EB-2017-0306
EB-2017-0307

ONTARIO ENERGY BOARD

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

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

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

ENBRIDGE GAS DISTIRBUTION INC.
UNION GAS LIMITED

COMPENDIUM OF MATERIALS
FOR CROSS-EXAMINATION OF PANEL 5

CONTENTS

TAB 1

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."

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

Questions:

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.

Responses: 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.

TAB 2

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.

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

Questions:

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 0.12% -- very close to zero.

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

Year	Output	Input Quantities			Productivity		
	Customers	OM&A	Capital	Total	OM&A	Capital	TFP
	[A]	[B]	[C]	[D]	[A-B]	[A-C]	[A-D]
1999	2.16%	-0.24%	1.23%	0.89%	2.40%	0.93%	1.27%
2000	2.67%	1.25%	1.68%	1.42%	1.41%	0.99%	1.25%
2001	1.30%	-7.89%	0.67%	-2.70%	9.19%	0.63%	4.00%
2002	0.82%	-2.14%	0.64%	-0.49%	2.96%	0.18%	1.32%
2003	2.21%	3.92%	0.97%	2.06%	-1.70%	1.24%	0.15%
2004	0.94%	0.92%	0.66%	0.74%	0.02%	0.29%	0.20%
2005	1.39%	1.58%	0.37%	0.89%	-0.18%	1.03%	0.50%
2006	0.77%	-6.99%	0.46%	-2.63%	7.75%	0.31%	3.40%
2007	0.62%	6.25%	0.24%	2.78%	-5.64%	0.37%	-2.16%
2008	0.33%	-0.72%	0.53%	0.03%	1.05%	-0.19%	0.30%
2009	0.29%	5.35%	0.76%	2.75%	-5.06%	-0.48%	-2.46%
2010	0.34%	0.00%	1.08%	0.61%	0.34%	-0.74%	-0.27%
2011	0.56%	0.75%	0.96%	0.91%	-0.19%	-0.40%	-0.35%
2012	0.87%	1.29%	2.06%	2.27%	-0.43%	-1.19%	-1.40%
2013	0.66%	3.21%	2.72%	2.48%	-2.55%	-2.07%	-1.83%
2014	0.85%	2.87%	3.54%	3.24%	-2.02%	-2.69%	-2.39%
2015	0.94%	-2.31%	3.77%	1.08%	3.25%	-2.83%	-0.14%
2016	0.88%	-4.36%	3.96%	0.12%	5.24%	-3.07%	0.76%
Average Annual Growth Rates							
1999-2016	**1.03%**	**0.15%**	**1.46%**	**0.91%**	**0.88%**	**-0.43%**	**0.12%**
Coefficient of Variation							
1999-2016	**0.64**	**24.28**	**0.82**	**1.78**	**4.30**	**-3.18**	**14.46**

Notes

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

TAB 3

AUC
Alberta Utilities Commission

Rate Regulation Initiative

Distribution Performance-Based Regulation

September 12, 2012

The Alberta Utilities Commission
Decision 2012-237: Rate Regulation Initiative
Distribution Performance-Based Regulation
Application No. 1606029
Proceeding ID No. 566

September 12, 2012

Published by
The Alberta Utilities Commission
Fifth Avenue Place, Fourth Floor, 425 First Street S.W.
Calgary, Alberta
T2P 3L8

Telephone: 403-592-8845
Fax: 403-592-4406

Website: www.auc.ab.ca

Contents

List of tables

The Alberta Utilities Commission
Calgary, Alberta

Rate Regulation Initiative
Distribution Performance-Based Regulation

Decision 2012-237
Application No. 1606029
Proceeding ID No. 566

1 Introduction and background

1. On February 26, 2010, the Alberta Utilities Commission (AUC or Commission) began a rate regulation initiative to reform utility rate regulation in Alberta. The first stage of the rate regulation initiative is to implement a form of performance-based regulation (PBR) for electric and natural gas distribution companies in place of the existing cost of service regulatory system, usually referred to as rate base rate-of-return regulation. The second stage of the rate regulation initiative will consist of generic reviews of legal and economic issues related to utility regulation for the purpose of making the regulatory system more consistent among companies, more predictable over time and more efficient.

2. In its February 26, 2010 letter,[1] the Commission indicated that the first stage of the rate regulation initiative would apply only to the electricity and natural gas services of Alberta distribution companies under the Commission's jurisdiction. It would not apply to the electricity and natural gas services of transmission companies or to retail electricity or natural gas sales. However, if a company provided both distribution and transmission services, the company was given the option to apply to include its transmission services in its PBR proposal.

3. The procedural steps for this stage of the rate regulation initiative are set out in Appendix 3 to this decision. The division of the Commission presiding over this proceeding was Mr. Willie Grieve (chair), Mr. Mark Kolesar and Dr. Moin Yahya.

4. This decision sets out the Commission's determinations about the form of performance-based regulation that will be employed beginning in 2013 for Alberta electric and natural gas distribution companies.

1.1 The current regulatory framework

5. The utility companies to which this decision applies (the companies) are three electric distribution companies, ATCO Electric Ltd. (ATCO Electric or AE), FortisAlberta Inc. (Fortis or FAI) and EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) and two gas distribution companies, ATCO Gas and Pipelines Ltd. (ATCO Gas or AG) and AltaGas Utilities Inc. (AltaGas or AUI). The distribution and transmission service rates charged by these companies are currently regulated under a rate base rate-of-return form of cost of service regulation.

6. The Commission also regulates the distribution and transmission rates of ENMAX Power Corporation (ENMAX or EPC). In 2009, the Commission approved a formula-based ratemaking

1 Exhibit 1.01, AUC letter of February 26, 2010.

or FBR plan (also known as a PBR plan) for ENMAX's distribution and transmission services.[2] Prior to that, ENMAX was also regulated under a rate base rate-of-return framework.

7. Under the current rate base rate-of-return regulatory framework, rates are established through a two-phase process. In the first phase, the total amount of money required by the company to provide its regulated services in a year is determined. This is referred to as the revenue requirement, and it is made up of the total annual operating, maintenance and administrative expenses of the company plus the company's capital-related costs (depreciation, debt, and return on equity). The company's debt and equity are used to finance the company's assets (wires, pipes, etc.), which are referred to as its rate base. The cost of debt is the interest that the company pays on its bonds. The cost of equity is determined by the regulator and is referred to as the approved rate of return on equity (ROE). The return on equity actually earned is sometimes referred to as the utility company's profit since all other expenses and costs (operating, maintenance, administration and debt costs) are recovered without any profit margin built into them.

8. In the second phase of a rate application, monthly, hourly or other rates to be paid by individual customers for use of the distribution system are established by determining how much of the revenue requirement should be recovered from each customer class (residential, commercial, etc.) and on what billing unit basis (monthly charge, per kilowatt hour or gigajoule, etc.). Rates are established by dividing the revenue requirement for each customer class by the billing units.

9. In Alberta, all of these determinations are made on a forecast basis, generally for two years. So, for example, a company could file a rate application for the two years 2011 and 2012. A forecast revenue requirement would be provided by the company for each of the two years, called test years. The Commission is required to test the application for reasonableness and allow only reasonable forecast expenses, including capital-related costs, to be included in the revenue requirement and rates for the two test years. These forecasts are based on the companies' plans and expectations over the two test years. When new rates are implemented for the two years, the company begins to collect them and may or may not carry out the plans it put before the Commission in its forecasts. At the end of the two years, the company may apply for rates for the next two test years.

10. If the company is able to provide service for less than it had forecast during the previous two years, or if billing units (the number of customers, electricity or natural gas use, etc.) are greater than were forecasted, the company is permitted to keep the extra revenue as extra profit in those years. However, the forecast revenue requirement and rates for the next two years are to take into account the actual results from the previous two years. In this way, customers receive the benefit of the company's improved productivity (lower costs and higher billing units) from the previous period in the rates determined for the next two years. If the company then improves its productivity in these next two years, those benefits will again be passed on to customers in the next period, etc. Of course, the actual results for the immediate prior year are not available to assist in assessing the forecasts for the two test years of a new test period. This means that any efficiency gains in the prior year may not be fully incorporated into those forecasts.

[2] Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID No. 12, March 25, 2009.

11. While this regulatory model is relatively straightforward in its conception, it produces some incentives and disincentives that are widely recognized.[3] Generally, under cost of service regulation, since the company earns a profit on the equity in its rate base, there is an incentive to choose spending money on capital assets, on which a return can be earned, over spending on maintenance, for example, on which a return is not earned. In addition, there is no incentive to minimize the costs of capital assets. The more that is spent and included in the company's rate base, the more return that can be earned. This means that the regulator must make some sort of after-the-fact assessment of whether the company spent too much money on capital assets and, if so, must disallow recovery of the amount by which actual costs exceeded a prudent amount. In addition, there is little incentive for the company to invest in long term cost reduction initiatives because any cost reductions achieved would be passed on to customers automatically in subsequent rate proceedings. The use of forecasted test years in Alberta was adopted partly in response to these incentives. However, while there are incentives to reduce expenses in the test years so as to beat the forecast and thereby increase profits, this only works for investments in efficiency that can be recovered in a year or two. In addition, this framework also creates an incentive for the companies to provide cost forecasts (both operating and maintenance (O&M), and capital) that are higher than what the company expects to be able to achieve or to provide conservative forecasts of the number customers and other billing units that are lower than what the company expects, thus increasing profits above the approved return.

12. In addition to the issues raised by the basic regulatory model, the framework has been made more complicated by the restructuring of the industries. In both the electricity and natural gas industries, companies that were once vertically integrated monopolies engaged in electricity generation, distribution, transmission and retailing, or in natural gas production, distribution, transportation and retailing, are now structurally separated. The production of electricity and natural gas and the retailing of electricity and natural gas are now open to competition. The costs for the distribution and transmission services must be separated from the costs of production and retailing and separate rate bases established. Issues of cost allocations among different regulated entities or among regulated and unregulated affiliates in the same corporate structure emerge and must be monitored. These issues include allocations of rate base, charges from one division to another, prices charged by affiliates providing services in competitive markets that also provide those services to the regulated affiliate, among others. In the current regulatory framework, each of these issues must be monitored and assessed in every regulatory application, and a number of new regulatory tools have been developed to deal with these costs and allocations both within and outside of the normal rate review process. As a consequence, the industry restructuring has added to the need for rate riders (items on the bill to recover costs that change from time to

[3] See Brown, Carpenter and Pfeifenberger regarding capital expenditure gaming (Exhibit 34.01, slide 3); Dr. Carpenter regarding incentive to bias its rate base allowance upward, (Transcript Volume 7, pages 1194 and 1195); Dr. Cronin that regulated firms are overcapitalized (Exhibit 299.02, page 124); Dr. K. Gordon, ATCO Gas witness in an earlier proceeding regarding over-forecasting, (Exhibit 357.06 citing Application No. 1400690, 2005-2007 Rate Application, Transcript Volume 5, pages 838-846); Ms. Frayer and Dr. Weisman, regarding cost-of-service's significant regulatory burden (Fortis application, Exhibit 100.02, Appendix 2, page 5, lines 20-23 and Exhibit 103.03, Dr. Weisman evidence, page 9, paragraph 20); Dr. Weisman's evidence that cost-of-service regulation "is essentially a cost-plus contract" (Exhibit 103.03 page 23 paragraph 57); Calgary evidence that a "regulated firm may use its information advantage strategically in the regulatory process to increase its profits ... to the disadvantage of ratepayers." Exhibit 298.02, page 15, paragraph 34; The United States Department of Justice that "cost-of-service regulation may do little to promote, and may actually inhibit the achievement of, technical, allocative, or dynamic efficiency" as quoted by the UCA in Exhibit 299.02, page 119.

time[4]), flow-through mechanisms and deferral accounts. At last count the Commission was administering approximately 100 deferral accounts, riders and pass-through mechanisms for the distribution and transmission companies under cost of service regulation.

13. One result of the basic regulatory model and the industry restructuring that has been imposed on top of it has been both a tremendous increase in the detailed information filed by the regulated companies and an increase in the number of ongoing proceedings for deferral accounts and related matters. For example, in a recent revenue requirement application filed by EPCOR amounted to approximately 4,200 pages including all schedules and appendices.[5] The process that followed produced another 8,000 pages of information requests and responses as well as additional evidence and written questions and responses. In addition, from that proceeding, one of the issues was spun-off to be considered in a separate proceeding. As another example, there is a 10-year ongoing series of proceedings to benchmark and, through that, to establish a method to review and approve charges to the ATCO utilities by their affiliate ATCO I-Tek Inc.[6] As a further complication, a number of issues have been litigated differently by different companies and decided differently by different board[7] or Commission panels.

1.2 Performance-based regulation

14. In its February 26, 2010 letter, the Commission stated that the rate regulation initiative:

> ... proceeds from the assumption that rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources. In addition, rate-base rate of return regulation is increasingly cumbersome in an environment where some companies offer both regulated and unregulated services and where operations that were formerly integrated have been separated into operating companies, some of which require their own rate and revenue requirement proceedings. These changes in the structure of the industry, occasioned by the introduction of competition in the retail and generation/production segments of the electricity and natural gas industries, have resulted in additional negative economic incentives for companies regulated under rate-base rate of return regulation. These conditions complicate the task for regulators who must critically analyze in detail management judgments and decisions that, in competitive markets and under other forms of regulation, are made in response to market signals and economic incentives. The role of the regulator in this environment is limited to second guessing. Traditional rate-base rate of return regulation provides few opportunities to create meaningful positive economic incentives which would benefit both the companies and the customers. The Commission is seeking a better way to carry out its mandate so that the legitimate expectations of the regulated utilities and of customers are respected.[8]

4 Examples of rate riders include but are not limited to: ENMAX's Quarterly Transmission Access Charge, FortisAlberta's Quarterly Transmission Access Rider, ATCO Electric's Rider S Quarterly System Access Services Adjustment and EPCOR'S Rider K Transmission Charge Deferral Account True-up Rider.

5 EPCOR Distribution & Transmission Inc., 2010-2011 Phase I Distribution Tariff, 2010-2011 Transmission Facility Owner Tariff, Application No. 1605759, Proceeding ID No. 437.

6 Decision 2010-102: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2003-2007 Benchmarking and ATCO I-Tek Placeholders True-Up, Application No. 1562012, Proceeding ID No. 32, March 8, 2010; Decision 2011-228: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2008-2009 Evergreen Application, Application No. 1577426, Proceeding ID No. 77, May 26, 2011; ATCO Utilities, 2010 Evergreen Proceeding for Provision of Information Technology and Customer Care and Billing Services Post 2009, Application No. 1605338, Proceeding ID No. 240.

7 The Alberta Energy and Utilities Board (board or EUB), is a predecessor to the Alberta Utilities Commission.

8 Exhibit 1.01, AUC letter of February 26, 2010, pages 1-2.

15. In stating its intention to move to a performance-based regulation framework for the distribution companies, the Commission also stated the following objectives for PBR:

> The first is to develop a regulatory framework that creates incentives for the regulated companies to improve their efficiency while ensuring that the gains from those improved efficiencies are shared with customers. The second purpose is to improve the efficiency of the regulatory framework and allow the Commission to focus more of its attention on both prices and quality of service important to customers.[9]

16. A basic PBR plan begins with rates established through a cost of service proceeding such as a rate base rate-of-return proceeding. Those rates are then adjusted in subsequent years by a rate of inflation (I) relevant to the prices of inputs the companies use less an offset (X) to reflect the productivity improvements the companies can be expected to achieve during the PBR plan period. Thus, adjusting rates by I-X, rather than in cost of service proceedings, breaks the link between a utility's own costs and its revenues during the PBR term. In much the same way as prices in competitive industries are established in a competitive market, prices adjusted by I-X reflect industry-wide conditions that would produce industry price changes in a competitive market. Each company's actual performance under PBR will depend on how its own performance compares to the industry's inflation and productivity measures.

17. Establishing prices in this way during the term of a PBR plan creates stronger incentives for the companies to improve their efficiency through cost reductions and other actions because they are able to retain the increased profits generated by those cost reductions longer than they would under cost of service regulation, especially with rates under cost of service regulation that are re-set every two years. At the same time, under a PBR regulatory framework, customers automatically share in the expected efficiency gains because they are built into rates through the X factor regardless of the actual performance of the companies. In addition, the X factor in a PBR plan is often increased by a stretch factor so as to capture efficiency gains that should be immediately realizable as the regulatory system changes from cost of service to PBR.

18. But an I-X mechanism alone is not sufficient. In competitive markets, other factors that affect only the industry in question, such as an increase in taxes, would be passed through to customers by that industry in its competitive prices. PBR plans typically include a Z factor to deal with such significant events outside the companies' control that are specific to the industry and would not be reflected through the inflation factor (I). The Z factor can also be used to increase or decrease the companies' prices to reflect cost changes caused by unique company-specific events (such as floods or ice storms) outside the company's control and that are not reflected in the inflation factor.

19. In some cases, these types of costs may be predictable, although the amounts of these costs may not be. In those cases, other mechanisms may be established to allow for automatic adjustments to rates to pass those costs through to customers. For example, in the ENMAX FBR plan established in Decision 2009-035, the Commission made provision for the flow-through of transmission system charges imposed on the distribution company by the Alberta Electric System Operator (AESO).[10] Other similar types of charges beyond the control of the companies

9 Exhibit 1.01, AUC letter of February 26, 2010, page 1.

10 Decision 2009-035, pages 52-53. For further discussion on the AESO's role see Section 7.4.2.1.1.

may also be included in a PBR plan as a Y factor to be passed through to customers. The companies' proposals in this proceeding included a number of these types of factors.

20. In the ENMAX FBR plan,[11] the Commission also established a G factor to deal with capital additions to ENMAX's transmission system. In this proceeding, each of the companies proposed specific provisions for some types of capital investments to be handled outside the I-X mechanism. In this decision those types of capital adjustments are referred to as K factors.

21. All of these types of cost-based adjustments (whether Z, Y or K) are carefully defined and limited in their scope because they are inconsistent with the objectives of PBR in that they have the effect of lessening the efficiency incentives that are central to a PBR plan.

22. PBR plans are typically established for a defined term such as five years. At the end of the term, rates are often re-established in a cost of service proceeding, and another PBR term begins based on those rates. Other approaches may also be used at the end of the PBR term, such as simply continuing the plan or making some changes to the parameters and continuing based on existing rates. However, it is likely that a cost of service review will occur eventually.[12] In either case, the values of I and X, for example, and the other parameters of the plan are reviewed and may be changed. The fact that eventually rates will be re-established based on cost of service lessens the efficiency incentives under PBR as the time for the cost of service review approaches. Generally, the longer the PBR term, the greater are the incentives for the company to look for and invest in new productivity-enhancing business practices.

23. Whereas an I-X mechanism creates efficiency incentives similar to those in competitive markets, it does not create incentives to maintain quality of service. In a competitive market, poor service quality will cause customers to switch companies, but poor service quality will not result in a loss of customers for a monopoly. The fact of monopoly supply of an essential public service has required regulators to monitor and regulate service quality, regardless of the form of regulation. The Commission has recognized from the outset of its rate regulation initiative that the creation of greater efficiency incentives through adoption of a PBR plan also creates concerns that the resulting cost cutting might lead to reductions in quality of service. It is for this reason that the adoption of PBR typically coincides with the development and adoption by regulators of stronger quality of service regulatory measures.

24. It is the Commission's expectation that the adoption of a PBR plan will make the regulatory system more efficient over time as the Commission, interveners and companies become more familiar with it. At the same time the Commission expects that, under PBR, customers will experience lower rates than they would have had if the current rate base rate-of-return framework had continued unchanged.

25. During the first PBR term, the Commission will also conduct generic proceedings to deal with a number of utility regulatory issues so that the regulatory framework will be more efficient in the future.[13]

11 Decision 2009-035, pages 41-48.
12 Transcript, Volume 1, page 197, lines 11 to 22, Dr. Makholm.
13 The generic cost of service proceedings is discussed in Section 16.

1.3 Performance-based regulation preparations

26. In its February 26, 2010 letter, the Commission invited interested parties to assist the Commission in determining the scheduling and the scope of issues for PBR implementation. The Commission held a roundtable with 18 interested parties on March 25, 2010 to discuss steps for the implementation of PBR.[14] The companies objected to the Commission's stated preference that PBR begin on July 1, 2011. The companies asked for more time to prepare for PBR and to file rate cases to establish their going-in rates for PBR, a process that would take some time. In addition, during the roundtable, participants agreed that the Commission should conduct a workshop so that the participants could become more familiar with the theory of and experience with PBR. Participants also agreed that the Commission should initiate a short proceeding to establish common principles to guide and assess PBR proposals to be subsequently filed by Alberta distribution companies within the Commission's jurisdiction.

27. In its April 9, 2010 letter[15] the Commission announced that in response to requests by participants, it had engaged the Van Horne Institute to conduct an independent PBR workshop on May 26 to 27, 2010 in order to educate participants about the issues, terminology and concepts raised by PBR. Participants were informed that the information provided and views expressed at the workshop did not necessarily represent the views of the Commission. Ninety-two people representing all of the utility companies and intervener groups attended the workshop.

28. Also, in its letter of April 9, 2010, the Commission initiated a proceeding to solicit comments on the principles that should guide the development of PBR in Alberta. The proceeding commenced on June 10, 2010 with submissions from the various parties and closed on June 24, 2010 with the submission of reply comments.[16] The Commission reviewed these submissions, and in Bulletin 2010-20,[17] dated July 15, 2010, the Commission found that there was general agreement on the following five principles:[18]

> **Principle 1.** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
>
> **Principle 2.** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3.** A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
>
> **Principle 4.** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> **Principle 5.** Customers and the regulated companies should share the benefits of a PBR plan.

---

14 See Attachment 1 of Exhibit 6.01 for a list of participants, page 2.
The following parties suggested clear objectives before instituting PBR: AltaLink, page 1; ATCO, page 1; Calgary, Principle 1, page 3; UCA, page 1; IPCAA, Principle 1, page 1.

15 Exhibit 6.01, AUC letter of April 9, 2010.

16 Appendix 1 of Bulletin 2010-20 lists the parties who made submission and the associated exhibit numbers.

17 Bulletin 2010-20, Regulated Rate Initiative – PBR Principles, July 15, 2010.

18 Exhibit 64.01, Appendix 2 of Bulletin 2010-20 lists references of parties with similar principles in their submissions.

29. The gas and electric distribution companies present at the March 25, 2010 roundtable (other than ENMAX) agreed that they could each file a PBR proposal by the end of the first quarter of 2011. Therefore, in Bulletin 2010-20, the Commission directed these gas and electric distribution companies to file their PBR proposals by March 31, 2011. The distribution companies that are also transmission facility owners could choose whether or not to include their transmission operations in their proposed PBR plans. Parties were required to explain how their PBR proposals were consistent with the Commission's five principles for PBR and how their proposals would satisfy the Commission's objectives for PBR.

30. On September 8, 2010, the Commission notified the parties that it had retained National Economic Research Associates (NERA) to prepare a total factor productivity (TFP) study that could be used as the basis for determining an X factor in a PBR plan for the electricity and natural gas distribution industries.[19] The NERA TFP study was to be filed by December 31, 2010.[20] The filing date for the companies' PBR proposals was later changed to July 26, 2011, in order to allow the companies sufficient time to consider the evidence to be filed by NERA, with the objective being to implement PBR effective January 1, 2013.[21]

1.4 Overview of PBR proposals and the Commission's approach

31. In Bulletin 2010-20[22] that established the PBR principles, the Commission also provided the following guidance to the companies and interveners:

> In the Commission's opinion, a PBR plan consisting only of an I - X formula would, to the greatest extent possible, mimic the efficiency incentives of competitive markets provided that the X factor requires the company to achieve annual productivity improvements at least equivalent to those of the relevant industry. Therefore, the Commission expects each proposal to include I - X as part of the PBR plan. Some parties proposed principles that dealt with certain aspects of various PBR plans such as exogenous adjustments, earnings sharing, the term of the plan, capital adjustments, reporting requirements and rate structure changes, among others. In the Commission's opinion, these are more properly considered as potential elements of a PBR plan and are not principles. In making their proposals, companies may choose to include these or other elements in order to address circumstances resulting from Alberta's market structure, the industries in which the companies operate, unique company-specific circumstances or other circumstances that may be relevant. Companies are expected to fully explain the circumstances that give rise to the need for each element, how each element addresses that need and how each element is justified by the principles and objectives of PBR.[23]

32. The companies filed their PBR proposals on July 26, 2011. Interveners filed their PBR evidence on December 16, 2011.

33. The Commission received a wide range of proposals from the companies and the interveners. Parties agreed with the Commission's objectives and principles and, for the most part, fashioned their PBR proposals to be consistent with them. The Office of the Utilities

19 Exhibit 71.01, AUC letter – Retention of Consultant to Develop a Basic X Factor.
20 Exhibit 80.02, NERA first report.
21 Please see Appendix 3 for details of the procedural steps.
22 Exhibit 64.01, AUC Bulletin 2010-20.
23 Exhibit 64.01, Bulletin 2010-20, page 3.

Commission directs the companies in their annual PBR rate adjustment filings to use the inflation indexes for the most recent 12-month period for which data is available, as specified in the formula below. The Commission considers that this approach will provide a fair balance between accuracy and regulatory efficiency and will make the companies' PBR plans more transparent and simple to understand thereby furthering the objectives of the third Commission PBR principle.

249. On the issue of the periodic revision of historical inflation indexes by Statistics Canada, the Commission agrees that Dr. Ryan's proposed method of accounting for revisions to the indexes by means of using the unrevised values in the subsequent I factor calculations represents an improvement over the rate adjustment method currently employed by ENMAX. Accordingly, the Commission finds that the periodic revision of inflation indexes by Statistics Canada need not affect the calculation of the I factor and directs the companies to use the unrevised actual index values from the prior year's I factor filing as the basis for the next year's inflation factor calculations.

250. The Commission also agrees with Dr. Ryan's recommendation that if a termination, substantial revision or substantial modification to the Statistics Canada data series used in the companies' I factors occurs, such changes should be brought forward to the Commission as part of the annual PBR rate adjustment filings. Any changes to the I factors arising from such data series modifications will be dealt with on a on a case-by-case basis.

5.4 Commission directions on the I factor

251. The Commission directs that the I factor to be used in the PBR plans of the Alberta utilities shall be calculated as follows:

$$I_t = 55\% \text{ x } AWE_{t-1} + 45\% \text{ x } CPI_{t-1},$$

where:

I_t	Inflation factor for the following year.
AWE_{t-1}	Alberta average weekly earnings index for the previous July through June period.[248]
CPI_{t-1}	Alberta consumer price index for the previous July through June period.[249]

6 X factor

6.1 Purpose of the X factor

252. The X factor is one of the key elements of PBR plans employing an I-X indexing mechanism to adjust a regulated company's prices or revenues each year during the PBR term. In general terms, the X factor can be viewed as the expected annual productivity growth during the

[248] The selection of the start and ending months for the 12-month period reflects the latest published Statistics Canada data prior to September.

[249] The Commission recognizes that Alberta CPI information for July may be available when the September annual PBR rate adjustment filing is made but the Commission is directing the July through June period in order to ensure the companies have enough time to prepare their filings.

PBR term. Through the I-X mechanism, a PBR plan is designed so that the changes in the prices of the company's distribution services reflect changes in input prices as reflected by the I factor and the rate of expected productivity growth.

253. The X factor, combined with the I factor, is designed to mirror the pressures of competitive market forces. In competitive markets, firms are not able to earn additional profits from productivity improvements that their competitors also adopt because competition acts to drive down prices.[250] However, to the extent that the firm is more productive than its competitors, it earns an extra return, which serves as a reward for its better than average productivity. Conversely, firms that are less productive than average earn lower returns.[251] The X factor in a PBR plan imitates these pressures by requiring the regulated companies to adjust their prices to reflect the expected productivity growth.

254. NERA and other experts in this proceeding drew attention to the fact that the magnitude of the X factor has no influence on the incentives for the company to reduce costs.[252] As Dr. Carpenter explained in his evidence:

> Under PBR, a utility which successfully saves a dollar of operating expenditure keeps that dollar (or a portion of the dollar under an earnings sharing mechanism). The opportunity to save the dollar (or portion thereof) of expenditure is unrelated to the level of rates, and therefore the magnitude of the productivity factor does not influence the incentive to find the savings.[253]

255. AltaGas explained that while the size of the X factor does have an impact on the company's return, it is the decoupling of the revenues and prices from the company-specific costs that provide the incentives, rather than the magnitude of the X factor itself.[254] Similarly, EPCOR and the CCA noted that it is the length of the term of the PBR plan (i.e., regulatory lag) that is the primary source of the incentives.[255]

Commission findings

256. During the term of the PBR, a company's prices or revenues will change with inflation, represented by the I factor, adjusted by the expected productivity growth represented by the X factor. Customers of a regulated company under PBR directly benefit from annual rates that are adjusted to reflect this expected productivity growth.

257. The Commission agrees with the experts of the companies, NERA and the CCA, that while the size of the X factor affects a company's earnings, it has no influence on the incentives for the company to reduce costs. As the companies' and the CCA's experts pointed out, the PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time of the PBR term, and not from the magnitude of the X factor itself.

---

250 Exhibit 98.02, Carpenter evidence, page 18.

251 Exhibit 616.02, page 13, William J. Baumol, "Productivity Incentive Clauses and Rate Adjustment for Inflation," *Public Utilities FORTNIGHTLY*, (22 Jul. 1982).

252 Transcript, Volume 1, page 117, lines 10-15; Exhibit 633, Fortis argument, paragraphs 140-141.

253 Exhibit 98.02, Carpenter evidence, page 17.

254 Exhibit 628, AltaGas argument, page 32.

255 Exhibit 630.02, EPCOR argument, paragraph 80; Exhibit 636, CCA argument, paragraph 105.

6.2 Approaches to determining the X factor

258. As the record of this proceeding demonstrates, there are different approaches to setting the productivity target included in the X factor of a PBR plan. In Decision 2009-035, the Commission expressed its preference for an approach to determining the X factor that is based on the average rate of productivity growth in the industry as a whole.[256] As NERA explained, under this concept, the purpose of the X factor is to reflect the long-term underlying industry productivity trend.[257] NERA favoured this approach to the determination of the X factor as evidenced by the two reports[258] prepared by NERA on total factor productivity for the regulated electric utility industry. While differing from NERA on how to determine the underlying industry productivity trend, EPCOR, AltaGas and the ATCO companies used this approach to setting the X factor.[259]

259. The CCA generally agreed with NERA's opinion that the X factor should reflect the productivity growth of the industry in which the company operates. In addition to using the index approach employed by NERA for estimating the industry productivity trend, the CCA's experts relied on an econometric model for this purpose as well. In PEG's view, the econometric approach produces a more customized productivity estimate reflecting Alberta business conditions.[260] The econometric approach to measuring TFP is further discussed in Section 6.3.4 below.

