EB-2017-0306
EB-2017-0307

ONTARIO ENERGY BOARD

Enbridge Gas Distribution Inc.
Union Gas Limited

Application for approval to amalgamate
Enbridge Gas Distribution Inc. and Union Gas Limited
and for approval of a rate-setting mechanism and associated
parameters from January 1, 2019 to December 31, 2028

SUBMISSIONS OF CANADIAN MANUFACTURERS & EXPORTERS ("CME")

June 15, 2018

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TABLE OF CONTENTS

1.0 INTRODUCTION

1. These submissions are made on behalf of Canadian Manufacturers & Exporters ("**CME**").

2. CME's members, which include over 1,400 Ontario based companies, operate energy intensive businesses. Their continued competitiveness in their respective industries is tied directly to how much energy costs them and, as a result, the dramatically increasing cost of energy in Ontario has made it much more difficult for CME members to be competitive in the market, compared with businesses from other jurisdictions where energy costs less.

3. The cost consequences of this application are significant, with the proposed amalgamation of Union Gas Limited ("**Union**") and Enbridge Gas Distribution Inc. ("**EGD**" or "**Enbridge**") (collectively "**Amalco**") forecasted to have a revenue requirement of over $29 billion during the course of the proposed deferred rebasing term. Furthermore, Union and EGD are proposing a 2.4% average increase in rates, which will drive increased energy rates for CME's members across the province.

4. In preparing these submissions, CME has benefitted from the contributions of many of the other intervenors, including reviewing their draft submissions. This has assisted CME in making efficient use of resources given the scope of this application.

5. These submissions focus on the components of Union and EGD's (collectively, the "**Applicants**") proposal which, in CME's submission, require adjustment in order to ensure rates in Ontario are just and reasonable, and to protect ratepayers with respect to the cost of natural gas distribution. Where these submissions do not touch on an issue that was outlined in the Board's approved issues list, CME takes no position with respect to that issue.

2.0 THE APPLICATION

6. On November 2, 2017, the Applicants filed an application seeking approval to effect the amalgamation of EGD and Union pursuant to subsection 43(1) of the *Ontario Energy Board Act, 1998* (the "***OEB Act***"), as well as approval to defer rebasing for ten years from 2019-2029.

7. On November 23, 2017, the Applicants filed an Application pursuant to subsection 36(1) of the *OEB Act* to approve a rate-setting mechanism that would apply during the proposed deferred rebasing period.

8. The Board combined the two applications in its Decision and Procedural Order No. 3, issued on March 1, 2018.

9. The combined application has the following features:

- Amalgamation of the two utilities, on the basis that the amalgamation passes the "no harm" test;
- A 10 year deferred rebasing period;
- A price cap mechanism to set rates during the 10 year deferred rebasing period, featuring an I – X formula for increasing rates that includes a combined "X" factor of 0%;
- No earnings sharing mechanism ("ESM") for the first five years, followed by an ESM in years 6-10 that shares over-earnings above 300 basis points with rate payers 50/50;
- A Z factor with a materiality threshold of $1 million;
- An incremental capital module; and
- Bi-annual stakeholder information sessions.

3.0 AMALGAMATION AND THE "NO-HARM" TEST

10. The Applicants propose to amalgamate what is currently Union and EGD. In these proceedings the merged company is referred to as Amalco.

11. In order to approve an amalgamation, the Board has to determine whether the proposed amalgamation passes the "no harm" test.[1] As stated by the Board in their Decision in EB-2016-0351, regarding Natural Resource Gas Limited's application to sell their distribution system to EPCOR Natural Gas Limited Partnership, the "no harm" test looks to see whether the proposed amalgamation will have an adverse effect on the Board' statutory objectives.[2] To the extent that the effects are neutral or positive, the application will be approved.[3]

12. The Applicants state that their proposed transaction meets the "no harm" test as it relates to the Board's statutory objectives. Specifically, with regards to consumer interests, the Applicants calculate that ratepayers will benefit by $410 million under their price cap amalgamation proposal when this proposal is compared to hypothetical custom IR applications that the Applicants might have filed absent the amalgamation.[4]

13. While CME believes that the benefits to ratepayers may be overstated as discussed in more detail in section 5.2, CME agrees with the Applicants that the merger of the two utilities should produce opportunities in increased productivity with the potential to reduce gas rates in Ontario. Furthermore, since Enbridge Inc. already owns both of the Applicants, the amalgamation of both utilities is much less likely to have adverse impacts on some of the Board's statutory objectives, such as financial viability of gas distribution industry. Accordingly, CME supports the amalgamation of Union and EGD.

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1 The Board determined that it would use the no harm test in its Decision and Procedural Order No. 3, March 1, 2018, p. 4.
2 EB-2016-0351, Decision and Order, August 3, 2017, p.3.
3 EB-2016-0351, Decision and Order, August 3, 2017, p.3.
4 EB-2017-0306, Exhibit B, Tab 1, p. 20.

14. CME submits however, that the deferred rebasing period chosen by the Applicants, as well as many features of the rate-setting mechanism are not supported by the evidence, and should be rejected by the Board.

4.0 DEFERRED REBASING PERIOD

15. The Applicants have applied to the OEB for a rate-setting mechanism that lasts for 10 years without rebasing from their respective existing rate-setting mechanism. In other words, the Applicants are proposing a 10 year deferred rebasing period, which would run consecutively from the end of the 5 year rate-setting mechanisms that were determined in EB-2012-0459 and EB-2013-0202.

16. In their argument-in-chief, the Applicants contend that a 10 year deferral period is consistent with the direction contained in the Board's *Handbook to Electricity Distributor and Transmitter Consolidations*, issued on January 19, 2016 (the "**Electricity MAADs Handbook**"), and that the Electricity MAADs Handbook applies wholesale to natural gas distributors. They also argue that the evidence in this proceeding, on its own merit, demonstrates that the 10 year deferred rebasing period is appropriate. CME disagrees on both counts.

17. CME has had the benefit of reviewing School Energy Coalition's ("**SEC**") position on the 10 year deferral period, and believes that it has merit. CME shares the concern of many intervenors that deferring rebasing for an additional 10 years extending from the end of a full 5 year IR term would allow for an inappropriate disconnect between rates and the costs the Applicants incur to serve ratepayers. While CME acknowledges that the purpose of incentive regulation is to decouple revenue from costs, a 15 year gap between rebasing is inappropriate.

18. Accordingly, CME submits that if the Board does not decide that immediate rebasing is appropriate, the Board should allow a 5 year deferred rebasing period at most.

4.1 The Electricity MAADs Handbook Does Not Apply on its Face

19. The Electricity MAADs Handbook does not apply to the Applicants in this case on its face. The Electricity MAADs Handbook specifically sets out those entities that it applies to. In addition to its title, "*Handbook to Electricity Distributor and Transmitter Consolidations*", the Electricity MAADs Handbook also states in the body of the text which regulated entities it applies to:

> ***While the Handbook is applicable to <u>both electricity distributors and transmitters</u>, most of the OEB's policies and prior OEB decisions have related to distributors.***[5] (emphasis added)

20. Despite this clear language of the document, the Applicants argue that the Electricity MAADs Handbook applies to natural gas distributors based on a tenuous set of connections between the Electricity MAADs Handbook, the *Handbook for Utility Rate Applications* (the "**Rate Handbook**") and the *Filing Requirements for Natural Gas Rate Applications*.[6]

21. In support of their contention, they point to Appendix 3 of the Rate Handbook, which references the Board's electricity MAADs policy, and argue that since the Rate Handbook applies to natural gas distributors, and Appendix 3 references the Board's Electricity MAADs Handbook, the inescapable conclusion is that the Electricity MAADs Handbook must also apply to natural gas distributors.[7]

22. CME submits that the proper interpretation is a much simpler one: the Electricity MAADs Handbook applies to the entities it states that it applies to.

