ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch.B, as amended;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving the balances and the clearance of certain Demand Side Management Variance Accounts into rates, within the next available QRAM following the Board's approval.

FINAL ARGUMENT
OF THE
SCHOOL ENERGY COALITION

June 15, 2018

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TABLE OF CONTENTS

1 GENERAL COMMENTS

1.1 *Introduction*

1.1.1 On November 2, 2017 and November 23, 2017 respectively the Applicants Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union) filed two Applications.

1.1.2 The first, EB-2017-0306, is an application under section 43(1) of the OEB Act for leave to amalgamate. That Application includes a request to defer rebasing from 2019 to 2029, which is not really a section 43(1) matter. That request also appears to require the Board to determine whether the Applicants should be relieved of certain past obligations to file full rebasing information for 2019, although this was not requested in the Application.

1.1.3 The second, EB-2017-0307, is an application under section 36(1) of the OEB Act for a rate-setting framework. It is not an application under section 36(3) to set actual rates, as the witnesses have made clear. It is a request for the Board to establish the rules under which future rate applications should be made by the amalgamated entity (Amalco).

1.1.4 By order dated March 1, 2018, the Board combined the two Applications, although technically they remain two separate applications. They were, however, heard together, and thus most of the overlaps between them have been dealt with in the hearing.

1.1.5 Under the proposal of the Applicants, Amalco would collect a forecast $29.2 billion from customers over the ten year period 2019-2028. Thus, this case supplants the recent OPG case (EB-2016-0085) as the largest energy rates proceeding in Canadian history.

1.1.6 The case included extensive interrogatories from the parties, both to the Applicants and to the experts from the Applicants and from OEB Staff. There was also a three-day technical conference and a six-day oral hearing, but given the complexity of the issues time was necessarily tight throughout.

1.1.7 The Applicant's Argument-in-Chief was filed on June 1, 2018. This is the Final Argument of the School Energy Coalition.

1.1.8 The Board will be aware that many of the customer groups who intervened in this proceeding have worked together extensively throughout the hearing to avoid duplication. In the preparation of final argument, that has included discussions between the parties, as well as exchanging drafts or partial drafts of their final arguments. We have been assisted in preparing this Final Argument by that cooperation amongst parties.

1.1.9 We did not in this proceeding have the benefit of seeing the final argument of OEB Staff, so we are unable to comment on OEB Staff positions on the issues.

1.1.10 SEC has not organized this Final Argument in accordance with the Issues List. Instead, we have grouped our submissions logically.

1.1.11 The record of this case includes discussion of a private meeting between the three CEOs of the Applicants, and the CEO and COO of the Board at the Applicants' offices[1]. That meeting, its purpose and results, were explored in the hearing. Having reviewed the record, SEC does not see any reason to provide comments with respect to that meeting in this Final Argument, and has not done so.

1.2 ***Summary of Responses to the Argument in Chief***

1.2.1 It may assist the Board for SEC to go through the Argument in Chief and provide responses to some of the key points made.

1.2.2 The AIC says[2]:

> *"Enbridge and Union have successfully delivered benefits to Ontario natural gas ratepayers over the past 15 years under their respective Incentive Regulation frameworks."*

This statement is not correct, because the Applicants propose to deny their customers the productivity benefits that have been generated over the last five years, as evidenced by their consistent over-earning. Under the Applicants' proposal, they would continue to benefit from that accumulated productivity for a further ten years, sharing none of it with their customers.

1.2.3 The AIC says[3]:

> *"At this juncture, the two utilities have limited individual opportunities to deliver similar benefits under a new five-year framework for rates."*

No evidence has been provided of this. All the Board has is the unsupported statements of the Applicants[4]. Those statements could only be true if the Board believes that while the Applicants have had productivity benefits every year for the

[1] Tr1:19-20 and many other references.
[2] AIC, p. 2
[3] AIC, p. 2
[4] E.g., Tr1:25.

last ten years at least, suddenly those have ended just as they are up for rebasing.

1.2.4 The AIC says[5]:

> *"The proposed amalgamation, with a ten year deferred rebasing period, will allow the amalgamated entity (referred to in this proceeding as "Amalco") to tackle integration of larger, more complex systems and processes with a view to delivering the benefits of such integration to ratepayers on rebasing. The Applicants' companion rate mechanism proposal will ensure that ratepayers also benefit during the deferral period from rates that are lower than they would otherwise have been."*
>
> *"In addition to the benefit that customers will receive on rebasing, they will be better off by $410 million during the deferred rebasing period than they would have been if Enbridge and Union were to continue to operate on a stand-alone basis."*

The supposed ratepayer benefit only arises if the Board believes that the standalone straw man prepared by the Applicants without any detailed planning – and representing what the Applicants say they would like to get from the Board in a Custom IR scenario – is also what the Board would <u>actually</u> allow in rates over the next ten years. That proposition is not credible. See Section 3 of this Final Argument.

1.2.5 The AIC says[6]:

> *"…[R]ates will be determined under a Price Cap mechanism and, in essence, customers will see increases in their rates which are limited to inflation along with recovery of such costs related to capital spending as may be allowed on Incremental Capital Module."*

The Applicants have admitted that, for many customers, rates and bills will not be "limited to inflation". In fact, rate increases would, under the proposal, vary widely between customers[7].

1.2.6 The AIC says[8]:

> *"The ten year rebasing deferral period will give Amalco the "runway" that it needs to carry out detailed integration planning, to make major capital investments, to execute on the integration while maintaining safe and reliable service to customers,*

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[5] AIC, p. 2,3
[6] AIC, p. 3
[7] K6.1, p. 7. Alternatively, the witnesses told the Board that they haven't really decided how to apply the rate-setting mechanism they propose to actual rates, so the Board really has no idea how this proposed "price cap" will actual play out for customers [TC3:67; Tr6:8-9, 146-7] See Section 5.6 of this Final Argument.
[8] AIC, p. 3.

> *to manage the risks associated with these activities and to optimize savings and synergies from the merger that will be delivered to ratepayers on rebasing. The Applicants' proposed approach ensures that all of the risk associated with the amalgamation is borne by the shareholder."*

The benefits of integration of the two utilities are available regardless of whether there is a ten year rebasing deferral period. Also, the high risks and capital investments alleged are inconsistent with the admission by the Applicants that the most they are out of pocket for this integration at any time is $8 million[9].

1.2.7 The AIC says[10]:

> *"The Board confirmed in Decision and Procedural Order No. 3 that it will use the no harm test for assessing the application."*

The AIC misquotes the Board. What the Board actually said is that it would use the no harm test "for assessing the <u>amalgamation</u>" [emphasis added]. This is important because the no harm test applies to MAADs proceedings (EB-2017-0306), but does not apply to setting rates (EB-2017-0307). In this Final Argument, SEC proposes that the no harm test is met with respect to the amalgamation, but that the rate setting proposal of the Applicants, including the deferred rebasing, is not just and reasonable (and thus, by implication, would be harmful to the customers).

Thus, the AIC discussion at page 5 relating to financial viability, which focuses on the rate plan, actually has nothing to do with the no harm test. Financial viability is relevant to ratemaking, of course, but under the "just and reasonable" test mandated by the statute. "No harm" is irrelevant. Similarly, the arguments on page 8 with respect to the ratepayer benefit – entirely aside from the straw man problem – miss the point. EB-2017-0307, which is the application for the rate mechanism, is not a MAADs application.

1.2.8 The AIC says[11]:

> *"In the Alectra Decision, the Board also found that the scale enhancements of service delivery embedded in the proposed transaction could be expected to result in long term benefits to customers. The evidence with respect to the amalgamation proposed by Enbridge and Union supports the same conclusion."*

> *"The MAADs Handbook states that consolidation is desired because it can increase efficiency through the creation of economies of scale and/or contiguity. It also states that consolidation permits a larger scale of operation with the result that customers can be served at a lower per customer cost."*

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[9] J2.4
[10] AIC p. 4
[11] AIC p. 8, 13

In fact, the evidence in this proceeding supports a different conclusion. The transaction being proposed is not a combination of two businesses. That has already happened: "there is only a conversion of Enbridge and Union shares into shares of Amalco and no change of control", says the AIC at page 5, talking about the lack of impact on financial viability[12]. The evidence in fact shows that all or almost all of the scale enhancements will happen because of the earlier transaction, the acquisition of Spectra by Enbridge. The amalgamation itself will have little effect. On this, and the many other ways in which this incorrect argument from the Applicants is presented (e.g. climate change and other challenges), see Section 3 of this Final Argument.

1.2.9 The AIC says[13]:

> *"The ten year deferral serves to align the interests of the Applicants and ratepayers…"*

The opposite is true. The sole purpose of the ten year deferral, in this case, is to allocate the savings arising out of integration of the two utilities to the shareholder, and not to the customers. See Sections 2.4 and 3.4 of this Final Argument.

1.2.10 The AIC says[14]:

> *"In addition, in response to undertaking Exhibit J4.1 and through testimony, the Applicants have indicated that the revenue projections already include a stretch. Amalco's revenues carry forward the $4.5 million productivity commitment and a PCI that is equal to 40% of inflation in Union Gas's 2014 to 2018 IRM."*

The essence of this surprising proposition is that the savings built into rates over the last IRM period can be counted again in the new IRM period as if they were new savings. This is not how productivity works. This also does not include the savings achieved over and above the amounts built into rates, the overearnings, since in the Applicants' proposal they get to keep those savings.

1.2.11 While there are many other statements in the AIC that can be challenged, these highlights should make clear that the fundamental construct the Applicants are presenting is untenable, and their Argument in Chief cannot be relied on by the Board. The bulk of this Final Argument deals with those problems in more detail.

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[12] The implication being that there is a change of form, but not substance. This is true.
[13] AIC p. 17
[14] AIC, p. 25

1.3 ***The Impact of the Board's Decision***

1.3.1 An unusual issue arose in this proceeding with respect to the impact of the Board's rate-setting decision. The Applicant advised that it plans to see what the Board determines in EB-2017-0307, before deciding whether they wish to proceed with the amalgamation, assuming it is approved under EB-2017-0306[15]. The implication was that the implementation of the Board's decision, not just as to the amalgamation, but as to rates, would be at the option of the Applicants[16].

1.3.2 The proposal of the Applicants appears to be that they will proceed with the amalgamation, and the efficiency savings that can be achieved, only if they like the rate-setting plan the Board establishes. They have been clear that the $680 million of consolidation savings are at risk if they don't get what they want[17].

1.3.3 There are two components to this: a) are the savings at risk, and b) is this an appropriate approach to decisions of this Board? SEC believes the savings are not at risk in any case, as discussed later in these submissions.

1.3.4 On the second question, though, we have a concern. This is the first time we have heard a utility say that they believe it is their choice whether they implement a Board decision on rates, or not.

1.3.5 Look at an analogy. A utility comes in for a five year custom IR application, seeking increases of 4% a year for five years. The Board only gives them a formula expected to deliver rate increases of 2% a year. Can that utility come in the following year with a cost of service application, because they didn't like the custom IR result? While technically they can ask for anything, of course, in fact the Board should not, and likely would not, allow that. Once the Board has determined the rate trajectory/ formula after a full review in a proceeding, the utility should live with that outcome.

1.3.6 The same is true here. Once the rate rules are established by this Board, the Applicants should live with them. A decision on just and reasonable rates has been made. They should not be allowed to keep coming back to the Board with different proposals until they get a decision they like.

1.3.7 The only complication here is that the Applicants do have the right to decide not to amalgamate, and under their view of the world that would mean that their costs would be higher going forward. If that were true, and if they sought higher rates because they decided not to amalgamate, the onus would be on them to show that the higher costs were prudently incurred. In our view, it is unlikely they would be able to do so.

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15 TC1:56; Tr1:13, 19.
16 Tr1:13, 22.
17 Tr1:25-6, 84.

1.3.8 SEC therefore concludes that the Applicants' view that the integration savings are only available if they decide they like the Board's decision is wrong on two counts. It is wrong because virtually all of the savings are available regardless of whether they decide to amalgamate. And, it is wrong because once the Board decides the basis on which their rates will be set going forward, we expect that the Board will implement rates on that basis regardless of whether the Applicants like the result, and regardless of whether they amalgamate. It appears to us unlikely that the Applicants will be able to obtain an order from the Board for a different rate plan that they like better.

1.3.9 We note that, if the Applicants don't like the Board's decision in this proceeding, they do have the right to apply to have it reviewed by the Board, or to appeal it to the appropriate court.

1.3.10 What the Applicants seek to do instead is arrogate to themselves – rather than the Board or the courts - the right to determine whether the Board's decision in this case leads to an acceptable result.