260. In Fortis' view, the analysis of the historical industry productivity trend needs to be complemented with an assessment of a company's going-forward costs and especially capital expenditure costs.[261] NERA pointed out that this type of X factor derivation resembles the building blocks concept currently employed by regulators in the United Kingdom and Australia. Under this approach, the X factor does not come from a TFP growth study, rather it is calculated as the value that would set the customer rates at a level to recover the company's cost of service revenue requirement over a forecast period.[262] Fortis' expert, Ms. Frayer, explained that in these circumstances, the X factor represents not a productivity factor itself, but rather a smoothing factor for rates, while the productivity target is embedded in the forecast of future operating and capital costs that are then used to forecast a revenue requirement and rate schedule.[263]

261. The UCA's preferred approach to determining the X factor centered upon efficiency benchmarking and consideration of a level of inefficiency for each particular company.[264] Under this method, the regulator must perform a benchmarking assessment of historical efficiency for a comparator group of companies, based upon a comprehensive analysis of their costs including capital, labour, materials and power losses. Following this analysis, the companies are assigned different productivity targets that are set higher, the more inefficient any particular company was

256 Decision 2009-035, paragraph 176.
257 Exhibit 391.02, NERA second report, paragraph 36.
258 Exhibit 80.02, NERA report and Exhibit 391.02, NERA second report.
259 Exhibit 630.02, EPCOR argument, paragraph 67; Exhibit 628, AltaGas argument, page 29; Exhibit 631, ATCO Electric argument, paragraph 84; Exhibit 632, ATCO Gas argument, paragraph 94.
260 Transcript, Volume 13, pages 2529-2530.
261 Transcript, Volume 11, page 2104, lines 23-24 and Exhibit 474.01, Fortis rebuttal evidence, paragraph 19.
262 Exhibit 391.02, NERA second report, pages 27-28.
263 Exhibit 474.02, Frayer rebuttal, page 38.
264 Transcript, Volume 17, page 3167, line 1 and Exhibit 299.02, Cronin and Motluk UCA evidence, pages 117-125.

found to be as compared to its peers (or, in other words, the further away a company was found to be from the efficiency frontier).[265]

262. In the absence of a complete set of the detailed historical cost information for Alberta gas and electric distribution companies upon which to base the benchmarking assessment, the UCA experts recommended constructing a menu which pairs data on a range of probable productivity performances with the associated ROE (return on equity) that would be permitted with each productivity choice. In the UCA's view, the menu approach to the X factor would mitigate the risks from information asymmetry and incent the companies to reveal their performance potential.[266]

263. For practical purposes, Dr. Cronin and Mr. Motluk recommended the use of the X factor and ROE menu discussed in the Ontario Energy Board's *2000 Draft Rate Handbook*.[267] This menu was based on the analysis of the performance of 48 distribution utilities in Ontario operating under the cost of service (1988 to 1993) and PBR (1993 to 1997) regimes.[268] The UCA's X factor menu recommendation is as follows:

Table 6-1 The X factor menu proposed by the UCA's experts[269]

Selection	X factor (in per cent)	ROE ceiling (in per cent)
A	1.25	10
B	1.50	11
C	1.75	12
D	2.00	13
E	2.25	14
F	2.50	15

264. Dr. Cronin and Mr. Motluk explained that under this arrangement, the companies can choose a combination of productivity growth and ROE: a higher productivity target would permit higher returns.[270] The UCA experts explained that the menu above has an earnings sharing mechanism embedded in it. In particular, the menu selections were designed in such as way that moving among menu choices (for example, from option A to option B) results in a 57:43 earnings sharing between a company and the ratepayers. At the same time, if a company's actual ROE exceeds the earnings ceiling associated with a particular menu option, 100 per cent of earnings above the ROE cap is given to ratepayers.[271]

Commission findings

265. NERA explained that because in competitive markets prices move according to the productivity of the industry in question rather than the particular costs of one company, it has

265 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 131-136.
266 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 140-141.
267 http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/handbook0.html.
268 Exhibit 299.02, Cronin and Motluk UCA evidence, page 154.
269 Exhibit 299.02, Cronin and Motluk UCA evidence, page 154.
270 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 153 and 154.
271 Transcript, Volume 17, page 3205, lines 11-20.

become customary for regulators in the design of objective PBR formulas to set the X factor based on the underlying trend in industry productivity growth.[272]

266. Similarly to the discussion in the proceeding dealing with ENMAX's FBR plan, in this proceeding the parties offered several principal approaches to determining the X factor. With respect to Fortis' approach, which involved setting the X factor based on the forecast revenue requirement over the PBR term, the Commission agrees with NERA's characterization that this method essentially resembles a five-year test period under traditional cost of service rate making.[273]

267. The Fortis approach first determines the forecast revenue requirement over the PBR term and then develops a formula to be applied to rates which will yield the forecasted revenue requirement each year. As NERA observed, while Fortis' approach resembles the practices of regulators in the United Kingdom and Australia, it is inconsistent with the institutional foundation for performance-based-rate regulation generally adopted in Canada and the United States.[274] Accordingly, the Commission restates its opinion expressed in Decision 2009-035 that this method effectively involves a multi-year cost of service rate setting exercise and changes the theoretical basis for utilizing the X factor, which is to emulate the incentives of a competitive marketplace for the benefit of ratepayers and shareholders alike.[275]

268. The efficiency frontier and benchmarking method advocated by the UCA's experts represents yet another approach to determining the value of the X factor. In contrast to productivity studies that deal with the rate of industry productivity growth over time, the efficiency frontier analysis focuses on a company's productivity level (i.e., efficiency[276]) at a particular time in relation to comparable companies. In other words, instead of looking at how the industry's productivity changes over time, this method examines whether one particular company is less or more efficient at the time of measurement as compared to its peers.

269. In the Commission's view, the efficiency benchmarking analysis is prone to two major criticisms. First, as NERA and Dr. Carpenter explained, the efficiency levels are hard to estimate as this type of analysis requires a multitude of historical company-specific data, which exhibit a great deal of year to year volatility and are prone to errors.[277] Indeed, as the UCA witnesses observed, this method of developing the X factor would busy "hundreds of analysts" both of the companies and the regulator.[278]

270. More importantly, Dr. Makholm and Dr. Carpenter pointed out that in practice it is virtually impossible to determine whether a firm is or is not efficient by looking at benchmark data alone, since relative efficiency depends on a boundless number of variables, both observable

272 Exhibit 80.02, NERA report, pages 1 and 3.
273 Exhibit 195.01, AUC-NERA-9(a).
274 Exhibit 391.02, NERA second report, page 9.
275 Decision 2009-035, paragraph 174.
276 The difference between terms "productivity" and "efficiency" is a definitional one. Dr. Makholm agreed when people refer to productivity, they usually refer to productivity growth, and they just leave out the word "growth" because productivity growth is measured in a percentage and some people confuse productivity growth with the actual efficiency at a point in time or the efficiency of one company. (Transcript, Volume 3, page 528, lines 5-25.)
277 Transcript, Volume 3, pages 490-491 and Volume 7, pages 1244-1245.
278 Transcript, Volume 17, page 3227 and pages 3430-3431.

and unobservable.[279] Factors such as age of plant, soil type, weather and geography, customer density, etc., are to be taken into account when considering efficiency levels. In these circumstances, inadvertently leaving out an important productivity driver may invalidate the results of the study.[280] Overall, the Commission agrees with the following criticism by NERA of the UCA's approach:

> So if you get into the business of drawing a productivity frontier and concluding that you know why a company is not on that frontier, that is, it's inefficient, you're making two errors. One, the error is concluding that you've actually measured a frontier, and we contend that, to a certain extent, you're measuring errors. And the second is that we economists have anything to say about whether a firm is or is not productive with the scarcity of data we have before us. Could be that you don't lie in the efficiency frontier because your utility is in a swamp. But if we can't measure swampiness, we have no way of correcting for that.[281]

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.

272. Under the UCA's efficiency benchmarking approach to developing the X factor, a company is incented to catch up to the level of efficiency experienced by peer companies deemed to be more efficient by the regulator, rather than to meet or beat the industry rate of productivity growth. Because of the practical and theoretical problems associated with measuring efficiency levels described above, the Commission does not accept this approach for the purposes of PBR in Alberta.

273. With respect to the menu approach to setting the X factor proposed as an alternative by the UCA's experts, for the reasons outlined below, the Commission is not prepared to adopt this approach.

274. First, similar to a discussion in sections 6.3.3 and 6.3.7 of this decision, the Commission is not persuaded that the UCA's X factors, based on ten-year data for Ontario distribution companies, represent a better indicator of the underlying long-term industry productivity trend than NERA's TFP based on a broad sample of companies over the period of 1972 to 2009. Second, as ATCO Electric pointed out, it is not clear why the X factor/ROE tradeoffs presented in the menu were reasonable for the Alberta companies.[282] In particular, the ROE ceilings in the menu do not correspond to the Commission's determinations in the most recent Generic Cost of Capital decision.[283] In addition, EPCOR pointed out that the UCA's menu approach presupposes the inclusion of an ESM (earnings sharing mechanism) in the PBR design.[284] The Commission determines in Section 10 of this decision that in order to maximize the incentive properties of PBR, an ESM should not be part of the companies' plans.

279 Transcript, Volume 3, pages 490-491 and Volume 7, pages 1244-1245.
280 Transcript, Volume 18, pages 3482-3483.
281 Transcript, Volume 3, page 491, line 20 to page 492, line 6.
282 Exhibit 647, ATCO Electric argument, paragraph 123.
283 Transcript, Volume 17, pages 3204-3205.
284 Exhibit 646.02, EPCOR reply argument, paragraph 74.

275. In addition, the Commission observes that the Ontario Energy Board did not accept the menu approach, partly because of the concerns regarding "the unnecessary complexity encompassed in the proposed menu."[285] A similar concern was expressed by EPCOR's expert, Dr. Weisman, who supported his view with the following quotation from an academic article:[286]

> Allowing for a choice among incentive plans can complicate the regulatory task, thereby sacrificing simplicity. The costs of reduced simplicity must be weighed against the expected gains from creating "win-win" situations.[287]

276. The Commission shares these concerns. In the Commission's view, the UCA's menu approach does not conform to AUC Principle 3, which requires, among other things, that a PBR plan should be easy to understand, implement and administer. Based on the above considerations, the Commission does not accept the menu approach proposed by the UCA.

277. The Commission restates the preference expressed in Decision 2009-035 for an approach to setting the X factor that is based on the long-term rate of productivity growth in the industry. During the hearing, NERA explained the rationale behind this approach as follows:

> The theory that we're drawing from doesn't require such precision. It says that there is an industry out there that's doing something. If it's a competitive industry -- it's an industry for making [hockey sticks], I don't know. [...] And of all the makers of hockey sticks, there's a productivity trend for hockey stick makers, and if you can't keep up, your business will fail. We don't need to be vastly more sophisticated than to measure the productivity of the hockey stick industry and use that as our way of allowing regulatory lag to eke out a few more years to avoid a couple of rate cases and to allow a little more productivity pressure to be visited on utility managements to try to make the businesses run better.[288]

278. As NERA emphasized, this concept corresponds to the underlying theory behind the PBR plans in Canada and the United States: to permit regulated prices to change to reflect general price changes and industry productivity movements without the need for a base rate case. The effect is to lengthen regulatory lag and better expose regulated utilities to the type of incentives faced by competitive firms.[289]

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.

285 Exhibit 299.02, Cronin and Motluk UCA evidence, page 174.
286 Sappington, David E. M., *Designing Incentive Regulation.* Review of Industrial Organization, Volume 9, 1994, page 260.
287 Exhibit 473.09, rebuttal testimony of Dennis L. Weisman, Ph.D., page 16.
288 Transcript, Volume 3, page 476, line 17 to page 477, line 5.
289 Exhibit 391.02, NERA second report, paragraph 2.

6.3 Total factor productivity

6.3.1 The purpose of total factor productivity studies

280. As set out in the previous section of this decision, the Commission opted for an approach to set the X factor based on the average rate of productivity growth in the industry. Under this approach, the first step in determining the X factor is to examine the TFP (total factor productivity) of the electric and gas distribution industries.

281. For this purpose, the Commission engaged NERA to conduct a TFP study applicable to Alberta gas and electric companies.[290] NERA filed its report entitled "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative" dated December 30, 2010 as Exhibit 80.02. The study was based on a population of 72 U.S. electric and combination electric/gas companies from 1972 to 2009. NERA measured the TFP of the distribution component of the electric companies. Costs related to power generation and transmission, as well as general overhead costs, were not included in the study.[291]

282. In addition to NERA's study, PEG on behalf of the CCA performed a TFP also referred to as a multifactor productivity (MFP)[292] study for the gas distribution industry. PEG's analysis examined the productivity growth of 34 U.S. gas distribution companies for the period from 1996 to 2009. In its study, PEG calculated the TFP trends of the sampled companied as providers of gas transmission, storage, distribution, metering and general administration services.[293]

283. In its report, NERA explained that productivity growth for a particular firm, by definition, is the difference between the growth rates of a firm's physical outputs and physical inputs. That is, to the extent that a firm's productivity grows, it will transform its inputs into a greater level of output. Accordingly, the task of productivity measurement involves comparing a firm's outputs and inputs over time. Total factor productivity measures all of a firm's inputs and outputs, combining the various inputs and outputs into single input and output indexes suitable for comparison to one another for purposes of measuring the rate of productivity growth over time.[294]

284. NERA pointed out that the main purpose of the TFP growth study is to measure the underlying long-term trend in industry productivity growth.[295] The UCA agreed with NERA that TFP should reflect long-term productivity growth.[296] Similarly, ATCO Electric and ATCO Gas expressed their understanding that a TFP study produces an estimate of the long-term TFP growth of the industry. At the same time, the ATCO companies cautioned that in using the TFP result as a starting point for determining the X factor in a PBR plan, it is necessary to

290 Exhibit 71.01, AUC letter – Retention of Consultant to Develop Basic X Factor, September 8, 2012.

291 Exhibit 80.02, NERA report, page 6.

292 Dr. Lowry explained that, strictly speaking, MFP is a more accurate term than TFP, since the latter implies that all of the company's inputs are taken into account in its computation, which is often not possible or practical to do. However, Dr. Lowry agreed that generally these terms can be used interchangeably. MFP is the term used by Statistics Canada (Transcript, Volume 13, page 2451).

293 Exhibit 307.01, PEG evidence, page 2.

294 Exhibit 80.02, NERA report, page 5.

295 Exhibit 391.02, NERA second report, paragraph 38.

296 Exhibit 634.02, UCA argument, page 21, paragraph 117.

consider whether the historical long-term productivity trend of the industry is a reasonable estimate of the expected productivity growth of the utility during the PBR plan term.[297]

285. EPCOR concurred that the purpose of the TFP is to assist in determining what productivity growth is expected to be over the course of the PBR term.[298] In contrast, IPCAA contended that TFP analyses have no apparent relevance to electric distribution system economics, save as broad long-term overall indicators.[299] However, IPCAA's concerns in this regard appeared to center on the fact that TFP studies rely on energy throughput as an output measure, as further discussed in Section 6.3.6 of this decision.

286. In Fortis' view, since statutory requirements must take precedence over other ratemaking principles, the TFP study should not be the core foundation for the Commission's determination of the X factor. Specifically, Fortis submitted that because the Alberta statutory framework under the *Electric Utilities Act*, SA 2003, c. E-5.1, mandates that the rates being set must provide a reasonable opportunity to recover the prudent costs of the provision of the regulated service, and because rates are being set for the initial PBR term, expectations as to the achievable productivity growth for the PBR term must prevail over considerations of the long-term industry productivity growth.[300]

Commission findings

287. As set out in Section 6.2 above, the objective of the PBR plan sought by the Commission is to emulate the incentives experienced by companies in competitive markets where prices move according to the productivity of the industry in question rather than with the particular costs of a company. Under this approach, the first step in determining the X factor is to examine the underlying industry productivity growth over time, commonly measured by total factor productivity.

288. Accordingly, the Commission agrees with NERA that, in these circumstances, the purpose of the TFP study is to estimate the long term productivity growth of the industry in question.[301]

289. The Commission does not share Fortis' view that expectations as to the achievable productivity growth for the PBR term must prevail over considerations of the industry TFP when determining the X factor. In the Commission's view, Fortis' submission is reflective of the company's overall approach to determining the X factor as a mechanism to recover the forecast cost of service revenue requirement over the PBR term. As set out in Section 6.2 above, the Commission does not agree with this approach.

290. Fortis emphasized that the *Electric Utilities Act* stipulates that the companies' rates must provide a reasonable opportunity to recover the prudent costs of the provision of the regulated service. In the Commission's view forecasting the projected revenue requirement over a PBR term is not the only way to satisfy this statutory mandate. In that regard, the Commission agrees with NERA's explanation that the rationale behind the X factor (to which the TFP study contributes) is to emulate the incentives of competitive markets as they relate to productivity. In

297 Exhibit 631, ATCO Electric argument, paragraph 81 and Exhibit 632, ATCO Gas argument, paragraph 90.
298 Exhibit 630.02, EPCOR argument, paragraph 62.
299 Exhibit 306.01, Vidya Knowledge Systems evidence, page 5.
300 Exhibit 633, Fortis argument, paragraphs 100-103.
301 Exhibit 391.02, NERA second report, paragraph 38.

competitive markets, if a company achieves greater productivity growth than the industry, it is rewarded by larger earnings in the short run. If a company's productivity growth is lower than the industry productivity, its earning suffer in the short run.[302] Accordingly, in the Commission's view, the approach to determining the X factor based on the average productivity growth in the industry together with the selection of the I factor and the other features of the approved PBR plans provide regulated companies with a reasonable opportunity to recover their prudent costs of providing the regulated services.

6.3.2 Relevant time period for determining the TFP

291. The appropriate time period over which to calculate TFP for purposes of the companies' PBR plans garnered much attention in this proceeding. NERA recommended the use of its full set of data from 1972 to 2009, being the longest time period available from the Federal Energy Regulatory Commission (FERC) Form 1 dataset that NERA relied on.[303] The majority of other parties recommended a substantially shorter period.

292. NERA pointed out that the TFP growth analysis should span a sufficient number of years to mitigate the effects of business cycles or other idiosyncratic swings associated with annual changes in the use of inputs and outputs, for example, major capital replacements. Consequently, NERA argued that the more years of data that are added to the study, the more the effects of year-to-year changes in TFP growth are moderated and a picture of long-term productivity growth emerges.[304] As a result, NERA's TFP calculation was based on the 38 years of available data.

293. In its second report NERA provided additional reasons in support of its position to use the longest time period available. NERA pointed out that in a competitive market, from which the incentives inherent in PBR plans are drawn, equilibrium prices are affected only by changes in long-run average cost. Short-run changes in productivity, even industry-wide changes in productivity, do not cause firms to enter or leave an industry.

294. Furthermore, on the issue of whether a more recent period is more reflective of the expected productivity growth in the coming years as advocated by most other parties, NERA argued that unless there is reliable proof to the contrary, the best and most supportable economic assumption is that while productivity growth may fluctuate in an erratic manner in the short term, or in a longer-term cyclical manner, it will eventually revert back to its long-term underlying trend.[305]

295. NERA noted that if one suspects that any of the TFP growth series are not stable in the long term (thereby justifying a departure from the use of long-term industry data), the appropriate response to such suspicion is to implement a statistical testing procedure in accordance with accepted research in the area of "structural breaks." In that regard, NERA experts explained that such analysis involves a two-step process: first, it is necessary to postulate a theory about why a structural break could have occurred, and, second, it is necessary to perform a number of statistical tests to see if the postulated hypothesis is supported by the data.[306] Dr. Makholm emphasized that performing an ex post statistical analysis of visual data without

302 Exhibit 195.01, AUC-NERA-8(a).
303 Transcript, Volume 1, pages 44-47.
304 Exhibit 80.02, NERA report, page 6.
305 Exhibit 391.02, NERA second report, page 14.
306 Transcript, Volume 1, pages 81-85.

having a supportable hypothesis for a structural break harms the process and biases the researcher.[307]

296. Dr. Makholm observed that he was not aware of any academic studies that would suggest that a structural break occurred at any time within the 1972 to 2009 time period for which data were available with respect to the electric distribution industry in North America.[308] As a result, NERA supported the use of the full time period as the most objective basis for the TFP calculation. Calgary supported this position.[309]

297. The companies' experts contended that NERA's sample period, especially the early part of it, was not relevant for estimating the industry's current TFP trends or the trends that might be expected to prevail during the PBR term. Specifically, ATCO and EPCOR experts in their respective evidence pointed out that in the 1970s and 1980s, the utilities sector was vertically integrated, owning and operating generation facilities with little wholesale and no retail competition. Dr. Carpenter and Dr. Cicchetti concluded that productivity improvements pertaining to the vertically integrated utilities observed in the early part of NERA's study period were unlikely to be realized by today's unbundled distribution companies and as a result, a more recent period should be used for estimating the industry TFP.[310]

298. Furthermore, to test NERA's conclusion that a structural break had not occurred in the electric distribution industry, Dr. Cicchetti performed a number of statistical tests on NERA's productivity data and found that the TFP growth in the 1999 to 2009 period was statistically different than in prior years. Dr. Cicchetti concluded that a structural break occurred in 1999 and, therefore, a more recent period should be used for the purpose of the TFP and X factor determinations.[311]

299. Ms. Frayer on behalf of Fortis also noted that there have been structural changes in the electric utility sector involving changes in investment trends, technology deployment, operating practices, customer consumption patterns, and regulatory incentives. In addition, Fortis' expert indicated that as industries and firms get more and more efficient, it is unreasonable to assume that they should sustain the same level of productivity growth over time. Accordingly, Ms. Frayer's analysis was mostly based on the data from the years 2000 to 2009.[312]

300. In the same vein, based on their observation of the cumulative rate of TFP growth, AltaGas experts argued that a significant break in the productivity trend occurred around the year 2000. Specifically, Dr. Schoech observed that prior to 2000, the TFP for the U.S. electricity distributors in the NERA study grew at a substantial 1.6 per cent, while since 2000, the TFP has been declining at the approximate rate of -1.4 per cent. Similar to the other companies' experts, Dr. Schoech offered restructuring of the industry and changing consumption patterns as possible explanations for changes in the productivity.[313]

301. In developing their recommendations as to the relevant time period for the TFP calculations, the companies' experts also considered regulatory precedents. Dr. Cicchetti noted

307 Transcript, Volume 1, page 88, lines 7-15 and page 95, lines 11-19.
308 Transcript, Volume 1, page 91, line 23 to page 92, line 2.
309 Exhibit 629, Calgary argument, page 23.
310 Exhibit 103.05 Cicchetti evidence, page 10 and Exhibit 98.02, Carpenter evidence, page 21.
311 Exhibit 473.07, Cicchetti rebuttal evidence, page 14.
312 Exhibit 474.02, Frayer rebuttal evidence, pages 18-20 and Exhibit 100.02, Frayer evidence, page 79.
313 Exhibit 110.01, Christensen associates evidence, pages 11-12.

that based on his experience with PBR plans for energy utilities, the typical range for estimating the industry TFP growth is about 10 to 11 years.[314] Dr. Carpenter indicated that other TFP studies that he had seen generally use time frames no longer than 10 to 15 years.[315] Ms. Frayer pointed to a number of TFP studies used by other regulators with sample periods from four to 13 years.[316]

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.[317]

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.[318]

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.[320] 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.

305. With respect to the 10 to 15-year timeframes advocated by the companies' experts relying on the NERA study, PEG contended that the suggested sample periods do not have an objective basis. In particular, Dr. Lowry noted that the companies have provided no credible explanation of why the sample period should begin just as the period of slower productivity growth begins. Moreover, Dr. Lowry reiterated his opinion that if a substantially shorter sample period (e.g., 10 to 15 years) such as those advocated by company witnesses is to be entertained, the exclusion of the 2008 to 2009 recession years becomes imperative for recognition of a long-term trend given the volumetric output index utilized in the NERA study.[322]

314 Exhibit 103.05 Cicchetti evidence, paragraph 18.
315 Exhibit 98.02, Carpenter evidence, page 25.
316 Exhibit 474.02, Frayer rebuttal evidence, page 21.
317 Transcript, Volume 13, pages 2490-2491.
318 Transcript, Volume 13, pages 2490-2491 and pages 2502-2503.
319 Exhibit 569.01, PEG evidence errata, page 9.
320 Transcript, Volume 13, pages 2490-2491.
321 Exhibit 372.01, AUC-CCA-5(a).
322 Exhibit 569.01, PEG evidence errata, pages 7-9.

Commission findings

306. The length of a sample period can be a critical issue when indexes are used to estimate long run productivity trends, as demonstrated by the fact that just removing the last two years from NERA's sample period raises the TFP growth trend from 0.96 to 1.13 per cent.[323] The CCA submitted that when selecting the relevant sample period for a TFP study, the following two objectives must be considered:

- smooth out the effect of cost and output volatility
- capture the TFP growth trend that is most likely to be pertinent during the PBR plan period[324]

307. Most experts in this proceeding agreed that the time period for the TFP measurement should be long enough to smooth out the inevitable year-to-year variation in results that obscures the long term productivity trend of the industry.[325] As Ms. Frayer observed, specific annual circumstances with respect to weather and consumption, capital spending, labour, etc., contribute to the volatility of year-to-year TFP numbers.[326] There appeared to be an agreement among the parties that a sample period of at least 10 years is desirable for the purpose of determining the long-term industry TFP.[327]

308. However, much of the debate in this proceeding was centered on the issue of what historical time period to use to predict the productivity growth likely to be experienced by the industry during the PBR term. NERA's experts contended that unless the TFP growth series is not stable in the long term, as demonstrated by a structural break, the best economic assumption is that the industry productivity growth will eventually revert back to its long-term underlying trend.[328] Therefore, the use of the longest time period for which data is available is warranted absent evidence of a structural break in the productivity of the industry.

309. While accepting that a long-term productivity measure is required, the companies' experts contended that the period recommended by NERA was too long. These experts pointed to a number of changes in the electric distribution industry over time, of which the unbundling of distribution and generation facilities and the introduction of retail competition in the mid 1990s were the most significant, and suggested that the underlying industry TFP trend had changed.[329] In other words, using NERA's terminology, the companies hypothesized that a structural break in the industry productivity trend had occurred.

310. A discussion arose during the hearing as to whether restructuring and various other changes to the electric distribution industry can be characterized as a structural break that alters the long-term industry productivity trend.[330] NERA was of the opinion that the determination on

323 Exhibit 307.01, PEG evidence, page 36.
324 Exhibit 636, CCA argument, paragraph 63.
325 See, for example, Exhibit 80.02, NERA report, page 6; Exhibit 307.01, PEG evidence, page 19; Exhibit 98.02, Carpenter evidence, page 25.
326 Exhibit 100.02, Frayer evidence, page 63.
327 Exhibit 307.01, PEG evidence, page 28, and Transcript, Volume 13, page 2494, line 6; Exhibit 631, ATCO Electric argument, paragraphs 61-62; Exhibit 632, ATCO Gas argument, paragraphs 69-70.
328 Exhibit 391.02, NERA second report, page 14.
329 Exhibit 630.01, EPCOR argument, paragraph 49; Exhibit 98.02, Carpenter evidence, page 21; Exhibit 474.02, Frayer rebuttal evidence, page 19; Exhibit 110.01, Christensen Associates evidence, pages 11-12.
330 See for example, Transcript, Volume 3, pages 477-481; Volume 4, pages 570-571; Volume 8, pages 1400-1403; Volume 11, pages 1995-1997; Volume 11, pages 2109-2113.

the subject of structural breaks lies outside the scope of regulatory proceedings and belongs to a realm of academic study. Dr. Makholm stated in testimony:

> [W]e want to stress the importance of making sure that something that would have such a severe affect on a TFP growth trend as bifurcating the study period would not come about lightly, and not come about in a contested proceeding among interested parties where the minutiae of econometrics or empirical work often go way beyond the heads of even the experts in the room. And in that respect, it was our search or objectivity and a support among people who have no interest in the outcome of the question that led us to say, in our second report, that you would want, if something so important as a structural break entered this kind of analysis, to have that support come from outside the proceeding from disinterested sources.[331]

311. With respect to the statistical tests performed by Dr. Cicchetti, NERA commented that without the underlying economic theory, these statistical tests have a very limited explanatory power. When viewed in isolation, the statistical tests simply confirm that the TFP growth in a particular period was distinctly (i.e., "statistically significant") different from the TFP growth in other periods. The test does not, by itself, explain the reasons for such a difference and cannot prognosticate whether the TFP growth in any particular period is indicative of the changes in productivity likely to occur during the prospective PBR term.

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.

313. NERA indicated that to the best of its knowledge, the only structural breaks discussed by scholars were the World Wars, the Great Crash in 1929 and the 1970s oil price shock.[332] The companies did not point to any external studies on this issue. In the absence of any independent academic studies examining the issue of structural breaks in the electric and gas distribution industries, the Commission is not prepared to accept the proposition that the long term underlying TFP trend of the industry had changed around the mid- or late1990s as implied by the companies' experts.[333]

314. With respect to the electric industry restructuring, the Commission observes that NERA used data only on the distribution portion of the sampled companies' businesses.[334] In the Commission's view, this approach sufficiently mitigates the concerns about the impact of industry restructuring on the TFP estimate. The Commission accepts NERA's view that electric industry restructuring did not necessarily lead to a change in the rate of growth of productivity for the distribution portion of the industry.[335]

315. Furthermore, the Commission is not persuaded by the companies' arguments that a more recent period provides a better indication of likely industry TFP during the PBR term. As further

331 Transcript, Volume 2, page 300, lines 8-22.
332 Exhibit 391.02, NERA second report, pages 15-16.
333 Exhibit 630.01, EPCOR argument, paragraph 49; Exhibit 98.02, Carpenter evidence, page 21; Exhibit 474.02, Frayer rebuttal evidence, page 19; Exhibit 110.01, Christensen Associates evidence, pages 11-12.
334 Exhibit 80.02, NERA report, page 6.
335 For example, Transcript, Volume 1, pages 109-111 (Dr. Makholm).

explained in Section 6.3.6 of this decision, because NERA used a volumetric output measure, the resulting TFP estimate is sensitive to economic recessions and upturns. In these circumstances, as PEG observed in its evidence, a company's productivity growth in one five or 10-year period may be very different from its productivity growth in the following five years, depending on what part of the business cycle the economy is in.[336] Dr. Lowry explained that the productivity of a company going into a recession (i.e., from peak to trough of a business cycle) may be very different from the productivity of the same company coming out of the recession when energy throughput is used as an output measure.[337]

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.[338] 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.[339] In AltaGas' view, it was vital that years 2008 and 2009 be included in the study to arrive at a balanced assessment of TFP.[340]

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.[341]

318. With respect to the argument that some other jurisdictions relied on a shorter time period for estimating TFP growth, the Commission notes that in many of those cases the period for a TFP study is driven by data limitations rather than a deliberate choice of the most relevant period for productivity calculations or is the result of settlement negotiations. This is especially true in the case of PBR plans based on efficiency frontiers and benchmarking studies which require a large amount of company-specific data for the selected group of peer companies. Dr. Cicchetti and Ms. Frayer noted that their observation of the other regulators' use of a 10-year period was more in the nature of a "rule of thumb."[342] The circumstances leading to the acceptance by other regulators of a sufficient TFP time period are varied and in the Commission's view do not suggest an accepted regulatory practice. This conclusion is reinforced by the differing views on the correct time period over which to conduct a TFP study reflected in the evidence of the various experts in this proceeding.

336 Exhibit 307.01, PEG evidence, page 23 and Exhibit 569.01, PEG rebuttal evidence (corrected), pages 7-9.
337 Transcript, Volume 13, page 2503, line 9 to page 2504 line 1.
338 Exhibit 569.01, PEG rebuttal evidence (corrected), pages 7-9.
339 Exhibit 632, ATCO Gas argument, paragraph 77 and Exhibit 628, AltaGas argument, page 21.
340 Exhibit 650, AltaGas reply argument, page 18.
341 Exhibit 645, CCA reply argument, paragraph 38.
342 Transcript, Volume 11, page 2056, lines 10-15 and Volume 11, page 2115, lines 1-14.

319. In light of the above considerations, the Commission agrees with NERA's view that using the longest time period for which data are available is theoretically sound and represents the most objective basis for the TFP calculation. In the Commission's view, in the absence of any external scholarly studies pointing to a structural break in the TFP trend of the electric distribution industry, NERA's analysis based on a full 1972 to 2009 sample is the best indicator of the expected industry productivity growth during the PBR term. Moreover, such an approach eliminates the inevitable subjectivity involved in choosing a truncated time period for determining the industry TFP and mitigates the incentive to "cherry-pick" the start and end points to arrive at a desired TFP value.

320. In this respect, the Commission observes that PEG's preference for a 15-year sample period appeared to be primarily based on Dr. Lowry's personal judgement:

> Q. But what I'm trying to understand, though, Sir, the principles that you're applying in coming up with your period so that the subjectivity of picking the dates is reduced?
> A. Yes. Just based on my experience, you know, I used to think that you needed 10 years to smooth things out, and now I'm thinking more like 15. I don't know what more to say.[343]

321. The Commission recognizes that because PEG did not use a volumetric output measure, the resulting TFP may be less sensitive to the choice of start and end dates. As well, Dr. Lowry noted that the quality of data on the gas industry prior to 1996 was not good.[344] As such, the Commission acknowledges that it is uncertain whether having a longer time period for PEG's data would result in a different TFP measure. Nevertheless, in the Commission's view, PEG's approach to selecting the time period is more subjective than NERA's. Dr. Lowry acknowledged that if the Commission were to adopt his approach, the start and end dates of a sample period have to be reconsidered at the time of any PBR rebasing.[345]

6.3.3 The use of U.S. data and the sample of comparative companies in the TFP study

322. NERA's TFP study used a population of 72 U.S. electric and combination electric/gas companies. NERA noted that this population includes companies of different sizes and located in differed parts of the United States reflecting a wide diversity of geography, development and age.[346] PEG's study was based on a national sample of 34 U.S. gas distributors,[347] also with different operating characteristics.[348] In both studies, the sample size reflected the availability of reliable data for the U.S. companies in question.[349]

323. When questioned by the CCA on whether it is preferable to use a region-specific sample rather than a national sample, NERA's experts indicated that it is acceptable to base a TFP study on either all companies in an industry for which good data are available or to select a sub-sample

343 Transcript, Volume 13, page 2499, lines 5-10.
344 Transcript, Volume 13, page 2495, lines 14-16.
345 Transcript, Volume 13, page 2506, lines 7-9.
346 Exhibit 80.02, NERA report, page 4.
347 In its evidence, PEG also reported results of a subgroup of 7 Western U.S. companies (Exhibit 307.01, tables 1 and 2). However, as Dr. Lowry indicated, PEG did not base its recommendations on the Western subgroup analysis and it was included just as "another number for the Commission to use if they see fit" (Transcript, Volume 13, pages 2525-2527). Accordingly, the Commission did not discuss this part of PEG's evidence.
348 Exhibit 307.01, PEG evidence, pages 26-27.
349 Transcript, Volume 3, page 458, line 23 to page 459, line 3 and Volume 13, page 2528, lines 16-21.

if the sub-sample is large enough to provide a reliable measure of productivity growth.[350] In that regard, Dr. Makholm pointed out that NERA's previous TFP study for Alberta from 2000[351] was based on a group of companies from the Western region. However, because the number of companies remaining in the Western region had declined since that time, NERA concluded that a TFP estimate based on this smaller group would give a less reliable, consistent and robust measure of productivity growth. As a result, NERA examined a national population of companies for its TFP analysis in this proceeding.[352]

324. The UCA indicated that NERA's sample of U.S. utilities is not comparable to Alberta gas and electric utilities in many respects. For example, the UCA noted that the NERA study sample contained companies that are unlike any Alberta distribution utility in terms of geography and climatic conditions. In addition, the UCA indicated that the U.S. utilities are subject to multiple different regulatory regimes with some operating under PBR and others under cost of service regimes. Further, the UCA pointed to differences in a number of other operational characteristics such as retail sales or number of employees between the companies in NERA's sample and Alberta utilities.[353]

325. In the UCA's opinion, it is critically important that the multiple differing regulatory, operational, organization and geographical circumstances of the companies included in the NERA sample be fully understood. Accordingly, the UCA argued that the companies included in the comparative group for Alberta utilities should be (i) unbundled, (ii) have some degree of comparability, and (iii) if possible, some should have been under PBR for quite some time.[354] Given the availability of historical data (1988 to 1997) for the distribution utilities in Ontario, the UCA argued that there is simply no need to use the U.S. data.[355]

326. In response to these criticisms, NERA explained that the purpose of the TFP study is not to explain productivity levels but instead productivity growth rates. In other words, NERA's study did not examine whether one company has a greater level of output for the same level of inputs than another. Rather, NERA looked at how the ratio of outputs to inputs changes over time. As such, the unique cost features of any particular company cancel out in the process.