23. When read in context, there is no confusion about what entities the MAADs discussion in the Rate Handbook is referring to. Appendix 3 sets the parameters of the scope by referencing an older MAADs handbook that only applied to electricity distributors. Appendix 3 goes on to reference the Electricity MAADs Handbook, a document that

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5 Ontario Energy Board, *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, p. 2.
6 EB-2017-0306, EB-2017-0307 Argument-in-Chief of the Applicants, June 1, 2018 ("**AIC**") at paras.33-37.
7 AIC at paras.34-35.

states in multiple locations that it only applies to electricity distributors and transmitters. As a result, the scope of the guidance in the Rate Handbook is clear.

24. Given that context, CME fails to see how the inclusion of a reference to the Electricity MAADs Handbook in the Rate Handbook leads to the conclusion that the Electricity MAADs Handbook is applicable to natural gas distributors. As a document that applies to both the electricity and natural gas industries, it is only logical that the Rate Handbook would include policies that are only applicable to one of the regulated industries. That way, the Rate Handbook could be a comprehensive starting point for utilities who want to apply in either sector, not simply a recitation of the requirements that are common to both sectors, with further requirements to be found in other documents.

25. The Applicants further argue that the application of the MAADs policy has been expanded to include natural gas distributors in a similar way to how the Renewed Regulatory Framework ("**RRF**") was expanded to natural gas distributors. What this ignores is the Board's proactive communication of such changes to stakeholders as a method of avoiding scope disputes. The RRF was originally entitled "Renewed Regulatory Framework for Electricity" ("**RRFE**"); however, the Board proactively and clearly informed parties about the change in the RRFE's scope to include natural gas distributors. In the Rate Handbook, the OEB stated:

> ***This Handbook outlines how the RRFE will be applied to all regulated utilities going forward. The framework will be referred to as the Renewed Regulatory Framework (RRF) in this document and by the OEB going forward to reflect this transition.***[8]

26. Indeed, CME notes that the Board specifically released an updated MAADs handbook when it moved from an 'electricity distributors' only policy to one encompassing transmitters as well. The current Electricity MAADs Handbook states that it is for electricity distributors and transmitters in the title, clearly indicating the updated scope.

[8] Ontario Energy Board, *Handbook for Utility Rate Applications,* October 13, 2016, p.4.

27. In CME's view, this marks a clear distinguishing feature between the two instances. When the Board wishes to expand the scope of its guidance, not only does it change the name of the applicable policy (from RRFE to RRF), but in complementary policies it indicates what entities the policy will apply to. In this case, there has been no such proactive communication. Accordingly, CME submits that the plain language reading of the Electricity MAADs Handbook is the correct interpretation: it only applies to electricity distributors and transmitters.

4.2 The Electricity MAADs Handbook Does Not Apply on a Principled Basis

28. The Board's Electricity MAADs Handbook also does not apply to natural gas distributors because it was developed in response to an issue that was specific to Ontario's electricity distributors.

29. The Electricity MAADs Handbook describes why it opted to provide for an extended deferred rebasing period:

> ***To encourage consolidations, the OEB has introduced policies that provide consolidating distributors with an opportunity to offset transaction costs with any Ontario Energy Board January 19, 2016 achieved savings. The 2015 Report permits consolidating distributors to defer rebasing for up to ten years from the closing of the transaction.***[9]

30. To determine the purpose of the 10 year deferred rebasing period, it must be determined why the OEB wanted to "encourage consolidations". The answer can also be found in the Electricity MAADs Handbook:

> ***The Commission on the Reform of Ontario's Public Services, the Distribution Sector Review Panel and the Premiers Advisory Council on Government Assets have all recommended a reduction in the number of local distribution companies in Ontario and have endorsed consolidation.***[10]

31. In the case of the Commission on the Reform of Ontario's Public Services, they recommended consolidating Ontario's 80 local electricity distribution companies in an

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[9] Ontario Energy Board, *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, p. 11-12.

[10] Ontario Energy Board, *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, p. 1.

effort to slow rising electricity prices, a concern exacerbated by Ontario's long term energy plan at the time, which projected that electricity prices would increase by 46% from 2010-2015.[11]

32. Accordingly, the clear stated purpose for allowing a 10 year deferred rebasing period was to combat rising electricity prices. This would also explain why the Board found it desirable to expand the Electricity MAADs Handbook to transmitters as well. While there are not a multiplicity of transmitters in Ontario, consolidation can lead to lower per-customer rates, which would help combat the dramatically increasing cost of electricity.

33. The purpose of incenting consolidation simply does not exist in this case. No commissions were struck to determine what to do about the price of natural gas, and there is no forecast predicting such a dramatic rise in gas prices. Accordingly, these policies, including the 10 year deferred rebasing period were not and are not applicable to natural gas distributors.

34. The Applicants argue that consolidations in both the electricity and gas context can create economies of scale, and allow for utilities to serve customers at a lower per customer cost.[12] Due to the similar salutary features common to both sectors, the Applicants argue that they should also have a 10 year deferred rebasing period available to them.

35. While CME agrees that mergers between natural gas distributors can create economies of scale, and can lead to lower costs on a per customer basis, CME submits that the Applicants have taken a myopic view of the principles of the Electricity MAADs Handbook.

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[11] Commission on the Reform of Ontario's Public Services, *Public Services For Ontarians: A Path to Sustainability and Excellence*, Chapter 12 – Infrastructure, Real Estate and Electricity, s. III: Options to Reduce Long-Term Electricity Costs, and Recommendation 12-13.

[12] AIC, pp. 13-15.

36. Mergers and acquisitions do not have uniformly salutary effects. Multiple service providers can spur innovation, not only technologically but also in terms of evolving best practices. Multiple service providers can also increase transparency and accountability, as service providers can be compared against one another. The salutary effects of multiple service providers wane as the result of consolidations, mergers and amalgamations.

37. Therefore, it is not correct to say that the Board wanted to incent consolidation for any distributor simply because consolidations can create economies of scale and lower unit costs. Instead, the Board's policy recognizes that in the context of electricity distributors (with approximately 80 in the province), and in answer to a very specific problem (the forecast 46% increase in electricity prices between 2010-2015), consolidations were the appropriate solution. Even after numerous consolidations, there are still enough electricity distributors in the province to spur innovation and maintain transparency and accountability.

38. Contrastingly, the circumstances of this case are very different. If the amalgamation of the Applicants is approved, there will only be 2 natural gas distributors left in Ontario, and the disparity in size between them may make comparisons difficult. There is also no dramatic price increase projected for natural gas as there was for electricity. Furthermore, Enbridge Inc. does not require incentives to acquire Union, it has already done so, and all that is left in this proceeding is merging the two commonly owned utilities.

4.3 The Board's Statutory Objectives

39. The *OEB Act* sets out a number of objectives for the regulation of electricity in the province. Largely these objectives pertain to the affordability of electricity and the cost effectiveness in transmission and distribution. Contrastingly, the Board's statutory

objectives for gas includes the objective of facilitating "competition in the sale of gas to users".[13]

40. Given that amalgamation necessarily reduces the number of competing entities in the marketplace, CME submits that it makes sense for the Electricity MAADs Handbook, which heavily incents consolidation, would only apply to the electricity sector. That would allow the Board to take a much more nuanced approach to regulating natural gas consolidations, which would require a weighing of competing interests with regard to rates and competition in the market.

