June 29, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2017-0306/EB-2017-0307 – Enbridge Gas Distribution Inc. and Union Gas Limited – Reply Argument

On November 2, 2017 in EB-2017-0306 the Applicants, Enbridge Gas Distribution Inc. and Union Gas Limited filed an Application seeking approval to amalgamate pursuant to subsection 43(1) of the Ontario Energy Board Act, 1998 ("OEB Act") and to defer rate rebasing from 2019 to 2029. On November 23, 2017 in EB-2017-0307 the Applicants filed an Application pursuant to subsection 36(1) of the OEB Act seeking approval of a rate-setting mechanism, and associated parameters, to apply during the proposed deferred rebasing period.

In accordance with Procedural Order No. 9, the Applicants filed argument-in-chief on June 1, 2018. Parties filed submissions on June 15, 2018. Enclosed is the reply argument of the Applicants with respect to the above-noted applications.

If you have any questions on this matter, please contact me at 519-436-5334.

Sincerely,

[*original signed by*]

Vanessa Innis
Manager, Regulatory Applications

cc: Andrew Mandyam, EGD
Mark Kitchen, Union
Fred Cass, Aird & Berlis
EB-2017-0306/EB-2017-0307 Intervenors

ONTARIO ENERGY BOARD

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

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

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

REPLY ARGUMENT
OF THE APPLICANTS

A. INTRODUCTION

1. The Applicants, Enbridge Gas Distribution Inc. ("Enbridge") and Union Gas Limited ("Union") filed their argument-in-chief ("AIC") in this combined proceeding on June 1, 2018. Procedural Order No. 9 provides for submissions by intervenors and Board staff to be filed by June 15, 2018 and for reply argument to be filed by June 29, 2018.

2. The Applicants have received the following submissions that were filed pursuant to Procedural Order No. 9:

(i) OEB Staff Submission ("Staff Submission");
(ii) Association of Power Producers of Ontario ("APPrO") submissions ("APPrO Submission");
(iii) Building Owners and Managers Association Toronto ("BOMA") final argument ("BOMA Submission");

(iv) Canadian Manufacturers & Exporters (“CME”) submissions (“CME Submission”);
(v) Consumers Council of Canada (“CCC”) final argument (“CCC Submission”);
(vi) Energy Probe Research Foundation (“Energy Probe”) argument (“Energy Probe Submission”);
(vii) Federation of Rental-Housing Providers of Ontario (“FRPO”) submissions (“FRPO Submission”);
(viii) Industrial Gas Users Association (“IGUA”) argument (“IGUA Submission”);
(ix) Kitchener Utilities (“Kitchener”) final argument (“Kitchener Submission”);
(x) London Property Management Association (“LPMA”) submissions (“LPMA Submission”);
(xi) Municipality of Chatham-Kent (“C-K”) submissions (“C-K Submission”);
(xii) Ontario Greenhouse Vegetable Growers (“OGVG”) submissions (“OGVG Submission”);
(xiii) School Energy Coalition (“SEC”) final argument (“SEC Submission”);
(xiv) TransCanada PipeLines Limited (“TransCanada”) written argument (“TransCanada Submission”); and
(xv) Vulnerable Energy Consumers Coalition (“VECC”) submissions (“VECC Submission”).

3. In this proceeding, the Board combined Applications filed by the Applicants for approval of the amalgamation of Enbridge and Union (the “MAADs Application”) and for approval of a rate mechanism to apply during a 10 year deferred rebasing period (the “Price Cap Application”). The proposals made in the two Applications are intended to advance the Board’s objectives and policy direction for regulation of Ontario utilities. In contrast, the Applicants submit that many of the arguments made in response to the Applications do not reflect the Board’s regulatory objectives and policy direction.

4. The Applicants will begin reply argument by setting out how their proposals are aligned with guidance provided in policy documents and decisions that outline the Board’s approach to regulation. The Applicants will then use the Staff Submission as a general framework within which to address the specific arguments made in the

submissions set out at paragraph 2, above. In their response to specific arguments, the Applicants will touch on areas where those arguments are out of step with the Board's overall approach to regulation and/or contrary to the evidence in the proceeding.

B. BOARD OBJECTIVES AND POLICY DIRECTION

5. The Board has made clear that it intends to bring an outcomes-based approach to the regulation of Ontario utilities. In October of 2012, the Board issued its Report on the *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE", now the *Renewed Regulatory Framework*, or "RRF"). In the RRFE Report, the Board said it "believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation".[1]

6. More recently, the Board issued its *Handbook for Utility Rate Applications* (the "Rate Handbook"). The Rate Handbook applies to all rate regulated utilities[2] and it indicates that, going forward, the RRFE will be known as the RRF.[3] The Rate Handbook reiterates that an important aspect of the RRFE/RRF is the evolution to an outcomes-based approach.[4]

7. This outcomes-based approach creates incentives for utilities and shareholders and also provides robust protections for customers. Incentives give utilities and shareholders the opportunity to achieve and potentially exceed the allowed return on equity ("ROE") through efficiency improvements. Customer protection measures ensure that the risks associated with efficiency investments are borne by utilities and shareholders, that performance is monitored, and that realized efficiencies are built into

[1] RRFE Report, October 18, 2012, page 2.
[2] Rate Handbook, October 13, 2016, page 1.
[3] Rate Handbook, page 4.
[4] Rate Handbook, page 2.

future rates. An Earnings Sharing Mechanism ("ESM") affords *additional* protection by providing customers with the opportunity to share in earnings until the efficiency improvements are incorporated into rates.

8. The Applicants' reliance on incentives as a core element of their proposals is aligned with the view of incentives and performance-based regulation ("PBR") that underlies the Board's outcomes-based approach to regulation. In the RRFE Report, the Board indicated that its rate-setting policy represents a further development of the approach adopted by the Board when it first established PBR for electricity distributors. The Board went on to quote a passage from a January 18, 2000 decision that includes the following comments:

> For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation. It provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies. Customers and shareholders alike can gain from efficiency enhancing strategies that will ultimately yield lower rates with appropriate safeguards for service quality.[5]

9. The Rate Handbook confirms that this approach to regulation applies to all rate-regulated utilities in Ontario. Among other things, the Rate Handbook refers to "key principles" of the RRFE/RRF, one of which is "strong incentives to enhance utility performance".[6]

10. The concept of incentives to drive utility performance is a central feature of the Board's decisions and policies on rate regulation.[7] Indeed, in one decision, the Board

---

[5] RRFE Report, pages 10-11.
[6] Rate Handbook, page 2.
[7] In its argument (at page 44, paragraph 4.2.22), SEC says: "There is nothing wrong with incenting a utility to maximize cost savings. That is, after all, what IRM does, and is the basis for most of the Board's rate-making."

referred to its “regulatory responsibility” to incent or disincent certain types of behaviour by the utility as part of its broad ratemaking authority.[8] The core elements of the Applications are based on these foundational policies, which drive an outcomes-based approach through a focus on incentives and performance.

11. Within this focus on outcomes and incentives, the regulatory framework recognizes a decoupling of costs and rates. In the RRFE Report, the Board noted that PBR decouples the price (the distribution rate) that a distributor charges for its service from its cost. The Board said that this is “deliberate” and is “designed to incent the behaviours described by the Board in 2000”. The Board also said that this approach provides the opportunity for distributors to earn, and potentially exceed, the allowed rate of return on equity.[9] The Applications are consistent with this aspect of regulatory policy as well.

12. The Board’s approach to mergers, acquisitions, amalgamations and divestitures (“MAADs”) complements its ratemaking framework. The Board’s MAADs policies recognize that integration brings additional risks and opportunities for efficiency improvements, and that the right balance of incentives and customer protection can facilitate the achievement of the Board’s overall regulatory goals.

13. While the MAADs policies were developed specifically for the electricity distribution sector, the underlying principles and goals are also applicable to natural gas and therefore the policies should inform the Board’s consideration of the Applications. These principles and goals include economies of scale and contiguity, lower per customer cost, ability to address the challenges of the evolving energy sector, and

[8] EB-2005-0211/EB-2006-0081 Decision and Order, January 30, 2007, page 14.
[9] RRFE Report, page 11.

meeting public policy goals.[10] It is appropriate to consider the current amalgamation and rate mechanism applications under the Board's MAADs policy framework, because the underlying principles and goals of the MAADs policy framework also apply to natural gas and are aligned with the Board's regulatory policy goals more broadly.

14. A similar situation arose when Enbridge applied for approval of a Custom Incentive Ratemaking ("IR") proposal under the RRFE, in advance of the framework being explicitly applied to natural gas utilities. In that case, the Board determined that the approach was appropriate because the "RRFE Report is the natural evolution of the Board's thinking in the areas of both natural gas and electricity rate-setting".[11]

15. The RRF is an example of how policies developed for one sector (either natural gas or electricity) have been adopted in the other. The Rate Handbook is another example of the Board's efforts to move towards harmonization in its regulation of gas and electricity utilities. The Rate Handbook outlines the key principles and expectations the Board will apply when reviewing rate applications and, as noted above, the Rate Handbook is applicable to all rate regulated utilities.[12] Further, as pointed out in the Staff Submission, the Incremental Capital Module ("ICM") was first developed for electricity distributors,[13] but reference is made to it in the RRF[14] and the Rate Handbook,[15] both of which apply to gas distributors.[16]

16. As the regulatory framework and policies continue to evolve, the Board has increasingly been articulating its approach in terms of the overall energy sector. The

[10] *Handbook to Electricity Distributor and Transmitter Consolidations,* Ontario Energy Board, January 19, 2016, page 1.
[11] EB-2012-0459, *Decision with Reasons*, July 17, 2014, page 5.
[12] Rate Handbook, page 1.
[13] Staff Submission, page 22.
[14] See, for example, RRFE Report, at pages 13, 18, 20 and 22.
[15] See, for example, Rate Handbook, Appendix 2, pages iv-v and Appendix 3, page i.
[16] OEB Staff "acknowledges the discussions in the Rate Handbook, extending the ICM to … natural gas distributors": Exhibit C.STAFF.26, page 1.

Board's approach to regulatory evolution is most recently expressed in the *Strategic Blueprint: Keeping Pace with an Evolving Energy Sector 2017-2022*, in which the Board's Vision is stated as follows: "The OEB supports and guides the continuing evolution of the Ontario energy sector by promoting outcomes and innovation that deliver value for all of Ontario energy consumers."[17]

17. The Board's focus on outcomes, innovation, and value for Ontario energy consumers is clearly directed at both the electricity sector and the natural gas sector. A compartmentalized view of the application of Board policies, as suggested by many of the intervenor submissions, is out of step with the efforts of the Board to exercise its regulatory mandate in a way that drives positive outcomes and delivers value for the Ontario energy sector at large.

18. The Chair's Message at the front of the *Strategic Blueprint* makes clear the integrated and broad reaching nature of the challenges ahead:

> The Blueprint reflects the OEB's recognition of the significant changes underway in the energy sector, not only in Ontario but around the globe. These changes are being driven by rapid technological innovation, the emergence of new business models, heightened customer expectations about service and affordability, and new public policy initiatives, particularly regarding carbon emissions and climate change.[18]

19. The Applicants have applied for consideration of their amalgamation and rate framework proposals within this broad regulatory policy context and under the specific MAADs and RRF policies. Wherever possible, the Applications have been aligned with

---

[17] *Strategic Blueprint: Keeping Pace with an Evolving Energy Sector 2017-2022*, Ontario Energy Board, page 10.
[18] *Strategic Blueprint*, page 1.

the Board's policies and guidance, with modifications where necessary on the basis of the specifics of the Applications.

20. The Applicants' proposals, which are consistent with the Board's frameworks and policies, result in effective incentives for the utilities and shareholders and ensure value and protection for consumers. In contrast to the proposals in the Applications, a number of the intervenor submissions, particularly those that propose no deferred rebasing, a shorter term, a large stretch factor, and/or significant base rate adjustments, run counter to the Board's policy direction for utility regulation. In the broadest sense, many of these proposals move away from a focus on outcomes and customer value to an older form of line-by-line cost-based regulation, where rates and costs are no longer decoupled, incentives are largely removed, and customers potentially bear more risk for less value. More specifically, these intervenor proposals create disincentives to amalgamation and the corresponding pursuit of deep synergies (or reduce the incentives significantly) in ways which do not in the end protect consumers or ensure value for them. Further, these proposals do not reflect the changes taking place within the broad energy sector that the Board considers in its approach to regulation.

21. The Applicants are committed to achieving customer outcomes and an incentive based approach to regulation. Three key elements work together to allow Amalco to drive the optimal level of long term synergies: an appropriate deferred rebasing term, an appropriate Price Cap formula, and an effective ESM. The combination of these three elements achieves a balance between customer protection and shareholder incentives.

22. This reply argument will address the Applicants' need for a 10 year deferred rebasing period due to the complexity of the integration and to ensure adequate time to invest in integration savings and earn an appropriate incentive. Further, the argument will address the 0.3% stretch factor proposed by OEB Staff and explain how it is unreasonable and unmanageable. In the Applicants' view, any concerns around the

appropriate balance of customer protection and incentives should be addressed through an appropriately structured ESM, and not through adjustments to the proposed deferred rebasing term or the level of stretch factor.

23. In reply argument, the Applicants are proposing some modifications to their proposals. These modifications (including using the ESM as the primary customer protection mechanism, a higher Z factor threshold, and commitments related to cost allocation and rate design) over the 10 year deferred rebasing period address the concerns raised by intervenors, in a way that is aligned with the Board's regulatory goals and principles.

24. Many of the specific proposals are discussed in more detail throughout this reply argument.

C. REPLY TO ARGUMENTS ON SPECIFIC ISSUES

25. As stated above, the Applicants will use the Staff Submission as a general framework to address the submissions that have been made in response to the Applicants' proposals. The Staff Submission begins with a section on Background that refers to the determinations made by the Board in Decision and Procedural Order No. 3 ("PO 3") regarding the no harm test and the MAADs policies.[19]

26. In line with the general sequence of the Staff Submission, the Applicants will begin by addressing the no harm test. The Applicants' submissions on the no harm test will lead into their response to new evidence and calculations presented in argument by SEC, after which the Applicants will return to the MAADs policies and continue with submissions based on the general order of arguments in the Staff Submission.

[19] Staff Submission, page 3.

1. The No Harm Test

27. The Staff Submission refers to the Board's determination in PO 3 that the no harm test will be used for assessing the amalgamation. The Staff Submission goes on to note that the test considers whether a proposed transaction will have an adverse effect on the attainment of the Board's statutory objectives in relation to gas, as set out in section 2 of the *Ontario Energy Board Act, 1998* (the "OEB Act").[20] Further, OEB Staff point out that, in applying the no harm test, the Board has focused on the objectives that are of most direct relevance to the proposed transaction, which, in the gas context, are price, reliability and quality of gas service, and financial viability.[21]

28. OEB Staff's conclusion with regard to the potential effect of the proposed amalgamation on the attainment of the Board's statutory objectives is that few concerns have been raised in this case about the reliability and quality of gas service or financial viability. According to OEB Staff: "The main issue is price".[22]

29. On the issue of "price", OEB Staff submit that the merger will result in synergy-related savings. As stated in the Staff Submission, it stands to reason that the underlying cost structures of the consolidating utilities will change for the better as synergies are achieved. Indeed, the Staff Submission says that the underlying cost structures will decrease "substantially". OEB Staff therefore support the proposed amalgamation as it will likely decrease the underlying cost structures.[23]

30. It is of particular interest that the Staff Submission adopts the approach of considering the impact of the proposed amalgamation on "underlying cost structures".

[20] Staff Submission, page 4.
[21] Staff Submission, page 5.
[22] *Ibid*. See also SEC Submission, page 16, paragraphs 2.2.6-2.2.7.
[23] *Ibid*.

As noted by OEB Staff,[24] this approach comes from the *Handbook to Electricity Distributor and Transmitter Consolidation* (the "MAADs Handbook"), where the Board indicated that, in considering the issue of "price" in a MAADs proceeding, it will assess the underlying cost structures of the consolidating utilities.[25] OEB Staff's reliance on the guidance in the MAADs Handbook with regard to underlying cost structures is an example of the value that the MAADs policies bring to consideration of a proposed MAADs transaction involving gas distributors.[26]

31. The conclusion reached by OEB Staff in this case with regard to underlying cost structures is much like the finding of the Board in another proceeding that was discussed in AIC. More specifically, the AIC includes a discussion of the Board's Decision and Order in the EB-2016-0025/EB-2016-0360 proceeding (referred to in AIC as the "Alectra Decision"),[27] in which the Board found that the scale enhancements of service delivery embedded in the proposed transaction could be expected to result in long term benefits to customers.[28]

32. A number of intervenors have come to similar conclusions about the amalgamation proposed by the Applicants. OGVG accepts that, ultimately, the result of merging Union and Enbridge will likely result in no long term harm to ratepayers in view of the sustainable cost savings that Amalco should be able to achieve directly as a result of the ability of the Applicants to combine their operations.[29] CME says that the merger of the two utilities should produce opportunities in increased productivity with the

---

[24] *Ibid*.
[25] MAADs Handbook, page 6.
[26] The Staff Submission also draws on the guidance provided by the MAADs Handbook when it addresses the subject of rate harmonization by Amalco: Staff Submission page 40.
[27] EB-2016-0025/EB-2016-0360 Decision and Order, December 8, 2016.
[28] AIC, page 8, paragraph 23.
[29] OGVG Submission, pages 8-9.

potential to reduce gas rates in Ontario.[30] IGUA foresees no harm, and indeed sees benefits for ratepayers from, the proposed amalgamation.[31]

33. Surprisingly, though, at least one intervenor, against all the weight of the evidence in this case, attempts to question the benefit of the proposed amalgamation. LPMA asserts that the Board should not consider "temporary rate impacts" as demonstrative of no harm[32] and goes so far as to refer to "probably imaginary savings".[33] It is telling that, immediately before its reference to "probably imaginary savings", LPMA contends that ratepayers should get to share in the savings "up front".[34] The Applicants submit that no credence whatsoever should be given to submissions that propose an "up front" share of savings while, at the same time, asserting that the savings are "probably imaginary".

