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

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

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

OEB Staff
CROSS-EXAMINATION COMPENDIUM
Panel 4

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Panel 4

Tab 1

Ontario Energy Board

Report of the Board

on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors

July 14, 2008

information on any changes to the index of two years ago. As with 2nd Generation IR, there will be no explicit adjustments for return on equity or debt costs.

2.4 Productivity and Stretch Factors

Under a price cap mechanism, the allowed rate of change in the price of regulated services is restricted by the growth in an inflation factor minus an X-factor. Generally, the X-factor has two main components: the productivity factor and the stretch factor.

The productivity component of the X-factor is intended to be the external benchmark which all firms are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.

The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that firms are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by company and depend on the efficiency of a given company at the outset of the IR plan. Stretch factors are generally lower for firms that are relatively more efficient.

Issues and Options Raised in Consultations

PEG's report entitled "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario" (the "PEG IR Report") makes specific recommendations for the productivity and stretch factor components of the X-factor and provides a discussion of relevant IR precedents.

In brief, PEG recommended in the PEG IR Report that for Ontario distributors, the X-factor be comprised of: (1) an industry TFP-based component reflecting TFP growth potential estimated using U.S. data; and (2) an efficiency benchmark-based stretch factor based on Ontario data.

Plan for the electricity distribution sector will stagger distributors' commencement onto 3rd Generation IR. To set the external benchmark that all distributors will be expected to achieve, the productivity factor will be the same for all distributors regardless of when they commence the plan.

While it is clear to the Board that participants support an index based approach for the derivation of an industry productivity trend to form the basis for the productivity factor for the IR plan, the Board would be assisted by further consultation on the interpretation of the results in order to determine the appropriate value for the productivity factor. The issue of the appropriate value for the TFP trend for 3rd Generation IR will therefore be included on the agenda for the August stakeholder conference (see Section 5).

The Stretch Factor

The Board has determined that non-negative (i.e., >0 or =0) stretch factors will be included in the X-factor. The Board believes that stretch factors are required in 3rd Generation IR and is not persuaded by the arguments that stretch factors are only warranted immediately after distributors switch from years of cost of service regulation to IR. Productivity stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation.

On the issue of the application of benchmarking to OM&A costs rather than total cost, The PEG IR Report describes OM&A benchmarking as a well-established technique with ample precedent in the academic literature and regulatory proceedings. Further, OM&A benchmarking can lead to appropriate inferences on a firm's efficiency provided that the model contains appropriate controls for capital stock. PEG's econometric model included two such capital-related control variables. The Board notes that the consultants generally agree that benchmarking OM&A costs is, in principle, a legitimate

Tab 2

Ontario Energy Board

EB-2007-0673

Supplemental Report of the Board

on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors

September 17, 2008

Generation IR. The Board accepts the use of U.S. data for the purposes of the derivation of the TFP trend for 3rd Generation IR. Use of this data set was supported by PEG and Prof. Yatchew. Ms. Frayer sought to circumvent the problem through a patchwork of studies that, in the Board's view, are not adequately demonstrated to be based on a series of consistent principles. Of greatest concern with Ms. Frayer's approach is the measurement of capital, which is inconsistent with the prior Ontario TFP studies and does not appear to have been adopted in any jurisdiction other than New Zealand. While the Board recognizes Ms. Frayer's efforts to construct an Ontario-specific TFP trend, the Board does not believe that the methodology advocated by Ms. Frayer is appropriate. The Board is optimistic that the current data deficiencies will recede as the Board accumulates data from the sector over the next several years. Within the next five years the data issue will have been resolved, and the development of an Ontario-specific TFP trend can proceed on a more solid footing.

The Board is not convinced that the "start date analysis" used by PEG, which limits the data sample to the period 1995-2006, is necessary or warranted. The Board agrees with Prof. Yatchew's statement that greater confidence can be derived from using the full data set, in this case representing U.S. data from 1988 to 2006.

Similarly, the Board is not persuaded that increased weight ought to be given to the most recent TFP trend. The merit of using the full data set is that the resultant TFP trend can be reasonably expected to reflect the ebbs and flows experienced over a relatively long period of time. To weight the most recent trend would undermine one of the virtues of using the full data set.

Accordingly, the Board has determined that the appropriate value for the TFP trend for 3rd Generation IR is 0.72 percent, the average annual productivity growth over the period 1988-2006 in the full set of U.S. electricity distributor data used by PEG. The Board is not convinced that the "start date analysis" is sufficiently well developed to justify limiting the sample. The Board believes that this value reflects a reasonable synthesis of the various points of view advanced in the course of the stakeholder misclassification concern should not be to reduce the stretch factor on average, but rather that it may be more appropriate to narrow the differences between the average stretch factor and the stretch factors for Group I and Group III. While CME did not recommend specific values, it recommended that the Group II stretch factor be set in the range of 0.25-0.50 percent. LPMA and Energy Probe, building on this idea, recommended that if the Board believes that some sort of mitigation against misclassification is required, then the stretch factor values could be set at 0.35 percent, 0.50 percent, and 0.65 percent for the three groups. CCC submitted that, if the Board were to accept the arguments about misclassification, CCC would support a stretch factor of 0.5 percent for all three cohorts.

Hydro One and the CLD noted that all participants seem to agree that benchmarking is in its infancy, that it needs to improve and that it will improve. These distributors acknowledged that there will likely be some misclassification, but that improvements will be made over time and therefore, they submitted, they support the Board's grouping approach. As to the values for the stretch factors, Hydro One and the CLD commented that, from their perspective, what is important is the combination of what is expected of them in terms of productivity plus a stretch factor because that is the number that needs to be achieved. Therefore, if the Board sets one high, perhaps it should set the other one low or vice versa – it is the combination that distributors are going to have to somehow manage to achieve. In summary, Hydro One and the CLD expressed a preference for the values 0.0 percent, 0.075 percent, and 0.15 percent for the three groups.

Board Policy and Rationale

It is important to note that stretch factors are consumer benefits. They are somewhat analogous to earnings sharing mechanisms, although stretch factors take effect immediately with the application of the formula and are not dependent on the realization of any productivity gains or excess earnings, as would be the case with an earnings sharing mechanism. Stretch factors are an integral part of the IR formula, and are not dependent on future performance by the utility.

In the July 14, 2008 Report, the Board determined that stretch factors will be a feature of the IR mechanism, and that benchmarking will provide the architecture for their assignment to distributors. These determinations were not intended to be revisited during the August stakeholder conference. The Board acknowledges the concerns expressed regarding the current state of benchmarking in Ontario, but is not convinced that it needs to reconsider the benchmarking architecture for purposes of 3rd Generation IR.

