

BOARD STAFF RESPONSE TO
ENBRIDGE GAS DISTRIBUTION INC. #12

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: ExhL/T1/S2

I.A1.Staff.EGDI.12

Preamble:

On page 5, PEG states that "the input price and TFP research for US gas distributors that was presented in Alberta can be used to assess the appropriateness of the elements of an IR plan for EGD," and on page 43 PEG states "in evidence presented in December 2011 on behalf of the Consumer Coalition of Alberta, PEG estimated that TFP for the US gas distribution industry grew at an average rate of 1.32% per annum over the 1996-2009 period."

Request:

- a. Please provide the referenced "input price and TFP research for US gas distributors that was presented in Alberta" where "PEG estimated that TFP for the US gas distribution industry grew at an average rate of 1.32% per annum over the 1996-2009 period."
 - i. Please provide all expert reports, data, workpapers, analysis and research that supports PEG's recommended I factor in Alberta. The data, workpapers and analysis should be provided in electronic format with all calculation formulas intact.
 - ii. Please provide all expert reports, data, workpapers, and research that supports PEG's TFP analysis and recommended X factor in Alberta. The data, workpapers and analysis should be provided in electronic format with all calculation formulas intact.
- b. Please provide the AUC decision that describes its I Factor and XFactor conclusions.
- c. Please summarize any sections of the AUC decision where it indicates that the AUC relied on PEG's analysis results in reaching its conclusions.
- d. Please provide a table contrasting the industry TFP estimates provided by PEG with those of other experts in the Alberta proceeding.

Witness: Dr. Lawrence Kaufmann, PEG

RESPONSE

- a. The requested working papers are the subject of a request for confidential treatment pursuant to Rule 10 of the Ontario Energy Board's Rules of Practice and Procedure. A CD containing the relevant information will be provided to any requesting party who signs the Board's Declaration and Undertaking.

The requested expert reports are attached:

- PBR Plans for Alberta Energy Distributors PEG 17 December 2011 (revised)
 - PBR Plans for Alberta: Response to Second NERA Report PEG 4 April 2012 (revised)
- b. Please see the attached AUC decision.
 - c. Please see pages 35-39 and 74-76 in the attached AUC decision.
 - d. Please see Table 6-2 on page 105 in the attached AUC decision.

PBR PLANS FOR ALBERTA

ENERGY DISTRIBUTORS

AUC ID 566 RRI

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17 December 2011 - Revised

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EXECUTIVE SUMMARY

The Alberta Utilities Commission (“AUC” or “the Commission”) in February 2010 began a Rate Regulation Initiative to reform rate regulation in the province. In conformance with Commission directives, performance-based regulation (“PBR”) plans were recently proposed by several provincial gas and electric power distributors. All of the proposed plans have rate escalation mechanisms with inflation – X formulas.

Rate escalation mechanisms of PBR plans are often designed using research on utility input price and productivity trends. The AUC retained National Economic Research Associates (“NERA”) to prepare a multifactor productivity (“MFP”) study or studies that could be used to design X factors for Alberta utilities. NERA filed testimony that includes a study of the historical productivity trend of US power distributors. NERA maintains that the results of the study are applicable to Alberta gas and electric power distributors alike. The productivity index that NERA developed displays a negative trend over the last nine years of the sample period.

ATCO Gas and AltaGas (“the Companies”), the two natural gas distributors in the proceeding, have each filed testimony proposing a PBR plan. In both proposed plans, the rate escalation mechanism takes the form of a revenue/customer cap. Both escalation mechanisms also feature an index that is purported to measure distribution input price inflation and a negative X factor that is rationalized in part on the basis of the recent negative trend in the NERA productivity index. Neither proposed X factor has a stretch factor, but earnings sharing mechanisms are proposed that have broad deadbands. Each gas distributor has also proposed that rates for a substantial portion of their capital expenditures (“capex”) be established independently of the indexing mechanism. Both Companies propose that service quality be addressed by a continuation of the Commission’s current monitoring program rather than an award/penalty mechanism. ATCO Gas proposes an efficiency carryover mechanism.