327. Furthermore, NERA observed that the theoretical purpose of the X factor (to which the TFP study contributes) is not to find proxies for the companies to be regulated but rather to find the long-term, underlying industry productivity growth trend that firms would face in competitive markets. As such, a focus on finding companies just like those in Alberta would not accomplish this objective. Given the generally-perceived similarity of both the legal construct for utility regulation in Canada and the United States as well as the organization of the utility industries in the two countries, NERA maintained that using the U.S. data is warranted in this case.[356] Calgary and Fortis agreed with this approach.[357]

---

350 Transcript, Volume 3, page 394, line19 to page 396, line 20.
351 Evidence of Jeff D. Makholm on behalf of UtiliCorp Networks Canada on its proposed PBR plan dated September 1, 2000 (Exhibit 195.01, AUC-NERA-5(a)).
352 Exhibit 391.02, NERA second report, paragraphs 45-46.
353 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 219-227.
354 Exhibit 634.02, UCA argument, paragraph 99.
355 Transcript, Volume 17, page 3219, lines 3-7 and page 3222, lines 1-16.
356 Exhibit 391.02, NERA second report, paragraphs 36-38.
357 Exhibit 629, Calgary argument, pages 23-24.

328. The other parties to this proceeding generally agreed with NERA's position on these issues. With respect to the study sample, EPCOR pointed out that the standard approach in North American PBR regulatory jurisdictions is to compare each company to the industry performance and not to specific peer groups.[358] Fortis also agreed with this approach, although Ms. Frayer expressed some concerns as to the applicability of the NERA study to Alberta companies.[359] The ATCO companies agreed with Dr. Makholm's opinion that a sample with fewer than 12 companies is too small to be representative of the industry TFP trends and supported NERA's approach of using the national population.[360]

329. Regarding the use of U.S. data, the CCA and the ATCO companies indicated that there are no suitable Canadian data available to make a reliable TFP estimate for the gas or electric distribution industries in Canada. Furthermore, even if suitable data were available, it is uncertain whether there are enough utilities in Canada to make a TFP estimate reliable given the small sample size it would be based upon.[361] Overall, the ATCO companies did not object to the use of the U.S. data, albeit subject to an adjustment for a productivity gap between the United States and Canadian economies, as further discussed in Section 6.4.2 of this decision.[362]

330. Similarly, Dr. Cicchetti on behalf of EPCOR noted that because of the differences between the United States and Alberta economies, the industry TFP trends that NERA estimated do not reflect economic conditions in Alberta. Nonetheless, Dr. Cicchetti concluded that NERA's U.S. data were a good starting point to use for the purposes of determining an X factor for EPCOR.[363] Ms. Frayer's preference was to consider relevant Canadian or Alberta utility data when available. However, in developing her recommendations for Fortis' X factor, Ms. Frayer used U.S. data and data from other jurisdictions, including the U.K., New Zealand and Australia.[364]

331. In the view of Dr. Schoech, it would be most desirable to look at the TFP growth for natural gas distribution companies that are most comparable to AltaGas in terms of their market context, in particular, the number of customers served and population density.[365] However, recognizing that there may not be historical data for utilities closely similar to AltaGas, the company's experts used broader sources of data to determine an appropriate historical estimate of TFP and to develop their proposal for the X factor. Specifically, in AltaGas' analysis, the results of the NERA's study were complemented with Statistics Canada's estimate of MFP trends in the gas distribution sector which also include water and other system utilities.[366]

332. AltaGas also took issue with PEG's study sample. First, AltaGas noted that PEG's productivity analysis was drawn from data representing less than half of the U.S. gas distribution industry. Second, in AltaGas' view, the selection of companies was biased, favouring larger service providers. And finally, AltaGas contended that it was unlikely that PEG's productivity study included any gas distributors with service territories and business contexts comparable to

358 Exhibit 630.02, EPCOR argument, paragraph 55.
359 Exhibit 633, Fortis argument, paragraph 91 and Exhibit 474.02, Frayer rebuttal evidence, pages 14-15.
360 Exhibit 631, ATCO Electric argument, paragraph 71; Exhibit 632, ATCO Gas argument, paragraph 78.
361 Exhibit 636, CCA argument, paragraph 75; Exhibit 631, ATCO Electric argument, paragraph 80; Exhibit 632, ATCO Gas argument, paragraph 89.
362 Transcript, Volume 3, page 591, line 23 to page 592, line 3.
363 Exhibit 630.02, EPCOR argument, paragraph 59.
364 Exhibit 633, Fortis argument, paragraph 96.
365 Transcript, Volume 8, page 1417, line 12 to page 1418, line 9.
366 Exhibit 628, AltaGas argument, pages 22-23.

those of the company.[367] The latter concern was also raised by Dr. Carpenter, who noted that ATCO Gas has a customer density well below the average of PEG's sample.[368]

Commission findings

333. As explained earlier in Section 6.2 of this decision, the UCA's approach to determining the X factor was based on an examination of the companies' efficiency or, in other words, whether one company has a greater level of output for the same level of inputs compared to other companies. The Commission explained that under this approach it is important to control for all the factors contributing to a firm's level of efficiency, since inadvertently leaving out an important productivity driver may invalidate the results of the study. In these circumstances, the search for companies with similar characteristics (location, size, geography, weather, consumption patterns, etc.) for the purposes of inclusion in the comparative group on which to base the productivity study becomes of paramount importance for the PBR plans based on efficiency benchmarking.

334. As set out in Section 6.2 above, the Commission does not accept the efficiency benchmarking approach for the purposes of PBR in Alberta because of the practical and theoretical problems associated with measuring efficiency levels.

335. 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.[369]

336. Indeed, the experience of Dr. Cronin and Mr. Motluk corroborates this conclusion. The UCA witnesses observed that the Ontario companies exhibited a similar productivity growth rate during the PBR term despite the inherent differences in age, past performance and investment needs.

> But what was remarkable about that performance was the near uniformity that the [local distribution companies] exhibited in engendering TFP of 1.2 percent per year. It didn't matter if they were large, medium, or small. It didn't matter if they had more aged infrastructure. It didn't matter if they were high growth or low growth. It didn't matter if they were high capital additions or low capital additions. What they did was they found a way to operate under the PBR for that period of time. This was again confirmed under the second variable [productivity factor] PBR in the first half of this decade.[370]

337. The Commission agrees with NERA's characterization that the TFP estimate that informs the X factor is supposed to reflect industry growth trends, not the trends in Alberta alone or among a group of companies with similar operations and cost levels to those in Alberta.[371]

[367] Exhibit 628, AltaGas argument, pages 23-24.
[368] Exhibit 472.02, Carpenter rebuttal evidence, page 80.
[369] Exhibit 391.02, NERA second report, paragraph 37.
[370] Transcript, Volume 17, page 3183, line16 to page 3185, line 4; and see also at Transcript, Volume 17, page 3192, lines 16-20.
[371] Exhibit 391.02, NERA second report, paragraph 38.

338. In these circumstances, it is the Commission's view that when it comes to the sample size and the use of U.S. data in TFP studies, the relevant question to ask is not whether the companies in the sample are similar to the Alberta utilities, but: (i) whether the sample in the TFP study is reflective of the productivity trend in the U.S. power distribution industry, and (ii) whether the U.S. industry TFP trend represents a reasonable productivity trend estimate for the Alberta companies.

339. Regarding the first question, the Commission agrees with NERA, ATCO Electric and the CCA that a TFP study can be based on either all companies in the industry for which good data are available or on a sample of companies as long as this sample can provide a reliable, consistent and robust measure of industry productivity growth. The Commission observes that both NERA and PEG used data availability and data consistency as the primary criteria for including a particular company in their study sample.[372] Accordingly, the Commission does not consider that NERA's and PEG's sample selection is biased in any respect.

340. Furthermore, NERA pointed out that a study sample has to be large enough to provide robust estimates and did not recommend using a sample with fewer than 12 companies.[373] As noted earlier in this section, NERA's sample consisted of 72 companies of different sizes, reflecting a wide diversity of geography, development and age.[374] As well, PEG's study was based on a sample of 34 U.S. gas distributors.[375] The Commission considers these samples to be large enough and diversified enough to produce a TFP estimate that is reflective of the overall industry productivity growth.

341. With regard to the second question, the Commission notes that the need to use U.S. data in establishing productivity targets for Alberta regulated companies arose because of the lack of uniform and standardized data for Canadian electric and gas distribution utilities. As NERA and PEG pointed out, unlike in the United States, there is no Canadian central repository of public data due to the lack of standardized accounting across provinces with respect to utility operating reports.[376] Because of this data problem, regulators in Canada have used U.S. data. For example, the Ontario Energy Board, in several decisions, used U.S. data in establishing its PBR plans.[377]

342. Mindful of the existing Canadian data limitations, the Commission agrees with NERA, the CCA, the ATCO companies and EPCOR that given the generally perceived similarity of both the utility regulatory systems in Canada and the United States, as well as the organization of the utility industries in the two countries, the U.S. power distribution industry TFP growth trend is a reasonable starting point in establishing a productivity estimate for the Alberta companies.[378] This issue is further discussed in Section 6.4.2 of this decision dealing with the proposal for a productivity gap adjustment.

343. In light of the above considerations, the Commission finds NERA's and PEG's TFP study samples of 72 and 34 U.S. companies, respectively, to be acceptable, subject to the

---

372 Transcript, Volume 3, page 458, line 23 to page 459, line 3 and Volume 13, page 2528, lines 16-21.
373 Transcript, Volume 3, page 395, lines 12-24.
374 Exhibit 80.02, NERA report, page 4.
375 Exhibit 307.01, PEG evidence, page 26.
376 Transcript, Volume 2, page 290, lines 22-24; Exhibit 307.01, PEG evidence, page 25.
377 Exhibit 195.01, AUC-NERA-7 and Exhibit 634.02, UCA argument, paragraphs 110-111.
378 Exhibit 391.02, NERA second report, paragraph 36; Exhibit 636, CCA argument, paragraph 75; Exhibit 631, ATCO Electric argument, paragraph 80; Exhibit 632, ATCO Gas argument, paragraph 89; Exhibit 630.02, EPCOR argument, paragraph 59.

issues discussed below, as the starting point for a TFP analysis applicable to Alberta distribution utilities.

6.3.4 Importance of publicly available data and transparent methodology

344. In its September 8, 2010 letter to the parties, the Commission included the use of publicly available data and a transparent methodology as part of the requirements for NERA to meet in respect of its TFP study contributing to a PBR plan.[379]

345. NERA agreed with these requirements and pointed out that the extent to which PBR regulation transmits incentives to company management is critically dependent on the transparency, stability and objectivity of the formula that governs price movements between rate cases. In NERA's view, creating an index number for relative industry TFP with those attributes requires a high-quality transparent and uniform source of data that is readily available to the parties of regulatory proceedings. For this purpose, NERA used the data collected by the Federal Energy Regulatory Commission (FERC) for electric and combination electric/gas utilities on its Form 1 and other publicly available sources.[380] In NERA's view, the FERC Form 1 data are the only data that satisfy the criteria of transparency and objectivity for a large number of industry participants.[381]

346. NERA also expressed its opinion that transparency is the essential component of any analysis for the purpose of PBR plans. To this end, for each step of its analysis NERA documented the methodology and the data used to measure TFP. In addition, NERA's calculations and working papers, including any adjustments to the electronic dataset (such as for missing observations or rare but evident data anomalies) were made available for inspection and assessment by other parties.

347. All parties confirmed the importance of relying on publicly available data and transparent methodologies for the purpose of the TFP studies used in regulatory proceedings in order to make such studies objective and neutral.[382] In this respect, while no party questioned the transparency of NERA's methodology and the availability of FERC Form 1 data, parties to this proceeding took issue with PEG's productivity study over issues of objectivity and transparency.

348. With respect to transparency, ATCO Gas and AltaGas pointed out that PEG's study relied on a proprietary data which could not be fully tested in a public forum. Furthermore, these companies noted that even after examining PEG's working papers (made available under a confidential process), it was still unclear where individual data came from, as limited details were provided on the methods and sources used in the study.[383] Because of this lack of transparency in PEG's data and calculations, Dr. Carpenter indicated that he was not able to fully evaluate and replicate the results of PEG's TFP study.[384]

379 Exhibit 71.
380 Exhibit 80.02, NERA report, pages 3-4 and Transcript, Volume 1, pages 55-57.
381 Transcript, Volume 1, page 56, lines 6-14.
382 Exhibit 630.02, EPCOR argument, paragraph 57; Exhibit 631, ATCO Electric argument, paragraph 73; Exhibit 632, ATCO Gas argument, paragraph 80; Exhibit 628, AltaGas argument, pages 24-25; Exhibit 645, CCA reply argument, paragraph 45.
383 Exhibit 476.01, Carpenter rebuttal evidence, pages 74-77 and Exhibit 477, Christensen Associates rebuttal evidence, paragraph 36.
384 Exhibit 476.01, Carpenter rebuttal evidence, page 77 and Transcript, Volume 6, page 1007, lines 7-15.

349. On the same subject, NERA observed that since there is no federal collection of universal and consistent data on the U.S. gas distributors similar to the FERC data set for the electric industry, statistical data from individual states must be used. Because of the varying data reporting requirements in different states, NERA cautioned that compilation of data from varying sources may not be consistent.[385]

350. The gas companies' concern regarding the lack of objectivity in PEG's study primarily related to the econometric model that Dr. Lowry and his colleagues used in addition to the index approach for estimating TFP. In particular, PEG regressed the TFP index for the 32 gas companies in its sample against the number of gas distribution customers, the number of electricity customers (for companies that provide both gas and electric service), the line miles and a time trend variable. Applying the obtained coefficients to the projected variables for Alberta gas companies, PEG came up with a TFP estimate customized for business conditions in Alberta.[386]

351. With regard to this method of TFP calculation, ATCO Gas' and AltaGas' experts pointed to a number of issues in the set-up of PEG's econometric model relating to the choice of explanatory variables, model specification, the interpretation of results, the presence of heteroskedasticity, etc.[387] NERA observed that an econometric estimation of TFP growth is unavoidably based on many judgments that are difficult for non-specialists to understand. In NERA's view, such econometric analyses are more suitable for the purpose of peer-reviewed scholarly research and not for setting the level of consumer prices in a PBR plan.[388]

352. To allay concerns about the use of proprietary data, PEG recalculated the TFP growth of the sample of gas distributors employing data that are entirely in the public domain. This resulted in a modest decrease in PEG's TFP number, from 1.32 per cent to 1.19 per cent. At the same time, PEG noted that although most of its data can be independently gathered from the public sources, it chose to purchase them from respected commercial vendors because of the higher quality and value added services that they provide.[389] In that regard, Dr. Lowry proposed that the value added by the commercial vendors in gathering and processing the data is well worth the restriction of a confidentiality agreement to permit their use in a regulatory proceeding.[390]

Commission findings

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.[391] In this respect, the Commission observes that having extensively scrutinized and tested NERA's study, the companies were satisfied that

385 Transcript, Volume 1, page 52, lines 16-22.
386 Exhibit 307.01, PEG evidence, page 33.
387 Exhibit 476.01, Carpenter rebuttal evidence, pages 83-84 and Exhibit 477, Christensen Associates rebuttal evidence, paragraph 46.
388 Exhibit 391.02, NERA second report, paragraph 99.
389 Exhibit 478.01, PEG rebuttal, pages 20-21.
390 Transcript, Volume 13, pages 2456-2459.
391 Exhibit 391.02, NERA second report, paragraphs 95-96 and Exhibit 476.01, Carpenter rebuttal evidence, page 29.

NERA's TFP analysis complies with these criteria.[392] The Commission agrees. As Dr. Cicchetti commented on this issue:

> So my conclusion is NERA was objective and neutral as required to be by this Commission. It's also transparent in that you can see where the information came from. You can actually go back to the raw information to see if NERA made any mistakes in building the data set together and the like. And in that fashion I think they did exactly what the Commission asked and therefore I would use it as I did in my starting point.[393]

354. With respect to PEG's study, the Commission shares the gas companies' concerns that the TFP analysis of Dr. Lowry and his colleagues was not fully transparent and conducive to the detailed scrutiny by other experts or by the Commission.

355. While there is nothing inherently wrong with using proprietary data in regulatory proceedings, procedural fairness requires that parties must be provided with the opportunity of a fair hearing in which each party is given the opportunity to respond to the evidence against its position. This requirement clearly requires parties and the Commission to be able to fully understand, test and respond to the evidence filed in a proceeding. Further, the Commission has the obligation to provide reasons for its decisions. It can only do so if it is able to fully understand, test and analyze the evidence filed before it. Accordingly, fully transparent information is always preferable to information that requires the filing of motions for protection of confidential information and the execution of confidentiality agreements. It is also problematic if, in order to fully comprehend the confidential information, further explanations must be provided on the procedures used, assumptions made, judgment exercised and data adjustments made that produced the confidential evidence. In addition, as NERA observed, the problem with data that are not publicly available is that the research cannot be replicated. As well, there is a concern that such data will not be available at all or that only the original provider using the same assumptions, methodology and adjustments could be engaged to provide a consistent analysis when the parameters of the PBR regime are to be reset.[394]

356. The Commission agrees that it is highly desirable that any TFP analysis can be replicated by all willing parties to the proceeding. As Dr. Carpenter explained, until one has managed to replicate a piece of analysis, it is not possible to look for errors, adjust assumptions, and test for sensitivities.[395] In addition, as NERA pointed out, if Dr. Lowry and his colleagues at PEG are the only persons who are able to repeat the TFP analysis, the success of any future PBR plans will depend on PEG's participation.[396] For all of the above reasons, the Commission confirms its preference for a TFP study that relies on publicly available data.

357. The Commission's main concern with PEG's study relates to the overall lack of transparency with respect to data processing. The Commission accepts that because there is no central repository for data on the gas distribution industry, any researcher of this subject would be compelled to combine information from different sources, thus facing a problem of data consistency and uniformity.[397] However, to the extent that PEG compiled its dataset from a

392 Exhibit 632, ATCO Gas argument, paragraph 83; Exhibit 631, ATCO Electric argument, paragraph 76; Exhibit 630.02, EPCOR argument, paragraph 57; Exhibit 628, AltaGas argument, page 24.
393 Transcript, Volume 11, page 2017, lines 10-17.
394 Exhibit 391.02, NERA second report, paragraph 98.
395 Exhibit 476.01, Carpenter rebuttal evidence, page 82.
396 Transcript, Volume 1, page 56, lines 15-23.
397 Transcript, Volume 1, page 56, lines 6-14 and Volume 13, page 2467, lines 2-7.

number of sources (publicly available or not), it is of vital importance that all the steps and any adjustments to the data be clearly documented and explained. This would allow other experts to verify the accuracy of the data. As well, computation of the TFP estimate must be clearly explained. In this way, other parties to the proceeding can test and verify the calculations and, if necessary, replicate them in future proceedings. PEG's study did not satisfy these requirements.

358. For example, Dr. Lowry explained that PEG examined the dataset obtained from a commercial vendor and when necessary, made adjustments to the data to correct for any obvious anomalies:

> [...] not only does my staff do an initial screening and look for oddities to correct, to look for corrections, go make sure that that's what the form really said; but then it comes to me, and that's the final step is that I will go through very carefully and meticulously all the data and see if it squares with my expectations. And there will usually be 10 or 15 observations that need to be changed based on my second screening of the data.[398]

359. The Commission accepts that sometimes it may be necessary to adjust the raw data and in fact, NERA had to adjust its data as well. However, as Dr. Carpenter explained in his evidence, PEG did not clearly outline the adjustments it made.[399] In contrast, NERA made available for inspection and assessment by other parties any adjustments to the electronic dataset that it made as an integral part of its report.[400]

360. The importance of publicly available data and transparent methodology is demonstrated by the extent to which parties to this proceeding relied on NERA's working papers for developing their recommendations. For example, Dr. Cicchetti was able to estimate partial factor productivity (PFP) for EPCOR relying entirely on NERA's data.[401] As well, Dr. Cicchetti performed a number of statistical tests on productivity using company-level panel data.[402] Dr. Lowry, after scrutinizing NERA's working papers, suggested a number of corrections to NERA's study and was able to immediately quantify the impact of his recommendations on NERA's TFP estimate.[403]

361. If the parties had been using PEG's data, they would not have been able to engage in this type of detailed analysis without first executing a confidentiality agreement and working with PEG to understand all adjustments that were made to the vendor's data. For example, Dr. Carpenter pointed out that the output file that PEG provided included only summary results and did not provide the data for individual companies. As well, Dr. Carpenter pointed to the fact that PEG's computer code was written for a software package that was not commercially available.[404]

362. With respect to PEG's econometric model for TFP, the Commission agrees with NERA's explanation that the outcome of any regression model is highly dependent on the choice of explanatory variables, which represents the subjective judgment of the person conducting the analysis. As NERA explained:

398 Transcript, Volume 13, page 2460, lines 4-12.
399 Exhibit 472.02, Carpenter rebuttal evidence, page 28.
400 Exhibit 80.02, NERA report, Appendix II.
401 Exhibit 103.05, Cicchetti evidence, pages 22-23.
402 Exhibit 473.07, Cicchetti rebuttal evidence, page 9.
403 Exhibit 478, PEG rebuttal evidence, Table 3 on page 12.
404 Exhibit 476.01, Carpenter rebuttal evidence, pages 74 and 77.

> DR. MAKHOLM: I was the first one to do that. I did the first decomposition of electric utility TFP numbers anywhere, and it's my thesis. I've done that. And if you go to the back of that, you'll see page after page after page of coefficients that depend on the specification that I chose, the number of things I decided to measure, the kind of dummy variables that I would use.
>
> And the results of those decompositions, as I call them, were dependent on my particular specification and what I judged to be useful at the time. I put it that -- to this group and to this Commission that those decisions of mine, which were useful for doing my thesis work, could have been done differently, and they could have changed the result of how we would predict the TFP growth should be for any region or size of company or any arbitrary company out there, and it could have been a lot different.[405]

363. Dr. Lowry also agreed that the exclusion of relevant variables biases the estimators and noted that PEG's analysis included "as many variables that matter as we can."[406] For example, PEG offered that a company's productivity growth is a function of the number of customers (gas and electric, if applicable), line miles and time.[407] However, in AltaGas' opinion, the model should also have included the volume of gas delivered, as variation in usage per customer also affects productivity.[408] Therefore, the Commission agrees with NERA's conclusion that econometric models are prone to the criticism of being less objective and too complex for the purposes of PBR plans.

364. In light of the above considerations, the Commission agrees with NERA, ATCO Gas and AltaGas that the lack of publicly available data and transparent methodology represent major drawbacks to the use of PEG's productivity analysis. In contrast, as noted earlier in this section, the Commission agrees with the companies that NERA's TFP study was transparent and objective.

6.3.5 Applicability of NERA's TFP study to Alberta gas distribution companies

365. The data used in NERA's study are for the distribution portion of the electric companies, whether standalone or combination electric/gas companies according to FERC Form 1. NERA indicated that its study did not include data for standalone gas companies, since it was not aware of a readily available data source that would permit a comparably transparent TFP study for standalone gas companies.[409]

366. In NERA's view, the productivity of gas and electricity companies is similar. For example, NERA observed that both electricity and natural gas distribution are highly capital intensive. Additionally, in some instances the electricity and gas distribution facilities share the same support structure.[410] During the hearing, Dr. Makholm noted that based on his personal knowledge of operations of gas and electric distribution industries, the institutional framework and regulatory and business requirements for the two sectors are quite similar. Accordingly,

405 Transcript, Volume 3, pages 475-476.
406 Transcript, Volume 13, page 2548, lines 14-22.
407 Exhibit 307.01, PEG evidence, page 33.
408 Exhibit 477, Christensen Associates rebuttal evidence, paragraph 46.
409 Exhibit 80.02, NERA report, pages 6-7.
410 Exhibit 80.02, NERA report, pages 6-7.

Dr. Makholm expressed his opinion that it is not necessary to differentiate the productivity growth for gas and electric distribution industries.[411]

367. Furthermore, NERA observed that according to data from Statistics Canada, TFP growth during the period 1972 to 2006 for Canadian electric power generation, transmission and distribution companies was 0.28 per cent while for natural gas distribution, water and other systems TFP growth was 0.21 per cent, using gross output as the output measure. Using value added as the measure of output, the numbers are 0.37 per cent for electric power generation, transmission and distribution companies and 0.34 per cent for natural gas distribution, water and other systems.[412] At the same time, Dr. Makholm cautioned that NERA's observation of the Statistics Canada indexes was merely a "relatively casual view" of a data source that NERA did not use in its study.[413] PEG, AltaGas and the ATCO companies also indicated that Statistics Canada's MFP indexes were subject to a number of reporting difficulties, as further discussed in Section 6.3.7 below.[414]

368. In light of the above considerations, NERA expressed its opinion that a specialized TFP study for gas distribution companies would not be a useful part of Alberta's PBR initiative, given the lack of uniform and objective data for a broad sample of gas companies that such a study would require to be a part of a transparent and objective PBR plan. Based on its familiarity with electricity and gas distribution and transmission businesses from a regulatory perspective, NERA concluded that a robust TFP study using FERC Form 1 data is a useful component of a PBR plan that applies to both the electricity and gas companies in Alberta.[415]

369. ATCO Gas and AltaGas noted that it would be preferable to base the X factor for gas companies on a study that measured TFP growth for the gas industry, if a study of sufficient transparency and quality were available. However, because the two gas companies rejected PEG's productivity study, they noted that no such study was available in this proceeding.[416]

370. In these circumstances, ATCO Gas expert Dr. Carpenter observed that in the absence of any compelling reason to distinguish between electric and gas companies, and having regard for the Statistics Canada figures that NERA cited in its report, it is reasonable to assume that the same TFP is appropriate for gas and electric utilities in Alberta.[417] Similarly, AltaGas noted that NERA's report, along with the examination of Statistics Canada MFP indexes, provides some evidence useful for estimating the TFP growth rate of Canadian gas distribution companies.[418]

371. In a similar vein, the CCA noted that since the gas and electric power distribution businesses have similarities (such as a gradual growth in rate base and the importance of customers as a cost driver), TFP research from one industry could be used to set a productivity estimate for firms in the other industry if data for both industries were unavailable. However, the CCA maintained that this was not the case in the present proceeding. In the CCA's view, PEG's analysis on U.S. gas distribution companies is suitable for the purpose of setting establishing a

411 Transcript, Volume 1, pages 49-51.
412 Exhibit 80.02, NERA report, page 7.
413 Transcript, Volume 1, page 47, lines 4-6.
414 Exhibit 307.01, PEG evidence, pages 41-43; Exhibit 99.01, Carpenter evidence, page 26; Exhibit 110.01, Christensen Associates evidence, paragraphs 43-44.
415 Exhibit 80.02, NERA report, pages 4-5.
416 Exhibit 632, ATCO Gas argument, pages 27-28 and Exhibit 628, AltaGas argument, page 25.
417 Exhibit 99.01, Carpenter evidence, page 31.
418 Exhibit 628, AltaGas argument, page 25.

TFP for Alberta gas utilities. In addition, the CCA noted that other studies of the TFP trends of Canadian gas distributors, prepared for disinterested parties such as the Ontario Energy Board and the Gaz Métro Task Force, could also be useful for the purpose of setting a gas distribution company TFP.[419] Calgary agreed that with the inclusion of PEG's TFP analysis, there are data on the record for both electric and gas companies and that the Commission's determination on TFP should reflect a range which includes both analyses.[420]

372. The UCA submitted that the range of its proposed X factor menu accommodates the TFP results of both NERA and PEG. Accordingly, the UCA argued that its X factor menu provides appropriate X factor choices for both electric and gas companies.[421]

Commission findings

373. 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.

374. 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.

375. 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.

376. In particular, PEG referenced the 1.07 per cent TFP estimate for Enbridge Gas Distribution and the 1.65 per cent TFP estimate for Union Gas over the period 2006 to 2010. PEG also referred to the 1.66 per cent average annual TFP growth of Gaz Métro over the period 2000 to 2009.[422] However, the Commission observes that these TFP estimates are company-specific (i.e., these studies measure each company's own historical productivity growth and not the TFP growth of the industry).[423] Relying on these TFP estimates is not consistent with the Commission's preferred approach to determining the X factor that is based on the average long term productivity growth of the industry, as set out in Section 6.2 above. As NERA explained, the theory behind this approach dictates that the purpose of a TFP study is to estimate the long-

419 Exhibit 636, CCA argument, paragraph 73.
420 Exhibit 629, Calgary argument, page 24.
421 Exhibit 634.02, UCA argument, paragraph 106.
422 Exhibit 307.01, PEG evidence, pages 40-41.
423 These reports were filed as Exhibit 376.03 (Gaz Métro) and Exhibit 376.04 (Union Gas Ltd. and Enbridge Gas Distribution Inc.).

term productivity growth of the industry, not the productivity growth of any particular company.[424]

377. PEG also referenced two TFP estimates with respect to the U.S. gas distribution industry. The first study found a TFP estimate of 1.18 per cent for the U.S. gas distribution industry over the period of 1999 to 2008, and the second study reported a TFP of 1.61 per cent over the period of 1994 to 2004.[425] In the Commission's view, differences in employed sample periods, input and output measures, as well as methodologies (e.g., indexing vs. econometric estimates), do not allow for a direct comparison of these numbers with NERA's TFP estimate.

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.

6.3.6 Output measure in the TFP study

379. As set out in Section 6.3.1 above, productivity growth is specified as the difference between the growth rates of a firm's physical outputs and physical inputs.[426] Accordingly, the choice of an output measure directly affects the estimated TFP growth.

380. NERA indicated that its practice, both in this proceeding and in previous TFP growth analyses that it has undertaken, has been to use the sales volume, measured in kilowatt hours (kWh) as the measure of output. NERA recognized that it is possible to specify two or more outputs (such as kWh or numbers of customers) into a single output for measuring TFP. However, NERA stated its preference for kWh sales output measure, as the most representative of the nature of a company, the size of its system, and its revenues.[427]

381. At the same time, NERA accepted that this measure is not perfect and indicated that for the energy delivery business where much of the cost is tied up in long-lived capital, there are trade-offs in using one measure of output or another. For example, NERA pointed out that in a recession or in response to a price shock, kWh sales may decline with a distribution system that is otherwise unchanged, thereby seeming to show a decline in productivity growth. In that regard, NERA explained that its preference has always been to use kWh with the longest time series available so as to dampen the effects of the short-term or cyclical patterns that would most influence kWh sales as a measure of output.[428]

382. According to the CCA's experts, the correct output specification in a TFP study depends on the nature of the PBR plan. Specifically, PEG contended that volumetric output measures, such as the kWh sales used by NERA in its TFP study, are not correct in the context of revenue-per-customer cap plans. To arrive at this conclusion, Dr. Lowry of PEG showed that, if one accepts the belief that the costs of gas distributors are chiefly driven by the growth in the number of customers served, the mathematical logic of Divisia indexes dictates that the number of

[424] Exhibit 391.02, NERA second report, paragraph 38.
[425] Exhibit 307.01, PEG report, page 40 and Exhibit 366.04.
[426] Exhibit 80.02, NERA report, page 5.
[427] Exhibit 391.02, NERA second report, paragraph 47.
[428] Exhibit 391.02, NERA second report, paragraph 47.

customers represents a relevant output measure to use in determining TFP as part of a PBR plan based on a revenue-per-customer cap.[429]

383. 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.[430] 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.[431] NERA agreed with this logic.[432]

384. Furthermore, Dr. Lowry observed that in the presence of declining use per customer, a gas TFP study based on a volumetric output index would produce a lower productivity growth estimate compared to using the number of customers as an output measure.[433] Consequently, using a volumetric output measure in this instance would result in a TFP estimate and an X factor that are too low, lower than if the correct customer output measure had been used. This is because when usage per customer is falling, the rate of growth of customers will be greater than the rate of growth of energy transported. Therefore, the TFP growth rate, which is determined by subtracting the rate of growth of inputs from the rate of growth of outputs, will be greater when the correct customer output measure is used rather than the incorrect volumetric output measure.

