L1.EGD/Union.1 – Workpapers

Reference: PEG Evidence, April 11, 2018

Preamble: In its report, PEG provides a number of quantitative results and 6 tables to support its analysis. The companies seek to fully understand PEG's calculations.

Questions:

a. Please provide the calculations in native format with all formulas intact. If not provided, explain why.

b. Please provide the source data, in spreadsheet format if available, and references for the data sources. If not provided, explain why.

Responses: The following responses were provided by PEG.

a. Source data and calculations for the U.S. gas utility productivity research can be provided in spreadsheet format to parties who sign a confidentiality agreement.[1] This agreement is similar to that required by Enbridge to examine the data used by its consultant, Concentric Energy Advisors, in a prior IR proceeding. Working papers for the rest of the empirical research supporting PEG's report are provided in Attachment EGD/Union.1a-1 to 1a-6. The papers include references to data sources.

b. Please see our response to part a of this question.

[1] The code for our gas TFP calculations is not confidential but will be sent with the confidential materials unless separately requested..

L1.EGD/Union.2 – Stretch Factor

References:

a. PEG Evidence, April 11, 2018, page 3:

"We disagree with Dr. Makholm's 0% stretch factor recommendation, which is based on the premise that stretch factors are only appropriate in first generation IRMs. The Board is correct to reconsider stretch factors for all utilities on a regular basis using statistical benchmarking. A utility is no more certain to be efficient after one or even several terms of IR than firms in unregulated markets are certain to be efficient. Several other regulators have approved stretch factors after the first generation of IR."

b. Makholm Direct Evidence, EB-2017-0307, Exhibit B, Tab 2, p. 12:

"The consensus among a broad cross-section of economists, as reflected by the AUC's discussion in that case, is that the foundation for the stretch factor lies in the *transition* to a PBR regime and away from cost-of-service regulation."

c. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Transcript Volume

13, May 2, 2012, pp. 2563, lines 24-25 to 2564, lines 1-6:

Question from Mr. B. McNulty, Board Commission Counsel: "Sir, turning to the stretch factor, could we stat by explaining to me in a concise way, if you can, sir, the rationale you see for including a stretch factor in a PBR plan?"

Answer from Dr. Mark Lowry, witness for Consumers Coalition of Alberta: "The rationale is to share some of the expected acceleration in productivity growth as you go from a cost-of-service ratemaking system to a performance-based ratemaking system."

d. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Transcript Volume

13, May 2, 2012, pp. 2564, lines 18-25:

Question from Mr. B. McNulty, Board Commission Counsel: "And can you elaborate a bit, sir, on how long that customer dividend, if you will, should be reflected in the PBR plan?"

Answer from Dr. Mark Lowry, witness for Consumers Coalition of Alberta: "In my opinion, it should be continue until a credible levels benchmarking study has shown that the utility is a superior performer, and that's a fairly tall order. I don't know that any such study has ever been performed for an Alberta utility of any sort."

e. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Decision 2012- 237,

September 12, 2012, paragraph 473:

"473. The CCA and its expert, Dr. Lowry, indicated that both the operating efficiency of the company and the difference between the incentive power of the current regulation and the PBR plan should form part of the consideration as to whether to add a stretch factor."

f. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Decision 2012- 237, September 12, 2012, paragraphs 479-480:

"479. The Commission agrees with the rationale for a stretch factor put forward by EPCOR, NERA, AltaGas, the UCA and Calgary. The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime."

"480. The ATCO companies and the CCA agreed that this reasoning forms part of the consideration when adding a stretch factor. As such, the Commission observes that this definition of stretch factor has been accepted by all parties to this proceeding, except Fortis."

g. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Decision 2012- 237, September 12, 2012, paragraphs 271 and 279.

"271. In contrast, because TFP (total factor productivity) studies (such as the one prepared by NERA in this proceeding) focus on rates of change in productivity within an industry, not levels, the unique cost features of any particular company cancel out in the process. In other words, these productivity studies do not examine whether one firm has a greater level of output for the same inputs levels as another firm. Rather, the focus is to study how the ratio of outputs to inputs changes over time for the industry as a whole."

"279. Given the approach approved above, the starting point for determining the X factor is to estimate the underlying industry TFP growth for the services included in the companies' PBR plans. Then, it is necessary to consider any adjustments to the industry TFP that may be required to arrive at an X factor for Alberta gas and electric distribution companies. And finally, the Commission will consider whether a stretch factor is justified and if so, the size of a stretch factor. Sections 6.3 to 6.5 below deal with each of these steps."

h. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Decision 2012- 237, September 12, 2012, paragraph 481.

"481. In Fortis' view, a stretch factor should be added if a particular company were found to be less efficient than the industry as a whole. The ATCO companies and the CCA also noted that this rationale should be considered when determining the need for a stretch factor.
However, as set out in Section 6.2 of this decision, the Commission does not wish to engage in this type of analysis for the purposes of PBR in Alberta because of the practical and theoretical problems associated with comparing efficiency levels among companies.
Therefore, the Commission did not include the consideration of the companies' comparative levels of efficiency in its determination on the need for a stretch factor."

<u>Preamble</u>: The companies would like to clarify Dr. Lowry's view on stretch factors.

<u>Questions</u>:

a. Please identify all of Dr. Lowry's written work including testimony, reports, published articles, and presentations on stretch factor. Provide active links or copies of that work.

b. Confirm Dr. Lowry's statement in **reference d.** If not confirmed, explain why.

c. Confirm that the consensus among parties with the exception of Fortis, including Dr. Lowry, involved in AUC Proceeding 566 was that "The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime." (see **references b and f**). If not confirmed, explain why.

d. Is Dr. Lowry aware of any "credible levels benchmarking" studies outside of Alberta (see **reference d**)? If so, please identify, describe, and provide those studies.

e. Confirm that the AUC agreed with Dr. Makholm in **references g and h**, that it is appropriate to look at TFP growth not levels for the purpose of calculating an X factor. If not confirmed, explain why.

f. Confirm that the AUC disagreed with Dr. Lowry's view that it is appropriate to compare efficiency levels among utilities for the purpose of calculating a stretch factor (see **references d-h**). If not confirmed, explain why.

<u>Responses</u>: The following responses were provided by PEG.

a) Attachment EGD/Union 2a.1 lists publications in which Dr. Lowry is believed to have discussed stretch factors. Links to these documents are provided where available. Attachment EGD/Union 2a.2 provides a list of recent testimony in which Dr. Lowry is believed to have discussed stretch factors. Links to this evidence are provided where available. Attachment EGD/Union 2a.3 provides copies of 12 documents for which links are unavailable.

The following comment from Dr. Lowry's recent PBR white paper for Lawrence Berkeley National Laboratory is representative of this thinking: "A 'stretch factor' (aka consumer dividend) is often added to *X* to share with customers the benefit of the stronger performance incentives expected under the plan."[2] He does not believe that this is only a concern in first-generation PBR plans. Here are some reasons for his conviction.

- The performance incentives generated by PBR plans are typically weaker than those in competitive markets.
- Even if incentives under PBR were somehow similar to those in competitive markets, accumulated inefficiencies would likely not be eliminated in one or even two consecutive five-year plans.
- Companies in competitive markets are, in any event, not always efficient. Benchmarking studies show that the efficiency of firms in competitive industries, to the contrary, varies greatly. On behalf of two British power distributors, PEG conducted surveys several years

[2] Mark Newton Lowry and Tim Woolf, *Performance-Based Regulation in a High Distributed Energy Resources Future*, Berkeley Lab Report No. 3, January 2016, p. 28.

ago of frontier benchmarking studies in two competitive sectors: banking and farming.

Results are reported in Tables 1 and 2. In some cases, more than one benchmarking method was used in the study. We present in these cases the results from each method.

Our survey on banking efficiency using frontier methods covered American, European, and Turkish banks. The bank studies produced average efficiency scores ranging from 30% to 92%. The studies for farms produced average efficiency scores ranging from 76% to 95%.[3]

Table 1. Survey of Efficiency Studies of Banking Firms

Study	Data Coverage	Method	Result
Bauer, Berger, Ferrier and Humphrey (1997)	US Banks 1977-1988	Method 1	Average cost efficiency = 83%
		Method 2	Average cost efficiency = 30%
Berger and Humphrey (1997)	Survey of 130 efficiency studies of financial institutions	Method 1	Average efficiency = 84%
		Method 2	Average efficiency = 72%
Berger and Mester (1997)	US Banks 1990 – 1995		Average cost efficiency = 86.8%
Casu and Girardone (2002)	European Banks 1993-1997	Method 1	Average economic efficiency = 86%
		Method 2	Average technical efficiency = 65%
Christopoulous and Tsionas (2001)	Greek Banks 1993-1998		Average economic efficiency = 65%
Christopoulous, Lolos and Tsionas (2002)	Greek Banks 1993-1998		Range of economic efficiency = 60% - 100%
Clark and Siems (2002)	US Banks 1992-1997	Method 1	Average cost efficiency = 86%
		Method 2	Average cost efficiency = 74%
Eisenbeis, Ferrier and Kwan (1999)	US Banks 1986-1991	Method 1	Range of average efficiency level by size = 81% - 92%
		Method 2	Range of average efficiency level by size = 60% - 72%
Fethi, Jackson and Weyman-Jones (2002)	Turkish Banks 1992-1999		Average technical efficiency = 57%
Vennet (2000)	European Banks 1995-1996		Average cost efficiency = 80%

[3] Note that the efficiency studies in the farming sector consider only technical efficiency, not all possible sources of inefficiency.