1.3.11 SEC believes that the Board should tell the Applicants, in the clearest possible terms, that, unless there is a successful review or appeal, the Board expects their decision on rates to be respected, and implemented.

1.4 ***Summary of Submissions***

1.4.1 ***Approval to Amalgamate.*** In application EB-2017-0306, the Board should approve the amalgamation of Union and EGD under section 43 of the Ontario Energy Board Act. The Board should make clear that this approval does not carry with it any assumptions or implications with respect to ratemaking. Without the rate plan, and without the ten year deferral of rebasing, the "no harm" test is met, because the Applicants are already under common ownership. It is only the proposed rate plan that harms the customers.

1.4.2 ***Rate Plan Application.*** In application EB-2017-0307, the Board should deny approval of the Applicants' proposed method of setting rates. It should be noted that the Board has not been asked to set rates under section 36(3) of the OEB Act. The actual application for rates would be in a separate proceeding, later this year, for 2019. The Applicants in this proceeding only sought approval for a methodology to set rates for 2019-2028.

1.4.3 That approval should be denied for five primary reasons:

(a) ***Overcompensates the Applicants.*** The proposed rate plan would result in the Applicants collecting at least $1 billion more from customers than under the alternative, the normal rate plans used by the Board (such as Custom IR), with

no apparent justification. If the proposed rate plan were allowed, the "no harm" test would not be met, and the rates would not be just and reasonable.

(b) ***MAADs Policy Does Not Apply.*** The only rationale given by the Applicants – invocation of the MAADs policy of the Board – has a fatal flaw. The MAADs policy does not apply here. It is inapplicable on its face (because the utilities are already under common ownership), the underlying policy drivers are not relevant (because incenting consolidation of gas distribution is not one of the Board's or the government's public interest goals), and the details of the policy were designed for a fundamentally different scenario.

(c) ***Need to Review the Applicants' Cost Structures.*** The costs of the Applicants have changed in material ways since they were last reviewed five years ago. Failure to review those costs for a further ten years would be contrary to good regulatory practice.

(d) ***Utility System Plan.*** The Applicants have yet to file a comprehensive Utility System Plan, and such a plan is essential under the Board's policies in order for the Board to meet its mandate under the OEB Act.

(e) ***Cost Allocation and Rate Design.*** The evidence shows that there are material cost allocation and rate design issues that appear to make rates for many customers no longer just and reasonable. The rate plan proposal would exacerbate those problems. Only a rebasing allows a proper review of cost allocation and rate design.

1.4.4 ***Implications of Denial.*** The Board should make clear that its denial of approval for the rate plan proposal has certain rate-setting implications. Those implications, as determined by this Board panel, should be the following:

(a) ***Obligation to File Full Cost of Service Information.*** Both Union (by agreement and Board order), and EGD (by formal commitment in a hearing) are obligated to file full cost of service information for the 2019 year, and supporting information for prior years. If the Board relieves them of those obligations, it is not only unfair to the customers who relied on them. It would also undermine the settlement process, because parties and the Board could no longer rely on future utility commitments to deal with issues. Instead, the Board should affirm and support, but interpret, the obligation. The Board should make clear that – in the special circumstances now before it[18] – the Board will consider the Applicants' obligations to be satisfied if that set of fully compliant cost of service information is included with respect to the

[18] The merger, and the Applicants' mistaken view that their previous rate plans and legal commitments thus no longer applied.

Historic, Bridge, or Test Year of a cost of service rebasing application, whether individual or joint. Thus, the Applicants can rebase with a test year as late as 2021, giving them sufficient time to prepare that application.

(b) ***Union Rates in the Meantime.*** Assuming Union cannot rebase for 2019 rates, the Union IRM plan can continue on its existing terms, including escalation at 40% of inflation, and continuing the existing capital pass-through mechanism. A 2019 rates application can be filed on that basis. In the event Union believes that the tax refund adjustment of $17.4 million should end at the end of 2018, that matter can be dealt with in an appropriate rates or DVA application before January 1, 2019.

(c) ***Enbridge Rates in the Meantime.*** EGD is on Custom IR, in which annual rate formulae are specific to each year, so it does not have a formula available to escalate its rates for 2019 and beyond. In light of EGD's consistent over-earnings, the Board should indicate that it would consider a 2019 application for rates applying the Union Gas price cap IRM model, and related rules, to be an acceptable approach. Failing use of that model, the EGD rates would remain at their current levels until rebasing.

(d) ***Rebasing.*** The Applicants should be ordered to rebase no later than 2021. The application should include a Utility System Plan that includes consideration of how the combined entity or, if they do not amalgamate, the entities under common ownership, will co-ordinate and optimize the management of the overall system. That application should also show that the Applicants have a comprehensive plan to maximize the benefits of common ownership or amalgamation for the benefit of the customers, and that they have started to implement that plan in a reasonable manner.

1.4.5 ***Alternative Rate Model***. SEC does not believe that any deferred rebasing period is appropriate. However, in the event that the Board determines that a deferred rebasing period should be allowed for the Applicants after amalgamation, the terms should be as follows:

(a) ***Base Rate Adjustments.*** Base rates on which escalation would be applied should be adjusted as follows:

(i) The proposed adjustments of $17.4 million for tax deferral, and $4.9 million for customer care smoothing, should be implemented.

(ii) In addition, the revenue requirements of the two Applicants should be reduced by the grossed-up value of their 2018 earnings in excess of the 2018 allowed ROE for each of them, so that customers get the benefit of past IRM productivity improvements, one of the key components of the IRM "bargain" between

customers and utility. This should be done in two stages. First, the estimated normalized overearnings for 2018 should be deducted from the initial revenue requirements on which the 2019 escalation would be calculated. Union's estimated overearnings, $16.9 million, are already on the record. EGD should be required to file their estimated 2018 overearnings no later than their 2019 rate application, or the $47.1 million from 2017 should be used as a proxy. When the actual normalized 2018 overearnings are known, the revenue requirement adjustment should be trued up to that figure, whether positive or negative, effective January 1, 2019, via a variance account.

(iii) Because overearnings already adjusts for all other cost components, no further base rate adjustments are required.

(b) ***Term.*** The rebasing deferral period should be no longer than five years, so that the latest rebasing year would be 2024.

(c) ***Inflation Escalator.*** GDP IPI should be stipulated as the inflation factor, as it is a simple approach and is almost identical to the two factor inflation approach otherwise available.

(d) ***Productivity and Stretch.*** Both companies have been able to over-earn consistently under their current plans, EGD more than Union. Therefore, the deferred rebasing period should include a productivity/stretch factor equal to 60% of inflation, the same as the current Union plan. The Board knows that, for these utilities, that amount of productivity can be achieved, because they have done so consistently for years.

(e) ***Application of I-X Formula.*** The rate formula should be applied to each component of distribution rates, including monthly charges, volumetric charges, and storage charges, in exactly the same percentages, unless the Board in a rate application has otherwise approved a change in the application of that principle for a given year.

(f) ***Incremental Capital.*** The combined entity should use the capital pass-through mechanism that is currently used by Union Gas. The same criteria, including materiality factors, should be applied. The materiality factor for the CPT is more complex than for a Z factor, and so the existing one should be retained until it can be reviewed in full at the next rebasing.

(g) ***Earnings Sharing.*** There should be asymmetrical 50/50 earnings sharing with a 100 basis points dead band, cleared annually.

(h) ***Z Factor.*** The combined entity should have the same Z factor materiality threshold as OPG, a utility of similar size, i.e. $10 million.

(i) ***Off-Ramp.*** The combined entity should be allowed to apply for an off-ramp only if it can demonstrate that it is in financial difficulty.

(j) ***Rate Harmonization.*** The combined entity should be required to provide, on rebasing, a detailed analysis of rate harmonization options and their impacts, and a proposal with respect to the utility's preferred approach.

(k) ***Information Commitments***. The Applicants should be ordered to comply with their commitments to file full cost of service rebasing information related to 2019, including prior year details as set forth in the Union EB-2013-0202 Settlement Agreement.

2 APPROVAL TO AMALGAMATE – EB-2017-0306

2.1 *The Application*

2.1.1 The elephant in the room in this proceeding is that this is not a proposed merger of two different utilities. In a typical merger, two or more independent entities with different ownership come together. Board policies incent that transaction, because bringing them under common management often creates opportunities for scale and other economies.

2.1.2 This is instead a proposal to change the form of an existing corporate group, already under common ownership and management, in order to simplify the implementation of efficiency savings. It does not in any way create the opportunity for those savings. That has already happened with the acquisition of Spectra and thus Union Gas by Enbridge Inc. in 2017.

2.1.3 This has two effects.

2.1.4 First, it makes it much simpler for the Board to deal with the application of the "no harm" test. Changes in form (as opposed to substance) rarely have substantive impacts, at least not any that are material.

2.1.5 Second, it makes it more difficult for the Board to believe the Applicants' narrative that somehow significant efficiencies will arise because of this change of form. By necessary implication, therefore, the "incentives" component of the Board's MAADs policy has no application in this case. Companies don't need to be incented to do something they have, in substance, already done.

2.2 *"No Harm" Test*

2.2.1 The Board does not have a written policy on the consolidation of gas distributors, as it does with respect to consolidation within the electricity sector. Thus, as the Board has determined already in this proceeding, the policy approaches that should be applied to gas mergers, including the Applications in this case, have to be determined for the first time. The Board said[19]:

> *"The OEB does not agree with the arguments of the applicants and accepts the position of intervenors and OEB staff that all aspects of the MAADs Handbook do not automatically apply to natural gas. The MAADs Handbook does not specifically reference natural gas and there is no specific guidance in the Handbook as to how gas mergers should proceed. The OEB is of the view that issues such as the deferral period and earnings*

[19] Decision and Procedural Order #3, p. 6.

> *sharing mechanism are legitimate areas of inquiry and are not pre-determined in this case. The OEB may find that the MAADs Handbook applies in part or in whole, but this does not preclude parties from arguing for or against the applicability of specific elements of the MAADs Handbook…"*

2.2.2 However, the Board went on to make clear that the "no harm" test does apply in this case. The no harm test arose, not out of a policy development process, but out of an adjudicated proceeding. It has subsequently been applied in many gas and electricity consolidation proceedings. It is thus an established principle at the Board[20]. The fact that this is also in the MAADs Handbook is for convenience only. That is not the source of the policy.

2.2.3 The Board has described the no harm test in more detail in the MAADs Handbook as follows[21]:

> *"The "no harm" test assesses whether the proposed transaction will have an adverse effect on the attainment of the OEB's statutory objectives. While the OEB has broad statutory objectives, in applying the "no harm" test, the OEB has primarily focused its review on impacts of the proposed transaction on price and quality of service to customers, and the cost effectiveness, economic efficiency and financial viability of the electricity distribution sector. The OEB considers this to be an appropriate approach, given the performance-based regulatory framework under which all regulated distributors are required to operate and the OEB's existing performance monitoring framework."*

2.2.4 SEC notes that the no harm test applies to transactions under section 86 or section 43. It does not apply to the setting of rates. That is driven by the statutory requirement that rates be "just and reasonable", and the extensive law surrounding rate-making. None of that applies the no harm test. While it is evident that, with few exceptions, rates that harm the customers will not be just and reasonable, the no harm test has no relevance to rates. The law on this is clear.

2.2.5 Union and EGD are under common ownership and management, and as a result they are rolling out standards of operation that seek to implement the best from each of the companies. Whether or not the amalgamation is approved by this Board, it is reasonable to expect that the operation of these two utilities will continue to be

[20] The "no harm" test is not a principle of universal application in energy regulation. Many jurisdictions have a "positive benefits" test, requiring that the applicants show that there are positive benefits in order to gain approval for their consolidation transaction. Ontario has not applied that test, although in most cases positive benefits have been demonstrated. For a good discussion of the difference between the two standards, see Hempling, Scott, "No Harm vs. Positive Benefits: The Wrong Conversation about Merger Standards", May 2014. http://www.scotthemplinglaw.com/essays/no-harm-vs-positive-benefits.

[21] *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, p. 6.

pursued by that common management with a view to meeting the needs of their customers. To the extent that they have a customer focus today – and they do – that will not change after amalgamation.

2.2.6 SEC thus agrees with the Applicants that the amalgamation of Union and EGD should not be expected to cause harm to the customers with respect to:

(a) Quality of service.
(b) Cost effectiveness.
(c) Economic efficiency.
(d) Financial viability.