41. In short, it is inappropriate under the circumstances to incent the Applicants into consolidating in the same way and to the same extent that the Board incents electricity distributors to consolidate. A deferred rebasing period of 5 years is sufficient incentive under the circumstances.

4.4 The Actual Implementation Process Will Not Take 10 Years

42. The evidence on the record in the proceeding demonstrates that the Applicants do not require a 10 year deferred rebasing period in order to successfully consolidate and achieve their anticipated efficiencies

43. As part of an interrogatory response, the Applicants provided a presentation that they gave to the Enbridge board of directors on October 31, 2017. In it, the Applicants demonstrate the expected timelines of the integration activities that will drive the savings under the amalgamation. They provide two timelines, one that projects a low/moderate scenario, and another that projects a moderate/aggressive timeline.

44. The moderate/aggressive timeline shows that the Applicants forecast the successful execution of most integration activities by 2022, with all integration execution activities being completed in 2023, five years into the deferred rebasing period. According to the

13 *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Sched B, s.2(1).

Applicants' evidence, a lot of the savings and efficiencies will be achieved during this period.[14]

45. The only activities that the Applicants show as ongoing past 2023 in the moderate/aggressive timeline are the "stabilization period" activities. According to the evidence presented on cross-examination, these activities are comprised of "fine-tuning" systems and processes, possible training, and fixing errors should any exist.[15] In other words, while there may be kinks in the new systems and processes, the vast majority of the integration occurs during the integration execution phase. In any event, the stabilization phase is only projected to last until 2025, a full three years before the end of the proposed ten year rebasing period.

46. In the low/moderate project timeline, the Applicants project that they will be completed integration execution activities by 2025, and completely finished all activities, including stabilization activities by 2026.[16] Similar to the moderate/aggressive timeline, this means that all integration work will be completed by the Applicants a full two years before the end of the 10 year deferred rebasing period.

47. The Applicants have not provided any evidence to suggest which timeline is more likely; however, given that the moderate/aggressive timeline is still within the realm of 'moderate' timelines, CME submits that the Board should accept the Applicants' ability to complete the required integration execution tasks within that timeframe.

48. Accordingly, the evidence of the actual implementation process supports the five year deferral period proposed by CME, not the Applicants' proposal of a 10 year deferred rebasing period.

14 Transcript Volume 1, p. 102.
15 Transcript Volume 1, pp.101-102.
16 Exhibit C, FRPO.1, Attachment 1, p. 19.

4.5 The Costs Associated with Integration Do Not Justify a 10 Year Deferred Rebasing Period

49. The evidence of the costs and savings provided by the Applicants also do not justify the 10 year deferred rebasing period.

50. The "Cumulative Integration Capital Investments and OM&A Savings" chart prepared by Board Staff shows that the Applicants' cross-over point, or the point where the savings occasioned by integration are greater than the costs of the integration investments occurs between 2020 and 2021.[17] In terms of the cost/benefit of investing in integration initiatives between the utilities, that means that between 2021 and 2028, the Applicants will be generating a net benefit.

51. The Applicants' position is that Board Staff's chart is too simplistic. In their view, it would be more appropriate to calculate the cross-over point at the moment where the net savings of integration outweigh both the capital cost to achieve those savings, and the "revenue shortfall" that the Applicants contend they will incur as the result of staying on a price cap formula.[18]

52. As discussed further in section 5.2, CME disputes the Applicants' calculation of their "revenue shortfall" as compared to the utilities filing two separate custom IR applications. The Applicants acknowledged on cross-examination that the cost assumptions embedded in the stand-alone applications include a finding of prudence by the Board on all capital amounts spent since the last rebasing, and that there will be no efficiencies between the commonly owned utilities, despite the fact that witnesses for the utilities have admitted that they have already achieved savings and would continue to even without amalgamation.[19]

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17 OEB Staff, Cross-Examination Compendium, Panels 1 and 2, Exhibit K1.6, Tab 3.
18 See Undertaking J2.4, p. 2.
19 Transcript Volume 1, p. 67.

53. Those issues notwithstanding, the Applicants' own cross-over chart depicts the cross-over point at 2025-2026, which would represent at least full two years before the end of the 10 year deferred rebasing.[20] Given the number of questionable assumptions made by the Applicants in determining their "revenue shortfall" as compared to stand-alone applications, CME submits that it would be appropriate to conclude that the cross-over point would occur well before 2025, and a five year deferred rebasing period would be appropriate.

5.0 EARNINGS SHARING MECHANISM

54. The Applicants propose to include a limited earnings sharing mechanism ("**ESM**") as part of their rate-setting mechanism. Specifically, the Applicants propose to have no ESM for years 1-5 of the deferred rebasing period. Starting in year 6 of the deferred rebasing period, the Applicants propose an ESM that is triggered if the utility earns more than 300 basis points (3%) higher than their allowed return on equity ("**ROE**"). Earnings above 300 basis points would be shared with rate-payers on a 50/50 basis.[21]

55. This is a considerable departure from the Applicants' current ESMs. EGD currently operates under an ESM that is triggered if the utility over-earns its ROE at all. In other words, there is no deadband on over-earnings before the ESM kicks in.[22] EGD's sharing mechanism splits over-earnings 50/50 with ratepayers. Union is required to share any earnings from 100 basis points above ROE to 200 basis points above ROE 50/50 with ratepayers, and any earnings from 200 basis points and above 90/10 with ratepayers.[23]

56. CME submits that the Applicants' ESM proposal is inappropriately favourable to the Applicants, and cannot be justified in this instance. Instead, it would be appropriate for the Applicants to operate with an ESM that begins in year one of the deferred rebasing

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20 Exhibit J2.4, p. 2. The cross over chart referenced is Graph 1, with $150 in capital investments for $680 million in net OM&A savings.
21 EB-2017-0306, Exhibit B, Tab 1, pp.42-43.
22 Exhibit C, FRPO 1, Attachment 3, p. 4.
23 Exhibit C, FRPO 1, Attachment 3, p. 4.

period, is triggered by any over-earnings above 100 basis points, and shares those over-earnings with ratepayers 50/50. The Applicants argue that a more stringent ESM would disincent them from pursuing amalgamation; however the evidence in the proceeding does not substantiate that claim. An ESM with a 100 basis point threshold and 50/50 sharing beginning from year one will strike the appropriate balance between utility incentive and ratepayer protection.

5.1 The ESM as a Disincentive

57. Throughout the evidence given in this proceeding the Applicants claim that a different or more strenuous ESM will be a "disincentive" to pursue amalgamation.[24] While CME Agrees that an inappropriately calculated ESM may diminish incentives in some instances, and acknowledges that the Board has identified this issue in the Rate Handbook, CME submits there is an important distinction between diminishing incentives and "disincentive".[25] A disincentive militates against taking a certain action. An incentive, even when diminished by an ESM, still militates in favour of undertaking a certain action.

58. In CME's view the proper question before the Board on this issue is: What level of ESM best balances the incentives required for the utilities to take on the risks involved with amalgamation against protection for ratepayers?

5.2 The Risks Taken on by the Applicants

59. In order to determine what level of ESM best balances the dual objectives of utility incentives and ratepayer protection, the Board should first determine what level of risk the Applicants are actually taking by embarking on their amalgamation. These risks break down into two categories, integration risks and price cap rate-setting mechanism risks.