Table 2. Survey of Efficiency Studies of Farming Firms

Study	Data Coverage	Method	Result
Brummer, Glauben and Thijssen (2002)	German, Dutch and Polish Dairy Farms 1991-1994		Range of average technical efficiency by country = 76% - 95%
Hadri, Guermat and Whittaker (2003)	English Cereal Farms 1982-1987		Average technical efficiency = 86%
Kumbhakar (2001)	Norwegian Salmon Farms 1988-1992		Range of average technical efficiency by specification = 79% - 83%
Kumbhakar, Ghosh and McGuckin (1991)	U.S. Dairy Farms 1985		Range of technical efficiency by size = 66.8% - 77.4%
			Range of average allocative efficiency by size = 84.6% - 87.6%

- Consider, finally, that utilities operating under PBR tend to have stronger performance incentives than the typical utilities in a sample used to estimate industry productivity trends. Thus, even if they have made considerable progress in eliminating inefficiencies, utilities operating under PBR may have greater productivity growth.

Dr. Lowry has also noted in his testimony and published work that linking stretch factors to benchmarking studies creates an efficiency carryover mechanism that strengthens performance incentives and discourages strategic cost deferrals.

b) Dr. Lowry confirms making this statement, which is consistent with his longstanding view that utilities should convincingly demonstrate superior cost performance before being exempted from a positive stretch factor. As a witness for CMP in 2007 and Gaz Metro in 2012 he recommended stretch factors despite their previous PBR experiences.

c) Dr. Lowry confirms this statement but notes that this was a generic proceeding applicable to multiple Alberta utilities. Each participating utility hired its own PBR witness, and utility witnesses constituted the majority of PBR witnesses in the proceeding. Dr. Lowry, as the witness for the Consumer Coalition of Alberta, took a different view.

d) Yes. Statistical benchmarking of utility cost levels has been routinely undertaken by several regulatory commissions. This work has sometimes been quite sophisticated. In the English-speaking world, for example, sophisticated econometric cost benchmarking studies have repeatedly been commissioned by the Ontario Energy Board and the Australian Energy Regulator. Other countries where cost level benchmarking has been commissioned by regulators include Austria, Great Britain, Germany, the Netherlands, and Norway. Please see Attachments EGD/Union.2d.1 and 2d.2 for a more extensive list of jurisdictions that have considered benchmarking evidence in other countries and a list of Commission decisions that included the use of benchmarking. The list in Attachment 2d.1 encompasses situations in which a regulator initiated benchmarking as well as situations in which the utility initiated benchmarking and the regulator appraised the work and, in some instances, commissioned another study. It shows that in North America statistical benchmarking has been initiated by regulatory commissions or government agencies in Maine, Ontario, and Vermont. All of these regulators apparently did not share the AUC's view that the benefits of benchmarking are outweighed by the "practical and theoretical problems associated with comparing efficiency levels among companies."

Many utilities have also recognized the value of statistical cost-level benchmarking. Dr. Lowry, for example, has prepared cost-level benchmarking studies for numerous North American gas and electric utilities. In the past year he has provided benchmarking research and testimony for Public Service of Colorado (gas and electric) and Green Mountain Power. He has in past years prepared cost level benchmarking research and testimony for Enbridge Gas Distribution.[4] Other clients for which Dr. Lowry has provided benchmarking research and testimony are detailed in Attachment EGD/Union.2d.3. Utilities that have retained other witnesses to prepare benchmarking research and testimony include Florida Power and Light and (quite recently) Public Service Electric and Gas.

In our review of benchmarking precedents we came across three reports that have useful discussions of the role of benchmarking in regulation. The first, from the National Regulatory Research Institute, was designed to give regulators an overview of various methods for measuring performance in the hope that these methods would spread. This document is included as Attachment EGD/Union.2d.4.

The second document is a 2009 paper by Aoife Haney and Michael Pollitt which provided the results of a survey on benchmarking in utility regulation. This document is included as Attachment EGD/Union.2d.5. The third document is a 2012 report by Frontier Economics on the use of benchmarking in regulation in Northwest Europe. This document is included as Attachment EGD/Unon.2d.6.

e) Dr. Lowry confirms that these statements were made but believe that they are being taken out of context. These passages were part of a discussion of whether X factors should be customized to reflect special business conditions in Alberta. The AUC stated that

> Under the approach adopted by the Commission, the focus of the TFP study is on the industry productivity growth rate, not levels. As NERA explained, in this case the manifest differences between the companies in terms of their geographic areas and climatic conditions, operational characteristics, regulatory regime, size or any other consideration do not matter as much to the study as it only deals with the average of year to year changes in productivity growth. As such, the unique cost features of any particular company cancel out in the process."[5]

The AUC correctly noted that external business conditions, such as extensive forestation, which

[4] Lowry, M.N., Hovde, D., Kalfayan, J. and Fenrick, S., *The O&M Cost Performance of Enbridge Gas Distribution: Update*, February 23, 2004.
[5] Alberta Utilities Commission, *Rate Regulation Initiative, Distribution Performance-Based Regulation*, Decision 2012-237, September 12, 2012, p. 70.

affect the *level* of utility cost do not always affect the *trends* in their costs. This is not, however, an argument against considering the level of a company's *cost inefficiency* when setting its stretch factor. Change in X inefficiency (defined as distance from the efficiency frontier) is well known to be a driver of productivity growth. A reduction of X inefficiency is more likely the higher is the current level. The existence of *initial* cost-level inefficiencies is, of course, part of Dr. Makholm's rationale for assigning stretch factors in first-generation PBR plans. If the initial level of cost inefficiency were zero there would be no need for a stretch factor.

f) Dr. Lowry confirms that the Commission rendered this judgement. He disagrees with this policy and believes that other regulators have better policies. Benchmarking has been used to set stretch factors by regulators in several jurisdictions, including Ontario, New Zealand, Vermont, and Dr. Makholm's home state of Massachusetts. A second group of regulators, largely in Europe, have occasionally added a component similar to a stretch factor in IR plans designed to reflect the inefficiency of poorly performing utilities in benchmarking studies. Countries whose regulators have incorporated such "efficiency catch up" terms as part of an X factor include Mexico, Denmark, Austria, the Netherlands, Finland, Germany, and Norway.

L1.EGD/Union.3 – Stretch Factor

References:

a. PEG Evidence, April 11, 2018, page 3:

"We disagree with Dr. Makholm's 0% stretch factor recommendation, which is based on the premise that stretch factors are only appropriate in first generation IRMs."

b. Makholm Direct Evidence, EB-2017-0307, Exhibit B, Tab 2, p. 12:

"The AUC made three important determinations regarding the stretch factor that I conclude are reasonable: (1) it does not have a "definitive analytical source" like a TFP growth study, but relies on a regulators' judgment and regulatory precedent; (2) it has no influence by itself on the incentives for regulated companies to reduce costs; and (3) it serves to reflect the "immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime."[footnote omitted]

c. Alberta Utilities Commission 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Decision 20414-D01-2016 and Errata, February 6, 2017, paragraph 148.

"148. Among other arguments, the interveners submitted that a stretch factor is necessary as it strengthens the incentives under PBR. 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 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)." [footnotes omitted]

d. Alberta Utilities Commission 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Decision 20414-D01-2016 and Errata, February 6, 2017, paragraph 152-153.

"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 subject to the same high-powered incentives to control costs as the expenditures under I-X. 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," 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.**"** [footnotes omitted]

"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."

e. PEG Evidence, April 11, 2018, page 43:

"Dr. Makholm maintained in his direct evidence that stretch factors are appropriate only for first generation IRMs. The AUC embraced this principle in its decision in its first generic IRM proceeding. However, the AUC in in its second generation IRM decision seemed to include a stretch factor in its 0.30% X factor decision." [footnotes omitted]

Preamble: The companies would like to clarify Dr. Lowry's view on stretch factors.

Questions:

a. Confirm that Dr. Makholm stated in **reference b** that he agrees with the AUC's view that the stretch factor "serves to reflect the "immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime." If not confirmed, explain why.

b. Given the **references c and d**, confirm that the second generation PBR plan adopted by the AUC contained an incentive formula element that did not appear in its first generation plan. If not confirmed, explain why.

c. Please confirm that given the additional I-X element in its second generation plan, it is not correct to imply as Dr. Lowry did in his testimony in **reference e**, that the use of a stretch factor in its second generation PBR plan contradicted Dr. Makholm's statements in **reference b**. If not confirmed, explain why.

d. Please confirm that the AUC never made any finding, in either of its two PBR proceedings, that the stretch factor had a permanent role in PBR plans rather than a role related solely to the transition to a new PBR regime. If not confirmed, explain why.