2.2.7 The only area in which the customers could be harmed is on price, and that arises only if the rate-setting application is approved, in whole or in part. The actual amalgamation itself should have no materially adverse impact on the customers, because it is a change of form rather than substance. The obligations of the amalgamating utilities would – subject to the Board issuing a supervening order – continue in Amalco[22], including the obligation to file rebasing application(s) for 2019 rates. Thus, if the Board approves the EB-2017-0306 request for consent to amalgamate, absent additional orders the prices to be paid by the customers should not be expected to be higher than if the Applicants do not amalgamate.

2.2.8 SEC therefore submits that, except for the request to allow a ten year deferred rebasing, and related relief, the Application for leave in EB-2017-0306 meets the no harm test.

2.3 ***Applicability of the MAADs Policy***

2.3.1 As noted above, the MAADs Handbook does not by its terms apply to gas distributors, and the Board has confirmed that in PO #3. The extent that individual policies within the MAADs Handbook should be imported by the Board into this situation (by analogy or otherwise) is a matter for determination by this Board panel. Neither the MAADs Handbook nor the Rate Handbook provide any direction in this respect.

2.3.2 The primary exception to that is the no harm test, which although in the MAADs Handbook existed and continues to exist as a principle applied by the Board,

[22] Business Corporations Act, Ontario, RSO 1990, c. B16, section 179(b), which says *"Upon the articles of amalgamation becoming effective, …(b) the amalgamated corporation possesses all the property, rights, privileges and franchises and is subject to all liabilities, including civil, criminal and quasi-criminal, and all contracts, disabilities and debts of each of the amalgamating corporations".* The same provision – or something very similar - exists in virtually all corporations statutes in Canadian jurisdictions. The ability to amalgamate is subject to the overriding authority of the Board to grant leave, which supersedes the right to amalgamate under the Business Corporations Act, but once the leave is granted and the amalgamation takes place, absent any further orders of the Board section 179(b) kicks in.

completely separate from the MAADs Handbook. Thus, no reliance on the MAADs Handbook is required to apply the no harm test, and it clearly applies in this case. As noted above, SEC believes that test is satisfied.

2.3.3 The remainder of the MAADs Handbook deals primarily with the Board's policies with respect to ratemaking on consolidation. Those policies apply expressly to electricity distributors. The Board has already determined in this proceeding that they do not apply to gas unless the underlying policy rationale for any given policy is applicable in this situation.

2.3.4 The Applicants, in their Argument-in-Chief, go to some length to try to show that the ratemaking policies in the MAADs Handbook, particularly the ten year deferred rebasing period, apply – as a matter of interpretation of the Board's intent – to this case[23]. SEC believes that issue has already been addressed by the Board in PO#3, and it is inappropriate for the Applicants to continue to argue "the Board policies say we are allowed to do this".

2.3.5 It is perfectly legitimate to argue – as the Applicants go on to do – that the underlying rationale of the Board's MAADs Handbook means it should be applied to this case. While we disagree (see below), we believe this is exactly what the Board anticipated in PO #3: a debate on the appropriateness of certain ratemaking approaches in this situation. What does not appear to be legitimate is the argument of the Applicants that proper interpretation of the MAADs Handbook means it is intended to apply to this situation. The Board has determined that is not the case. End of discussion.

2.4 ***<u>Ten Year Deferral Period</u>***

2.4.1 EB-2017-0306 proposes a ten year deferred rebasing period. The apparent reason for its inclusion in that Application, rather than the rates Application, is that the Applicants seek to apply the MAADs Handbook to this case. Otherwise, generally speaking rates are not part of a MAADs application. In fact, as the MAADs Handbook (which the Applicants seek incorrectly to apply) points out[24]:

> *"Rate-setting following a consolidation will not be addressed in an application for approval of a consolidation transaction unless there is a rate proposal that is an integral aspect of the consolidation e.g. a temporary rate reduction. Rate-setting for the consolidated entity will be addressed in a separate rate application, in accordance with the rate setting policies established by the OEB. The OEB's review of a utility's revenue requirement, and the establishment of distribution rates paid by customers, occurs through an open, fair, transparent and robust process ensuring the protection of customers."*

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[23] AIC, p. 11-13.
[24] MAADs Handbook, p. 11.

2.4.2 On the Applicants' theory of the case, the MAADs Application gets them the right to the deferred rebasing period under the MAADs Handbook. Then, of course, they would not have a method to set rates for the next ten years (the rules in the MAADs Handbook assume a pre-existing set of ratemaking options, as is the case for electricity distributors), so the EB-2017-0307 (rates) Application is designed to fill in that gap by establishing a new rate-setting methodology for that ten year period.

2.4.3 The Applicants' arguments in favour of the ten year rebasing straddle the two policy paradigms.

2.4.4 Their first set of arguments (aside from those parsing the language of the various policies to seek automatic application of the ten year rebasing) relate to the underlying reasons for the ten year rebasing period in the MAADs Handbook and the MAADs Policy. Under those arguments, the MAADs Handbook should apply because the rationale for the policy applies.

2.4.5 Their second set of arguments is not about MAADs, but about rate-setting approaches. Under those arguments, the ten year rebasing is necessary to ensure that deep and lasting cost efficiencies are implemented.

2.4.6 Both sets of arguments in favour of the ten year rebasing period fail when subjected to analysis.

2.4.7 ***The Rationale in the MAADs Handbook***. The Applicants list two underlying drivers of the MAADs policy on rates that apply here just as much as in the electricity sector[25]:

(a) Economies of scale; and

(b) Economies of contiguity (reduction in costs or improvements of service resulting from reducing geographic barriers between utilities).

2.4.8 With respect to economies of scale, there is little doubt that the consolidation of Union and EGD allows the combined entity to realize efficiencies and thus generate a lower cost per customer. Much evidence has been provided in this proceeding on that score, and if anything the forecasts of scale economies are understated, not overstated[26]. All parties appear to agree that there are scale economies. While economies of contiguity were not discussed as much, it also appears to be the general view of the parties that the combination of Union and EGD (whether through common management or through amalgamation) should allow for more cost effective ways to serve customers

[25] AIC, p. 13.
[26] See, e.g. Tr6:95-7, and many other references.

near the border areas.

2.4.9 While these are both true, the thing the Applicants have failed to do is connect those economies to the ten year rebasing period. The ten year rebasing period has a specific policy rationale, and there is no credible evidence in this proceeding to show that policy rationale applies here.

2.4.10 The MAADs Handbook expressly refers[27] to its 2015 policy report Rate-setting for Distributor Consolidation[28], and notes that the Handbook is simply a consolidation of the existing policy. It recommends that parties review the original policies to understand them fully.

2.4.11 The MAADs Rate Policy is specifically directed at consolidation within the electricity distribution sector[29]:

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

2.4.12 The policy discusses the OEB and government policy direction to encourage electricity distributor consolidation. The policy document also goes on to explain the reason for the extension of the five year deferred rebasing period to ten years:

> *"The OEB believes that the decision to extend the deferred rebasing period for distributors who are party to a MAADs transaction supports the OEB's own expectations, as well as those of the government, that the distribution sector should continue to seek out efficiencies, especially through consolidation."*

2.4.13 The point, the Board went on to say, is to allow the consolidating entities sufficient time to recover the costs of the consolidation. This is described more clearly in the original 2007 rate-making policy on electricity distributor consolidation as follows[30]:

> *"In general, consolidation costs may include out-of-pocket/transaction costs, acquisition premiums, and restructuring costs. Regardless of the nature, timing, or certainty of expected benefits of a consolidation, the*

[27] MAADs Handbook, p. 10-11.
[28] *Rate-Making Associated with Distributor Consolidation*, March 26, 2015 (the "MAADs Rate Policy").
[29] MAADs Rate Policy, p. 4.
[30] Rate-Making Associated with Distributor Consolidation, July 23, 2007 (the "2007 Policy"), p. 4.

ability to retain any achieved savings for a sufficient amount of time to provide a reasonable opportunity to at least offset the costs of a transaction will be an important factor in a distributor's consideration of the merits of consolidation."

2.4.14 In this case, the evidence before the Board is that the total cost of the consolidation is expected to be $150 million, and the maximum excess of cost over achieved savings is expected to be $8 million[31]. By the end of 2020, the costs exceed the shortfall by only $4 million, and that excludes the $5.2 million in continuing annual savings already achieved by the end of 2017[32], and all of the annual savings to be achieved in 2018[33].

2.4.15 Thus, the primary rationale for the ten year rebasing period – we need more time – does not appear to apply in this case. That stands to reason. In electricity distribution transactions, there are substantial premiums paid to acquire utilities[34], and there are substantial transaction costs associated with an acquisition or merger between two independent entities. Neither is the case here. The only costs are the small investment of $150 million to achieve $680 million[35] of savings.

2.4.16 Further, the higher level policy rationale – the desire to incent distributor consolidation – is also not apparent here. This consolidation has already occurred, and doesn't need to be incented.

2.4.17 In any case, it is not evident that there are too many gas distribution companies in Ontario, and the Board has to act to convince them to consolidate.

2.4.18 ***Time Needed to Deliver Deep Savings.*** Of course, the Applicants argue, in the second branch of their deferred rebasing argument, that the Applicants need more time to achieve deep savings within their organizations[36]. Indeed, the very same table in J2.4 quoted above appears to show that the shareholder only achieves benefits in years 8-10.

2.4.19 The reason for this apparent anomaly is that the Applicants claim to be giving $410 million of rate reductions to their customers, eating up all of the savings until the later

[31] See J.2.4, p. 2. The Undertaking response seeks to mask the low risk by adding in the supposed revenue shortfall from the Applicants' proposal. This is discussed in more detail in Section 3 of this Final Argument. The actual net is shown by the difference between lines A2 and A4. In fact, SEC estimates that, by the beginning of 2019, savings will already be exceeding cost to implement each year, so that at no time during the proposed deferred rebasing period will the Applicants ever be out of pocket for the consolidation.
[32] JT3.1 and Tr1:68.
[33] The Board does not have an estimate of this amount. The Applicant's forecasts start in 2019, even though it is acknowledged that savings have already started, and are continuing.
[34] There are none in this case: Tr1:29.
[35] Which SEC believes is materially understated.
[36] AIC, p. 15-17.

years. Without that largesse, the ten year rebasing period is not required. The policy rationale of the MAADs Rate Policy – allowing full recovery of the costs of consolidation - would be achieved by the end of 2020, or earlier.

2.4.20 The argument in favour of the ten year rebasing thus rests entirely on the Board believing two assertions by the Applicants:

(a) The savings estimate of $680 million is a reasonable one; and

(b) The standalone straw man used to calculate the $410 million ratepayer benefit represents the costs the Board would allow in rates for the Applicants in the absence of the amalgamation.

2.4.21 SEC submits that neither of these assertions is credible. As discussed elsewhere in this Final Argument, the Applicants admit that the $680 million excludes savings from areas that will likely produce something greater than zero. As well, we discuss later the fact that the $410 million rate benefit is illusory, because the standalone straw man is dramatically overstated.

2.4.22 ***Problems with Deferring Rebasing.*** In section 4 of this Final Argument, SEC discusses the value of rebasing these Applicants as soon as possible. In summary, rebasing results in the following benefits, among others:

(a) ***Transparency.*** The Board gets detailed information on the costs of two major utilities. Their detailed operational data has not been available to the Board for five years, and under the Applicants' proposal would not be available to the Board for a total of fifteen years.

(b) ***Achieving the IRM Paradigm.*** The fundamental "deal" in IRM is that the shareholders are incented to drive savings, and get to keep them for up to five years. Then, on rebasing, the savings are baked into rates for the benefit of the customers.

(c) ***Utility Commitments.*** Both Union and EGD made formal commitments to provide detailed cost of service information no later than 2019, and they should not be allowed to renege on those commitments.

(d) ***Cost Allocation and Rate Design.*** There are numerous outstanding cost allocation and rate design issues that can only be addressed properly in the context of a rebasing.

(e) ***Sharing Integration Risks/Rewards/Incentives.*** Rebasing would allow the customers to share in both the risk, and the rewards of integration of the two utilities' operations, while allowing the Board to fashion situation-specific

incentives for the shareholder to maximize those rewards.

2.4.23 SEC therefore submits that the arguments in favour of deferred rebasing are weak and unpersuasive, and the arguments against deferred rebasing are substantial and compelling.

2.5 ***SEC Recommendation***

2.5.1 SEC submits that the Board should give leave to the Applicants under section 43 to amalgamate.

2.5.2 However, the Board should not approve the ten year deferral of rebasing requested in EB-2017-0306. Since there is a rate application before the Board, all questions relating to setting rates for the Applicants from 2019 onwards should be dealt with together as a comprehensive rate plan.

3 RATE-SETTING PROPOSALS – EB-2017-0307

3.1 *Background*

3.1.1 The entire justification for the Applicants' rate-setting proposals is a comparison of those proposals to a counterfactual, i.e. a set of future events that the Applicants say would happen if their rate proposals are not accepted by the Board[37].