The Board notes that all of the participants in the consultation agreed that the setting of stretch factors is a matter that calls for the exercise of judgment. As such, there are no hard and fast principles to guide the Board's determination of an appropriate value. The Board also notes that each of the participants urged the Board to take a conservative approach with respect to the stretch factor values in light of the fact that the Board's experience with benchmarking is in its early stages.

The Board is not convinced that the potential for misclassification raised by Dr. Yatchew is such that the Board needs to reduce the stretch factors so that they are of little or no materiality. As described in the July 14, 2008 Report, the three groupings have been developed using two distinct benchmarking evaluations. The two evaluations will be compared and those distributors that rank superior in both will be assigned to Group I. Those distributors that rank inferior in both will be assigned to Group III. All other distributors, including those that rank superior or inferior in only one of the evaluations, will be included in the broad middle cohort, Group II. The Board recognizes that the risk of misclassification cannot be ruled out. The Board intends to undertake further work on the model and will consult with stakeholders to identify whether it can improve the grouping approach and further reduce the potential for misclassification in the two OM&A benchmarking evaluations. It is also expected that the Board's knowledge of and facility with benchmarking will improve over the course of the 3rd Generation IR, and that any anomalies will be addressed in due course.

The Board also believes that it is important that the stretch factors be sufficient to influence distributor behaviour over the course of the plan. While the Board accepts that this is not the time to adopt large stretch factors, it does believe that they must be of such magnitude that they are likely to motivate distributors to change or maintain their status, as the case might be. The proposals put forward by Ms. Frayer and Prof. Yatchew would not, in the Board's view, be meaningful in that regard. The Board also believes that Ms. Frayer's approach would conflate the TFP and the stretch factor, effectively eliminating the consumer benefit element normally associated with the stretch factor.

As noted above, some participants argued that the best performers, or even average performers (i.e., those falling within Group I, or Group II), ought to enjoy a zero stretch factor. In fact, in earlier comments made within this consultation some participants argued for negative stretch factors for high performing distributors. At this time, the Board is not prepared to accept the premise there are no prospects for incremental productivity gains above the expected industry trend that should be shared with ratepayers – which a stretch factor of zero or less would connote. While these options may commend themselves in future IR plans, the Board does not think it appropriate at this time, and has adopted a modest but still meaningful stretch factor for Group I, and a higher stretch factor for Group II.

With respect to Group III (the poorest performers), the Board believes that the stretch factor value should not be so demanding as to be considered punitive. In the Board's view, the stretch factor approach ought to serve as an incentive for incremental productivity improvement and not as a punitive measure.

Tab 3

Ontario Energy Board

EB-2010-0379

Draft Report of the Board

on Empirical Research to Support Incentive Rate-setting for Ontario's Electricity Distributors

September 6, 2013

2.2.2 Stretch Factor

What the Board Said

In its RRF Report, the Board determined that its approach in relation to the use and assignment of stretch factors under 3rd Generation IR will continue under the Board's Price Cap IR. Consistent with the policies set out in the Board's 3rd Generation IR report, non-negative (i.e., >0 or =0) stretch factors will be included in the X-factor. The Board believes that stretch factors continue to be required and is not persuaded by arguments that stretch factors are only warranted immediately after distributors switch from years of cost of service regulation to IR. Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation. However, the Board in its RRF Report concluded that it will make the stretch factor assignments under Price Cap IR on the basis of total cost benchmarking evaluations. The assignments will continue to be revised annually to reflect changes in efficiencies.

The Board also stated in its RRF Report that it would consider whether the current three stretch factor values of 0.2%, 0.4%, and 0.6% continue to be appropriate or whether there should be greater differentiation between the three values, and that it would determine the appropriate stretch factor values in conjunction with its determination of the productivity factor for Price Cap IR.

Proposed Policy and Rationale

The Board re-iterates that "[i]t is important to note that stretch factors are consumer benefits. They are somewhat analogous to earnings sharing mechanisms, although stretch factors take effect immediately with the application of the formula and are not dependent on the realization of any productivity gains or excess earnings, as would be

Tab 4

Ontario Energy Board

EB-2010-0379

Report of the Board

Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors

Issued on November 21, 2013 and as corrected on December 4, 2013

At the Stakeholder Conference and in the subsequent written comments, distributors expressed the view that setting the productivity factor to zero when estimated TFP growth is negative constitutes an implicit stretch factor in the X-factor. The Board notes that if that argument is accepted, then the 2-factor IPI may also be considered to constitute an implicit, and offsetting, input price differential in the overall price cap index ("PCI") adjustment. For the 2002 to 2012 period, the PCI growth that would have resulted from the combination of the 2-factor IPI inflation and a zero productivity factor exceeds the growth that would have resulted from the combination of the 3-factor IPI inflation and PEG's estimated -0.33% TFP growth by an average of 0.5% per annum.[19]

All stakeholders supported the Board's efforts to estimate an Ontario TFP trend; however, some proposed alternative methods to indexing and others proposed alternative inputs and/or assumptions for the indexing method. The alternatives proposed are outlined in Appendix A. While the Board finds that there may be merit in some of the alternatives presented; there is insufficient information at this point to incorporate them into the calculation of the TFP to be used for setting rates for 2014 and beyond. The Board may further explore some of these alternatives when carrying out the 2019 update.

2.2.2 Stretch Factor

In its RRF Report, the Board determined that its approach in relation to the use and assignment of non-negative (i.e., >0 or =0) stretch factors under 3rd Generation IR will continue under the Board's Price Cap IR. The Board believes that stretch factors continue to be required and is not persuaded by arguments that stretch factors are only

[19] Table 2 on page 12 shows that GDP-IPI (FDD) grew by 1.9% per annum between 2002 and 2012, and AWE-All Employees-Ontario grew by 2.45% over the same period. The 2-factor IPI over that period would have yielded 2.1% (i.e., 0.7*GDP-IPI(1.9%) + 0.3*AWE(2.45%)). Table 1 in the Board's Draft Report shows that industry input price index as estimated by the 3-factor IPI grew by 1.3% between 2002 and 2012. The input price differential (inflation factor minus input price inflation) is therefore 2.1% - 1.3% = 0.8%. The 2-factor IPI exceeds the industry's computed growth in input price inflation by an average of 0.8% per annum, over the same historical period used to estimate the -0.33% productivity factor. Combining these two effects yields the 0.5% PCI growth differential.

warranted immediately after distributors switch from years of cost of service regulation to IR. Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation. However, the Board in its RRF Report concluded that it will make the stretch factor assignments under Price Cap IR on the basis of total cost benchmarking evaluations, rather than the two OM&A cost benchmarking evaluations used in 3rd Generation IR. The assignments will continue to be revised annually to reflect changes in efficiencies.