The Consumer’s Coalition of Alberta (“CCA”) has retained Pacific Economics Group (“PEG”) Research LLC to provide research and testimony that would be pertinent to the design of the PBR plans for ATCO Gas and AltaGas. The scope of work includes input



price and productivity research. This document reports on our research for the CCA and provides our views on key issues in the design of PBR plans for Alberta gas utilities. Some of our commentary is relevant to the regulation of provincial power distributors as well.

Base Productivity Factor

Our productivity research for the CCA was based on a sizable sample of data on the operations of U.S. investor-owned gas distributors. All data used in the study were drawn from respected public sources. The sample period was the fourteen years from 1996 to 2009.

We calculated the trends of MFP indexes of the sampled distributors as providers of gas transmission, storage, distribution, metering, and general administration services. For all of these services the costs considered comprised operation and maintenance (“O&M”) expenses and costs of plant ownership. Expenses for gas production and purchases, customer service and information, sales, customer accounts (other than metering), pensions and other benefits, and income taxes were excluded from the costs to better match the costs that the Companies propose to recover via indexing. Output was measured by the number of customers served, as this specification is consistent with the proposed revenue per customer index.

The average trend in the productivity of all of the gas distributors in our US sample was found to be 1.32% growth per annum over the full 1996-2009 period. The average trend in the productivity of the sampled gas utilities located in the western U.S. was 1.84% growth per annum. The western companies averaged 2.52% customer growth, which was well above the sample norm and similar to that achieved by ATCO Gas in the last decade.

To obtain base productivity growth factors more customized to business conditions in Alberta, we developed an econometric model of MFP growth. MFP growth was found to be higher the more rapid was gas and electric customer growth, the slower was growth in miles of main, and the more rapid was technological change. Assuming 2% annual growth in line miles and the number of gas customers served, the model predicts 1.69% annual MFP growth. A higher productivity growth target would be warranted if expected customer growth was higher.

An adjustment to the base productivity factor may be warranted if the Commission sanctions the recovery of certain capex costs outside the indexing mechanism. To



investigate the dimension of the possible adjustment, we recalculated the productivity trends of the western and full sample groups, having excluded a fixed percentage of the plant additions used in cost computations. Excluding 10% of plant additions, we found that the productivity trend of the full sample rose from 1.32% to 1.53%. The productivity trend of the western group rose from 1.84% to 2.05%. The Commission should consider allowing the Companies flexibility in the year to year escalation of revenue per customer subject to the constraint that cumulative escalation cannot exceed that of the revenue per customer escalation index. If certain capex costs are Y factored consideration should also be paid to their ongoing Y factoring in subsequent plans so that, having accelerated revenue growth in one plan, they slow it in later plans.

Other recent studies support the notion that the productivity growth of North American gas and electric power distributors is typically substantial. PEG Research studies released this year found annual MFP growth trends exceeding 100 basis points for Enbridge Gas Distribution (“EGD”), Gaz Metro, and Union Gas. Recent PEG Research findings that the MFP trends of US power and gas distributors were 0.88% and 1.18% respectively were confirmed by the Division of Ratepayer Advocates of the California Public Utilities Commission. The Statistics Canada MFP index for the gas and water industry does not contradict the notion of brisk productivity growth. The Statistics Canada MFP index for the utility industry is less relevant for various reasons and results after 2008 should be given little weight given the sensitivity of the output index to economic conditions.

The NERA study of the MFP trend of US power distributors reaches very different results for power distributors in recent years than those produced by other recent power distribution studies. We believe that this is chiefly because the NERA study has flaws that especially compromise its estimate of the MFP trend in recent years. NERA’s results for this period do not provide a suitable basis for Alberta X factors. The NERA results are most reliable for the 1981-1995 period. In this interval MFP growth averaged 1.43% annually.