3.1.2 Based on that straw man proposal, the Applicant says that they are offering the following deal to the customers via the Board[38]:

(a) The Applicants will invest a forecast $150 million to integrate the operations of Union and EGD.

(b) From that investment, a forecast $680 million of cost efficiencies will emerge during the next ten years.

(c) The first $150 million of those efficiencies will go to pay the investments required to achieve them.

(d) The next $410 million will go to the customers in the form of rate reductions over the next ten years, measured by comparison between the proposed rates and the standalone straw man rates[39].

(e) The remaining $120 million will go to the shareholder as its incentive for doing this.

(f) In the deferred rebasing period, to the extent that the Applicants are able to achieve greater savings, or reduce the cost to generate them, 100% of that net benefit will accrue to the shareholder.

(g) On rebasing in 2029, the full value of the savings will be baked into rates for the benefit of customers.

3.1.3 SEC believes that no ratepayer benefits are in fact included in the proposed rate-setting structure. In fact, we believe that rates for customers would be $1 billion higher under the proposal than under any reasonable alternative scenario. We also believe that the integration savings are understated, with the result that the benefits to the shareholder are significantly greater than the Applicants have asserted.

[37] Tr6:21.
[38] Tr1:26; Tr6: 18-19; and many other places.
[39] Tr1:153; Tr2:133.

3.1.4 In this section of our Final Argument, we deal with the claims that a ratepayer benefit is being provided, and conclude that the opposite is true.

3.2 ***The Standalone Straw Man***

3.2.1 The detailed calculations of the Standalone Straw Man are contained in FRPO 11, as well as KT3.3. In this Section, we will look at that standalone straw man from two perspectives:

(a) What work was done by the Applicants to provide a robust counterfactual for the Board?

(b) Are the details of the standalone straw man reasonable?

3.2.2 ***Basis of the Counterfactual.*** The Applicants have prepared a forecast of what they say would happen to rates charged to customers if they did not amalgamate[40]. Their forecast[41] starts from the premise that each of the utilities will apply for 2019-2023 rates using the Custom IR option[42]. Then, they will each apply again for 2024-2028 rates using the same method. The result of their four forecasted Custom IR applications is total revenues of $29.6 billion over the ten year period[43]. They compare that with their forecast of revenues under the Amalco plan, including ICM revenues of $1.2 billion, and they come up with a shortfall under the Amalco plan of $410 million[44]. SEC calls this counterfactual the “standalone straw man”.

3.2.3 The standalone straw man is not a detailed analysis of what would be included in the fictional Custom IR applications[45]. It is, instead, a “high level” forecast by management, using their best judgement, as to what they would propose to the Board were they not to amalgamate[46].

3.2.4 The problem with every counterfactual is that, by definition, it is not going to happen. There is thus no way to verify, after the fact, whether it is correct. It is thus, by definition, a straw man. Since it is never going to happen, it’s only value is to compare to what will actually happen, in order to measure improvement over a baseline, or the extent to which a proposed future is better than another[47].

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[40] Tr2:121.
[41] The details are found in FRPO 11.
[42] Tr2:123, 138.
[43] K3.3.
[44] Tr1:80.
[45] BOMA 29, p. 3; TC3:121-2; Tr5:23, 53.
[46] TC3:118-120; Tr6:28.
[47] Counterfactuals are the primary basis for bottom-up conservation savings calculations, but they appear in many other scenarios as well.

3.2.5 Whether any counterfactual is reasonable depends on the assumptions that went into it. Like any other forecast, the phrase "garbage in, garbage out" applies. Some counterfactuals are based on a very detailed analysis, backed up by evidence that supports the assumptions used. Other counterfactuals are high level estimates, often designed to prove a point rather than accurately set out a realistic set of future events.

3.2.6 The standalone straw man put forward by the Applicants is not based on detailed homework, nor strong evidence on which the Board can rely. There are no capital continuity tables, or detailed tax calculations, or year by year OM&A budgets, or the like. There is no detailed past history, line by line, actual and approved, to show the trajectory of costs proposed in the standalone straw man. There is not even a detailed breakdown of the first year revenue requirement relative to prior years, as would be seen in a Custom IR, to show that the starting point is reasonable.

3.2.7 If there was a rebasing, the Board would have visibility on all of these things, and more. The Board would be in a position to assess the prudence of the Applicants' spending forecasts, and the forecast of billing determinants, and the deficiencies or sufficiencies produced. None of that is available here.

3.2.8 Further, there is doubt from the start that the standalone straw man is reasonable, on two counts.

3.2.9 First, the standalone straw man forces the conclusion that, in order to earn its allowed rate of return, the Applicants would need:

(a) A 4.8% rate increase in the first year.

(b) No return of the benefits of the past IRM to customers (i.e. the continuing overearnings).

(c) A full inflation factor annually on incoming rates.

(d) No productivity factor, unlike both of their previous plans.

(e) No stretch factor, unlike every plan the Board has ever approved.

(f) ICM recovery of all capital spending in excess of an artificially low threshold, even though the actual capital spending program is not higher than the previous five years.

PLUS

(g) Another $410 million out of the integration savings[48].

3.2.10 This is completely inconsistent with the past history of both Union and EGD.

3.2.11 Second, the standalone straw man leads to the conclusion that the Applicants plan to spend $150 million to get $680 million of savings, and propose to share the net savings $410 million (77.4%) to the ratepayers, and $120 million (22.6%) to the shareholder. The result, they say, is ROE 20 basis points higher than Board approved.

3.2.12 Neither Enbridge or Union ever earns only 20 basis points higher than Board approved[49], even without the availability of integration savings, so saying that is the true result of their proposal is not believable. Further, saying that they will voluntarily give more than 77% of the savings to the ratepayers is not consistent with the Union and EGD the Board knows well. They will share, sure, but not <u>that</u> much.

3.2.13 Given the fact that the standalone straw man is not based on detailed analysis, and has no real evidentiary base (at least, not that the Board has seen), and given the surprising results the Applicants claim flow from the model, SEC believes that it is important to look under the hood of the standalone straw man, and see what the assumptions are that are producing those anomalies.

3.2.14 ***Details of the Standalone Straw Man.*** There are really three main problems with the standalone straw man that make it unreliable for the Board's purposes:

(a) The 2019 starting point is substantially overstated.

(b) The plan assumes that the entire capital plan of the Applicants will be approved by the Board without adjustment.

(c) The standalone assumes that there will be no savings from the common ownership and management of the Applicants.

3.2.15 ***Questionable Starting Point.*** The total revenue requirement for 2019 under the standalone straw man is $2,531, essentially identical to the $2,530 forecast revenues under the Applicants' rate proposal. As we note below, under our "Gives and Gets" analysis, the underlying facts do not indicate that the two figures should be the same, however convenient that might be for the credibility of the Applicants' proposal.

3.2.16 The standalone plan makes a number of assumptions about 2019 increases relative to prior year actual spending. While the Board obviously does not have 2018 figures for the two utilities available, it does have 2017 figures available. From those figures, it is

[48] J2.4, Tr1:153; and many other references.
[49] See, e.g., LPMA 18, Table 1 and 2. For context, see Tr1:70-73.

possible to determine exactly what the Applicants think the Board will approve with respect to their costs in 2019. The following table sets it out:

Comparison of 2017 Actual vs. Standalone				
Enbridge Gas Distribution				
($millions)				
Component	***2017***	***2019***	***"+/-***	***Percent***
Rate Base	6,465.2	7,025.0	559.8	8.7%
Cost of Capital	389.1	435.0	45.9	11.8%
OM&A	431.7	441.0	9.3	2.2%
Depreciation	301.3	328.0	26.7	8.9%
Fixed Financing	2.8	3.0	0.2	7.1%
Municipal Taxes	44.6	51.0	6.4	14.3%
Other Revenues	-42.2	-43.0	-0.8	1.9%
Income Tax - Base	1.0	43.0	42.0	NA
Total Costs	1,128.3	1,258.0	129.7	11.5%
Union Gas				
($millions)				
Component	***2017***	***2019***	***"+/-***	***Percent***
Rate Base	5,473.6	6,417.0	943.4	17.2%
Cost of Capital	344.9	384.0	39.1	11.3%
OM&A	413.6	443.0	29.4	7.1%
All other costs	368.1	404.0	35.9	9.8%
Total Costs	1,126.6	1,231.0	104.4	9.3%

Sources: SEC 17, 18 and 19 and KT3.3

3.2.17 The Board will readily understand that the 2019 starting point for the standalone straw man is intended to be on a cost of service basis, but the Board does not have the full details of that proposed cost of service and how the Applicants got to the numbers they did. In particular, the Board does not have the information it would normally have on the Historic and Bridge years, in order to assess whether the "Test Year", in this case 2019, is reasonable.

3.2.18 For EGD, the Board does have some 2017 information, in the same format as FRPO 11, but with some notable differences. What that information shows is that EGD believes that the Board would approve an increase in its costs of 11.5% from 2017 to 2019 (excluding the impact of operational efficiencies due to common ownership). This is despite the fact that, under IRM, EGD has made substantial progress in cutting back OM&A, $31 million in total in 2017[50]. None of this IRM efficiency

[50] SEC 18 vs. SEC 19.

improvement would accrue to the benefit of the customers, in part because of substantial increases in rate base and municipal taxes.

3.2.19 In addition, Enbridge assumes that its income taxes will go up $42.0 million from 2017 to 2019, from $1.0 million to $43.0 million. The standalone straw man assumes that the effective income tax rate for 2019 will be 18.6% ($43 million of tax on $231.4 million of return on equity). For the period 2014-2018, the Board in EB-2012-0459 approved an effective tax rate of 11.3% on income[51]. Actually, though, in the four years 2014-2017 for which we have actual results, EGD had an effective tax rate of 6.0%[52].

3.2.20 If EGD paid the same rate of tax as it has for the last four years of actuals, the 2019 provision should be $13.9 million, meaning that 2019 standalone straw man revenue is overstated by $29.1 million. If the assumption were instead that the Board would authorize a total tax provision similar to EB-2012-0459, 11.3%, the 2019 provision would be $26.1 million, meaning that 2019 standalone straw man revenue is only overstated by $16.9 million.

3.2.21 SEC notes that, for the ten years 2019-2028, the standalone straw man assumptions have EGD collecting $554 million from its customers to pay income taxes. The ROE for that period[53] is $2.851 billion. This is a total tax provision of 20.9% of ROE. If that provision was, instead, the 6% actually paid for the last four years, the tax provision would be $171.1 million, removing $382.9 million (93%) of the $410 million "ratepayer benefit".

3.2.22 And that, of course, is only the overestimate on the EGD side. We do not have the same level of detail on the Union side. What we know is that the standalone straw man has Union collecting in rates $533 million for taxes over the period 2019-2028. The total ROE for that period[54] is projected at $2.417 billion. This is a total tax provision of 22.1% of ROE. Union's last Board-approved is from EB-2011-0210, which is 14.3%[55]. More important, the Board has actual Union tax rates for 2014, 2015 and 2016 (2017 is not yet reported)[56], which show that Union actually paid tax, excluding the tax on overearnings, at a rate of 4.9% for those three years. If the tax

[51] Total Board-approved income tax provision 2014-2018, from SEC 19, $101.8 million. Total Board-approved return on equity 2014-2018, from SEC 18, $899.4 million. The ratio is 11.3%.
[52] Total actual income tax provision 2014-2017, from SEC 19, $43.8 million. Total actual return on equity (excluding overearnings) 2014-2017, from SEC 18, $728.4 million. The ratio is 6.0%. All of these tax amounts, in both approved and actual, appear to be grossed-up figures.
[53] Calculated from Table 4 of FRPO 11.
[54] Calculated from Table 8 of FRPO 11.
[55] A grossed-up tax provision of $17.1 million on ROE of $119.4 million (as set out in the updated DRO for that proceeding). The ratio is 14.3%. This is complicated by the unusual tax calculation in that proceeding, so it may be a less reliable figure. However, given the actual tax rates paid by Union, this isn't a material issue.
[56] EB-2016-0118 for 2014, EB-2017-0091 for 2015 and 2016. Total tax provision for those three years, $44.1 million. Total return on equity for those three years, $891.2 million, excluding over-earnings. The ratio is 4.9%.

provision in the Union standalone straw man were, instead, the 4.9% actually paid, for the last three years for which we have information, the tax provision would be $118.4 million, removing $414.6 million of the $410 million "ratepayer benefit".

