cap IR term. The nature, need for, and pacing and prioritization of the project already reviewed and approved as part of an LtC would not be reviewed again in the Price Cap IR application. However, determination of the dollars for the qualifying incremental capital, the associated revenue requirement, and rate riders to recover that, should and would only be determined as part of the annual Price Cap IR application. OEB staff expects that Amalco will file a subsequent USP five years after the 2019 USP filing, in line with the electricity distributors. This further supports staff's recommendation of a six-year deferred rebasing period.

Sudbury Expansion Project

Under cross-examination from School Energy Coalition's counsel, Union Gas' witness confirmed that they were intending to seek ICM approval for the Sudbury expansion project as part of the 2019 rate application.[59] However, the Sudbury project is expected to come into service in 2018. Union Gas' witness explained that they would be seeking recovery of the full qualifying amount. However, under the capital funding policy for ICM and ACM, application for recovery is made in the year that the asset enters (or is forecasted to enter) service – not earlier or later. Union Gas is under its current 2014-2018 Price Cap IR plan (with the capital pass-through, not the ICM), and so the Sudbury project is outside of the proposed Price Cap IR plan. [60]

Union Gas' witness explained that they are not seeking approval for how the Sudbury project should be treated as part of this application; that would be considered in the 2019 application (to be filed later this year).[61] OEB staff concurs with this suggestion. OEB staff notes that deviations from policy are possible, dependent on circumstances. There is a precedent in this case, with respect to Rideau St. Lawrence's 2018 IRM application.[62] This application was resolved by a settlement agreement between that utility and OEB staff, which was accepted by the OEB. Under the settlement, recovery of amounts prior to the current rate year were forgone.

Whether or how the Sudbury project would be treated should be fully tested in the forthcoming 2019 application.

[59] Transcript, Vol. 1, (May 3, 2018) REDACTED, p. 90/l.10 to p.93/l. 23.
[60] Transcript, Vol. 2 (May 4, 2018), p. 94/l.7 to p.98/l. 1.
[61] *Ibid.*
[62] EB-2017-0265.

Calculation of Rate Riders and "Truing Up"

A second area where OEB staff have concerns is with the applicants' understanding of the ACM/ICM policy and their proposal for calculating the rate riders and "truing up" of recoveries versus the revenue requirement until rebasing.

Under the ICM approach, since inception in 2008 to date, the revenue requirement, and the rate riders to recover it, are determined on the year that the asset goes into service. Subsequent depreciation each year until rebasing, and the reduction in the return on capital and associated taxes, is not considered. Thus, the ACM/ICM rate riders will over-recover against the actual revenue requirement associated with the asset, even ignoring growth in demand. As the ICM was introduced for 3rd Generation IRM, where the maximum amount of time until rebasing was 3 years, or even under the current Price Cap IR plan for electricity distributors, where there should normally be at most four years until rebasing, the over-recovery was not considered significant, and did not warrant recalculation each year.

However, extension of the ICM for price cap plans of up to 10 years following mergers and acquisitions, as allowed for in the MAADs Handbook, exacerbates this situation. At the oral hearing, OEB staff presented a hypothetical example that compared the revenues recovered via the ICM rate riders, per OEB policy, and the cumulative revenue requirement over the ten year period (2019 to 2018) proposed by Amalco.[63] The example showed that over-recovery would be about 11 percent higher than what should be recovered (i.e. the actual revenue requirement associated with the asset over the ten years). A second calculation showed that, if the revenue requirement was calculated based on the average net book value from when the asset goes into service until the end of the Price Cap IR plan (i.e. opening net book value during the subsequent rebasing year), the rate riders should recover about the revenue requirement per an annual cost of service approach. (In all of this, growth in demand is ignored.)

The applicants' witnesses did not dispute the example, but explained that their understanding was that the revenue requirement and rate riders would be updated annually, and that any variance between the revenues recovered and the revenue requirement would be trued up through the ICM deferral/variance account (DVA), similar to how Union Gas' current capital pass-through works.[64]

This is not the current OEB ICM policy and practice. The DVA for ACM and ICM tracks differences between the forecasted qualifying ICM capital expenditure approved, and

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[63] OEB Staff's Compendium for Panel 1, Exhibit K1.6 /Tab 6.

[64] Transcript, Vol. 2 (May 4, 2018), p. 91/l. 2 to p. 94/l. 5, Transcript, Vol. 6 (May 28, 2018), p. 80/l. 7 to p. 85/l.22.

the actual amount. At the time of the next rebasing application, the difference is reviewed. The OEB panel then can decide if the variance, typically where the actual expenditure is less than forecasted, is material, and can determine that the over-collection be refunded to customers. If the variance is driven by over-spending, then a further prudence review is conducted on the over spending to determine if amounts will be trued up at all. However, the rate rider is not updated through the IRM period. OEB staff acknowledges that the applicants' proposed approach could work, but this would be a departure from existing policy as applied in the electricity sector and would mean adding more complexity to the annual price cap application. OEB staff would not be opposed to this approach for a ten year deferral period as it works in favour of ratepayers. OEB staff does not believe this added complexity is necessary if OEB staff's positon of a six year deferral period is accepted.