34. In short, no credible argument has been made in this case to challenge the Applicants' position that the proposed amalgamation meets the no harm test. The Applicants submit that the only reasonable conclusion on the record of this case is that the no harm test has been met and, accordingly, the Board should approve the amalgamation.

2. New Evidence in SEC Submission

35. Much of the SEC Submission is focused on a discussion of the stand-alone scenario presented by the Applicants in their evidence in support of the MAADs Application. The stand-alone scenario was developed for the purposes of the no harm test, and, specifically, to address whether the proposed amalgamation will have any

[30] CME Submission, page 5, paragraph 13.
[31] IGUA Submission, page 1, paragraph 4.
[32] LPMA Submission, page 10.
[33] LPMA Submission, page 14.
[34] *Ibid*.

adverse effect on the attainment of the Board's statutory objective with regard to "price".[35]

36. As stated by FRPO in its submissions, the Board applies the no harm test by comparing the effect of the proposed transaction to the status quo.[36] The Applicants compared the forecast revenue for Amalco as an amalgamated entity with the annual revenue requirement for Enbridge and Union, were they to continue as stand-alone entities. The result of that comparison is that customers will be better off by $410 million if the amalgamation proceeds.[37] The Applicants put forward this analysis in support of their conclusion that the proposed amalgamation meets the no harm test with respect to "price".[38]

37. Obviously, in a case seeking approval of an amalgamation, it is not possible for the applicants to bring forward, for comparison purposes, the full and detailed evidence that the consolidating utilities would develop to support applications in a scenario where they continue as stand-alone entities. Nevertheless, the Applicants in this case developed a reasonable basis for comparison of the effect of the proposed amalgamation to the status quo.

38. While there have been criticisms levelled at the Applicants' comparison of the proposed amalgamation to the stand-alone scenario, similar criticisms were made in the Alectra proceeding, and in that case, the Board said that the cost estimates provided by the consolidating entities were a sufficiently accurate basis for its analysis.[39] In any event, regardless of these criticisms, OEB Staff and many intervenors accept that the proposed amalgamation meets the no harm test and, as discussed above, no credible

[35] EB-2017-0306 Exhibit ("MAADs Exhibit") B-1, pages 20-23.
[36] FRPO Submission, page 1, paragraph 2.2.
[37] MAADs Exhibit B-1, pages 20-22.
[38] MAADs Exhibit B-1, page 23.
[39] AIC, page 8, paragraph 22.

argument has been made in this case to challenge the Applicants' position that the no harm test has been satisfied.

39. For its part, SEC refers to economies of scale and says there is little doubt the consolidation of Union and Enbridge allows the combined entity to realize efficiencies and thus generate a lower cost per customer.[40] Indeed, according to SEC, all parties appear to agree that there are economies of scale.[41] SEC submits that, but for request for a 10 year deferred rebasing, the MAADs Application meets the no harm test.[42]

40. Despite SEC's submission that, but for the deferred rebasing request, the MAADs Application meets the no harm test, the SEC Submission includes a speculative re-casting of the stand-alone scenario. SEC discusses its "Gives and Gets Summary" briefly and then sets out a series of assertions about the stand-alone scenario that have no basis in the evidence in this proceeding.

41. As stated in AIC, counsel for SEC was unsuccessful in eliciting evidence to support the insertion of meaningful financial data in a number of categories of SEC's Gives and Gets Summary.[43] The SEC Submission says that the Gives and Gets Summary is a "simplistic approach" and that a better way to test the Applicants' proposal is to "recast the standalone straw man".[44] But, in doing so, the SEC Submission moves from an approach for which SEC at least attempted (without success) to build an evidentiary basis during cross-examination (the Gives and Gets Summary) to a new approach (referred to by SEC as the "Realistic Standalone Model") which SEC has not even attempted to test with the witnesses.

[40] SEC Submission, page 18, paragraph 2.4.8.
[41] *Ibid*.
[42] SEC Submission, page 16, paragraph 2.2.8.
[43] AIC, page 7 paragraph 19. See 6 Tr. 54 and 89-90.
[44] SEC Submission, page 35, paragraphs 3.4.1 and 3.4.2

42. Given that SEC has posited its new approach in final argument, rather than during the evidentiary phase of this proceeding, the Applicants will not provide a point by point discussion of what the evidence would have been if the new approach had been tested with the witnesses. Instead, the Applicants will provide examples of incorrect assumptions and calculations in the new approach which are sufficient to demonstrate that SEC's attempt to re-cast the stand-alone scenario without a proper evidentiary basis cannot and should not be given any weight in this case.

43. In SEC's discussion of the stand-alone scenario, a key area of focus is income taxes, and SEC claims that an "overstatement of the tax provision" in the stand-alone scenario is almost twice the ratepayer benefit.[45] The assertions that lead SEC to this claim primarily involve a comparison of Enbridge's effective income tax rate for periods prior to 2019[46] with the tax rate assumed in the stand-alone scenario.[47] However, SEC's discussion of income taxes does not account for the fact that $379 million[48] in tax deductions associated with Enbridge's refund of Site Restoration Costs ("SRC") - which will conclude at the end of 2018 - have significantly lowered Enbridge's historic average effective tax rates. The reduced effective tax rate will not persist into the deferred rebasing period because the deductions will no longer exist.

44. Further, although SEC alludes to a "high capital spend in the last few years" and the consequential "tax shield" effect,[49] SEC's discussion takes no account of significant IT spending[50] by Enbridge in recent years that, due to advanced tax deductibility, has lowered historical effective tax rates to an extent that is not expected to be replicated during the deferred rebasing period. And, to give one more example of problems with

[45] SEC Submission, page 29, paragraph 3.2.23.
[46] SEC Submission, pages 27-28, paragraphs 3.2.18-3.2.19.
[47] SEC Submission, page 28, paragraphs 3.2.19-3.2.21.
[48] Exhibit C.SEC.40, Attachment 1, page 6
[49] SEC Submission, page 36, paragraph 3.4.11.
[50] Specifically, spending on Customer Information System ("CIS") and Work and Asset Management System ("WAMS") capital projects.

SEC's calculations, the Applicants note that effective tax rates for 2019 and later are materially lower than the rates calculated by SEC when properly calculated on the basis of the grossed-up ROE amount.

45. The Applicants submit that the Board cannot and should not give any weight to the new approach proffered by SEC in final argument that does not have an evidentiary foundation and was not tested with the witnesses in this proceeding.

3. MAADs Policies

46. In its submissions with regard to the MAADs policies, IGUA observes that the Applicants "appear to maintain" their position that the MAADs Handbook applies to the proposed amalgamation.[51] With particular reference to the Applicants' selection of a 10 year deferred rebasing period, IGUA refers to PO 3 and says that the Board has "already clearly ruled" on the applicability of the MAADs Handbook.[52]

47. The Applicants maintain their position that the MAADs policies apply to the proposed amalgamation. The AIC sets out the Applicants' reasoning in support of the conclusion that the MAADs policies can and should be applied in this case[53] and, the submissions filed in response to the AIC leave many of the points made by the Applicants unanswered.

48. With respect to IGUA's reliance on PO 3, the words of the particular passage from PO 3 relied upon by IGUA belie IGUA's proposition that the Board has ruled on the applicability of the MAADs Handbook. In that passage, the Board said that "all aspects" of the MAADs Handbook do not "automatically apply" to natural gas and that issues

[51] IGUA Submission, page 3, paragraph 12.
[52] IGUA Submission, page 3, paragraphs 13-14.
[53] AIC, pages 11-15, paragraphs 31-44.

such as the deferral period and ESM are legitimate areas of enquiry and are not "pre-determined" in this case.

49. The statements in PO 3 relied on by IGUA make clear that the Board has been careful not to apply policies automatically or to pre-determine the application of policies and thus the Board has avoided not only a fettering of discretion, but even any perception of a fettering of discretion. However, statements that all aspects of MAADs policies do not apply "automatically" in this case, and that the application of policies has not been "pre-determined", are by no means a final determination with respect to the application of the policies.

50. The fact that the Board has not made a final determination with respect to the application of the MAADs policies is confirmed by the statement in PO 3 that the Board "will not restrict the ability of OEB Staff and intervenors to question the applicability of the policies within the electricity MAADs policy framework".[54] The indication from the Board that it will not restrict the ability of parties to question the applicability of the MAADs policies simply cannot stand together with IGUA's notion that the Board has "already clearly ruled" on the application of the policies.

51. The most extensive submissions made in response to AIC on the applicability of the MAADs policies are those of CME. The Applicants disagree with every branch of CME's argument that the MAADs policies are not applicable to the proposed amalgamation.

52. CME submits that a "proper interpretation" of the MAADs Handbook is that it applies only to the "entities" specifically referred to in it.[55] Yet, the RRFE Report, which

[54] PO 3, page 4.
[55] CME Submission, pages 7-8, paragraphs 22-24.

specifically and extensively refers to electricity distributors, introduced the Custom Incentive Rate-making ("IR") method of setting rates and the first Custom IR plan approved by the Board was one proposed by Enbridge.[56] The Rate Handbook explicitly points out that Enbridge applied to the Board "using the principles of the RRFE".[57]

53. CME submits that the Applicants' points about the applicability of MAADs policies have ignored the Board's practice of proactive communication of changes that expand the application of Board policies.[58] CME's assertion about proactive communication relies on the paragraph of the Rate Handbook which states that the RRFE will be applied to all regulated utilities going forward.[59] But the decision approving Enbridge's Custom IR came more than two years before the explicit statement in the Rate Handbook about the application of the RRFE to all regulated utilities.[60]

54. CME submits that the Rate Handbook is not simply a recitation of requirements that are common to the electricity and gas sectors, but includes policies that are "applicable to only one of the regulated industries".[61] It is indeed the case that particular provisions of the Rate Handbook explicitly differentiate between electricity utilities and gas utilities.[62] However, the section of the Rate Handbook under the heading "Mergers, Acquisition, Amalgamations and Divestitures (MAADs)" makes no differentiation at all between electricity and gas utilities.[63] Further, as pointed out in AIC, the section of Appendix 3 to the Rate Handbook entitled Rate-setting Policies for Consolidations similarly does not differentiate between electricity and gas utilities, except that specific

---

[56] EB-2012-0459 Decision with Reasons, July 17, 2014.
[57] Rate Handbook, page 4.
[58] CME Submission, page 8, paragraph 25.
[59] *Ibid*.
[60] As set out in footnotes above, the decision approving Enbridge's Custom IR application was issued on July 17, 2014 and the Rate Handbook was issued on October 13, 2016.
[61] CME Submission, page 8, paragraph 24.
[62] See, for example, pages 23-25 of the Rate Handbook.
[63] Rate Handbook, page 21.

reference to electricity distributors is made in the third sentence of this section (on the subject of an ESM).[64]

55. CME's submissions include a series of assertions under a heading which suggests that CME intends to address whether the MAADs Handbook applies to the proposed amalgamation "on a principled basis".[65] However, in AIC, the Applicants set out a principled basis for the application of the MAADs policies in this case[66] and CME makes no attempt to address the Applicants' points.

56. The first paragraph of the "principled basis" put forward by CME says that the MAADs Handbook was developed in response to an issue that was specific to Ontario's electricity distributors. The concluding paragraph of CME's "principled basis" says that, if the proposed amalgamation is approved, there will be only two gas distributors in Ontario and the disparity in size between them may make comparisons difficult.[67]

57. It is clear that these propositions do not shed any meaningful light on the applicability of the MAADs policies, because, if they did, they would have to be taken as an indication that the MAADs Handbook does not apply to transactions involving Hydro One's electricity transmission operations. Hydro One's transmission operations are vastly larger than those of any of the very small number of other electricity transmitters in Ontario and an issue specific to electricity distributors would not be at play in an electricity transmission MAADs transaction. But, as addressed in AIC, the policies set out in the MAADs Handbook were applied by the Board in its decision with respect to the acquisition of Great Lakes Power Transmission by Hydro One Inc.[68]

---

[64] AIC, page 12, paragraph 35.
[65] CME Submission, at pages 9-11, section 4.2, "The Electricity Handbook Does Not Apply on a Principled Basis".
[66] AIC, pages 13-14, paragraphs 38-42.
[67] CME Submission, pages 9-11, paragraphs 28-38.
[68] AIC, page 14, paragraph 43.

58. The arguments made by CME simply do not support CME's contention that the MAADs policies are not applicable to the proposed amalgamation. On the contrary, given the shortcomings in CME's arguments discussed above, reliance on such arguments to support the position that the MAADs policies are not applicable does more to expose that position as a weak one than it does to advance CME's contention.

4. Deferred Rebasing Period

59. The 10 year deferred rebasing term is necessary. Ten years will allow Amalco to achieve the maximum benefits for customers while recognizing the complexity of the integration and allowing Amalco to take on the investment risk.

60. According to the Staff Submission, 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, but were persuaded that a shorter period is warranted by issues raised at the hearing.[69] The primary issue that caused OEB Staff to favour a deferral period of less than 10 years seems to be the length of time that revenues will be decoupled from costs if the 10 year deferral is approved.[70]

61. The Applicants submit that, on the subject of decoupling revenues from costs, it is important to bear in mind that the MAADs Handbook gives consolidating distributors a right to select a deferred rebasing period of up to 10 years. Leaving aside altogether the application of the MAADs policies to the proposed amalgamation in this case, it is clearly the intent of the MAADs Handbook, that, in cases to which it applies, decoupling

[69] Staff Submission, page 8.
[70] *Ibid*.

of revenues and costs can continue for as long as 10 years *plus* the period of time since the last cost of service rebasing for any one of the consolidating utilities.

62. In other words, it is to be expected that rebasing deferrals that accord with the provisions of the MAADs Handbook can or will result in a decoupling of revenues from costs for more than 10 years. Any suggestion that decoupling revenues from costs for more than 10 years is problematic, simply by reason of the length of the decoupling period, is not consistent with the MAADs Handbook.

63. As appears from the Alectra decision, which was released on December 8, 2016, the Applicants in that proceeding proposed a rebasing deferral for the consolidated entity for 10 years from the date of closing of the last of the transactions needed to complete the consolidation.[71] The Board approved this proposal.[72] The Board had previously approved a deferral of 2017 rebasing for one of the consolidating parties, Enersource Hydro Mississauga Inc. ("Enersource").[73] Enersource's prior cost of service proceeding was heard in 2012 and was the subject of a decision issued by the Board on December 13, 2012.[74]

64. OEB Staff's arguments about the proposed rebasing deferral period touch on cost allocation issues that have been raised in this case. However, in AIC, the Applicants committed that Amalco will carry out a cost allocation study. This study will provide visibility on differences in the allocation of costs from the last Board-approved study for each of Union and Enbridge and, if deemed appropriate by the Board, it could be used to address whether there should be any rebalancing of rates.[75]

[71] Alectra decision, *supra*, at page 17.
[72] Alectra decision, pages 18-19.
[73] EB-2015-0065 Decision with Reasons, April 7, 2016, page 2.
[74] EB-2012-0033 Decision and Order.
[75] AIC, page 29, paragraph 93.

65. The Staff Submission does not mention the commitment made in AIC.[76] On the contrary, OEB Staff's arguments about cost allocation and rate design set out later in the Staff Submission begin with the statement that: "The Applicants do not intend to undertake a complete cost allocation study during the deferred rebasing period."[77]

66. The Applicants submit that their commitment to cost allocation studies answers the points about cost allocation raised by OEB Staff, as well as arguments about cost allocation put forward by a number of intervenors. Further, the Applicants submit that the Board can give little or no weight to arguments about cost allocation when it is not possible to discern whether, in the formulation of such arguments, any consideration was given to the Applicants' commitment to carry out cost allocation studies. And arguments explicitly based on the incorrect premise that the Applicants do not intend to undertake a complete cost allocation study clearly carry no weight at all.

67. In its argument, APPrO says that a commitment by the Applicants to undertake a cost allocation study "at some point during the deferred rebasing period, perhaps at the five year point" is not sufficient.[78] APPrO has incorrectly connected proposals around rate harmonization and cost allocation referred to in paragraphs 92 and 93 of AIC.