3.2.23 Between Union and EGD, the tax provision for the standalone straw man totals $1.087 billion. In fact, something closer to $289.5 million is probably what will happen, and what the Board would approve given what we know today. That apparent $800 million overstatement of the tax provision is almost twice the "ratepayer benefit". For the Board to believe that the Applicants' standalone straw man shows a benefit for customers, the Board would have to believe that at least half of that tax overstatement is instead a reasonable assumption about the tax provision the Board would allow the Applicants in rates in a Custom IR proceeding.

3.2.24 For EGD, it would appear that they expect an increase in revenues of 11.5% over two years will be approved by the Board. Some of the details underlying that increase can be seen, and it is clear that the main component is the increase in rate base (which drives depreciation and cost of capital), which we discuss briefly below.

3.2.25 For Union, the expected approved increase in revenues is 9.3% over two years. On that, the Board doesn't have the same level of visibility, because Union has used the fact that it is under price cap to limit its disclosure of past actuals in this proceeding. What the Board can see is that a sizeable amount of the Union rate increase is driven by a high bump in rate base. There is also a 7.1% increase in OM&A, which is well above what the Board normally is happy with, but even if that were cut to 4% over two years, that would still only be a $13.4 million reduction in the 2019 revenue requirement.

3.2.26 The big assumption (other than taxes) for the initial year appears to be that the Board will accept the entire opening rate base of the Applicants[57].

3.2.27 For EGD, this includes cost overruns on some major projects. EGD 2017 Board-approved rate base was $6,024.1 million, but actual was $6,465.2[58]. Thus, in addition to the increase from 2017 actuals to 2019 forecast of $559.8 million, EGD has to deal with an overrun from previous Board-approved of $441.1 million. Some of that total of more than a billion dollars would likely be at risk in a cost of service proceeding for 2019. Assuming that all of it will be allowed into rate base by the Board appears to be an overstatement of the likely result.

3.2.28 Union is probably slightly less at risk. While the increase in rate base from 2014 actual of $3,976.4 million[59] to 2019 forecast of $6,417.0 million[60], 61.4%, is high,

[57] Tr1:78.
[58] SEC 18, Attach. 2
[59] SEC 18, Attach 1.

much of that is taken up with capital pass-through projects that have been reviewed by the Board, at least in part. There remains a rate base increase of $943 million from 2017 to 2019 that has not been fully reviewed, so some is likely at risk, but less so than EGD. The Union rate base assumption is not as obviously overstated[61].

3.2.29 SEC submits that the assumption that the Board will approve all of the $1.5 billion increase in Union and EGD rate base from 2017 to 2019 is overly optimistic, and makes the standalone straw man look more expensive than it is likely to be. If the Board were to disallow just $200 million of that big jump in rate base, the impact over the ten year period of the forecast would be about $160 million, an overstatement of the revenue requirement for the standalone straw man.

3.2.30 SEC submits that the assumptions used by the Applicants for the initial year of the proposed plan, carried through for the ten year period, dramatically overstate the costs to ratepayers of that standalone straw man. Thus, even without the assumptions with respect to capital spending during the plan, or the potential for efficiencies without the proposed amalgamation, it would appear to us that, far from being a ratepayer benefit, the proposed plan is actually more expensive for ratepayers than what would actually occur in the normal course.

3.2.31 ***Assumed Approval of the Capital Plan.*** An assumption that the Board will approve all of the capital plan of the Applicants for a ten year period is a significant stretch. The Applicants propose to increase their rate base over ten years by 42.1%[62], a total increase of $5.2 billion on capital spending of more than $11 billion[63]. One result is that, on a cost of service basis (and without taking into account the pattern of over-earnings), the Applicants expect the Board to increase their return on equity from $400.2 million in 2018[64] to $590.6 million ten years later, a 47.6% increase in their level of profits.

3.2.32 Approval of the entire capital plan of the utilities for the next ten years is not, it is submitted, a credible assumption. Particularly in an era of increasing costs of carbon, SEC submits that this massive capital expansion would likely not be approved unaltered.

3.2.33 Having said that, SEC notes that the Applicants confirm they used the same capital plan in their standalone straw man, and in their Amalco price cap proposal[65]. They even calculated them in the same way, rather than using the ICM calculation method

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[60] FRPO 11, Table 6.
[61] The Board can't really tell until it sees full cost of service information, which is yet another reason for a rebasing sooner rather than later.
[62] KT3.3.
[63] KT3.4.
[64] SEC 18.
[65] TC3:121; Tr6:78.

for the price cap[66]. Thus, while the Board would certainly scrutinize $11 billion of capital spending with considerable care, SEC note that it would do so in either of the two scenarios. Therefore, while the assumption of approval of the entire capital plan is probably an over-estimate, it is not an over-estimate that skews the comparison between the standalone straw man and the Amalco price cap proposal. As presented, a change in one would generate a change in the other.

3.2.34 SEC therefore submits that the standalone straw man cannot be challenged on the basis of overly ambitious capital spending, because even if corrected there would be no substantive impact. It is the delta between the two proposals that matters for the Board's purposes, and that would not change[67].

3.2.35 ***Common Ownership Savings.*** The same is not true of the assumption that the savings from the merger are a binary calculation. If the Board approves the Applications, there will be $680 million of savings. That is what is assumed in the Amalco price cap proposal. If the Board does not approve the Applications, the savings will be zero[68]. That is what is assumed in the standalone straw man.

3.2.36 This assumption has been shown in the hearing to be untrue. In 2017, the Applicants were already generating savings from their common ownership, a total impact of more than $50 million over the next ten years[69]. Further, the companies are continuing to implement cost efficiency initiatives associated with their common ownership[70], and that will certainly continue.

3.2.37 Pressed on this point at the Technical Conference, the witnesses for the Applicants had no answer as to why the same cost efficiencies would not arise even without the proposed amalgamation[71]. The only example they could give was the complications of the Affiliate Relationships Code, and even for that they have admitted that the problems with ARC could be solved by the Board with a simple exemption order, given their common ownership.

3.2.38 Underlying the assumption that the standalone straw man has no cost efficiencies is not an assumption that the Applicants <u>can't</u> achieve those efficiencies. The

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[66] Tr6:29-31, 59.
[67] We note that the other difference between the two capital plans actually arises within OM&A. In Custom IR plans, one of the things the Board looks at is the savings generated by high capital spending. With $11 billion of capital spending, it is virtually certain that the Board would expect there to be OM&A savings as a result. The price cap plan doesn't provide for that, while the standalone straw man, properly done, would have to include OM&A savings. The amount of this differential cannot be estimated with any reliability, but it would certainly be material. We have assumed $2 million per year of incremental savings in our subsequent analysis, but this is an estimate rather than a calculated number.
[68] Tr1:30, 146.
[69] JT3.1 and Tr1:68.
[70] Tr1:32-40, 49, and many other references.
[71] Tr1:43.

assumption is that they won't. If they are not allowed to keep all of the benefits of those efficiencies for an extended period of time, they are telling this Board that they simply won't try to achieve those efficiencies. They would prefer to run the utilities inefficiently than to be more efficient and benefit their customers in so doing.

3.2.39 This unstated major premise is wrong on two counts.

3.2.40 First, the Board will not allow a utility to intentionally operate inefficiently, when more efficient approaches are available and known to the Board. The Board is aware that the Applicants have identified $680 million of cost savings. It is inconceivable that the Board would require a rebasing, but then say "We understand that you will not be seeking efficiencies because we wanted the benefits to go to the customers". The Board expects regulated entities to seek continuous improvement, and that includes improvements arising out of this existing common ownership situation.

3.2.41 Second, and more important, the Applicants would not in fact refuse to implement efficiencies because the customers were getting the benefit. The Applicants chase efficiencies all the time, knowing that eventually those efficiencies will go to reduce costs baked into rates. In practical terms, a rebasing by the Applicants would mean that the Board would build a reasonable amount of efficiencies into the revenue requirement. The Applicants would then treat that as their baseline, and seek to implement efficiencies exceeding that level. It is not by accident that these Applicants always earn more than their allowed rate of return. They have a corporate culture that pushes for cost efficiencies.

3.2.42 Thus, SEC submits that the standalone straw man should include most of the cost savings that would arise in the Amalco scenario. Since those cost savings are included in the Amalco scenario for comparison purposes, every dollar of cost savings that would arise in any case is a dollar reduction in the $410 million that is being allocated to the customers.

3.2.43 The Applicants will argue, of course, that the customers are still benefitting, and that is entirely true. However, it would miss the point. The question is not whether the customers benefit from the integration efficiencies. The question is whether the cause of that benefit is the rate plan proposed by the Applicants. That rate plan is largely irrelevant to the delivery of benefits to customers.

3.2.44 If the rate proposal is not there to share the benefits of the integration efficiencies with the customers, what is it there for? SEC submits that the purpose of the proposal is to ensure that the Applicants do not have to share on rebasing the efficiencies they have already generated from the last ICM periods, and that they get a larger than needed annual increase in rates going forward. They are offering savings to customers that the customers will get anyway, and want in return to keep savings to which the customers are currently entitled until the ICM paradigm, and to get higher rate increases in the future.

3.2.45 SEC therefore submits that the standalone straw man is not a credible counterfactual against which to measure supposed ratepayer benefits. Below we will seek to estimate a more realistic straw man. It will show that the customers are worse off under the Applicants' rate proposal to the tune of more than $1 billion compared to rebasing in the normal course.

3.3 ***Gives and Gets***

3.3.1 The above discussion raises the question that SEC raised – to much fuss – on Day 6 of the oral hearing. That is, what are the components of the "deal" that the Applicants are offering, and do those components demonstrate that the deal is a fair one?

3.3.2 The evidence in the hearing allows us to put numbers to the various gives and gets in the Applicants' rate proposals. Those numbers are as follows:

Gives and Gets Summary

(in millions of dollars)

"Gives"		
Category	**10 yr.**	**Notes**
Increase in Opening Rate Base not included in costs recovered	$369	Assuming it is $457 million [Tr1:135]. See J6.1, p. 49; Tr1:78
Higher allowed ROE not included in costs recovered	$120	$11.5 million in 2019 [Tr6:56], times ten, plus escalation
Merger Integration Investments for account of shldr.	$150	J2.4
TOTAL	$639	

"Gets"		
Category	**10 yr.**	**Notes**
No clawback of overearnings on rebasing	$675	$47.1M EGD from 2017 (J1.2), $16.9 Union 2018 forecast (SEC 19), times ten years, plus escalation
Merger Integration savings	$680	J2.4 and many other sources; the actual would likely be at least $200 million higher; See TC3: 25, 45, 108
GTA Reinforcement & WAMS Overspend not reviewed	$182	Full capital cost for GTA only [TC3:169]; $147 million in the ten year period [JT3.22]
No stretch in X factor	$387	J4.1; Tr6:76
Growth in customer revenues greater than incremental costs	??	Enbridge revenues in 2017 are higher than Custom IR Board approved, but whether forecast should be adjusted is not known; See generally Tr6:58, 62
Gains on property sales for account of shareholder	$100	There is no basis of this figure; It is known that the property held has a cost of $580 million [See Tr:93, and letter from the Applicants]
ICM for Union based on 2013 figures	??	The likely amount is $1,294 {Tr6:89-90] but the Applicants have not agreed to this number
TOTAL	$2,024	The total is much higher, because of the items with no amounts

"Neutrals"		
Category	**10 yr.**	**Notes**
Capex in excess of formula/ICM recovered	$1,184	KT3.4; JT3.20
Base rate adjustments	$140	$13.5 initially, times ten years plus escalation
Inflation factor in rates	$2,316	Tr6:57
Zero productivity	??	Not clear that this is neutral, since both Applicants had productivity in their past plans
Sudbury Pass-through	$67	Propose special treatment of ICM to avoid losing this - J6.1, p. 49; OEB Staff 5

3.3.3 The Applicants do not agree with these figures. However, that is not the point of the exercise. The point, instead, is diagnostic in nature. If the Applicants appear to be giving up a lot less than they are getting in this "deal" they are offering to the Board, and the ratepayers, that suggests that there is more investigation needed to see whether the deal is really a fair one.

3.4 ***A More Realistic Standalone Scenario***

3.4.1 The "Gives and Gets" summary is a simplistic approach. It helps indicate strengths and weaknesses in a deal, but it is not a substitute for more rigorous analysis.

3.4.2 SEC believes that a better way to test the Applicants' proposal is to recast the standalone straw man using more realistic assumptions. We have attempted to do that, and have attached as Appendix A to this Final Argument the results of that analysis (the "Realistic Standalone Model"). A live version of that Excel spreadsheet is being filed along with this Final Argument, so that the Applicants, the Board, and anyone else can do sensitivity analysis and determine for themselves whether our approach is in fact more realistic.