Amalco's proposal borrows elements from Union's current capital pass-through mechanism. In its first rate application for which ICM-qualifying capital treatment is proposed – presumably the 2019 application, Amalco should provide full details on its proposed treatment (in the event the OEB approves it), including the accounting treatment and proposed accounting order for the ICM DVA.

ICM is for Material, Discrete Projects not Normally Funded Through Existing Rates / Discussion of FRPO 11 and J4.2

Based on the evidence, OEB staff's understanding of the applicants' rate-setting proposal is that a majority of the capital costs in excess of the ICM materiality threshold will qualify for ICM treatment during the deferred rebasing period.

OEB staff submits that this should not be the case. The OEB ACM/ICM policy per the 2014 and 2016 capital funding options reports identified earlier define ICM/ACM projects as being discrete, necessary, material, and not part of capital projects "normally" funded through existing rates. The ICM is not a guaranteed recovery for amounts above the materiality threshold. The applicants acknowledged these considerations at the Technical Conference.[65]

While continuing to acknowledge this, Amalco maintains that the majority of incremental capital additions will be afforded ICM treatment.[66] This is particularly evident in the stand-alone versus amalgamated scenarios detailed in the response to FRPO 11, and to subsequent analyses based on it, including Undertaking J4.2 (assuming a 0.3% stretch factor).

[65] Technical Conference Transcript, Vol. 3 (April 2, 2018), p. 152/l. 5 to p. -159/l. 11.

[66] Transcript, Vol. 1 (May 3, 2018) REDACTED, p. 86/l. 27 to p. 88/l. 22, Transcript, Vol. 6 (May 28, 2018), p. x/. x to p. y/l. y.

A review of FRPO 11 shows that Amalco has assumed that most of the forecasted capital expenditures exceeding the materiality threshold will be afforded ICM treatment to recover it. In the case of Enbridge Gas, all capital expenditures above the materiality threshold is assumed to qualify for ICM treatment in every year except 2019, where a small amount of about $19M is excluded. For Union Gas, there are amounts in most years where ICM funding is not expected, but, still, most capex exceeding the materiality threshold is assumed to qualify for recovery through the ICM.[67] OEB staff notes that the analysis shown in FRPO 11 (and Undertaking J2.4, based on it but assuming a 0.3% stretch factor) should only be considered illustrative, as it probably overstates what would (or should) be qualifying ICM capital over the term of the plan. (In part, the calculation of the materiality threshold as shown in FRPO 11 is incorrect, as acknowledged by the applicants' witness during the Technical Conference.[68])

OEB staff submits that the applicants' assumption that the ICM will be a "catch-all" for nearly all capex above the materially threshold is inconsistent with the policy and practice of the ICM/ACM policy. OEB staff notes that BOMA, in its compendium for Panel 4,[69] included excerpts from the recent 2019 rate application decision[70] for Alectra, an electricity distributor, out on a 10-year deferred rebasing pursuant to a recent merger and acquisition and in accordance with the policies in the MAADs Handbook. The OEB, in that proceeding, did not approve ICM treatment for a number of the proposed projects; in fact, out of $56.18M applied for, the OEB approved $28.79M or just over half of the proposed ICM. OEB staff is of the view that the OEB should confirm, in this current proceeding, the scope of the availability of incremental capital during the deferral period pursuant to the intent of the OEB policy.

Cost Allocation and Rate Design Changes During Deferred Rebasing Period

The applicants do not intend to undertake a complete cost allocation study during the deferred rebasing period. The applicants, however, expect to propose allocation of specific, distinct cost elements to rate classes for allocating ICM revenue requirement and demand side management (DSM) costs. In addition, the applicants indicated at the oral hearing that they intend to propose cost allocation changes to the Panhandle and St. Clair system in the upcoming rates application.[71]

[67] Technical Conference Transcript, Vol. 3 (April 2, 2018), p. 155/l. 15 to p. -159/l. 11, Transcript, Vol. 6 (May 28, 2018), p. 63/l. 16 to p. 64/l.19, p.78/l. 13 to p. 85/l. 22.
[68] Technical Conference Transcript, Vol. 3 (April 2, 2018), p. 152/l. 11 to p. 155/l. 24
[69] Exhibit K1.4.
[70] Decision and Order EB-2017-0024, April 5, 2018. The ICM proposal and panel findings are extensively documented on pages 20-30. BOMA's Compendium, Exhibit 1.4, contains pages 23-30 of the EB-2017-0024 Decision and Order.
[71] Transcript Volume 3, Page 160, May 14, 2018.

The question is whether discrete cost allocation changes should be permitted during a price cap framework apart from allocating ICM revenue requirement changes and DSM costs. Although the proposed cost allocation changes to the Panhandle/St. Clair system are supposedly based on cost causality principles and reflect the updated design day demands of the customer class, the question is whether such discrete changes are appropriate in the absence of a comprehensive cost allocation study. In addition, it is possible that a full cost allocation study may reveal that the demand patterns of other assets have also changed but will not be subject to an update. The cost causality principle should not be applied to a single customer class or some classes but should be applied to the entire pool of assets. One customer class should not be allowed to benefit from a discrete adjustment. In an appeal from a decision of the OEB, the Divisional Court agreed with the OEB that updating load data relating to the street lighting class of Horizon Utilities (now Alectra Utilities) on the basis of partial information would not be fair to the other rate classes. Selective updating would benefit the street lighting rate class but would do so at the expense of other rate classes. As the Court said, "Cost allocation is a zero sum game. If one class' rates go down, another class' rates must go up."[72]

OEB staff submits that in the absence of a full cost allocation study, discrete adjustments to certain assets should not be permitted. The applicants' proposal to make discrete adjustments merely supports OEB staff's position that the imbalance in cost allocation exists for a number of assets and therefore a shorter deferral period is appropriate.