385. In a similar vein, Mr. Johnson on behalf of Calgary noted that in the case of a gas company with declining use per customer, it is likely that under a price cap approach the I-X component would have to be higher than if it was applied to a revenue cap.[434] That is, if one assumes that the I factor remains unchanged, Mr. Johnson appeared to suggest that for a company experiencing the declining use per customer, the X factor will be lower under a price cap plan as compared to a revenue cap plan in order to generate the same revenue stream.

386. AltaGas' expert, Dr. Schoech, generally agreed with Dr. Lowry that in the presence of declining use per customer for gas distribution companies, the use of a volumetric output measure would result in a lower TFP growth rate than is reflective of actual productivity growth and some adjustment would be necessary to account for this fact if the TFP study were to be used for the gas distribution companies.[435] Since Dr. Schoech expressed his preference that the output measure should include both volumes and customers, he indicated that any adjustment to an X factor for a price cap to determine an X factor for a revenue-per-customer cap must apply only to the portion of the revenue requirement generated through the volumetric charges.[436]

429 Exhibit 307.01, PEG evidence, pages 16-17; Exhibit 610.03, Attachment to CCA undertaking; Exhibit 645, CCA reply argument, paragraphs 89-91.
430 Transcript, Volume 14, page 2871, line 25 to page 2872, line 11.
431 Exhibit 636, CCA argument, paragraph 113.
432 Exhibit 273.03, CCA-NERA-2(e).
433 Transcript, Volume 14, page 2872, line 20 to page 2873, line 4.
434 Transcript, Volume 15, page 2926, line 23 to page 2927, line 8.
435 Transcript, Volume 8, page 1528, lines 12-17 and page 153, line 23 to page 1534, line 7.
436 Transcript, Volume 9, pages 1714-1715.

387. At the same time, Dr. Schoech pointed out that because both the NERA study and the Statistics Canada MFP measures base their output only on volumes, and not on both volumes and customers, the baseline for making this type of adjustment was not available.[437] Consequently, since the number of customers variable was not available for neither NERA's nor Statistics Canada's studies, AltaGas submitted that there is no basis for making an adjustment to the X factor to account for declining usage per customer.[438]

388. Similarly, Dr. Carpenter on behalf of the ATCO companies generally acknowledged that in the presence of declining use per customer, a volumetric output index employed in a gas utility TFP study produces a lower gas TFP growth rate compared to an output measure based on the number of customers.[439] However, Dr. Carpenter did not accept PEG's premise that the number of customers is a primary driver of the gas companies' costs.[440] With regard to the relevant output measure for a gas TFP study, Dr. Carpenter concluded that it is unclear whether the output index should be based on the number of customers, energy delivered, or a combination of the two.[441] Nevertheless, based on his examination of the record of this proceeding, Dr. Carpenter concluded that "the NERA output index is the best we have."[442]

389. ATCO Gas did not agree with Dr. Lowry's logic and submitted that the way in which TFP is measured should not depend on the use of the resulting estimate. As such, ATCO Gas argued that the determination of whether the TFP estimate should be made using the number of customers as the output measure or energy delivered as the output measure should not depend on what use is to be made of the resulting estimate.[443]

390. The experts of the other electric companies expressed some concerns with NERA's use of kWh as the measure of output. Dr. Cicchetti noted that any TFP study for electricity distribution should reflect the fact that activities associated with customer numbers are critical to the services that distributors provide, for example extending distribution networks to serve new customers, meter reading, service calls, etc. Accordingly, in Dr. Cicchetti's view, an output measure in a TFP study should include the number (and perhaps location) of customers that the companies serve.[444] A similar argument was put forward by IPCAA's and the UCA's experts who noted that using kWh as the only output measure does not accurately reflect the outputs the distribution company is providing.[445] In this case, Dr. Cicchetti explained that because in the electric distribution industry the usage per customer is growing, not declining, the rate of growth of customers will be smaller than the rate of growth of energy throughput.[446] Accordingly, Dr. Cicchetti's, IPCAA's and the UCA' recommendations on output measure would result in a lower TFP and a lower X for electric companies.

391. Ms. Frayer noted that the use of a single output measure will make the resulting TFP estimate more volatile, as demonstrated by the year-to-year results in NERA's report. In

437 Transcript, Volume 8, page 1534, lines 9-17.
438 Exhibit 628, AltaGas argument, page 36.
439 Transcript, Volume 6, page 979, lines 20-24.
440 Transcript, Volume 6, page 983, lines 3-11.
441 Exhibit 472.02, Carpenter rebuttal evidence, page 32.
442 Transcript, Volume 6, page 981, lines 1-2.
443 Exhibit 632.01, ATCO Gas argument, pages 21-27.
444 Exhibit 103.05, Cicchetti evidence, pages 13-14.
445 Exhibit 306.01, Vidya Knowledge Systems evidence, pages 4-5; Exhibit 299.02, Cronin and Motluk UCA evidence, page 235.
446 Exhibit 103.05, Cicchetti evidence, page 14.

Ms. Frayer's view, using more than one output measure would smooth out this volatility and produce a more stable output index that is more consistent with the multi-dimensional service that the distribution companies provide.[447]

Commission findings

392. The Commission agrees with the experts in this proceeding that each possible output measure (for example, energy sales, number of customers, line miles, peak usage, etc.) or combination thereof has its own merits and disadvantages.[448] However, the Commission agrees with NERA's and PEG's view that when selecting a particular output measure, it must be matched to the type (price cap or revenue-per-customer cap) of a PBR plan.[449]

393. As discussed in Section 4 of this decision, the Commission recognizes that the rate designs of the gas distribution companies do not entirely reflect their cost drivers. While a large proportion of gas distributors' costs are fixed, a significant portion of these costs is recovered through variable charges. Also, as discussed in Section 4, both AltaGas and ATCO Gas are experiencing a declining use per customer. In these circumstances, a decline in use per customer would lead to a decrease in the companies' revenues that would not be offset by a decrease in costs. As a result of these considerations, the Commission is approving PBR plans in the form of a revenue-per-customer cap for ATCO Gas and AltaGas.

394. The experts in this proceeding explained that by focusing on revenue per customer as opposed to prices per unit of gas delivered, the revenue-per-customer cap plan effectively shields the revenue of gas companies from variations in energy use per customer.[450] In these circumstances, Dr. Schoech[451] on behalf of AltaGas and Dr. Cicchetti[452] on behalf of EPCOR acknowledged that the number of customers, not the volumes sold, becomes the driver of a company's revenues.[453] 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.

395. Using similar logic, the Commission agrees with Dr. Lowry that output measures that place a heavy weight on volumetric and other usage measures should be used for TFP studies that are part of a price cap PBR plan.[454] Therefore, the Commission considers that kWh sold output measure used by NERA in its TFP study remains an acceptable output measure to use for the purpose of the price cap PBR plans approved for ATCO Electric, Fortis and EPCOR.

396. The Commission acknowledges the concerns of Fortis, EPCOR, IPCAA and the UCA that a single output measure such as kWh may not capture all of the outputs that an electric distribution company provides. However, as the Commission observed earlier in this section, a consensus on the best measures to use has not been reached, with different experts offering different measures. For example, Dr. Cronin noted that the most relevant output measure is the

447 Exhibit 474.02, Frayer rebuttal evidence, page 16.
448 Exhibit 391.02, NERA second report, paragraph 47.
449 Exhibit 307.01, PEG evidence, page 12; Exhibit 273.03, CCA-NERA-2(e).
450 Exhibit 100.02, Frayer evidence, page 23; Transcript, Volume 6, page 986, lines 9-13; Transcript, Volume 14, pages 2871-2872.
451 Transcript, Volume 9, pages 1714-1715.
452 Transcript, Volume 11, page 2070, lines 3-6.
453 Transcript, Volume 9, page 1714, lines 8-18.
454 Transcript, Volume 14, 2872 lines 4-7.

number of customers.[455] In Dr. Cicchetti's[456] and Ms. Frayer's[457] view, both megawatt hours and the number of customers have to be considered. Dr. Carpenter concluded that it is unclear whether the output measure should be based on the number of customers, energy delivered, or a combination of the two.[458] Dr. Lowry preferred energy delivered.[459] In light of this uncertainty, the Commission is not persuaded that NERA's output measure of kWh sold is an inferior output measure compared to the variety of alternatives proposed.

397. With respect to Ms. Frayer's concern that the use of a single output measure based on energy volumes will make the resulting TFP estimate more volatile, the Commission agrees with NERA that using kWh with the longest time series available will mitigate such volatility.[460] Overall, the Commission agrees with Dr. Carpenter's view that NERA's output index measuring kWh sold is an acceptable measure to use for the purpose of calculating TFP growth for electric distribution companies.

6.3.7 Other productivity indexes

398. In addition to the two TFP studies performed by NERA and PEG, ATCO's, Fortis' and AltaGas' experts relied on the various MFP indexes published by Statistics Canada and academic publications examining productivity in different sectors of the U.S. and Canadian economies. In developing their productivity target recommendations, the experts of Fortis and AltaGas examined the Statistics Canada MFP indexes for the utilities industry. However, Ms. Frayer and Dr. Schoech acknowledged that the use of these indexes may be problematic for establishing the TFP for electric and gas distribution companies because, for the purposes of the Statistics Canada MFP index, electric distribution is combined with power generation and transmission. Natural gas distribution is combined with water, sewage and other systems.[461]

399. Because of the presence of these items not pertaining to electric distribution, Ms. Frayer's preference was to rely on the Statistics Canada MFP for the utilities sector in general, not the more specific index for electric utilities.[462] Similarly, Dr. Schoech and his colleagues observed that the Statistics Canada MFP for the natural gas and water subsector showed some "significant structural anomalies" and also considered data for the utilities sector in general.[463]

400. The CCA's experts pointed out that the Statistics Canada MFP indexes have several problems that limit their usefulness in this proceeding. First of all, PEG noted that the inclusion of power generation and transmission in the electric sector and the inclusion of water systems in the gas sector substantially reduces the relevance of Statistics Canada's MFP indexes for the electric and gas distribution companies. Second, PEG highlighted the fact that the output of the industry is measured volumetrically and thus may not be an accurate reflection of gas sector productivity growth, as discussed earlier in Section 6.3.6 of this decision. In addition, PEG also expressed a number of other concerns with Statistics Canada's MFP indexes, including the influence of large conservation programs in several Canadian provinces not experienced in

455 Transcript, Volume 17, page 3236, lines 6-8.
456 Transcript, Volume 11, page 2070, lines 1-2.
457 Transcript, Volume 11, pages 2108-2109.
458 Exhibit 472.02, Carpenter rebuttal evidence, page 32.
459 Exhibit 307.01, PEG evidence, page 36.
460 Exhibit 391.02, NERA second report, paragraph 47.
461 Exhibit 110.01, Christensen Associates evidence, paragraph 43; Exhibit 100.02, Frayer evidence, pages 58-66.
462 Exhibit 100.02, Frayer evidence, pages 65-66.
463 Exhibit 110.01, Christensen Associates evidence, paragraphs 44 and 47.

Alberta, the effect of the recent economic recession and the use of value added indexes which ignores the productivity of intermediate inputs.[464]

401. Ms. Frayer[465] and Dr. Carpenter[466] also examined the study of productivity trends at the provincial level prepared by the Center for the Study of Living Standards (CSLS).[467] As Ms. Frayer explained, the CSLS report "provides an analysis of the economic conditions and productivity of ten Canadian provinces over a ten-year period from 1998 to 2007."[468] Ms. Frayer observed that this report used the same methodology and underlying data that Statistics Canada employed in the calculation of its MFP indexes. As a result, Ms. Frayer noted that the CSLS productivity indexes do not differ substantially from the MFP indexes published by Statistics Canada.[469]

402. Because of the similarities between the Statistics Canada and the CSLS analyses, the CCA indicated that its concerns with respect to the Statistics Canada MFP indexes equally apply to the CSLS estimates. Additionally, PEG indicated that in correspondence with the authors of the CSLS study, the authors "conceded that the study used an experimental methodology and is not of a high enough standard to be used in X factor determination."[470]

403. Finally, for this proceeding Ms. Frayer also updated her TFP study performed for the Ontario Energy Board in 2007. Ms. Frayer's updated study covered 78 local distribution companies in Ontario for the period 2002 to 2009 and found negative TFP growth in the range of -0.4 per cent to -1.5 per cent.[471]

404. PEG expressed its concerns with this study primarily relating to methodology and the short sample period. With respect to methodology, PEG took issue with Ms. Frayer's use of line miles as a proxy for the capital quantity trend. The UCA echoed this concern.[472] In addition, PEG noted that Ms. Frayer's sample period was "far too short" to smooth out the effects of annual variations in productivity growth arising from the use of volatile output measures such as energy volumes and peak demand.[473]

Commission findings

405. The Commission agrees with the CCA's experts that 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. The Commission does not share Ms. Frayer's view that looking at a more aggregated MFP index for the utilities sector in general would help to address this problem. As the CCA

464 Exhibit 307.01, PEG evidence, pages 41-43.
465 Exhibit 100.02, Frayer evidence, page 58.
466 Exhibit 98.02, Carpenter evidence, page 33, A74.
467 The Center for the Study of Living Standards, *New Estimates of Labour, Capital, and Multifactor Productivity Growth and Levels for Canadian Provinces at the three-digit NAICS Level, 1997-2007,* issued on June 8, 2010.
468 Exhibit 100.02, Frayer evidence, page 66.
469 Exhibit 100.02, Frayer evidence, pages 66-68.
470 Exhibit 307.01, PEG evidence, pages 43-44 and Exhibit 376.01, ATCO-CCA-57(b).
471 Exhibit 100.02, Frayer evidence, pages 72-76.
472 Exhibit 299.02, Cronin and Motluk UCA evidence, page 81.
473 Exhibit 645, CCA reply argument, pages 32-33.

explained, such an aggregate index still includes such items as generation, transmission and water systems, which further dilutes the productivity trend of the distribution component.[474]

406. In addition, PEG observed that Statistics Canada uses volumetric output measures for calculating its MFP indexes.[475] As mentioned in Section 6.3.6 above, Dr. Lowry explained that in the presence of a declining use per customer experienced by the gas distribution industry, a gas TFP study based on a volumetric output index will understate the productivity of the gas industry.[476]

407. As Ms. Frayer observed, the CSLS study used the same methodology and underlying data that Statistics Canada employed in calculating its MFP indexes. Accordingly, the Commission considers that this study is prone to the same criticisms as the Statistics Canada indexes. Overall, the Commission considers that while Statistics Canada's MFP indexes and the CSLS report can be a useful reference for gauging the general productivity trends of the utilities sector, these analyses cannot be a substitute for a TFP study for either the electric or gas distribution industries.

408. With respect to Ms. Frayer's updated study on Ontario distribution companies, the Commission shares the CCA's concern that the short period covered by the study (2002 to 2009) does not allow measuring the long-term industry productivity trend. As the Commission observed in Section 6.3.2 of this decision, most experts in this proceeding agreed that a period of less than 10 years will not achieve this purpose.[477] Furthermore, the Commission is not persuaded that a TFP study based exclusively on Ontario distribution companies represents a better indicator of the underlying industry productivity trend for the electric or gas distribution industries compared to NERA's study covering a broad sample of companies from across the United States.

6.3.8 Commission determinations on TFP

409. There are two productivity studies on the record in this proceeding. The first, conducted by NERA, calculated a TFP of 0.96 per cent.[478] This TFP value was based on an analysis of the distribution portion of 72 U.S. electric and combination electric/gas companies over the period of 1972 to 2009.[479] The second study was conducted by PEG on behalf of the CCA for the gas distribution industry and found a TFP in the range of 1.32 to 1.69 per cent. PEG's study examined 34 U.S. gas distribution companies over the period of 1996 to 2009.[480]

410. The ATCO companies, Fortis and AltaGas relied on the various MFP indexes published by Statistics Canada as well as the CSLS study examining productivity in different sectors of the U.S. and Canadian economies for a variety of purposes.[481] As explained in Section 6.3.7 above,

474 Exhibit 645, CCA reply argument, paragraph 113.
475 Exhibit 307.01, PEG evidence, page 42.
476 Transcript, Volume 14, page 2872, line 20 to page 2873, line 4.
477 Exhibit 307.01, PEG evidence, page 28; Exhibit 631, ATCO Electric argument, paragraphs 61-62; Exhibit 632, ATCO Gas argument, paragraphs 69-70.
478 In its first report NERA estimated a TFP of 0.85 per cent. However, in its second report it accepted one of the adjustments proposed by PEG (related to labour quantity estimation for the period 2002 to 2009). This adjustment resulted in a recalculated TFP estimate of 0.96 per cent.
479 Exhibit 391.02, NERA second report, Table 3.
480 Exhibit 307.01, PEG evidence, page 2.
481 Exhibit 98.02, Carpenter evidence, paragraph 43; Exhibit 100.02, Frayer evidence, page 58; Exhibit 110.01, Christensen Associates evidence, paragraph 43.

the Commission determined that the MFP indexes published by Statistics Canada as well as the CSLS study are unsuitable for determining TFP for either the electric or gas distribution industries.

411. The Commission has evaluated the NERA and PEG TFP studies with respect to a number of issues and criteria discussed by the parties, such as the relevant time period and sample size, the relevance of the U.S. data to Alberta companies, the use of publicly available data and transparent methodology, and the applicability of the obtained TFP number to both gas and electric companies as set out in sections 6.3.2 to 6.3.6 of this decision. Based on this evaluation, the Commission finds that NERA's study is preferable to use in this proceeding given the objectivity and transparency of the data and of the methodology used, the use of data over the longest time period available and the broad based inclusion of electric distribution companies from the United States.

412. In the Commission's view, NERA's study was more objective and transparent compared to PEG's analysis. First, as the Commission observed in Section 6.3.2 above, the choice of a sample period in PEG's study was primarily based on Dr. Lowry's personal judgment, not on objective criteria. Moreover, as set out in Section 6.3.4, PEG's lack of transparency in data processing did not allow either the other parties nor the independent consultant NERA, to fully test and verify its TFP recommendation. As such, while the Commission recognizes the value of a separate productivity study focusing on gas distributors, the drawbacks of PEG's TFP research do not allow the Commission to rely on it.

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.[482] 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.[483] 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.[484] Overall, the Commission considers that PEG's criticisms do not undermine the credibility of NERA's TFP study.

414. The Commission also observes that all of the companies' experts used NERA's study as a starting point for their X factor recommendations despite expressing some reservations about particular aspects of the study and offering various adjustments primarily relating to the sample period.[485]

415. In light of the above considerations, the Commission accepts NERA's methodology and finds that NERA's TFP estimate of 0.96 per cent represents a reasonable starting point for setting an X factor for the Alberta companies. Accordingly, based on NERA's study, the Commission

[482] Exhibit 569.01, PEG rebuttal evidence, redlined pages; Exhibit 478, PEG rebuttal evidence, pages 11-17; Exhibit 609.02, CCA undertaking response: PEG adjustments to NERA.
[483] Transcript, Volume 1, pages 76-77.
[484] Transcript, Volume 1, pages 74-75 and Exhibit 461.02, AUC-NERA-16.
[485] Exhibit 103.05, Cicchetti evidence, page 16; Exhibit 98.02, Carpenter evidence, page 32; Exhibit 100.02, Frayer evidence, page 79; Exhibit 110.01, Christensen Associates evidence, page 15.

finds that a long-term industry TFP of 0.96 per cent represents a reasonable basis for determining the X factors to be used in the PBR plans of the electric distribution companies.

416. With respect to the gas companies, as discussed in Section 6.3.6 above, the Commission agrees with Dr. Lowry's argument that it is necessary to match the output measure to the type of PBR plan (price cap or revenue-per-customer cap).[486] However, in the absence of a reliable and transparent TFP study on the gas distribution industry and information on how changes in the relevant output measures and input measures for electric and gas distribution industries compare to each other over the 1972 to 2009 study period, the Commission is not prepared to make any adjustment to NERA's TFP estimate in order to obtain a TFP estimate for the gas distribution companies.

417. The Commission observes that NERA, ATCO Gas and AltaGas agreed that NERA's study represents a reasonable starting point for determining the TFP trend for gas distributors.[487] The Commission agrees. Accordingly, the Commission finds that NERA's TFP of 0.96 per cent represents a reasonable basis for determining the X factors to be used in the PBR plans of the gas distribution companies.

6.4 Adjustments to arrive at the X factor

418. In this proceeding, parties discussed several potential adjustments to TFP to arrive at the X factor. Specifically, NERA explained that the theory behind PBR plans may require an input price differential and a productivity differential adjustment if an output-based measure is used for the I factor.[488] Additionally, Dr. Carpenter on behalf of the ATCO companies,[489] Dr. Cicchetti on behalf of EPCOR,[490] and Dr. Schoech on behalf of AltaGas[491] expressed their views that NERA's TFP analysis based on the U.S. data needed to be adjusted for the differences in the economy-wide productivity growth between the United States, Canada and Alberta.

419. In addition to the above adjustments, parties discussed whether the companies' proposals to exclude all of or part of capital from the I-X mechanism should have any effect on the X factor. Each of these possible adjustments is addressed in the following sections of this decision.

6.4.1 Input price and productivity differential if an output-based measure is chosen for the I factor

420. Similar to the discussion in Decision 2009-035 dealing with ENMAX's FBR plan,[492] parties to this proceeding pointed out that the choice of an I factor can influence the X factor depending on the productivity that may be embedded in a particular inflation measure.

421. As Dr. Carpenter and Ms Frayer explained, there are two types of inflation measures that can be used for the I factor: input-based and output-based. Input-based measures reflect the change in the prices of goods and services purchased as inputs into the companies' production

486 Exhibit 307.01, PEG evidence, page 12.
487 Exhibit 80.02, NERA report, pages 4 and 5; Exhibit 99.01, Carpenter evidence, page 31; Exhibit 628, AltaGas argument, page 25
488 Exhibit 461.02, AUC-NERA-17(a) and (b).
489 Exhibit 98.02, Carpenter evidence, pages 26-34.
490 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).
491 Transcript, Volume 8, page 1414, lines 9-25.
492 Decision 2009-035, paragraphs 126-128.

6.5 Stretch factor

6.5.1 Purpose of the stretch factor

468. Generally speaking, a stretch factor is an additional percentage applied to 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.[564]

469. Parties to this proceeding differed in their interpretation as to the purpose of the stretch factor and based their recommendations accordingly. Nevertheless, most parties to this proceeding agreed that the rationale behind the stretch factor is to share with customers the benefits of the expected acceleration in productivity growth as the company transitions from a cost of service ratemaking system to performance-based regulation. Dr. Cicchetti explained the logic behind this reasoning as follows:

> In North America, an industry productivity trend that is estimated using historical data will overwhelmingly reflect the productivity experience of an industry that has been regulated using cost of service methods. [...] A principal rationale for PBR is to create stronger performance incentives compared with cost of service regulation. This, in turn, implies that when utilities become subject to PBR, it is expected that they will achieve incremental productivity gains compared to what has been observed under traditional cost of service regulation. The productivity "stretch factor" reflects the expectation that productivity growth will increase, at least temporarily, under incentive regulation and adding this "stretch" goal to an estimate of the historical productivity trend embodies an estimate of these expected, incremental productivity gains in the approved X-factor.[565]

470. Another EPCOR expert, Dr. Weisman, further elaborated on this reasoning and emphasized that the stretch factor is designed to ensure that consumers share in part of the efficiencies created by moving from the cost of service to the PBR regime:

> DR. WEISMAN: The typical rationale, and one that I would agree with, is that when you move to a more high powered regulatory regime, such as price cap regulation, that this will fundamentally change the incentives of the firm, that it will be able to enhance its efficiencies, and the stretch factor is designed to ensure that consumers share in part of those efficiencies. So it basically bounces up our historical view of productivity growth to account for the change of the enhanced incentives that accompany price cap regulation relative to traditional cost-of-service regulation.
> Q. So it's good for that period of time when you move from cost of service into incentive-based regulation? Is that fair?
> A. DR. WEISMAN: Generally the focus is on the transition. You probably heard the so-called low-hanging fruit argument, that the -- in the initial transition the efficiency gains what we can change, how we can innovate are more obvious and apparent than they are later on.[566]

471. AltaGas,[567] NERA,[568] the UCA[569] and Calgary,[570] supported this rationale behind the stretch factor. Accordingly, these parties supported the inclusion of a stretch factor in the

564 Exhibit 98.02, Carpenter evidence, page 34; Exhibit 307.01, PEG evidence, page 16.
565 Exhibit 103.05, Cicchetti evidence, pages 27-28.
566 Transcript, Volume 9, page 1766, lines 4-22.
567 Exhibit 110.01, AltaGas application, paragraph 45 and Transcript, Volume 9, page 1689, lines 19-24.
568 Exhibit 195.01, AUC-NERA-12(a) and Transcript, Volume 1, page 116, lines 21-24.
569 Transcript, Volume 17, page 3287, lines 14-25.

6.5 Stretch factor

6.5.1 Purpose of the stretch factor

468. Generally speaking, a stretch factor is an additional percentage applied to 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.[564]

469. Parties to this proceeding differed in their interpretation as to the purpose of the stretch factor and based their recommendations accordingly. Nevertheless, most parties to this proceeding agreed that the rationale behind the stretch factor is to share with customers the benefits of the expected acceleration in productivity growth as the company transitions from a cost of service ratemaking system to performance-based regulation. Dr. Cicchetti explained the logic behind this reasoning as follows:

> In North America, an industry productivity trend that is estimated using historical data will overwhelmingly reflect the productivity experience of an industry that has been regulated using cost of service methods. [...] A principal rationale for PBR is to create stronger performance incentives compared with cost of service regulation. This, in turn, implies that when utilities become subject to PBR, it is expected that they will achieve incremental productivity gains compared to what has been observed under traditional cost of service regulation. The productivity "stretch factor" reflects the expectation that productivity growth will increase, at least temporarily, under incentive regulation and adding this "stretch" goal to an estimate of the historical productivity trend embodies an estimate of these expected, incremental productivity gains in the approved X-factor.[565]

470. Another EPCOR expert, Dr. Weisman, further elaborated on this reasoning and emphasized that the stretch factor is designed to ensure that consumers share in part of the efficiencies created by moving from the cost of service to the PBR regime:

> DR. WEISMAN: The typical rationale, and one that I would agree with, is that when you move to a more high powered regulatory regime, such as price cap regulation, that this will fundamentally change the incentives of the firm, that it will be able to enhance its efficiencies, and the stretch factor is designed to ensure that consumers share in part of those efficiencies. So it basically bounces up our historical view of productivity growth to account for the change of the enhanced incentives that accompany price cap regulation relative to traditional cost-of-service regulation.
> Q. So it's good for that period of time when you move from cost of service into incentive-based regulation? Is that fair?
> A. DR. WEISMAN: Generally the focus is on the transition. You probably heard the so-called low-hanging fruit argument, that the -- in the initial transition the efficiency gains what we can change, how we can innovate are more obvious and apparent than they are later on.[566]

471. AltaGas,[567] NERA,[568] the UCA[569] and Calgary,[570] supported this rationale behind the stretch factor. Accordingly, these parties supported the inclusion of a stretch factor in the

564 Exhibit 98.02, Carpenter evidence, page 34; Exhibit 307.01, PEG evidence, page 16.
565 Exhibit 103.05, Cicchetti evidence, pages 27-28.
566 Transcript, Volume 9, page 1766, lines 4-22.
567 Exhibit 110.01, AltaGas application, paragraph 45 and Transcript, Volume 9, page 1689, lines 19-24.
568 Exhibit 195.01, AUC-NERA-12(a) and Transcript, Volume 1, page 116, lines 21-24.
569 Transcript, Volume 17, page 3287, lines 14-25.

companies' PBR plans. The parties' specific recommendations as to the size of the stretch factor are discussed in the following section of this decision.

472. In Ms. Frayer's view, which Fortis adopted, a stretch factor is a mechanism to adjust the company's revenue or rates each year to reflect firm-specific expected productivity gains vis-à-vis the gains expected for the industry as a whole. In other words, according to Ms. Frayer, a stretch factor "creates an incremental incentive for productivity, in order to "catch-up" with the rest of industry, in the case of a company that is underperforming."[571] In that regard, Fortis argued that because of its strong productivity performance in recent years (as demonstrated by the continued reduction in controllable operating costs per customer since 2004), there was no "low-hanging fruit" for the company to pick under PBR.[572]

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.[573] Similarly, Dr. Carpenter expressed his view that both of these considerations are relevant in determining whether a stretch factor is required:

> If there is evidence to suggest that a particular utility is less efficient than the industry as a whole, and if the incentives for improving efficiency are likely to be much stronger in the future than they have been in the past, then it might be reasonable to expect that utility to be able to achieve more rapid productivity growth than the historical trend rate measured in a TFP study. A stretch factor may then be appropriate.[574]

474. However, the Dr. Lowry and Dr. Carpenter did not agree on whether a stretch factor should be assigned to Alberta companies. In Dr. Carpenter's view, it is not clear whether the PBR regime will create much stronger incentives for efficiency than the existing cost of service regime since the current regulation in Alberta contains "significant efficiency incentives because of the time between rate cases and the forward-looking test periods."[575] As such, the ATCO companies argued that a stretch factor should not be applied to their PBR plans.[576]

475. In contrast, Dr. Lowry and his colleagues at PEG argued that the current regulatory system in Alberta, under which the companies file rate cases every two years, has "weak performance incentives."[577] Accordingly, Dr. Lowry noted it is reasonable to expect that there will be some productivity acceleration in Alberta with the adoption of a PBR regime and, as a result, a stretch factor should be included in the companies' PBR plans.[578]

476. Finally, in discussing whether a stretch factor should be a part of the companies' PBR plans, parties to this proceeding pointed to an inter-relationship between a stretch factor and an ESM (earnings sharing mechanism). Specifically, all the companies contended that a stretch factor and an ESM were mutually exclusive and preferred to keep only the one alternative of

570 Exhibit 298.02, Calgary evidence, paragraph 133 and Transcript, Volume 15, page 2935, lines 18-25.
571 Exhibit 100.02, Frayer evidence, page 79.
572 Exhibit 633, Fortis argument, paragraphs 144-146.
573 Exhibit 636, CCA argument, paragraph 108 and Transcript, Volume 13, pages 2564-2565.
574 Exhibit 476.01, Carpenter rebuttal evidence, page 62.
575 Exhibit 476.01, Carpenter rebuttal evidence, page 58.
576 Exhibit 631, ATCO Electric argument, paragraph 108; Exhibit 632, ATCO Gas argument, paragraph 118.
577 Transcript, Volume 13, page 2564, lines 6-10 and Exhibit 307.01, PEG evidence, page 46.
578 Transcript, Volume 13, page 2564, lines 3-10 and Exhibit 636, CCA argument, paragraph 118.

their choice.[579] Accordingly, EPCOR and AltaGas argued that an ESM should not be a part of their plans, given that their PBR proposals contained a stretch factor.[580] Conversely, in the view of the ATCO companies and Fortis, the inclusion of an ESM in their PBR plans provided an additional justification for not imposing a stretch factor.[581]

477. On this issue, NERA commented that, although there may be some aspects of a trade off between an ESM and a stretch factor, it does not view an ESM and a stretch factor as mutually exclusive.[582] The CCA and the UCA experts shared this view as demonstrated by the fact that PEG's incentive power model and the X factor menu advocated by Dr. Cronin and Mr. Motluk included both an ESM and a stretch factor.[583]

478. Calgary also offered that there is no mutual exclusivity between an ESM and a stretch factor. In Calgary's view, a stretch factor is intended to deal with the attempt to capture the additional efficiencies resulting from the transition from the cost of service regime to PBR. In contrast, the ESM is intended to address the proper sharing of any efficiencies derived from operating under the I-X mechanism that are achieved during the PBR term.[584] Calgary noted that a number of PBR plans in North America have both of these elements, as shown in NERA's second report.[585]

Commission findings

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.

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.

482. The Commission agrees with Dr. Weisman that the transition from cost of service regulation to PBR provides an opportunity to realize more easily-achieved efficiency gains (the

579 Exhibit 98.02, ATCO Electric application, paragraph 45; Exhibit 99.01, ATCO Electric application, paragraph 41; Exhibit 529, AltaGas corrections and amendments to application, page 4; Exhibit 100.02, Fortis application, paragraphs 83-84; Exhibit 103.02, EPCOR application, paragraphs 84-85.
580 Exhibit 103.02, EPCOR application, paragraphs 84-85; Exhibit 529, AltaGas corrections and amendments to application, page 4.
581 Exhibit 98.02, Carpenter evidence, page 35; Exhibit 100.02, Fortis application, paragraph 85.
582 Exhibit 195.01, AUC-NERA-12(d).
583 Transcript, Volume 13, page 2579, lines 17-21; Transcript, Volume 17, page 3188, lines 13-19.
584 Exhibit 629, Calgary argument, page 60.
585 Exhibit 391.02, NERA second report, Table 3, page 30.