3.4.3 What the SEC analysis shows is that the Applicants are overstating the standalone revenues, and therefore the rates under the standalone model, by $1.4 billion.

3.4.4 To prepare this analysis, SEC took the figures supplied by the Applicants in FRPO 11, Tables 2 and 6. Together those two tables make up the standalone straw man of the Applicants.

3.4.5 ***Capital Plan.*** The Realistic Standalone Model makes no changes to the capital plan of the Applicants, nor any changes to the cost of capital in any year. The evidence of the Applicants is that the capital plan was modeled in the same way for their standalone and their Amalco scenarios. While SEC believes that the capital plan is too aggressive, and doubts that there is absolutely no difference between the two scenarios on capital, there is no evidence of any differences, so we have left it alone.

3.4.6 The other area of capital is opening rate base. As noted earlier, there is clearly an issue with capital overspending by the Applicants prior to 2019, with the potential for disallowance. SEC believes that, of the more than $13 billion of opening rate base, it is reasonable to assume that $200 million will be disallowed by the Board. This would result in a reduction in standalone revenues, and therefore rates, of about $160 million over the ten year period.

3.4.7 Despite this, we have not adjusted opening rate base. There is insufficient evidence of the amount that would be disallowed, and we preferred to be conservative in this forecast.

3.4.8 We have also not adjusted other revenues, even though it seems clear that some properties will be sold during the next ten years as the companies rationalize their holdings. This would reduce rate base, cost of capital and depreciation, and would increase other revenues to the extent that a share of the profits were allocated to the customers. We do not believe these impacts will be zero, but we have assumed zero to be conservative.

3.4.9 ***Changes Made.*** The changes SEC made to the standalone straw man to make it more realistic are the following:

(a) The income tax has been set at 11.6% of the ROE, the same as the Board-approved in EB-2012-0459, which was cost-based..

(b) OM&A is assumed to be reduced by $2 million a year as a result of high capital spending.

(c) Municipal taxes jump in 2019, as the Applicants propose, but then increase at 2% per year.

(d) A stretch/productivity factor of 30 basis points is applied to revenues except cost of capital.

(e) The $5.2 million of net integration savings already achieved, plus 80% of the net integration savings forecast over the period, are deducted from revenue requirement.

3.4.10 ***Income Tax.*** As noted earlier, the income tax assumptions in the Applicants' standalone straw man are significantly higher than the Board has approved in the past, and even higher still than the actual income tax paid by the Applicants in the last several years.

3.4.11 The Realistic Standalone Model uses the 11.6% level of tax approved by the Board for EGD in EB-2012-0459. This is much higher than the actuals for Union and EGD, 4.9% and 6.0% respectively. That is because the last Union Board-approved was adjusted, and showed a taxable income in excess of regulatory income. That will have changed, of course, because of the high capital spend in the last few years (which creates a tax shield due to the excess of CCA over depreciation). That is likely to continue given the continuing high capex proposed.

3.4.12 However, it is not possible, on the information before the Board, to provide a calculated result. The most conservative approach appears to be to use the Board-approved from the last EGD rebasing. That is likely high, but the SEC model allows the Board and parties to change the assumed tax rate to see the impacts.

3.4.13 ***OM&A Reduction.*** The annual $2 million reduction to reflect high capital spending (which in the normal course will reduce operating costs) has a cumulative impact of $110 million over ten years. There is no methodology to this figure. While it is a very small amount, it makes a difference over time, so it would not be appropriate to use zero. On the other hand, anything larger could only be used if there was an evidentiary foundation for it.

3.4.14 ***Municipal Taxes.*** We have assumed that the jump in municipal taxes in 2019 has a firm basis, so we have included most of it, even though the evidentiary record is empty on this point. Going forward, an assumption of 2% per year is probably reasonable, unless the Applicants dispose of some buildings. If they do, municipal taxes will decline.

3.4.15 ***Stretch Factor.*** Every Custom IR or other IRM rate plan approved by the Board has some form of productivity and/or stretch factor. To assume otherwise in the standalone straw man is simply incorrect.

3.4.16 The Realistic Standalone Model assumes that a total productivity/stretch factor of 30 basis points would be included in any Board-approved plan. To be more conservative, we have applied that to all parts of revenue requirement except cost of capital. This makes the stretch effectively equivalent to about 20 basis points.

3.4.17 ***Integration Savings.*** The Applicants have admitted that they have already achieved $5.2 million in continuing integration savings[72], over and above those forecast in their Amalco scenario. We have deducted those from the standalone revenue requirement.

3.4.18 In addition, the Applicants have forecast $680 million of savings at a cost of $150 million. The details, by year, are included in J2.4. SEC believes that the savings forecast is understated, and further that the Applicants can achieve 100% of a more realistic savings forecast, and faster than the current plan.

3.4.19 However, to be conservative we have assumed that the $680 million forecast is reasonable, and that under the standalone scenario only 80% of the costs and savings will arise. The net is then deducted from the standalone revenue requirement.

3.4.20 ***Overearnings.*** SEC has not included an express adjustment for overearnings going into the 2019 year. While as a matter of principle the overearnings at the end of the IRM plan should be baked into rates for the benefit of the customers, we skipped this adjustment to avoid double-counting.

3.4.21 This is seen using EGD (which has the higher overearnings) as the example, by

[72] Jt3.1 and Tr1:68.

comparing their 2017 actuals to Board-approved. The $47.1 million of overearnings appears to come from higher revenues ($7.1 million) and lower costs ($40.0 million)[73].

3.4.22 The revenue figure can only be reviewed in the context of a rebasing. There is certainly insufficient information on the record to test whether assumed billing determinants should be adjusted going forward.

3.4.23 On the cost side, much of the cost differential appears to be taxes[74], and that is already being adjusted in the Realistic Standalone Model. We are also adjusting for $5.2 million of merger savings. The main things left are higher capital costs, and lower OM&A. While a further adjustment could be made for those, SEC felt it was better to keep the alternate model as simple as possible.

3.4.24 The effect is that the model probably under-adjusts for the going-in revenue requirement of the Applicants.

3.4.25 ***Use of the Model***. The Realistic Standalone Model is not a substitute for a full cost of service application, any more than the standalone straw man is. What the Realistic Standalone Model demonstrates is that, with just a few reasonable changes to the counterfactual proposed by the Applicants, the proposed rate plan goes from being a $410 million benefit to the customers, to a billion dollar net cost to the customers.

3.4.26 SEC proposes that the Realistic Standalone Model be used to test the reasonableness of the counterfactual. By providing a live Excel spreadsheet, SEC is facilitating the creation of sensitivities. Change the tax assumption, change the stretch factor, assume a greater or lesser achievement of synergies. It is possible to test whether, on any reasonable set of assumptions, the customers are better off under the Applicants' proposal vs. the more normal rebasing plus IRM (price cap, revenue cap, or custom) approach.

3.4.27 SEC submits that, on any reasonable set of assumptions, the customers will be far worse off under the Applicants' proposal. It should not, therefore, be approved by the Board.

3.5 SEC Recommendation

3.5.1 SEC therefore recommends that the Board should deny approval of the rate plan proposed by the Applicants.

3.5.2 In the next section, SEC makes recommendations for what the Board should order with respect to rates. Then, in Section 5, SEC proposes the terms of a deferred

[73] This can all be calculated from SEC 18 and 19.
[74] See Tr6:38.

rebasing should the Board determine that any deferral of rebasing is appropriate.

4 REBASING

4.1 Introduction

4.1.1 SEC believes that the Applicants should be ordered to file full cost of service applications at the earliest possible time, which it would appear to us is in late 2019 for 2021 rates. With an approval to amalgamate in hand, the applications could in fact be a single application from Amalco, if the Applicants still elect to amalgamate. Or, if they don't amalgamate, there would be two applications, one from Union and one from EGD. In the latter case, recommends that the Board order the Applicants to file together, so that the applications can be heard together.

4.1.2 This section sets out the details of why SEC believes a rebasing is appropriate, and, if the Board agrees, the specific proposals SEC is making with respect to the Board's order for rebasing.

4.2 Benefits of Rebasing

4.2.1 As noted earlier, there are basically five reasons why a rebasing is appropriate, rather than a deferral:

- ***(a)*** ***Transparency.*** The Board gets detailed information on the costs of two major utilities. Their detailed operational data has not been available to the Board for five years, and under the Applicants' proposal would not be available to the Board for a total of fifteen years.

- ***(b)*** ***Achieving the IRM Paradigm.*** The fundamental "deal" in IRM is that the shareholders are incented to drive savings, and get to keep them for up to five years. Then, on rebasing, the savings are baked into rates for the benefit of the customers.

- ***(c)*** ***Utility Commitments.*** Both Union and EGD made formal commitments to provide detailed cost of service information no later than 2019, and they should not be allowed to renege on those commitments.

- ***(d)*** ***Cost Allocation and Rate Design.*** There are numerous outstanding cost allocation and rate design issues that can only be addressed properly in the context of a rebasing.

- ***(e)*** ***Sharing Integration Risks/Rewards/Incentives.*** Rebasing would allow the customers to share in both the risk, and the rewards of integration of the two utilities' operations, while allowing the Board to fashion situation-specific incentives for the shareholder to maximize those rewards.

4.2.2 ***Transparency.*** SEC is concerned that the Board does not have sufficient information on the costs for Union and EGD. This raises a prima facie question whether rates are, even today, just and reasonable. There are several elements the Board does know that should lead to a desire to see more complete information:

(a) Rate base has increased dramatically since the last cost of service review of these utilities.

(b) The amounts being charged by Enbridge Inc. to EGD for shared services are tens of millions of dollars higher than the Board-approved amounts[75], and the process has already started internally with a view to ramping up charges to Union as well[76].

(c) EGD did a significant re-organization in 2016, resulting in OM&A reductions of at least 7%[77], which is not factored into rates. It is likely that there are similar changes at Union, but the evidence in this proceeding doesn't provide any details.

(d) The amounts included in rates for income taxes for both EGD and Union are about twice what they are actually paying in taxes[78].

(e) The Applicants have not filed Utility System Plans, either separately or together. The Board relies on these plans to ensure rates are just and reasonable.

(f) There have been significant changes in gas supply, transportation and storage in the last five years, which will have impacts on the Applicants' costs. This is further complicated by the fact that, as affiliates, new rules apply to their inter-company relationships.

4.2.3 These are just some examples of why the Board needs to look at the costs of these utilities.

4.2.4 SEC notes that, if the Board were to allow the proposed rebasing deferral, the resulting fifteen year period during which the Applicants' costs were not reviewed would be the longest in Ontario history, and perhaps the longest in Canadian history for any energy regulator.

[75] Energy Probe 5; Tr1:45, 181-2.
[76] Tr1:50.
[77] Tr1:132; Tr6:35.
[78] See Section 3.4 of this Final Argument.

4.2.5 ***Achieving the IRM Paradigm.*** IRM is fundamentally a "deal" between the Board, on behalf of the customers, and the utility, on behalf of its shareholders. The deal is that revenues will be decoupled from costs, allowing the utility freedom to implement cost reductions and keep the benefits. That is why it is called incentive regulation. On the other side, though, the reason IRM is good for the customers is that the result is a more efficient utility. Thus, when it next returns for cost of service, that cost will be lower, and the customers will benefit through lower cost-based rates.

4.2.6 IRM thus only works if there is a periodic rebasing, building the cost efficiencies into rates for the benefit of customers.

4.2.7 The Board has ample evidence that the Applicants have been generating efficiencies during the current IRM, exactly as they are expected to do. That evidence includes information on specific improvements (like the EGD reorganization discussed earlier), and evidence that both have consistently over-earned, in part because of cost reductions.

4.2.8 The customers support IRM precisely because it is a fair deal. If the Board, however, decides to skip the last part of the deal, where the ratepayers get their long term benefit, that is no longer a fair deal.

4.2.9 ***Utility Commitments.*** Both of the Applicants have made formal commitments to file full cost of service information for 2019. In the case of Union, their commitment was in a written agreement with the parties, approved by the Board[79]. In the case of EGD, their commitment was made by a senior member of their staff, under oath[80], and the utility has never resiled from that commitment.

4.2.10 In each case, the commitment was carefully worded to ensure that, whether there was a request for cost of service rates in 2019 or not, the utility would still file full cost of service information, for that and prior years.

4.2.11 In the Union case, the agreement contains considerable detail as to the test year and prior year information that will be filed. It also makes clear that only a subsequent agreement by all of the parties to the Settlement would let them off the hook.

4.2.12 In the EGD case, SEC simply put the terms of the Union Settlement to the witness during the hearing, and the answer from the witness was unequivocal.