The Board also stated in its RRF Report that it would consider whether the current three stretch factor values of 0.2%, 0.4%, and 0.6% continue to be appropriate or whether there should be greater differentiation between the three values.

The Board re-iterates its earlier conclusion:

> It is important to note that stretch factors are consumer benefits. They are somewhat analogous to earnings sharing mechanisms, although stretch factors take effect immediately with the application of the formula and are not dependent on the realization of any productivity gains or excess earnings, as would be the case with an earnings sharing mechanism. Stretch factors are an integral part of the IR formula, and are not dependent on future performance by the distributor. [20]

With the development of total cost benchmarking, and in light of continuing concerns with the use of peer group analysis, **the Board has determined that distributors will be assigned to one of five groups with stretch factors based on their efficiency as determined through PEG's econometric total cost benchmarking model**.

PEG developed two benchmarking models, one econometric and one unit cost using peer groups. The models are described in the May 2013 Updated PEG Report. Also in

[20] Ontario Energy Board. EB-2007-0673 Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. September 17, 2008. p.19.

that report, PEG recommended that the Board rank distributors according to their relative cost efficiency and unit cost performance, and that the Board assign distributors to one of five groups based on statistical significance and quintile alignment between the two rankings.

While this aligns with the approach used in 3rd Generation IR, the Board has decided to rely solely on the econometric model to assign stretch factors to distributors. In general, there is lack of support amongst stakeholders for the use of peer groups and the Board finds the reasons cited compelling. In particular, stakeholders persuasively argued that there are too many variables that can affect distributor costs to be confident in peer group allocations. The Board notes that unit cost comparisons can still be done without pre-defining peer groups. The Board expects that the use of one benchmarking model to produce a single efficiency ranking be more transparent and understandable for customers and distributors. Consequently, it should be easier for a distributor to identify its relative cost efficiency, act to improve it, move up the efficiency ranking and be rewarded through the annual group assignments by moving into a more efficient group. Benchmarking is further discussed in Chapter 3.

The five groups will be established by segmenting the resultant efficiency ranking based on the percentage deviation between actual and predicted costs. The use of an odd number of groups continues to provide a middle group of “average” performers, while increasing the number of groups to five should facilitate the movement of distributors into more efficient groups.

The Board has determined that the appropriate stretch factor values range from 0.0% to 0.6%. The Board is setting the lower-bound stretch factor value to zero to strengthen the efficiency incentives inherent in the rate-adjustment mechanism and in doing so reward the top performers.

As described above, the Board has determined an approach to assigning stretch factors to distributors based on a distributor’s actual costs relative to its predicted costs. The

Tab 5

EB-2013-0202

SETTLEMENT AGREEMENT

This Settlement Agreement ("Agreement") is for the consideration of the Ontario Energy Board ("the Board") in its determination, under Docket No. EB-2013-0202, of the 2014-2018 rate-setting methodology for Union Gas Limited ("Union").

On April 29, 2013, Union convened a meeting with stakeholders to present its 2014-2018 Incentive Rate Mechanism ("IRM") proposals. Those invited were intervenors that participated in Union's 2013 Rebasing Proceeding (EB-2011-0210), and representatives of Board Staff. The purpose of the meeting was to inform stakeholders of Union's proposals and provide an opportunity for stakeholders to ask questions to better understand those proposals. A copy of the slides used at that meeting are included at Appendix A. Those slides describe the original Union proposals for 2014-2018 rates. At the end of the April 29, 2013 meeting, it was determined that further meetings would be held, which occurred on May 23, June 10, June 11, June 17 and July 15, 2013. It was agreed that Union would provide written responses to the information requests stakeholders had with respect to Union's proposals contained in Appendix A. All of the written responses Union provided to such information requests are included in Appendix B. The initial stakeholder meeting and all subsequent discussions, except the July 15 meeting, were facilitated by Mr. Ken Rosenberg, who was retained by Union to perform this function.

At the May 23, 2013 meeting, Union responded to further information requests from stakeholders. It was also determined in the May 23rd meeting that the further discussions in June and July would take the form of a Settlement Conference with a view to agreeing on some or all of Union's IRM proposals. Parties agreed that all discussions would be subject to the Board's Settlement Conference Guidelines, interpreted as if this Agreement were the result of a Board-ordered settlement conference.

Settlement negotiations between Union and stakeholders took place on June 10, June 11, June 17 and July 15, 2013. The product of those negotiations is the comprehensive settlement of the IRM by which Union would set rates over the 2014-2018 period, subject to the determination of certain issues remaining to be determined, as set forth in Section 13.3 of this Agreement.

At the time that the April through July of 2013 discussions between the parties took place, Union's application in EB-2013-0202 (the "Application") had not been filed. Union has prepared its Application for Approval of a 2014-2018 Incentive Rate Making Framework based on this Agreement, and the documents considered by the parties hereto which are included in appendices to this Agreement. Additional evidence filed in support of the Application has been reviewed by the parties to the Agreement prior to filing. The parties agree that they regard the Application materials and this Agreement to constitute a sufficient evidentiary record to support the resolution of each of the issues as set forth in this Agreement.

The parties to the Agreement acknowledge and agree that none of the completely settled provisions of this Agreement are severable. If the Board does not accept the completely settled provisions of the Agreement in their entirety, there is no Agreement (unless the parties agree that any portion of the Agreement the Board does accept may continue as a valid Agreement).

Tab 6

Alberta Utilities Commission

Errata to Decision 20414-D01-2016

2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities

February 6, 2017

with Dr. Meitzen arguing that "this span of years provides a sufficiently long period that overcomes transient, short-run shocks that could influence TFP growth (such as with a 5-year average) and also avoids anchoring the forward-looking estimate with values from the distant past that no longer provide a reasonable basis for establishing a forward-looking X factor."[179] A drawback of the 10/15 method compared to simple averages of either the last 10 or last 15 years is that the last 10 years appear in both components that are averaged in the 10/15 method and, therefore, have higher weights than do the five years that precede them. A different choice of years (such as 8/13) would necessarily result in a different weighting scheme. This unequal weighting can only be avoided with a simple average and for this reason, the Commission prefers this latter approach.

145. The effect of the Commission's determination to dismiss the Meitzen study recommendation of the 10/15 method in favour of a simple average is to increase the lower bound of recommended TFP growth values in Table 1, which was previously associated with the 10/15 method. Again, however, due to the variability that results from the use of different assumptions underlying input growth, and the choice of the output measure, as described in the previous sections, and accounting for this variability means that this TFP growth component is not necessarily prevented from lying below the lowest remaining final recommendation (as shown in Table 1) of -0.79.