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[24] Transcript Volume 1, p. 28. See also Transcript Volume 1, pp. 120-121.

[25] Ontario Energy Board, *Handbook for Utility Rate Applications*, October 13, 2016, p. 28.

5.2.1 Integration Risks

60. According to the Applicants, in order to implement integration between the two utilities, they will have to spend between $50 million and $250 million on capital investments over the ten year term.[26] In exchange for those investments, the Applicants estimate that they will generate savings of between $350 million to $750 million.[27]

61. CME submits that given the Applicants' forecasts, the integration activities by themselves are not a risk to the Applicants, and do not justify a generous and one-sided ESM such as the one proposed by the Applicants. Even with the most conservative estimates, the Applicants will be spending $250 million in capital expenditures to gain $350 million in savings over the ten year term, a ratio that is already beneficial to the Applicants, and in their interest to pursue. Furthermore, it is likely to be a much more favourable savings ratio, as the Applicants' acknowledged that the conservative estimate shown above was not very likely.[28]

5.2.2 Price Cap Rate-Setting Mechanism Risks

62. The Applicants also state that in addition to the costs and risks associated with the actual integration activities, they are also taking on a great deal of risk by proposing a price cap mechanism rather than filing separate custom IR applications. In their calculation, they are earning approximately $410 million less than they would be if they had filed custom IR applications. The Applicants argue that because they are at risk of not being able to earn their allowed ROE if they fall short of the $410 million mark, that they need a weak ESM in order to properly incent them to take that risk.[29]

63. CME submits that the calculation used to derive the $410 million difference between the price cap mechanism and stand-alone rebasing applications contains a number of

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[26] Exhibit C, FRPO.1, Attachment 2, p.4.
[27] Exhibit C, FRPO.1, Attachment 2, p.4.
[28] Transcript Volume 2, p. 32.
[29] AIC, pp. 18-19 and Transcript Volume 2, pp. 46-49.

unjustified assumptions. Accordingly, when corrected for these assumptions, the amount of risk taken on by the Applicants is far less than $410 million, supporting the application of a stronger ESM.

5.2.3 Efficiencies in the Stand-Alone Applications

64. In order to derive the $410 million that the Applicants state that they are giving up by not rebasing, they compared their price-cap proposal with two stand-alone custom IR applications. As part of that comparison, the Applicants calculated the revenue requirement for both Union and EGD from 2019 to 2028 pursuant to hypothetical custom IR applications. Part of that calculation included estimating costs across the business, including operations and maintenance, as well as rate base.

65. As part of this estimation, the Applicants did not incorporate any efficiencies that the utilities could achieve as the result of common ownership, even without an amalgamation. As demonstrated in JT1.3, this assumption is already false.

66. According to the Applicants, despite not doing much of the planning required to integrate services absent amalgamation,[30] they were able to achieve $5.2 million annual savings for a one time cost of $9.2 million. Over the course of the 10 year term, this would result in a net savings of $42.8 million.[31]

67. Additionally, the Applicants have acknowledged that there would be the potential for a number of cost reductions even in the stand-alone scenario as the result of common ownership. Areas where there would be cost reductions but were not included in the Applicant's cost assumptions include:

(a) Shared services;[32]

(b) Business development;[33]

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30 Transcript Volume 1, p. 40.
31 Transcript Volume 1, p. 68. $5.2 million per annum over the ten year term is $52 million, minus the $9.2 million cost to achieve.
32 Transcript Volume 1, p.50.
33 Transcript Volume 1, p.33.

(c) Customer care;[34]

(d) Finance;[35]

(e) Human resources;[36]

(f) Information technology;[37]

(g) Facilities;[38] and

(h) Regulatory.[39]

68. On top of the efficiencies that could be gained through integration, there is also very likely to be further efficiencies to be found in the business as a whole. On cross-examination, when confronted with the fact that the utilities had continued to find significant productivity improvements to allow them to over-earn their allowed ROE in each year of the previous plan, the Applicants' witnesses did not dispute that there were still productivity improvements that could be achieved even under the status quo.[40]

69. In short, while the Applicants knew the number of savings driven by efficiencies was not going to be zero, they modelled it as though it would be.[41]

70. Given the breadth of the possible areas where the Applicants could save costs, which were not modelled in their comparison showing a $410 million detriment in choosing the price-cap rate setting mechanism, CME believes that the actual differential between the two scenarios is significantly smaller. Accordingly, since the Applicants are not taking on nearly as large a risk as their calculations would make it appear, CME submits that a more stringent ESM is appropriate.

[34] Transcript Volume 1, pp.37-39.
[35] Transcript Volume 1, pp.51-53.
[36] Exhibit JT1.5, p.2.
[37] Exhibit JT3.1.
[38] Exhibit JT3.1.
[39] Exhibit JT3.1.
[40] Transcript Volume 4, p.32.
[41] Transcript Volume 1, p.31.

5.2.4 Additions to Rate Base without a Discount

71. Another assumption made by the Applicants in their calculation of the stand-alone scenario was assumptions of what additions would be made to rate base. According to their evidence, the Applicants' rate base is $457 million higher in their stand-alone scenario than in the price-cap rate-setting mechanism proposal that is before the Board.[42] The reason for this is that the stand-alone scenario assumes that the Applicants will rebase and make additions to the rate base, whereas the amalgamation proposal simply continues a price cap mechanism without rebasing.

72. The revenue requirement impact of the $457 million of rate base over the course of the ten year term is $369.1 million.[43] The critical assumption made by the Applicants, which in CME's view is unwarranted, is that 100% of the spending would be added to rate base without a reduction by the Board. While it is true that the Applicants, if they proposed stand-alone custom IR applications, would have the ability to ask the Board to add amounts to rate base, the Board has the responsibility to review those amounts, and only add them to rate base if they were prudently incurred.

73. There are reasonable grounds to anticipate that the Board will make some disallowances, especially with regard to the GTA Reinforcement Project. Enbridge acknowledged that the GTA Reinforcement Project had a $182 million dollar cost overrun.[44] The value of that addition to rate base in the Applicants' stand-alone scenario is $147.3 million.[45] CME submits that cost overruns are particularly likely to have some or all of their costs disallowed as the result of a finding of imprudence.

74. While CME would not speculate on the particular likelihood of the Board disallowing rate base additions for the Applicants with regard to the $457 million, CME believes it is

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42 Transcript Volume 6, p.32.
43 Transcript Volume 6, p.33.
44 Transcript Volume 6, p.39.
45 Transcript Volume 6, p.39.

inappropriate and unreasonable to model a scenario where rate base additions are 100% guaranteed to be approved. Under the circumstances, it would be appropriate to model those amounts with a discount to reflect the uncertainty inherent in rate base additions.

75. Given the undiscounted additions to rate base, as well as the unwarranted assumptions regarding a lack of efficiencies absent the amalgamation, CME submits that the Applicants are not taking on nearly as much risk by proposing a continuation of their price cap mechanism as their calculations may suggest. Accordingly, they do not require as large of an incentive to make full integration a commercially worthwhile undertaking. A 100 basis point ESM beginning in year one would still provide the opportunity for the Applicants to earn hundreds of millions of dollars above ROE over the course of the deferred rebasing period, and even if the Applicants triggered the threshold, would still allow them to keep 50% of over-earnings above and beyond the 100 basis points threshold. This would be an appropriate and fair way to balance the utility incentive and ratepayer protection under the circumstances.