68. For greater clarity, and in response to submissions by OEB Staff and intervenors such as Kitchener about a 10 year deferred rebasing period without review of cost allocation, the Applicants propose that Amalco prepare cost allocation studies twice during the 10 year deferred rebasing period. Each of the cost allocation studies will be

[76] Note that the Staff Submission, at page 9, footnote 16, refers to the Applicants' oral testimony about a review of cost allocation methodologies in the context of rate harmonization. This oral testimony is addressed in the AIC at page 29, paragraph 92. However, there is no indication in the Staff Submission that OEB Staff gave any consideration to the commitment made in AIC at page 29, paragraph 93.
[77] Staff Submission, page 28.
[78] APPrO Submission, page 10, paragraph 35.

the subject of a consultative process with intervenors and will be submitted for review by the Board.

69. More specifically, the Applicants propose that Amalco will prepare cost allocation studies for each of the years 2022 and 2026 using Board-approved methodologies. The cost allocation studies will be prepared based on an internal forecast of costs for each year proportionately adjusted to equal the forecast of revenue for the year as determined through the approved rate setting mechanism. The cost allocation studies will exclude amalgamation integration savings and costs.

70. On the basis of Board-approved rate design methodology, Amalco will derive rates for each rate class from results of the cost allocation studies. Amalco will engage OEB Staff and intervenors in a consultation on the rates derived from each cost allocation study and the rates derived from the rate setting mechanism. The cost allocation study results for 2022 will be provided for review and consultation early in 2021 and the cost allocation study results for 2026 will be provided early in 2025.[79] While this proposal is made in recognition of intervenor concerns, a guiding principle of the consultation process will be to keep Amalco whole with respect to its revenue forecast for any prospective or forward-looking shift of costs between rate classes as a result of the cost allocation study and resulting rates.

71. OEB Staff's arguments about the deferred rebasing period similarly overlook the AIC on the subject of average use ("AU") and Normalized Average Consumption ("NAC"). It is apparent from the Staff Submission that, in coming to the conclusion that the deferred rebasing period should be less than 10 years, OEB Staff assumed that

[79] Note that the timeline associated with completion of a cost allocation study is relatively consistent with the timeline required to produce a rebasing application. Thus, the first cost allocation study by Amalco proposed by the Applicants will be completed in roughly the same period as would be required for Amalco to file a rebasing application.

AU or average consumption will "only be examined at rebasing".[80] To the contrary, though, the Applicants proposed in AIC that Amalco will consult with stakeholders as it works towards a single, revenue-neutral approach to AU/NAC for a future rate application.[81]

72. OEB Staff submit that a six year deferral period is appropriate. They say they are not convinced that "management integration" will take longer than five years and assert that most of the integration will be complete by 2024.[82] In fact, as discussed in AIC, the overall range for execution and stabilization in the Moderate/Aggressive scenario is seven years and in the Low/Moderate scenario it is eight years. The evidence is that the stabilization period is a critical piece of the implementation of systems and processes and, further, that the Moderate/Aggressive scenario is very aggressive and is something that neither utility has done before.[83] OEB Staff's submissions about the period of time required to complete the integration are not based on any evidence in this case and do not consider the complexity involved in the integration, which is discussed in further detail below.

73. OEB Staff also submit that, by 2024, Amalco will have attained a net benefit from the costs and savings of amalgamation.[84] For the purpose of this submission, OEB Staff rely on a table using integration investment and savings amounts that were discussed during OEB Staff's cross-examination of the Applicants' witnesses. The synergy savings shown in the table total to a cumulative amount of $680 million. As Mr. Reinisch pointed out during cross-examination, this amount is at the high end of the range of savings estimated by the Applicants, which is $350 million to $750 million.[85]

[80] Staff Submission, page 8.
[81] AIC, page 30, paragraph 97.
[82] Staff Submission, page 9.
[83] AIC, pages 16-17, paragraphs 49-50.
[84] Staff Submission, page 9.
[85] 2 Tr. 84.

Indeed, the $680 million amount includes unidentified efficiencies of $60 million added to the Applicants' forecasts of savings that can be achieved in particular areas.[86]

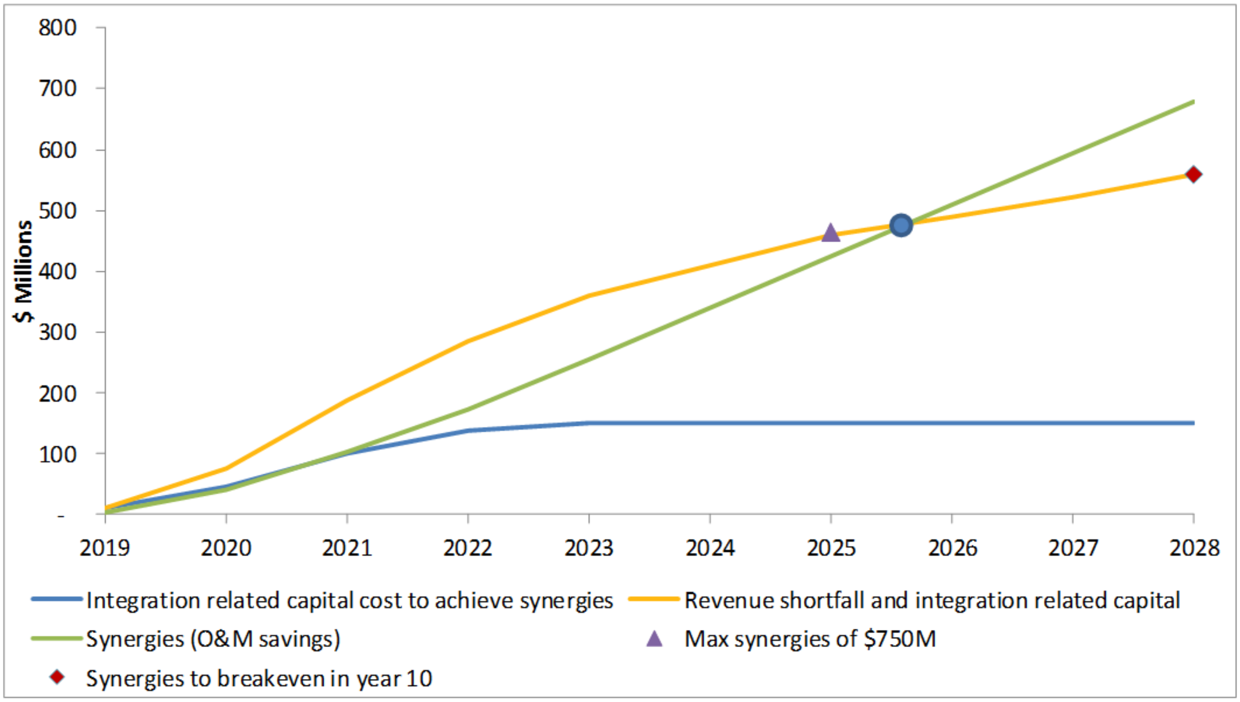
74. Further, Mr. Reinisch explained during cross-examination that savings from the integration are assumed in the Applicants' forecasts to be available to allow Amalco to earn its allowed ROE.[87] Mr. Kitchen elaborated on this point in the following testimony:

> …this doesn't reflect the simple payback of the two streams of cost and benefits, because you have to take into account the fact that not only are we making these investments in technology and processes to get a benefit, but we're also continuing to run a base business and that base business requires us to use the synergy savings in order to maintain our allowed ROE.[88]

75. As a result of the cross-examination by OEB Staff, the Applicants gave Undertaking J2.4 to present a full representation of the forecast payback period.[89] And, in response to the Undertaking, the Applicants did, in fact, provide graphs and tables that incorporate the numbers relied on in the Staff Submission into a full representation of the forecast payback scenario. Graph 1, copied below, shows Case A with $150 million capital investment and $680 million Net O&M savings.

---

[86] Exhibit B-1, Attachment 12, "Additional Unidentified Efficiencies".
[87] 2 Tr. 81.
[88] 2 Tr. 82.
[89] 2 Tr. 88-89.



76. The first table provided in the response to Undertaking J2.4 is as follows:

A Base Case: $150M/$680M (capex/synergies)

	Payback Net cash flow approach ($ Millions)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Source/Calculation
A.1	Revenue shortfall to meet allowed ROE	1	28	59	62	60	50	49	30	34	38	Exhibit B, Tab 1, Table 3
	Cumulative	1	29	87	149	209	260	309	338	372	410	
A.2	Integration related capital cost to achieve synergies	11	36	53	37	13	-	-	-	-	-	Exhibit B, Tab 1, Attachment 12
	Cumulative	11	47	100	137	150	150	150	150	150	150	
A.3	Revenue shortfall and integration related capital	12	64	112	99	73	50	49	30	34	38	Line A.1 plus Line A.2
	Cumulative Shortfall	12	76	187	286	359	410	459	488	522	560	
A.4	Synergies (O&M savings)	3	38	63	70	81	85	85	85	85	85	Exhibit B, Tab 1, Attachment 12
	Cumulative	3	41	104	174	255	340	425	510	595	680	
A.5	Gap - synergies vs revenue shortfall and integration related capital	(9)	(35)	(83)	(112)	(104)	(70)	(34)	22	73	120	Cumulative A.4 less Cumulative Shortfall (A.3)

77. As stated in the response to Undertaking J2.4:

(i) for Case A, the Crossover Point for Amalco is 7.5 years into the ten year term; the 7.5 year mark is when Amalco is forecasted to recover the cost to operate its base business and recover its integration capital outlay;

(ii) Graph 1 also shows two sensitivities for Case A; the triangle mark found at year 2025 on the yellow line identifies a payback period of 7 years should Amalco outlay $150 million in capital investment and achieve the maximum forecasted savings of $750 million; and

(iii) the diamond mark found at year 2028 of the yellow line identifies that if Amalco spends $150 million in capital investment and achieves savings of $560 million, the payback period would be 10 years.

78. Based on the evidence of the Applicants, the graph and table set out above are the appropriate representation of a forecast payback period using the integration cost and savings amounts set out in the Staff Submission. The Applicants note the length of the payback period is highly dependent on the amount and timing of capital spent savings achieved. Obviously this does not support the views expressed by OEB Staff about a deferred rebasing period of six years; on the contrary, it supports the 10 year deferral proposed by the Applicants.

79. The Board scheduled a partial day of hearing for the specific purpose of cross-examination on undertaking responses,[90] and OEB Staff took the opportunity to cross-examine on the response to Undertaking J2.4. During that cross-examination, the Applicants explained the difference between a payback calculation based simply on a cash flow calculation and a calculation that takes account of the ability of Amalco to earn the allowed ROE. For example, Mr. Reinisch explained the distinction in the following testimony:

> …two different concepts. One is a cash flow break-even type concept, which strictly takes cash flows and determines a break-even point, whereas the presentation we provided to the Board … is based on the results for each given year and the ROE that comes out of the revenues that we'll be collecting from customers less the costs that we will be incurring.[91]

[90] Procedural Order No. 8, May 9, 2018, page 1.
[91] 6 Tr. 111.

80. This sequence of evidence – cross-examination at the hearing, undertaking response and cross-examination on the undertaking response – was triggered by OEB Staff seeking to put forward a view of the payback period that, according to the testimony given in response to OEB Staff's questions, fails to present "the whole picture".[92] Nevertheless, OEB Staff do not address the sequence of evidence triggered by their questions and, in particular, the Staff Submission does not address, nor even allude to, the response to Undertaking J2.4. Put simply, OEB Staff's approach to the payback period fails to include consideration of Amalco's ability to earn the Board-approved ROE.

81. The graphical representation shows how three key elements, namely ESM, deferred rebasing period and Price Cap formula, work together. The payback period reflects the need for a 10 year deferred rebasing period with a Price Cap formula that includes zero stretch factor. An appropriate ESM provides the OEB with confidence that there is an adequate level of consumer protection over the deferred rebasing period.

82. Certain intervenors argue that rebasing should occur immediately, or as soon as is possible or practical.[93] The Applicants submit that these arguments for a rebasing at the earliest opportunity fail to address the incentive that is inherent in a 10 year deferred rebasing period and the risks that are associated with the integration of Enbridge and Union. These approaches are contrary to the Board's policies that focus on incentives, outcomes and performance, both in ratemaking generally and in relation to MAADs specifically.

[92] 2 Tr. 88.
[93] APPrO Submission, page 10, paragraph 35; BOMA Submission, pages 8-9; CCC Submission, page 8; CME Submission, page 6, paragraph 18; Energy Probe Submission, page 3, FRPO Submission, page 3, para. 3.3; Kitchener Submission, pages 2-8; and SEC Submission, page 44.

83. There surely can be no doubt that the integration of Enbridge and Union is a complex and significant undertaking. The point of the 10 year deferred rebasing period is to provide not only the time-frame, but also the incentive, for Amalco to complete the amalgamation thoughtfully, thoroughly and effectively. The expected outcome of the incentive for Amalco to complete a thorough and successful integration is that synergies will be optimized to the benefit of ratepayers on rebasing. And all of this happens while the attendant risks are borne by shareholders. As discussed above, this approach is aligned with the Board's emphasis on outcomes-based regulation and the Board's aim of creating incentives for behaviour which more closely resemble that of competitive cost-minimizing profit-maximizing companies.

84. SEC disagrees with the statement in AIC that the proposed 10 year deferral serves to align the interests of the Applicants and ratepayers.[94] In doing so, SEC disagrees with a fundamental premise of the Board's approach to regulation.

85. There can be no doubt that an incentive is – and, as confirmed by the MAADs policies, is intended to be[95] - inherent in a rebasing deferral. As elaborated on above, incentives are a central feature of the Board's decisions and policies on rate regulation and the Board has clearly indicated its view that, with appropriate safeguards for service quality, customers and shareholders both gain from these efficiency enhancing strategies. SEC's disagreement with the statement made in AIC reflects a disagreement with the premise that incentives for utility performance serve to align the interests of utilities and customers, even though this premise is fundamental to the Board's approach to regulation

[94] SEC Submission, page 7, paragraph 1.2.9.
[95] MAADs Handbook, pages 11-12.

86. The intervenors who argue for rebasing at the earliest possible opportunity obviously care little, or not at all, about the incentive that is inherent in the 10 year rebasing deferral. Their arguments are out of step with the statement in the Rate Handbook that one of the key principles of the RRFE/RRF is "strong incentives to enhance utility performance".[96]

87. Of course, an important element of IR is a balancing of the incentive to enhance utility performance with risks taken on by utilities and their shareholders. Just as the intervenors who argue for the earliest possible rebasing give no credence to the incentive aspect of deferred rebasing, many intervenors also give no credence to the risks associated with the integration of Enbridge and Union. They show little or no concern about a scenario in which ratepayers will, at least to some extent, take on the risks of the integration.

88. A lack of concern about the risks of integration comes through in the arguments of a number of intervenors. BOMA says that the risks are limited since "they already own both businesses"[97] and submits that ratepayers would be better served by "taking responsibility" for the integration capital expenditures and receiving the benefits of the savings.[98] CME says that, given the Applicants' forecasts, the integration activities by themselves are not a risk to the Applicants.[99] Energy Probe says there is little, if any risk to the utility in this application.[100] SEC says that the "high risks and capital investments" are inconsistent with the admission by the Applicants that the most they are out of pocket for the integration at any time is $8 million.[101] And SEC submits that

[96] Rate Handbook, page 2.
[97] BOMA Submission, page 15.
[98] BOMA Submission, page 8.
[99] CME Submission, page 17, paragraph 61.
[100] Energy Probe Submission, page 6, paragraph 14.
[101] SEC Submission, page 6, paragraph 1.2.6.

an early rebasing would "allow" customers to share in the risk and the rewards of integration.[102]

89. As is apparent from the comments of CME and SEC, these observations about the risks taken on by Amalco assume that the forecasts of integration costs will prove to be accurate when the integration actually occurs. But of course a key aspect of the overall risk taken on by Amalco is the risk that complex and large system and process integrations will cost more than the forecasts.[103] Ratepayers are protected from such overall risk through the price cap mechanism during the 10 year deferred rebasing period.

90. OGVG acknowledges some of the difficulties that would arise if the Board were to require an early rebasing. OGVG notes, for example, the problematic nature of a full cost of service filing by Amalco at the outset of a period when it will be undertaking a significant effort to integrate as a consolidated utility, before integration savings and implications have been realized or become known.

91. There is considerable evidence on the record of this proceeding with regard to the challenges involved in bringing together Enbridge and Union. Some of this evidence was canvassed in AIC,[104] including the following testimony by Mr. Rietdyk:

> …I can assure you that we know enough to know that we have different operating models, different systems, and different processes and even use different materials in our system, so we are sufficiently different that we know it's going to be a significant effort to bring these two organizations together, and that in and of itself drives significant risk.[105]

[102] SEC Submission, page 21, paragraph 2.4.22(e).
[103] March 28, 2018 Tr. 91-95.
[104] AIC, pages 15-17, paragraphs 45-50.
[105] March 28, 2018 (Technical Conference) Tr. 127.