Responses: The following responses were provided by PEG.

a. Dr. Lowry confirms that Dr. Makholm has stated his agreement with the ruling of the AUC in this matter. The AUC retained Dr. Makholm as a PBR consultant in Proceeding 566 and embraced his views on several PBR issues. However, the AUC is only one of many PBR practitioners, has less experience than several, and has taken positions on some issues that are out of step with those of the OEB and other experienced practitioners. The government of Alberta recently retained PEG to prepare a statistical benchmarking study of provincial power distributors.

   The AUC has taken positions on other issues that may also interest the OEB as it considers the Applicants' proposal and supportive evidence. These include the following statements.

   > The allowed ROE for 2017 of 8.50 per cent awarded in this decision will remain in place on

> an interim basis for 2018 and for subsequent years until changed by the Commission.[6]
>
> . . . [productivity] studies must provide information describing all aspects of the study, with considerable detail – including easily reproducible supporting calculations – on the effects, both separately and jointly, of changing each of the assumptions used, where the set of assumptions is widely defined, and includes assumptions with respect to data source selection.[7]
>
> . . . the Commission considers that as much incremental capital funding as possible should be managed under the Type 2 capital mechanism during the next generation PBR plans. The Commission has learned that the distribution utilities have considerable flexibility in dealing with the timing of their capital programs and are capable of accommodating many changes in circumstances without any immediate concerns about service quality and meeting their obligation to serve.[8]

b. Dr. Lowry confirms that the second generation PBR plan approved by the AUC has stronger incentive properties. Most notably, it greatly scales back the role of capital cost trackers after an unhappy experience with these trackers, which the Commission had embraced in the first generic PBR proceeding at the recommendation of NERA.

c. Dr. Lowry cannot fully confirm this statement. The AUC implicitly ruled that a stretch factor could be warranted if a prospective IR plan had stronger performance incentives than the previous plan.

> . . . 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. [italics added] For this reason, stretch factors are common in first-generation PBR plans.[9]

d. Dr. Lowry confirms this statement.

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[6] AUC Decision 20622-D01-2016, *op. cit.,* p. 73.
[7] AUC Decision 20414-D01-2016, *op. cit*., p. 43.
[8] AUC Decision 20414-D01-2016, *op. cit*., p. 52.
[9] Alberta Utilities Commission, *2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities,* Decision 20414-D01-2016, December 16, 2016, p. 38.

L1.EGD/Union.4 – Transparency, Objectivity, and Consistency and Stretch

References:

a. PEG Evidence, April 11, 2018, page 3:

"We disagree with Dr. Makholm's 0% stretch factor recommendation, which is based on the premise that stretch factors are only appropriate in first generation IRMs. The Board is correct to reconsider stretch factors for all utilities on a regular basis using statistical benchmarking. A utility is no more certain to be efficient after one or even several terms of IR than firms in unregulated markets are certain to be efficient. Several other regulators have approved stretch factors after the first generation of IR."

b. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Decision 2012- 237, September 12, 2012, paragraph 353.

"353. Because the parameters of the PBR formula will be used to determine customer rates in a contested regulatory process and those rates will be in place for a number of years, the significance of the objectivity, consistency, and transparency of the TFP analysis to be employed in calculating the X factor cannot be understated."

c. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Decision 2012- 237, September 12, 2012, paragraph 479.

"479. The Commission agrees with the rationale for a stretch factor put forward by EPCOR, NERA, AltaGas, the UCA and Calgary. The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime."

Preamble: The companies wish to understand Dr. Lowry's position on stretch factors.

Questions:

a. Confirm that the AUC emphasized transparency, objectivity and consistency as parameters for the TFP analysis used to calculate X factors. If not confirmed, explain why.

b. Confirm that the AUC's position on transparency, objectivity and consistency in TFP growth studies was consistent with its findings on the source of the stretch factor. If not confirmed, explain why.

c. Confirm that the AUC's position is contrary to Dr. Lowry's statements about the stretch factor having a foundation as a permanent part of a multi-generation PBR regime. If not confirmed, explain why.

Responses: The following responses were provided by PEG.

a. Dr. Lowry confirms that the AUC emphasized transparency, objectivity, and consistency as guiding criteria for the TFP analysis used to calculate X factors. These goals were at times emphasized over other important goals such as relevancy and accuracy. Most notably, they chose a study of power distribution productivity by NERA, which they considered transparent, to calibrate the X factors of provincial gas utilities instead of a study of gas utility productivity that they deemed less transparent which was prepared by a noted expert.

   Similarly, the AUC chose the TFP trend of the entire U.S. power distribution industry to avoid a search for a more appropriate peer group which it feared might not be fully objective. In contrast, Ontario bases X factors on the TFP trends of Ontario power distributors, while Massachusetts and Maine on several occasions based X factors on the TFP trends of Northeast U.S. utilities. Dr. Makholm had himself proposed a regional peer group in a past Alberta PBR proceeding.

   The Commission sought, in this and other rulings on PBR issues, to contain controversy, but ironically embraced a method for measuring TFP devised by NERA that has engendered increasing controversy. There is a legitimate theoretical debate about the correct benchmark year adjustment as well as empirical debates about the average service life and the appropriate sample period. A great deal of discretion must therefore be exercised to choose the right X factor from NERA-style productivity research. Dr. Makholm does not appear in every proceeding to provide a recommendation that balances many considerations. This was not fully foreseen at the time that the AUC first embraced NERA's research results.

b. Dr. Lowry confirms that concerns about objectivity prompted the AUC to eschew the use of benchmarking in the establishment of X factors. However, there is no reason that a benchmarking study cannot be transparent and consistent with the cost theory and statistical methods supporting productivity trend research.

c. Dr. Lowry confirms that the AUC did not embrace his advice and this issue and has instead embarked on a path quite different from that followed by Ontario's regulators.

L1.EGD/Union.5 - Calculating Capital

References:

a. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Transcript Volume 13, May 12, 2012, p. 2590, lines 8-17:

Dr. Lowry: "You haven't noticed, but I don't think Dr. Makholm or any other party using their approach to capital costing to shed light on the proper design of the inflation measure, because those other approaches to capital costing like the geometric decay that Dr. Schoech often favours and that I've used in the past and the one hoss shay that Dr.
Makholm uses, the input prices that go along with those don't remotely resemble the way input prices affect costs growth under regulatory accounting, whereas my approach is expressly designed to be relevant for that purpose."

b. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Transcript Volume 13, May 12, 2012, p. 2744, line 5 to p. 2745, line 24:

Question from Mr. L. Smith, Q.C., Counsel for ATCO Electric Ltd. and ATCO Gas: "Okay. Now, when I look at the TFP growth rates for 1999 -- and then I think what I'm going to ask you to do, Dr. Lowry and Mr. Chairman and members, is just sort of focus on '99 to 2004, which is the period in which TFP -- now, this is U.S. national gas industry total factor productivity growth rates, are reproduced from the four studies which Dr.
Lowry has prepared. We see from '99 through 2004 what I would put to you to be widely varying results, sir.

Would you agree? Let's go through it."

Answer from Dr. Mark Lowry, witness for Consumers Coalition of Alberta: "No, I can respond to that. The year-to-year results are sometimes quite different. The trends are much more similar. We -- I think I've got this calculated right. We looked at the trends over the common periods and found that the one in this proceeding was 1.21 percent. The more recent San Diego study was 1.08. The Ontario study before that was 1.08, and the only one that was more of an outlier was the SoCalGas study over that period.

As for those year-to-year differences, I said before they were -- a big part of that is due to -- a lot of reasons. I've already given you a lot of reasons why they could be different, but the biggest thing to take note of is the difference between the studies that used the geometric decay approach and the one that used the cost of service approach to capital costing and which of the two yields numbers that raise the eyebrow a little bit, like TFP declining by 1 percent in a few years, why that would be the geometric decay approach.

And that's an example of the greater instability of the geometric decay approach because the cost shares on capital vary wildly under geometric decay.

And why? Because they include capital gains, which, obviously, are not a consideration under traditional regulation, but they can really swing a result in a year. Some years capital has surprisingly little weight because of capital gains and then other years it will be a much bigger amount.

Well, this is one of the reasons that I stepped away from using geometric decay except in a context where people really appreciate the tradition of having always done it that way. The cost of service approach on a year-to-year basis -- well, in the long run the trends are similar. On a year-to-year basis everything is a little more sensible, and that goes for the input price index as well as the productivity index. I think this is what you're seeing here."

c. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Transcript Volume 13, May 12, 2012, p. 2746, lines 2-21:

Question from Mr. L. Smith, Q.C., Counsel for ATCO Electric Ltd. and ATCO Gas: "I have the evidence you filed in this proceeding with a TFP of .21 and a SoCalGas negative 1.19, and I have San Diego results which are a negative .65 and the Ontario results which are a positive .52.

Now, we're supposed to be measuring the same thing, aren't we?"

Answer from Dr. Mark Lowry, witness for Consumers Coalition of Alberta: "Well, these indexes are designed to measure trends in the longer term, and as I just tried to explain, with the geometric decay approach, you can expect to see more volatility than you will with a cost of service approach.