<u>Additional Consideration and Requirements to Protect Customer Interests</u>

Gas Supply Contracts between Enbridge Gas and Union Gas

One of the outcomes of the proposed amalgamation is that the existing contracts between Enbridge Gas and Union Gas will cease to have effect as they will be contracts between the same party. These contracts apply to various gas supply (transportation and storage) arrangements.

Enbridge Gas relies on long-term contracts with Union Gas for transportation and storage of natural gas to meet the gas supply requirements of customers in Enbridge Gas' franchise areas. Transportation services are provided at regulated rates and storage services are provided at market prices. The cost consequences of these contracts are passed through to customers in rates. The applicants noted that the

[72] *City of Hamilton v. Ontario Energy Board,* 2016 ONSC 6447, para. 6.

amalgamation will not change the price, quality or reliability of these services for customers. Amalco will continue to have access to existing storage and transportation capacity to meet the gas supply requirements of customers.[73]

The applicants stated that despite the fact the contracts will cease to have effect upon amalgamation, the commitments in those contracts will continue.[74]

Transportation

Currently, Union Gas provides Enbridge Gas approximately 3 PJ/day of transportation on the Dawn-Parkway system.[75]

The applicants stated that the Enbridge Gas rate zone will receive the same required transmission services upon amalgamation as it did pre-amalgamation. However, after amalgamation, the Enbridge Gas rate zone will shift from being considered an ex-franchise customer of Union Gas that received M12 transportation services to an in-franchise customer that is serviced using the same transmission facilities it did prior to amalgamation.[76]

The applicants stated that there is no difference in the costs allocated to the Enbridge Gas rate zone as a result of treating Enbridge Gas as an in-franchise customer (as opposed to a M12 ex-franchise customer). This is due to Enbridge Gas taking service on the Dawn-Parkway system for which the related costs are allocated on distance-weighted design day demands and Enbridge Gas is at the end of the system.[77]

OEB staff has no concerns with the proposed treatment of the existing transportation contracts between Enbridge Gas and Union Gas after amalgamation whereby the formal contracts will cease but the commitments will continue. The costs to Enbridge Gas' customers remain unchanged whether it is considered an in-franchise or ex-franchise customer due to the assets it uses and its location relative to Union Gas' system.

In regard to meeting future transportation requirements either through the use of assets owned by the amalgamated company or third-parties, OEB staff submits that Amalco will need to prove the prudence of the cost consequences of the decisions made at the appropriate time (either through the gas supply planning filings that are expected to occur

[73] MAADs application, Exhibit B, Tab 1, p. 40.
[74] Transcript, Vol. 3, p. 44.
[75] Interrogatory Response Staff.10.
[76] Interrogatory Response Energy Probe 7(a).
[77] Transcripts, Vol.3, p. 54.

during the deferred rebasing period[78] or through the annual rates proceeding). OEB staff submits that the applicants must take steps to ensure that the transportation contracting decisions made by the amalgamated company are prudent when the cost consequences of those decisions are brought forward for OEB review. OEB staff submits that the OEB should be clear in its decision that the utility is at risk for cost disallowances if it is found that the manner in which it is meeting its transportation requirements is not prudent.

Storage

Similar to the transportation contracts, the storage contracts between Enbridge Gas and Union Gas will cease to have effect after amalgamation, however, the commitments in those contracts will continue. As noted previously, Enbridge Gas currently purchases storage services from Union Gas at market based prices as it does not have sufficient utility storage to meet the entire storage requirement of its in-franchise customers.

In the Natural Gas Electricity Interface Review (NGEIR) proceeding,[79] the OEB determined that 100 PJ of Union Gas' existing storage capacity and all of Enbridge Gas' storage capacity of 99.4 PJ would be allocated to meet the needs of in-franchise customers at cost-based rates. All existing storage in excess of the above limit or new storage would not be rate regulated. While Enbridge Gas has insufficient storage to meet the needs of its in-franchise customers, Union Gas has excess storage. Union Gas' in-franchise customers typically use around 93 PJs annually with the balance being sold as short-term storage. The net revenues from short-term storage and load balancing transactions are shared 90:10 to the benefit of ratepayers.

Union Gas provides 19.5 PJ of Enbridge Gas' 26.4 PJ of third party storage services. The question is whether Union Gas should provide the approximately 7 PJ of excess storage (100 PJ – 93 PJ) to meet the needs of Enbridge Gas' in-franchise customers post amalgamation. This would reduce the benefit for Union Gas in-franchise customers as they currently benefit from the sale of short-term storage and balancing services. On the other hand, Enbridge Gas in-franchise customers would benefit as they would receive some portion of their storage needs, approximately 7 PJ, at cost-based rates.