4.2.13 The Board will be aware that one of the benefits of the ADR process is the ability to make future commitments that deal with current issues. If there is a concern, for

[79] EB-2013-0202, p. 44-45 of the Settlement Agreement.
[80] EB-2012-0459, Tr1:127.

example, that the terms of an agreed IRM plan are potentially highly beneficial to the utility, the customer groups negotiating with them can make sure that under no circumstances will that plan go on too long, by getting a commitment such as the one found in the Union Settlement Agreement.

4.2.14 This is one example of many. Utilities often commit to do studies of particular issues, especially if there is customer concern about the issue, but insufficient evidence to implement a principled solution. There are many examples of future commitments contained in settlement agreements, a useful way to resolve difficult issues.

4.2.15 Of course, there are legal ramifications of a utility agreeing to terms, and then not complying with those terms. However, the preferred solution is generally to make sure that commitments are met, or are amended by the parties (with the Board's approval) so that they evolve with future events. It is rarely a good idea to fight about it, and it is never a good idea to simply renege on a commitment.

4.2.16 It is thus somewhat surprising that, in this proceeding, the Applicants' didn't even ask to be relieved of these obligations.

4.2.17 SEC believes that they should not be relieved of these obligations. Not only is that morally wrong, but it would do damage to the Board's ADR process. If parties cannot rely on binding commitments freely made through negotiations, it will be much more difficult to reach consensus on how to deal with difficult issues. More cases will have to be resolved through the adversarial process, rather than through a collaborative process. The Board will be signaling that it prefers utilities and their customers to fight, rather than work things out.

4.2.18 There is a practical problem, though. It is now too late for the Applicants to meet these commitments with respect to 2019 COS information in a timely manner.

4.2.19 SEC's proposed solution is that the Board should interpret the Applicants' commitments to be met, in the unique circumstances of this case, if full COS information is filed for 2019, whether it is the Historic, Bridge, or Test Year in a rebasing application. This would allow Union and EGD to file the information specified in the Settlement Agreement, without being required to seek cost-based rates for 2019 (as it is too late to do that). That filing would therefore comply with the specific requirements of the Settlement Agreement. The Applicants would not have reneged, and the ADR process would be supported by the Board.

4.2.20 ***Cost Allocation and Rate Design***. The Board has heard in this proceeding about a number of cost allocation and rate design issues that need to be addressed. Kitchener is obviously concerned[81], and there is significant concern from some parties about the

[81] See their Final Argument.

Parkway Delivery Obligation[82]. There is also concern about storage costs being charged by Union to EGD, as well as evidence on the record that the Applicants' proposal would result in widely variable rate increases[83]. Many schools, for example would see their delivery bills double, despite the Applicants' average impact estimates[84].

4.2.21 It is not fair to those affected customers to let their cost allocation and rate design issue slide for ten years. By ordering an early rebasing, the Board can see the new cost structures of the Applicants, and the updated cost allocation and rate design that recovers those costs.

4.2.22 ***Sharing Integration Risks/Rewards/Incentives.*** 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[85].

4.2.23 However, what is proposed in this case is an allocation of costs and benefits of the integration of these two utilities that is not only one-sided, but it is also based on incomplete, even sketchy, information.

4.2.24 By ordering a rebasing, the Board can get full visibility into the costs to integrate, and the nature, amount, and timing of benefits. That information will be based on a full plan, not an initial set of estimates[86]. With full information, the Board can then assess what risks should be properly borne by the customers in rates, and what risks should be allocated to the shareholder. More important, the Board can develop an incentive model that gives reasonable incentives to the Applicants to maximize savings, but doesn't overcompensate them for doing so.

4.2.25 The Board has ample experience with productivity incentives. In each case, though, the incentives are developed only after a thorough review of comprehensive evidence, and with knowledge of the underlying cost structure that will be affected.

4.2.26 ***Conclusion.*** There are numerous reasons for ordering an immediate rebasing, of which those listed above are just the primary ones. SEC submits that these reasons demonstrate that it is essential for the Board to require the Applicants to rebase no later than 2021.

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[82] We understand that FRPO will be dealing with this in detail in their Final Argument, which at this point we have only seen in early drafts.
[83] See K6.1, p. 7, and the discussion on Day 6 of the proceeding on this point.
[84] See, e.g. J5.1.
[85] In principle, SEC agrees with IGUA on this incentive point, although our proposed solution is different from theirs.

4.3 *Guidance for Rebasing Application*

4.3.1 If the Board agrees with SEC (and others) that a rebasing in 2021 or earlier should be required, SEC believes that it would be helpful to the Applicants, and would simplify the rebasing application(s), if the Board provided guidance on what it expects to see at the time of rebasing.

4.3.2 Although there are obviously many variables, of which the biggest is whether or not the Applicants decide to amalgamate (even if they are rebasing), some areas of guidance seem to us to be useful in any case.

(a) ***Combined Proceeding.*** The application(s) should be filed in a manner that allows them to be considered within a single proceeding. This will facilitate the most efficient operation of the regulatory process.

(b) ***Utility System Plan***. In the same vein, the Applicants should be required to file one or more Utility System Plans compliant with the Board's rules. In the event that they are amalgamated, that would be a combined plan. In the event that they are not amalgamated, the plans should deal expressly with how their common management of their systems is being coordinated and optimized.

(c) ***Shared Services Plan***. The Applicants should file full details on how the RCAM, or any similar shared services arrangements, are evolving to deal with the common ownership of Union and EGD. This should include full compliance with ARC. The Applicants should be encouraged to have a detailed independent review of their shared services proposals.

(d) ***Integration Savings Plan***. The Applicants' should complete the work to plan for integration savings, as already expected and advised to their boards of directors. The Board should see the full plan, including timelines, costs to implement, and forecast savings, with all of the homework done to support the plan. The plan should include the Applicants' proposals for sharing of the risks and benefits, and any proposed incentives for better than forecast results. In the event that the Applicants have not amalgamated, the plan should also identify all ARC and other barriers to maximizing the savings, and any actions the Board could take to reduce those barriers. The Integration Savings Plan should demonstrate that the Applicants have already started to implement its initiatives in a timely manner.

(e) ***Property Plan.*** If not included in the Integration Savings Plan, the Applicants should be expected to file a plan for the rationalization of their many properties around the province. This should also include proposals for any sharing of gains on the sale of any properties.

(f) ***Cost Allocation Study.*** While this would likely be filed in any case, the Board should make clear that such a study is required.

(g) ***Rate Design/Harmonization Proposal***. The Applicants should be expected to complete a review of their respective rates, particularly in light of their new cost allocation, and make a proposal to the Board for how to rationalize those rates for similar customers. The Applicants should not be allowed to proceed under common ownership (or even amalgamated) with similar customers, in geographically close areas, having broadly different rates.

(h) ***Commitment Information***. The Board should specify that the Applicants must file at a minimum the detailed information referred to in the EB-2013-0202 Settlement Agreement.

4.3.3 SEC believes that the Applicants, if they are ordered to rebase, would likely include most or all of the above information anyway. On the other hand, we believe it is helpful if the Board puts its mind to what the Board should see at that time, and provides guidance to the Applicants.

4.4 ***Timing Issues and RateSetting in the Interim Period***

4.4.1 SEC submits that the rebasing application(s) of the Applicants should be filed by November 1, 2019 if the target is January 1, 2021 rates. This would allow fourteen months for the Board to consider a massive and complex rate case. This would appear to us to be a reasonable amount of time.

4.4.2 There remains the issue of what to do with the rates of Union and EGD (or the Union and EGD rate zones of Amalco) in the meantime.

4.4.3 ***Union 2019 and 2020 Rates.*** SEC submits that, with respect to Union, it is already on a price cap plan that can easily be extended for two more years. While this delays the sharing of their over-earnings with customers, the amounts involved are small enough to accept that delay. In fact, given the timing, the extension might incent Union to accelerate their integration savings, since integration savings until the end of 2020 would be for account of the shareholder (subject to earnings sharing).

4.4.4 The one complication that arises is the deferred tax drawdown, since by its terms it may no longer be required for the next two years. SEC believe this is best handled in the next ESM/DVA application, when in the normal course the DVA accounts are reviewed and any changes implemented.

4.4.5 Alternatively, since the overearnings and the deferred tax drawdown are similar amounts, this Board panel could order that they be offset against each other. That is, the deferred tax drawdown could be removed, but the $16.9 million of over-earnings could be built into rates in its place. SEC does not believe this is necessary, but considers it a viable alternative for this issue.

4.4.6 We note that extending the Union plan for two years would also solve their Sudbury problem.

4.4.7 ***EGD 2019 and 2020 Rates***. EGD is on Custom IR, so it does not have a rate formula in place that can be applied to 2019 and 2020. Because it is not an electricity distributor, the application of 4th Generation IRM, or the Annual IR, does not apply, and the Board has no evidence before it to justify applying either of those by analogy.

4.4.8 SEC believes a possible solution is to apply the Union IRM method to EGD for 2019 and 2020. This has three things going for it:

(a) It would simplify rate-making for Union and EGD, especially if they decide to amalgamate. The same rules would apply to both, in all respects, and effectively the rates could be set in one process.

(b) EGD has substantial over-earnings. By implementing the productivity factor in the Union plan (60% of inflation), a portion of the over-earnings would effectively be shared with the customers for those two years.

(c) EGD has some substantial capital projects it wants to pursue in those two years. Without a plan in place, it has no means to recover the incremental costs of any of those projects. The Union capital pass-through would provide large project relief for EGD.

4.4.9 SEC therefore submits that the Board should allow EGD to file for 2019 and 2020 rates using the Union IRM plan. In the event that EGD does not do so, its rates would remain at the 2018 levels until rebasing in 2021**.**

4.5 ***SEC Preferred Approach***

4.5.1 SEC therefore submits that the Applicants should be ordered to file for rebasing, either as an amalgamated entity or separately, for rates January 1, 2021 at the latest. The Board should also, in our submission, provide guidance to the Applicants on what should in in the rebasing application(s). Finally, the Board should stipulate how rates will be set for 2019 and 2020 while awaiting the rebasing application(s).

5 DEFERRED REBASING ALTERNATIVE

5.1 ***Qualification***

5.1.1 SEC believes that any deferral of rebasing beyond 2021 will cause harm to the customers, and will cause rates to be no longer just and reasonable.

5.1.2 In the event that the Board disagrees with our conclusion, and determines that it will allow some form of deferred rebasing for the Applicants/Amalco, SEC in this Section of its Final Argument is providing its views on the terms under which that deferred rebasing should be allowed.

5.1.3 SEC notes that, although we are setting out these terms, we believe that even with these terms the deferred rebasing option is less fair to the customers than the proposed rebasing described in Section 4. These submissions are therefore in the nature of second best.

5.2 ***Base Rate Adjustments***

5.2.1 ***Applicants' Proposal.*** The Applicants have proposed that base rates be adjusted as of January 1, 2019 to

(a) Remove the $17.4 million deferred tax drawdown; and

(b) Remove the $4.9 million customer care smoothing credit.

5.2.2 SEC agrees that these adjustments should be made. In our view, they would have been made in a rebasing scenario as well.

5.2.3 ***IRM Savings.*** The Applicants have generated productivity savings over the course of their respective IRM plans. They should not be allowed to defer rebasing without first completing their last IRM plans by delivering the productivity savings to their customers in rates.

5.2.4 The IRM savings are most easily measured by 2018 over-earnings[87], since that takes into account all of the puts and takes associated with cost reductions (and upward pressures as well) during the IRM plan.

5.2.5 The Board does not have actual 2018 over-earnings for the Applicants, of course. However, it has a forecast of Union 2018 over-earnings[88], $16.9 million[89]. It also

[87] See Tr6:67-8.
[88] SEC 19, Attachment 1.

has EGD's actual 2017 over-earnings[90], $47.1 million.

5.2.6 SEC submits that base rates for 2019 should be adjusted at the outset to reflect over-earnings. This should be done in two steps.

5.2.7 First, EGD should be required to file its current forecast of 2018 normalized over-earnings no later than its 2019 rate application. That forecast can be reviewed in that proceeding. If it cannot file such a forecast, the 2017 actual of $47.1 million can be used as a proxy.

5.2.8 Once EGD has filed the forecast, the Board should reduce 2019 rates for the Applicants by the aggregate of the two forecasts (either together or separately, depending on whether the Applicants have amalgamated). A variance account should be established to reflect the fact that those are forecasts, and it is the actual normalized over-earnings that should finally adjust rates.

5.2.9 Second, once the actual 2018 normalized over-earnings are known[91], that should be compared to the forecast amounts, and a debit or credit to the variance account allowed for the difference, positive or negative. That would then be cleared in the normal course.