"low hanging fruit") due to increased incentives.[586] In the Commission's view, two issues are salient when considering the need for a stretch factor. The first issue is whether NERA's TFP estimate, on which the X factors for the Alberta companies are based, provides a good estimate for the productivity growth under PBR. As Dr. Cicchetti explained, in the case that an industry TFP trend is estimated using historical data that predominantly reflect the productivity experience under cost of service regulation, such a TFP target may need to be "stretched" to account for higher incentives under PBR.[587] However, it is not clear the extent to which NERA's data include both cost of service and PBR forms of regulation,[588] and there was no evidence on the record of this proceeding upon which to make such an adjustment.

483. The second issue to consider is whether there is a potential for the Alberta companies to collect the "low-hanging fruit" when transitioning from the current cost of service regulation to a PBR framework. In that regard, the Commission does not share Dr. Carpenter's view that the efficiency incentives under the current cost of service price setting framework in Alberta and PBR are going to be largely the same.

484. On the same topic, Fortis and the ATCO companies also argued that there will be no "low-hanging fruit" to pick under PBR because of the companies' strong productivity performance in recent years.[589] However, as the CCA pointed out, it is possible that the companies are unable to appraise the productivity gains that are achievable under PBR.[590] Dr. Weisman addressed this matter in an academic article that he co-authored as follows:

> With very limited potential rewards but significant disallowance risks, the traditional regulatory model strongly encourages the prudent use of tried-and-true operating practices and technologies. It thus provides very limited incentives, if not explicit disincentives, to look beyond the status quo to discover and employ new, innovative operating practices and technologies. This is why the provision of enhanced incentives can stimulate a discovery process that enables regulated firms to become more efficient than they previously knew how to be.[591]

485. The Commission observes that having analysed its recent experience under PBR, ENMAX also pointed to a number of efficiency improvements and cost-minimising measures that were realized since the transition to a regulatory regime with stronger efficiency incentives. Notably, ENMAX indicated that the company would not have undertaken these productivity initiatives under a traditional cost of service regulatory framework.[592]

486. Finally, the Commission notes that the companies characterized the inclusion of a stretch factor (or a lack thereof) as an alternative to an ESM. In this regard, the Commission agrees with NERA and the interveners that although there is some trade-off between an ESM and a stretch

586 Transcript, Volume 9, page 1766, lines 4-22.
587 Exhibit 103.05, Cicchetti evidence, pages 27-28.
588 Exhibit 299.02, Cronin and Motluk UCA evidence, page 79, footnote "c".
589 Exhibit 633, Fortis argument, paragraphs 144-146; Exhibit 631, ATCO Electric argument, paragraph 271; Exhibit 632, ATCO Gas argument, paragraph 296.
590 Exhibit 645, CCA reply argument, paragraph 47.
591 Exhibit 500.02, Weisman, Dennis L., and Pfeifenberger, Johannes P., *Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates*, The Electricity Journal, January-February 2003, page 60.
592 Exhibit 297.01, ENMAX evidence, pages 16-18.

factor, they are not mutually exclusive.[593] This is demonstrated by the fact that a number of PBR plans in North America have both of these components.[594] Nevertheless, as set out in Section 10 of this decision, the Commission determined that an ESM should not be part of the companies' PBR plans. Accordingly, the inclusion of an ESM in the PBR plans of the companies cannot provide an additional justification for not imposing a stretch factor.

487. In light of the above considerations, the Commission agrees with EPCOR, AltaGas and the interveners that a stretch factor should be a part of the PBR plans for the Alberta companies.

6.5.2 Size of the stretch factor

488. Parties acknowledged that unlike TFP estimates, stretch factors are commonly set based upon regulatory judgment and evidence from other jurisdictions rather than on a theoretical basis.[595] However, in the parties' view, this judgement has to be informed by the empirical evidence to accord with best regulatory practices.[596]

489. In this respect, Dr. Cicchetti found informative the average level of the stretch factor assigned to electric distributors in Ontario. The Ontario Energy Board, in its third generation incentive regulation plan, set the stretch factors at 0.2 per cent, 0.4 per cent and 0.6 per cent for the most efficient, the average efficient and the least efficient distributors, respectively. The average of the stretch factors imposed by the Ontario Energy Board is 0.4 per cent. Dr. Cicchetti noted that this was also the stretch factor approved by the Commission for ENMAX in Decision 2009-035.[597] Given Dr. Cicchetti's view that his recommended O&M PFP was of a "conservative nature," and in conjunction with not having an ESM, EPCOR's expert recommended that the company's PBR plan include a stretch factor of 0.2 per cent that lies at the mid-point between a stretch factor of zero (Dr. Cicchetti's preferred value), and the 0.4 per cent assigned to ENMAX.[598]

490. The UCA also relied on the Ontario Energy Board's determination on the stretch factor. The UCA indicated that if the menu approach to the X factor is not adopted, it recommends stretch factors for the companies of between 0.2 and 0.6 per cent based on the current Ontario third generation PBR plan approach.[599]

491. AltaGas indicated that it is prepared to dispense with the ESM with the addition of a "modest stretch factor of between 0.1-0.2 per cent."[600] Dr. Schoech explained that this recommendation reflected his evaluation of how the X factor should change if an ESM is removed from the plan.[601]

---

593 Exhibit 195.01, AUC-NERA-12(d); Transcript, Volume 13, page 2579, lines 17-21 (Dr. Lowry); Transcript, Volume 17, page 3188, lines 13-19 (Dr. Cronin); Exhibit 629, Calgary argument, page 60.
594 Exhibit 391.02, NERA second report, Table 3, page 30.
595 Exhibit 195.01, AUC-NERA-12(d); Transcript, Volume 9, page 1688, lines 18-23 (Dr. Schoech); Transcript, Volume 4, pages 776-778 (Dr. Carpenter).
596 Exhibit 103.05, Cicchetti evidence, page 28; Exhibit 634.02, UCA argument, paragraph 152; Transcript, Volume 13, page 2567, lines 1-10 (Dr. Lowry).
597 Decision 2009-035, paragraph 185.
598 Exhibit 103.05, Cicchetti evidence, pages 30-31.
599 Exhibit 634.02, UCA argument, paragraph 146.
600 Exhibit 529, AltaGas corrections and amendments to application, page 4.
601 Transcript, Volume 9, page 1689, lines 9-16.

492. PEG indicated that its research suggests that stretch factors for Alberta companies should lie in the range of 0.19 to 0.5 per cent. In developing its stretch factor recommendations, PEG examined regulatory precedent and noted that the average explicit stretch factor approved for PBR plans of energy companies with rate escalation mechanisms informed by productivity research is about 0.50 per cent.[602] In addition, PEG developed an incentive power model that estimates the typical cost performance improvements that will be achieved by companies under stylized regulatory systems. Calibrating this model for the circumstances of Alberta companies produced a stretch factor value of 0.19 per cent.[603] Based on the results of PEG's research, the CCA recommended that all companies be assigned the 0.19 per cent stretch factor that resulted from PEG's incentive power model.[604]

493. Based on the record of this proceeding, Calgary recommended that the stretch factor be in the range of 0.13 per cent to 0.5 per cent.[605]

494. Similar to the discussion about the size of the X factor, parties commented on whether the presence and the magnitude of a stretch factor have any effect on the incentives of PBR plans. EPCOR, AltaGas and the ATCO companies submitted that the strength of the incentives under a PBR plan is not tied to the magnitude of the X factor (including the stretch).[606] NERA and the CCA supported this view.[607]

495. In contrast, Calgary argued that inasmuch as the companies are going to be incented to find capital and operating efficiencies under PBR relative to the cost of service regulation, a stretch factor "will play a key role as an additional driver to achieve those efficiencies."[608] In a similar vein, the UCA submitted that a stretch factor should incent a company to "obtain maximum efficiency improvements."[609]

496. Fortis' evidence on this matter was contradictory. On one hand, Fortis argued that "the level of X, regardless of whether that level includes some notion of stretch, does not determine if the incentive properties of PBR grow or diminish. Whatever X is, or more accurately the result of I-X is, the incentive to attain and better that result exists."[610] On the other hand, Fortis submitted that "the imposition of a stretch factor [...] by its nature and effect could only increase the perceived incentive to cut costs in any available manner."[611]

602 Exhibit 307.01, PEG evidence, page 45.
603 Exhibit 307.01, PEG evidence, page 45 and Exhibit 478, PEG rebuttal evidence, page 24.
604 Exhibit 636, CCA argument, paragraph 106.
605 Exhibit 629, Calgary argument, page 33.
606 Exhibit 630.02, EPCOR argument, paragraph 86; Exhibit 628, AltaGas argument, page 34; Exhibit 631, ATCO Electric argument, paragraph 112; Exhibit 632, ATCO Gas argument, paragraph 122.
607 Transcript, Volume 1, page 117, lines 10-15 (NERA); Exhibit 636, CCA argument, paragraph 112.
608 Exhibit 641, Calgary reply argument, paragraph 132.
609 Exhibit 634.02, UCA argument, paragraph 157.
610 Exhibit 644, Fortis reply argument, paragraph 86.
611 Exhibit 633, Fortis argument, paragraph 157.

Commission findings

497. As parties pointed out, the determination of the size of a stretch factor is, to a large degree, based on a regulator's judgement and regulatory precedent and does not have a "definitive analytical source" like the TFP study represents.[612]

498. The UCA's experts recommended that the Commission assign stretch factors of between 0.2 and 0.6 per cent, similar to the Ontario Energy Board's determination in its third generation incentive regulation plans.[613] Dr. Cicchetti also found informative the average level of the stretch factor assigned to electric distributors in Ontario, and recommended a stretch factor of 0.2 per cent.[614] PEG proposed that stretch factors for Alberta companies should lie in the range of 0.19 to 0.5 per cent.[615] A similar range of 0.13 to 0.5 per cent was advocated by Calgary.[616] AltaGas recommended a stretch factor of 0.1 to 0.2 per cent.[617]

499. Taking into account the fact that the companies are moving from a cost of service regulatory framework to PBR, and being cognizant of the uncertainties associated with the change in regulatory framework, the Commission is taking a conservative approach to setting a stretch factor. Accordingly, the Commission considers that a stretch factor for Alberta companies should be on the lower end of the 0.2 to 0.6 per cent ranges recommended by PEG and the UCA's experts. The Commission observes that the CCA expressed its preference for a stretch amount on the lower side of the 0.19-0.5 per cent range recommended by its experts, PEG.[618] The Commission has considered the recommended stretch factors and finds a 0.2 per cent stretch amount to be reasonable. This stretch factor should apply to the companies' plans for the duration of the PBR term.

500. Finally, the Commission agrees with the parties who argued that while the size of a stretch factor affects a company's earnings, it has no influence on the incentives for the company to reduce costs.[619] Similar to a discussion in Section 6.1 of this decision, the Commission considers that PBR plans derive their incentives from the decoupling of a company'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).[620]

6.6 X factor proposals and the Commission determinations on the X factor

501. As discussed previously in this section, the X factor proposals in this proceeding reflected the parties' views as to the purpose of and approaches to determining the X factor, the relevant productivity estimates to use and the need for any adjustments, as well as considerations on the need for a stretch factor. Table 6-2 below shows that the parties' recommendations for an X factor are based on a variety of time periods and TFP indexes that the parties considered relevant.

612 Transcript, Volume 1, page 115, lines 6-19 (NERA). On this subject, see also Exhibit 103.05, Cicchetti evidence, page 28; Transcript, Volume 9, page 1688, lines 18-23 (Dr. Schoech); Transcript, Volume 4, pages 776-778 (Dr. Carpenter).
613 Exhibit 634.02, UCA argument, paragraph 146.
614 Exhibit 103.05, Cicchetti evidence, pages 30-32.
615 Exhibit 307.01, PEG evidence, page 45 and Exhibit 478, PEG rebuttal evidence, page 24.
616 Exhibit 629, Calgary argument, page 33.
617 Exhibit 628, AltaGas argument, page 33.
618 Exhibit 636, CCA argument, paragraph 106.
619 Exhibit 628, AltaGas argument, page 34;
620 Transcript, Volume 1, page 117, lines 10-15 (NERA); Exhibit 636, CCA argument, paragraph 112.

TAB 4

ALBERTA UTILITIES COMMISSION

Application No. 1606029
Proceeding ID No. 566

RATE REGULATION INITIATIVE

P R O C E E D I N G S

Volume 14
May 3, 2012
Calgary, Alberta

AMICUS
REPORTING GROUP

Proceedings taken at the offices of the Alberta Utilities Commission, 5th floor, 425 - 1st Street S.W. Calgary, Alberta.

Volume 14

May 3, 2012

Mr. W. Grieve	Chair
Dr. M. Yahya	Commission Member
Mr. M. Kolesar	Commission Member
Mr. B. McNulty	Commission Counsel
Ms. C. Wall	Commission Counsel
Ms. A. Sabo	Commission Counsel
Mr. J. Thygesen	Commission Staff
Mr. O. Vasetsky	Commission Staff
Mr. B. Miller	Commission Staff
Mr. S. Levin	Consultant to the Commission
Mr. J. Cusano Ms. L. Aufricht	National Economic Research Associates, Inc.
Ms. N. McKenzie	AltaGas Utilities Inc.
Mr. L. Smith, Q.C. Ms. K. Illsey	ATCO Electric Ltd. and ATCO Gas
Mr. D. Evanchuk	City of Calgary
Mr. J. Wachowich	Consumers Coalition of Alberta
Mr. J. Liteplo	EPCOR Distribution & Transmission Inc.
Mr. T. Dalgleish, Q.C.	FortisAlberta Inc.
Mr. D. Wood Mr. L. Cusano	ENMAX Power Corporation
Mr. M. Forster	Industrial Power Consumers Association of Alberta
Mr. C. R. McCreary Mr. N. Parker	Office of the Utilities Consumer Advocate?

the first of which is annual TFP growth rates from PEG studies as Exhibit 595.

EXHIBIT 595 - THREE DOCUMENTS, FIRST BEING ANNUAL TFP GROWTH RATES FROM PEG STUDIES

MR. SMITH: Maybe if we, just for simplicity, page 2 of that exhibit will be the page with the single table, and page 3 is the page with the three tables.

Is that acceptable, sir.

THE CHAIR: Yes, it is.

Q. MR. SMITH: Now, Dr. Lowry, on page 3, would you be able to confirm that the column indicated "Index" under each of those three tables: SDG&E Ontario and SoCalGas Company are faithfully reproduced from the source identified underneath them?

A. Well, I'll accept that subject to check of course.

Q. Fair enough. I provided these the other day. I thought you might have been able to look at them, but that's fine.

Now, they needed to be, because they were index numbers, the growth rates had to be calculated from the TFP index volumes -- or, sorry, values.

And, sir, there is a brief explanation of that and what was done under each of those three tables. And again, at the bottom of the table on page 2, and it's indicated there that they've been converted to growth rates using the formula growth -- and I'm not going to try and read out that formula. But is that an accurate way of deriving the growth rates?

A. It's one way to do it. It's the arithmetic formula.

Q. 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.

A. 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.

Q. Thank you. Dr. Lowry, that wasn't what I was trying to get at. It's not the changes year over year, '99 to 2000 and so on. What I'm looking at is let's look at 2003. 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?

A. 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.

Q. Well, SDG&E was done in 2010?

A. Yeah. And the trends for that period are very similar to the ones in this case.

Q. The evidence in this proceeding, the TFP was done when?

A. You mean when we did the study? Last fall -- last --
Q. 2011?
A. -- late last year.
Q. 2011. And so what I see as a total factor productivity trend for gas utilities in the nation in 2003 is a negative .65 and here it's a positive .21?
A. Right. And one used geometric decay and the other used the cost of service approach to capital costing.
Q. So you're saying the San Diego one is wrong?
A. No. They each have their merits. Each approach has its merits, but all of these TFP indexes -- and I think if you went through the testimony of the various utility witnesses, you would probably see statements like the following. TFP is very volatile and has to be measured over a longer term period to get a proper trend.
So you're highlighting the volatility, and you're highlighting the fact that different capital cost measures in a single year can yield different results.
Q. Well, I think what I'm highlighting is your varying approach to measuring the same thing in the same time period, am I not?
A. Well, you know, Dr. Makholm is an example of a person that's kind of done -- made a virtue of doing things the same way every year, every time he's done this study; but then again, he's only done about three studies ever for power

TAB 5

AUC
Alberta Utilities Commission

Distribution Performance-Based Regulation 2013 Capital Tracker Applications

AltaGas Utilities Inc.,
ATCO Electric Ltd.,
ATCO Gas and Pipelines Ltd.,
EPCOR Distribution & Transmission Inc. and
FortisAlberta Inc.

December 6, 2013

The Alberta Utilities Commission
Decision 2013-435: Distribution Performance-Based Regulation
2013 Capital Tracker Applications
Application No. 1608827
Proceeding ID No. 2131

December 6, 2013

Published by
The Alberta Utilities Commission
Fifth Avenue Place, Fourth Floor, 425 First Street S.W.
Calgary, Alberta
T2P 3L8

Telephone: 403-592-8845
Fax: 403-592-4406

Website: www.auc.ab.ca

Contents

List of tables

The Alberta Utilities Commission
Calgary, Alberta

Distribution Performance-Based Regulation
2013 Capital Tracker Applications

Decision 2013-435
Application No. 1608827
Proceeding ID No. 2131

1 Introduction

1. On September 12, 2012, the Alberta Utilities Commission (AUC or Commission) released Decision 2012-237,[1] Rate Regulation Initiative, Distribution Performance-Based Regulation, that established performance-based regulation (PBR) for the distribution utility functions of AltaGas Utilities Inc. (AltaGas or AUI), ATCO Electric Ltd. (ATCO Electric or AE), ATCO Gas and Pipelines Ltd. (ATCO Gas or AG) collectively referred to as the ATCO companies, EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) and FortisAlberta Inc. (Fortis or FAI). These distribution utilities are collectively referred to as "the companies" in this decision. Decision 2012-237 (also referred to as the PBR decision) approved a five-year PBR plan for each of the companies that included an annual rate adjustment formula, commencing January 1, 2013. The PBR rate adjustment formula replaced the cost-of-service rate setting method that was used previously.

2. In Decision 2012-237, the Commission determined that a mechanism to fund certain capital-related costs outside of the I-X mechanism through a capital factor is required for the approved PBR plans.[2] This supplemental funding mechanism was referred to in Decision 2012-237 as a "capital tracker" with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate setting formula.

3. The PBR decision provided each of the companies with the opportunity to file a capital tracker application with respect to 2013 supplemental capital funding requirements.[3] Each of the companies filed a 2013 capital tracker application. These applications were considered in the present proceeding.

4. Pending consideration of the 2013 capital tracker applications in this proceeding, Decision 2013-072,[4] dealing with the 2012 PBR compliance filings, approved capital tracker placeholders equal to 60 per cent of the applied-for capital tracker amounts for inclusion on an interim basis in 2013 rates.[5] These placeholder amounts will be trued-up to the amounts approved in this decision in subsequent proceedings.

---

1 Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Application No. 1606029, Proceeding ID No. 566, September 12, 2012.
2 Decision 2012-237, paragraph 586.
3 Decision 2012-237, paragraphs 616 and 978.
4 Decision 2013-072: 2012 Performance-Based Regulation Compliance Filings, AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc. and FortisAlberta Inc., Application No. 1608826, Proceeding ID No. 2130, March 4, 2013.
5 Decision 2013-072, paragraph 41.

5. Decision 2012-237 directed the companies to file their initial capital tracker applications by November 2, 2012.[6] Subsequent to the initial filing date, the companies requested, and were granted, an extension to December 14, 2012.

6. Some parties had previously registered statements of intent to participate (SIPs) for the proceeding in order to participate in an information session regarding Decision 2012-237 held on September 28, 2012. In addition to the companies, the other parties registering SIPs in advance of the information session included ENMAX Power Corporation, the City of Calgary (Calgary), the Consumers' Coalition of Alberta (CCA) and the Office of the Utilities Consumer Advocate (UCA). In addition, on November 5, 2012, the Commission issued a notice of proceeding soliciting SIPs from any party wishing to intervene or participate that had not registered prior to the information session. An additional SIP was filed by AltaLink Management Ltd. (AltaLink).

7. On February 15, 2013, most parties submitted information requests to the companies in accordance with a process established by the Commission by letter dated December 18, 2012. The CCA was granted an extension by the Commission and submitted information requests on February 19, 2013. The companies responded to the information requests on March 13, 2013.

8. After receiving the responses to its information requests, the CCA submitted a motion on March 25, 2013 to compel further and more complete responses.[7] The companies responded to the motion on April 3, 2013, and the CCA commented on the companies' responses on April 5, 2013. The Commission ruled on the motion on April 23, 2013, approving some portions of the CCA's motion, and denying others.[8] As a result, some of the companies were required to submit additional information responses on May 7, 2013.

9. In accordance with the procedural schedule established by the Commission, intervener evidence was filed on April 15, 2013 by the CCA and the UCA. Information requests to interveners were issued by most parties on April 26, 2013. Additional information requests were issued later by ATCO Electric and AltaGas on April 29, 2013. Responses to the information requests were provided on May 24, 2013 by the CCA and on May 27, 2013 by the UCA.

10. On April 25, 2013, the Commission issued a letter[9] scheduling an oral pre-hearing conference to be held on May 13, 2013 at the Commission's offices in Edmonton. The Commission's letter attached a draft of a preliminary issues list and invited comments from parties. The preliminary issues list is included as Appendix 4.

11. Parties commented in writing on the preliminary issues list on May 1, 2013, and provided reply comments in writing on May 8, 2013.

12. On May 15, 2013,[10] following the pre-hearing conference, the Commission issued a final issues list that further refined the scope of the relevant issues. The final issues list is included as Appendix 5.

---

6 Decision 2012-237, paragraph 616.
7 Exhibit 96.02, CCA motion for further IR responses, March 25, 2013.
8 Exhibit 112.01, Commission ruling on motion to compel further and better information responses, April 23, 2013.
9 Exhibit 113.01, AUC letter regarding pre-hearing conference, April 25, 2013.
10 Exhibit 147.01, AUC letter regarding capital tracker proceeding final issues list and procedural schedule, May 15, 2013.

13. As a result of some of the issues being clarified in the final issues list, in a manner that may not have been foreseeable by some parties prior to the pre-hearing conference, in the letter setting out the final issues list, the Commission allowed parties to submit supplemental evidence on a limited number of issues on June 7, 2013. Parties could also apply to the Commission for permission to file supplemental evidence on additional matters. EPCOR, the UCA and Calgary filed requests to submit supplemental evidence.

14. In a ruling dated May 23, 2013,[11] the Commission acknowledged that the UCA and Calgary intended to file supplemental evidence on the matters directed by the Commission and denied the request of EPCOR to file supplemental evidence on additional matters, indicating that EPCOR would have an opportunity to deal with such matters in its rebuttal evidence.

15. The UCA and the CCA filed supplemental evidence on June 7, 2013 and June 10, 2013, respectively.

16. After reviewing the supplemental evidence, ATCO Gas filed a motion to exclude the Calgary supplemental evidence on the basis that it exceeded the scope of the issues permitted by the Commission.[12] Calgary replied to the motion on June 13, 2013 and ATCO Gas responded on June 14, 2013. The Commission granted ATCO Gas' motion on June 14, 2013,[13] with reasons set out in correspondence dated June 17, 2013[14] and Calgary's supplemental evidence was subsequently removed from the record of the proceeding.

17. The companies submitted rebuttal evidence on June 18, 2013.

18. An oral hearing was held at the Commission's Edmonton offices from June 24, 2013 through June 27, 2013, July 15, 2013 through July 19, 2013, and July 22, 2013 through July 24, 2013. The division of the Commission presiding over this proceeding was Mark Kolesar (panel chair), Neil Jamieson and Henry van Egteren.

19. Argument was filed by most parties on August 16, 2013, with the UCA and Calgary filing on August 19, 2013. Reply argument was submitted by all parties on September 9, 2013.

20. The Commission considers the record for this proceeding to have closed on September 9, 2013.

21. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

11 Exhibit 156.01, AUC letter ruling on supplemental evidence filings, May 23, 2013.
12 Exhibit 179.01, ATCO Gas motion to exclude the supplemental evidence of Calgary, June 11, 2013.
13 Exhibit 192.01, AUC ruling on ATCO Gas' motion to exclude supplemental evidence of Calgary, June 14, 2013.
14 Exhibit 193.01, AUC letter providing supporting reasons of the Commission's June 14, 2013 ruling on ATCO Gas motion to exclude supplemental evidence of Calgary, June 17, 2013.

1.1 Background to performance-based regulation

22. In its letter dated February 26, 2010 announcing a Commission initiative on regulatory reform, the Commission noted that "[t]raditional rate-base rate of return regulation provides few opportunities to create meaningful positive economic incentives which would benefit both the companies and the customers."[15] Specifically, the Commission stated that the rate regulation initiative proceeds from the assumption that rate-base rate of return regulation offers few incentives to improve efficiency by minimizing costs and efficiently allocating resources.[16] This is because traditional rate-base rate of return regulation is essentially a cost-plus arrangement in which all of the utility's costs are recovered from customers. As Dr. Weisman explained in the PBR proceeding, traditional cost-of-service regulation "is essentially a *cost-plus* contract that affords the regulated firm a high degree of pass-through of cost-increases in the form of price increases."[17]

23. The February 26, 2010 letter also indicated that the Commission was "seeking a better way to carry out its mandate so that the legitimate expectations of the regulated utilities and of customers are respected."[18] The Commission's regulatory reform initiative led to the PBR proceeding,[19] the purpose of which was to employ performance-based regulation as an alternative to the cost-of-service regulatory model in order to emulate, to the greatest extent possible, the same efficiency incentives as those experienced in a competitive market while maintaining service quality. Enhanced incentives would result in productivity improvements, the benefits of which would accrue to both the companies and customers. In addition, the Commission anticipated that the overall effectiveness of the regulatory framework would be improved.

24. The Commission's regulatory reform initiative establishing the PBR framework, which led to Decision 2012-237, was guided by the following five principles established by the Commission for the development of PBR plans in Bulletin 2010-20,[20] issued on July 15, 2010.

> **Principle 1.** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
>
> **Principle 2.** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3.** A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
>
> **Principle 4.** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> **Principle 5.** Customers and the regulated companies should share the benefits of a PBR plan.

15 Proceeding ID No. 566, Exhibit 1.01, AUC letter of February 26, 2010, page 2.
16 Proceeding ID No. 566, Exhibit 1.01, AUC letter of February 26, 2010, pages 1-2.
17 Proceeding ID No. 566, Exhibit 103.03, evidence of Dr. Weisman, paragraph 57.
18 Proceeding ID No. 566, Exhibit 1.01, AUC letter of February 26, 2010, page 2.
19 Application No. 1606029, Proceeding ID No. 566 leading to Decision 2012-237.
20 Bulletin 2010-20, Regulated Rate Initiative – PBR Principles, July 15, 2010.

25. The attributes of a PBR plan were explained by the Commission as follows:

> A basic PBR plan begins with rates established through a cost of service proceeding such as a rate base rate-of-return proceeding. Those rates are then adjusted in subsequent years by a rate of inflation (I) relevant to the prices of inputs the companies use less an offset (X) to reflect the productivity improvements the companies can be expected to achieve during the PBR plan period. Thus, adjusting rates by I-X, rather than in cost of service proceedings, breaks the link between a utility's own costs and its revenues during the PBR term. In much the same way as prices in competitive industries are established in a competitive market, prices adjusted by I-X reflect industry-wide conditions that would produce industry price changes in a competitive market. Each company's actual performance under PBR will depend on how its own performance compares to the industry's inflation and productivity measures.
>
> Establishing prices in this way during the term of a PBR plan creates stronger incentives for the companies to improve their efficiency through cost reductions and other actions because they are able to retain the increased profits generated by those cost reductions longer than they would under cost of service regulation, especially with rates under cost of service regulation that are re-set every two years. At the same time, under a PBR regulatory framework, customers automatically share in the expected efficiency gains because they are built into rates through the X factor regardless of the actual performance of the companies. In addition, the X factor in a PBR plan is often increased by a stretch factor so as to capture efficiency gains that should be immediately realizable as the regulatory system changes from cost of service to PBR.[21]

26. The Commission went on to explain that, through the I-X mechanism, a PBR plan is designed so a company's prices or revenues-per-customer change with the change in input prices as measured by the I factor and decrease by the rate of productivity growth, as measured by the X factor.

27. The I factor provides a mechanism to adjust a company's prices (in the case of a price cap plan) or revenues-per-customer (in the case of a revenue-per-customer cap plan) year-over-year to reflect changes in the prices of inputs that the company uses. The Commission recognized that a PBR plan should provide incentives for the company to undertake productivity improvements to manage and minimize the costs that are within its control. However, changes in a company's input prices due to inflation (e.g., driven by macroeconomic forces) are not within its ability to control, although the company may be able to use those inputs more effectively than its competitors. In competitive markets, when faced with a universal economy-wide increase in input prices, such as an increase in salaries and wages or higher fuel prices, companies are often left with no choice but to pass on these higher costs to consumers. Similarly, when the prices of inputs go down, competition forces the companies to lower their prices.[22]

28. Therefore, in order for a regulated utility to earn its allowed rate of return, it must limit its input cost increases to the broad index of input price changes, as measured by the Commission-approved I factor. Because this measure is based on the input price changes experienced in the Alberta economy, it is reflective of input cost increases that are generated by competitive market forces. As the UCA pointed out in the PBR proceeding, the I factor mirrors the process of reviewing a company's costs and adjusting rates on a prudency basis, in effect using the selected inflation measure as a prudency test.[23] This preserves the incentive properties of PBR while

21 Decision 2012-237, paragraphs 16 and 17.
22 Decision 2012-237, paragraphs 153 and 154.
23 Decision 2012-237, paragraph 148.

allowing a reasonable opportunity for the companies to recover their prudently incurred input costs.

29. The X factor reflects the rate of productivity growth that a company is expected to achieve annually during the PBR term. Because this measure is based on the average total factor productivity (TFP) growth experienced by the distribution utility industry over a long period of time, the Commission considers that it is reasonable to expect that Alberta distribution utilities will be able to achieve this rate of productivity growth during the PBR term. In the PBR proceeding, the Commission agreed with National Economic Research Associates' (NERA) explanation that the rationale behind the X factor (to which the TFP study contributes) is to emulate the incentives of competitive markets as they relate to productivity. In competitive markets, if a company achieves greater productivity growth than the industry, it generally is rewarded with larger earnings in the short run.[24] If a company's productivity growth is lower than the industry productivity, its earnings generally suffer in the short run. The X factor preserves the incentive properties of PBR while allowing a reasonable opportunity for the companies to earn their allowed rate of return.

30. At the same time, under a PBR regulatory framework, customers automatically share in the expected productivity gains because they are built into rates through the X factor, regardless of the actual performance of a company. Customers of a regulated company under PBR directly benefit from annual rates that are adjusted to reflect these expected productivity gains. In addition, the X factor in the PBR plans was increased by a stretch factor to capture efficiency gains that should be immediately realizable as the regulatory system changes from cost-of-service to PBR. The inclusion of a stretch factor provides a further benefit to customers.

31. In Decision 2012-237, the Commission explained that while the size of the X factor affects a company's earnings, it has no influence on the incentives for the company to reduce costs. The PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of the PBR term (i.e., regulatory lag).[25] The longer the regulatory lag, the stronger the PBR incentives to reduce costs. NERA provided the following general explanation of the PBR framework:

> The theory that we're drawing from doesn't require such precision. It says that there is an industry out there that's doing something. If it's a competitive industry -- it's an industry for making [hockey sticks], I don't know. [...] And of all the makers of hockey sticks, there's a productivity trend for hockey stick makers, and if you can't keep up, your business will fail. We don't need to be vastly more sophisticated than to measure the productivity of the hockey stick industry and use that as our way of allowing regulatory lag to eke out a few more years to avoid a couple of rate cases and to allow a little more productivity pressure to be visited on utility managements to try to make the businesses run better.[26]

32. However, the Commission also recognized that the I-X mechanism may not provide sufficient revenue to allow the companies to recover all of their prudently incurred costs. To that end, the Commission approved the use of Y factor and Z factor rate adjustments to deal with certain flow-through costs beyond the control of the company and the impact of significant

[24] Decision 2012-237, paragraph 290, referring to footnote 302 in that paragraph.
[25] Decision 2012-237, paragraph 257.
[26] Decision 2012-237, paragraph 277, quoting NERA.

unforeseen events outside of the control of the company that would not otherwise be reflected in rates through the inflation factor adjustment.

33. In addition, the Commission recognized that there may be circumstances during the PBR term where certain required capital-related costs could not be adequately funded through the I-X mechanism or through either a Y factor or Z factor adjustment. Each of the approved PBR plans included the opportunity for the company to apply for supplemental capital funding through the approval of a capital project identification and tracking mechanism referred to as a capital tracker. Costs for capital projects approved for capital tracker treatment would be recovered by way of a K factor component of the PBR rate adjustment formula.