And I think that's what you're looking at. I mean, you're going from a COS to a geometric decay and then to a COS and then back to a geometric decay, and the two geometric decay ones are not so different from each other.

And also, as I have just said, the trends over this period actually are pretty similar, excepting the SoCalGas study which uses those regional weights and has the maximum number of differences from the present. There are a lot of things done differently in that study."

d. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Transcript Volume 13, May 2, 2012, p. 2748, lines 8-25:

Question from Mr. L. Smith, Q.C., Counsel for ATCO Electric Ltd. and ATCO Gas: "So five years from now, when we have to revisit all this and see if we got the right TFP growth rates and so on, which one do we go back to?"

Answer from Dr. Mark Lowry, witness for Consumers Coalition of Alberta: "We'll do -- if I'm involved, we'll do whatever makes the most sense at the time."

Question from Mr. L. Smith, Q.C., Counsel for ATCO Electric Ltd. and ATCO Gas: "For whom?"

Answer from Dr. Mark Lowry, witness for Consumers Coalition of Alberta: "For the calibration of an X factor in Alberta. Likely will include the COS because I've been using the COS consistently in regulatory applications that produce X factors. The one exception is California, but that's not used for X factor calibration. It's just an informational aid to the Commission. And by the way, the other two big utilities in California have gotten out of filing these studies. They say it's a waste of time because it's not even used in the regulatory arena, which is true.

I mean, it's not used to set their rates, and so they say, 'Why do we even have to do these studies?' And they've been given permission to stop doing them."

e. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Interrogatory NERA-CCA-2:

Reference: PBR Plans for Alberta Energy Distributors – Pacific Economics Group Research LLC – Index Research and Incentive Regulation, Price and Productivity Indexes, Calculating Capital Costs, Section 2.1.4, p. 14

Preamble: PEG states that
"The cost of service ("COS") approach to calculating capital cost, prices, and quantities is designed to approximate the way that capital cost is calculated in utility regulation.
This approach is based on the assumption of straight line depreciation and the historic (book) valuation of capital. The capital price is a function not simply of the *current* construction price but, rather, of a weighted average of current and past prices. The intuition is that inflation in the rate base results from the fact that the cost of constructing plant that is two, four, and twenty years old is higher than it was last year. The weight for a given year is larger the larger is its representation in the current value of the rate base. Weights tend to be larger for more recent years than for earlier years. The COS capital price also depends on the weighted average cost of acquiring funds in capital markets."

Request:
a. Please describe and explain PEG's views on what drives "the way that capital cost is calculated in utility regulation" in the United States and Canada.

b. Does the calculation of capital costs for productivity measurement purposes differ in a fundamental way from the way that capital costs are derived by regulators and courts of law for ratemaking purposes? Please fully explain your response.

Response:
a. Dr. Lowry has not considered what "drives" the way that capital cost is calculated in utility regulation in the United States and Canada.

b. There are numerous ways to calculate capital cost for use in productivity measurement. The recommended approach depends upon the use of the study. When the study is for use in the selection of an X factor for a multi-year rate plan, Dr. Lowry believes that it is advantageous to use a methodology that mirrors how capital cost is calculated in rate cases.

<u>Preamble</u>: The companies would like to understand Dr. Lowry's use of geometric decay and cost of service for measuring capital quantity.

<u>Questions</u>:

a. Confirm that in AUC Proceeding 566, Dr. Lowry used the "cost of service" or "COS" method for measuring capital quantity. If not confirmed, explain why.

b. Confirm that in this proceeding, Dr. Lowry used the "geometric decay" or "GD" method for measuring capital quantity. If not confirmed, explain why.

c. Confirm that in **references b and c**, Dr. Lowry provided examples of results with greater instability because of the geometric decay approach and that he steps away from using that approach except in situations where people appreciate the tradition of having always used such an approach. If not confirmed, explain why.

d. Confirm that in **reference d**, Dr. Lowry stated that he would likely use COS because he has used that method consistently in regulatory applications that produce X factors. If not confirmed, explain why.

e. Confirm that Dr. Lowry believes that it is advantageous in a multi-year rate plan to use a methodology that mirrors how capital cost is calculated in rate cases. If not confirmed, explain why.

f. Confirm that Dr. Lowry understands that the current proceeding involves setting a rate mechanism for multiple years. If not confirmed, explain why.

g. Explain the discrepancy between Dr. Lowry's use of COS in AUC Proceeding 566 and GD in this proceeding. If not confirmed, explain why.

Responses: The following responses were provided by PEG.

a. Dr. Lowry confirms that he used a COS approach to measuring capital costs and quantities in AUC Proceeding 566.

b. Dr. Lowry confirms that he has featured results for a geometric decay ("GD") approach to measuring capital costs and quantities in this proceeding.

c. Dr. Lowry confirms making these statements in the AUC proceeding. However, his occasional use of the COS approach has not been motivated by a perception that GD produces volatile TFP results.

   Dr. Lowry initially developed the COS approach for use in Maine and Massachusetts PBR proceedings chiefly because the *input price* trends of utilities are often a central issue in these proceedings. U.S. regulators typically choose macroeconomic inflation measures such as the gross domestic product price index ("GDPPI") for rate and revenue cap indexes. In the United States, macroeconomic measures of the inflation in the prices of final goods and services tend to understate the input price growth of utilities due to the rapid productivity growth of the economy. For these reasons, there is a particular need in some U.S. PBR proceedings to consider whether an adjustment should be made to the X factor for the typical difference between macroeconomic inflation and the input price inflation of utilities. For example, this was an issue in a recent Massachusetts PBR proceeding and in a Central Maine Power proceeding in which Dr. Makholm was a witness. [10]

[10] See Massachusetts Department of Public Utilities, DPU-17-05, *Order Establishing Eversource's Revenue Requirement*, November 30, 2017 and the direct testimony of Neil Talbot and Ronald Norton for Maine's Office of the Public Advocate in Maine PUC Proceeding 99-666, May 19, 2000.

Input price indexes based on the GD and OHS approaches can be quite volatile due to the replacement valuation of assets and the consequent need for a capital gains term. The COS approach to measuring capital cost has an input price index that is much more stable and suitable for these inflation differential calculations than either the GD or the one hoss shay approach.

The need for COS specifications in X factor calibration studies has been declining, however. Index-based PBR now occurs chiefly in Canada, and regulators in Ontario and other Canadian provinces have in several recent proceedings chosen inflation measures for rate and revenue cap indexes that are more industry-specific. The AUC, for example, ruled that

> . . . since both components of the approved I factors can be considered input-based price indexes, there is no need in this case for the Commission to consider an adjustment to TFP for an input price differential or productivity differential in the calculation of the X factor.[11]

Additionally, the multifactor productivity trend of the economy places less of a drag on macroeconomic inflation measures in Canada than it does in the U.S.

Dr. Lowry has taken a fresh look at the relative volatility of capital *quantity* indexes using the GD and COS approaches. He calculated volatility metrics for the growth rates of the capital quantity indexes he has used in publicly available gas productivity studies using COS and geometric decay. He found that the volatility of the *COS* capital quantity indexes was actually greater than the volatility of the *GD* indexes. In his Alberta testimony, Dr. Lowry was thus right to point to different capital cost treatments as a source of differences in his productivity results but misstated which kind of capital quantity index tends to be more volatile.

Dr. Lowry also acknowledges that the familiarity of a regulatory community with GD would be one valid reason for using it in an X factor calibration study. GD has, for example, typically been used in productivity studies considered in Ontario, including one submitted by Enbridge Gas Distribution witness Concentric Energy Advisors.

There are many other arguments for using GD. For example, GD is mathematically much easier than COS to code and for other parties to review. The assumption of gradual decay produces productivity trends that tend to be similar to those produced by the COS approach. For example, increasing system age will tend to accelerate capital productivity growth.

d. Dr. Lowry cannot confirm this statement. He stated in the quoted passage that he reconsiders the appropriate approach to capital cost measurement in every project. He had used the COS approach in several recent proceedings at the time of his quoted Alberta remarks. However, he has used the GD method in most of his TFP and econometric total cost research and testimony over the years. He has been swinging back to the GD approach for X factor calibration studies in Canadian PBR proceedings. In the second Alberta proceeding he presented productivity results using both GD and COS. He used the GD approach in his 2017 testimony for the OEB on the productivity trends of U.S. hydroelectric power generators. He also used GD in recent cost-level benchmarking studies for Green Mountain Power and Alberta’s Utilities Consumer Advocate. He is inclined to feature GD in future Canadian proceedings if industry-specific inflation measures continue to be the norm and the TFP growth of the economy remains sluggish.

[11] AUC Decision 2012-237, *op. cit*., p. 89.

e. Dr. Lowry believes that, *all else being equal*, an approach to measuring capital cost that mirrors how capital cost is calculated in rate cases is advantageous in TFP studies intended to calibrate X factors. This is an advantage of COS approaches to capital cost measurement. It is also an advantage of GD approaches relative to OHS approaches. However, there are other criteria for choosing an approach to capital cost measurement, as Dr. Lowry notes in Section 3.2 of his report.

f. Dr. Lowry agrees that this proceeding will establish a rate adjustment mechanism that will be applicable for several years.

g. Dr. Lowry used the GD method in this proceeding for several reasons.