In an undertaking response, the applicants provided a hypothetical analysis of the net benefit to Enbridge Gas customers if market-based storage was replaced with cost based excess utility storage space from Union Gas.[80] The analysis reveals that the net benefit to Enbridge Gas customers outweighs the forgone net benefit to Union Gas

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[78] There is Draft Report of the OEB titled, "Framework for the Assessment of Distributor Gas Supply Plans," dated April 12, 2018 issued for comment and a Final Report of the OEB is expected in the future.
[79] EB-2005-0551, NGEIR Decision with Reasons, November 7, 2006, page 74 and 83.
[80] Undertaking JT2.12.

customers as a result of not receiving revenues from the sale of excess utility storage. OEB staff therefore submits that Enbridge Gas customers should receive the benefit of Union Gas' excess utility storage space post amalgamation. Once the amalgamation is approved, there should not be any distinction between Enbridge Gas and Union Gas in-franchise customers; all in-franchise customers of Amalco should have access to utility storage that has been allocated to in-franchise customers as per the NGEIR Decision.

If the OEB were to determine that Enbridge Gas customers should have access to the excess utility storage space of Union Gas at cost-based rates, then some adjustment would be required to the base rates of Union Gas. Customers in Union North and Union South currently receive a net benefit in rates of $4.5 million from the sale of short-term storage and other balancing services. Of this amount, $2.3 million is related to the sale of Union Gas' excess utility storage space as short-term peak storage and $2.2 million is related to the sale of other short-term storage and balancing services. If the OEB were to determine that the excess Union Gas utility storage space should be used to serve Enbridge Gas customers, consideration would need to be given to the $2.3 million net benefit in Union Gas' rates. It is assumed that the net revenue from other short-term storage and balancing services would continue to accrue to Union Gas' ratepayers as it relates to optimizing all rate-regulated storage. OEB staff therefore submits that Union Gas' base rates for 2019 should be adjusted to reflect the removal of the net benefit of $2.3 million that would not be realized as a result of allocating the excess utility space to serve Enbridge Gas customers. Similarly, Enbridge Gas' revenue requirement for 2019 would also need to be adjusted downwards to reflect the replacement of market-based storage with cost-based storage. If the OEB agrees with OEB staff's submission on this issue, the OEB should order the applicants to file a proposal for a base rate adjustment as part of the 2019 rates proceeding.

Blind RFP Process for the Purchase of Unregulated Storage Services for Enbridge Gas Zone Customers

As noted earlier, Enbridge Gas does not have sufficient storage to meet the needs of its in-franchise customers while Union Gas has excess storage that is not rate-regulated. Post amalgamation, the legacy Enbridge Gas will continue to receive storage services from Union Gas at market-based rates. Amalco will continue to purchase market-based storage services and will evaluate alternatives available in the competitive market. Amalco is one of the parties that can provide storage services in the competitive market. In other words, Amalco will be purchasing storage at market-based rates from itself. In order to ensure an unbiased storage procurement process, Amalco has indicated that it will conduct a blind request for proposals through an independent third party for storage capacity.[81] The applicants have confirmed that the evaluation and selection of the most appropriate storage services will be on the basis of an objective matrix of criteria.

At the oral hearing, the applicants confirmed that if Amalco purchased market-based storage from itself, the contract would be publicly reported on its website in accordance with the Storage and Transportation Access Rule (STAR)[82]. OEB staff is satisfied with the proposed approach.

Base Rate Adjustments

The applicants have proposed certain base rate adjustments that were the subject of settlements from prior proceedings and expire at the end of 2018.The applicants' 2019 rates application will be adjusted to reflect the proposed base rate adjustments. OEB staff accept the proposed base rate adjustments, as described below.

Union Gas Deferred Tax Drawdown

The first adjustment is an increase to Union Gas' rates for the completion of the OEB-approved deferred tax drawdown. The applicants propose to increase Union Gas' 2018 OEB-approved revenue by $17.4 million pre-tax ($12.8 million after-tax) to recognize the accumulated deferred tax balance. This amount represents the difference between the credit to ratepayers included in 2018 rates, and the accumulated deferred tax balance at the end of 2018 of zero.

The OEB-approved drawdown spanned a period of 20 years, beginning in 1999 and ending in 2018. Since the balance is zero, Union Gas has proposed to remove the benefit from rates. This proposed adjustment will lead to an increase in Union Gas' rates in 2019.

Enbridge Gas CIS and Customer Care Costs

The second adjustment is a decrease to Enbridge Gas' rates for the smoothing of costs related to its Customer Information System (CIS) and customer care forecast costs. The applicants propose to decrease Enbridge Gas' 2018 OEB-approved revenue by $4.9 million to recognize the approved CIS and customer care cost level of $126.2 million rather than the $131.1 million in 2018 OEB-approved rates. In the OEB-approved settlement proposal[83], parties agreed that forecast CIS and customer care costs for the

[81] Response to Ontario Greenhouse Vegetable Growers IR#4.
[82] Transcript, Volume 3, Page 118, May 14, 2018.
[83] EB-2011-0226.

six-year period would have a smoothing mechanism applied to them for determination of revenue and rate recovery purposes. The result was that in 2018 the approved rates will recover revenues of $131.1 million while the approved costs are effectively $126.2 million. Enbridge Gas will book an entry to credit the deferral account by an amount of $4.9 million such that the income statement recognizes a match between approved revenues and costs. As a result, Enbridge Gas would decrease 2018 rates by $4.9 million.