92. This was also addressed in testimony by Mr. Kitchen:

> Well, if you look at BOMA 16D, one of the things you will notice is the number and -- the number of systems and the differences between the number of systems that we have, and there's lots of interdependencies between those systems.
>
> We can't just simply start looking at customer care and move forward. What we need to do is to take an approach that looks at all the systems and how we will integrate those systems, what is the best timing for implementing those systems, and how do they all integrate with each other.
>
> It is not a small undertaking, which is why, again, I go back to the fact that why we need a ten-year deferred rebasing period, because of the nature and complexity of the amalgamation and the technology involved.[106]

93. In a context unrelated to risk, a number of intervenors have made a point about the size and significance of the proposed amalgamation.[107] It is to be expected that an amalgamation will involve risks that are at least roughly commensurate with its size and significance. The Applicants' proposal relieves ratepayers of these risks and provides Amalco with an incentive to complete the amalgamation in a manner that, far from placing any integration risks on ratepayers, delivers to ratepayers on rebasing the results of Amalco's efforts to optimize savings and synergies.

94. CCC says that "if the plan [is] not going well for Amalco, we know that they would be coming back to the OEB for relief".[108] Likewise, IGUA says that "if things go poorly, Amalco will without doubt be back".[109] The fact that these intervenors have seen fit to comment on the prospect that the amalgamation may go "poorly" is inconsistent with the lack of concern about the risks of the amalgamation shown by other intervenors.

---

[106] 1 Tr. 42-43
[107] See, for example, CCC Submission, at page 1; OGVG Submission, page 3; and SEC Submission, page 3, paragraph 1.1.5. The FRPO Submission, at page 16, paragraph 6.1, refers to "the scale, scope and complexity of these matters".
[108] CCC Submission, page 9.
[109] IGUA Submission, page 5, paragraph 18(d).

95. As for the prospect that Amalco may be “back” to the Board because the amalgamation is going poorly, while the Applicants have no expectation that this will happen, it is of course to be assumed that in the event of any such future application, the Board will reach a decision that is reasonable and appropriate in the circumstances. Speculation that Amalco might be “back” to the Board in the future should not be treated as if it is cause for alarm or suggestive of a negative implication of the proposal currently before the Board.

96. Arguments by APPrO and others about early rebasing rely on a provision of the EB-2013-0202 Settlement Agreement.[110] In this Settlement Agreement, Union agreed that (subject to any subsequent agreement of all parties to extend the IRM term) it would prepare a full cost of service filing “at the time of rebasing”, regardless of whether it applies to set rates for 2019 on a cost of service basis or not.[111] The Settlement Agreement goes on to indicate with more specificity certain information to be provided by Union “[a]t the time of rebasing”.[112]

97. In essence, intervenor submissions ask the Board to interpret the Union Settlement Agreement as if it says that Union will rebase at the end of its 2014-2018 Price Cap plan, regardless of the rate-setting model proposed for 2019. But the Settlement Agreement does not say that Union will rebase at the end of the 2014-2018 plan, nor does it say that Union will rebase at any particular time.[113] It sets out what Union will do “at the time of rebasing”.

[110] APPrO Submission, page 7, paragraph 27. See also BOMA Submission, page 16.
[111] Settlement Agreement, EB-2013-0202 Exhibit A, Tab 2, page 34, section 14, first paragraph.
[112] Settlement Agreement, EB-2013-0202 Exhibit A, Tab 2, page 34, section 14, second paragraph.
[113] There has been a fundamental and unforeseen change in circumstances since the time of the Union Settlement Agreement by reason of the merger of the ultimate parent companies of Union and Enbridge. If Union had agreed to rebase at the end of the 2014-2018 Price Cap plan, any such agreement would need to be considered in the light of a fundamental change in circumstances, but in fact Union did not agree to rebase at any particular time.

98. Given the Applicants' proposal that rebasing by Enbridge and Union be deferred, "the time of rebasing" for Union is not yet known. The Board's ruling in respect of the Applicants' proposal will determine the "time of rebasing". Until the Board has determined "the time of rebasing", it is not possible to conclude that Union's agreement to prepare a full cost of service filing has been triggered.

99. Intervenors also refer to evidence in the EB-2012-0459 proceeding about the filing of a cost of service application by Enbridge.[114] SEC says that it "simply put the terms of the Union settlement to the [Enbridge] witness during the hearing, and the answer from the witness was unequivocal".[115] Thus, Enbridge's evidence about a cost of service filing was given in the context of the Union Settlement Agreement which, again, refers to preparation of a cost of service filing at the time of rebasing. Further, the context of responses and positions about a cost of service filing was an expectation that each of the utilities would continue to operate on its own and there was no anticipation of a situation involving a proposed amalgamation of the utilities.

100. APPrO's argument about early rebasing reveals an inconsistent use of the no harm test that pervades a number of the intervenor submissions. The no harm test of course applies to the request for approval to amalgamate made by the Applicants. But, by linking their views about the MAADs application to the proposed rate mechanism, APPrO and other intervenors[116] also apply the no harm test to the elements of the rate mechanism. Among other things, APPrO contends that the no harm test is not met by the proposed stretch factor and the proposed ICM.[117]

---

[114] See, for example, the APPrO Submission, page 8, paragraph 29.
[115] SEC Submission, page 42, paragraph 4.2.12.
[116] For example, OGVG submits that whether the proposed amalgamation causes harm depends on the implementation of an appropriate rate setting proposal (OGVG Submission, page 9) and LPMA submits that the Applicants' Z factor proposal results in harm to Union ratepayers (LPMA Submission, page 11).
[117] APPrO Submission, page 3, paragraph 7.

101. Quite apart from the question of whether it is appropriate to apply the no harm test to elements of the rate mechanism, the inconsistency in the approach of APPrO and other intervenors is that they do not apply the no harm test to their own proposals and arguments.[118]

102. APPrO supports the amalgamation subject to conditions,[119] but contends for an early rebasing and an order that the Applicants undertake a full cost allocation study as soon as possible. APPrO puts forward these contentions as if it is obvious that a full cost allocation review is a benefit to all ratepayers. But of course to the extent that changes in cost allocation work to the benefit of a particular group of ratepayers, those changes will work to the detriment of other ratepayers. As stated by LPMA, cost allocation is a "zero-sum exercise".[120]

103. Despite APPrO's argument that elements of the rate mechanism and the proposed rebasing deferral do not meet the no harm test, APPrO does not apply the no harm test to its own contentions. APPrO does not explain how the Board can approve the amalgamation subject to a full rebasing and a "complete" and "comprehensive"[121] cost allocation study while being satisfied that there will be no harm to any ratepayers.

104. This lack of consideration for the no harm test can also be seen from BOMA's submissions on rebasing. BOMA says that a "rebasing soon after the merger" would, among other things, enable the company to allocate capital on an Amalco-wide basis,

[118] See, for example, the BOMA Submission, at page 19, where an argument is made about making cost-based storage available to customers in the Enbridge rate zone from reserved capacity that is excess to the needs of customers in the Union rate zones. This would cause harm to customers in the Union rate zones, as is pointed out in the LPMA Submission, at page 13. LPMA says: "Clearly the no harm test would not be met … ."
[119] APPrO Submission, page 3, paragraph 8.
[120] LPMA Submission, page 18.
[121] APPrO Submission, page 12, paragraph 44.

unconstrained by the Enbridge and Union "silos".[122] In its use of the words "silos", BOMA presumably is referring to the Enbridge and Union rate zones that, under the Applicants' proposal, will be maintained after the amalgamation. The key point, though, is that maintaining rate zones protects customers who would or could otherwise be harmed by rate changes due to the amalgamation.[123] LPMA, for example, asserts that there should not even be movement towards rate harmonization over the deferred rebasing period and that a harmonization proposal "would result in the failure of the no harm test".[124] BOMA does not explain how the no harm test can be met if the rate zones are not maintained.

5. ESM

105. The Applicants believe that the ESM is the appropriate tool to ensure customer protection during the 10 year deferred rebasing period while still providing effective incentives for the utility to achieve deep and enduring synergies. The OEB is challenging utilities to focus on innovation[125] and with innovation comes risks. In establishing an ESM the OEB should ensure the ESM maintains the incentive for Amalco to take on that risk.

106. OEB Staff submit that the Applicants' proposal does not achieve the objective of adequately protecting customer interests. OEB Staff recommend a "customized ESM" that aligns with the specific deferral period they have proposed.[126]

107. Many arguments have been made in this proceeding about mechanisms to pass "savings" through to ratepayers prior to the end of the deferred rebasing period. CCC

---

[122] BOMA Submission, page 12.
[123] Exhibit C.FRPO.1, Attachment 2, pages 4-5; Exhibit C.CCC.2, part a); and Exhibit C.VECC.36, part b).
[124] LPMA Submission, page 37.
[125] OEB Advisory Committee on Innovation
[126] Staff Submission, page 10.

and LPMA, for example, say that ratepayers should get a "share in the savings" or a benefit "up front".[127] The concept of an "up front" sharing of savings with ratepayers takes shape in intervenor submissions about a stretch factor,[128] or a base rate adjustment for 2019 rates, both of which are addressed below.

108. As was discussed when the implications of a particular stretch factor were addressed at the hearing, it is important to understand the financial impact on the Applicants' forecasts of any proposed mechanism for sharing savings with ratepayers and, further, to consider whether the outcome is "even achievable".[129]

109. Accordingly, the Applicants submit that, in order to support the imposition of an "up front" sharing mechanism, there must, at a minimum,[130] be an evidentiary basis for a finding that Amalco can reasonably be expected to realize sufficient savings to offset the impact of the sharing mechanism. In this case, the evidence is that the Applicants expect Amalco to earn only 20 basis points over the Board-allowed ROE during the deferred rebasing period.[131] To the extent that any stretch factor, base rate adjustment or other form of "up front" benefit has an impact of more than 20 basis points on Amalco's achievement of Board-allowed ROE, the effect of adding such an element to the Applicants' proposals is to turn the Applicants' forecasts towards an expectation that Amalco will not earn the allowed ROE.

110. In other words, the effect of a mechanism for providing an "up front" benefit to ratepayers is to put at risk Amalco's ability to earn the allowed ROE. This is where there is a critical difference between any such mechanism and an ESM. An ESM that

[127] CCC Submission page 12, LPMA Submission, page 14.
[128] CCC Submission, page 12.
[129] 2 Tr. 134.
[130] An evidentiary basis showing only that Amalco can realize savings to offset the impact of a sharing mechanism does not of course take account of an incentive for Amalco.
[131] Exhibit C.OGVG.6; Exhibit C.FRPO.1, Attachment 1, page 23.

takes effect at a threshold using allowed ROE as a reference point does not put at risk Amalco's ability to earn the allowed ROE. As stated in AIC, an ESM is the appropriate tool to achieve the objective of customer protection during the deferred rebasing period.[132]

111. The MAADs Handbook confirms that an ESM is the appropriate tool for customer protection in the context of a proposal such as that made by the Applicants in this case. The MAADs Handbook says that the ESM is designed to protect customers and ensure that they share in any increased benefits from consolidation during the deferred rebasing period.[133]

112. According to the MAADs Handbook, consolidating entities proposing to defer rebasing beyond five years must implement an ESM for the period beyond five years and no evidence is needed in support of an ESM that follows a particular form.[134] The ESM proposed by the Applicants in this case follows the form referred to in the MAADs Handbook.[135]

113. The MAADs Handbook goes on to say, however, that an ESM such as that proposed by the Applicants in this case may not achieve the intended objective of customer protection for all types of consolidation proposals and, for such cases, applicants are invited to propose an ESM that better achieves the objective of protecting customer interests.[136] Presumably, an ESM proposed in accordance with this provision of the MAADs Handbook would be a "customized ESM", as that term is used in the Staff Submission.[137]

---

[132] AIC, page 19, paragraph 59.
[133] MAADs Handbook, page 16.
[134] *Ibid*.
[135] MAADs Exhibit B-1, pages 42-43.
[136] MAADs Handbook, pages 16-17.
[137] Staff Submission, page 10.

114. The Applicants have given careful consideration to the invitation in the MAADs Handbook that they propose an alternative form of ESM. The Applicants have also considered the provisions of the Rate Handbook which say that, while an ESM protects customers from excess earnings, it can diminish the incentives for a utility to improve their productivity, and any benefits to customers are deferred.[138]

115. As confirmed by the Board's guidance, competing considerations are at play. On the one hand, an ESM is the appropriate mechanism for customer protection and, to the extent that the ESM proposed by the Applicants does not achieve the intended outcome of customer protection for the proposed amalgamation, consideration should be given to an ESM that better achieves the consumer protection objective. On the other hand, reliance on incentives to drive utility performance is a central feature of the Board's decisions and policies on rate regulation[139] and thus an important consideration is the extent to which an alternative form of ESM would diminish incentives for Amalco.

116. Moreover, the individual elements of an ESM also require a judicious balancing. One such element is the threshold at which sharing is triggered. The effect of a threshold that is too low is to diminish the incentive for Amalco management to strive for deep savings. A threshold that is set too high may tilt away from the objective of achieving appropriate customer protection.

117. Not only is the level of the threshold a factor in the extent to which incentives are diminished, it also drives decision-making about the level of risk to be taken on by Amalco management in order to pursue deep and sustainable savings. Consider a scenario where due to integration risks, Amalco would underearn in the early years of

---

[138] Rate Handbook, page 28.
[139] As noted above, the SEC Submission says (at page 44, paragraph 4.2.22), that: "There is nothing wrong with incenting a utility to maximize cost savings. That is, after all, what IRM does, and is the basis for most of the Board's rate-making."

the 10 year period as it invests in integration capital, and then in the latter years when the integration savings are being realized, exceed the allowed ROE. Amalco would share on the upside but not on the downside. The Applicants believe that because of the asymmetric nature of ESM, that a model that does not take into account this scenario will not be appropriate and not aligned with the Board's outcome-based policies. Hence, a consideration in setting threshold levels is the integration activities and incentives that come into play at different phases of the integration period.

118. Actions taken by Amalco management in the early portion of the integration term, including large system implementations that will streamline technology and processes, establish the foundation for deep sustainable savings in the latter part of the deferred rebasing term.[140] The latter years of the integration term offer opportunities for Amalco management to push for even deeper savings.[141] It is important that consideration of sharing threshold levels take into account the incentive for Amalco to press for these deeper savings in the latter part of the integration period.

119. For several reasons, the Applicants submit that sharing thresholds should start at a level that is higher than allowed ROE (i.e. a deadband is required) and should not require sharing of all earnings above allowed ROE as suggested by some intervenors.[142] OEB staff supports a structure with no earnings sharing for the first half of the deferred rebasing period, and a deadband for the latter half of the term. The Applicants submit that earnings sharing from the allowed ROE is not commensurate with the complexity of integration and innovation required to maximize customer outcomes and achieve the objectives of the RRFE. First and foremost, setting an earnings threshold at allowed ROE contradicts the incentive-based approach to regulation that the Board has established as its norm. Second, such a threshold would

[140] Exhibit C. STAFF.4; 2 Tr. 50-51
[141] AIC, page 17, paragraphs 50-51.
[142] APPrO Submission pages 10-11; BOMA Submission, page 15; and IGUA page 8.

not drive Amalco management to take on risk to achieve deep and significant savings. Third, this approach is not aligned with the customer outcomes focus of the RRFE/RRF.

120. Should the Board agree with the argument by OEB Staff and others that the Applicants' proposal does not achieve the objective of adequately protecting customer interests, the Applicants propose approval of an ESM that the Board considers to be suitable in conjunction with the proposed Price Cap formula for the 10 year deferred rebasing period using a productivity factor of zero and a stretch factor of zero. The Applicants note earnings sharing at 100 basis points as referenced in OEB staff's submission is not likely to result in sufficient incentive for Amalco, as the 300 basis points from the Board's MAADs policy and the Applicants' proposal would. More specifically, the Applicants propose that the Board create an ESM including threshold levels that balance adequate customer protection over the 10 year deferred rebasing term with retention of incentives to recognize risks and opportunities for Amalco to strive for deep savings over all phases of the integration period.

121. The Applicants submit that such an ESM, by effecting an appropriate sharing of savings with ratepayers, obviates any need for consideration of a stretch factor and, in fact, gives much better recognition to risks and incentives through different phases of the integration period than a stretch factor.

122. In this regard, the Applicants point out that, while an ESM may diminish incentives, a stretch factor is not a positive incentive at all. A stretch factor does not drive performance by making available the opportunity to earn a reward. It does not afford an opportunity to earn a reward at all. In contrast, as long as sharing thresholds include a meaningful margin above approved ROE and a fair sharing above that margin, an ESM retains a positive incentive to drive performance. Further, as set out above, an ESM with a threshold above approved ROE would not put at risk Amalco's ability to earn the allowed ROE in the same way as other mechanisms, such as a stretch factor.

123. Thus, the Applicants submit that, to the extent the Board is concerned about additional customer protection, a *balanced* ESM over a 10 year deferred rebasing period, with a zero stretch factor, will deliver the best outcomes for customers. The incentive for Amalco to strive for deep and lasting savings will be retained, ratepayers will receive the benefit of savings on rebasing and, during the deferral period, ratepayers will be protected by the ESM from earnings in excess of a defined ROE threshold.