- The COS approach to measuring capital cost is particularly difficult to code and review.
- He anticipated that the inflation measure in the rate or revenue cap index would be industry-specific. Even if it were not, the slower MFP growth of the economy has historically placed less drag on a macroeconomic inflation measure in Canada than it does in the States. Hence, the advantage of the COS approach in calculating inflation differentials is less germane.
- The COS approach is not ideal for measuring trends in cost efficiency since it values plant in historical dollars.
- Amongst the more stylized monetary approaches for measuring capital cost, such as the one hoss shay and geometric decay, the GD approach has numerous advantages. Dr. Lowry discusses some of these advantages in Section 3.2 of his report.
- A faster productivity growth trend was *not* a consideration of Dr. Lowry in choosing GD. Table EGD/Union.5g presents gas utility productivity results for the full sample period using a methodology that differs from that he featured in his report only in using a COS method rather than the GD method. It can be seen that the TFP growth of sampled gas utilities averaged -0.04% -- very close to zero.

Table EGD/Union.5g
Productivity Trends of U.S. Gas Distributors[1]

	Output	Input Quantities			Productivity		
Year	**Customers**	**OM&A**	**Capital**	**Total**	**OM&A**	**Capital**	**TFP**
	[A]	**[B]**	**[C]**	**[D]**	**[A-B]**	**[A-C]**	**[A-D]**
1999	2.12%	0.75%	1.27%	1.33%	1.37%	0.85%	0.79%
2000	2.67%	3.62%	1.78%	2.55%	-0.96%	0.88%	0.12%
2001	1.30%	-5.02%	0.79%	-1.49%	6.33%	0.52%	2.80%
2002	0.82%	-3.89%	0.76%	-1.11%	4.72%	0.07%	1.93%
2003	2.21%	2.42%	1.08%	1.53%	-0.21%	1.13%	0.68%
2004	0.94%	2.93%	0.52%	1.47%	-1.98%	0.43%	-0.52%
2005	1.39%	1.77%	0.10%	0.81%	-0.38%	1.29%	0.59%
2006	0.77%	-3.92%	0.22%	-1.46%	4.69%	0.55%	2.23%
2007	0.62%	3.18%	0.08%	1.32%	-2.57%	0.54%	-0.70%
2008	0.33%	0.32%	0.25%	0.35%	0.01%	0.08%	-0.02%
2009	0.29%	3.26%	0.62%	1.77%	-2.97%	-0.34%	-1.48%
2010	0.34%	1.81%	0.89%	1.34%	-1.47%	-0.55%	-1.00%
2011	0.56%	1.02%	0.69%	0.90%	-0.46%	-0.13%	-0.34%
2012	0.87%	2.05%	1.67%	2.29%	-1.19%	-0.80%	-1.42%
2013	0.66%	2.46%	2.40%	2.15%	-1.80%	-1.75%	-1.49%
2014	0.85%	5.55%	3.17%	4.16%	-4.70%	-2.32%	-3.31%
2015	0.94%	-2.14%	3.58%	1.10%	3.08%	-2.64%	-0.16%
2016	0.88%	-3.55%	3.87%	0.35%	4.43%	-2.99%	0.53%
Average Annual Growth Rates							
1999-2016	**1.03%**	**0.70%**	**1.32%**	**1.07%**	**0.33%**	**-0.29%**	**-0.04%**

Notes

[1]Research used cost of service and a 1994 benchmark year for capital quantity.

L1.EGD/Union.6 - Calculating Capital

References:

a. PEG evidence, page 20-21

> "For example, GD [Geometric Decay] is used to calculate capital quantities in the National Income and Product Accounts of the US and Canada. Statistics Canada also uses GD in its multifactor productivity studies for sectors of the economy."

Preamble: The companies would like to confirm Dr. Lowry's understanding of capital specification in productivity growth studies.

Questions:

a. Confirm that data used to calculate data in the examples listed in **reference a** is not collected in the same manner as FERC Form 1. If not confirmed, explain why.

b. Describe the difficulties associated with data used to calculate capital quantities and multifactor productivity studies described in **reference a**.

c. Confirm that FERC Form 1 data does not encounter the same difficulties described in part b. If not confirmed, explain why.

Responses: The following responses were provided by PEG.

a. This statement is confirmed.

b. Dr. Lowry believes that data on the value of retirements are not as readily available outside the utility industry. The assets under consideration have diverse asset lives that are frequently not well known.

c. Data on the value of retirements are available on FERC Form 1. However, the average service lives of the retired assets are not well known, as Dr. Lowry explains in his report.

L1.EGD/Union.7 – Electric v. Gas

References:

a. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Transcript Volume 13, May 2, 2012, p. 2448, line 4 to p. 2449, line, 8:

   Answer from Dr. Mark Lowry, witness for Consumers Coalition of Alberta: "Well, I was, as I understand it, retained to provide commentary on an appropriate X factor for Alberta utilities, and one of the parties to the proceeding, Dr. Makholm, alleged that the -- that his research on the productivity trend of US power distributors would be suitable for use in an application to the gas companies. So that has drawn me into the issue of the strengths and weakness of his research.

   …

   "Well, I, among other things, have spent quite a bit of time going through Dr. Makholm's study to see whether it could possibly be appropriate for a gas distributor, and along the way because Dr. Makholm has elected to use a volumetric output appendix that is highly volatile, we have gone a couple steps further to try to get down to the underlying cost based productivity trends to see – for example, to evaluate a contention such as that the alleged productivity slowdown is due to restructuring.

   It's hard to assess that when you're just looking at the volumetric output indexes that Dr. Makholm has provided because they're so -- they have eccentricities. For example, perhaps the utilities that are subject to restructuring also had larger DSM programs, so their volumes grew more slowly, so it might seem that their productivity growth was slower, when in actuality the underlying cost based productivity has actually been more rapid."

b. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Decision 2012-237, September 12, 2012, paragraphs 373-375:

   "Based on the evidence in this proceeding, and because of the similarities in the institutional framework, business environment and regulatory requirements between the gas and electric distribution industries, the Commission finds that TFP research from one industry can be used to estimate productivity growth for firms in the other industry when transparent and robust data for both industries are not available.

   However, parties could not agree on whether the TFP estimates from PEG's study and various other studies on the productivity trends of Canadian and the U.S. gas distributors used by other regulators, as well as Statistics Canada's MFP indexes, represent a superior indicator of TFP for gas distribution companies as compared to the TFP estimate from NERA's study of the electric distribution industry.

   As set out in Section 6.3.7 of this decision, because the Statistics Canada MFP indexes include power generation and transmission in the electric sector and water systems in the natural gas sector, these indexes are not suitable for estimating the TFP for distribution companies. With respect to the TFP studies of Canadian gas distributors prepared for other regulators (such as the Ontario Energy Board and the Gaz Métro Task Force) that PEG discussed, the Commission considers that while this productivity research can provide a useful reference for determining the general reasonableness and direction of a productivity estimate for the gas distribution companies, these studies cannot be viewed as substitutes for NERA's TFP study."

c. PEG Evidence, April 11, 2018, page 24:

"Our first concern is that the Applicants, who will run one of North America's largest gas utilities, would submit a study of power distribution industry TFP in this proceeding but not a study of gas utility industry productivity. While there are admittedly similarities, power and natural gas distribution have noteworthy differences, and the Amalco IRM would apply to gas transmission and storage services of the Amalco as well as its distributor services."

<u>Preamble</u>:

The companies want to confirm Dr. Lowry's view on electric and gas distribution data.

<u>Question</u>:

When Dr. Makholm and Dr. Lowry both appeared in the AUC Proceeding 566, confirm that in AUC Decision 2012-237, the AUC agreed that Dr. Makholm's study of TFP growth for the electric distribution industry was applicable to the gas distribution industry. If not confirmed, explain why.

<u>Response</u>: The following response was provided by PEG.

Dr. Lowry acknowledges that in AUC Proceeding 566 the AUC used Dr. Makholm's estimate of the TFP trend of U.S. power distributors to calibrate the X factors for two Alberta gas distributors. However, this is not because Dr. Makholm's study was deemed more relevant to gas distributors or more methodologically appropriate than the study of gas utility productivity which Dr. Lowry submitted in the proceeding. The NERA study was described as an "acceptable starting point" for gas X factor calibration.

Even though Dr. Lowry had testified on gas utility productivity in numerous past proceedings for both utilities and regulators and had published articles on his gas productivity research in scholarly journals, the AUC questioned the transparency of his work. For example, he used confidential capital cost data that he had obtained from American Gas Association members. The AUC considered this to be a disadvantage, rather than evidence that Dr. Lowry had special expertise on gas productivity. PEG has not used these data in this proceeding.

Gas utility data are difficult to gather because they are filed with state commissions. These data were therefore rented from a specialist vendor, SNL Financial. Stakeholders were asked to sign confidentiality agreements to examine these data. This is not an unusual arrangement in Ontario and other jurisdictions.