OEB staff has no concerns with the two proposed rate adjustments described above.

Enbridge Gas' Pension and OPEB Costs

In the 2018 Rate Adjustment proceeding[84], Enbridge Gas had proposed to include in its revenue requirement certain pension and Other Pension and Employee Benefits (OPEB) costs associated with the new Pension Benefits Act legislation in Bill 177. Although initially agreed to by all parties in that proceeding, the OEB expressed concerns with the inclusion of such costs in the revenue requirement because Bill 177 had not yet been formally passed. As a result, the approved settlement proposal in that proceeding removed $6.5 million from the revenue requirement related to the expected impact of the new Pension Benefits Act legislation. Instead, all parties agreed that Enbridge Gas would recover the actual amount of its pension and OPEB costs and related revenue requirement in 2018 through amounts to be recorded in the Post-Retirement True-Up Variance Account (PTUVA).

On December 14 2017, Bill 177 was given third reading and received Royal Assent. Therefore Enbridge Gas is proposing to adjust its 2018 OEB-approved revenue requirement by $6.5 million (increase) to account for the impact of the new Pension Benefits Act legislation for the purpose of determining rates for 2019 and beyond under the rate-setting mechanism being proposed in this application. As noted above, the $6.5 million had been excluded from the OEB approved 2018 revenue requirement, and the impact of these legislative changes will continue beyond 2018.

OEB staff does not object to the proposed adjustment to the OEB approved 2018 revenue requirement.

[84] EB-2017-0307.

Enbridge Gas Tax Deduction Related to SRC Refund

In Enbridge Gas' Custom IR proceeding (2014-2018)[85], the OEB had approved a revised methodology for determining the net salvage percentages to be used by Enbridge Gas in the calculation of its depreciation rates, called the Constant Dollar Net Salvage (CDNS) approach. In addition to approving this new approach, the OEB also approved a proposal to return to ratepayers, through a rate rider (Rider D), certain amounts that had been recovered through past depreciation rates based on the traditional method for determining net salvage percentages. A total of $379.8 million was to be returned to ratepayers over the five year period 2014-2018 through Rider D (referred to as the site restoration cost (SRC) refund). In addition, a related annual tax deduction specifically arising from the SRC amounts being returned to customers during the term of Enbridge Gas's 2014-2018 Custom IR was also embedded in the approved rates. The 2018 revenue requirement approved in the Custom IR proceeding included $11.2 million in expected tax deductions arising from the SRC refund payments to ratepayers. No adjustment to that revenue requirement amount was made during Enbridge Gas's recent 2018 Rate Adjustment proceeding.[86]

For purposes of determining rates for 2019 and beyond under the rate-setting mechanism being proposed in this application, Enbridge Gas is proposing to remove the $11.2 million in tax deductions that are currently embedded in its approved 2018 revenue requirement because there is no longer any ongoing SRC refund and therefore the associated tax deductions will no longer exist in years following 2018. OEB staff agrees with the applicant's assessment and therefore does not object to the proposed adjustment (increase) to its 2018 approved revenue requirement.

Deferral and Variance Accounts

The applicants set out the list of deferral and variance accounts for which they seek approval at Exhibit B, Tab 1, Attachment 4 of the Rate Setting Mechanism application. The applicants also confirmed that the accounts that they propose to continue will operate in the same manner as they have during the historical period.[87]

OEB staff has no concerns with the continuation of the accounts proposed by the applicants based on the existing accounting orders.

[85] EB-2012-0459.
[86] EB-2017-0086.
[87] Oral Hearing Transcript Vol. 3, p. 137.

The applicants also requested closure of the following accounts for Enbridge Gas: (a) Customer Care CIS Rate Smoothing Deferral Account (Account 179.16); (b) Constant Dollar Net Salvage Adjustment Deferral Account (Account 179.34); (c) Relocations Mains Variance Account (Account 179.96); (d) Replacement Mains Variance Account (Account 179.98); (e) Post-Retirement True-Up Variance Account (PTUVA) (account 179.24); and (f) the Earnings Sharing Mechanism Deferral Account (ESMDA) (Account 179.58). For Union, the applicants requested closure of the CGAAP to IFRS Conversion Costs Account (Account 179-120) and the Tax Variance Deferral Account (Account 179-134). The applicants provided rationale for the closure of each of the noted accounts.[88]

OEB staff has no concerns with the closure of the accounts as proposed by the applicants with the exception of PTUVA and the Tax Variance Deferral Account (TVDA).

With respect to the closure of Enbridge Gas' ESMDA, OEB staff is of the view that Amalco must use a variance account to track sharing amounts that may be generated during the deferred rebasing period for both legacy utilities. This is the typical approach used for tracking prior period balances.