6.0 IMPACTS OF THE MERGER

6.1 The NGEIR Decision

76. CME shares the concern expressed by other intervenors that the merger of Union and EGD may impact the Board's decision on natural gas storage.

77. In EB-2005-0551, the Board initiated a review of, *inter alia*, natural gas storage in Ontario (the "**NGEIR Decision**"). As part of the NGEIR decision, the Board found that Union was required to reserve 100 PJ of natural gas storage space at cost based rates

for "in-franchise" customers.[46] Union was free to sell storage above and beyond 100 PJ at market rates.[47]

78. Contrastingly, Enbridge was required to purchase storage at market rates from storage providers in order to ensure that the gas supply was sufficient to serve their customers. The main supplier of Enbridge's natural gas storage services was Union.

79. Currently Enbridge still purchases market storage for their customers, and Union still has a surplus of cost-based regulated storage.

80. While CME acknowledges that the NGEIR Decision was forward looking, it submits that the merger between Union and EGD was not foreseeable by the Board at that time. Given that a key component of that decision was the existence of two independent utilities, and which customers were considered to be in-franchise and ex-franchise customers, CME believes that it would be appropriate for the Board to review the allocation and regulation of natural gas storage in Ontario when Amalco rebases.

7.0 RATE ESCALATION FORMULA

7.1 Appropriate Inflation Factor

81. The Applicants propose to use the GDP IPI FDD Canada index as the inflation factor in their I – X formula to adjust rates. CME notes that this is in contrast to the inflation factor used by the electricity distributors in Ontario, which use the GDP IPI FDD weighted as 70% of the inflation factor, as well as the Average Weekly Earnings ("**AWE**") weighted as 30% of the inflation factor.

82. While CME believes there could be some administrative efficiencies if gas and electricity distributors used the same inflation measures, it does not oppose the Applicants proposal of using only the GDP IPI FDD. Undertaking J5.2 illustrates that the difference in bottom line inflation when using the two different methods is minimal, with GDP IPI

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46 EB-2005-0551, Natural Gas Electricity Interface Review, Decisions with Reasons, November 7, 2006, ("**NGEIR Decision**"), p. 83.

47 NGEIR Decision, pp. 82-83.

FDD alone showing an average of 1.8% inflation since 2007, and the GDP IPI FDD and AWE method showing an average of 1.9% inflation over the same period.[48]

7.2 Productivity Factor

83. The Applicants propose a 0% productivity factor for the 10 year deferred rebasing period. Both the Applicants' expert, Dr. Makholm of National Economics Research Associates Inc. ("**NERA**") and Dr. Lowry from Pacific Economics Group Research LLC ("**PEG**") agree that a 0% productivity factor is appropriate for the Applicants in this instance. While CME acknowledges this consensus, it nevertheless believes it is important to bring forward its views regarding the methodological shortcomings of NERA's approach so that they are not replicated in future proceedings.

7.2.1 <u>The use of revenue-weighted average growth in sales volumes as an output measure</u>

84. As part of their TFP study, NERA selected the units of measurement used for both the inputs and the outputs of the distribution industry as well as the Applicants. In terms of the output measure, NERA chose to use sales volumes.[49]

85. While sales volumes would often be an appropriate output measure in this type of study, PEG found that it is inappropriate in cases involving the Applicants,[50] since they have adjustments mechanisms in place to account for average use.[51]

86. As the result of NERA's choice of sales volume as the output measure, NERA's results are sensitive to the fact that average use has been declining. In other words, the firms in NERA's study have a downward pressure on productivity growth as the result of the fact that the output (sales) is decreasing on a per customer basis. PEG found that residential

[48] Undertaking J5.2, p.1.

[49] EB-2017-0307, Expert Report and Direct Testimony, prepared by Jeff D. Makholm, National Economics Research Associates Inc., dated November 23, 2017, Exhibit B, Tab 2, p.1-171 (the "**NERA Report**") at p. 25, Q. 30.

[50] IRM Framework for the Proposed Merger of Enbridge and Union Gas, April 11, 2018, Pacific Economics Group Research LLC (the "**PEG Report**"), Exhibit M1, p.29.

[51] This would include the Normalized Average Consumption adjustment for Union, the Average Use mechanism for EGD and the LRAM.

and commercial average use of the utilities in NERA's study grew by 1.5% annually from 1973-2000, but averaged a .3% annual decline from 2001-2016.[52] PEG found that this was the primary driver of the slowing growth in NERA's TFP indexes.[53]

87. The issue with this methodology as it relates to the Applicants is that the Applicants have adjustment mechanisms that normalize for average use variances. The Applicants have not had to face the same downwards pressure on output growth that NERA's distribution industry sample has, and more importantly, propose to continue to use those adjustment mechanisms, so will not have to face those downward pressures going forward into the deferred rebasing period.

88. As a result, the use of sales volume as an output measure artificially decreases the productivity results for the natural gas distribution industry, and is inappropriate and inapplicable to the Applicants. CME agrees with PEG that a more appropriate output measure would be the number of customers in this instance, as they would not be impacted by the changes in average use during the sample period.[54]

7.2.2 The Use of One Hoss Shay Depreciation Approach

89. CME also shares PEG's concerns regarding NERA's use of the one hoss shay method to measure capital cost,[55] which made up a part of the input measurement in NERA's study. The one hoss shay method models a circumstance where an assets, once purchased, provides a continuous flow of services until it breaks down entirely and is removed from service. The most intuitive example of this is a lightbulb, which provides a steady stream of light until it burns out, and is removed.

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52 PEG Report, Exhibit M1, p.29.
53 PEG Report, Exhibit M1, p.29.
54 PEG Report, Exhibit M1, p.17.
55 PEG Report, Exhibit M1, pp. 21-25.

90. In contrast, PEG used a geometric decay method of measuring capital cost. Under the geometric decay method, the flow of services from an investment declines at a constant rate over time.[56]

91. PEG points out two issues with the one hoss shay approach that suggest to CME that it is inappropriate to use in TFP studies before the OEB: it is quite sensitive to the choice of average service life assumption, and the actual observable capital cost trends of the applicants run contrary to the fundamental assumptions in one hoss shay.

92. The one hoss shay methodologies requires the analyst performing the TFP study to know both the deflation of gross plant additions and retirements. PEG's report notes that while the deflation of gross plant additions is known, the deflation of plant retirements is not, and requires an assumption about the average service life of the assets in question.[57]

93. Dr. Lowry testified that the lower the average service life assumption, the slower the productivity growth.[58] In their study, NERA assumed a 33 year average service life; however, PEG noted that the Applicants themselves have an average service life of approximately 37 years.[59] Additionally, PEG reviewed recent power distributor proceedings as well as performed their own calculations on retirements and in both cases, found the average service life to be well above 33 years.[60]

94. In CME's view, given the sensitivity of one hoss shay to the assumption regarding average service life, and the evidence demonstrating that NERA's assumption of the average service life of the Applicants' assets is not accurate, PEG's use of the geometric decay method should be preferred.

[56] PEG Report, Exhibit M1, p.18.
[57] PEG Report, Exhibit M1, p.21.
[58] Transcript Volume 4, p.148.
[59] Transcript Volume 4, p.148.
[60] Transcript Volume 4, p.148.