5.3 Stretch factor

146. Generally speaking, a stretch factor is an additional percentage incorporated in the X factor, thereby increasing the overall value for X and thus slowing the price or revenue cap growth determined by the I-X indexing mechanism. On this basis, the stretch factor can be viewed as sharing with customers the expected additional cost reductions that result from the move from a low-incentive regime such as COS regulation to a higher-incentive regime such as PBR. For this reason, stretch factors are common in first-generation PBR plans.

147. In this proceeding, parties disagreed on whether a stretch factor should be applied in the next generation PBR plans. The distribution utilities and their experts contended that readily available efficiency gains (the "low hanging fruit") have already been captured in the current generation PBR term.[180] In contrast, all interveners argued for a continuation of a stretch factor in the next generation PBR term in an amount not lower than the 0.2 per cent approved in Decision 2012-237.[181]

148. Among other arguments, the interveners submitted that a stretch factor is necessary as it strengthens the incentives under PBR.[182] On this point, the Commission disagrees. As indicated in Decision 2012-237, while the size of a stretch factor affects a utility's earnings, it has no

179 Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, PDF page 219.
180 Exhibit 20414-X0056, Brattle evidence, page 36, Q/A 70; Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 43; Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 44; Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraph 79; Exhibit 20414-X0073, Fortis PBR plan proposal, paragraph 60; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraphs 92-94.
181 Exhibit 20414-X0630, CCA revised argument, paragraph 204; Exhibit 20414-X0618, UCA argument, paragraph 86; Exhibit 20414-X0625, Calgary argument, paragraph 77.
182 Exhibit 20414-X0625, Calgary argument, paragraph 75. Exhibit 20414-X0618, UCA argument, paragraphs 74 and 88. Exhibit 20414-X0630, CCA revised argument, Section 12 was titled "Including a Stretch Factor Will Increase Efficiencies Not Yet Realized."

influence on the incentives for the utility to reduce costs. PBR plans derive their incentives from the decoupling of a utility's revenues from its costs as well as from the length of time between rate cases and not from the magnitude of the X factor (to which the stretch factor contributes).[183]

149. Brattle confirmed this observation stating that the existence of a stretch factor does not increase the benefits seen by customers. Rather, a stretch factor benefits customers because it provides the expected gains of PBR to them more quickly than the alternative of waiting until rebasing.[184] Brattle explained:

> … the purpose of the stretch factor is to anticipate additional cost savings that are expected to be achieved under PBR, and set the path of base rates lower than it would have been in the absence of the stretch factor because of the anticipated additional savings. One way to characterize a stretch factor is that it passes on to customers anticipated additional savings (over and above those incorporated into the X-factor) immediately which would otherwise, in the absence of the stretch factor, be passed back to customers at the end of the PBR plan (by rebasing).[185]

150. Dr. Weisman expressed a similar view and indicated that "the question is whether those efficiency gains, to the extent they exist, the additional efficiency gains, should be guaranteed to consumers through the stretch factor rather than be passed along to consumers at the time of rebasing."[186] From this perspective, Dr. Weisman noted that the relevant factor for a regulator to consider when determining the need for the stretch factor is the certainty of additional efficiency gains, so as to make a decision on whether such gains should be passed along in the form of rebasing rather than guaranteed to consumers *a priori* through the stretch factor in the PBR formula.[187]

151. The distribution utilities and their experts have interpreted the Commission statement in paragraph 479 of Decision 2012-237 to mean that the inclusion of a stretch factor is warranted only during a transition from COS regulation to PBR.[188] Although the context for paragraph 479 concerned a transition from COS to first-generation PBR, the UCA's more general interpretation is that a stretch factor was approved in Decision 2012-237 because increased efficiencies were expected to be realized from the transition from a low incentive regulatory regime (in that case, COS) to a higher incentive regulatory regime (in that case, first-generation PBR). In the UCA's view, a better general definition of the purpose for a stretch factor is to share the efficiency gains that are expected to result when the subsequent generation of regulatory framework provides enhanced incentives relative to the previous generation (i.e., when there is a transition from a less-incentivized form of regulation to regulation that embodies greater incentives).[189]

152. Parties in this proceeding pointed out that because expenditures under the capital tracker mechanism in the 2013-2017 PBR plans were largely treated on a COS basis, they were not

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183 Decision 2012-237, paragraph 500.
184 Exhibit 20414-X0387, Brattle reply evidence, page 47, Q/A 97.
185 Exhibit 20414-X0056, Brattle evidence, pages 35-36, Q/A 68.
186 Transcript, Volume 14, page 2915, lines 11-17 (Dr. Weisman).
187 Transcript, Volume 14, page 2915, lines 18-23 (Dr. Weisman).
188 Exhibit 20414-X0623, EPCOR argument, paragraph 79; Transcript, Volume 14, page 2917, lines 4-10 (Dr. Weisman); Exhibit 20414-X0446, Brattle supplemental reply evidence, page 9, Q/A 24; Exhibit 20414-X0624, Fortis argument, paragraph 70.
189 Exhibit 20414-X0618, UCA argument, paragraphs 73 and 77.

subject to the same high-powered incentives to control costs as the expenditures under I-X.[190] The Commission agrees. In Section 6 of this decision, the Commission approves the K-bar mechanism, which, as Dr. Weisman put it, is "a lot more high powered in terms of incentives,"[191] compared to capital trackers. Mr. Baraniecki for EPCOR agreed with the logic that if capital is moved from a low-powered incentive regime, such as capital trackers, to a higher-powered incentive regime, such as K-bar, there may be a need for a stretch factor.[192]

153. Given that current generation PBR plans include a COS-based capital trackers mechanism, which will be mostly replaced in the next generation PBR plans by the K-bar mechanism, the Commission expects that next generation PBR plans will be largely devoid of any significant COS elements. Therefore, the Commission finds merit in including a stretch factor component in the X factor for the next generation PBR plans for all distribution utilities. In a similar vein, because ENMAX was regulated under COS in 2014, the commencement of the 2015-2017 PBR plan warrants inclusion of a stretch factor in the X factor for the ENMAX 2015-2017 PBR plan as well.