34. While the Commission found that Y, Z and K factor adjustments were necessary elements of the approved PBR plans, the Commission was careful to limit the scope and application of these adjustments, noting that they reduce the incentives that a PBR plan is intended to promote. The Commission stated:

> All of these types of cost-based adjustments (whether Z, Y or K) are carefully defined and limited in their scope because they are inconsistent with the objectives of PBR in that they have the effect of lessening the efficiency incentives that are central to a PBR plan.[27]

35. The Commission concluded in Decision 2012-237 that the X factor, based on the average productivity growth in the industry, together with the I factor, based on Alberta inflation, along with the other features of the approved PBR plans, provides "each of the companies with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return over the five-year term of the plan."[28]

36. The next section of this decision reviews the Commission's findings in Decision 2012-237 on the need for, availability and use of capital trackers and the K factor rate adjustment.

1.2 Selection of capital trackers as the method for addressing capital requirements that are not funded under the I-X mechanism

37. During the PBR proceeding, the companies expressed concern that an I-X mechanism by itself would provide insufficient revenues to fund necessary capital expenditures. Of particular concern were accelerated system modernization projects, externally driven projects, and capital expenditures required for a rapidly expanding system. Experts appearing in the PBR proceeding generally agreed that some method of funding certain capital expenditures outside of the I-X mechanism is required in a PBR plan, although there was no agreement on how to determine what capital expenditures should be eligible for supplemental funding or how to fund them.[29]

38. The Commission agreed "that a mechanism to fund certain capital-related costs outside of the I-X mechanism through a capital factor is required."[30] In approving a supplemental capital funding mechanism, the Commission's objective was to provide the companies with the opportunity to fund prudently incurred capital expenditures that could not be funded under the I-X mechanism, while minimizing negative impacts on the incentives created under the PBR

[27] Decision 2012-237, paragraph 21.
[28] Decision 2012-237, paragraph 35.
[29] Decision 2012-237, paragraphs 544 to 546.
[30] Decision 2012-237, paragraph 586.

with the interpretation, implementation and application of each of the three capital tracker criteria.

3.1 Criterion 1 – The project must be outside of the normal course of the company's ongoing operations

123. Decision 2012-237 noted the following in respect of Criterion 1:

> 594. The first criterion is required to avoid double-counting between capital related costs that should be funded by way of a capital tracker and those that should be funded through the I-X mechanism. This criterion is also required to ensure that capital tracker projects are of sufficient importance that the company's ability to provide utility service at adequate levels would be compromised if the expenditures are not undertaken. Projects that do not carry this level of importance are likely subject to a reasonable level of management discretion, therefore allowing special treatment for this type of capital would eliminate the incentive for the company to examine all alternatives. Therefore, this criterion would require that an engineering study be filed to justify the level of capital expenditures being proposed. That is, the company must demonstrate that the capital expenditures are required to prevent deterioration in service quality and safety, and that service quality and safety cannot be maintained by continuing with O&M and capital spending at levels that are not substantially different from historical levels. The company will also be required to demonstrate that the capital project could not have been undertaken in the past as part of a prudent capital maintenance and replacement program.[133] (footnote omitted)

124. There was substantial debate in this proceeding about which projects may be considered outside the normal course of the company's ongoing operations. In addition, parties to this proceeding did not agree on how to demonstrate that there is no double-counting between capital related costs that should be funded by way of a capital tracker and those that should be funded under the I-X mechanism. Parties also disagreed on the role of engineering studies in identifying projects qualifying for capital tracker treatment. Each of these aspects of Criterion 1 is addressed in the sections that follow.

125. Section 3.1.1 provides a definition of "outside the normal course of the company's ongoing operations." Subsequent sections establish two tests, both of which must be met in order to satisfy Criterion 1. Sections 3.1.2 and 3.1.3 establish the "accounting test" that the Commission will use to determine the absence of double-counting and to calculate the amount of investment that is outside the normal course of the company's ongoing operations. Section 3.1.4 sets out the "project assessment" that the Commission will use to evaluate the need for, and reasonableness of, a project proposed for capital tracker treatment.

3.1.1 Defining "outside the normal course of the company's ongoing operations"

126. In the PBR proceeding, the concept of the normal course of the company's ongoing operations was discussed in the following exchange between Commission counsel and Dr. Makholm, on behalf of NERA:

> Q. And that's -- okay. So, in other words, it has to be something unusual, out of the normal course of the utility as opposed to what the industry group that formed the basis for the TFP study that carries on?

[133] Decision 2012-237, paragraph 594.

A. DR. MAKHOLM: Well, sure. Because everybody's rates are based on their own books and records in base rates, and if the company has been doing whatever it is that we're describing consistently over the course of many years, it's in their base rates, and hence the base rates ought to be able to reflect that capital expense. It's what isn't in base rates that's idiosyncratic and out of phase and deferred and lumpy that the formula wouldn't be able to cover, and that's the dividing line for derogating from a formula that's supposed to cover everything, is whether or not you decide by looking that there's a certain category of costs or a certain practical nature of any particular company's activities that lead it to conclude and convince the Commission that a straight-forward formula of the RPI minus X plus Z variety won't do.[134]

127. In this proceeding, parties' views with respect to which projects may be considered outside of the normal course of the company's ongoing operations tended to polarize around two different interpretations. Calgary and the UCA favoured a qualitative approach based on past operations of a utility. The companies favoured a quantitative approach that demonstrated how much of the revenue requirement for capital projects will be funded under the I-X mechanism. The CCA observed that several definitions of the normal course of the company's ongoing operations are pertinent in this proceeding.

128. Calgary submitted that in order for a project to be considered outside of the normal course of the company's ongoing operations, the project has to be "outside of the same or similar type of activity a utility has been typically carrying out for years."[135] Further, according to Calgary, a demonstration of outside the normal course is not dependent on what the I-X mechanism will yield.[136]

129. In a similar vein, the UCA concluded in its argument that, to be outside the normal course of the company's ongoing operations, "the project should not be an activity or part of a program that the utility has previously undertaken such that it is idiosyncratic, not routine or regularly undertaken, and would not include costs that relate to the continuation of programs that are already in place."[137] In its argument, the UCA also advocated the use of the following test to determine whether a project is outside the normal course of the company's ongoing operations:

1. The project must be outside the normal course of the company's ongoing operations.
   a. Is the project required to prevent deterioration in service quality and safety?
   b. Does the project require spending outside of historical trends?
   c. If the answer to both are yes, the project is outside of the normal course of business.[138]

130. The UCA's technical engineering experts, SMi Faciliop (SMi) and Teshmont Consultants LP. (Teshmont), generally defined the normal course of the company's ongoing operations as the ongoing activities of the distribution company to provide reliable and safe distribution service

134 Decision 2012-237, paragraph 589, quote from Proceeding ID No. 566, Transcript, Volume 1, pages 160-163 (Makholm).
135 Exhibit 269.01, Calgary argument, paragraph 128.
136 Exhibit 269.01, Calgary argument, paragraph 128.
137 Exhibit 268.02, UCA argument, paragraph 109.
138 Exhibit 268.02, UCA argument, paragraph 20.

while meeting expected service levels, as defined by a pre-determined set of service level measures.[139]

131. Teshmont added that incremental improvement of safe and reliable service is also expected in normal operations.[140] Teshmont indicated that, from an engineering perspective, "normal course of business includes but is not limited to replacing damaged or aged system elements, removing or correcting impediments to service, gathering measurements and data on equipment to be used to assess [declining] performance, assessing and responding to normal changes in customer behaviors, some improvements to safe and reliable service, and similar activities."[141] According to SMi, however, projects and programs designed to enhance or improve the level of service would be considered outside of the normal course of utility operations.[142]

132. Both of the UCA's engineering consultants indicated they had not considered the concept of a normal course from a financial (i.e., project cost) perspective.[143] In addition to considering whether proposed projects were outside the normal course the company's ongoing operations, the UCA stated that its engineering experts, SMi and Teshmont, "also focused on whether the projects were required to prevent deterioration in service quality and safety and whether alternatives to the project were adequately discussed, addressed or even disclosed."[144]

133. In response to AUC-UCA-1, the UCA's witness, Mr. Bell, indicated that "projects that are outside the normal course of business must not be costs that relate to the continuation of programs that have been in place."[145] At the same time, Mr. Bell noted that historical costs and costs included in going-in rates are an indicator for costs that are in the normal course of business. Therefore, according to Mr. Bell, "historic spending patterns set a baseline as to what is included in the normal course of business, and to be considered outside of the normal course of business, the utility must demonstrate that it cannot maintain safe and reliable service using historic spending levels."[146]

134. During the hearing, Mr. Bell accepted Commission counsel's interpretation of his position that the definition of normal course of the company's ongoing operations is partially functional and partially financial.

> Q. So, sir, I take it that your definition of normal course is partially a functional one and partially a financial one. If a particular activity has been carried out in the past by a utility, then it is within the normal course of operations, unless it can be said that the current level of activity is substantially different than historical levels. Have I understood your position properly?
> A. MR. BELL: That would be my interpretation of the Commission's criteria, yes.[147]

[139] Exhibit 167.02, AUC-UCA-1(a), responses from SMi and Teshmont.
[140] Exhibit 167.02, AUC-UCA-1(a), response from Teshmont.
[141] Exhibit 167.02, AUC-UCA-1(a), response from Teshmont.
[142] Exhibit 167.02, AUC-UCA-1(a), response from SMi.
[143] Transcript, Volume 9, page 1771, lines 14-17 (Teshmont) and Volume 10, page 1953, lines 8-11 (SMi Faciliop).
[144] Exhibit 266.02, UCA argument, paragraph 26.
[145] Exhibit 167.02, AUC-UCA-1(a), response from R. Bell.
[146] Exhibit 167.02, AUC-UCA-1(d), response from R. Bell.
[147] Transcript, Volume 11, page 2106, line 18 to page 2107, line 2 (Bell).

135. In its argument, the UCA explained that in order to identify projects outside the normal course of the company's ongoing operations under Mr. Bell's approach, "[f]irst, the extent of projects which the utility has or should have been performing in order to provide safe and reliable service must be determined and compared with the proposed project. Second, the level of cost expended must be compared to historic levels."[148]

136. The CCA observed that several definitions of the normal course of the company's ongoing operations are pertinent to this proceeding.

> One is the capital cost growth the company has experienced in the recent past. A second is capital cost growth in excess of the company's longer term historical norms. A third is capital cost growth in excess of the norms for utilities in the TFP research sample. In all three cases, comparisons would be more useful if they were adjusted for customer growth and an estimate of construction cost inflation. The comparator would then effectively be capital productivity growth.[149]

137. During the hearing, when questioned on his views with regard to determining whether a project is inside or outside the normal course of a company's ongoing operations, the CCA's expert witness, Dr. Lowry responded:

> You know, what you ideally like to do -- it's hard and maybe impossible in the short run -- is to ascertain what's normal compared to other utilities in the sample. But at least it can be informative to look in the absence of that, which is hard -- this whole area of capital benchmarking which Dr. Weisman mentioned is very much in its infancy, and I don't think it's going to happen any time soon. You can get capital productivity trends. That's easy. But capital levels benchmarking would be harder. [...] So in the absence of well-developed methodologies for capital benchmarking between firms, it is helpful to look at what they did in the past versus what they're doing now, and certainly there are examples of it in this case like where ATCO would like to step up their urban mains replacement.[150]

138. The companies relied on a quantitative approach that purported to demonstrate how much revenue requirement associated with capital projects would not be funded under the I-X mechanism, thereby establishing the level of capital investment that is outside the normal course of the company's ongoing operations.

139. Specifically, the ATCO companies indicated that the "costs of capital investments which cannot be addressed by the base rates under the PBR formula are the things which would be outside the 'normal course of ongoing operations'."[151] According to the ATCO companies' expert witness, Dr. Makholm, determination of whether incremental funding by way of a capital tracker was required should be based on "things that have not, as an empirical matter, entered the base rates as coming out of the last base rate case."[152]

140. Fortis offered a definition similar to the ATCO companies, and stated that the concept of the normal course of the company's ongoing operations cannot be interpreted as an "activity or function-based concept."[153] In Fortis' view, such an interpretation could exclude virtually any

[148] Exhibit 268.02, UCA argument, paragraph 30.
[149] Exhibit 270.02, CCA argument, paragraph 32.
[150] Transcript, Volume 12, pages 2365, line 14 to page 2366, line 3 (Lowry).
[151] Exhibit 265.01, ATCO argument, paragraph 80.
[152] Transcript, Volume 1, page 106, lines 6-10 (Makholm).
[153] Transcript, Volume 7, page 1371, line 16 (Lorimer).

utility investment from capital tracker eligibility. The concept of normal course must be interpreted as a financial consideration, which looks at whether the particular capital investments for which capital tracker treatment is sought can or cannot be funded by going-in rates escalated by I-X.[154]

141. EPCOR expressed a similar view and indicated that the line of demarcation between what is inside or outside the normal course of the company's ongoing operations is not to be limited to a determination of whether a particular capital project is similar to capital projects that the utility has engaged in at some point in its history, or even on an ongoing basis. Instead, the focus is on whether or not the capital-related costs associated with the work included in the capital tracker are funded under the I-X mechanism.[155]

142. At the same time, EPCOR did not disagree with Dr. Makholm's statement in the PBR proceeding that projects outside the normal course of the company's ongoing operations would be "idiosyncratic and out of phase and deferred and lumpy."[156] EPCOR's expert witness, Dr. Weisman, in this proceeding, described the concept of outside the normal course as encompassing either the qualitative characteristics of a project (e.g., idiosyncratic or lumpy) or the quantitative characteristics of a project (e.g., current costs exceeding historical costs).[157] Mr. Elford, on behalf of EPCOR, expressed a similar view.[158]

143. In its argument, AltaGas indicated that a capital program "is definitely not 'normal course' if the revenue requirement associated with the program will not be fully funded through the I-X."[159] During the hearing, AltaGas indicated that the concept of normal course relates to the historical practices of the company.[160] During the hearing, AltaGas agreed with Commission counsel's characterization that its proposed capital tracker projects are "lumpy, idiosyncratic, out of phase, do not include any routine items, and, thus, are outside the normal course of the utility's operations."[161]

Commission findings

144. In Decision 2012-237, the Commission acknowledged that there are circumstances in which a PBR plan would need to provide for revenue in addition to the revenue generated under the I-X mechanism in order to provide for certain capital expenditures.[162] In evaluating the interveners' and the companies' proposed definitions of "the normal course of the company's ongoing operations," the Commission considered the basic relationship between capital expenditures and the I-X mechanism outlined in Decision 2012-237.

145. As noted in Decision 2012-237, the TFP growth study used to determine the X factor adopted by the Commission measures the rate of change in productivity of the distribution industry over time. The TFP growth study necessarily encompassed all input costs, including all

154 Transcript, Volume 7, page 1371, lines 20-24 (Lorimer).
155 Exhibit 263.02, EPCOR argument, paragraph 115.
156 Decision 2012-237, quoting Dr. Makholm in paragraph 589.
157 Transcript, Volume 6, pages 1059-1060 (Weisman).
158 Transcript, Volume 6, pages 1053-1055 (Elford).
159 Exhibit 267.01, AltaGas argument, paragraph 9.
160 Transcript, Volume 5, page 794, line 21 to page 795, line 6 (Johnston).
161 Transcript, Volume 5, page 826, lines 15-22 (Johnston).
162 Decision 2012-237, paragraph 549.

types of capital expenditures and all of the year-to-year fluctuations in capital investments.[163] Because this measure is based on the average TFP growth experienced by the distribution utility industry over a long period of time, the Commission considered that it was reasonable to expect that Alberta distribution utilities would be able to achieve this rate of productivity growth during the PBR term. In addition, the Commission increased the X factor in the PBR plans by a stretch factor to capture efficiency gains that should be realizable immediately as the regulatory system changes from cost-of-service to PBR.

146. Under the PBR plans, productivity represented by the X factor, together with the I factor, are applied to the going-in rates or revenues-per-customer. As the Commission explained in Section 1.1 of this decision, under PBR, a company will normally earn its allowed rate of return if it limits its input cost increases to the broad index of input price changes in the Alberta economy, as measured by the Commission-approved I factor, and achieves its productivity growth equal to the Commission-approved X factor, based on the long-term average productivity growth in the industry.

147. Because a company's rate base reflects historical capital expenditures, the going-in rates developed in the cost-of-service proceeding prior to PBR reflect the historical capital expenditures of the company. The underlying assumption in the PBR plans is that the company's historical productivity growth is similar to the historical productivity growth of the distribution industry reflected in the X factor. Therefore, applying I-X (reflecting inflation and the industry's historical rate of productivity growth) to going-in rates (reflecting the company's historical expenditures including the allowed rate of return component) will provide revenue sufficient to accommodate the company's historical rate of growth in capital expenditures for the duration of the PBR term.

148. However, incremental funding by way of capital trackers is warranted when a company's rate of growth in inputs associated with its prudent capital expenditures in a PBR year is sufficiently greater than the company's growth in outputs associated with its prudent capital expenditures, so that even if the company were to achieve the productivity growth implied by the Commission-approved X factor, the company would have insufficient revenue from the I-X mechanism to fund all of its prudent capital expenditures in the PBR year and, at the same time, have a reasonable opportunity to earn an allowed rate of return.

149. The Commission concludes that, in general, in order for a capital project to be considered outside of the normal course of the company's ongoing operations, the increase in associated revenue provided under the I-X mechanism (reflective of historical expenditures embedded in going-in rates and industry productivity growth) would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for this project. However, this definition does not mean that customers will pay for the companies' inability to achieve productivity growth at least equivalent to the Commission-approved X factor. As set out in Section 3.1.3 of this decision, a company will get incremental funding only for that portion of the revenue requirement associated with a project afforded capital tracker treatment in excess of the revenue available from the I-X mechanism. Therefore, customers will benefit from the expected productivity gain embedded in X, whether or not it is achieved.

[163] Decision 2012-237, paragraph 549.

TAB 6

AUC
Alberta Utilities Commission

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

December 16, 2016

Alberta Utilities Commission
Decision 20414-D01-2016
2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities
Proceeding 20414

December 16, 2016

Published by the:
Alberta Utilities Commission
Fifth Avenue Place, Fourth Floor, 425 First Street S.W.
Calgary, Alberta
T2P 3L8

Telephone: 403-592-8845
Fax: 403-592-4406

Website: www.auc.ab.ca

Contents

List of tables

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

Decision 20414-D01-2016
Proceeding 20414

1 Decision

1. Customer rates for all Alberta electric and gas distribution utilities are currently set by the Alberta Utilities Commission in accordance with the provisions of performance-based regulation (PBR) plans, the parameters of which were approved by the Commission in Decision 2012-237[1] and Decision 21149-D01-2016.[2] Under these plans, a utility's rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation, less an offset to reflect the productivity improvements the firm can be expected to achieve during the PBR plan period (X factor), plus other specific adjustments. As a result, with the exception of specifically approved adjustments, a utility's revenues are generally no longer linked to its costs; this decoupling of costs and revenues promotes behaviours that increase productivity and decrease costs. The term of the current generation PBR plans expires on December 31, 2017.

2. This decision establishes the parameters to be included in the next generation of PBR plans (next generation PBR plans) to be implemented for the 2018 to 2022 period. This decision applies to four electric distribution utilities, ATCO Electric Ltd. (distribution), ENMAX Power Corporation (distribution), EPCOR Distribution & Transmission Inc. (distribution), and FortisAlberta Inc. and two gas distribution utilities, AltaGas Utilities Inc., and ATCO Gas and Pipelines Ltd. (distribution), together referred to as the distribution utilities.

3. In particular, this decision deals with four main next generation PBR plan parameters: (i) rebasing and the going-in rates for the next generation PBR term, (ii) the X factor, (iii) the treatment of capital additions, and (iv) the calculation of the return on equity (ROE) for reopener purposes.

4. In Section 4 of this decision, the Commission determines that the going-in rates for the next generation PBR plans will be established on the basis of a notional 2017 revenue requirement using costs and capital additions that are rooted in actual data. Cost-of-service (COS) studies, including Phase II applications and depreciation studies, will not form part of the rebasing applications. However, Phase II applications and depreciation studies will be considered by the Commission subsequent to the approval of the going-in rates. Also in Section 4, the Commission determines that the efficiency carry-over mechanism (ECM) "50 per cent" ROE add-on will be applied to the 2017 notional mid-year rate base.

5. In Section 5 of this decision, based on the considerations of industry total factor productivity (TFP) growth and a stretch factor, the Commission determines the X factor for the next generation PBR plans, to be 0.3 per cent. The same X factor of 0.3 per cent will also apply

1 Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.

2 Decision 21149-D01-2016 (Errata): ENMAX Power Corporation Distribution 2015-2017 Performance-Based Regulation – Negotiated Settlement Application and Interim X Factor, Proceeding 21149, October 3, 2016.

to the ENMAX 2015-2017 PBR plan. The Commission did not include the provision to limit the value of the I-X index to be non-negative for either plan.

6. In Section 6 of this decision, the Commission determines that capital will be divided into two categories: Type 1 and Type 2 capital. For Type 1 capital, the Commission approves a continuation of capital trackers with some modifications, including the replacement of forecast applications with a placeholder amount, which is detailed in Section 6.4.2. For Type 2 capital, the Commission approves a K-bar methodology, which is detailed in Section 6.4.3. The Commission also determines that negative and positive accounting test results with be netted in each of the Type 1 and Type 2 categories.

7. In Section 7, the Commission determines that the latest information available, be it the initial Rule 005: *Annual Reporting Requirements of Financial and Operational Results* filing or a subsequent ROE restatement filed as part of the annual PBR rates adjustment filing, can serve as a basis for a reopener application. In considering whether a reopener may be required, a distribution utility may be asked for ROE adjustments to account for any outstanding true-up amounts and unusual events that may have affected its earnings.

8. The remaining parameters of the next generation PBR plans, such as the I factor, Y factor, Z factor, and annual reporting requirements, among others, are to be unchanged from those established in Decision 2012-237. These parameters are set out in Appendix 5 to this decision.

2 Procedural summary

9. On May 8, 2015, the Commission issued Bulletin 2015-10,[3] indicating the Commission's intention to proceed with a next generation PBR regulatory regime for the distribution utilities, stating:

> The Commission proposes to continue with PBR regulation of electric and gas distribution utilities in accordance with the five PBR principles that the Commission adopted in the first generation PBR plans. [footnote omitted]

10. The bulletin initiated the present generic proceeding to establish parameters for the next generation PBR plans for the electric and gas distribution utilities under its jurisdiction.

11. The Commission invited interested parties to participate in this generic proceeding by filing a statement of intention to participate (SIP) in the Commission's electronic filing system by May 22, 2015. SIPs were received from ATCO Gas, ATCO Electric (referred to as the ATCO utilities), AltaGas, ENMAX, EPCOR, Fortis, Devon Canada, AltaLink Management Ltd., The City of Calgary, the Consumers' Coalition of Alberta (CCA), and the Office of the Utilities Consumer Advocate (UCA).

12. The bulletin included a preliminary list of issues for parties upon which to comment. Following submissions from various parties, the Commission issued a final issues list identifying the scope of the proceeding on August 21, 2015. Further, the bulletin invited parties to file their proposals for the parameters to apply to the next generation PBR plans and established a

3 Bulletin 2015-10, Generic proceeding to establish parameters for the next generation of performance-based regulation plans, May 8, 2015.

preliminary timeline for the proceeding. The main process steps, as amended throughout the course of the proceeding, are set out in the table below:

Process step	Deadline
Bulletin 2015-10 issued, initiating this proceeding	May 8, 2015
Parties' comments on the draft list of issues	June 5, 2015
Parties' reply comments on the draft list of issues	June 19, 2015
Final issues list issued by the Commission	August 21, 2015
Next generation PBR plan proposal submissions	March 23, 2016
Information requests (IRs) to parties	April 15, 2016
IR responses from parties	May 6, 2016
Reply evidence from all parties	May 27, 2016
Commission's Round 2 IRs to all parties	June 3, 2016
Sur-rebuttal evidence from all parties to address IR responses that were filed late or were subject to motions	June 13, 2016
Responses from all parties to the Commission's Round 2 IRs	June 17, 2016
Oral hearing	July 6 to July 29, 2016
Argument	August 26, 2016
Reply argument	September 16, 2016

13. In addition to filing their respective plan proposals, AltaGas, ATCO Gas, ATCO Electric, ENMAX and Fortis sponsored the evidence of Dr. P. Carpenter and Dr. T. Brown of The Brattle Group, which included Brattle's TFP growth study as well as its views on the issues in scope for this proceeding. In addition to filing its plan proposal, EPCOR sponsored the TFP growth study by Dr. M. E. Meitzen of Christensen Associates and the evidence of Dr. D. Weisman on the issues in scope for this proceeding. The CCA sponsored the evidence of Dr. M. N. Lowry of Pacific Economics Group Research LLC (PEG), which included PEG's TFP growth study as well as its views on the issues in scope for this proceeding. PEG's rebuttal evidence was written by Dr. Lowry and D. Hovde. The CCA also sponsored the evidence of Mr. J. Thygesen. Messrs. D. Simpson and R. Bell filed evidence for the UCA. The UCA also sponsored the reply evidence by K. Pavlovic, M. Griffing and D. Mugrace of PCMG and Associates LLC, on matters related to a TFP growth calculation. Mr. H. Johnson and Mr. D. Matwichuk filed evidence for Calgary.

14. Following the filing of parties' PBR plan proposal submissions on March 23, 2016, the Commission issued a notice of proceeding inviting interested parties, other than parties who had already filed submissions with the Commission, who wished to participate in the proceeding, to file a SIP by April 1, 2016. No new SIPs were received.

15. The division of the Commission presiding over this proceeding comprises Chair Willie Grieve, QC, who chaired the panel, Commission Member Neil Jamieson and Commission Member Henry van Egteren.

16. The Commission considers the record for this proceeding to have closed on September 16, 2016, when reply arguments were filed.

17. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding. Accordingly, reference in this decision to specific parts of the record are intended to assist the reader in

understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to a particular matter.

3 Background

18. In Decision 2012-237, the Commission implemented PBR for certain electric and gas distribution utilities in Alberta. The utilities regulated under this PBR framework are AltaGas, ATCO Electric, ATCO Gas, EPCOR and Fortis. The approved PBR plans that resulted from Decision 2012-237 are for a five-year term from January 1, 2013 to December 31, 2017, referred to throughout this decision as the "2013-2017 PBR plans."

19. The PBR framework approved in Decision 2012-237 provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation (I), which is relevant to the prices of inputs the firms use, less a productivity offset (X), which is relevant to the productivity improvements the distribution utilities are expected to achieve during the PBR plan period. As a result, with the exception of specifically approved adjustments, a utility's revenues are no longer linked to its costs during the PBR term, thereby enhancing incentives for the distribution utilities to improve their productivity.

20. Additionally, under the provisions of the PBR plans approved in Decision 2012-237, a distribution utility may apply for approval of certain rate adjustments to enable the recovery of specific costs where it can be demonstrated that the costs cannot be recovered under the I-X mechanism and where certain other criteria have been satisfied. These adjustments could include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly (a Y factor), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan (a Z factor). In addition, the Commission determined that a rate adjustment mechanism to fund certain capital-related costs may be required under the approved PBR plans. This rate adjustment mechanism was referred to in Decision 2012-237 as a "capital tracker" with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate-setting formula. The criteria and calculation parameters of the capital tracker mechanism were further developed and clarified in Decision 2013-435[4] and subsequent decisions.[5]

21. ENMAX is also subject to PBR but, unlike the other electric distribution utilities, ENMAX was not directed to file a PBR plan pursuant to Decision 2012-237 because it already had an incentive plan in place at that time. In Decision 2009-035,[6] the Commission approved formula-based ratemaking (or FBR, a term sometimes used as a synonym for PBR) for ENMAX's distribution and transmission services, over the 2007 to 2013 term. Following the

4 Decision 2013-435: Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.

5 Decision 3434-D01-2015: Distribution Performance-Based Regulation, Commission-Initiated Review of Assumptions Used in the Accounting Test for Capital Trackers, Proceeding 3434, Application 1610877-1, February 5, 2015; Decision 3558-D01-2015: Distribution Performance-Based Regulation, Commission-Initiated Proceeding to Consider Modifications to the Minimum Filing Requirements for Capital Tracker Applications, Proceeding 3558, Application 1611054-1, April 8, 2015.

6 Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Proceeding 12, Application 1550487-1, March 25, 2009.

expiration of the ENMAX plan, ENMAX was regulated under a traditional COS framework in 2014. In Decision 21149-D01-2016, the Commission approved a second incentive plan for ENMAX distribution services only, for the years 2015 to 2017. This incentive plan is, in most material respects, with the exception of the X factor, consistent with the PBR plans approved in Decision 2012-237.[7] Decision 21149-D01-2016 approved an interim X factor with the direction that the final X factor for the ENMAX 2015-2017 PBR plan will be determined in the present proceeding.[8] The parameters of the next generation PBR plan for ENMAX for the 2018-2022 period, also will be determined in this proceeding. Throughout this decision, the term "current generation PBR plans" is used to refer to the ENMAX 2015-2017 PBR plan and the 2013-2017 PBR plans for other distribution utilities.

22. In commencing the present generic proceeding to establish parameters for the next generation PBR plans for all electric and gas distribution utilities under its jurisdiction, the Commission indicated in Bulletin 2015-10 that it continued to support the five PBR principles that the Commission adopted in the first generation PBR plans. Those principles were:[9]

> **Principle 1.** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
>
> **Principle 2.** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3.** A PBR plan should be easy to understand, implement and administer, and should reduce the regulatory burden over time.
>
> **Principle 4.** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> **Principle 5.** Customers and the regulated companies should share the benefits of a PBR plan.

23. As noted above, in a letter dated August 21, 2015 (attached as Appendix 4 to this decision), the Commission limited the scope of the present proceeding to four main topics:[10]

(i) rebasing and the going-in rates for the next generation PBR term, discussed in Section 4;

(ii) the X factor, discussed in Section 5;

(iii) the treatment of capital, discussed in Section 6; and

(iv) the calculation of ROE for reopener purposes, discussed in Section 7.

24. The Commission also confirmed that the parameters of the current generation PBR plans (established in Decision 2012-237 for five distribution utilities and for ENMAX in Decision 21149-D01-2016) that were not specifically addressed in the final issues list would continue into

7 Decision 21149-D01-2016 (Errata), paragraphs 45-47.
8 Decision 21149-D01-2016 (Errata), paragraph 53.
9 Decision 2012-237, paragraph 28.
10 Exhibit 20414-X0026, AUC letter - Final issues list, August 21, 2015.

and form part of the next generation PBR plans to be implemented, subject to possible rebasing considerations, at the end of the current generation PBR term. These parameters, which include the type of plan (price cap or revenue cap), I factor, Y factor, Z factor, ECM, service quality provisions and annual reporting requirements, are summarized in Appendix 5 to this decision.

25. In making its decisions in this proceeding, the Commission has considered not only the discrete issues that need to be decided but also how all of the elements of PBR, both those that are being considered in this proceeding and those that continue from the current generation PBR plans, are interconnected and affect each other. In the Commission's view, a PBR plan must be viewed and considered as a whole. It is not enough to pick one element of the PBR plan, argue that it should be eliminated, left unchanged or fixed and consider that to be the end of the conversation. All of the elements of the plan must be considered together in order for the Commission to design a PBR plan that satisfies the PBR principles set out above.

4 Rebasing

26. During a PBR term, the linkage between a utility's revenues and costs of providing utility service is intentionally broken to provide the distribution utility with the flexibility to manage its business in an environment which fosters incentives to seek out and realize process, operational, capital and financial efficiencies so as to reduce costs while maintaining existing service levels. "Rebasing" refers to the exercise of re-establishing the linkage between a utility's revenues and costs with the objective of generally realigning revenues and costs in anticipation of, or at the end of, a PBR plan term. Depending on the context, the word "rebasing" can be used as a noun (the process of rebasing), an adjective (the rebasing process) or as a verb (the process involves rebasing costs and revenues). The rebasing of costs and revenues is used to establish new going-in rates for the next generation PBR plan. If a utility was successful in achieving efficiencies that resulted in cost savings during a PBR plan, the new going-in rates which result from rebasing should reflect these realized savings, thereby benefiting customers throughout the next generation PBR term.

27. Rebasing and setting the going-in rates for the next generation PBR plan was the first item on the final issues list established by the Commission in its letter dated August 21, 2015. All parties indicated that some form of rebasing is necessary prior to the next generation PBR plans,[11] to realign costs and revenues for the benefit of the distribution utilities and customers.[12] In addition, ENMAX noted that rebasing could allow the distribution utilities the opportunity to update relevant COS studies; for example, depreciation studies.[13] The Commission agrees that a form of rebasing is required in order to set the going-in rates for the next generation PBR plans and to review and update certain parameters of the plan.

11 Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 33; Exhibit 20414-X0073, Fortis PBR plan proposal, paragraphs 18-19; Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 13; Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraph 27; Exhibit 20414-X0074, EPCOR PBR plan proposal, Appendix A, paragraph 30; Exhibit 20414-X0618, UCA argument, paragraph 3; Exhibit 20414-X0071, Calgary PBR plan proposal, page 10. Although at paragraph 135 of his evidence for the CCA, Exhibit 20414-X0084, Mr. Thygesen stated that a rebasing is not required, he then proceeded to recommend a form of a rebasing in paragraph 175. The CCA, in its argument, Exhibit 20414-X0630, recommended various rebasing approaches, at paragraphs 110-111 and 126.