95. Furthermore, the fundamental underpinning of the one hoss shay depreciation method does not accord with the actual trends in the Applicants' capital spending. One hoss shay depreciation posits that there is a constant flow of services from the assets until they break down completely and are removed from service. PEG points out that a common sign in the decline in the flow of service from assets is the increase in expenses to operate and maintain those assets.[61]

96. PEG further found that gas distributor assets do not exhibit a constant flow of services, but that they often tend to experience rising OM&A expenses and refurbishment capex as their assets age.[62] As a result, CME agrees with PEG that geometric decay is the appropriate method for calculating capital cost in TFP studies for the Applicants.

7.3 Stretch Factor

97. The Applicants propose a 0% stretch factor as part of the rate-setting framework for the 10 year rebasing period. The basis for this recommendation is NERA's report, which opined that the use of a stretch factor in the I – X regulatory construct is only appropriate when a regulated entity transitions from a cost of service regime to an incentive based or performance based regulatory regime.[63]

98. Board Staff also commissioned an expert report to review the Applicants' proposed rate-setting mechanism, and opine on, *inter alia*, the appropriate stretch factor. PEG found that the appropriate stretch factor was .3% on the basis that the Applicants had not provided evidence that they were superior cost performers.[64]

99. CME submits that the stretch factor evidence submitted by PEG should be preferred to that of NERA for a number of reasons, including:

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61 PEG Report, Exhibit M1, p.23.
62 PEG Report, Exhibit M1, p.23.
63 NERA Report, Exhibit B, Tab 2, at Q9, Q19.
64 Transcript Volume 4, p. 164.

(a) The Board has previously held that the stretch factor should be employed beyond the initial transition to incentive regulation;

(b) the Applicants are undergoing a transition which would justify the imposition of a stretch factor under NERA's framework;

(c) NERA's concerns militating against the use of the stretch factor beyond the initial transition to incentive regulation are not present in this case; and

(d) The Applicants have not Provided Sufficient Evidence to Warrant a 0% Stretch Factor.

7.3.1 <u>The Board has Previous Held that a Stretch Factor Should be Employed Beyond the Initial Transition to Incentive Regulation</u>

100. The central pillar to NERA's contention that the Applicants should have a stretch factor of 0% is the idea that stretch factors are only appropriate when a regulated firm moves from a cost of service regime to an incentive regulation regime. NERA states:

> ***The consensus among a broad cross-section of economists, as reflected by the AUC's discussion in that case, is that the foundation for the stretch factor lies in the <u>transition</u> to a PBR regime and away from cost-of-service regulation.***[65] (emphasis in original)

101. However, this is in direct contrast to the Board's articulation of the purpose of the stretch factor. The Board has, on a number of occasions, found that stretch factors can be a useful regulatory tool to apply to distributors well after they have transitioned from a cost of service regime to incentive regulation. For instance, in the Draft Report of the Board on Empirical Research to Support Incentive Rate-setting for Ontario's Electricity Distributors, the Board stated:

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

[65] NERA Report, Exhibit B, Tab 2, at Q19.

> ***continue to have an important role in IR plans after distributors move from cost of service regulation.***[66]

102. Similarly, NERA's view of the purpose of the stretch factor runs counter to the Board's consistent previous practice with regard to the Applicants. For example, both of the Applicants have been under incentive regulation for over a decade, with Union being subject to various levels of incentive regulation for 15 years, and EGD, 13 years.[67] Despite having made the transition from cost of service regulation to incentive regulation many years earlier, Union operated under a price cap mechanism in EB-2013-0202 which had a productivity factor, inclusive of a stretch factor, of 60% of inflation.[68] Similarly, in EGD's application before the Board in EB-2012-0459 they forecast no increases to full time employee ("**FTE**") levels as a form of stretch factor.[69]

103. In its evidence and cross-examination, NERA attempts to explain the Board's express direction on stretch factors as being specifically directed towards the multiplicity of electricity distributors in the province.[70] In essence, NERA and the Applicants argue that the Board's previous statements do not apply to the gas distributors in the province, and ignore the utilities' previous experience being subject to a stretch factor beyond the transition to incentive regulation.

104. CME finds this argument to be unpersuasive. In addition to the incongruence such an interpretation would create between the Board's statements and its past practice with the Applicants, the Board's statements make it clear that stretch factors should be applied beyond transitions to incentive regulation for electricity and gas distributors in Ontario.

105. The Board's statements with regard to the applicability of the stretch factor beyond the transition to IR were made in relation to the Board's report for the Renewed Regulatory

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[66] Board Staff Cross-Examination Compendium for Panel 4, Exhibit K4.1, p.15. This is far from the only time the Board has made statements to this effect. See also: Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008, p. 20 and EB-2010-0379 Draft Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors.

[67] Transcript Volume 4, pp.26-27.

[68] Transcript Volume 4, pp. 32-33.

[69] Transcript Volume 4, p. 35.

[70] Transcript Volume 4, p. 24.

Framework.[71] While the framework was initially entitled the "Renewed Regulatory Framework for Electricity", it was later changed to the Renewed Regulatory Framework to denote its application to both electricity and natural gas distributors.[72] Indeed the Applicants acknowledge in their argument-in-chief that the RRF applies to natural gas distributors.[73] As a part of that framework, the Board sets out the following table:

Table 1: Rate-Setting Overview - Elements of Three Methods

<table>
<tr><th colspan="2"></th><th>4th Generation IR</th><th>Custom IR</th><th>Annual IR Index</th></tr>
<tr><td colspan="5">Setting of Rates</td></tr>
<tr><td colspan="2">"Going In" Rates</td><td>Determined in single forward test-year cost of service review</td><td>Determined in multi-year application review</td><td>No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism</td></tr>
<tr><td colspan="2">Form</td><td>Price Cap Index</td><td>Custom Index</td><td>Price Cap Index</td></tr>
<tr><td colspan="2">Coverage</td><td colspan="3">Comprehensive (i.e., Capital and OM&A)</td></tr>
<tr><td rowspan="2">Annual Adjustment Mechanism</td><td>Inflation</td><td>Composite Index</td><td rowspan="3">Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts</td><td>Composite Index</td></tr>
<tr><td>Productivity</td><td>Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor</td><td>Based on 4th Generation IR X-factors</td></tr>
<tr><td colspan="2">Role of Benchmarking</td><td>To assess reasonableness of distributor cost forecasts and to assign stretch factor</td><td>n/a</td></tr>
<tr><td colspan="2" rowspan="2">Sharing of Benefits</td><td colspan="3">Productivity factor</td></tr>
<tr><td>Stretch factor</td><td>Case-by-case</td><td>Highest 4th Generation IR stretch factor</td></tr>
</table>

106. Listed above are the three types of incentive regulation options available to distributors under the RRF. In this instance, the Applicants are proposing a price cap. This price cap mechanism in the 4th generation of incentive regulation is modeled by the first column.[74]

71 EB-2010-0379, *Draft Report of the Board on Empirical Research to Support Incentive Rate-setting for Ontario's Electricity Distributors*, September 6, 2013.

72 Ontario Energy Board, *Handbook for Utility Rate Applications*, October 13, 2016, p. 4.

73 AIC, p. 13.

74 The Board's Handbook to Utility Rate Applications states that natural gas distributors are not eligible for the Annual IR Index, column 1 is the only mechanism available to the Applicants that is a price cap. See Transcript Volume 1, p. 80 for confirmation that the application being put forward includes a price cap.

Under the row entitled "Sharing of Benefits", the Board expectation is clearly that utilities will be subject to a stretch factor. CME notes that the Board does not indicate, as it does for custom IR applications, that stretch factors or other sharing mechanisms will be evaluated on a case-by-case basis, but they are a necessary component of the rate-setting mechanism.