5.4 Commission determination on the X factor for the 2018-2022 PBR plans

154. The TFP growth values that have been produced by the various studies in evidence are the result of an index-number type of calculation, rather than estimation, that can (but need not) be obtained using a spreadsheet. Despite this characteristic, even were the examination of the three TFP growth studies in this proceeding limited to a period comprising the last 15 years, a range included in all three studies, the range of TFP values that have been proposed for this period is strikingly large. Brattle expressed its view that "it is unusual for there to be more than one TFP study in evidence in a single proceeding,"[193] as in the case of the current proceeding where three TFP growth studies were filed, at least two of which involve some fundamental differences. Had only one objective and transparent study been filed in evidence, the variability inherent in the TFP growth value, which is a function of the assumptions and data used, and is evident from a comparison of the three studies, easily could have remained unknown. This could have led the Commission to conclude that there is a single TFP growth value that could be regarded as "correct." Rather, the Commission views the variety of results that have been provided as confirming that the TFP growth value is likely not a correct single number, but that a reasonable value likely falls within a range of values, demarcated by the breadth of assumptions and data sets that may be reasonably employed in producing the studies. This view was shared by some of the experts in this proceeding. For example, in its evidence, Brattle indicated that "Certainly estimating TFP trends is not an exact science."[194] This opinion was explained further in testimony by Dr. Carpenter when he stated the following:

> There's noise in the data, and there's noise in the results. So I think you have to take a practical view as to how much uncertainty there is in these numbers. I think at some point in our evidence we say there's probably about 150 basis points of potential just noise in

[190] Transcript, Volume 1, page 63, lines 3-8 (Dr. Brown); Transcript, Volume 12, page 2443, line 12 to page 2444, line 8 (Dr. Lowry); Transcript, Volume 14, page 3021, lines 2-21 (Dr. Weisman); Exhibit 20414-X0618, UCA argument, paragraph 83.
[191] Transcript, Volume 14, page 2918, lines 15-18 (Dr. Weisman)
[192] Transcript, Volume 14, page 2932, line 15 to page 2933, line 12 (Mr. Baraniecki).
[193] Exhibit 20414-X0387, Brattle reply evidence, page 43, Q/A 85.
[194] Exhibit 20414-X0387, page 43 Q/A 85.

Tab 7

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2012-0459

IN THE MATTER OF AN APPLICATION BY

Enbridge Gas Distribution Inc.

2014 - 2018 Rate Application

DECISION WITH REASONS

July 17, 2014

savings related to, for example, switching from Envision to WAMS, and the rollout of GPS. SEC submitted that the approach is flawed because these factors are not directly reflected in the forecasts. SEC submitted that Enbridge had developed
a hybrid of a 3-year forecast and two years using a formula, which in SEC's view was an indirect and inappropriate approach to traditional IR plan.

The Board does not agree with this overall criticism. A bottom up approach with known or expected specific costs, combined with a top down approach which applies specific cost constraints, can be an appropriate way to develop a reasonable forecast. This is discussed further below. The Board also considers it reasonable to include productivity expectations even if specific programs are not fully identified. This is also discussed further below.

Board staff submitted that Other O&M may include over-forecasting given the inherent incentive in the building blocks approach and that this could be addressed through staff's stretch factor proposal. Board staff submitted that there was no way to verify whether a lower achievable budget could have been presented. CCC submitted that there was no external analysis as to whether the expenditures are reasonable.

The Board agrees that there is an inherent incentive to over-forecast when setting rates for multiple years. The Board's RRFE report contemplates that an applicant will provide independent expert analysis to support its forecasts and/or provide robust benchmarking evidence as to the level of efficiency of the applicant. Enbridge has provided no external analysis of its O&M budgets, and the benchmarking analysis has significant limitations. The Board has taken this into account in its adjustments.

Productivity

Earlier in this decision, the Board has found that the benchmarking evidence does not support a conclusion that Enbridge is particularly efficient. Without this external analysis, the Board must rely on the internal analysis of the budget and the company's own plans for productivity improvements.

A number of parties criticized Enbridge for not identifying specific productivity improvement programs. Board staff argued that there are no specific productivity programs associated with the embedded savings of $172.5 million, and therefore these cost savings may not be sustainable and may not be productivity improvements. In staff's view, the Board should be looking for something more tangible than a “baked in” amount. Board staff also noted that the savings are not large in percentage terms compared to total revenue requirement. CCC, BOMA and SEC also argued that productivity improvements had not been identified sufficiently. Enbridge responded that productivity improvements have been embedded in the forecast and are the difference between the forecast and the expected actuals. Enbridge also pointed to evidence regarding a number of specific productivity programs, including GPS and locates.

The objective is for Enbridge to develop a forecast which is reasonable and defensible. The Board finds that it can be an appropriate approach to develop a forecast which includes self-imposed cost reduction assumptions as a means of ensuring productivity improvements, even if those productivity improvements cannot be precisely identified. The Board would expect a combination of planned programs and unplanned targets given the duration of the Custom IR plan. However, it would also be necessary to ensure that the budget constraints are sufficient to drive an appropriate level of efficiency and that the result is genuine productivity improvements and not merely short-term cost cutting.

One of the specific measures which Enbridge incorporated into its budgets was the requirement that the FTE level be held flat over the IR term. Enbridge maintained that its use of flat FTEs represents “an embedding of productivity” and a stretch factor. However, APPrO argued that holding FTEs flat does not imply the level of productivity which Enbridge is asserting because FTEs increased by about 15% between 2011 (2,070 actual) to 2013 board approved (2,388). The increase between 2011 and the 2014 budget (2,377) was slightly below 15%. APPrO also argued that the vacancy rate would provide flexibility as to the actual level of FTEs and that therefore the budget should be reduced to remove the costs associated with the vacancy rate. Enbridge responded that the 2013 rates include a credit for a 2.5% vacancy rate, and that this credit continues through the forecast period because it is in the base.

The Board agrees that holding FTEs flat is a form of cost containment; however, the Board finds that it is not as significant a constraint as Enbridge claims. First, the increase in FTEs between 2011 and 2014 is close to 15%, which is a significant level of increase over a short period. Second, the rates include a credit equivalent to a 2.5% vacancy rate, but the evidence is that the actual vacancy rate is running at 5%, thereby affording Enbridge with additional flexibility.

Productivity was also analyzed in the context of O&M cost per customer measures. Enbridge noted that total utility O&M per customer is declining in 2016 constant dollars and flat in nominal dollars, and that it is lower than Concentric derived from its approach to a traditional IR plan. The Vulnerable Energy Consumers Coalition ("VECC") argued that the declining cost per customer does not demonstrate efficiency because it is almost exclusively due to customer growth and monopoly economics. The increases in cost per customer for 2014-2018 are lower than in 2013, but in SEC's view that is because of the significant increases in 2012 and 2013.

The Board finds that the cost per customer data is not strong evidence of productivity improvement. The evidence is clear that Enbridge is growing and as a result the Board would expect to see the cost per customer show a declining trend as a result of scale economies. Enbridge witnesses testified that there are limits to scale economies and pointed to customer care as an area that would not decline on a per customer basis as customers are added. However, the customer care costs are subject to a separate budget setting mechanism.