Post Retirement True-Up Variance Account

In regard to the PTUVA, OEB staff submits that it should remain in operation until at least the end of 2019. The PTUVA has a smoothing mechanism inherent in its design whereby if the balance in the account (either debit or credit) is greater than $5 million that incremental amount (beyond $5 million) is carried forward into a future year (for smoothing purposes). It is unknown at this time whether after the disposition of the 2018 account balance there will be a residual balance, above $5 million, which remains to be disposed in the account. As such, the account should remain until such time that any residual balance in the account is disposed. However, no new amounts related to the variance between Enbridge Gas' actual and forecast pension costs should be recorded in the account after amalgamation and Enbridge Gas moves to a Price Cap IR.

Tax Variance Deferral Account

The applicants have proposed to close Union Gas' TVDA. The TVDA captures 50% of the difference between the actual tax rates and the approved tax rates included in rates resulting from, among other things, changes to federal and/or provincial tax legislation.

[88] Rate Setting Mechanism Application, Exhibit B, Tab 1, pp. 23-26.

Simple interest is computed monthly on the opening balance in the said account in accordance with the methodology approved by the OEB.

The applicants have instead proposed that any significant changes in taxes occurring during the deferred rebasing period that are outside of management's control will be addressed through the Z factor. OEB staff submits that Union Gas' TVDA should not be closed and should continue to capture any tax variances resulting from factors such as changes in federal and/or provincial tax legislation during the deferred rebasing period. To that end, OEB staff further submits that Enbridge Gas should open an equivalent TVDA to be used for the same purpose. Z factor adjustments under the proposed rate setting mechanism in this application are subject to threshold restrictions and therefore would not address tax variances that fall below the pre-determined threshold. As part of its submission in this proceeding, OEB staff has proposed to increase the Z factor threshold. If approved, this increased threshold would make it even less likely that future tax variances would be adjusted for through the Z factor.

Changes to Accounting Practices

During the deferred rebasing period, the applicants expect to change accounting policies and practices as part of the implementation of an integrated accounting system, including changes in the calculation of depreciation rates and its cost capitalization policy. In response to an OEB staff interrogatory,[89] the applicants have indicated that the process of aligning the accounting practices will not begin until after the OEB approves the proposed amalgamation and therefore, at this time, it is not possible to quantify the impacts that the integration of the accounting policies and practices will have on the rates approved by this application. As such, OEB staff proposes that the applicants each be required to open a new deferral account that captures the revenue requirement impacts associated with the integration of their accounting policies and practices during the deferred rebasing period. The account should be symmetrical and simple interest should be computed monthly on the opening balance in the said account in accordance with the methodology approved by the OEB. The balances in the accounts should be subject to an OEB prudence review and may be brought forward for disposition at the applicants' next rebasing application.

The applicants also stated that there may be changes to accounting and reporting processes that result from amalgamation that impact the deferral and variance accounts that are proposed to be continued during the deferred rebasing period. If this occurs, the applicants plan to bring forward proposals to change specific deferral and variance

[89] OEB Staff IR #55.

accounts during the deferred rebasing period in either annual rate applications or deferral account clearance applications.[90] OEB staff submits that if changes result in material impacts to the operation of deferral and variance accounts, the applicants may bring these forward for consideration but would have to be assessed on a case by case basis. OEB staff expects that the applicants will take a symmetrical approach to the assessment of impacts to DVAs.

Responses to OEB Directives and Prior Commitments

The applicants noted that both Enbridge Gas and Union Gas have received numerous directives and/or made prior commitments that were to be addressed as part of each utility's respective 2019 rebasing proceeding. Many of the directives and commitments are dependent on a comprehensive review that would occur as part of rebasing.

The applicants intend to respond to two directives during the deferred rebasing term (both of which are Union Gas related directives) and the remaining eleven as part of the 2029 rebasing.[91]

With respect to the two commitments that the applicants intend to respond to during the deferred rebasing period, OEB staff has submissions for each.

Appropriateness of Existing NAC/AU Methodologies

The first directive is for Union to file a study assessing the continued appropriateness of its methodology for determining NAC. The applicants noted that Union will continue to review NAC as a part of Amalco and if changes to NAC are appropriate it will be considered as a part of a future rate proceeding. Through cross-examination, the applicants stated that it is still uncertain whether it will be filing a formal study during the deferred rebasing period or at the time of the next rebasing. The applicants' position is that it is most useful to review the NAC methodology in the context of the amalgamated company.[92] It is OEB staff's understanding that the amalgamated company will look at both the AU and NAC forecasting methodologies for both companies either during the deferred rebasing period or at the time of the next rebasing.

OEB staff have already argued that the forecasting methodologies need to be updated and reviewed. Should the OEB accept staff's submission on a shorter deferred rebasing period, the amalgamated utility can file the updates at the next rebasing. If a longer deferred rebasing period is approved, OEB staff submits that the OEB should order that a

[90] School Energy Coalition IR #45.
[91] Rate Setting Framework Application, Exhibit B, Tab 1, pp. 30-31.
[92] Transcript, Vol. 3, pp. 134-135.

study on the NAC/AU forecasting methodology for the amalgamated company be filed early in the deferred rebasing period (year two or three) as there are clear problems (noted earlier) with the existing methodology.

Review of Panhandle and St. Clair Cost Allocation

The second directive that Amalco proposed to address during the deferred rebasing period is to file a comprehensive review of the Panhandle and St. Clair System cost allocation methodology in the 2019 rates application. In the cost allocation section of this submission, OEB staff argued that in the absence of a full cost allocation study, discrete adjustments to certain assets should not be permitted. As such, OEB staff submits that the review set out in this directive should not be completed until such time that a comprehensive cost allocation study is filed.