L1.EGD/Union.8 – TFP output measure

References:

a. PEG Evidence, April 11, 2018, page 33:

"Finally, we replaced NERA's volumetric output index with the number of customers served."

b. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Decision 2012- 237, September 12, 2012, paragraphs 378:

"378. Accordingly, the Commission finds that, in the absence of superior TFP data for the gas distribution industry, NERA's TFP study is an acceptable starting point for determining a productivity estimate for Alberta gas distribution companies."

Preamble:

The companies want to confirm Dr. Lowry's view on output specification.

Question:

When Dr. Makholm and Dr. Lowry both appeared in the AUC Proceeding 566, confirm that in AUC Decision 2012-237, the AUC agreed that the use of a volumetric output index was appropriate for measuring productivity for the gas distribution industry. If not confirmed, explain why.

Response: The following response was provided by PEG.

Dr. Lowry cannot confirm this statement. He believes that the AUC glossed over the issue of whether NERA's volumetric output index was appropriate for measuring gas utility productivity. The AUC did acknowledge that the number of customers was the most appropriate output variable when calibrating the X factor for a revenue per customer indexing mechanism.

> During the hearing, Dr. Lowry also explained that since under a revenue-per-customer cap plan, a company's revenues are driven by customer growth and are largely insensitive to the amount of energy sold, the number of customers is the relevant output measure to use for TFP studies used in a revenue-per-customer cap PBR plan. In contrast, under a price cap plan, a change in the amount of energy sold has an immediate effect on a company's revenues, and thus the use of a volumetric output measure is justified. Accordingly, the CCA argued that output measures that place a heavy weight on volumetric and other usage should be used to determine the output index for TFP studies used in the context of a price cap PBR plan, while the number of customers should be used to determine the output index for TFP studies used in the context of a revenue-per-customer cap PBR plan. NERA agreed with this logic.[12] [footnotes omitted] . . .
>
> . . . The Commission agrees with Dr. Lowry and his colleagues at PEG that for revenue-per-customer cap plans, the number of customers, rather than a volumetric output measure, is the correct output measure for a TFP study.

[12] AUC Decision 2012-237, *op. cit*., p. 80.

L1.EGD/Union.9 – Dr. Makholm's Evidence

Reference:

a. Makholm Direct Evidence EB-2017-0307, Exhibit B, Tab 2, p. 22:

Q28. What is this section of your testimony about?

A28. I briefly describe my methods for computing TFP growth for the regulated distribution component of local utility operations. Those methods include isolating the distribution component of such utilities and then measuring the various inputs and outputs that result in TFP growth measures. For a longer and more comprehensive explanation of my methodology, please see my report in Alberta Proceeding 566, attached as Exhibit JDM-2. I provide a list of all documents I relied upon as Exhibit JDM-5.

Q29. Please briefly explain your TFP methodology.

A29. My TFP studies for EGD, Union and the distribution industry all utilize the Tornqvist/Theil index methodology to construct output, input and TFP indexes using the various components of outputs and inputs. For my study of the distribution industry I use a population of 65 US electric and combination electric and gas distributors over the time period 1973-2016.[footnote omitted] I create individual TFP indexes and growth rates for each company and year and then take a weighted average of these growth rates to calculate average TFP growth over the time period. [footnote omitted] For EGD and Union, I use their own company-specific data to calculate average TFP growth for each company. The EGD study spans the years 1993-2016, while the Union study covers the time period 2001-2016.

b. Answer to Interrogatory from Ontario Energy Board Staff ("Staff"), Exhibit C.STAFF.34, part b):

Question: b) Is the report filed in Exhibit JDM-2 the first or the second NERA report? If it is the first report, please file the second report.

Response: b) Please see Atachment 2 for the NERA second report in Alberta Proceeding 566.

c. PEG Evidence, April 11, 2018, p. 32:

"We are also concerned that NERA's documentation of their research for the Applicants in his direct evidence is substandard for an IRM filing in Ontario. For example, he did not discuss his methods for calculating the TFP trends of Enbridge and Union. To describe NERA's US power distribution productivity research, Enbridge attached his first report in the 2012 Alberta proceeding even though NERA revised their methodology during the proceeding and presented new results."

Preamble: The companies wish to confirm Dr. Lowry's understanding of Dr. Makholm's evidence.

Questions:

a. Confirm that in **reference a**, Dr, Makholm states that "My TFP studies for EGD, Union and the distribution industry all utilize the Tornqvist/Theil index methodology to construct output, input and TFP indexes using the various components of outputs and inputs." If not confirmed, explain why.

b. Confirm that Dr. Makholm attached his first report in Alberta Proceeding 566 as Exhibit JDM-2 to his evidence provided in this proceeding. If not confirmed, explain why.

c. Confirm that Dr. Makholm attached his first report in Alberta Proceeding 566 as Exhibit JDM-2 to his evidence provided in this proceeding to provide "…a longer and more comprehensive explanation of [his] methodology (**reference a**). If not confirmed, explain why.

d. Confirm that Dr. Makholm provided his second report in Alberta Proceeding 566 in response to Exhibit C.STAFF.34 part b) (**reference b**). If not confirmed, explain why.

Responses: The following responses were provided by PEG.

a. Dr. Lowry confirms that this statement was made but notes that this is an extremely high-level discussion of methodology. TFP witnesses in Ontario typically submit custom reports that describe all of their work in a proceeding in considerable detail. See for example, the productivity evidence of Power Systems Engineering ("PSE")[13] and London Economics ("LEI")[14] in recent OEB proceedings.

b. The statement is confirmed, but this report is not an entirely accurate portrayal of the research methods NERA used in its work for the Applicants and does not discuss their studies of Enbridge and Union's productivity. In the technical conference Dr. Makholm acknowledged one change to his methodology for measuring US power distribution TFP that he has made since this report.

c. This statement is confirmed.

d. This statement is confirmed.

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[13] OEB Proceeding EB-2017-0049, Exhibit A-3-2, Attachment 1, *Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry*, prepared by PSE, Filed March 31, 2017.

[14] OEB Proceeding EB-2016-0152, Exhibit A1-3-2, Attachment 1, *Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry,* prepared by LEI, Filed May 27, 2016.

L1.EGD/Union.10 – Length of TFP Growth Study

References:

a. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Decision 2012-237, September 12, 2012, paragraphs 302-304:

"302. PEG agreed that there is some value in a shorter period because even long term drivers of TFP growth such as technological change can vary over a period of several decades. Dr. Lowry noted that in the past he often advocated a period of at least 10 years, but recent empirical results and NERA's testimony persuaded him that a minimum of 15 years is typically more desirable."[footnote omitted]

"303. In reviewing NERA's TFP estimate, PEG submitted that the relevant time period should essentially focus on the concept of a business cycle. As Dr. Lowry explained, because NERA's study used delivery volumes as an output measure, the resulting TFP is highly sensitive to changes in economic conditions. Therefore, Dr. Lowry advocated that when choosing the relevant time period, it is necessary to choose a start and end date that are at a similar point with respect to the business cycle, so that the key demand drivers are at the same levels.**"**

"304. In that regard, Dr. Lowry observed that the last two years in NERA's sample, 2008 to 2009, were characterized by a deep recession and he recommended excluding these years to avoid distorting the long-run TFP trend. As a result, the CCA expert recommended a sample period for NERA's TFP study that ends in 2007 (avoiding the two recession years) and begins in 1988, a year with similar values for two key volume driver variables, cooling degree days and the unemployment rate.**319** For the purpose of its MFP study of U.S. gas distribution companies, PEG used the sample period of 14 years from 1996 to 2009 based on Dr. Lowry' judgment and experience. PEG noted that this was the longest period available for the dataset on which PEG relied.**321** The CCA's expert explained that a 2009 sample end date was acceptable in this case, since his study did not use a volumetric output index and therefore would not be subject to volume related impacts of the 2008 to 2009 recession."

b. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Decision 2012-237, September 12, 2012, paragraphs 312, 316-317:

"312. The Commission agrees with NERA's view that a deviation from reliance on the longest period of available data requires support that a structural break in the industry has occurred. The Commission also agrees that the determination of whether a structural break has occurred demands the scrutiny of academic experts, peer review and testing by parties independent of the current proceeding."

"316. In that regard, the Commission considers that Dr. Lowry's approach to determining the relevant time period to capture the entire business cycle in the sample period represents an improvement over the companies' approach of focusing on the most recent 10 to 15 years of data. However, PEG's method is also not entirely devoid of subjectivity, as judgement has to be applied as to what start and end points

> to use. For example, PEG offered that cooling degree days and the unemployment rate be used to select similar levels of a business cycle. Building on this logic, PEG recommended that recession years 2008 and 2009 be excluded from the analysis, because in this period the volumetric output indexes were extraordinarily depressed.The gas companies did not agree with PEG's choice of start and end dates and submitted that this method resulted in biased and subjective estimates of TFP trends. In AltaGas' view, it was vital that years 2008 and 2009 be included in the study to arrive at a balanced assessment of TF. [footnotes omitted]
>
> "317. In the Commission's view, NERA's approach of using the longest time period available allows a smoothing out of the effects of variations in economic conditions on the estimate of TFP growth, without engaging in a subjective exercise of picking the start and end points of a business cycle. Notably, the CCA seemed to reach a similar conclusion and indicated that if the years 2008 and 2009 were to be included in the study, the length of a sample period would have to be considerably longer than 10 to15 years and NERA's use of the full set of 1972 to 2009 data becomes reasonable, subject to certain other reservations about NERA's analysis."