The Board concludes that while Enbridge's approach is reasonable, the evidence is not sufficient to reach a conclusion that an appropriate level of productivity has been incorporated into the forecast. A number of parties made specific recommendations as to how the Other O&M forecast should be adjusted to incorporate a sufficient level of productivity. These are discussed in the next section.

Adjustments to the Forecast

Board staff proposed that a productivity factor be imposed on Enbridge in the form of a reduction to the total revenue requirement of $20 million per year. Staff pointed to a number of factors in support of its proposal:

- the recent levels of over-earning
- statements in the Strategic Plan
- the "stretch objective" included in Enbridge's memo to its Board of Directors regarding this application.

This productivity factor, totalling $100 million over the five years, would be a direct consumer benefit. Staff also submitted there should be a further stretch factor beginning

Tab 8

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2017-0306** **EB-2017-0307**	**Enbridge Gas Distribution Inc.** **Union Gas Limited**

VOLUME: **Technical Conference**

DATE: **March 29, 2018**

investments they need to make in order to serve the public.

That connection between investor-owned companies and the capital markets is distinctly investor-owned territory. It does not apply to municipal utilities or state-owned utilities or anything else that goes to a different source of capital funding, despite what the law says.

But let's get back to the other part of your question, because you asked a multiple question, with respect to muddying waters --

MR. BRETT: On that part, or do you want to finish -- you finish up --

DR. MAKHOLM: No, let me finish. I don't want to delay things, but I think -- you said page 15. I think we only went to page 13. I think you were originally right. You were talking about page 13.

MR. BRETT: I can't see very well here. It is 13 --

DR. MAKHOLM: And as we -- as I talked about this morning, I think it was a misuse -- a terminological misuse to use stretch factor for two entirely different purposes.

The way in which stretch factor has been applied by consensus amongst the experts in the field and is recognized by the AUC has to do with a transitionary device, as I talked about with Ms. Girvan.

The way in which stretch has been used for the 70 municipal distributors in the electricity business that the OEB has to oversee is a statistical econometric benchmarking regime where companies are sorted out according to the model that's maintained by PEG, and separated according to their measured areas of productivity.

Nothing like that looks like what I've done here or what the various consultants, including PEG, did in Alberta. That is a different pursuit with different kinds of data, with different practices and different outcomes. They shouldn't have called it a stretch factor. They should have called it something else, and we wouldn't have this confusion.

MR. BRETT: Let me ask you this then: Are you aware that some of these municipally owned utilities in Ontario regularly access the capital debt markets? Are you aware of that? They raise money on Bay Street with bonds, debentures, and the like.

DR. MAKHOLM: I'm well-aware of municipal bonds.

MR. BRETT: You're aware, so that you -- it's not correct to say, is it, that they don't have any involvement with the capital markets? They do have involvement with the capital markets.

DR. MAKHOLM: They issue bonds, yes, municipal utilities all over the country, your country and mine, issue bonds, but they don't go to the capital markets for equity, and the -- the reason why the payment of interest on bonds is something that no one ever hires an outside expert to do because it is so elementary is that there is no contention involved. The contention surrounding investor-owned companies has to do with the return on equity, and how you pay equity investors for devoting

Tab 9

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2016-0152

ONTARIO POWER GENERATION INC.

Application for payment amounts for the period from January 1, 2017 to December 31, 2021

BEFORE: Christine Long
Vice Chair and Presiding Member

Cathy Spoel
Member

Ellen Fry
Member

December 28, 2017

Findings

The OEB has considered the SEC submission that the inflation factor should not apply to GRC, and the OEB staff submission that a portion of the GRC could be excluded from inflation treatment.

Section 92.1(4) of the *Electricity Act, 1998* provides that the GRC tax component is a percentage of gross revenue from annual generation. Section 92.1(5) also sets out the rates for the GRC water rental component as a percentage of gross revenue from annual generation. Accordingly, the entire GRC is determined on the basis of gross revenue from annual generation and not on production as submitted by SEC. Under IRM, the gross revenue which is underpinned by hydroelectric payment amounts will reflect some level of inflation, and therefore the tax and water rental components of the GRC will reflect similar levels of inflation as OPG's other costs and those of businesses in other sectors of the economy. This inflation in business costs is measured in macroeconomic price indices like the GDP-IPI.

The OEB finds that it is appropriate to apply the I – X factor to the GRC.

8.1.4 Productivity Factor

The OEB and the electricity distributors are experienced with the index method which converts outputs and inputs into an index value for the determination of industry total factor productivity (TFP). There is no precedent for TFP studies of the hydroelectric generation industry for the purposes of ratemaking.

As directed by the OEB in the 2011-2012 payment amounts decision, OPG contracted with LEI in 2013 to conduct an independent productivity study of the hydroelectric generation industry. The report summarizing that work was filed with the OEB on December 18, 2014. The report was subsequently updated and filed in this proceeding. Based on an analysis of OPG and 15 US peers using data from 2002-2014, LEI calculated an estimated annual TFP of -1.01%. LEI explained that a negative TFP should be expected for the mature hydroelectric generation industry as there is increasing OM&A, relatively constant capital and relatively stable output. In the application, OPG proposed a 0% productivity factor, noting that the OEB has declined to accept negative productivity for electricity distributors.

OEB staff retained Pacific Economics Group Research LLC (PEG) to review OPG's hydroelectric IRM proposal, LEI's TFP study, and to conduct an independent study.

PEG's analysis and its determination that a TFP of 0.29% is appropriate was filed as evidence in the proceeding.[145]

Representatives of both LEI and PEG appeared as expert witnesses at the oral hearing. OPG and the unions urged the OEB to accept LEI's analysis, while OEB staff and the other intervenors argued in favour of PEG's analysis.

The following table summarizes the TFP methodologies and results:

Table 33: LEI and PEG Productivity Factor Methodologies and Results

	LEI	PEG
Output	Generation (MWh)	Capacity (MW)
Inputs	Operating Cost	Operating Cost
	Capital Measure (MW – physical) No depreciation assumed	Capital Measure (monetary) depreciation based on geometric decay, return on rate base, taxes
Sample	US utilities and OPG (16 total)	US utilities (21 total)
Period	2002 to 2014	1996 to 2014
Total Factor Productivity	-1.01%	0.29%

LEI selected plant capacity as the capital input measure. Capacity data are readily available and consistently measured in the industry. Further, assuming proper maintenance, productive capacity does not generally depreciate or decline significantly over time. OPG's Reply Argument states that LEI's approach does not require the OEB to make any assumptions about depreciation of hydroelectric assets.