Unaccounted for Gas

OEB staff submits that an additional commitment should be addressed during the deferred rebasing term. OEB staff submits that the OEB should order Amalco to file the specified reporting on Unaccounted for Gas (UAF) during the deferred rebasing period that Enbridge Gas agreed to file as part of its 2018 Rates proceeding.[93] Enbridge Gas agreed to review the potential metering issues that might be contributing to UAF and report on that review. OEB staff submits that there is no reason that this commitment could not be fulfilled as part of the 2019 rates proceeding. OEB staff is of the view that Enbridge Gas' response to an interrogatory from OEB staff that this issue is best considered and dependent on a comprehensive review within the eventual amalgamated entity and structure is not convincing.[94] If there are metering problems contributing to UAF, the amalgamated company should review the issue, report to the OEB, and advise how the company intends to address the problem as part of its 2019 rates proceeding (or at the latest as part of the 2020 rates proceeding if there are timing issues).

In regard to the directives/commitments that Amalco proposes to address as part of its next rebasing application[95], OEB staff has no specific concerns. As an example, Enbridge Gas has a directive to file a capital and operating cost benchmarking study. OEB staff is of the view that this is best addressed as part of a rebasing application when the benchmarking information could be used by the OEB in determining whether the proposed capital and operating costs are reasonable.

[93] EB-2017-0086 Settlement Agreement, p. 12.
[94] OEB Staff IR# 59(a).
[95] Rate Setting Framework Application, Exhibit 5, Tab 1, Appendix 5.

Rate Harmonization

The MAADs Handbook notes that a consolidated entity is expected to propose rate structures and rate harmonization plans following consolidation at the time of rebasing. Distributors are not required to file details of their rate-setting plans, including any proposals for rate harmonization, as part of the application for consolidation.[96]

The applicants have not filed a plan to harmonize rates. At the oral hearing, the applicants indicated that Amalco would consider harmonization of rates over the deferred rebasing period, and to the extent that rates can be harmonized, Amalco would bring forward a proposal for consideration of the OEB.[97] The applicants also noted that Amalco could bring forward a harmonization study in the mid-term (five years) of the deferred rebasing period.[98]

OEB staff accepts the position of the applicants but recommends that the applicants should seriously consider rate harmonization for the Enbridge Gas Greater Toronto Area franchise and Union Gas south at the time of rebasing. There is no reason that a ratepayer in Milton should pay different rates than a neighbouring ratepayer in Mississauga when they are both served by the same utility.

Scorecard

The applicants propose a single scorecard for Amalco to measure and monitor performance over the deferred rebasing period. The proposed scorecard is modelled after the electricity distributors' scorecard and includes measures for customer focus, operational effectiveness, public policy responsiveness and financial performance.[99] The scorecard metrics include a combination of existing metrics, Service Quality Requirement (SQRs) and best practice metrics. The applicants assert that the use of existing SQRs will help ensure that Amalco's progress can be compared relative to its predecessors.

While Amalco intends to track the electricity distributors' scorecard in terms of safety, reliability, customer focus and financial performance, it has not proposed to track cost control in the scorecard as is done for the electricity distributors. OEB staff submits that the proposed scorecard should also track cost control measures such as total cost per

[96] Handbook to Electricity Distributor and Transmitter Consolidations, Page 17, January 19, 2016.
[97] Oral Hearing Transcript, Volume 3, page 66, May 14, 2018.
[98] Oral Hearing Transcript, Volume 5, page 13, May 18, 2018.
[99] Report of the Board - Performance Measurement for Electricity Distributors: A Scorecard Approach, March 5, 2014.

customer and total cost per km of distribution pipeline. In addition, OEB staff recommends that the scorecard also track net savings on an annual basis.

Reporting During Deferred Rebasing Period

The applicants propose that Amalco will prepare consolidated utility information for the most recent fiscal year and distribute it annually to stakeholders during the deferred rebasing period. The information to be provided aligns with that currently required of Enbridge Gas pursuant to its 2014-2018 Custom IR plan and Union Gas' pursuant to its 2014-2018 IRM plan, and includes financial reporting and scorecard results as outlined below:

1. Calculation of revenue deficiency / (sufficiency)
2. Statement of utility income
3. Statement of earnings before interest and taxes
4. Summary of cost of capital
5. Total weather normalized throughput volume by service type and rate class
6. Total actual (non-weather normalized) throughput volumes by service type and rate class
7. Total weather normalized gas sales revenue by service type and rate class
8. Total actual (non-weather normalized) gas sales revenue by service type and rate class
9. Delivery revenue by service type and rate class and service class
10. Total customers by service type and rate class
11. Summary revenue from regulated storage and transportation
12. Other revenue
13. Operating and maintenance expense by cost type (actuals only)
14. Calculation of utility income taxes
15. Calculation of capital cost allowance
16. Provision for depreciation, amortization and depletion
17. Capital budget analysis by function
18. Statement of utility rate base (actuals only)

19. Scorecard results.

OEB staff submits that the nature and extent of the proposed reporting structure is acceptable.