107. Accordingly, CME submits that the Board should reaffirm the general applicability of the stretch factor beyond the initial transition from cost of service to incentive regulation, and find that a stretch factor of .3% is warranted in this instance.

7.3.2 The Applicants are Undergoing a Transition that Would Warrant the Imposition of a Stretch Factor

108. As part of their original report, PEG suggested that NERA's position was that stretch factors are only appropriate in first generation IRMs.[75] Dr. Makholm clarified in cross-examination that it was NERA's position that it is changes from cost of service regimes to IR regulation more generally that justify the imposition of a stretch factor.[76] As an example, the second generation proceeding in Alberta was discussed, where the regulator decided to once again apply a stretch factor. In that case, the original cost of service capital tracker was expected to be replaced with an incentive regulation mechanism for capital costs. As a result, Dr. Makholm stated that it was appropriate to apply a stretch factor. Specifically, Dr. Makholm stated:

> ***The regime has gone from I minus X or PBR or IRM for base rates and cost of service for the incremental capital to IRM or PBR, including the incremental capital. So there's a new regime, there is a new sheriff in town, and the new sheriff is going to incent different kinds of behaviour, which is exactly what I'm saying. The AUC only predicated the stretch in the second generation on the fact that the IRM regime itself was broader and covered more stuff than their first IRM regime.***[77] (emphasis added)

75 PEG Report, Exhibit M1, p.46.
76 Transcript Volume 4, pp. 42-43.
77 Transcript Volume 4, p. 43.

109. Currently, EGD operates under a custom IR plan. In EB-2012-0459, EGD proposed a rate-setting framework which had a number of cost of service elements. In the Board's Decision with Reasons in that case, they differentiated EGD's previous IR mechanism from what the company was proposing then. The previous "traditional IR" mechanism involved setting costs based on a single forward test year cost of service, and were escalated based on inflation and productivity. In contrast, EGD's proposal in EB-2012-0459, the mechanism that they are under today, involved setting rates based on a five year forecast of its revenue requirement and sales volume.[78]

110. Comprehensive cost forecasting is one of the fundamental aspects of cost of service regulation. While EGD layered on IR adjustments to their cost forecasting, their ratemaking application, as it is currently constituted, has significant elements of cost of service regulation. In contrast, as part of their application in this proceeding EGD is proposing to move to a price cap mechanism which does not involve a comprehensive forecast in costs for each year of the application, and instead relies on the incentive regulation mechanism determined by the I – X formula to derive rates. As a result, the IRM regime itself is broader in this rate-setting mechanism than it was in the previous IRM regime.

111. Accordingly, it is appropriate to apply in this instance as the breadth of the IRM regime has grown.

7.3.3 <u>The concerns militating against the use of the stretch factor beyond the initial transition to incentive regulation are not present in this case</u>

112. During cross-examination, a number of parties attempted to discern the principled basis behind NERA's insistence that stretch factors were only appropriate during the initial transition from cost of service regulation. The following statements by Dr. Makholm on

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[78] EB-2012-0459, Enbridge Gas Distribution Inc. 2014-2018 Rate Application, Decision with Reasons, dated July 14, 2014, pp.4-11.

cross examination illuminate NERA's underlying concerns regarding the broad applicability of the stretch factor:

> ***Any regulation 2.0 regime, I minus X or equivalent, depends on the credibility of the regime to do what it said it was going to do. It depends on some objective credibility. And what I'm saying here, if you take something called stretch and for these companies use it just as a way to appropriate gains ... you are ... undermining the credibility of the commitment to pursue this kind of I minus X regulation.***[79]
>
> ***[I]n my experience, in front of regulators, for instance, like the AUC, credibility and consistency was the most important thing for them, and I think it's still important here to have a regime for these companies that's based on accepted principles, and that's our quibble about stretch.***[80]
>
> ***[I[t had to do with whether or not, whether in the hole or in the ladder, the ability to contemplate actually profiting from your innovations is there with a credible regime.***[81]

113. CME submits that from these exchanges, the Board can derive two principled reasons why NERA feels that applying a stretch factor is inappropriate beyond the initial transition from cost of service to incentive regulation:

   (a) Applying the stretch factor after the initial transition can be perceived as a disguised attempt to appropriate gains thereby undermining the credibility of the regulator; and

   (b) It deprives the utility of the ability to "contemplate actually profiting" from their innovations.

114. Neither of these concerns are engaged in this proceeding.

115. Credibility and consistency of the regulator are not at issue in this proceeding because, as discussed above, the Board has consistently stated, and indeed acted as though stretch factors were going to be applied to all distributors, whether electrical or natural gas, past their initial transition.

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79 Transcript Volume 4, p.108.
80 Transcript Volume 4, p.108.
81 Transcript Volume 4, p.123.

116. In addition to the Board's repeated comments in Board reports and handbooks,[82] both Union and Enbridge are currently under rate-setting mechanisms that are inclusive of a stretch factor.[83] Accordingly, CME submits that it would not be possible for the Board to compromise their credibility and consistency, or the credibility of the regulatory regime precisely because applying a stretch factor beyond the initial position is exactly what the Board said it was going to do.

117. Indeed, in CME's view, an inconsistency would lie in the failure to apply a stretch factor to natural gas distributors simply because it is not the initial transition away from a cost of service regime.

118. CME also disagrees that the addition of a stretch factor could deprive the Applicants of the ability to contemplate earning a profit as the result of their innovations.

119. Union is currently under a price cap regime which includes a productivity factor equal to 60% of inflation. Given that the inflation rate in the recent past has been greater than 1%, Union's productivity factor is higher than the highest stretch factor given by the Board to electricity distributors, and at least twice as high as the stretch factor proposed by PEG. Despite this strong productivity measure, Union has over-earned its allowed ROE in every single one of the years covered by its last rate-setting mechanism, and indeed every year since at least 2008. As the table provided at JT1.3 demonstrates, Union has, on average, over-earned in relation to its allowed ROE by approximately 2%.[84]

120. Similarly, in the Board's decision regarding EGD's current rate-setting mechanism, the Board described EGD as having a built in stretch factor by stating:

> ***One of the specific measures which Enbridge incorporated into its budgets was the requirement that the FTE level be held flat over the***

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82 See Board Staff Cross Examination Compendium, Panel 4, Exhibit K4.1 for a list of the various instances that the Board has discussed continuing stretch factors beyond the initial transition to incentive regulation.

83 Transcript Volume 4, pp. 33-36.

84 Derived by taking the average of Union's achieved ROE from the 2008-2017 period, calculated as 10.655% and subtracting the average allowed ROE for the period, calculated as 8.624%.

IR term. Enbridge maintained that its use of flat FTEs represented an embedding of productivity and a stretch factor.[85]

121. Despite EGD's incorporation of a built-in productivity and stretch factor, EGD has also over-earned its allowed ROE in every single one of the years covered by its last rate-setting mechanism, and every year since 2008. JT1.3 shows that EGD has, on average, over-earned in relation to its allowed ROE by approximately 1.6%.[86]

122. Under these circumstances, despite the continued existence of the stretch factor, not only have the Applicants been granted the ability to "contemplate earning a profit" as the result of their innovations, but they have consistently and significantly profited over and above the allowed ROE.

7.3.4 <u>The Applicants have not Provided Sufficient Evidence to Warrant a 0% Stretch Factor</u>

123. In their expert report, PEG determined that the appropriate stretch factor to apply to the Applicants in this case was .3%. This factor is an appropriate default position given that there is insufficient evidence on the record in this proceeding to determine what sort of cost performance Amalco would have.