Preamble**:** The companies would like to understand Dr. Lowry's study time-period.

Question**:**

When Dr. Makholm and Dr. Lowry both appeared in the AUC Proceeding 566, confirm that in AUC Decision 2012-237, the AUC agreed with Dr. Makholm's approach of using the longest time-period available for a TFP growth study.

Response: The following response was provided by PEG.

Dr. Lowry confirms that the AUC embraced TFP results for NERA's full sample period in AUC Proceeding 566. He believes that they did this because they thought that this was the most objective means of finessing the considerable volatility in NERA's volumetric output index.

> NERA's approach of using the longest time period available allows a smoothing out of the effects of variations in economic conditions on the estimate of TFP growth, without engaging in a subjective exercise of picking the start and end points of a business cycle."[15]

However, in its second generic PBR proceeding the AUC made a different decision. The Commission having embraced NERA's general method in the first proceeding, two utility witnesses argued energetically in the second proceeding in favor of using NERA's method but with a truncated and more recent sample period. The AUC set aside its concern about subjectivity by exercising its discretion to balance results using Dr. Makholm's full sample period and a truncated sample period, along with results from a study by Dr. Lowry, in choosing a 0.30% X factor.[16] Dr. Makholm has in this proceeding used similar discretion in proposing a 0% base TFP trend for the Amalco which differs from the trends for either his full sample period or a truncated sample period.

[15] AUC Decision 2012-237, *op. cit*.
[16] AUC Decision 20414-D01-2016, *op cit*.

L1.EGD/Union.11 – Customer Care Costs

References:

a. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Transcript Volume 14, May 3, 2012, p. 2894, line 24 – p.2885, line 16:

   Question from the Chair: "So what are customer care expenses? What do you mean by that? Things like -- well, you tell me."

   Answer from Dr. Mark Lowry, witness for Consumers Coalition of Alberta: Well, it's pretty much anything you can think of. We left the metering in because with the understand that the utilities still did the metering here, so we left that part in.

   But customer account expenses, customer service and information, which would include DSM. That's out. And then a little bit for sales. I mean, in the United States there's a small category for sales.

   Question from the Chair: So really what you're talking about is the stuff that's done on the retail level?

   Answer from Dr. Mark Lowry, witness for Consumers Coalition of Alberta: Yes.

   Question from the Chair: So it wouldn't be billing, for example, because even a wholesale company has to do some billing?

   Answer from Dr. Mark Lowry, witness for Consumers Coalition of Alberta:No. It includes the billing. The billing is out.

   Question from the Chair: Okay.

   Answer from Dr. Mark Lowry, witness for Consumers Coalition of Alberta: Of both of our indexes.

b. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Transcript Volume 14, May 3, 2012, p. 2814, lines 2-9.

   Question from Ms. N. McKenzie, Counsel for AltaGas. What intermediate inputs included in the gross output productivity index were excluded from your gas distribution MFP study?

   Answer from Dr. Mark Lowry, witness for Consumers Coalition of Alberta: The customer care expenses were the main category that's relevant to our study. We also excluded gas and upstream transmission costs. But in terms of those that are subject to base rate inputs, it would be the customer care and the customer service and information expenses.

c. PEG Evidence, April 11, 2018, pp.38-39:

   "We calculated indexes of trends in the OM&A, capital, and total factor productivity of each sampled utility in the provision of gas transmission, storage, and distributor services. Costs of administrative and general functions and many customer services (e.g., billing and collection) were included in the study. The costs considered also encompassed taxes and pension and other benefit expenses."

"We also excluded customer service and information expenses. These costs grew briskly during the sample period for many utilities due to the growth in utility CDM programs. The cost of these programs is not itemized in the U.S. data for easy removal. CDM programs are not covered by the indexing provisions of the Applicants' proposed IRM."

Preamble: The companies would like to understand Dr. Lowry's approach to customer care costs.

Questions:

a. With regard to **reference a**, please provide Dr. Lowry's definition of "customer care costs."

b. With regard to **reference b**, please confirm that Dr. Lowry excluded "customer care costs" from his TFP growth estimate in AUC Proceeding 566.

c. With regard to **references a and b, and parts a and b of this question**, explain whether Dr. Lowry included "customer care costs" in his TFP growth estimate in AUC Proceeding 566.

d. With regard to **reference c**, describe which customer care costs Dr. Lowry includes in his TFP growth study in the current proceeding and which customer care costs Dr. Lowry excludes from his TFP growth study in the current proceeding. Explain why those costs are included or excluded. Identify and describe any differences between those costs included or excluded in the current proceeding and AUC Proceeding 566.

Responses: The following responses were provided by PEG.

a. By customer care costs, Dr. Lowry means operation and maintenance expenses for customer accounts, sales, and customer service and information.

b. Apart from meter reading expenses, Dr. Lowry did not include costs of customer care in his research for AUC Proceeding 566. One reason is that Alberta gas and electric power distributors do not provide as many of these services as U.S. power distributors typically do. Another is that U.S. customer service and information expenses include expenses for conservation and demand management ("CDM"), and these costs are not itemized for easy removal.

c. Please see the response to part b of this question.

d. Dr. Lowry included sales expenses and all customer account expenses save those for uncollectible bills because these are important costs incurred by the Applicants. Customer service and information expenses were once again excluded due to the CDM problem.

L1.EGD/Union.12 – Asset Service Life

References:

a. PEG Evidence, April 11, 2018, pp.28-30:

"Table 2 summarizes data we have gathered from utility filings on the average service lives of US power distributors today. It can be seen that they typically exceed 40 years. In response to an undertaking, Enbridge and Union report average service lives of about 38 years and 36 years in 2016, respectively. As explained further in Appendix 1, we calculated an alternative average service life that…"[footnote omitted]

…[Table 2 omitted]…

"is commensurate with retirements using a better formula and detailed retirement data from FERC Form 1. Our alternative estimate was 42 years. We demonstrated in the second Alberta IRM proceeding that,with an average service life of even 37 years, TFP growth using NERA's methodology is much higher."

b. Alberta Utilities Commission 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Decision 20414-D01-2016 and Errata, February 6, 2017, paragraphs 118-120:

"118. More specifically, the differences in the calculation methods pertained to the use of the chain-weighted index in the Lowry study, while the NERA-based studies relied on the multilateral index. As well, NERA's TFP calculations put more weight on larger utilities, whereas the Lowry study averages growth rates across firms in any year, thereby weighting firms equally. The assumptions pertaining to measuring input growth included among others, the depreciation method (one hoss shay, geometric decay or a straight line method), the use of net rather than gross plant in the benchmark year of the TFP growth study, the asset service life, and the choice of price indexes used in calculating such input quantities as labour, materials and services. In addition, while NERA-based studies include only costs labelled as "distribution" in FERC Form 1 accounts, the Lowry study includes a wider range of cost categories by allocating some expenses and wages related to customer accounts, administrative and general, and some general plant."

"119. These issues were for the most part, debated in the PBR Proceeding 566 and in Decision 2012-237, the Commission noted that "Some of these issues reflect an ongoing academic debate on which consensus has not been reached, or for which there is no right or wrong answer." As a result, and contrary to EPCOR's view in this proceeding, in Decision 2012-237, the Commission did not explicitly reject the different assumptions used by different parties. Along the same vein, Drs. Brown and Carpenter were generally neutral about the particular assumptions that were adopted, referring to the debate about the various methodologies as being "within the range of statistical precision of a TFP study," whereas Dr. Meitzen and Dr. Lowry were more adamant that the assumptions each of them had adopted were to be preferred."

"120. In the Commission's view, there is no overwhelming new evidence in this proceeding that any of these particular assumptions are correct or incorrect. The assumptions chosen reflect the practitioner's decisions and beliefs based on the available choices that can be applied to the data, and there is generally no test presented in evidence that can be applied to determine which assumptions are more applicable to particular data or the purposes for which it is used. It is unlikely that any group of unassociated practitioners will make the same choices for all the assumptions, even with the same universe of data series available to them. For this aspect of the analysis, the Commission is, therefore, unwilling to specify a preference for the set of assumptions used by any particular one of the three TFP growth studies."

Preamble: The companies would like to understand Dr. Lowry's service life calculations.

Questions:

a. Please provide all of Dr. Lowry's filed evidence in AUC Proceeding 20414, including any models used to calculate Dr. Lowry's proposed X factor.

b. Please provide any analysis Dr. Lowry conducted to arrive at an average service life assumption of 37 years in AUC Proceeding 20414.

c. Confirm that in **reference b**, in AUC Proceeding 20414, the AUC declined to adopt the 37-year average service life assumption proposed by Dr. Lowry.

d. Please provide Table 2 on page 29 and the calculations associated with Appendix A.1 , in Microsoft Excel format with formulas intact.