6. Price Cap Mechanism

(i) Inflation Factor

124. The Applicants have proposed that the quarterly Gross Domestic Product Implicit Price Index Final Domestic Demand ("GDP IPI FDD") Canada be used as the inflation factor in the Price Cap rate-setting mechanism.[143] The submissions of OEB Staff and intervenors reveal a difference of opinion about the appropriate inflation factor.

125. OEB Staff are not opposed to the inflation factor proposed by the Applicants, but would prefer a two-factor IPI that uses weighted labour and non-labour inflation factors; OEB Staff note that a two-factor IPI would bring more consistency between the natural gas and electricity sectors.[144] OGVG's view is that it would be appropriate for the inflation factor to be based on the same two-factor methodology established for electricity distributors. OGVG says that, given the potentially different emphasis on capital and labour in natural gas operations compared to electricity operations, it would be appropriate to customize the ratio of capital and labour to reflect the actual underlying split between capital and labour for Union and Enbridge.[145]

[143] EB-2017-0307 Exhibit ("Mechanism Exhibit") B-1, page 8.
[144] Staff Submission , page 12.
[145] OGVG Submission, page 17.

126. LPMA does not support the use of the two-factor approach. LPMA argues that the wage escalator tends to be more volatile on a year to year basis, that the appropriate weighting for labour would need to be estimated and that the labour weight for Amalco may be contentious.[146] SEC does not see "any reason to depart from the GDP IPI inflation escalator".[147] For its part, VECC generally believes that price cap plans should use CPI as an inflator.[148]

127. Although, as stated above, the Applicants are cognizant of a trend towards greater harmonization of the Board's policies and methodologies for regulation of utilities in the natural gas and electricity sectors, the Applicants do not perceive the inflation factor for Amalco to be an important element of the Board's harmonization efforts. Should it in fact be the view of the Board that consistency between regulation of gas and electricity utilities is of sufficient importance to drive the use of the two-factor approach for Amalco, the Applicants will readily accept the Board's view as the determining consideration. But, if the Board does not consider consistency to be of such importance as to over-ride the reasons that have been given for using GDP IPI FDD, then, for the reasons set out in evidence,[149] in AIC[150] and in the arguments of intervenors who support the proposed inflation factor,[151] the Applicants submit that their proposal should be approved.

128. OEB Staff suggest that, if the Board approves use of the GDP IPI FDD inflation factor proposed by the Applicants, the measurement of inflation change should be

---

[146] LPMA Submission, page 21.
[147] SEC Submission, page 50, paragraph 5.4.1.
[148] VECC Submission, page 13, paragraph 5.6.
[149] 5 Tr. 60-61.
[150] AIC, page 22, paragraphs 68-69.
[151] See, for example, LPMA Submission, at pages 21-22.

based on calendar year-over-year comparison, rather than a mid-year calculation.[152] This suggestion by OEB Staff is acceptable to the Applicants.

(ii) Productivity Factor

129. National Economic Research Associates Inc. ("NERA") and Pacific Economics Group Research LLC ("PEG") both carried out analysis and made recommendations in this proceeding with regard to a productivity factor for the Price Cap rate-setting mechanism. Both recommended that the productivity factor be zero. OEB Staff,[153] BOMA,[154] CME,[155] LPMA,[156] OGVG,[157] and VECC[158] all accept (or, in the case of CME, "acknowledge") the consensus of the experts on a zero productivity factor.

130. In AIC, the Applicants noted that NERA and PEG had arrived at the same result, even while following different approaches. The Applicants did not offer argument about the relative merits of the two approaches but instead submitted that the Board need not embark on consideration of methodological issues when the outcome of both approaches is the same.[159]

131. The Staff Submission refers to the submissions made in AIC and says that it may not be necessary for the Board to make detailed findings on the relative merits of the two approaches, as the experts both came to the same conclusion.[160] The Staff Submission then goes on to make relatively short submissions on methodologies that

[152] Staff Submission, page 12.
[153] Staff Submission, page 15.
[154] BOMA Submission, page 22.
[155] CME Submission, page 23, paragraph 83.
[156] LPMA Submission, page 22.
[157] OGVG Submission, page 17.
[158] VECC Submission, page 14, paragraph 5.8.
[159] AIC, pages 23-24, paragraphs 73-75.
[160] Staff Submission, page 13.

are put forward “to the extent that the OEB opines on the relative merits of the experts’ analysis”.[161]

132. CME, has engaged in more extensive debate about methodologies and, in doing so, it has advanced a non-expert and one-sided view of complex issues. A less one-sided commentary on the methodological issues would have addressed the decision of the Alberta Utilities Commission (“AUC”) in the proceeding that was the largest-ever generic investigation of objective and transparent Total Factor Productivity (“TFP”) growth studies for electricity and gas distribution rate incentive purposes,[162] particularly because both Dr. Lowry and Dr. Makholm were among the many expert witnesses who gave evidence in that proceeding.[163] In their commentaries on methodology, OEB Staff and CME make no mention of the AUC proceeding.

133. The AUC accepted NERA’s theory, data, sources, timing, judgments on inputs and computations for deriving the TFP element of the X-factor,[164] but, as Dr. Lowry himself testified, the AUC was more skeptical of PEG’s work.[165]

134. In order for a credible comparison of the NERA and PEG methodologies to be done, it is important to understand and give consideration to the reasons why the AUC, after a very thorough generic investigation of TFP growth studies, favoured NERA’s work over that of PEG. However, OEB Staff and CME simply avoid any mention of the AUC proceeding in their submissions on methodology.

135. In this proceeding, because the experts agree that the productivity factor for Amalco should be zero, it was unnecessary to explore methodological differences in the

[161] Staff Submission, pages 13-14.
[162] 4 Tr. 4.
[163] 4 Tr. 167-170.
[164] 4 Tr. 4.
[165] 4 Tr. 173.

TFP analysis of the experts. Because it was unnecessary to explore methodological differences, there is not an appropriate record in this proceeding for determinations about methodology. As stated in AIC, the important point is that NERA and PEG, while following different approaches, have both recommended a productivity factor of zero.[166]

(iii) Stretch Factor

136. The Applicants' submissions with respect to the stretch factor should be considered within the overall approach taken in this reply argument. Specifically, to the extent that the Board sees merit in arguments that ratepayers should benefit from savings and efficiencies prior to rebasing, the Applicants submit that a balanced ESM during a 10 year deferred rebasing period, with a zero stretch factor, will deliver the best outcomes for customers.

137. OEB Staff submit that the Board should apply a stretch factor of 0.3% to Amalco's price cap plan.[167] OEB Staff's arguments in support of this proposition discuss, first, whether a stretch factor should be included in the proposed Price Cap formula and, second, what the size of a stretch factor should be.

138. Most of the stretch factor discussion in the Staff Submission addresses the first of these two areas, namely, whether there should be a stretch factor. After a number of pages of discussion,[168] the Staff Submission comes to the conclusion[169] that all of the Board's policy guidance, for both gas and electricity, states that a stretch factor is appropriate.[170]

[166] AIC, page 23, paragraph 73.
[167] Staff Submission, page 15.
[168] Staff Submission, pages 15-18.
[169] Staff Submission, pages 18-19.
[170] CME Submission, pages 28-30, paragraphs 105-106.

139. With all due respect to OEB Staff, the Applicants submit that the stretch factor debate in this case is not advanced by the conclusion that, based on "all of the Board's policy guidance", a stretch factor is appropriate. As OEB Staff note in their own arguments about the size of a stretch factor for Amalco, the stretch factors for electricity distributors range from 0% to 0.6%.[171] The Applicants propose a stretch factor of zero for Amalco.[172] Clearly there is no policy direction from the Board that a stretch factor cannot be zero, because there are electricity distributors with a zero stretch factor.

140. Given that a stretch factor can be zero, the question here is whether, based on the evidence in this proceeding, the Board should accept the Applicants' proposal for a zero stretch factor. In this regard, OEB Staff note that the Applicants did not file total cost benchmarking evidence.[173] At the same time, OEB Staff allude to a difficulty with benchmarking analysis relevant to a stretch factor for the consolidated entity, Amalco (which of course does not yet exist), when they point out that Enbridge may be "a bit less productive than average" and Union "a bit more productive".[174]

141. OEB Staff apparently do not see any reason why "benchmarking could not have been conducted for the applicants",[175] yet they need look no farther than the evidence of their own witness, Dr. Lowry, to find such reasons. Dr. Lowry confirmed that a total cost benchmarking study for gas distributors has never been done in Ontario.[176] Among other things, he said that this is an area he will be working on with the Board and that he has just done a study for the Alberta government which he described as "experimental".[177]

[171] Staff Submission, page 19.
[172] Mechanism Exhibit B-2, page 6, Q/A9.
[173] Staff Submission, page 19.
[174] *Ibid*.
[175] *Ibid*.
[176] 4 Tr. 192.
[177] 4 Tr. 190-191.

142. Of course, public bodies and regulators are to be commended for initiating efforts to gain a better understanding of subjects like total cost benchmarking for gas distributors. But it is an altogether different matter to expect an applicant to wrestle such an issue to the ground with sufficient conclusiveness to meet the onus placed on the applicant in an application to the Board. To put it another way, it is not reasonable to put an onus on an applicant to support its case with evidence in an area where current work is "experimental".

143. Certain intervenors go beyond the evidence of the experts, Dr. Lowry and Dr. Makholm, and assert different ideas about a stretch factor for Amalco, such as a stretch factor of 0.6%,[178] or 60% of the inflation factor.[179] But when the Applicants' witnesses were asked about "this 60% of inflation productivity factor", the response was that a stretch factor at such a level would put Amalco significantly below allowed ROE.[180]

144. This is the first case in which the Board has heard evidence relevant to the determination of a stretch factor for Amalco and that determination should be made on the basis of evidence in this case. The evidence before the Board bearing directly on the circumstances of this particular case is that the likely result of the stretch factor of 0.3% recommended by PEG, and contended for by OEB Staff, is to make it unreasonable to expect that Amalco will even be able to achieve the allowed ROE.[181]

145. Dr. Lowry and OEB Staff rely on stretch factors for other utilities[182] without reference to the evidence in this proceeding and, in particular, the Staff Submission

[178] OGVG Submission, page 19.
[179] LPMA Submission, page 22; SEC Submission, page 50, paragraph 5.5.5.
[180] 6 Tr. 75-76.
[181] 2 Tr. 135.
[182] Exhibit M1, pages 43-45; Staff Submission, pages 19-20. For example, Dr. Lowry (Exhibit M-1, page 45) and the Staff Submission (page 20, "hydroelectric generation") refer to a stretch factor approved for Ontario Power Generation Inc. ("OPG") but it is clear from the Board's decision that the stretch factor determination for OPG was based on the specific circumstances of that case, including a finding that

makes no attempt to address the evidence throwing doubt on whether the savings associated with a 0.3% stretch factor are even achievable by Amalco.[183]

146. To illustrate the amount of overachievement necessary to overcome the impact of a 0.3% stretch factor, the Applicants will provide an empirical illustration. For Amalco to achieve its forecasted ROE over the 10 year term, with the application of this stretch factor, Amalco would need to find additional savings of $410 million over the deferred rebasing period. The impact of this stretch factor in 2028, the year prior to rebasing, is Amalco needing an extra $80 million[184] in savings (total savings of $165 million[185]) to achieve the forecasted ROE. The $165 million in savings equals approximately 18%[186] of that year's total forecasted O&M net of DSM.[187]

147. In fact, during the last five years of the deferred rebasing term – that is, the period when Amalco has the opportunity to achieve the greatest amount of savings - the impact of the 0.3% stretch factor results in Amalco needing a five year average reduction of approximately 17%[188] in its total O&M net of DSM. This equates to Amalco doubling its current forecasted O&M savings. Over the 10 year term, the impact of the stretch factor is a 45% increase in savings being required when compared to the forecasted maximum savings of $750 million.[189]

OPG's performance with respect to reliability metrics and the partial cost function metric is second quartile: EB-2016-0152 Decision and Order, December 28, 2017, at page 129.

[183] 2 Tr. 134; Staff Submission, pages 19-20.

[184] Exhibit K2.3 Row 12.

[185] For year 2028: $85 million (Attachment 12) plus $80 million (Exhibit K2.3 row 12) = $165 million

[186] $165 million divided by $917 million (Exhibit C.FRPO.11 EGD O&M net of DSM + Union Gas O&M net of DSM) = 18%.

[187] A large portion of Amalco's O&M is fixed. Savings as a percentage of variable O&M would be much larger.

[188] Sum of last 5 years $85 million (Attachment 12) plus sum of last 5 years of Exhibit K2.3 row 12 = $732 million divided by sum of last 5 years (Exhibit C.FRPO.11 EGD O&M net of DSM + Union Gas O&M net of DSM = $4,401) = 17%.

[189] $1,089 million less $750 million divided by $750 million = 45.2%.

(iv) Y Factors

148. The Applicants propose Y factor treatment for the following:

(i) cost of gas and upstream transportation;
(ii) Demand Side Management ("DSM") costs as determined in EB-2015-0029/EB-2015-0049 and any subsequent proceeding;
(iii) Lost Revenue Adjustment Mechanism ("LRAM") for the contract market;
(iii) NAC/AU;
(iv) cap and trade; and
(v) capital investments that qualify for ICM treatment. [190]

149. OEB Staff state that they have no concerns with the use of the Y factors proposed by the Applicants.[191] However, OEB Staff go on to express their concerns with AU and load forecasting models. OEB Staff assert that Enbridge's AU model is not reliable and will not be corrected before rebasing and note that the AU and load forecasting models for both Applicants have not been revised or reviewed since 2012.[192]

150. It appears that OEB Staff formulated its submissions without consideration of the AIC. In AIC, the Applicants proposed that Amalco will consult with stakeholders to work towards a single, revenue-neutral approach to NAC/AU for a future rate application.[193] The Applicants' proposal squarely addresses OEB Staff's comment about models that have not been reviewed since 2012 and disposes of the concern that these matters might not be addressed until rebasing.

---

[190] Mechanism Exhibit B-1, pages 9-10.
[191] Staff Submission, page 20. The BOMA Submission (at pages 24-25) and the OGVG Submission (at page 21) indicate support for continued use of Y factors as part of Amalco's rate setting mechanism, although OGVG takes no position on NAC/AU.
[192] *Ibid*. See also VECC Submission, at page 18, and LPMA Submission, at pages 25-26.
[193] AIC, page 30, paragraph 97.

151. For the reasons elaborated on at some length in evidence, the existence of a true-up for AU is important to the gas utilities.[194] The Board can approve the Y factors proposed by the Applicants with the knowledge that NAC/AU will be looked at holistically across Amalco,[195] that stakeholders will be consulted, and that Amalco will be working towards an approach to be filed for the Board's review in a future rate application.

(v) Z Factor

152. The Applicants have proposed a Z factor mechanism based on the criteria defined in the Board's *Filing Requirements for Natural Gas Rate Applications* (the "Gas Filing Requirements")[196] with a materiality threshold of $1 million.[197] The proposed materiality threshold, which is consistent with the threshold for electricity distributors,[198] was the focus of submissions from OEB Staff and intervenors on the subject of the Z factor.

153. OEB Staff note that the sum of the current Z factor materiality thresholds for Enbridge and Union is $5.5 million. On the basis of their calculation that the revenue requirement of Amalco will be approximately 75% of the revenue requirement of Ontario Power Generation Inc. ("OPG"), OEB Staff submit that the Z factor materiality threshold for Amalco should be 75% of OPG's threshold, or $7.5 million.[199]

[194] 5 Tr. 21-26.
[195] 5 Tr. 23. See also 3 Tr. 139-140 where the witnesses explained that these issues are best looked at in the context of the consolidated entity, rather than individual companies.
[196] Gas Filing Requirements, February 16, 2017, pages 39-40, section 2.9.3.
[197] Mechanism Exhibit B-1, pages 11-12.
[198] Mechanism Exhibit B-1, page 12, including footnote 7.
[199] Staff Submission, page 21.

154. VECC submits that the materiality threshold for Amalco should be between $5.5 million and $10 million.[200] LPMA submits that an appropriate threshold for Amalco would be in the $8 million to $10 million range.[201] A number of other intervenors submit that the threshold should be $10 million and most of these arrive at the $10 million amount by reference to the threshold for OPG.[202]

155. The Applicants submit that comparisons made to OPG for the purposes of submissions about Amalco's Z factor materiality threshold are inapt. OPG is an entirely different entity than a gas distributor and, in determining a threshold of $10 million for OPG, the Board clearly did not set it at a relative level to the thresholds of gas distributors (for example, Enbridge's $1.5 million threshold) or electricity distributors (for example, Hydro One's $1 million threshold).

156. The Applicants continue to see merit in a Z factor threshold for Amalco that is consistent with the threshold for electricity distributors, but they also see merit in arguments, such as the submission by VECC,[203] that Amalco's threshold should not be lower than the current thresholds of Union and Enbridge. Given the concern that Amalco's threshold should not be lower than the current thresholds of the two consolidating entities, the Applicants submit that the appropriate course of action is to sum the current Union and Enbridge thresholds and set the threshold for Amalco at $5.5 million.