Stakeholder engagement during deferred rebasing period

The applicants propose that, during the deferred rebasing period, Amalco will conduct a bi-annual stakeholder meeting to review Amalco's integration results and plans going forward.

The expectation of the applicants is that more meaningful discussions are likely to occur at stakeholder meeting held every two years than at annual meetings. However, the applicants are open to holding stakeholder meetings annually if the approach has general support from intervenors.[100]

OEB staff would prefer an annual stakeholder meeting considering that rates will be adjusted on an annual basis and parties would benefit from the update on the company's efforts to integrate their operations.

Status of Union Gas Undertakings

Under the terms of the Undertakings made by Union Gas and related parties to the Lieutenant Governor in Council, which took effect in 1999, Union Gas is required to maintain its head office in the Municipality of Chatham-Kent. Upon amalgamation, the Undertakings would cease to have effect.[101] However, the applicants have agreed with the Municipality to request that the OEB include conditions in its approval to ensure Amalco maintains a significant presence in Chatham-Kent. The Municipality has advised that it would not object to the merger if such conditions were included.[102]

[100] Argument-in-Chief, Page 32

[101] The Undertakings are found in EB-2017-0306, Exh. B, Tab 1, Att. 8. Article 10.1 provides that Union Gas and its related parties are released from the Undertakings on the day that Westcoast Gas Holdings Inc. no longer holds, directly or indirectly, more than 50% of the voting securities of Union Gas.

[102] The specific wording of the proposed conditions, as agreed by the applicants and the Municipality, can be found in the letter from the Municipality to the OEB dated May 1, 2018. A minor clarifying amendment was proposed by the applicants in their response to undertaking J2.1.

This raises two questions for the OEB: Does the OEB have jurisdiction to include the requested conditions?[103] And, if so, should it include them?

OEB staff submits that the answer to the first question is “Yes”. The OEB has broad authority under the OEB Act to attach conditions to any approval: subsection 23(1) provides that, “The Board in making an order may impose such conditions as it considers proper, and an order may be general or particular in its application.” Although broad, that authority is not, in OEB staff’s view, unlimited. The OEB, in determining what conditions are “proper”, must not lose sight of its statutory mandate. As the Divisional Court noted in *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board* (finding that the OEB had the jurisdiction to approve a rate assistance program for low income gas consumers), “the power granted to a regulatory authority ‘must be exercised reasonably and according to the law, and cannot be exercised for a collateral object or an extraneous and irrelevant purpose, however commendable.”[104]

The proposed conditions are remote from the OEB’s guiding objectives in relation to gas under section 2 of the OEB Act. Nevertheless, that does not, in the unique circumstances of this case, prevent the OEB from approving the proposed conditions. What makes the case unique is that, under the terms of the Undertakings approved by the Lieutenant Governor in Council, the OEB was given a supervisory role. In particular, Article 6.1 provides that “The Board may dispense, in whole or in part, with future compliance by any of the signatories hereto with any obligation contained in an undertaking.” And under Article 8.1, the OEB can compel Union Gas and its related parties to provide any information “related to compliance with these undertakings”. Clearly, then, it was the Government’s intention for the OEB to oversee compliance with the Undertakings, including the specific commitment to maintain the head office in Chatham-Kent. In light of the OEB’s historical role as overseer of the Undertakings, it would be within the OEB’s authority to include conditions in respect of Amalco’s continued presence in Chatham-Kent.

Nevertheless, OEB staff has some concerns about doing so in this case. The conditions are not necessary because the evidence suggests that the applicants are committed to maintaining a significant presence in Chatham-Kent despite the lapsing of the

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[103] The Chair of the OEB panel noted during the hearing that the panel would be interested in submissions on whether the proposed conditions are consistent with the OEB's mandate: Tr. Vol. 1 at pp. 165-166.
[104] (2008), 293 DLR (4th) 684, at para. 58 (citing *Re Multi Malls Inc. et al. and Minister of Transportation and Communications et al.* (1977), 14 O.R. (2d) 49).

Undertakings;[105] indeed there would be significant costs associated with closing down the Chatham-Kent facility.[106] Imposing the conditions might even be seen as frustrating the Government's policy intent. The Government did not have to draft the Undertakings in such a way as to expire upon a change of control, but that is what it decided to do. Moreover, the Government has been aware of the potential merger before these applications were even filed[107] – if the Government wished to ensure there was a continuing legal obligation for Amalco to stay in Chatham-Kent, it presumably could introduce one through legislation or some other binding legal instrument. Yet the Government has not done so, and in OEB staff's view, it is not the OEB's obligation to fill the gap. OEB staff would add that the OEB is above all an economic regulator. If the conditions requested by the applicants and the Municipality were accepted, the OEB might one day, if Amalco applied to reduce its presence in Chatham-Kent, find itself having to arbitrate a situation which may require the weighing of interests that are outside its core expertise.

– All of which is respectfully submitted –

[105] In its EB-2017-0306 application, the applicants note that Union recently invested $17 million on renovations of a facility in Chatham, and commenced construction of another multi-million dollar facility: Exh. B, Tab 1, p. 17.
[106] Tr. Vol. 2 at pp. 12-13; J2.1.
[107] Technical Conference Tr. Vol. 1, p. 73.