5.2.10 The final result is that the actual normalized 2018 over-earnings, which are a reasonable proxy for the continuing IRM productivity savings, go to the customers, as the IRM paradigm requires.

5.3 ***Term***

5.3.1 SEC does not believe that there is any need for a deferred rebasing term longer than five years. The need for a longer period is predicated on the high costs associated with electricity distribution mergers, including transaction costs, premiums, and integration costs. Here, the costs are small.

5.3.2 SEC notes that the Applicants' forecasts show[92] that the amounts invested by the Applicants in integration initiatives are less than the savings by the end of 2020. In fact, that overstates the case, because the $5.2 million that has already been achieved is not included. When that is included, the breakeven is early in 2020. All investments in integration initiatives are completed by 2023, and by that time there is a substantial net savings.

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89 Which is similar to the 2017 actual normalized: Tr6:47.
90 J1.2.
91 From the 2018 ESM/DVA applications.
92 J2.4.

5.3.3 It is therefore submitted that a deferred rebasing of more than five years is not required or justified. Even if the Applicants' figures are correct, they are "in the money" early on, and then are in that state continuously.

5.4 *Inflation Escalator*

5.4.1 SEC does not see any reason to depart from the GDP IPI inflation escalator.

5.5 *Productivity and Stretch Factors*

5.5.1 The high levels of over-earning by both of the Applicants over the last ten years[93] demonstrate that they can find productivity savings over and above a substantial built-in productivity factor.

5.5.2 Dr. Lowry has agreed with the Applicants that a 0.0% productivity factor is acceptable, but believes that a stretch factor of 30 basis points should be applied.

5.5.3 The Board never allows an IRM plan without some form of productivity and/or stretch factor, so the minimum that the Board should allow is the 30 basis points proposed by Dr. Lowry.

5.5.4 However, SEC believes that is not enough. Union has been able to over-earn every single year, and forecasts to continue that into 2018, despite having a productivity factor of 60% of inflation. Further, if that same productivity factor had been applied to EGD for the last several years, it too would still have over-earned.

5.5.5 SEC therefore submits that the Union formula, with 60% of inflation as the productivity factor, should be applied to any deferred rebasing period[94].

5.6 *Application of Escalator/ Design of Price Cap*

5.6.1 The Applicants did not provide information, until very late in the proceeding, on the widely different rate impacts that could be expected under their deferred rebasing proposal. J2.2 and J5.1 appear to show that rate impacts will be moderate, but they give only averages[95].

5.6.2 Even though the Amalco plan is referred to as a price cap, in fact what is being proposed is that rate increases will be applied in a manner that is largely within the Applicants' discretion[96], and will likely result in some customers, including schools

[93] Tr1:68-9.
[94] See, e.g. FRPO 15.
[95] Tr6:17.
[96] Tr6:8-9, 146-7.

having increases many times those averages, including for a big group of customers, rates doubling over ten years[97].

5.6.3 SEC believes this is unacceptable. In our submission, if a deferred rebasing is allowed, all components of rates for all customers should be escalated at the same rates. The Applicants should not be permitted to raise rates for some customers by 2% a year, and others by 10% a year.

5.6.4 Therefore, SEC submits that any rate formula should be applied equally to each component of distribution rates, including monthly charges, volumetric charges at each band level, and storage charges. Any deviation from that rule should require the approval of the Board in the rate application proposing to implement that deviation.

5.7 ***Additional Capital Funding***

5.7.1 There is no apparent reason why the ICM model, which has never been applied to gas distributors, should apply to any deferred rebasing in this case. The only justification the Applicants have provided for doing so has been that the MAADs Handbook allows it[98]. As noted earlier, that justification is not really a valid one unless the Applicants demonstrate that the policy in the MAADs Handbook should be applied in this case because the policy drivers are the same. No such demonstration has been provided, and the policy drivers are not the same.

5.7.2 In this case, the ICM if applied would use wildly outdated rate base and depreciation information for Union, with the result that the ICM threshold would be very low relative to the normal situation, and the recovery would be too high[99].

5.7.3 The Board does not need to deal with a capital funding model that doesn't clearly apply, and if applied would have to be adjusted in ways that have not been dealt with fully in the evidence. Union Gas has a capital funding model in its current price cap plan that was specifically designed for a large gas distributor. That model can and should be used for the Applicants in any deferred rebasing period.

5.7.4 SEC notes that, if the Union Gas capital pass-through mechanism is used during any deferred rebasing, the rules are clear, and the kind of debates that the Board sees in ICM applications in electricity would be unlikely to occur. The recent Alectra case[100] is a good example of a situation in which a utility had different expectations of what would qualify, and what would not, relative to both the

[97] K6.1, p. 7.
[98] E.g, Tr6:91.
[99] TC3:112; Tr6:85.
[100] EB-2017-0024.

customer groups, and the Board itself. Using the Union capital pass-through would avoid those problems.

5.7.5 Further, the Union mechanism is consistent with the IRM concept employed by gas distributors. It is limited to large projects, with clear tests for which projects will qualify. Normal capital spending is managed by the distributors, as they have always done in the past. It is projects with big impacts that generate extra rate recovery. This is an appropriate result for large gas distributors, especially one the size of Amalco.

5.7.6 Therefore, SEC submits that extra capital funding in any deferred rebasing period should use the capital pass-through mechanism currently in use by Union.

5.8 ***Earnings Sharing***

5.8.1 SEC submits that any earnings sharing in a deferred rebasing period should commence at the outset, and should be 50/50 on anything above 100 basis points, cleared annually.

5.9 ***Z Factor***

5.9.1 The Applicants have proposed that their Z factor materiality threshold should be $1 million, despite their large size relative to other Ontario utilities.

5.9.2 As SEC noted in the hearing, only one other Ontario regulated utility is similar in size to Amalco, and that is OPG. For OPG the materiality threshold ordered by the Board is $10 million.

5.9.3 SEC submits that the same materiality threshold should apply to Amalco during any deferred rebasing period, i.e. $10 million. Any unforeseen event that has impacts below that amount should be within the ability of Amalco management (with annual distribution revenues exceeding $2.5 billion each year) to manage.

5.10 ***Off-Ramp***

5.10.1 In our submission, Amalco is too big to have an off-ramp. This is a company that should be able to handle pretty well everything that is thrown at it. Further, it is part of an even larger corporate group that can support it.

5.10.2 In this situation, it would appear to us that any rule, such as 300 basis points variation from allowed ROE, is not really useful for an entity of this size.

5.10.3 Further, the Board will see the detailed results of Amalco twice each year, in the DVA application and in the next year rate application. If Amalco is starting to veer off course in any material way, the Board will be able to see that. Since Amalco would be the gas distributor for almost all Ontarians, the Board will be able to initiate any corrective action on its own motion if that is required.

5.10.4 The one exception would be if management of Amalco believes the company is heading into financial difficulty. In that case, we would expect them to come to the Board as soon as possible with a proposal to alleviate the problem, and sufficient details to help the Board address it.

5.10.5 With that exception, SEC believes that no off-ramp is required for any deferred rebasing period.

5.11 *Rate Harmonization*

5.11.1 Whatever the length of any deferred rebasing period, SEC submits that the Board should require Amalco, at the time of rebasing, to submit a proposal for how to deal with rate harmonization going forward. That proposal might include a view that some or even all rates should not be harmonized, with justification for that position. However, the rebasing application should deal with the rate harmonization issues in detail, based on comprehensive evidence from Amalco.

5.12 *Rebasing Filing Commitment*

5.12.1 Even if a deferred rebasing is allowed, Union and EGD should be required by the Board to live up to their commitment to file full rebasing cost of service information for the 2019 year. Binding commitments should not simply be ignored.

5.13 *SEC Submissions in the Alternative*

5.13.1 Based on the foregoing, SEC submits that the above conditions should be implemented if the Board determines that a deferred rebasing is appropriate.

6 OTHER MATTERS

6.1 ***Costs***

6.1.1 The School Energy Coalition hereby requests that the Board order payment of our reasonably incurred costs in connection with our participation in this proceeding. It is submitted that the School Energy Coalition has participated responsibly in all aspects of the process, in a manner designed to assist the Board as efficiently as possible.

All of which is respectfully submitted.

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Jay Shepherd
Counsel for the School Energy Coalition

APPENDIX A TO SEC FINAL ARGUMENT

Revised Standalone Model Using More Realistic Assumptions

(ii) EGD Revenues and Earnings - Stand Alone **Table 2**

$ Millions		**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Cost of Capital												
Rate base		7,025	7,422	7,776	8,060	8,330	8,576	8,842	9,238	9,623	9,869	
Required rate of return		6.19%	6.27%	6.31%	6.31%	6.30%	6.31%	6.33%	6.34%	6.35%	6.36%	
		435	**465**	**490**	**509**	**525**	**541**	**559**	**586**	**611**	**628**	
Cost of Service												
Gas costs		-	-	-	-	-	-	-	-	-	-	
Operation and maintenance		439	447	454	460	466	472	478	485	491	498	
Depreciation and amortization		328	349	367	382	392	401	411	419	428	439	
Fixed financing costs		3	3	3	3	3	3	3	3	3	3	
Municipal and other taxes		50	51	52	53	54	55	56	57	59	60	
		820	**850**	**876**	**897**	**914**	**931**	**949**	**964**	**981**	**1,000**	
Stretch	0.3%	**(2)**	**(5)**	**(8)**	**(10)**	**(13)**	**(16)**	**(19)**	**(22)**	**(25)**	**(28)**	
Income Taxes	11.6%	**27**	**29**	**30**	**32**	**33**	**34**	**35**	**36**	**38**	**39**	
Total Revenues		**1,279**	**1,339**	**1,389**	**1,427**	**1,459**	**1,490**	**1,524**	**1,565**	**1,605**	**1,639**	**14,714**
Utility Earnings		**231**	**248**	**262**	**272**	**281**	**289**	**298**	**312**	**325**	**333**	

(ii) UG Revenues and Earnings- Stand Alone **Table 6**

$ Millions		**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Cost of Capital												
Rate base		6,417	6,732	6,852	7,003	7,116	7,362	7,549	7,586	7,612	7,638	
Required rate of return		5.99%	6.05%	6.16%	6.18%	6.22%	6.23%	6.20%	6.24%	6.24%	6.24%	
		384	**408**	**422**	**433**	**443**	**459**	**468**	**473**	**475**	**477**	
Cost of Service												
Gas costs		-	-	-	-	-	-	-	-	-	-	
Operation and maintenance		441	452	457	465	474	482	491	500	509	518	
Depreciation and amortization		298	319	330	340	353	369	382	393	404	415	
Fixed financing costs		2	2	2	2	2	2	2	2	2	2	
Municipal and other taxes		78	80	81	83	84	86	88	90	91	93	
		819	**852**	**870**	**890**	**913**	**939**	**963**	**984**	**1,006**	**1,028**	
Stretch	0.3%	**(2)**	**(5)**	**(8)**	**(10)**	**(13)**	**(16)**	**(19)**	**(22)**	**(25)**	**(28)**	
Income Taxes	11.6%	**25**	**26**	**27**	**27**	**28**	**29**	**30**	**30**	**30**	**30**	
Total Revenues		**1,228**	**1,286**	**1,319**	**1,351**	**1,384**	**1,427**	**1,461**	**1,487**	**1,511**	**1,535**	**13,989**
Utility Earnings		**211**	**225**	**231**	**236**	**240**	**248**	**255**	**256**	**257**	**258**	
Gross Standalone Revenues		**2,507**	**2,624**	**2,708**	**2,778**	**2,843**	**2,917**	**2,985**	**3,052**	**3,115**	**3,174**	**28,703**
Integration Savings	Initial	5	5	5	5	5	5	5	5	5	5	
Additional: J2.4 @	80%	-6	2	8	26	54	68	68	68	68	68	
Net Standalone Revenues		**2,508**	**2,618**	**2,694**	**2,747**	**2,783**	**2,844**	**2,912**	**2,979**	**3,042**	**3,101**	**28,227**
Percentage increase			4.38%	2.94%	1.93%	1.34%	2.16%	2.40%	2.30%	2.13%	1.93%	
Applicants' Model		**2,531**	**2,657**	**2,768**	**2,850**	**2,932**	**3,014**	**3,103**	**3,174**	**3,268**	**3,352**	**29,649**
Percentage increase			4.98%	4.18%	2.96%	2.88%	2.80%	2.95%	2.29%	2.96%	2.57%	
Net Overstatement		**23**	**39**	**74**	**103**	**149**	**170**	**191**	**195**	**226**	**251**	**1,422**

Base data from FRPO 11; Adjustments as described in the text