PEG chose geometric decay to model depreciation for the capital input measure based on monetary data of hydroelectric assets. Geometric decay is widely used in North America and has been used by PEG for most of the research it has completed in the past for the OEB. It is PEG's view that hydroelectric assets do not exhibit a constant flow of service throughout their lives.[146] There is a decline in the flow of service as measured by a continual stream of "refurbishment" capital to maintain productive capacity. Further, individual assets have components with different service lives.

[145] Exh M2.
[146] PEG response to LEI memorandum, February 16, 2017.

OPG argued that PEG's use of the geometric decay profile is primarily responsible for the positive TFP identified. OPG states that the use of geometric decay contradicts references cited by PEG, namely an Organization of Economic Cooperation and Development manual, which suggests that bridges and dams are examples of assets that show no (or little) functional depreciation until end-of-life.

Whether water availability was correctly or adequately reflected in the analysis was central to examination of and submissions on TFP output measures. OPG stated that generation is a superior output measure as this is how OPG is paid and hydroelectric and efficiency improvements generally increase generation. However, PEG and several parties observed that generation is sensitive to weather fluctuations and hydrology, and therefore choice of the sample period as well. While PEG selected capacity as the appropriate output measure citing its stable growth and the importance of MW as a cost driver, OPG argued that it would incent a utility to build excess capacity despite lacking water to use the capacity.

There were differing views on which methodology best reflected the impact of the Niagara Tunnel Project which cost $1.5 billion and increased generation by 1.5 TWh. LEI's methodology captures the increased MWh impact, while PEG's methodology captures the expense.

In reply argument, OPG stated that the matter before the OEB is not which TFP methodology to apply, rather the issue is whether OPG`s proposed 0% productivity factor is appropriate.

Findings

While there have been TFP based empirical studies for generation in academia, the LEI and PEG TFP studies are the first TFP studies for the hydroelectric generation business sector for the purposes of regulatory ratemaking.[147] The OEB is not prepared to completely accept the approach of either expert. As discussed extensively in responses to interrogatories, during the oral hearing, and in submissions, there are strengths and weaknesses of both approaches.

The OEB agrees with LEI that generation (MWh) is the most appropriate measure of output, as it is generation produced, and not capacity, which is the basis for revenues to recover capital and operating costs. However, the OEB also recognizes limitations with LEI's approach. The OEB questions LEI's physical approach which uses MW capacity as an input, as this measure does not take into account financial considerations, such

[147] Exh A1-3-2, Attachment 1 Footnote 3.

as the capital costs. Although many hydroelectric generation assets have very long useful lives, the OEB is not convinced that there is no functional depreciation until end of life. In fact, reviews of capital projects to sustain, refurbish and replace hydroelectric stations and assets in OPG's prior payment amount applications confirm that capital expenditures and operating costs are needed to maintain capacity to the end of a station's life. Absent ongoing capital and operating expenditures, hydroelectric generation assets will depreciate over time. In the OEB's view, LEI's physical method, which assumes no depreciation until the end of life, is not a realistic basis for the analysis of productivity of hydroelectric generation facilities.[148]

However, the OEB is also not persuaded that PEG's approach using MW as the output measure is appropriate. MW as an output does not seem reasonable as an underutilized asset will still be considered to be productive. How many MWh can be produced from a plant of a particular MW capacity must bear some relationship to productivity, as, for example, improvements in maintenance (e.g. shorter down time) may result in more output from a plant of the same capacity.

In OPG's situation, the major capital investment in the Niagara Tunnel is intended to result in greater production even if the capacity of the Sir Adam Beck plants is not increased. However, at the same time, there are also factors, such as water availability, which are beyond the control of the plant operator. Not all hydroelectric generation is used as base load, so output may also be reduced due to market conditions.

However, PEG's financial approach, which does take into account depreciation of assets in some form, is in the OEB's view more realistic than LEI's approach, although the OEB observes that there is no consensus on the best method for accounting for economic and physical depreciation or deterioration of assets in these types of analyses.

The OEB also has other reservations about aspects of both LEI's and PEG's studies. Neither study included Canadian generators other than OPG. The OEB accepts that Canadian data was difficult to obtain, but is concerned about the reliance solely on OPG's own and U.S. based generators' data. The OEB notes that neither study provided evidence on how the regulatory environment may influence the production of a hydroelectric generator in a particular jurisdiction. Improved sample, data and

[148] The OEB made similar findings about LEI's physical approach assuming no economic depreciation of assets with respect to analyses conducted by LEI in the process to develop the 3rd Generation IRM for electricity distributors. See "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors," EB-2007-0373, September 17, 2008, pages 7-8 and 11-12.

consideration of business and regulatory factors that influence a generator's operations and production would improve the usefulness of the results of studies.

Energy Probe submitted that, while neither expert identified a historical trend in TFP growth, the PEG estimate was superior. Energy Probe's submission and analysis referred extensively to its note on data aggregation which was appended as three appendices to its final submission. Little of this was reviewed in detail with any of the witnesses, nor did Energy Probe provide its own witness. The OEB does not find this information to be helpful.

Given the limitations of the samples, the data and the econometric approaches described above, the OEB finds that, at this time, it cannot accept either LEI's or PEG's analysis in its entirety. Given that these studies suggest a range from 0.29% to -1.01%, the OEB finds that a base productivity factor of 0%, as proposed by OPG, is appropriate for OPG's hydroelectric IRM plan.

The OEB expects that OPG and other stakeholders will take into account the OEB's concerns about the approaches and limitations of the experts' analyses on the record in this proceeding. Improvements in methodology and data, and translation of the results of the studies as to how they more directly translate to rate-setting would provide more useful and convincing information on which OPG could make its next proposal and the OEB would make its determination for subsequent IRM plans.

8.1.5 Stretch Factor

In the EB-2013-0321 decision, the OEB found the hydroelectric benchmarking to be inadequate and ordered OPG to complete a fully independent benchmarking study of hydroelectric operations. The decision stated that the benchmarking should be comparable to the benchmarking in place for the nuclear operations. The decision also stated that the results of the hydroelectric benchmarking study would be important in developing the IR methodology for OPG.

OPG retained Navigant Consulting Inc. (Navigant) to benchmark the hydroelectric operations. The analysis of 2013 performance was filed with the application. OPG's cost and reliability performance are shown in the table below:

Tab 10

OPG Interrogatory #1

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 General

a) Please provide the data set, TFP model, and any other quantitative analysis and models (e.g., regression analysis for the cost elasticities for generation capacity and volume as discussed on page 48 of PEG's report) used by PEG in its TFP analysis.