157. OEB Staff submit that increases in the cost of borrowing are not Z factors.[204] The Applicants' proposal in this case is that the Board establish a Z factor mechanism

[200] VECC Submission, page 19, paragraph 5.29.
[201] LPMA Submission, page 27.
[202] See, for example, APPrO Submission, page 21, paragraph 86; BOMA Submission, page 25; CME Submission, page 38, paragraph 141; Energy Probe Submission, page 13; IGUA Submission, page 11, paragraph 45; and SEC Submission, page 52.
[203] VECC Submission, page 19, paragraph 5.27.
[204] Staff Submission, pages 21-22.

for Amalco by approving the Z factor criteria and materiality threshold. There is no request in this proceeding for any specific relief under a Z factor mechanism and there is no need or basis for the Board to make advance determinations about whether Z factor relief will be available in particular circumstances. The Applicants submit that OEB Staff's submissions about whether an increase in borrowing cost might qualify for Z factor treatment should not be the subject of any decision at this time.

(vi) ICM

158. The MAADs Handbook makes clear that the ICM is an additional rate-setting mechanism under Price Cap IR that is available during a deferred rebasing period to allow adjustment to rates for discrete capital projects.[205] The ICM is also identified as a mechanism under Price Cap IR in both the RRF[206] and the Rate Handbook.[207] During the deferred rebasing period, Amalco will apply for rate adjustments to recover costs associated with qualifying incremental capital investment, consistent with the Board's ICM policy.[208]

159. OEB Staff submit that the Board should, in this proceeding, confirm the scope of the availability of incremental capital during the deferral period pursuant to the intent of the policy.[209] Apparently, OEB Staff are concerned that the Applicants have made assumptions about the availability of ICM relief that are inconsistent with the Board's policy and practice. In their submissions on this point, OEB Staff comment on a recent decision in which the Board did not approve ICM treatment for a number of projects

[205] MAADs Handbook, page 17.
[206] See, for example, RFE Report, at pages 13, 18, 20 and 22.
[207] See, for example, Rate Handbook, Appendix 2, pages iv-v and Appendix 3, page i.
[208] Mechanism Exhibit B-1, page 12.
[209] Staff Submission, page 28.

proposed by Alectra, referred to by OEB Staff as "an electricity distributor, out on a 10-year deferred rebasing".[210]

160. The Applicants are aware of the Board's ICM policies and they understand that proposals by Amalco to recover costs associated with incremental capital investment will not be allowed by the Board if they do not comply with the policies. The Applicants are aware of the recent decision in respect of projects proposed by Alectra and they understand the implications of that decision. There is no need for the Board to provide direction in this proceeding with regard to the intent of the ICM policy and, further, issues about the extent to which incremental capital spending by Amalco will be eligible for ICM relief should be left until the Board actually has an ICM application from Amalco before it, with evidence setting out the circumstances in which ICM relief is requested.

161. The Staff Submission also addresses the Applicants' evidence that Amalco will apply for ICM relief in respect of the Sudbury expansion project.[211] The Applicants do not seek any determination at this time regarding ICM treatment for this project[212] and have indicated that they expect the ICM application for the project to be brought forward for consideration as part of Amalco's 2019 rate application.[213] OEB Staff agree that consideration of ICM treatment for the Sudbury expansion project should be left for the ICM application that Amalco is expected to bring forward.[214] Hence, there is no determination for the Board to make in this proceeding with respect to the Sudbury project.

---

[210] *Ibid*.
[211] Staff Submission, page 25.
[212] 2 Tr. 97.
[213] 2 Tr. 94.
[214] Staff Submission, page 25.

162. OEB Staff state that they are opposed to the Applicant's proposal with respect to cost of capital to be used in determining revenue requirement in ICM applications.[215] The Applicants propose that the cost of capital for ICM applications will reflect the latest forecast of debt, incremental long term debt requirement for the particular project and allowed ROE at the time of the application.[216]

163. The Staff Submission does not address the evidence explaining that the approach proposed by the Applicants is fair to both ratepayers and Amalco's shareholder. As stated in an interrogatory response:

> The proposed use of incremental rather than embedded capital costs will ensure that incremental revenue requirement for each project is matched to the incremental costs of the project. This protects ratepayers from having to pay a higher than incremental cost of capital between the in-service of an ICM project and the next rebasing, and protects shareholders from having to make significant investments at a cost of capital below current market rates.[217]

164. The Applicants submit that their proposal for treatment of cost of capital in ICM applications is consistent with the overall intent of their Applications in this proceeding, which is to put forward a framework for the amalgamation that is fair and balanced as between ratepayers and the shareholder.

165. The Staff Submission includes comments about the review of ICM projects in leave to construct applications.[218] OEB Staff submit that Amalco could identify in a leave to construct application its belief that the proposed project qualifies for ICM treatment. The Board, in the leave to construct application, could test and determine the need for, prioritization and pacing of the project within the context of Amalco's Utility

[215] Staff Submission, page 23.
[216] Mechanism Exhibit B-1, pages 15-16.
[217] Exhibit C.STAFF.14, page 2.
[218] Staff Submission, pages 24-25.

System Plan. The nature, need for, and pacing and prioritization of the project would not be reviewed again in the Price Cap IR application, but the determination of the amount of the qualifying incremental capital, the associated revenue requirement and rate riders would occur in the Price Cap IR application.[219]

166. The Applicants submit that it is not necessary to draw such a distinct line between relief granted in a leave to construct case and relief granted in the annual Price Cap IR application. A request for approval of rate relief can be made in the same proceeding as a request that leave to construct be granted for a particular project. The Applicants submit that ICM relief may be applied for in a leave to construct proceeding and, in support of this point, they note that this is “the same approach as with the capital pass through mechanism in Union’s current IRM”.[220] However, if the Board has any reason for concern about the determination of incremental capital, revenue requirement and rate riders in the context of a request for leave to construct, the Applicants agree that OEB staff have made a reasonable suggestion that allows for determination of these matters in the annual Price Cap IR application.

167. Some intervenors have argued that Amalco could or should use Union’s capital pass through mechanism rather than applying in accordance with the ICM.[221] As discussed above, the ICM is identified as an additional rate-setting mechanism under Price Cap IR not only in the MAADs Handbook, but also in the Rate Handbook and the RRF. A clear theme of consistency, if not convergence, of Board policies relating to incremental capital spending is apparent from these sources of guidance issued by the Board.

---

[219] *Ibid*.
[220] Exhibit C.STAFF.26, page 3.
[221] CCC Submission, page 13; LPMA Submission, page 29; OGVG Submission, page 24.

168. OEB Staff acknowledge that the discussions in the Rate Handbook extend the ICM to OPG, electricity transmitters and natural gas distributors.[222] Union's capital pass through mechanism was one component within a negotiated rate framework, and it has never been used by Enbridge. The ICM has developed and evolved over a number of years such that there is a considerable body of Board policy and decisions, including the Alectra decision referred to by OEB Staff, to guide the application of the ICM in particular cases. The Applicants submit that requests by Amalco for approval of rate relief in respect of incremental capital spending should be made under the ICM.

169. Further, some intervenors have argued that Amalco should use Union's 2018 depreciation expense in the calculation of the ICM threshold.[223] This is not consistent with the ICM policy or the evidence provided by the Applicants. Since Union and Enbridge are not rebasing, the Applicants will continue the capital pass through deferral accounts for Union capital projects put into service over the 2014 to 2018 IRM term through to the end of the deferred rebasing term. As a result the depreciation associated with the capital pass through projects cannot and should not be included in the calculation of the ICM threshold.

170. Essentially the capital pass through projects are treated on a cost of service basis and are outside of the Price Cap mechanism. The depreciation expense embedded within the revenue requirement for a capital pass through project represents the recovery of the (original) cost of that specific project over its useful life. Given that, in respect of capital pass through projects, rates are set to match/recover exactly the revenue requirement associated with those projects (no more and no less), depreciation expense for these projects is not available to support investments in other projects.

[222] Exhibit C.STAFF.26, page 1.
[223] CCC Submission, page 13; LPMA Submission, page 29; OGVG Submission, page 24; SEC Submission, pages 51-52.

171. As indicated by Mr. Reinisch in response to Mr. Shepherd:

> MR. REINISCH: Again, I don't want to speculate, but I disagree with the premise of the assertion that you're making. The challenge is that -- again, a couple of things. First of all, the capital pass-through, as rate base decreases, as our average net book value decreases through the current rebasing period and the future rebasing period, we do not have that depreciation expense available to us to reinvest in maintenance capital activities, so those dollars are not in rates. We are not recovering.
>
> The purpose of the ICM materiality threshold is to calculate how much the utility can spend within their existing rates. The capital pass-through mechanisms are handled outside of that and they are effectively treated as cost-of-service projects, so there is no mechanism to reinvest that depreciation expense and for the utilities to recover that investment.[224]

172. Accordingly, there is no merit in the arguments of intervenors supporting the use of 2018 depreciation expense in the calculation of the ICM threshold.

173. Finally, LPMA has suggested that the materiality factor of 10% should be increased to 40%.[225] This suggestion was never tested or put to the Applicants' witnesses. To raise this prospect in a final submission is inappropriate and it should be disregarded.

7. Gas Supply, Transportation and Storage

174. The Staff Submission discusses the status of gas supply and transportation contracts between Enbridge and Union after the proposed amalgamation.[226] OEB Staff do not mention any concerns about the status of gas supply contracts and state explicitly that they have no concerns with the proposed treatment of transportation contracts between Enbridge and Union after amalgamation.[227] OEB Staff suggest that

[224] 6 Tr. 89.
[225] LPMA Submission, page 32.
[226] Staff Submission, pages 29-33.
[227] Staff Submission, page 30.

the Board should be clear about the risk of disallowances if it is found that future transportation contracting decisions are not prudent,[228] but the Applicants submit that there is no reason for the Board to express comments in this case about the consequences of hypothetical contracting decisions found, in the future, to be imprudent.

175. As far as storage is concerned, the Staff Submission indicates that OEB Staff are satisfied with the proposed process for the purchase of unregulated storage services for customers in the Enbridge rate zone.[229] However, OEB Staff disagree[230] with the Applicants' position regarding the availability to customers in the Enbridge rate zone of cost-based storage from capacity reserved for in-franchise customers in the Union rate zones.[231]

176. As outlined in AIC, one aspect of the EB-2005-0551 Decision and Reasons in the Natural Gas Electricity Interface Review ("NGEIR") was that the Board reserved 100 PJ of Union's storage capacity for the needs of Union's in-franchise customers at cost-based rates.[232] Union's customers benefit from the sale of excess storage from the 100 PJ of reserved capacity, in that Union's rates include about $2.5 million associated with the sale of excess capacity from the 100 PJ and revenue over $2.5 million is shared on a 90/10 split with Union's ratepayers.[233]

177. OEB Staff submit that, after amalgamation, customers in the Enbridge rate zone should receive the benefit of cost-based storage from the excess space that is currently sold at market-based rates for the benefit of Union's customers. OEB Staff say that, if

[228] Staff Submission, page 31.
[229] Staff Submission, page 33.
[230] Staff Submission, pages 31-32. See also BOMA Submission, at page 19.
[231] The Applicants' position is summarized in AIC at page 9, paragraphs 25-26.
[232] NGEIR Decision and Reasons, November 7, 2006, pages 82-83.
[233] 3 Tr. 68.

the Board agrees with this submission, the Board should order the Applicants to file a proposal for a base rate adjustment as part of the 2019 rates proceeding.[234]

178. In order to meet the no harm test, the Applicants have proposed that, during the deferred rebasing period, rates will be determined using the Price Cap mechanism on the basis of Union's two existing rate zones and an Enbridge rate zone. The Applicants propose to maintain these rate zones so that no customers will be harmed by rate changes due to the amalgamation.[235]

179. If the Applicants had not proposed to maintain the distinction between Union and Enbridge rate zones and had put forward a post-amalgamation approach that allows for changes to the benefit of current Enbridge customers and the detriment of current Union customers (or *vice versa*), they would most certainly have been met with arguments that their proposal does not meet the no harm test.[236] In point of fact, LPMA submits that the no harm test clearly would not be met if excess storage from the capacity reserved for Union in-franchise customers were to be made available at cost-based rates to customers in the Enbridge rate zone.[237]

180. The Applicants submit that the no harm test does not fall away from consideration simply because a particular proposal is put forward by another participant in this proceeding rather than by the Applicants. The submission made by OEB Staff does not meet the no harm test.

[234] Staff Submission, page 32.
[235] Exhibit C.FRPO.1, Attachment 2, pages 4-5; Exhibit C.CCC.2, part a); and Exhibit C.VECC.36, part b).
[236] See, for example, LPMA's argument that a rate harmonization proposal "would result in the failure of the no harm test": LPMA Submission, page 37.
[237] LPMA Submission, page 13. LPMA points out that, not only would customers in the Union rate zones lose the benefit of storage sold at market-based rates, they would incur additional costs in the future to the extent that they require more storage capacity which must then be acquired at market-based rates.

181. Some intervenors put into question whether the NGEIR decision should be reviewed by the Board.[238] The Applicants submit that the evidence in this case does not support a conclusion that a review of the NGEIR decision is necessary or appropriate.

182. In the NGEIR decision, the Board found that the storage market is sufficiently competitive to protect the public interest within a geographic market identified by the Board.[239] The evidence filed by the Applicants makes clear that there is no reason to revisit or question this finding in light of current circumstances or the proposed amalgamation of Union and Enbridge. More specifically, the evidence is that: the storage market in which Enbridge and Union merchant storage competes is highly competitive; the merger of the merchant storage operations of Union and Enbridge would have little impact on the concentration of merchant storage services; and traders and marketers, not end users, dominate the merchant storage at Dawn.[240]

183. Charles River Associates ("CRA") conducted a similar statistical analysis to that which was presented in evidence in the NGEIR proceeding.[241]. CRA found that the competitive market region is similar to, or potentially somewhat larger than, the competitive market region identified by the OEB in the NGEIR decision, based on an assessment that included analysis of natural gas price correlations between different regions.[242]

---

[238] BOMA Argument page 20, CCC Argument page 14, CME Argument pages 21 to 22, Energy Probe Argument page 14, FRPO Argument pages 4 to 5, VECC Argument page 7.
[239] NGEIR decision, page 3.
[240] Applicants' April 19, 2018 Submission on SEC Motion, Attachment 1, page iv.
[241] Applicants' April 19, 2018 Submission on SEC Motion, Attachment 2.
[242] Applicants' April 19, 2018 Submission on SEC Motion, Attachment 2, pages 2-3., page 7.

184. It is also suggested by some intervenors that the Board should initiate a review of the *Storage and Transportation Access Rule* ("STAR").[243] The Applicants submit there is no reason for the Board to embark on a review of STAR at this time. The Applicants provided evidence about how STAR reporting may be harmonized or integrated by Amalco[244] and no material issue has been raised in respect of this evidence. The Applicants have committed that Amalco will post the Design Day Dawn Parkway System capacity required for Union North, Union South and Enbridge zones on an aggregated basis on its website as part of the Index of Transportation Customers.[245] There is no question that the minimum requirements of STAR have been met or exceeded to date and Amalco will continue to meet or exceed the requirements.

185. TransCanada has expressed concerns about changes to transportation services and the availability of capacity after completion of the proposed amalgamation.[246] However, shippers that hold M12 and C1 transportation capacity will see no change to their current contractual rights.[247] In response to TransCanada's submissions, the Applicants note that, with respect to nominations, M12 and C1 shippers have the ability to nominate all of their firm transportation capacity on the timely window to ensure it is scheduled. With respect to the priority of service, in-franchise needs and M12 firm needs are at the same priority level.[248] This will not change with amalgamation. In addition, parties that need access to firm intraday increases to timely window nominations can contract for a firm all day service which is rate-regulated.[249]

186. The evidence is that, in the past, Union has not rejected intraday capacity increase requests on the Dawn Parkway System and therefore has not had to allocate

[243] FRPO Submission, page 6, paragraph 4.1.5.
[244] Exhibit C.VECC.22.
[245] Exhibit C.TCPL.3, page 3, part f).
[246] TransCanada Submission, pages 3-4.
[247] 3 Tr. 58.
[248] 3 Tr. 58.
[249] 2 Tr.154.

capacity between in-franchise and ex-franchise needs. Further, Union sees this as an improbable scenario.[250] Shippers are informed by the Operationally Available Transportation Capacity being posted online daily, which provides customers with warning in times of constraint.[251]

187. Another concern noted in the TransCanada Submission relates to access to expansion capacity after the completion of the amalgamation.[252] On this point, the evidence is that Amalco will continue to award bids based on the highest economic value as Union does today[253], with longer term needs driving higher net present value.[254] Available capacity will continue to be provided on a first-come, first-served basis.[255]

188. The Applicants submit that all concerns raised by TransCanada have been addressed in the evidence. Issue 6 in the Issues List for this proceeding raises for consideration whether the proposed merger will impact any Board policies, rules or orders, such as STAR and the regulation of new storage.[256] The Applicants submit that the proposed amalgamation will not have a negative impact on any Board policies, rules or orders.