12 Exhibit 20414-X0056, Brattle written evidence, PDF page 16, Q/A 24-25.

13 Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 20.

28. As a result of the inclusion of this issue in the final issues list, the Commission heard evidence on various matters relating to rebasing, as discussed in the sections of this decision that follow. Section 4.1 discusses the importance of going-in rates. Section 4.2 sets out the Commission's determination on the method of rebasing and setting going-in rates for the next generation PBR plans. Section 4.3 addresses the timing and review of Phase II applications and COS studies, such as depreciation studies. Finally, the issue of how to incorporate the ECM amounts approved in the 2013-2017 PBR plans into the rebasing process or next generation PBR plans is discussed in Section 4.4.

4.1 The importance of going-in rates

29. As noted above, the Commission recognizes the interdependence of the various elements of a PBR regime. These include the elements that are at issue in this proceeding and others, such as I, Y and Z, that are not. The significance of this interdependence of the elements of a PBR regime and, in particular, the importance of taking great care in the establishment of the going-in rates became evident from the way in which the positions of parties on the PBR mechanism overall were developed and argued.

30. Broadly speaking, the Commission identified two different views regarding how the three parameters of the PBR plan under consideration in this proceeding (rebasing, X Factor and treatment of capital additions) should be designed and implemented for the next generation PBR term. The first view, formulated from the evidence of the distribution utilities, with the exception of EPCOR, is that the current PBR regime should continue with some amendments such as changing the X factor to something less stringent; continuing with a capital mechanism in much the same form, with some amendments, including the elimination of the true-up on capital additions; and employing an intervening traditional forecast COS test year to realign rates with costs, albeit with a streamlined cost review process. These COS proceedings would likely include many of the typical issues that the distribution utilities might choose to raise in a traditional forecast test year, rate-base rate-of-return proceeding. For example, the distribution utilities subject to the 2013-2017 PBR plans indicated that they expect to file revised depreciation studies, cost allocation studies and Phase II proposals as part of the process to set going-in rates.

31. The second view, formulated by the Commission from the evidence of the interveners (CCA, UCA and Calgary), is that the rates of return earned by the distribution utilities subject to the 2013-2017 PBR plans are too high and that the principal cause of these high earnings appeared to be the capital tracker mechanism. Consequently, in order to ensure that the proper incentives were applied to as much of the distribution utilities' decision making as possible, capital trackers should be eliminated (or constrained significantly) in the next generation PBR plans including the possibility of a "pure" PBR plan with an I-X formula but no additional provision for capital other than as part of a Z factor application. Failing that, the Commission should return to traditional rate-base rate-of-return regulation because capital trackers had resulted in excessive earnings for the distribution utilities, at the same time creating a very large regulatory burden akin to the regulatory burden of traditional rate-base rate-of-return regulation and resulting in large portions of the distribution utilities' capital not being subject to the superior incentives provided by the I-X regime.

32. These two views identified by the Commission evolved as the particular circumstances of ENMAX, which had been regulated for seven years beginning in 2007 under an FBR model, were brought to light and understood during the course of the proceeding. ENMAX had, on

average, earned below its allowed rate of return over its FBR period. Because the ENMAX FBR plan did not include a special capital module, such as capital trackers, ENMAX used its experience to argue against proposals to eliminate capital trackers in the next generation PBR plans. ENMAX argued that had capital trackers been part of its 2007 FBR plan, it would not have earned below its allowed rate of return.

33. In response to ENMAX, the UCA filed evidence arguing that had ENMAX begun its FBR term with rates sufficient for it to earn its allowed rate of return in 2006, it would not have needed capital trackers to earn its allowed rate of return over the FBR term. The UCA's evidence focused the Commission on the importance of going-in rates. This suggested that to the extent that the earnings of the distribution utilities subject to the 2013-2017 PBR plans exceeded their allowed rate of return, this may have been due, at least in part, to the distribution utilities' going-in rates and not due entirely to capital trackers, as the interveners had suggested.

34. All parties agreed on the need to ensure that the going-in rates are not too high or too low, in the sense that they would be only sufficient for the utility to earn the allowed rate of return. The Commission understands that getting the going-in rates correct is critical to the success of a PBR plan. When the Commission repeated the analysis employed by the UCA to get the going-in rates "right" for the distribution utilities subject to the 2013-2017 PBR plans, the Commission found that most of the distribution utilities would not have earned their allowed rates of return over the PBR term if capital trackers had not been included in the plan.

35. The Commission considers that the methodology and analysis used by the UCA and repeated by the Commission has not been fully tested in this proceeding. Therefore, while the analysis is instructive, no definitive or general statement about the merits of capital trackers as they were implemented in the 2013-2017 PBR plans or in ENMAX's FBR plan can be made. However, these observations during the proceeding about the importance of going-in rates being set to provide the distribution utilities with only a reasonable opportunity to earn their allowed rate of return has served to heighten the attention to the setting of going-in rates for the next generation PBR term.

4.2 Rebasing method to set the new going-in rates

36. While the objective of rebasing is stated to be the re-establishment of the linkage between costs and rates, parties pointed out that realigning a utility's revenues with its costs, as part of rebasing, may be done in different ways ranging from traditional COS methods to methods using historical actual costs, with varying levels of adjustments to reflect known or anticipated anomalies. These approaches do not align rates with actual costs but, rather, align rates with forecasted or projected costs using various inputs (including some actual costs) to arrive at the revenue requirement used to establish going-in rates. Two general approaches to rebasing using forecast or projected costs were proposed by the parties in this proceeding.

37. Under the first general approach, advocated by Brattle and the distribution utilities sponsoring its evidence, going-in rates would be established based on forecast costs. Specifically, Brattle proposed setting going-in rates in a COS proceeding based on forecast costs for either 2017 or 2018. If 2017 costs were used, Brattle proposed that the distribution utilities would forecast their 2017 costs and revenue requirement, separate from their 2017 PBR rates. This notional 2017 revenue requirement would not be charged to customers but would be used for the sole purpose of establishing the going-in rates for the next generation PBR plan commencing in 2018. Using 2018 for rebasing would result in an intermediate COS year

between PBR plans. The 2018 rates would be determined on a forecast forward test year basis following a rate case similar to how rates were determined for the distribution utilities in 2012. The next generation PBR plans would commence in 2019 under this proposal using approved 2018 rates as the going-in rates.[14] The distribution utilities sponsoring Brattle's evidence supported using the 2018 intervening COS year.[15] Some of these distribution utilities suggested a streamlined rate proceeding process without a prudence review of actual operating and maintenance (O&M) and non-capital tracker capital costs incurred during the current generation PBR term on the basis that PBR incentives were sufficient to ensure the prudence of these costs.[16] Although ENMAX supported a streamlined approach, from its perspective, this should not be a main objective of the rebasing process.[17]

38. EPCOR and the interveners favoured a different general approach to rebasing that used actual, rather than forecast costs, to calculate going-in rates for the next generation PBR plans. Similar to Brattle, EPCOR suggested using 2017 to determine a notional revenue requirement which would not be charged to customers but would be used for the sole purpose of establishing the going-in PBR rates for the next generation PBR plans.

39. Specifically, EPCOR proposed that the O&M portion of its going-in rates be calculated as a simple average of 2014, 2015 and 2016 actual operating expenditures restated in 2017 dollars. In EPCOR's view, the middle three years of the current generation PBR term are reflective of the strongest incentives. The capital cost portion of EPCOR's going-in rates would be set based on the distribution utility's actual capital costs (i.e., the return and depreciation on EPCOR's 2017 actual mid-year rate base plus 2017 working capital costs) for 2017, the last year of the current generation PBR plans.[18]

40. Calgary agreed with EPCOR's proposed rebasing approach, noting that 2013 could also be included in the calculation of an average O&M expense. Calgary supported using the 2017 actual mid-year rate base for capital rebasing.[19] The CCA accepted EPCOR's selection of years with respect to operating costs, indicating that using an average of 2014-2016 addressed its concern with the potential to lose the efficiencies gained by PBR should the distribution utilities strategically increase costs towards the end of the PBR term.[20] Regarding capital additions, the CCA recommended the use of a 2017 forecast number, rather than actual costs, that does not allow for any cost increases above the I-X level for any capital additions which were under I-X during the PBR term.[21] In his evidence for the CCA, Mr. Thygesen proposed to set going-in rates by simply adjusting the 2017 PBR rates to remove any earnings above the allowed rate of return.[22]

14 Exhibit 20414-X0056, Brattle written evidence, PDF pages 17-18, Q/A28-Q/A29.
15 Exhibit 20414-X0622, ATCO utilities argument, paragraphs 6 and 19; Exhibit 20414-X0624, Fortis argument, paragraph 18; Exhibit 20414-X0619, ENMAX argument, paragraph 13; Exhibit 20414-X0616, AltaGas argument, paragraph 10.
16 Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 19(b); Exhibit 20414-X0073, Fortis PBR plan proposal, paragraphs 30-31; Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 34-35.
17 Exhibit 20414-X0619, ENMAX argument, paragraph 21.
18 Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraphs 26-32.
19 Exhibit 20414-X0625, Calgary argument, paragraph 8.
20 Exhibit 20414-X0638, CCA reply argument, paragraph 91.
21 Exhibit 20414-X0630, CCA revised argument, paragraphs 123-126.
22 Exhibit 20414-X0084, CCA evidence of Mr. Thygesen, paragraphs 173-175.

41. Concerned with a possibility that the distribution utilities may take rebasing as an opportunity to increase forecast costs and the resulting necessity to then fully test the forecast, the UCA suggested that the Commission rebase on the 2016 actual operating and capital additions, adjusted for "known and measurable changes." Mr. Bell explained that such changes could include 2017 capital additions, changes in billing determinants, the impact of staff reductions, an inflation adjustment, and one time occurrences such as severance payments.[23]

42. In reaching its determinations regarding the alternative approaches proposed by the parties for rebasing and establishing the going-in rates for the next generation PBR plans, in order to promote the objectives of PBR, the Commission considered the relative merits of the various approaches to rebasing offered by the parties. These objectives (i.e., reduce regulatory burden, minimize the perverse incentives of rate base rate of return applications and enhance the incentive properties of the PBR plan) were communicated in the final issues list.[24]

43. In the Commission's view, achieving these objectives requires balancing of the features of both proposed general approaches to rebasing, as each has its merits and disadvantages. EPCOR and the interveners pointed out that setting going-in rates in a COS proceeding based on forecast costs may create incentives to over-forecast, with the result that customers do not share in the benefits of productivity gains achieved by the distribution utilities in the current generation PBR plans.[25] In testimony, Dr. Weisman, an expert witness for EPCOR, supported this view as reflected in the following extract:

> Forecasts are by their very nature, and the issue of information asymmetries comes up here, are always a source of angst for commissions and regulators. And to the extent they can be avoided, they should. Just because of that information asymmetry, which may be a problem in some cases but not a problem in others, but it also -- the forecast component, in my mind, also renders it a bit less certain that the gains from PBR 1, the first generation PBR, are actually going to be passed on to consumers at the time of rebasing.[26]

44. Additionally, the interveners stated in argument that because of information asymmetry, testing cost forecasts would require the same level of detail as in a traditional COS proceeding. As such, regulatory burden is unlikely to be reduced under this approach to rebasing.[27]

45. Rebasing on actual results addresses these concerns to a large degree.[28] However, some distribution utilities pointed out that rebasing based on forecast costs will reflect changing circumstances in the test year and thus may result in going-in rates better reflective of a reasonable opportunity to earn a fair rate of return.[29] Nevertheless, the principal reason for not using 2017 actual costs is the incentives the distribution utilities have in the final year of current

23 Exhibit 20414-X0066, UCA evidence of Mr. Bell, PDF pages 26-27, Q/A 21; Exhibit 20414-X0184, UCA-AUC-2016APR15-001.
24 Exhibit 20414-X0026, Final issues list, paragraph 26.
25 Exhibit 20414-X0623, EPCOR argument, paragraph 9; Exhibit 20414-X0618, UCA argument, paragraphs 7 and 14; Exhibit 20414-X0630, CCA argument, paragraph 110; Exhibit 20414-X0625, Calgary argument, paragraph 50.
26 Transcript, Volume 14, page 2973, line 20 to page 2974, line 4 (Dr. Weisman).
27 Exhibit 20414-X0618, UCA argument, paragraph 16; Exhibit 20414-X0625, Calgary argument, paragraph 38; Exhibit 20414-X0457, PARTIES(Calgary)-AUC-2016JUN03-001(b), PDF page 4.
28 Exhibit 20414-X0625, Calgary argument, paragraph 55; Exhibit 20414-X0632, UCA reply argument, paragraph 5.
29 Exhibit 20414-X0622, ATCO utilities argument, paragraphs 12 and 56; Exhibit 20414-X0624, Fortis argument, paragraph 13; Exhibit 20414-X0619, ENMAX argument, paragraph 30.

generation PBR to inflate their costs so as to increase going-in rates for the next generation PBR term. The Commission is also concerned that using the 2017 actual results, which would not be available until May 2018, would not allow for implementation of the next generation PBR rates on January 1, 2018.

46. Having considered the evidence and argument of the parties and after applying its judgement in light of the objectives and purposes of rebasing as described earlier in this section, the Commission does not consider it necessary or desirable to employ a 2018 forecast COS year in order to set going-in rates. Rather, the Commission has determined that it will set going-in rates on the basis of a notional 2017 revenue requirement using actual costs experienced during the current generation PBR term for each distribution utility with any necessary adjustments to reflect individual distribution utility anomalies. The Commission's focus in setting the 2017 going-in rates for each distribution utility will be on using its judgement to estimate the costs that each distribution utility operating under the incentives of the PBR mechanism, unencumbered by incentives inconsistent with the PBR incentives, would have incurred in 2017. It agrees with those parties who submitted using actual pre-2017 costs to develop a notional 2017 revenue requirement, adjusted as required for anomalies, best reflects expected revenues and costs without the distorting influence of the incentives which arise during the last year of a PBR term. The Commission directs each distribution utility to file on or before March 31, 2017, an application to determine a notional 2017 revenue requirement to be used to determine the going-in rates used in setting 2018 PBR rates. The Commission will establish a proceeding for the March 31, 2017 compliance filings. The distribution utilities are directed to file their respective applications under the proceeding number advised by the Commission at a later date. The period of data and mechanisms to be used are specified below.

47. AltaGas, the ATCO utilities, EPCOR and Fortis (utilities on the 2013-2017 PBR plans), in preparing their respective rebasing applications, shall use actual O&M data, 2016 rate base and 2013-2016 actual non-capital tracker data, and 2017 approved capital tracker forecast data. Following the determination of final approved K factor amounts, the going-in rates will be adjusted to reflect the approved actual additions consistent with the capital tracker mechanism established in the 2013-2017 PBR plans approved in Decision 2012-237.

48. The Commission notes that ENMAX was not on the same PBR plans as the utilities on the 2013-2017 PBR plans. The last year of ENMAX's FBR term was 2013 and its intervening COS year was 2014. The actual cost data should reflect the year(s) where the incentives were the strongest resulting in the greatest efficiencies and cost savings. For ENMAX, the time period under consideration will be 2015-2017, the term of its 2015-2017 PBR plan.

49. ENMAX, in preparing its application, shall use actual O&M data, 2016 rate base and 2015 and 2016 actual non-capital tracker capital data. ENMAX will also use its 2017 applied-for capital tracker forecast data. Following the determination of final approved K factor amounts, the going-in rates will be adjusted to reflect the approved actual additions consistent with the capital tracker mechanism approved for ENMAX in Decision 21149-D01-2016.

50. To accommodate the March 31, 2017 filing date for rebasing applications, the Commission directs the distribution utilities to use their available 2016 actual unaudited data as a placeholder for actual 2016 O&M costs and actual rate base. When audited 2016 actual data become available in the May 2017 Rule 005 filings, each distribution utility is directed to file an amendment to their rebasing application to update the 2016 actual O&M and capital data.

O&M component of the revenue requirement

51. Various methods were proposed by parties for using actual costs to determine a notional 2017 revenue requirement. These methods included the use of averages, indexing, or a trending analysis of past expenditures. For example, EPCOR proposed to set the 2017 O&M estimate based on the three-year average actual expenditures for 2014 to 2016, adjusted for 2017 dollars.[30] Calgary proposed using the 2013-2016 average for this purpose.[31] Fortis suggested a forecast based on trending of actual expenditures from the current generation PBR term.[32] Using this method, an O&M forecast would be developed using a year-over-year average of the change in operating costs over the PBR term, and a capital forecast for non-capital tracker expenditures would incorporate the three-year average of actual expenditures for these capital costs.[33] Mr. Bell proposed to index 2016 actuals by I-X to determine 2017 going-in rates.[34]

52. In the Commission's view, given the incentive properties of PBR, rebasing of O&M costs should be based on the lowest O&M cost year during the current generation PBR term, restated to 2017 dollars, with adjustments as necessary to reflect material anomalies specific to that year. Given that distribution utilities will respond differently to the incentives inherent in any PBR plan, the lowest cost year for a particular distribution utility, everything else equal, represents the largest response to the incentives faced by that distribution utility during the PBR term. The Commission is prepared to adjust the 2017 notional revenue requirement estimate obtained by utilizing prior lowest actual O&M expenditures for a particular distribution utility should the distribution utility or interveners provide evidence demonstrating to the satisfaction of the Commission that specific and identifiable adjustments are required to account for unique existing or anticipated material cost anomalies. Allowing for these adjustments that may result in the 2017 costs being lower or higher than they would otherwise be, permits the Commission to recognize the unique circumstances of each distribution utility. The Commission retains its discretion to determine what it considers to be reasonable going-in rates for each distribution utility.

53. Accordingly, the distribution utilities shall prepare a 2017 calculation of O&M costs in the following manner, to be included in a notional 2017 revenue requirement based on actual costs:

Each of the utilities on a 2013-2017 PBR plan shall:

(a) Provide its annual O&M expenditures during the 2013-2016 time period in the format as will be provided by the Commission by January 31, 2017.

(b) Express annual O&M expenditures during the 2013-2016 time period, in 2017 dollars converting as spent dollars to 2017 dollars using their respective approved I-X index and Q factor approved for each year given that I-X reflects the

---

30 Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 29.

31 Exhibit 20414-X0071, Calgary PBR plan proposal, page 53.

32 Exhibit 20414-X0624, Fortis argument, paragraphs 19-20.

33 Exhibit 20414-X0073, Fortis PBR plan proposal, paragraphs 30-34; Exhibit 20414-X0183, FAI-AUC-2016APR15-001.

34 Exhibit 20414-X0184, UCA-AUC-2016APR15-001(g).

productivity and inflation expectations built into the 2013-2017 PBR plans and the Q factor allows for an adjustment for customer growth.[35]

(c) Utilize the lowest actual annual O&M expenditures, adjusted in accordance with paragraph (b), in preparing its estimate of the notional 2017 revenue requirement.

ENMAX shall:

(a) Provide its annual O&M expenditures for 2015 and 2016, in the format as will be provided by the Commission by January 31, 2017.

(b) Express annual O&M expenditures for 2015 and 2016, in 2017 dollars converting as spent dollars to 2017 dollars using its approved I-X index and Q factor approved for each year given that I-X reflects the productivity and inflation expectations built into its 2015-2017 PBR plan and the Q factor allows for an adjustment for customer growth. ENMAX shall use the X factor approved for its 2015-2017 PBR plan, which is equal to 0.3, as noted in Section 5.5.

(c) Utilize the lowest actual annual O&M expenditures, adjusted in accordance with paragraph (b), in preparing its estimate of the notional 2017 revenue requirement.

Capital component of the revenue requirement

54. With respect to the capital component of the notional 2017 revenue requirement, the Commission has determined that the capital component of the notional 2017 revenue requirement must be divided into capital additions that are subject to I-X in 2017 and those subject to the capital tracker treatment in 2017.

55. Capital additions are generally in respect of investments in long-lived assets. This fact necessitates reliance on longer trends or patterns of past actual expenditures than when coming up with an estimate of O&M costs. Also, the Commission generally agrees with EPCOR's proposal that in calculating the average, historical numbers should be converted to 2017 dollars.

56. In the Commission's view, given the incentive properties of PBR, in developing a 2017 estimate for the non-capital tracker component of the notional 2017 revenue requirement and going-in rates, the revenue requirement should be based on the average actual capital additions for years of the current generation PBR plans, excluding the last year, restated to 2017 dollars.

57. Regarding the capital additions subject to capital tracker treatment, the Commission observes that the capital tracker capital additions for the utilities on a 2013-2017 PBR plan were previously scrutinized and approved in prior capital tracker decisions, either on a forecast or true-up basis. Given that the going-in rates will be adjusted to reflect the approved actual additions following the determination of final approved K factor amounts, the Commission will accept on an interim basis, the actual 2016 rate base and the approved 2017 capital tracker forecast for capital additions. For non-capital tracker capital additions, the Commission agrees

[35] The ATCO utilities, ENMAX and Fortis pointed the need to adjust for customer growth in any averaging approach. See: Exhibit 20414-X0637, ATCO reply argument, paragraph 53; Exhibit 20414-X0619, ENMAX argument, paragraph 33; Exhibit 20414-X0624, Fortis argument, paragraph 43.

with parties that non-capital tracker additions can generally be assumed to be prudent,[36] because these costs were subject to the incentive properties of the I-X mechanism.

58. The Commission notes that ENMAX does not have any capital tracker capital additions approved either on a forecast or actual basis. Therefore, the Commission will accept on an interim basis, 90 per cent of the applied-for 2017 capital tracker forecast for capital additions.

59. Given the above, the distribution utilities shall prepare a 2017 calculation of capital costs in the following manner, using the following assumptions in developing the notional 2017 revenue requirement and going-in rates based on actual costs:

Each of the utilities on a 2013-2017 PBR plan shall:

(a) Use the actual 2016 closing rate base, as the starting point.

(b) Adjust the rate base, removing related utility assets as directed in prior utility asset disposition proceeding decisions,[37] as applicable.

(c) For the non-capital tracker component, add to the 2016 closing rate base, the average actual capital additions for years 2013 to 2016 for non-capital tracker capital in order to estimate this portion of the 2017 rate base, converting the 2013 to 2016 spent dollars to 2017 dollars using their respective approved I-X index and Q factor approved for each year.

(d) For the capital tracker component, add the approved 2017 forecast capital tracker capital additions to the 2016 closing rate base in order estimate this portion of the 2017 rate base, to be used in developing the notional 2017 revenue requirement and going-in rates.

(e) Apply 2017 depreciation using the distribution utility's most recent approved depreciation methodologies applied to the 2016 actual closing rate base, to the notional non-capital tracker 2017 additions referred to in paragraph (c) and to the 2017 forecast capital additions referred to in paragraph (d). Also apply 2017 notional retirements and contributions (net of amortization of contributions) based on the average actual retirements and contributions for years 2013 to 2016 for non-capital tracker capital, converting the 2013 to 2016 dollars to 2017 dollars using their respective approved I-X and Q factor approved for each year. These assumptions will be used in developing the notional 2017 revenue requirement and going-in rates.

ENMAX shall:

(a) Use the actual 2016 closing rate base, as the starting point.

(b) Adjust the rate base, removing related utility assets as directed in prior utility asset disposition proceeding decisions, as applicable.

---

36 Transcript, Volume 13, page 2590, line 25 to page 2591, line 14 (Mr. Zurek); Exhibit 20414-X0255, ATCO-AUC-2016APR15-002(b).

37 For example, Decision 20271-D01-2015: FortisAlberta Inc., Disposition of Land in High River, Proceeding 20271, August 31, 2015 and Decision 3206-D01-2015: EPCOR Distribution & Transmission Inc., Disposition of Substation Property, Proceeding 3206, Application 1610546-1, February 25, 2015.

(c) For the non-capital tracker component, add to the 2016 closing rate base, the average actual capital additions for years 2015 and 2016 for non-capital tracker capital in order to estimate this portion of the 2017 rate base, converting the 2015 and 2016 spent dollars to 2017 dollars using its respective approved I-X index and Q factor approved for each year.

(d) For the capital tracker component, add 90 per cent of the 2017 forecast capital tracker capital additions to the 2016 closing rate base in order estimate this portion of the 2017 rate base, to be used in developing the notional 2017 revenue requirement and going-in rates.

(e) Apply 2017 depreciation using the distribution utility's most recent approved depreciation methodologies applied to the 2016 actual closing rate base, to the notional non-capital tracker 2017 additions referred to in paragraph (c) and to the 2017 forecast capital additions referred to in paragraph (d). Also apply 2017 notional retirements and contributions (net of amortization of contributions) based on the average actual retirements and contributions for years 2015 and 2016 for non-capital tracker capital, converting the 2015 and 2016 dollars to 2017 dollars using its respective approved I-X and Q factor approved for each year. These assumptions will be used in developing the notional 2017 revenue requirement and going-in rates.

60. In light of the future going-in rate adjustments associated with the yet to be approved true-up of K factors, the notional 2017 revenue requirement and going-in rates for each distribution utility will be approved on an interim basis only. Once all capital tracker actual amounts are approved on a final basis and all other going-in rates adjustments required pursuant to any approved changes in depreciation expense as discussed in Section 4.3 are finalized, the going-in rates will be finalized effective January 1, 2018, with rate adjustments made on a prospective basis, with subsequent adjustments.

61. The Commission does not consider that an adjustment to O&M costs and non-capital tracker capital costs is required to going-in rates to reflect actual 2017 costs because the application of the I-X mechanism and Q adjustment to the rebasing amounts determined using the mechanisms referred to above, plus any adjustments for anomalies as discussed below, should be sufficient for the purposes of determining going-in rates. This is reinforced by an understanding that some of these O&M and non-capital tracker capital costs will increase while others will decrease or disappear in 2017 while the entire amount established using these mechanisms will be adjusted by I-X and Q in setting the going-in rates for the next generation PBR term.

62. The notional 2017 revenue requirement used to determine going-in rates will be based on past actual expenditures. The Commission agrees with those parties who considered that this approach would reduce regulatory burden because a line-by-line review of actual costs for prior years would not be necessary as the O&M costs and non-capital tracker capital costs were subject to PBR incentives.[38] Regarding the estimates of capital additions subject to capital tracker treatment, the Commission agrees with the views of the distribution utilities that since these capital additions are (or will be in the case of ENMAX), tested under the capital tracker mechanism, no further testing or duplication of information would be required as part of the

38 Exhibit 20414-X0056, Brattle written evidence, page 11, A18; Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 26; Exhibit 20414-X0255, ATCO-AUC-2016APR15-002.

rebasing process for previously approved actual or forecast costs subject to capital tracker treatment.[39] Therefore, an examination of higher-level aggregate costs and methods used to determine the 2017 notional revenue requirement, together with an examination of applied-for cost additions or reductions due to present or anticipated cost anomalies may be sufficient to test the rebasing applications.[40] [41]

63. As noted earlier in this section, there was widespread recognition among the parties that, unless streamlined, rebasing applications for six distribution utilities may result in significant regulatory burden. The Commission agrees. To aid in the assessment of their rebasing compliance applications to this decision, the Commission directs the distribution utilities to provide their Rule 005 reports for each of 2013, 2014 and 2015, and their available 2016 actual data (with a view of updating them when the 2016 Rule 005 report becomes available). The distribution utilities are also required to fill out the template that the Commission will provide by January 31, 2017, and to fully describe any deviations from the utilization of the lowest actual annual O&M expenditures in arriving at the 2017 notional revenue requirement estimate.

64. The Commission considers that the mechanics of calculating going-in rates should follow the same process as set out in Decision 2012-237 and subsequent compliance filing decisions. To highlight a few specific areas, the distribution utilities should continue to rely on the mid-year rate base convention.[42] Any amounts to be treated as flow-through items in the next generation PBR plans should be removed from going-in rates.[43]

4.3 Phase II, depreciation, and other COS studies

65. Several issues related to the timing and nature of rebasing were the subject of submissions during the proceeding. Among these issues was the timing and incorporation of results arising from Phase II proceedings. The purpose of Phase II proceedings is primarily to revise rate design and rate class cost allocations used in determining how much of the revenue requirement should be recovered from each customer class and the billing determinants that will apply to each class. In a PBR environment, cost allocation methodologies based on approved Phase II methodologies and updated billing determinants are used to establish K, Y and Z factor rate adjustments by rate class.[44]

66. With the exception of EPCOR, all distribution utilities proposed filing Phase II applications subsequent to filing rebasing applications.[45] EPCOR preferred to base its going-in rates on an new Phase II rate design methodology to be approved prior to filing a rebasing application.[46] The UCA and the CCA expected that a Phase II application would follow after the

39 Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 26; Exhibit 20414-X0255, ATCO-AUC-2016APR15-002; Exhibit 20414-X0624, Fortis argument, paragraph 33.
40 Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 30; Exhibit 20414-X0157, EPC-AUC-2016APR15-002.
41 Exhibit 20414-X0625, Calgary argument, paragraph 61; Exhibit 20414-X0624, Fortis argument, paragraph 22; Exhibit 20414-X0637, ATCO utilities reply argument, paragraph 52.
42 Decision 2012-237, paragraphs 101-103.
43 Decision 2012-237, paragraph 719.
44 Decision 2012-237, paragraphs 977, 982 and 993.
45 Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 39; Exhibit 20414-X0073, Fortis PBR plan proposal, paragraphs 53-54; Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 35; Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraph 64.
46 Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 65.

revenue requirement was determined in the rebasing process,[47] with rates adjusted accordingly as part of the annual PBR rate adjustment filings.[48]

67. To keep the scope of the distribution utility specific next generation PBR plan applications limited for regulatory efficiency and to provide rate certainty with respect to the going-in rates at the start of the next generation PBR term on January 1, 2018, the Commission agrees with the position of the UCA and the CCA. New approved Phase II methodologies supported by updated rate class cost allocation studies or rate design studies should not be filed prior to the commencement of the next generation PBR plans, and since rate class allocations are revenue-neutral, they may be filed and implemented on a go-forward basis any time during the PBR term. The Commission has previously employed this approach in Decision 2014-018,[49] where it accepted Fortis' proposal to incorporate a new cost allocation and rate design set out in an approved Phase II application on a go-forward basis during the current generation PBR term, rather than reflecting the updated design and cost allocations through an adjustment to going-in rates.[50] Therefore, the Commission will not accept Phase II applications intended to establish a new rate design or cost allocation among rate classes to take effect upon the commencement of the next generation PBR plans. Phase II applications will be accepted for consideration which are intended to take effect sometime following the commencement of the next generation PBR plans on a prospective basis.

68. Following the approval of any updated Phase II study during the term of the next generation PBR plans, the Commission will not consider further Phase II applications. This is consistent with the determination in Decision 2012-237.[51]

69. Parties also expressed the need to update other COS studies, including depreciation studies, to be approved in the rebasing proceedings.[52] ENMAX and AltaGas anticipated that, as part of its rebasing application, a distribution utility would have an opportunity to apply for approval of one or more of the following studies: depreciation, pension, compensation, shared services, and necessary working capital.[53] Fortis and EPCOR proposed that depreciation rates used to determine its forecast or actual rate base for the next generation PBR term would be based on a depreciation study that would form part of their rebasing applications. EPCOR submitted that if depreciation rates were not approved when its PBR going-in rates were approved, the rates should be trued-up following final approval of the depreciation rates.[54] Fortis stated that according to Section 122(l)(a)(i)[55] of the *Electric Utilities Act*, utilities should be given

---

47 Exhibit 20414-X0618, UCA argument, paragraph 13; Exhibit X0084, CCA evidence of Mr. Thygesen, paragraph 179.

48 Exhibit 20414-X0066, UCA evidence of Mr. Bell, PDF page 28,Q/A 24, Exhibit X0084, CCA evidence of Mr. Thygesen, paragraph 180.

49 Decision 2014-018: FortisAlberta Inc., 2012-2014 Phase II Distribution Tariff, Proceeding 2363, Application 1609211-1, January 27, 2014.

50 Decision 2014-018, paragraph 329.

51 Decision 2012-237, paragraph 996.

52 Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 20; Exhibit 20414-X0637, ATCO reply argument, paragraph 53; Exhibit 20414-X0624, Fortis argument, paragraph 21; Exhibit 20414-X0618, UCA argument, paragraph 9.

53 Exhibit 20414-X0157, EPC-AUC-2016APR15-001; Exhibit 20414-X0289, AUI-AUC-2016APR15-001(d).

54 Exhibit 20414-X0183, FAI-AUC-2016APR15-001 and FAI-AUC-2016APR15-002(b); Exhibit 20414-X0256, EDTI-AUC-2016APR15-004(b) and (c).