124. As part of the Renewed Regulatory Framework, the Board stated that it would make stretch factor assignments under the Price Cap IR regime on the basis of total cost benchmarking evaluations.[87] This is consistent with PEG's evidence, which suggested that a stretch factor should be applied to firms that are unable to demonstrate that they are superior cost performers.[88]

125. The Applicants have not provided any evidence regarding total cost benchmarking in this proceeding. Union's witness stated that it would be difficult or impossible to benchmark it

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85 Transcript volume 4, p. 35.

86 Derived by taking the average of EGD's achieved ROE from the 2008-2017 period, calculated as 10.255% and subtracting the average allowed ROE for the period, calculated as 8.636%.

87 Board Staff Cross-Examination Compendium for Panel 4, Exhibit K4.1, p. 15. See also Report of the Board, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012 at p. 60.

88 Transcript Volume 4, p. 164. See also PEG Report, Exhibit M1, p. 48.

against other utilities because Union is a distribution, transmission and storage, and partially unregulated business.[89] However, under cross-examination, Union's witness admitted that, to their knowledge, Union had never retained anyone to determine whether cost benchmarking was feasible.

126. For their part, EGD's witness stated that it had been EGD's intent to file a cost benchmarking study in support of their original, custom IR application, but that as a result of switching to a rate-setting mechanism pursuant to the MAADs policy, they determined that a cost benchmarking study "wasn't a necessity".[90]

127. CME disagrees.

128. The Board's policy regarding price cap stretch factors is clear. Not only are they a mandatory part of price cap incentive regulation, regardless of whether the utility has recently transitioned from cost of service or not, but that the quantum of the stretch factor is to be determined with reference to a full cost benchmarking.

129. Other idiosyncratic utilities, such as Ontario Power Generation engage in full cost benchmarking, despite its unique place among Ontario's regulated utilities, as well as its mix of assets. There is no reason why the Applicants could not have conducted a full cost benchmarking to support their contention that a 0% stretch factor was appropriate.

130. In the absence of such a study, CME agrees with PEG's report that finds that a .3% stretch factor should be applied on the basis that .3% is the stretch factor accorded to average cost performing power distributors in the 4th generation incentive rate making framework.

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89 Transcript Volume 4, pp.25-26.

90 Transcript Volume 4, p.26.

8.0 Z FACTOR

131. The Applicants propose a Z factor as part of their rate-setting mechanism in order to deal with "material changes in costs associated with unforeseen events" that are outside of management's control.[91]

132. The Applicants utilize the OEB's *Filing Requirements for Natural Gas Rate Applications* to determine the criteria for when Z factor amounts are eligible for recovery. These criteria include:

(a) Causation;

(b) Materiality;

(c) Prudence; and

(d) Management Control.[92]

133. The Applicants propose a materiality threshold of $1 million. The basis for this materiality threshold is the Filing Requirements for Electricity Rate Applications.[93]

134. CME agrees that the Z factor is an appropriate mechanism for the Applicants to include as part of their rate-setting mechanism; however, CME submits that the materiality threshold proposed by the Applicants is inappropriate, and significantly out of step with the economic realities of the proposed amalgamated utility.

135. The purpose of a materiality threshold for Z factors is intended to ensure that the utility does not come before the regulator repeatedly because of various unforeseen events that occur over the course of the IR term. While it is appropriate for a utility to be able to make adjustments to rates as the result of significant or "material" unforeseen circumstances, smaller unforeseen circumstances are part of the normal operation of any business. As such, the utilities should be responsible for managing those non-material circumstances within the boundaries of existing rates.

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91 Exhibit B, Tab 1, p.11.

92 Exhibit B, Tab 1, p.11.

93 Transcript Volume 3, pp. 143-144. See also EB2017-0307, Exhibit B, Tab 1, p. 4, footnote 6.

136. CME notes that PEG also discussed the importance of materiality threshold for Z factors, and held in their report that the materiality threshold reduces regulatory cost and can increase cost containment incentives.[94]

137. Currently, Enbridge's materiality threshold for Z factors is $1.5 million.[95] Union's current materiality threshold is $4 million.[96] As a result, the Applicants' proposed materiality threshold of $1 million is not only lower than the two constituents' materiality factors combined, but is, in fact lower than either one of the constituent utilities' materiality threshold.

138. The Applicants justify their proposal on the basis that the Filing Requirements for Electricity Rate Applications states that for electricity distributors with a revenue requirement over $200 million have a materiality threshold of $1 million. CME notes however, that natural gas distributors also have a document setting out the filing requirements. The *Filing Requirements for Natural Gas Rate Applications* states that the OEB's practice to date has been to approve "utility-specific criteria and materiality thresholds."[97]

139. CME submits that the Board should continue that practice, and approve a utility-specific materiality threshold. It should be crafted with reference to utilities that are of a similar size and economic means as Amalco will have.

140. This is another instance where the Applicants' reliance on the Board's electricity filing guidelines falls short. There are no true comparators in the electricity distribution context. During cross-examination, the Applicants' witnesses indicated that it would not surprise them if Amalco's revenue requirement were roughly twice as large as the next largest

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94 PEG Report, Exhibit M1, p.53.
95 Transcript Volume 1, p.140.
96 Transcript Volume 1, p.140.
97 Ontario Energy Board, *Filing Requirements for Natural Gas Rate Applications*, February 16, 2017, p. 39.

distribution utility in the province.[98] They further stated that Amalco was going to be the largest gas utility in Canada and either the second or third largest in North America.[99]

141. Given that context, the Board's policy on materiality thresholds for Ontario's electricity distributors, which are many orders of magnitude smaller than Amalco, would be ill-fitting. CME submits that a much more appropriate comparator to Amalco's economic means would be Ontario Power Generation. The Board has determined OPG's materiality threshold to be $10 million. Accordingly, it is CME's view that the appropriate Z factor materiality threshold for Amalco should be $10 million.

9.0 STAKEHOLDER INFORMATION SESSIONS

142. The Applicants propose to reduce the number of stakeholder information sessions from one, per year, per utility, to one information session every two years for Amalco. The Applicants contend that, in the past, there has not been enough to talk about to justify the yearly meeting.[100]

143. In cross examination, the Applicant acknowledged that as the result of combining utilities, Amalco would have significantly more to talk about than either one of the current utilities.[101] Furthermore, due to the number of amalgamation activities that Amalco will be undergoing as the result of the merger, there would be more to talk about than there had been in previous years.[102]

144. In their argument-in-chief, the Applicants have indicated that they are willing to hold annual stakeholder meetings if that proposal has support from intervenors.[103] CME appreciates the Applicants' willingness to hold an annual stakeholder meeting, and submits that it is appropriate under the circumstances. Stakeholder meetings are a valuable way for Amalco to provide proactive information relevant to stakeholders and

98 Transcript Volume 2, p.21.
99 Transcript Volume 2, p.22.
100 Transcript Volume 2, p. 117.
101 Transcript Volume 2, p. 117.
102 Transcript Volume 2, p. 118.
103 AIC, p. 32.

their interests, and will be especially important to the goal of transparency given the potential length of the deferred rebasing period. Accordingly, CME submits that an annual stakeholder meeting is appropriate.

10.0 COSTS

145. CME requests that it be awarded 100% of its reasonably incurred costs in connection with this matter.

ALL OF WHICH IS RESPECTFULLY SUBMITTED this 15th day of June, 2018.

Emma Blanchard
Scott Pollock

Counsel for CME

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