8. Base Rate Adjustments

189. The Applicants propose to make four adjustments to base rates, as follows:

---

[250] Response to Undertaking JT3.12.
[251] April 3, 2018 Technical Conference Tr. 90-91.
[252] TransCanada Submission, pages 4-5.
[253] Exhibit C.TCPL.2 part b, M12 General Terms & Conditions – Schedule "A 2010" – XVI Allocation of Capacity.
[254] 3 Tr. 59.
[255] 3 Tr. 58.
[256] Decision and Procedural Order No. 6, March 1, 2018, Schedule A, Issues List, page 1,

(i) an increase to Union's rates for the completion of the Board-approved deferred tax drawdown;
(ii) a decrease to Enbridge's rates to remove the smoothing of costs related to EGD's Customer Information System ("CIS") and customer care forecast costs;
(iii) an increase to Enbridge's rates to reflect Pension and Other Post-Employment Benefits ("OPEB") given the enactment of pension reform legislation in December, 2017; and
(iv) an increase to Enbridge's rates to reflect the removal of the tax deduction associated with the Site Restoration Cost ("SRC") refund that has been discontinued.[257]

190. OEB Staff comment on each one of these four proposed adjustments and, in all instances, OEB Staff say that they do not object to, or have no concerns with, the Applicants' proposal.[258] Thus, OEB Staff accept the proposed adjustments.[259] BOMA[260] and LPMA[261] also support all of the base rate adjustments as filed. In fact, no party has objected to the adjustments.

191. Given the explicit indications of support for the adjustments, and given that no party objects to the adjustments, the Applicants submit that the four base rate adjustments should be approved.

192. Some intervenors propose an additional adjustment to base rates that they have formulated by reference to earnings of Enbridge and Union prior to amalgamation.[262] The concept, as put forward by LPMA, is that Enbridge and Union have gained

[257] Mechanism Exhibit B-1, pages 16-20 and Addendum.
[258] Staff Submission, pages 33-35.
[259] Staff Submission, page 33.
[260] BOMA Submission, pages 29-30.
[261] LPMA Submission, page 36,
[262] CCC Submission, page 11; LPMA Submission, page 16; SEC Submission, pages 11-12, paragraph 1.4.5 and pages 48-49, paragraphs 5.2.3-5.2.10.

efficiencies during the period from 2014-2018[263] and these efficiencies should be reflected in rates at the start of the IR plan that is proposed to being in 2019.[264]

193. The problem with this proposed adjustment, from the outset, is that, in order to determine the amount that base rates should be adjusted, if at all, a rebasing is necessary. Without a rebasing, there is no way of knowing the extent to which earnings of Enbridge and Union over the period from 2014 to 2018 reflect efficiencies and savings that carry forward into 2019. Not only does the Board not have evidence in this proceeding about the extent of efficiencies and savings that carry forward into 2019, there is clear evidence in this proceeding that earnings of Enbridge and Union over allowed ROE reflect other important factors in addition to efficiencies and sustainable savings.

194. In the case of Union, the reasons for earnings in excess of allowed ROE were explained in the response to an undertaking given at the Technical Conference, which states as follows:

> From 2013 through 2017, the primary drivers of Union's earnings above Board-approved ROE were lower interest expenses as a result of the refinancing of long term debt, lower pension expense and colder than normal weather in the early years of the IRM. Small productivity gains throughout the period also helped contribute to earnings.[265]

195. In the case of Enbridge, Mr. Culbert did not agree with the proposition that over-earnings in and of themselves are something that carries forward. He said, for

[263] LPMA Submission, page 11.
[264] LPMA Submission, page 16.
[265] Response to Undertaking JT3.18

example, that Enbridge's 2017 results include additional tax deductions from the cost of retirements that will not necessarily be accruing going forward.[266]

196. The Applicants submit that, on the evidence in this proceeding, an attempt to determine a base rate adjustment purportedly representing efficiencies and savings that carry forward into 2019 would be arbitrary. There is no evidence to support a calculation of efficiencies that would carry forward were Enbridge and Union to rebase for 2019. There is evidence that certain drivers of the earnings amounts relied on by intervenors were factors that cannot be presumed to carry forward into 2019.

197. Essentially, intervenors are arguing that, if the Board grants the request for approval of a deferred rebasing period, the Board should try to calculate a rate adjustment, even though the evidence to determine such an adjustment is evidence that would be presented were Enbridge and Union to rebase for 2019. The Applicants submit that this is an untenable proposition. Should the Board decide in favour of a rebasing deferral, the Board cannot make an adjustment for which the Board needs the evidence that would be filed on rebasing.

198. Moreover, it is important to bear in mind that approximately $30 million of O&M expense reductions for Enbridge have been assumed in the stand-alone scenario.[267] Given that the proposed Price Cap IR mechanism results in slightly lower total required revenues than the stand-alone scenario,[268] and given that the stand-alone scenario includes $30 million of O&M reductions for Enbridge, it is clear that there is no need or justification for an adjustment to base rates to reflect O&M savings by Enbridge.

---

[266] 6 Tr. 38-39.
[267] Exhibit C.SEC.19, Attachment 3,18 pages 1 and 2, page 1 shows OEB approved O&M of $462.7M for 2017 and $472.3 for 2018, and page 2 shows actual of $431.7M for 2017 --- a reduction of $31M vs 2017 approved which makes up the majority share of the 2017 higher earnings of $47M. Exhibit C.FRPO.11, page 2 line 2.6 shows the 2019 forecast O&M at $441M which when compared to the 2018 approved of $472.3Mshows a lower O&M of $31M; 6 Tr. 38-39.
[268] MAADs Exhibit B-1, page 20, Table 3, rows 5 and 6 for the year 2019.

199. Finally on this point, the Applicants reiterate their submission that, should the Board consider it necessary or appropriate that a change be made to the Applicants' proposals to allow ratepayers to share in more savings prior to the end of the deferral period, a balanced ESM over the 10 year deferred rebasing period will deliver the best outcomes for customers, as opposed to other mechanisms such as a base rate adjustment or a stretch factor.

200. FRPO submits that "[t]he additional ratepayer contribution of $9.7 million" for the demand costs of the Parkway Delivery Obligation ("PDO") should be removed as a base rate adjustment for Union South customers.[269] LPMA adopts, without discussion, FRPO's submission.[270] There is no merit to FRPO's submission and it should be rejected by the Board.

201. While lengthy and somewhat difficult to follow, FRPO's argument can be distilled to one fundamental assertion: the claim that ratepayers are paying for the cost of eliminating the Parkway Delivery Obligation twice. This can be seen most clearly in the following claim made by FRPO:

> Even with the last tranche of Parkway to Dawn shift Nov. 1/17, there is an equivalent of 200 TJ of Dawn-Parkway which ratepayers are now paying for through PDO Reduction costs in rates. Since that amount is less than the 210 TJ of original surplus, ratepayers are paying twice for the 200 TJ."[271]

202. FRPO's claim is wrong. Indeed, not only are ratepayers not paying twice, but the PDO has been eliminated in precisely the manner contemplated and agreed to by the parties in the PDO Settlement Agreement approved by the Board in EB-2013-0365.

[269] FRPO Submission, page 7, paragraph 5.3
[270] LPMA Submission, page 16.
[271] FRPO Submission, page 7, paragraph 5.6

This Agreement followed shortly after the Board's decision in respect of Union's 2013 rebasing application, EB-2011-0210.

203. In EB-2011-0210, the Board considered and approved:

- the costs of the Dawn-Parkway system;
- the methodology for allocating those costs (distance weighted easterly design demands); and,
- the demands used in the allocation.

204. The final item noted above, the "demands used", was based, in part, on Union's forecast of ex-franchise M12 transportation on the Dawn-Parkway system. Contrary to a statement made in the FRPO Submission,[272] this was a contested issue in the EB-2011-0210 proceeding. The Board came to the following conclusion on this issue:

> The Board accepts Union's forecast of 2013 M12 Long-Term Transportation Revenue, Other Long-Term Transportation Revenue, and Other S&T Revenue as reasonable. The Board will not require Union to adjust estimated revenues as was suggested by some parties, as the Board concurs with Union that the adjustments are selective in nature. <u>The Board rejects LPMA's request to establish a variance account related to Long-term Transportation Revenue, as the Board believes that Union should continue to bear this forecast risk, consistent with the current treatment.</u>[273]
>
> (Emphasis added.)

205. Throughout its submission, FRPO refers to Union having "surplus" or "excess" capacity.[274] This is a red-herring that has nothing to do with the Parkway Delivery Obligation. It is a backdoor attempt by FRPO to re-argue the above issue in relation to the appropriate M12 revenue forecast. As the Board decided, Union should be at risk in

[272] FRPO Submission, page 9, footnote 19.
[273] EB-2011-0210 Decision and Order, page 22.
[274] For example, FRPO Submission, page 13

relation to the forecast: if Union fails to meet the forecast, the company bears the loss; if it exceeds the forecast, subject to earnings sharing, both the company and ratepayers benefit.

206. Ultimately, as a result of the Board's decision, all costs of the Dawn-Parkway system (and the capacity available on the system) were allocated to ratepayers in proportion to distance weighted easterly design day demands. This produced the following allocation: 84% to ex-franchise rate classes, 11% to Union South in-franchise rate classes and 5% to Union North rate classes.

207. On design day, Union requires gas at Parkway to meet the needs of its customers.

208. The PDO Settlement was reached in Union's first rate proceeding following rebasing. The purpose of the Settlement Agreement was set out in the "context and guiding principles." In those paragraphs, the parties, including FRPO and LPMA, agreed that there was an "inequity" in that direct purchase customers with a PDO were conferring a benefit on users of the system (primarily Union South in-franchise customers); that the PDO should be permanently reduced primarily in the manner proposed by Union; and that Union should be kept "whole", with the reduction neither intended to reduce or increase its earnings potential over the IR term.

209. The parties next set out in the Agreement the timing and manner in which the PDO would be reduced and ultimately eliminated (the PDO Reduction Proposal). While divided into three phases, only the period after Phase 1, April 2014 is relevant. Fundamentally, the parties agreed that Dawn to Kirkwall M12 capacity turned back by ex-franchise shippers would be used to reduce the PDO. The parties agreed that:

> All incremental costs associated with the incremental PDO reduction [subsequent to the Phase 1 reduction], including demand charges and fuel, will be recovered by Union either through the deferral account due to timing differences or included in rates per paragraphs B.1(d), B.1(e), B.1(f) and B.3.[275]

210. In simple terms, the parties recognized (i) that as M12 shippers turned back capacity (which capacity could then be used to move gas to Parkway thus reducing the need for a PDO) this would result in decreased revenues to Union - a shortfall relative to what had been approved by the Board in EB-2011-0210 – and agreed (ii) that, to keep Union "whole" relative to that decision, in-franchise rate payers would make up that revenue through a change(s) in their rates.

211. As explained by Union's witnesses during cross-examination in this proceeding, eliminating the PDO came at a cost. For example:

> MR. KITCHEN: The Parkway delivery obligation and the shift to Dawn was something that customers wanted for quite a long time, and it was something that we worked very hard as a group to facilitate.
>
> But the move was not free. <u>When you move the deliveries from Parkway to Dawn you need facilities equivalent to get that gas back to Parkway because that's where it's needed, and so the costs that were built into rates in '15 and throughout the last term of the IRM were costs associated with facilitating that shift.</u>
>
> So in essence, customers were getting an additional service, and they paid for that service.[276]
>
> (Emphasis added.)

212. And, to the same effect:

---

[275] EB-2013-0365 Decision and Order on Parkway Delivery Obligation, June 16, 2014, Appendix B, page 4, part iii.
[276] 3 Tr. 15-16.

> MS. MIKHAILA: Yes, because we had customers that had M12 capacity, turned it back so that they could deliver at Dawn, and we included that -- the offset of that is included in line 15, the recovery of Dawn to Parkway demand cost.[277]

213. Since entering into the PDO Settlement Agreement, Union has used easterly Dawn-Parkway system capacity to allow direct purchase customers to shift their obligated deliveries from Parkway to Dawn, which has resulted in Union South in-franchise rate classes requiring firm Dawn-Parkway capacity on design day that is incremental to the original allocation of Dawn-Parkway costs from the 2013 Board-approved cost allocation study. In other words, in-franchise ratepayers have been asked to pay costs not previously allocated to them; they are not paying twice. These costs are the current Dawn-Parkway system demand costs of $9.7 million shown in Exhibit J2.5.[278]

214. In each rates proceeding subsequent to the PDO Settlement Agreement, Union has proposed to adjust rates as contemplated by the Agreement and the Board has approved these adjustments. In none of the proceedings has any party objected to the adjustment.

215. The Applicants submit that it would be inappropriate, and contrary to the PDO Settlement Agreement and the various Board decisions which have subsequently implemented the Agreement, to now deny recovery of Dawn-Parkway demand costs during the deferred rebasing term (as argued by FRPO) while at the same time maintaining the PDO shift to Dawn for direct purchase customers. The recovery of the Dawn-Parkway demand costs for the capacity used to facilitate the PDO shift and the benefit to customers of shifting their obligated deliveries to Dawn are elements of the comprehensive PDO Settlement Agreement agreed to by all parties.

---

[277] 3 Tr. 14.
[278] Exhibit J2.5, Attachment 1, line 15.

216. As a final point on this matter, the fact that Union South in-franchise ratepayers are not paying the same Dawn-Parkway system costs twice is further evident from evidence given by the Applicants in an undertaking response.[279] The analysis in the undertaking response shows that the change in rates since the PDO Settlement Agreement reasonably reflects the result that would have obtained had the PDO shift occurred at the time of rebasing. Union South in-franchise demands would have made up a larger portion of overall demands and those customers would have been allocated a greater portion (greater than the 11% they were allocated) of the Dawn-Parkway system costs.

9. Deferral and Variance Accounts

(i) Continuation of Existing Accounts

217. The Applicants propose to continue the deferral and variance accounts listed in the pre-filed evidence for the Price Cap Application.[280] OEB Staff have no concerns with the continuation of the accounts[281] and, with the exception of the NAC/AU accounts, others support the continuation of accounts as proposed by the Applicants.[282]

218. The Applicants' submissions on NAC/AU are set out above.[283] Given the Applicants' submissions with respect to NAC/AU, and given that there is no opposition to the Applicants' proposal regarding continuation of any other existing deferral and variance accounts, the Applicants submit that approval should be granted to continue accounts as listed in the Price Cap pre-filed evidence.

---

[279] Exhibit J3.5.
[280] Mechanism Exhibit B-1, Attachment 4.
[281] Staff Submission, page 35.
[282] LPMA Submission, page 35; OGVG Submission, page 25.
[283] See section 6(iv), Y Factors, above.

(ii) Elimination of Accounts

219. The Applicants propose to eliminate eight deferral and variance accounts, as listed in the pre-field evidence for the Price Cap Application.[284] OEB Staff support the closure of the accounts proposed by the Applicants, except for Enbridge's Post-Retirement True-Up Variance Account ("PTUVA") and Union's Tax Variance Deferral Account ("TVDA").[285]

220. OEB Staff submit that, while no new amounts should be recorded in the PTUVA following amalgamation, the account should remain in operation until at least the end of 2019 because, after the disposition of the 2018 account balance, it is unknown whether there will be a residual balance (above the disposition threshold of $5 million) which remains to be cleared from the account.[286] The Applicants have no objection to OEB Staff's submission regarding the PTUVA.

221. OEB Staff submit that the impact of changes in tax rates for Amalco's Union rate zones should continue to be captured in the TVDA and, further, that an equivalent TVDA should be opened for Amalco's Enbridge rate zone.[287] OEB Staff's main point in support of this submission seems to be that tax variances below the Z factor materiality threshold cannot be addressed with the Z factor mechanism. As indicated in the evidence[288], TVDA is only capturing variances in HST input tax credits, the calculation of which will become increasingly complex through amalgamation. Changing the Z-factor threshold has no bearing on whether or not the deferral account should be

[284] Mechanism Exhibit B-1, pages 23-26.
[285] Staff Submission, pages 36-37
[286] Staff Submission, page 36.
[287] Staff Submission, pages 36-37.
[288] Mechanism Exhibit B-1, page 25

maintained as the ratepayer, in the case of tax reductions, or the utility, in the case of tax increases, are subject to the same Z-factor threshold. Connecting the continuation and expansion of TVDA to the EGD rate zone to the increase in the Z-factor criteria is inappropriate. Accordingly, the OEB Staff submission should be disregarded.

222. Apart from the submissions of OEB Staff, there are no objections to the Applicants' proposal for the elimination of deferral and variance accounts and, accordingly, subject to the comments above about the PTUVA, the Applicants submit that approval should be granted to discontinue accounts as listed in the Price Cap pre-filed evidence.