   Please provide all materials in "live" format, such as Microsoft Excel. Please make sure all formulas are intact and operable.

b) Please provide documentation to facilitate understanding of the materials and to link them to the discussion of results in PEG's report. Sufficient information should be provided on the design and working of the model, the data used, and the firms used in the data set for the analysis to enable another researcher to replicate the results of PEG's analysis.

Response:

The following response was provided by PEG:

a) Please see the attached working papers PEG-WP-1.xlsx, PEG-WP-2.xlsx, PEG-WP-3, and PEG-WP-4.zip. These contain data and formulas to support the calculations contained on tables 1-7 of the original report. The PEG-WP-1 file supports the US calculations, PEG-WP-2 supports variations on the LEI work and OPG/Ontario Hydro TFP calculations, PEG-WP-3 supports the econometric model presented on Table 7 and PEG-WP-4 provides miscellaneous items. The program code to do the econometric work is written in the R language which is freely available on the internet. Some tables have been added to the working papers or augmented to support other PEG interrogatory responses.

   Please note that the results reported in PEG's report were calculated using computer code. In addition to providing this code in its working papers, PEG has reproduced these results in Microsoft Excel in order to comply with OPG's request.

b) Documentation in the form of labeling and annotations is provided in both the code and the spreadsheets. PEG's report in Exhibit M2 also explains the calculations.

OPG Interrogatory #8

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 page 21

PEG lists three depreciation profiles used to establish the capital input quantity under the monetary method: geometric decay, one-hoss shay, and cost of service. Please identify all jurisdictions that calibrate utility X-factors using each type of depreciation profile.

Response:

The following response was provided by PEG:

PEG has several concerns with the way this question is posed. First, some regulators may consider more than one capital input methodology when calibrating X factors. For example, over the years the OEB has based X factors in IRMs for power distributors on studies using both the geometric decay and cost of service methodologies. For that reason, PEG believes that it is better to review capital input quantity methods underlying the calibration of X factors on a plan by plan basis rather than on a jurisdictional one.

Second, approved IRMs are often the outcome of settlements. In those instances, it is often the case that the resulting X factor was informed by one or more productivity studies but their influence is unclear. It is also possible that an X factor in a PBR plan that is outlined in a settlement may be informed by productivity studies involving more than one capital input quantity method. For example, the Enbridge Gas PBR settlement in 2008 defined X as a percentage of inflation rather than a specific number. The productivity studies presented in the proceeding relied on both the geometric decay and cost of service methods and it is not clear which method was more important.

Third, PEG does not have all of the productivity studies that were the basis of or informed every X factor that's been approved. This is especially true of earlier plans.

With these caveats, Attachment M2-11.1-OPG-8 is a table that details instances in which productivity studies for X factor calibration which were submitted in regulatory proceedings used monetary capital quantity treatments. Outcomes of these proceedings are briefly discussed.

Attachment M2-11.1-OPG-8

CAPITAL QUANTITY METHODS USED IN X FACTOR CALIBRATION STUDIES FOR COMPREHENSIVE INDEX-BASED ARMs OF ENERGY UTILITIES[1]

Applicable Service	Utility	Jurisdiction	Term	Cap Form	Capital Quantity Methods Featured
Bundled power service	Central Maine Power (I)	Maine	1995-1999	Price Cap	Settlement's X factor proposal informed by productivity study featuring a geometric decay approach to capital quantity
Gas distribution	Southern California Gas	California	1997-2002	Revenue Cap	Geometric decay
Gas distribution	Boston Gas (I)	Massachusetts	1997-2003	Price Cap	Geometric decay
Gas distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Geometric decay
Power distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Geometric decay
Power distribution	All Ontario distributors	Ontario	2000-2003	Price Cap	Geometric decay
Gas distribution	Union Gas	Ontario	2001-2003	Price Cap	MFP study featuring geometric decay capital quantity informed Board's decision
Power distribution	Central Maine Power (II)	Maine	2001-2007	Price Cap	Settlement's X factor proposal informed by productivity study featuring a one hoss shay approach to capital quantity
Gas distribution	Berkshire Gas	Massachusetts	2002-2011	Price Cap	X factor calibrated using MFP study filed in a previous proceeding featuring a geometric decay capital quantity
Gas distribution	Boston Gas (II)	Massachusetts	2004-2013, terminated in 2010	Price Cap	Geometric decay
Power Distribution	All Ontario Distributors	Ontario	2006-2009	Price Cap	X factor informed by a review of other X factors, many of which were calibrated in MFP studies featuring geometric decay capital quantity
Power distribution	Nstar	Massachusetts	2006-2012	Price Cap	Settlement's X factor proposal was informed by a productivity study featuring a geometric decay approach to capital quantity
Gas distribution	Bay State Gas	Massachusetts	2006-2015, terminated in 2009	Price Cap	X factor calibrated using MFP study filed in a previous proceeding featuring a geometric decay capital quantity
Bundled power service	Pacificorp (II)	California	2007-2009, extended to 2010	Price Cap	BLS MFP study of electric, gas, and sanitary sector featuring a hyperbolic depreciation profile informed settlement X factor
Power Distribution	ENMAX	Alberta	2007-2013	Price Cap	X factor informed by a review of other MFP trends and X factors, many of which relied on geometric decay capital quantity indexes
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Revenue Cap	Settlement's X factor proposal was informed by productivity studies featuring geometric decay and cost of service approaches to capital quantity
Gas Distribution	Union Gas	Ontario	2008-2012	Revenue Cap	Settlement's X factor proposal was informed by productivity studies featuring geometric decay and cost of service approaches to capital quantity
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	Revenue Cap	Results from a productivity study featuring a cost of service approaches to capital quantity informed Commission's X factor determination
Power Distribution	Central Maine Power (III)	Maine	2009-2013	Price Cap	Settlement's X factor proposal was informed by productivity studies featuring geometric decay and cost of service approaches to capital quantity
Power Distribution	All Ontario Distributors	Ontario	2010-2013	Price Cap	Cost of service
Power Distribution	All Distributors	New Zealand	2010-2015	Price Cap	Productivity studies featuring both the geometric decay and physical asset approach informed the Commission's X factor decision
Power Distribution	ATCO Electric, EPCOR, FortisAlberta	Alberta	2013-2017	Price Cap	One hoss shay
Gas Distribution	All Distributors	Alberta	2013-2017	Revenue Cap	One hoss shay
Power Distribution	All Distributors except those who opt out	Ontario	2014-2018	Price Cap	Geometric decay
Bundled power service	FortisBC	British Columbia	2014-2019	Revenue Cap	Cost of service
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	Revenue Cap	Cost of service

[1] Shaded plans are plans that are not currently in effect.