Responses: The following responses were provided by PEG.

a. Dr. Lowry's direct evidence and reply evidence in AUC Proceeding 20414 are provided in Attachment EGD/Union.2a.3.

b. The 37-year figure was based upon the estimated average service life of EPCOR, which we obtained in response to an information request.

c. This statement is confirmed, but Dr. Lowry notes that the decision of the AUC in Proceeding 20414 did not discuss the empirical research showing the extreme sensitivity of NERA's results to the service life assumption which he submitted in his reply evidence. Costs that PEG incurred in preparing its evidence were subsequently disallowed by the AUC in part on the grounds that it did not consider this evidence because no working papers were provided.[17] The reply evidence was due shortly before hearings started, and no working papers were requested by the parties.

d. Please see the working papers submitted in response to EGD/Union question 1.

[17] AUC Proceeding 20414, Decision 22082-D01-2017, *Costs Award*, February 6, 2017, pp. 9-10.

L1.EGD/Union.13 – Other Concerns

References:

a. PEG Evidence, April 11, 2018, pp.31-32:

"Recall from Section 3 that the computation of a capital quantity index starts with a benchmark year adjustment. We believe NERA's calculations of capital quantity indexes in their initial benchmark year were also incorrect. OHS is sometimes characterized as a method for calculating the quantity associated with gross plant value. Yet NERA deflated net plant values by an average of past values of a construction cost index. As a consequence, we believe that the initial quantities of capital for each utility in their sample were understated. Their method effectively removed accumulated depreciation associated with older capital twice. It was first removed when calculating net plant value and then removed again when the original value of plant is retired. When an alternative and higher average service life is used to calculate capital quantities, this can result in negative capital quantities for some utilities. Utility witnesses in Alberta used these negative capital quantities as an argument against a higher average service life." [footnote omitted]

…

"A Törnqvist/Thiel multilateral form was used for the productivity indexes. This form is not the best available for measuring productivity trends. Chain-weighted Törnqvist and Fisher Ideal forms are preferable for trend studies. PEG conventionally uses chain- weighted Törnqvist forms for input price and productivity indexes used in productivity trend studies."

b. Alberta Utilities Commission Rate Regulation Initiative, Proceeding 566, Decision 2012- 237, September 12, 2012, paragraph 413:

"413. The Commission notes that in addition to the issues discussed in sections 6.3.2 to 6.3.7 above, PEG expressed a number of other concerns with NERA's study relating to the correct index form and the capital quantity index to use, among others. Some of these issues reflect an ongoing academic debate on which consensus has not been reached, or for which there is no right or wrong answer. For instance, PEG advocated the use of a chain-weighted form of a Tornqvist-Theil index, while NERA preferred the use of a multilateral Tornqvist-Theil index. Similarly, PEG indicated that the correct capital quantity measure to use should be the inflation-adjusted value of gross plant, while NERA insisted on using the net plant value.Overall, the Commission considers that PEG's criticisms do not undermine the credibility of NERA's TFP study." [footnotes omitted]

c. Alberta Utilities Commission 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Decision 20414-D01-2016 and Errata, February 6, 2017, paragraphs 118-120:

"118. More specifically, the differences in the calculation methods pertained to the use of the chain-weighted index in the Lowry study, while the NERA-based studies relied on the multilateral index. As well, NERA's TFP calculations put more weight on larger utilities, whereas the Lowry study averages growth rates across firms in any year, thereby weighting firms equally.

The assumptions pertaining to measuring input growth included among others, the depreciation method (one hoss shay, geometric decay or a straight line method), the use of net rather than gross plant in the benchmark year of the TFP growth study, the asset service life, and the choice of price indexes used in calculating such input quantities as labour, materials and services. In addition, while NERA-based studies include only costs labelled as "distribution" in FERC Form 1 accounts, the Lowry study includes a wider range of cost categories by allocating some expenses and wages related to customer accounts, administrative and general, and some general plant."

"119. These issues were for the most part, debated in the PBR Proceeding 566 and in Decision 2012-237, the Commission noted that "Some of these issues reflect an ongoing academic debate on which consensus has not been reached, or for which there is no right or wrong answer." As a result, and contrary to EPCOR's view in this proceeding, in Decision 2012-237, the Commission did not explicitly reject the different assumptions used by different parties. Along the same vein, Drs. Brown and Carpenter were generally neutral about the particular assumptions that were adopted, referring to the debate about the various methodologies as being "within the range of statistical precision of a TFP study," whereas Dr. Meitzen and Dr. Lowry were more adamant that the assumptions each of them had adopted were to be preferred."

"120. In the Commission's view, there is no overwhelming new evidence in this proceeding that any of these particular assumptions are correct or incorrect. The assumptions chosen reflect the practitioner's decisions and beliefs based on the available choices that can be applied to the data, and there is generally no test presented in evidence that can be applied to determine which assumptions are more applicable to particular data or the purposes for which it is used. It is unlikely that any group of unassociated practitioners will make the same choices for all the assumptions, even with the same universe of data series available to them. For this aspect of the analysis, the Commission is, therefore, unwilling to specify a preference for the set of assumptions used by any particular one of the three TFP growth studies."

Preamble: The companies would like to understand Dr. Lowry's "other concerns" regarding Dr. Makholm's TFP growth study.

Questions:

a. Please confirm that Dr. Lowry raised the concerns identified in **reference a** in Alberta Proceeding 566 (in which Dr. Makholm also appeared), in Alberta Proceeding 20414 (in which Dr. Makholm did not appear), and in the current proceeding.

b. Please confirm that the AUC found that Dr. Lowry's concerns about NERA's study with regard to net versus gross plant and the use of a chain-weighted form of a Tornqvist-Theil index did not "undermine the credibility of NERA's TFP study" in Alberta Proceeding 566.

c. Confirm that in Alberta Proceeding 20414 (in which Dr. Makholm did not appear), the AUC found that "there is no overwhelming new evidence in this proceeding that any of these particular assumptions are correct or incorrect."

Responses: The following responses were provided by PEG.

a. Dr. Lowry confirms this statement.

b. Dr. Lowry confirms that the AUC was unwilling to weigh in on these issues in Proceeding 566.

c. Dr. Lowry confirms that the AUC made this statement. However, as noted in response to EGD/Union.12c, the AUC did not consider PEG's empirical reply evidence which demonstrated the magnitudes of various NERA methodology deficiencies.

L1.EGD/Union.14 – Alternative Results

References:

a. PEG Evidence, April 11, 2018, p. 33:

"We next corrected for a small problem with NERA's labor quantity calculation. This raised the estimated TFP trend by about 8 basis points, to -0.83%."

b. PEG Evidence, April 11, 2018, p. 33:

"We next removed some merged companies from the sample. This lowered the estimated TFP trend by 3 basis points, to -0.86%.".

Preamble: The companies would like to understand Dr. Lowry's changes to Dr. Makholm's study.

Questions:

a. Please explain Dr. Lowry's "correction for a small problem with NERA's labor quantity calculation."

b. Please provide all associated calculations in Microsoft Excel format with formulas intact.

c. Please identify the merged companies that Dr. Lowry removed from Dr. Makholm's study.

Responses: The following responses were provided by PEG.

a. For the earlier years of its sample period, NERA measured the quantity of distribution labor as the total number of full time equivalent ("FTE") employees x the share of distribution in total electric salaries and wages. For the years after utilities stopped reporting FTE employees, NERA escalated the discontinued series of *total* FTE employees by the trend in inflation-adjusted *distribution* salaries. The method NERA used will overstate the number of employees employed by restructured transmission and distribution utilities and artificially lower the trend in productivity. This problem was noted by Dr. Mark Meitzen, witness for EPCOR in the second Alberta generic PBR proceeding, and he made a correction in his research.[18]

   Our correction was to escalate this series by the inflation adjusted salaries for *all* employees. This is an upgrade because many utilities divested their generation facilities in the years after the FTE series was discontinued. Using total salaries to estimate employee counts in later years will take account of these divestitures whereas distribution salaries will not. The method of allocating the estimate total number of employees to distribution using the percentage of salaries that are distribution was not changed.

b. Please see the working papers attached in response to EGD/Union.1 for further details.

c. Green Mountain Power and NSTAR were the most obvious examples of utilities that had

[18] Meitzen, Mark, *Determination of the Second-Generation X Factor for the AUC Price Cap Plan for Alberta Electric Distribution Companies*, AUC Proceeding 20414, Exhibit 20414-X0074, Appendix B, March 21, 2016, pp. 19-20.

mergers and/or acquisitions mishandled by NERA and were excluded for this reason from the sample in PEG's upgraded analysis. Perpetual inventory methods for calculating the capital quantity such as one-hoss shay build upon capital from a benchmark year. In the NERA study, when these utilities acquired another utility, accumulated capital from the acquired entities up until the merger were excluded from the index in subsequent years. In contrast, the additions and retirements of the consolidated company data are considered. This correction was not expected to have a large impact on results and did not.