55 Section 122(1) When considering a tariff application, the Commission must have regard for the principle that a tariff approved by it must provide the owner of an electric utility with a reasonable opportunity to recover

an opportunity to update depreciation parameters.[56] Further, Fortis and the ATCO utilities described the need for a depreciation study in the context of setting a K-bar factor amount.[57] In a similar vein, the ATCO utilities submitted that rebasing forecasts would require an update to depreciation rates reflected by current depreciation and other studies.[58] The UCA and the CCA submitted that a depreciation study would be required if a utility wished to change its depreciation rates at rebasing.[59] Calgary expressed its view that a depreciation study is not necessary for rebasing.[60]

70. The Commission will provide the distribution utilities with an opportunity to update depreciation studies if they choose. However, the Commission considers, for purposes of regulatory efficiency, updated depreciation studies may not be included in distribution utility rebasing applications. Distribution utilities may file separate depreciation related applications during the first year of the next generation PBR term, i.e., in 2018, and the Commission will make its determinations based on the merits of such applications at that time. Going-in rates will be adjusted effective January 1, 2018, on a prospective basis, to reflect any changes in approved depreciation parameters.

71. Following the approval of any updated depreciation study, any subsequent depreciation changes during the next generation PBR plans may be reflected in rates only if they are eligible for Z factor treatment, and may not be accounted for through either a Y factor[61] or a K factor.[62] [63] This practice is consistent with the practice established in Decision 2012-237.

72. With respect to pension, compensation, shared services, and necessary working capital[64] costs, the Commission considers that these types of costs, to the extent they fall under the I-X mechanism, adjusted by Q, are no different than other types of operating costs and can be adequately reflected in the rebasing process through the O&M mechanism and non-capital tracker capital cost averaging mechanism described above. The Commission may also direct the distribution utilities to undertake certain studies as part of the ongoing rate regulation initiative.

4.4 Efficiency carry-over mechanism

73. A utility's incentive to find efficiencies weakens as the end of the PBR term approaches, in part because there is less time remaining for the utility to benefit from any efficiency gains. The purpose of an efficiency carry-over mechanism (ECM) is to address this problem by permitting the utility to continue to benefit from any efficiency gains after the end of the PBR

(a) the costs and expenses associated with capital related to the owner's investment in the electric utility, including ... (i) depreciation, ...

56 Exhibit 20414-X0633, Fortis reply argument, paragraphs 17-18.

57 Transcript, Volume 9, pages 1812-1815 (Ms. Sullivan); Exhibit 20414-X0565, undertaking response by Mr. Grattan to Ms. Sabo at Transcript, Volume 7, page 1425, line 25 to page 1426, line 10, response to bullet 2.

58 Exhibit 20414-X0454, PARTIES(ATCO)-AUC-2016JUN03-002(a)(ii).

59 Exhibit 20414-X0618, UCA argument, paragraph 9; Transcript, Volume 10, page 1954, lines 7-16 (Mr. Thygesen).

60 Exhibit 20414-X0625, Calgary argument, paragraph 59; Transcript, Volume 16, page 3307, lines 14-22 (Mr. Matwichuk).

61 Decision 2012-237, paragraph 688.

62 Decision 20407-D01-2016: EPCOR Distribution & Transmission Inc., 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast, Proceeding 20407, February 7, 2016, paragraphs 607-616.

63 Decision 20497-D01-2016: FortisAlberta Inc., 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast, Proceeding 20497, February 20, 2016, paragraphs 137-143.

64 Exhibit 20414-X0157, EPC-AUC-2016APR15-001; Exhibit 20414-X0289, AUI-AUC-2016APR15-001(d).

term. As Brattle noted, an ECM strengthens incentives to control costs towards the end of the PBR term by "carrying over" some of the rewards from successful cost control from one PBR term to the next one.[65] The Commission approved an ECM in Decision 2012-237 to encourage distribution utilities to continue to make cost-saving investments near the end of the PBR term and discourage gaming regarding the timing of capital projects or programs.[66]

74. In accordance with the terms of settlement for the negotiated settlement of the ENMAX 2015-2017 PBR plan, the Commission observes that ENMAX's 2015-2017 PBR plan is not subject to an ECM. Therefore, the determinations made below are only applicable to the distribution utilities on the 2013-2017 PBR plans. However, for the next generation PBR plans, all distribution utilities will be on similar plans, and therefore, ENMAX's next generation PBR plan will include an ECM.

75. Decision 2012-237 approved an ROE-based ECM based on the ATCO utilities' proposal.[67] As set out in paragraph 766 of that decision, the ATCO utilities described the workings of this mechanism as follows:

> … a post PBR add-on to the approved ROE equal to one half of the difference between the simple average ROE achieved over the term of the Plan and the simple average approved ROE over the term of the Plan (providing the difference is positive), multiplied by 50%, to a maximum of 0.5%. The "ROE bonus" would apply for 2 years after the end of the PBR Plan.[958]
>
> [958] [Proceeding 566] Exhibit 98.02, ATCO Electric application, page 11-2, paragraph 238 and [Proceeding 566] Exhibit 99.01, ATCO Gas application, page 44, paragraph 129.

76. The Commission specified that the "simple average approved ROE" referenced in the quote above should be the average approved generic ROE in place during each year of the current generation PBR term.[68] In terms of the "simple average ROE achieved," the Commission determined that the distribution utilities' actual ROE calculated in the same way as the actual ROE reported in the Rule 005 filings should be used.[69]

77. In its August 21, 2015 letter, establishing the scope of this proceeding, the Commission asked parties to consider how the ECM approved in the 2013-2017 PBR plans should be incorporated into the rebasing process or next generation PBR plans.[70] The Commission did not include the continued use of the ECM or the five-year averaging parameters within the scope of this proceeding. Accordingly, subject to two clarifications on the ECM calculations discussed below, this decision is limited to a consideration of two issues. First, given that the ECM for the 2013-2017 PBR term will take the form of a ROE add-on percentage to the ROE approved for the first two years of the next generation PBR plans, it is necessary to determine the rate base or rate bases to which the approved ROE add-on will be applied. Secondly, the Commission must determine how the ECM amount will be collected during the next generation PBR term.

65 Exhibit 20414-X0056, Brattle evidence, PDF page 23.
66 Decision 2012-237, paragraphs 759 and 775.
67 In Decision 2012-237, at paragraphs 775-776, the Commission approved an ECM for ATCO Electric, ATCO Gas, and EPCOR. In Decision 2013-072, at paragraph 83, the Commission approved the same ECM for AltaGas and Fortis.
68 Decision 2012-237, paragraph 779.
69 Decision 2012-237, paragraph 780.
70 Exhibit 20414-X0026, AUC letter - Final issues list, August 21, 2015, attachment, Issue 1(d), PDF page 11.

Accordingly, the interveners' proposal that the ECM not be renewed for the next generation PBR plans is outside of the scope of this proceeding.[71] EPCOR's proposal to change the methodology and use a three-year average ROE rather than a five-year average, as approved in Decision 2012-237, is similarly outside the scope of this proceeding.[72]

78. Prior to addressing the principal issues of the rate base to be used in determining the ROE add-on percentage and the collection mechanics, the Commission considers that two matters relating to the ECM calculation require clarification. In this proceeding, the UCA pointed out that a verbatim read of the ECM calculation proposed by the ATCO utilities and referenced in paragraph 766 of Decision 2012-237 implies an ECM add-on equal to the 25 per cent of the difference between the average allowed and average actual ROEs, to a maximum of 0.5 percentage points.[73] The distribution utilities have all argued that the intention of the ATCO utilities' wording was to calculate the ECM add-on as a one half the difference, subject to the same maximum value.[74] The distribution utilities pointed out that the ATCO utilities' examples of an ECM calculation provided in the proceeding leading to Decision 2012-237, also provided on the record of this proceeding, reflect the ECM calculation to be 50 per cent of the difference.[75]

79. Although the ATCO utilities' proposed language allows for ambiguity in the method by which the ECM is to be calculated, the examples provided by the ATCO utilities in support of its ECM proposal clearly demonstrated the calculation. The Commission confirms that the ECM calculation required by paragraph 766 of Decision 2012-237 is to be done in accordance with the examples provided by the ATCO utilities on the record of that proceeding. Accordingly, the Commission confirms that the ECM ROE add-on calculation to be 50 per cent of the difference between the average allowed and average actual ROEs over the course of the PBR term.

80. The second issue to be clarified is whether original Rule 005 filings are to be used in calculating the average actual ROE at the end of the next generation PBR plans or if the ROE restatements discussed in Section 7 of this decision in connection with reopener applications are to be used. AltaGas, Calgary, EPCOR and the UCA submitted that if ROE restatements are included in the next generation PBR plans, restated ROEs should be used for ECM calculations, as they provide a more accurate assessment of a utility's performance.[76]

81. The Commission has determined that the original Rule 005 filings will be used for purposes of calculating the average actual ROE during the 2013-2017 PBR term. Unlike reopeners, which will be assessed annually based on a Rule 005 ROE or restated ROEs for a given year, ECM calculations are based on a five-year average ROE. Using restated ROEs in the calculation of an average for ECM purposes will likely lead to inconsistency and confusion as restated ROEs for each PBR year may be reflective of differing degrees of finality. For example, at the end of the PBR term, the Commission will likely have all the final data for 2018 and 2019, less for 2020 and 2021, and perhaps none for 2022. Further, it is not clear that the restated ROEs

71 Exhibit 20414-X0618, UCA argument, paragraphs 30-31; Exhibit 20414-X0638, CCA reply argument, paragraph 76; Exhibit 20414-X0636, Calgary reply argument, paragraph 207.
72 Exhibit 20414-X0623, EPCOR argument, paragraphs 37-38.
73 Exhibit 20414-X0618, UCA argument, paragraphs 25-27.
74 Exhibit 20414-X0622, ATCO utilities argument, paragraph 61; Exhibit 20414-X0624, Fortis argument, paragraph 54; Exhibit 20414-X0616, AltaGas argument, paragraph 96; Exhibit 20414-X0635, EPCOR reply argument, paragraph 27.
75 Exhibit 20414-X0513, undertaking response by Mr. Stock to Ms. Preda at Transcript, Volume 5, page 873.
76 Exhibit 20414-X0289, AUI-AUC-2016APR15-016; Exhibit 20414-X0238, CALGARY-AUC-2016APR15-011; Exhibit 20414-X0256, EDTI-AUC-2016APR15-032; Exhibit 20414-X0184, UCA-AUC-2016APR15-013.

for the last year of the next generation PBR term, 2022, will be available in time to apply the ECM in the following two years, 2023 and 2024. For these reasons, the Commission finds that as set out in Decision 2012-237, the distribution utilities' ROE from Rule 005 filings should be used for ECM calculations.[77]

82. As noted above, the Commission needs to determine the rate base to be used in applying the ROE add-on percentage associated with the first term's ECM. The Commission must also determine how this ECM amount will be collected during the first two years of the next generation PBR term.

83. The Commission generally agrees with the UCA's position[78] that because the ECM ROE add-on percentage is calculated based on a utility's earnings in the 2013-2017 PBR term, it should not be applied to the actual 2018 and 2019 rate base amounts, as proposed by AltaGas, the ATCO utilities and Fortis.[79] Additionally, such an approach would not promote regulatory efficiency as an ECM placeholder would need to be established, and subsequently trued up, when the final rate base amount for each of 2018 and 2019 became known. Also, as EPCOR pointed out, this approach may require the Commission to test the 2018 and 2019 rate base amounts.[80] The Commission does not agree, however, with the UCA's position that the ROE add-on percentage should be applied to the actual average rate base over the entire 2013-2017 PBR term. Such an approach does not correspond with the intention of the ECM which was to incent efficient behaviours at the end of the term. The Commission favours an ECM calculation based on the mid-year rate base during the final year of the 2013-2017 PBR term.

84. In light of these considerations, the Commission finds reasonable EPCOR's proposal to calculate the ECM amount by applying the ECM ROE add-on to the 2017 mid-year rate base and escalating the obtained ECM dollar amount by the approved next generation I-X value for each for 2018 and 2019, with subsequent true-up.[81] Consistent with the overall rebasing approach set out in sections 4.1 and 4.2, the Commission directs the distribution utilities on the 2013-2017 PBR plans to calculate the interim ECM amount by applying the ECM ROE add-on to the interim 2017 notional estimated mid-year rate base and escalating the obtained interim ECM dollar amount by the approved I-X value for each of 2018 and 2019. Following the determination of a final 2017 notional estimated mid-year rate base (reflective of the final approved 2016 and 2017 K factor amounts), the ECM add-on percentage will be determined as a final dollar amount for each qualifying distribution utility, escalated by the approved I-X value for each of 2018 and 2019.

85. With respect to the second issue, the collection mechanics for both the interim and final ECM add-on amounts, the Commission agrees with those parties that indicated the ECM dollar amounts should not be included in the going-in rates but rather collected by way of a Y factor in

77 Decision 2012-237, paragraph 780.
78 Exhibit 20414-X0618, UCA argument, paragraph 29.
79 Exhibit 20414-X0616, AltaGas argument, paragraph 97; Exhibit 20414-X0622, ATCO utilities argument, paragraph 59; Exhibit 20414-X0624, Fortis argument, paragraphs 47.
80 Exhibit 20414-X0256, EDTI-AUC-2016APR15-008(b).
81 Exhibit 20414-X0256, EDTI-AUC-2016APR15-008(b).

each of 2018 and 2019.[82] This will avoid making additional going-in rates adjustments for 2018 and 2019 and clearly identify the ECM amount to be collected.

5 Productivity offset (X factor)

5.1 Setting the X factor

86. In its past decisions dealing with prior generations of PBR plans, the Commission expressed its preference for an approach to setting the X factor that is based on the average rate of long-term productivity growth in the industry.[83] The X factor, combined with the I factor, is designed to create incentives similar to those in competitive markets.

87. The first step in determining the X factor is to examine the underlying industry TFP growth over time, commonly determined by measuring TFP growth. The TFP growth value percentage result may then be supplemented by adjustments applicable to the utilities subject to the PBR plans, for example, a stretch factor, to arrive at a final X factor.[84] Reflecting the above approach, in Decision 2012-237, the X factor of 1.16 per cent was determined as the sum of the underlying long-term industry TFP growth value of 0.96 per cent and a stretch factor of 0.2 per cent.[85]

88. Determination of the X factor in the next generation PBR term was the second item on the final issues list established by the Commission for the current proceeding. Although the Commission decided not to sponsor a new TFP growth study, parties were free to address all aspects of the X factor for the next generation PBR plans.[86]

89. All parties to this proceeding generally agreed that, for the next generation PBR term, the X factor should be determined in the same way as previously; that is, a component based on industry TFP growth and a stretch factor. However, parties disagreed on the details of how TFP growth should be calculated, and limitations on its range, and also on the value of the stretch factor, if any, as discussed in the sections of this decision that follow. Specifically, Section 5.2 discusses the TFP growth studies, including a discussion of assumptions. The use and size of a stretch factor is discussed in Section 5.3. Section 5.4 addresses the Commission's determination on the X factor for the next generation PBR plans, and Section 5.5 addresses the X factor for ENMAX's 2015-2017 PBR plan. Finally, Section 5.6 discusses the proposals for a non-negative I-X provision.

5.2 Revised TFP growth studies

90. In Proceeding 566 leading to Decision 2012-237, the Commission engaged National Economic Research Associates (NERA) to conduct a TFP growth study. NERA's study involved analysis of the distribution component of 72 U.S. electric and combination of electric/gas utilities over the period from 1972 to 2009. Although NERA's was not the only TFP growth study

[82] Exhibit 20414-X0616, AltaGas argument, paragraph 99; Exhibit 20414-X0622, ATCO utilities argument, paragraph 59; Exhibit 20414-X0624, Fortis argument, paragraph 51; Transcript, Volume 14, page 2965, lines 10-21 (Mr. Zurek).

[83] Decision 2009-035, paragraph 176; Decision 2012-237, paragraphs 277 and 288.

[84] Decision 2012-237, paragraph 279.

[85] Decision 2012-237, paragraphs 514-515.

[86] Exhibit 20414-X0026, AUC letter – Final issues list, August 21, 2015, paragraph 34.

considered in that proceeding, the Commission found the NERA study to be preferable because of the "objectivity and transparency of the data and of the methodology used, the use of data over the longest time period available and the broad based inclusion of electric distribution utilities from the United States."[87] The final approved TFP growth value of 0.96 per cent, determined as the difference between growth in output and growth in inputs, was obtained as the average of 37 annual TFP growth values for the 1972-2009 period, where each annual value comprised a weighted average of TFP growth values for the 72 individual firms for that year, with weights based on relative firm size in terms of sales volume in megawatt hours (MWh), where these sales were also used as the output measure for the distribution utilities.

91. Three TFP growth studies were provided in this proceeding: (i) a study undertaken by Dr. Brown and Dr. Carpenter of Brattle for the distribution utilities other than EPCOR (Brattle study);[88] (ii) a study undertaken by Dr. Meitzen of Christensen Associates for EPCOR (Meitzen study);[89] and (iii) a study undertaken by Dr. Lowry of PEG for the CCA (Lowry study).[90] Dr. Pavlovic et al. of PCMG filed reply evidence for the UCA, where they criticized a number of aspects of the NERA TFP methodology used in the Brattle and Meitzen studies but did not provide a TFP growth recommendation.[91]

92. Both Brattle and Dr. Meitzen described their approach as extending or updating the NERA study analysis for five more years, 2010 to 2014.[92] Both the Brattle study and the Meitzen study updated the NERA study by including data from 2010-2014 period and also made certain refinements to the NERA study. In contrast, the Lowry study "uses alternative methods and is more customized to special operating conditions in Alberta."[93] Although the Lowry study relied on the same general index approach used by NERA for calculating the TFP growth number,[94] there were a number of important differences in approach. Among other differences, the Lowry study used a different output measure (number of customers instead of MWh volumes), a shorter data period (1997-2014), a different and larger set of firms (88 instead of the 72 in the NERA study, although the Lowry study also considers smaller subsets of the 88 firms), a different method for aggregating across firms (unweighted instead of weighted), output data combined from two sources (FERC Form 1, as used in the NERA, Brattle and Meitzen studies, and EIA Form 861),[95] and some different assumptions underlying the determination of the input growth index. In addition, the Lowry study was produced using computer code and proprietary computer software rather than spreadsheets as used in the NERA, Brattle and Meitzen studies.

93. A summary of the TFP growth findings, including recommendations, from the three studies filed in this proceeding, as well as from the NERA study filed in the PBR Proceeding 566 (NERA 2012), are shown in Table 1. In each case, the TFP growth values are averages of all the annual values in the specified time period, although for the Meitzen study, the recommendation

87 Decision 2012-237, paragraph 411.
88 Exhibit 20414-X0056, Brattle evidence, Section III, pages 23-38.
89 Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, PDF pages 185-244.
90 Exhibit 20414-X0082, CCA evidence of Dr. Lowry, Section 4, pages 42-73.
91 Exhibit 20414-X0403, UCA reply evidence of K. Pavlovic, M. Griffing and D. Mugrace.
92 Exhibit 20414-X0056, PDF pages 27-28 (Brattle), and Exhibit 20414-X0074, PDF pages 202-204 (Meitzen).
93 Exhibit 20414-X0082, page 57.
94 The Lowry study refers to multifactor productivity (MFP) rather than TFP, to reflect the use of multiple inputs, but this is principally an issue of nomenclature.
95 Specific data sources are U.S. Federal Energy Regulatory Commission (FERC), Form 1: Electric Utility Annual Report, and U.S. Energy Information Administration (EIA), Form 861: Electric power sales, revenue, and energy efficiency.

is to use the average of two averages, one based on all the annual values in the last 15 years and one based on all the annual values in the last 10 years. As this table shows, the Brattle and Meitzen studies yield similar TFP growth value estimates, with differences mainly attributable to the different data periods used.[96] The table also shows there is a considerable difference in TFP growth calculated in the Lowry study when compared to the results of the Brattle and Meitzen studies. Similarly, TFP growth is almost twice as large in the Lowry sample when a smaller selected sample of the 88 firms is used in the calculation when compared to the full sample. This sample size issue is addressed in Section 5.2.2 below. Finally, differences between initial and final TFP growth calculations reflect corrections made in reply evidence as the result of self-identified errors and/or accepted improvements suggested by other parties.

Table 1. TFP growth study findings

Study	Output measure	Recommended data period	Number of firms	TFP growth calculation	
				Initial	Final
NERA 2012	Volume (MWh)	1972-2009	72	-	0.96
Brattle	Volume (MWh)	2000-2014	67	-0.89%	-0.79%
Meitzen	Volume (MWh)	Average of last 15 (2000-2014) and last 10 (2005-2014) years	68-72	-1.11% [Note 1]	-1.11% [Note 1]
Lowry	Number of customers	1997-2014	88 21	+0.48% +0.80%	+0.43% +0.78%

Note 1: As per Exhibit 20414-X0074, paragraph 95, clarified in Exhibit 20414-X0623, paragraph 55, EPCOR and Dr. Meitzen recommended a methodology for calculating TFP growth rather than a specific value, with the numerical value to be decided using a new TFP growth study that utilizes the latest available data before the next generation PBR term begins.

Source: Brattle study initial TFP growth: Exhibit 20414-X0056, PDF pages 36-37, final TFP growth: Exhibit 20414-X0387, PDF pages 21-22; Meitzen study, initial TFP growth (71 firms): Exhibit 20414-X0074, PDF page 225, (67 firms): Exhibit 20414-X0256, EDTI-AUC-2016APR15-010, Table 3, PDF page 41; Lowry study initial TFP growth: Exhibit 20414-X0082, Table 5a on page 64 (88 firms), Table 5c on page 68 (21 firms), final TFP growth: Exhibit 20414-X0468, PDF pages 40, 42.

94. The three studies filed in this proceeding provide a relatively wide range of TFP growth values, with all final recommendations smaller than, and in some cases much smaller than, the TFP growth number adopted by the Commission in Decision 2012-237. The issue that the Commission must address, therefore, assuming the Commission finds any of the studies to be acceptable, is not whether the TFP growth component of 0.96 per cent adopted in Decision 2012-237, needs to be lowered for the next generation PBR plans, but rather the extent to which it needs to be lowered. In order to address this issue, the Commission must evaluate the applicability of the various TFP growth values provided by the expert evidence in this proceeding. The Commission's considerations are provided in the following sections 5.2.1 to 5.2.5. Specifically, Section 5.2.1 deals with the objectivity, consistency and transparency of the three studies in this proceeding. Section 5.2.2 focuses on which firms were included in the studies. Section 5.2.3 addresses differences in study calculation methods and assumptions pertaining primarily to growth of inputs. Section 5.2.4 deals with the output measures. Finally, time period considerations are set out in Section 5.2.5.

5.2.1 Objectivity, consistency and transparency of TFP growth studies

95. This section focuses on some of the elements of TFP growth studies that were considered to be of importance in Decision 2012-237. They include objectivity, consistency and

[96] For example, as per Exhibit 20414-X0256: EDTI-AUC-2016APR15-010, PDF page 41, the Meitzen study growth estimate for the same 67 firms as in the Brattle study sample, using just the last 15 years (2000-2014), is -0.81 per cent.

transparency.[97] Satisfaction of these conditions by any particular study does not contribute to a determination of the magnitude of an X value, but it does help the Commission decide if the numbers from that study are even worthy of consideration given the regulatory context in which they are presented. In Decision 2012-237, the NERA study was found to satisfy these requirements,[98] and since the Brattle and Meitzen studies in the current proceeding use the same methodology but update the NERA analysis to include additional years of data from the same publically available data sources, they also satisfy them.

96. The distribution utilities submitted that caution should be exercised when relying on the results of the Lowry study because of the same lack of objectivity, consistency and transparency that the Commission identified with respect to his work in Decision 2012-237.[99] Specifically, while the Lowry study in this proceeding relied on publicly available data, the distribution utilities stated that these TFP results were obtained using a software package that is not widely used, rather than spreadsheets, and that the underlying calculations and assumptions were not documented or clearly explained.[100] The distribution utilities also expressed concerns with the potential lack of objectivity and consistency in the Lowry study, based on their observation that "PEG's TFP results vary considerably from study to study, even though the input data and the study time period were exactly the same."[101]

97. Dr. Lowry responded that the employed software is used "for all of our [PEG's] projects since the inception of the company" and is available for purchase.[102] Dr. Lowry defended performing the TFP growth calculation using computer code because it is "easier to review and validate than the array of spreadsheets."[103] Dr. Lowry also expressed his view that he provided at least the same level of information, if not more, as NERA in the last proceeding and experts replicating NERA's study in this proceeding.[104] Further, the CCA submitted that additional information or explanation was available should it be needed and requested.

98. The Commission does not view the use of computer code and proprietary software in and of itself as limiting the transparency of a study, particularly if the analysis can be reproduced in a spreadsheet format with intact formulas and assumptions provided. In the future, the Commission would prefer such analysis to also be reproduced using spreadsheets when, as in this situation, it is possible to do so.[105] The Commission considers that the present proceeding provided sufficient opportunity for all parties, and the Commission, to explore the basis of Dr. Lowry's calculations and assumptions that were put forward in his direct evidence through IRs and cross-examination.

---

97 Decision 2012-237, paragraph 353.

98 Decision 2012-237, paragraph 353.

99 Decision 2012-237, paragraph 364.

100 Exhibit 20414-X0619, ENMAX argument, paragraphs 47-50; Exhibit 20414-X0623, EPCOR argument, paragraphs 71-73.

101 Exhibit 20414-X0634, ENMAX reply argument, paragraph 23; Exhibit 20414-X0635, EPCOR reply argument, paragraph 33. The other studies referred to were provided in other proceedings and/or jurisdictions.

102 Transcript, Volume 12, page 2422, lines 2-3 (Dr. Lowry) and Exhibit 20414-X0203 CCA-EDTI-2016APR15-001(s).

103 Exhibit 20414-X0203 CCA-EDTI-2016APR15-001(t).

104 Transcript, Volume 12, pages 2425-2426 (Dr. Lowry).

105 The PEG study data were provided in spreadsheet form in Exhibit 20414-X0100, with variable definitions in Exhibit 20414-X0106. These data were used by Dr. Meitzen in an attempt to reproduce the PEG study results using a spreadsheet in Exhibit 20414-X0417. The replication results obtained by Dr. Meitzen, for input, output, and TFP (MFP) growth, are almost identical to those in Table 5a of the PEG study, Exhibit 20414-X0082, page 64.

99. An additional issue considered by the Commission was the "customization" undertaken in the Lowry study. The CCA stated that "Dr. Lowry customizes his results to the application," which, in the CCA's view, "enhances the methodology."[106] Customization of TFP growth studies introduces a level of subjectivity that may obscure the objectivity and transparency of the TFP growth value that would result without the customization, unless the results are provided both with and without any added customizations. The Lowry study provided TFP growth results, as well as the input and output growth components of TFP growth, for each sample year, for both the full sample of 88 firms and for specific customized subsamples. Consequently, for the purposes of the present proceeding, the Commission will not reject, or attach less weight to, the Lowry study presented in his primary evidence on the grounds of lack of objectivity, consistency, and/or transparency.

5.2.2 Sample of comparative firms in the TFP growth study

100. This section focuses on the particular firms included in the various TFP growth studies. One issue here pertains to input data modifications arising from firm mergers, asset transfers, etc., while another concerns whether analysis that utilizes data from a subset of the available firms, rather than from all available firms, should be afforded lesser, equal, or preferential treatment. As shown in Table 1, TFP growth values from analysis that utilizes subsets of firms selected in the Lowry study are much higher than TFP growth values in the same study that utilizes all firms. Consequently, determination of this issue concerning subsets of firms may affect the range of possible values that the Commission considers for the TFP growth component of the X factor.

101. The NERA study in the PBR Proceeding 566 included 72 firms for which data were available for the full sample period from 1972 to 2009, with certain data series for capital additions and retirements reaching back to 1964. The Brattle study updated the NERA study to 2014; however, in doing so, it discarded the 2010-2014 data for five firms due to issues with missing or inconsistent data; for example, due to mergers.[107] In updating the NERA study, the Meitzen study did not check for inconsistent data,[108] and discarded four utilities for years 2010-2014 for which data were unavailable.[109]

102. While both Brattle and Dr. Meitzen excluded data for years 2010-2014 for the discarded utilities, they retained these data in the 1972-2009 calculation, resulting in an unbalanced panel (i.e., a different number of utilities, between 67 and 72, was used in the calculation in different years). In its reply evidence update, Brattle excluded the five utilities for all of the sample years; this did not have a significant effect on the resulting TFP growth value. Dr. Meitzen retained his original recommendation. However, in response to Commission IRs and follow-up calculations, some of Dr. Meitzen's calculations were undertaken using the 67 firms in the Brattle sample. As shown in this response, using an unbalanced panel in Dr. Meitzen's case did not appear to have a significant effect on the resulting TFP growth calculation.[110]

103. In the case of the NERA study and, therefore, the Brattle and Meitzen studies, as well as the Lowry study, their respective samples included all firms for which data of sufficient quality

[106] Exhibit 20414-X0630, CCA revised argument, paragraph 197.
[107] Exhibit 20414-X0056, Brattle evidence, page 26, Q/A 52.
[108] Transcript, Volume 13, pages 2646-2647 (Dr. Meitzen).
[109] Exhibit 20414-X0074, Appendix B, EPCOR evidence of Dr. Meitzen, paragraph 36.
[110] Exhibit 20414-X0256, EDTI-AUC-2016APR15-010(a).

TAB 7

The O&M Cost Performance of Enbridge Gas Distribution: Update

23 February 2004

Mark Newton Lowry, Ph.D.
Partner

David Hovde, M.S.
Senior Economist

John Kalfayan
Senior Economist

Steve Fenrick, B.S.
Economist

PACIFIC ECONOMICS GROUP

22 East Mifflin, Suite 302
Madison, Wisconsin USA 53705
608.257.1522 608.257.1540 Fax

Executive Summary

Enbridge Gas Distribution made a filing in December of 2003 in support of new cost-based rates for its delivery services. In support of its previous cost filing, Enbridge in 2002 commissioned Pacific Economics Group to prepare a statistical benchmarking study of its operation and maintenance expenses. Last December, Enbridge asked PEG to update this study for submission in its latest evidence.

We developed indexes that compared the O&M productivity of Enbridge to that of samples of U.S. and Canadian gas distributors. The productivity indexes were calculated using the results of an econometric model that helped identify the drivers of distributor cost. The cost model was also used to make direct appraisals of the company's O&M cost management.

On February 4, 2004, we completed a preliminary report on our research. It discussed work that was based on a sample of data ending in 2001 and addressed the performance of Enbridge through the 2004 "bridge year". Since filing that report, we have had the time to make several enhancements to the research. Specifically, we have added U.S. data from 2002 to the sample, refined our methodology, and extended our analysis to the 2005 test year. This is the final report on our research.

Indexing Research

A productivity index is the ratio of an output quantity index to an input quantity index. It is used to make productivity comparisons. In this study we used productivity indexes to compare the O&M expenses of Enbridge to industry norms.

The indexing work was based on a sample of the latest available data for 2 Canadian and 66 U.S. distributors. The sample year for these data is 2002. We used the data to appraise the efficiency actually achieved by Enbridge from 2000 to 2003, as well as the efficiency reflected in its estimate of its 2004 "bridge year" expenses and in its proposed 2005 test year expenses.

Our indexing work provided a number of insights on the cost structure of gas distribution. We found that productivity is typically higher for gas and electric distributors than for those that serve only gas customers. Large distributors generally have a productivity advantage over smaller ones. Productivity (as we measure it) is also higher for distributors that do not provide a sizeable share of their services in densely settled urban cores. These distinctions are important since Enbridge is a large gas-only utility that serves two urban cores.

The O&M productivity levels achieved by Enbridge were well above the year 2002 mean for the full U.S. sample throughout the historical 2000-2003 period and the bridge year. The productivity implicit in the 2005 test year proposal is about 14% above the mean productivity of the full U.S. sample and also about 14% above the mean for the large gas-only utilities in the sample that provide extensive service in urban cores. The productivity reflected in the proposal also exceeds that achieved by the 2 Canadian companies.

Econometric Results

Our econometric model is based on a smaller sample of data for 37 U.S. distributors that spanned the period 1990-2002. We used the model to predict the O&M expenses of Enbridge given its values for variables representing several relevant business conditions. Model development made use of economic theory and established statistical methods. Business conditions were included in the model only if their estimated cost impact was plausible in sign and magnitude and statistically significant. The model includes trend terms so that appraisals of the 2004 bridge year estimate and the 2005 test year proposal reflect an expectation of continuing efficiency gains.

The econometric research helped us to identify business conditions that are important drivers of gas distribution costs and may vary between sampled companies. These conditions included the extent of cast iron materials in the distribution system, the number of electric customer served, frost depth, and the importance in the service territory of urban cores. The Company was found to face some challenging conditions in its efforts to contain gas distribution cost. For example, it is not a combined gas and electric utility and operates in an area of extreme frost depth. Enbridge also has unusually large expenditures for demand-side management.

The Company's historical O&M expenses and 2004 bridge year estimate were well below the cost model's predictions throughout the 2000-2003 historical period. The level of O&M expenses proposed for 2005 is about 24% below the cost model's prediction. Were the Company to achieve this spending level it would be a significantly superior cost performer.

Conclusion

We have assessed the Company's O&M cost performance using two sophisticated benchmarking methods. Both methods suggest that the Company's recent historical O&M expenses, estimated 2004 bridge year O&M expenses, and proposed 2005 test year expenses reflect superior cost efficiency.