(iii) New Accounts

223. The Applicants do not propose any new deferral and variance accounts. In addition to the proposed TVDA for the Enbridge rate zone, OEB Staff submit that Amalco should be required to open new accounts for the Enbridge and Union rate zones to capture the revenue requirement impacts associated with the integration of their accounting policies and practices during the deferred rebasing period.[289]

224. The Applicants disagree with OEB Staff's submissions that new accounts should be created to capture impacts of the integration of accounting policies and practices. The Applicants submit that it is unnecessary and inappropriate to make a determination regarding the establishment of such accounts at this time. Rather, as set out in AIC, the Applicants propose that Amalco will provide annual reporting to the Board with regard to the financial impacts of accounting changes until all changes due to harmonization have been implemented. When all changes have been implemented, Amalco will report to

[289] Staff Submission, page 37.

the Board on the net financial impact of the changes and it will put forward a proposed treatment of any material net impact.[290]

225. In addition, the Applicants note that OEB Staff's proposal does not address the Board's criteria for establishment of deferral and variance accounts. As set out in the Gas Filing Requirements, a request to establish a new deferral or variance account is to be accompanied by evidence of how the eligibility criteria will be met. The eligibility criteria are causation, materiality and prudence.[291] In particular, there is no evidence on the record of this proceeding to satisfy the materiality criterion for the establishment at this time of the accounts proposed by OEB Staff.

10. Directives and Commitments

226. In the pre-filed evidence for the Price Cap Application, the Applicants indicated their intention to respond to certain directives and commitments during the deferred rebasing period.[292] OEB Staff make submissions with regard to two of these directives.[293]

227. First, OEB Staff comment on a directive that Union file a study assessing the methodology for determining NAC.[294] Again, the Applicants' submissions on NAC (as well as AU) are set out above.[295]

228. Second, OEB Staff refer to a directive regarding a review of the Panhandle and St. Clair system cost allocation methodology.[296] As well as submissions about the

[290] AIC, page 31, paragraph 101.
[291] Gas Filing Requirements, page 38, section 2.9.2.
[292] Mechanism Exhibit B-1, page 30.
[293] Staff Submission, pages 38-39.
[294] *Ibid*.
[295] See section 6(iv), Y Factors, above.

Panhandle project in the context of directives and commitments, OEB Staff refer to that project in discussing their concerns about the absence of a cost allocation study from Amalco during the 10 year deferred rebasing period.[297] Other submissions about a cost allocation study by Amalco also refer to the Panhandle project.[298]

229. The Applicants have fully met submissions and concerns about a cost allocation study from Amalco by making the commitment, as described above, that Amalco will complete two cost allocation studies during the deferred rebasing period and will consult with OEB Staff and intervenors on rates derived from each study.[299]

230. Notwithstanding the proposal that Amalco will file cost allocation studies, it is important to be clear that the Applicants consider existing cost allocation methodologies to be appropriate. Union's 2013 cost allocation study allocated costs in an appropriate manner and was approved by the OEB at that time.[300] Subsequent to the 2013 cost allocation study, Union included incremental costs in rates using Board-approved methodologies. The existing methodologies appropriately allocated the incremental costs with the exception of the Panhandle revenue requirement.[301]

231. The Panhandle project is unique[302] as it involved incremental costs not considered in the 2013 cost allocation study. If Union had known about the project at the time of the 2013 cost allocation study, it would have proposed an alternative allocation methodology at that time. In the pre-filed evidence for the Price Cap

---

[296] Staff Submission, page 39.
[297] Staff Submission, page 8.
[298] See, for example, APPrO Submission, page 9, paragraph 32, VECC Submission, page 8, paragraph 3.5, and IGUA Submission, pages 12-15.
[299] See section 4, Deferred Rebasing Period, above.
[300] EB-2011-0210, 2013 Cost of Service, Decision and Order, page 53.
[301] 3 Tr. 174-175.
[302] 3 Tr. 168.

Application, the Applicants stated unequivocally that Amalco will address the cost allocation of the Panhandle system and St. Clair system in the 2019 rate application.[303]

232. The Applicants have also made clear their expectation that cost allocation for the Panhandle system and St. Clair system can be addressed as a discrete cost element within one functional classification.[304] OEB Staff submit that the review of Panhandle and St. Clair cost allocation should not be completed until a comprehensive cost study is filed.[305] However, the Applicants submit that the Board should not pre-judge whether cost allocation for Panhandle and St. Clair can be addressed as a discrete cost element before the Board has even seen and considered Amalco's 2019 filing.

233. The Applicants submit that the Board need not and should not decide or comment on OEB Staff's assertion in this proceeding about the need for a comprehensive cost allocation study in order to review Panhandle and St. Clair cost allocation. This issue should be left for Amalco's 2019 rate application when the Board will actually have before it Amalco's proposal and evidence. Of course, regardless of the view that the Board takes of Amalco's proposal and evidence in the 2019 rate application, the commitment for Amalco to provide the first of the two cost allocation studies for 2022 will still stand.

11. Annual Rate Application, Reporting and Related Matters

234. The Applicants have outlined their proposal and suggested timing for annual rate applications by Amalco.[306] OEB Staff did not address the proposed annual process and there were very few submissions from intervenors on this subject. LPMA comments on

[303] Mechanism Exhibit B-1, page 31. The Applicants' submissions on Panhandle and Cost Allocation address IGUA's request to reply to these topics (IGUA Submission, page 15, paragraph 63).
[304] 5 Tr. 58.
[305] Staff Submission, page 39.
[306] Mechanism Exhibit B-1, page 26.

the timing of applications that include requests for ICM relief. The Applicants have proposed earlier timing for the filing of applications that include ICM requests than for those that do not,[307] but they submit that the Board should not be prescriptive about filing dates, particularly because Amalco's 2019 application cannot be filed until the final decision in this proceeding has been released.

235. The Applicants propose annual reporting of utility information aligned with the schedules provided during Enbridge's 2014-2018 Custom IR plan and Union's 2014-2018 IRM plan.[308] OEB Staff submit that the proposed reporting is acceptable, both as to its nature and its extent.[309]

236. The LPMA Submission supports reporting on material changes associated with efforts to harmonize accounting policies.[310] As discussed above,[311] the Applicants proposed in AIC[312] that Amalco will provide annual reporting to the Board with regard to the financial impacts of accounting changes until all changes due to harmonization have been implemented. When all changes have been implemented, Amalco will report to the Board on the net financial impact of the changes and it will put forward a proposed treatment of any material net impact.

237. In AIC, the Applicants indicated they are open to the suggestion that stakeholder meetings be held annually if this suggestion has general support from intervenors.[313] OEB Staff express a preference for an annual stakeholder meeting[314] and several

[307] *Ibid*, paragraph 3.
[308] Mechanism Exhibit B-1, page 28.
[309] Staff Submission, page 42.
[310] LPMA Submission, page 38.
[311] See section 9(iii), Deferral and Variance Accounts - New Accounts, above.
[312] AIC, page 31, paragraph 101.
[313] AIC, page 32, paragraph 103.
[314] Staff Submission, page 42.

intervenors also note support for annual stakeholder sessions.[315] Although there is not unanimous support amongst intervenors and Board staff, the Applicants are amenable to annual stakeholder sessions if the Board finds merit in them

238. The Applicants propose a scorecard to measure and monitor Amalco's performance over the 10 year deferred rebasing period.[316] OEB Staff submit that the proposed scorecard should also track cost control measures such as total cost per customer and total cost per kilometre of distribution pipeline.[317] OEB Staff also recommend that the scorecard "track net savings on an annual basis".

239. OEB Staff's idea about tracking savings was not explored during the evidence in this proceeding. The Applicants are not certain what OEB Staff mean by the suggestion that Amalco track "net savings" nor do the Applicants understand how OEB Staff contemplate that such tracking would be accomplished. Because the merits of, and any concerns about, a specific proposal have not been explored in this case, the Applicants submit that the Board should not accept OEB Staff's recommendation. The Applicants do accept, though, that cost per customer information could be included in the proposed scorecard as a cost control metric.

240. On the subject of rate harmonization, OEB Staff refer to the guidance provided by the MAADs Handbook, namely, that distributors are not expected to file proposals for rate harmonization as part of an application for consolidation, but are expected to propose rate structures and harmonization plans following consolidation at the time of rebasing.[318] LPMA takes the position that the provisions of the MAADs Handbook

---

[315] APPrO Submission, page 27, paragraph 119; CME Submission, page 39, paragraph 144; LPMA Submission, page 38.
[316] Mechanism Exhibit B-1, pages 20-22 and Attachment 2.
[317] Staff Submission, pages 40-41.
[318] Staff Submission, page 40; MAADs Handbook, page 17.

related to rate harmonization are not applicable in this case,[319] but then proceeds to argue strongly that only after the deferred rebasing period can the issue of rate harmonization be reviewed,[320] which of course is entirely consistent with the guidance in the MAADs Handbook.

241. The Staff Submission summarizes the evidence of the Applicants regarding rate harmonization by Amalco. Specifically, rate harmonization by Amalco will be a matter for consideration by the Board on rebasing, but the evidence of the Applicants is that, at some point during the deferred rebasing period (for example, the five-year point), Amalco could bring forward a study regarding harmonization that would be the subject of stakeholder consultation.[321] This would give the Board and stakeholders an opportunity to see where Amalco is headed on harmonization and it would afford an opportunity for input before the Board considers harmonization at rebasing.[322]

242. The Applicants submit that they have proposed a fair and balanced approach to rate harmonization that is aligned with Board policy and that affords an opportunity for all perspectives on harmonization to be brought forward during consultations before harmonization is considered on rebasing.

12. Undertakings

243. The Applicants have made commitments to C-K with regard to the presence that Amalco will maintain in C-K in the event that the amalgamation is approved and they have proposed wording to make these commitments a condition of Board approval for

[319] LPMA Submission, page 36.
[320] LPMA Submission, page 37.
[321] 5 Tr. 13.
[322] 5 Tr. 13-14.

the amalgamation.[323] The C-K Submission explains in detail why these conditions are critical to C-K.[324]

244. The C-K Submission also explains that the length of the proposed rebasing deferral is critical. The conditions are linked to the duration of the deferred rebasing period, which allows C-K time to adjust to potential implications of the amalgamation.[325]

245. OEB Staff submit that the Board has jurisdiction to approve the proposed conditions. In support of this conclusion, OEB Staff point to the unique circumstances of this case, arising from Undertakings (the "Undertakings") given by Union and its parent affiliated companies to the Lieutenant Governor in Council.[326] Similar submissions were made the by the Applicants in AIC.[327]

246. The Staff Submission says that clearly it was the intention of the government of Ontario "for the OEB to oversee compliance with the Undertakings". The Staff Submission also refers to "the OEB's historical role as overseer of the Undertakings".[328] However, OEB Staff express concerns about the OEB exercising its jurisdiction to approve the conditions in this case.

247. The reasons for OEB Staff's concerns are primarily based on the notion that, if the government wished to ensure a continuing legal obligation for Amalco in respect of its presence in C-K, it could have done so through legislation or some other binding

[323] Exhibit C.STAFF.12, response to OEB Staff Interrogatory #12 modified in response to Undertaking J2.1.
[324] C-K Submission, page 2, paragraph 6, and pages 4-5, paragraphs 18-24.
[325] C-K Submission, pages 5-6, paragraph 26.
[326] Staff Submission, pages 42-43.
[327] AIC, pages 20-21, paragraphs 62-67.
[328] Staff Submission, page 43.

legal instrument. Given that the government has not taken any such action, OEB Staff say "it is not the OEB's obligation to fill the gap".[329]

248. The Applicants submit that, especially in view of the Board's historical role as overseer of the Undertakings, it is not reasonable to expect that the government of Ontario would have gone to the length of passing legislation to ensure a continuing legal obligation in respect of Amalco's presence in C-K. On the contrary, as stated by OEB Staff, the government's intention is for the OEB to oversee compliance with the Undertakings, and the reasonable conclusion is that, in not taking steps such as the enactment of legislation, the government was leaving this matter to be addressed by the Board.

249. The Applicants therefore submit that the Board should approve the proposed conditions for the reasons set out in the C-K Submission and in AIC.

13. Other Arguments

250. In its submissions, SEC says the proposal of the Applicants appears to be that they will proceed with the amalgamation "only if they like the rate-setting plan the Board establishes".[330] At no time have the Applicants indicated that the decision to proceed with the amalgamation depends on whether they "like" the decision of the Board at the conclusion of this proceeding.

251. The Applicants have proposed an amalgamation with a 10 year deferral of rebasing. Until the Board has issued its decision, there is no certainty about the rate mechanism that will apply during the deferral period of 10 years. Should the Board not

[329] Staff Submission, page 44.
[330] SEC Submission, page 8, paragraph 1.3.2.

approve the Applicants' proposals, and, in particular, should the Board issue a decision indicating an expectation that the proposals be changed significantly, it is entirely reasonable that the Applicants consider their plans for amalgamation in view of the Board's decision. Not only is this course of action reasonable, it is also consistent with situations where the Board, when coming to a decision not to accept a proposal made by a utility, has recognized that its guidance will allow the utility to make effective decisions about the way in which the utility will proceed.[331]

252. Another argument made by SEC relates to potential rate impacts of applying the proposed Price Cap formula.[332] As explained in evidence, the rate impacts referred to by SEC are not driven by the Price Cap mechanism itself.[333] The reason for the rate impacts observed by SEC is because, in preparing answers to particular undertakings, the Applicants did not escalate monthly charges.[334]

253. As to the application of the escalator, SEC asserts in argument that rate increases will be applied in a manner that is largely within the Applicants' discretion.[335] In fact, when counsel for SEC suggested to the Applicants' witnesses that the Board would not "have a say" in how the escalator is applied, the response was that the Board does have a say in it and whatever is done going forward will be subject to Board approval.[336]

[331] For example, in E.B.O. 179-14/15, The Consumers' Gas Company Ltd. (now Enbridge) made a proposal for the basis upon which certain programs would be maintained within the "core utility". Some intervenors urged the Board to "just say no", but the Board attempted to craft a solution to address its concerns with the proposal and "to provide the Company with sufficient information and guidance to allow it to make effective decisions about the way in which it will proceed": E.B.O. 179-14/15 Decision with Reasons, March 31, 1999, at page 24.
[332] SEC Submission, pages 50-51, paragraphs 5.6.1-5.6.4.
[333] 6 Tr. 16.
[334] 6 Tr. 9.
[335] SEC Submission, page 50, paragraph 5.6.2.
[336] 6 Tr. 9-10.

254. In this proceeding, the Applicants have not made a proposal with regard to the escalation of monthly fixed charges.[337] They are seeking approval of a price-setting framework and proposals as to "how the rates would actually be set" will be made in subsequent proceedings.[338] This is consistent with the Board's approval of previous price-setting frameworks: in each instance, the Board approved a mechanism and the "working papers" and "backup" for the actual setting of rates came in later proceedings.[339]

D. CONCLUSION

255. The Applicants therefore submit that the record of this proceeding provides a strong foundation for the following conclusions:

(i) the proposals made in the Applications are aligned with the Board's objectives and policy direction for regulation of Ontario utilities;

(ii) consistent with the Board's expectations regarding an outcomes-based approach to regulation, the Applicants' proposals will bring a singular focus to the successful completion of the integration of Enbridge and Union and the optimization of synergies and savings, consistent with the Board's expectations regarding an outcomes-based approach to regulation[340];

(iii) the no harm test has been met and the proposal that leave be granted for Enbridge and Union to amalgamate stands virtually unchallenged;

[337] 6 Tr. 10.
[338] 6 Tr. 12.
[339] *Ibid*.
[340] 1 Tr. 25-26

(iv) the 10 year deferred rebasing period gives Amalco the incentive to pursue deep, meaningful and lasting savings and synergies[341], while a shorter rebasing deferral would diminish the incentive for Amalco to take on major expenditures with multi-year payback periods and to tackle savings and synergies with a longer term outlook;

(v) the Price Cap mechanism using the parameters proposed by the Applicants, together with including the availability of the ICM, is a fair and balanced framework for rate-setting during the deferred rebasing period;

(vi) the experts agree that the productivity factor in the Price Cap formula should be zero and no credible reason has been given for the Board not to accept the recommendation of the experts;

(vii) a stretch factor greater than zero should not be added to the Price Cap formula because, among other reasons, it would put at risk Amalco's ability to earn allowed ROE and it would be incompatible with the Amalco forecasts presented in evidence by the Applicants;

(viii) ratepayers will not bear the risks of the amalgamation, but will benefit on rebasing from sustainable synergies and savings achieved by Amalco and will be protected during the deferred rebasing period by reason of the measures proposed by the Applicants[342]; and

(ix) to the extent that the Board considers additional customer protection to be necessary or appropriate, a balanced ESM over the 10 deferred rebasing period, with a zero stretch factor, will deliver the best outcomes for customers.

---

[341] Exhibit C.STAFF.4, page 1.
[342] MAADs Exhibit B-1, pages 41-42; Mechanism Exhibit B-1, pages 20-21.

256. The Applicants submit that the Board should approve the Applications in accordance with the foregoing conclusions.

All of which is respectfully submitted.

June 29, 2018

Fred D. Cass
Counsel for the Applicants