Our research using for the CCA suggests a base productivity factor for Alberta Gas utilities in the [1.32% - 1.69%] range. Witnesses for the Companies advocate much lower productivity factors despite the proposals of the Companies to exempt some capex from the indexing mechanism. We urge the Commission to base its decision on the best available research and not “split the baby” by taking the average of all proposals in this proceeding.



Stretch Factor

A stretch factor is often added to the X factor of a rate escalation mechanism. This can help guarantee customers a share of the expected benefits of any accelerated productivity growth that is expected under the stronger performance incentives generated by the PBR plan. Our research suggests that stretch factors for Alberta gas utilities should lie in the [0.13-0.50] range. The Company proposals to have zero stretch factors and earnings sharing mechanisms with broad deadbands would give the companies most of the expected productivity gains.

Inflation Measure

Some rate escalation mechanisms of PBR plans in Alberta have used an inflation measure designed to measure the input price trends of utilities. An alternative is to use a macroeconomic price index. The Consumers Price Index for Alberta and the Gross Domestic Product Implicit Price Index for Final Domestic Demand for Alberta are both serviceable for this purpose.

Should the Commission wish to use a custom input price index, the weight assigned to the labor price index should be limited to the share of direct salaries and wages in the expected total cost that will be subject to the rate escalation mechanism. Any capital price index used in the inflation measure formula should track the trend in the rate of return and a weighted average of current and historical construction prices.

Service Quality

The move from Alberta's current system of regulation to PBR is likely to strengthen incentives for cost containment substantially. Service quality and safety can suffer, and mishaps in both areas have occurred during PBR plans. Award/penalty mechanisms are commonly featured in PBR plans to forestall service quality and safety degradation. A noteworthy Canadian precedent can be found in the PBR plan of Gaz Metro. We recommend that award/penalty mechanisms be developed for all Alberta utilities.



1. INTRODUCTION

The Alberta Utilities Commission (“AUC” or “the Commission”) in February 2010 began a Rate Regulation Initiative to reform rate regulation in the province. Pursuant to Commission directives, performance-based regulation plans have been proposed by several provincial gas and electric power distributors. The Commission has indicated that it would like the PBR plans to have a design broadly similar to that which it approved for ENMAX. The ENMAX plan features a multi-year rate case moratorium and a rate escalation mechanism with an inflation – X escalation formula. The inflation measure in the formula is a custom measure of input price inflation.

In North America, the rate escalation mechanisms of PBR plans are often designed using research on the input price and productivity trends of utilities. The AUC retained NERA to prepare an MFP study or studies that would be useful in the design of X factors for Alberta distributors. In testimony filed last December, NERA presented a single study of the historical productivity trend of US power distributors and maintained that the results were applicable to Alberta gas and electric power distributors alike. The productivity index that NERA developed displays a markedly negative productivity trend in the last decade of the sample period.

ATCO Gas and AltaGas, the two natural gas distributors in the proceeding, have each filed testimony proposing a PBR plan. In both proposed plans, the rate escalation mechanism takes the form of a revenue/customer cap with an inflation – X formula. The formulas feature custom indexes of input price inflation and negative X factors that are rationalized on the basis of the negative trend in the NERA MFP index for the later years of the sample period.

Each gas distributor has also proposed that rates for a substantial portion of their capital expenditures be established independently of the indexing mechanism. ATCO Gas proposes a capital intensity factor (“K factor”) adjustment to the X factor and the Y factoring of “material capital investment that is unique in nature”. AltaGas proposes a major projects (“MP”) factor that would recover the annual cost of certain system safety and reliability projects. Both Companies propose that service quality be addressed by a



continuation of the Commission's current monitoring program rather than an award/penalty mechanism. ATCO Gas proposes an efficiency carryover mechanism.

The Consumer Coalition of Alberta has retained Pacific Economics Group Research LLC to provide research and testimony pertinent to the design of the PBR plans for ATCO Gas and AltaGas. Some of our work is relevant to the design of PBR plans for Alberta power distributors as well. The scope of work includes input price and productivity research that would be pertinent to the design of rate adjustment mechanisms for the Companies.

PEG Research personnel have decades of experience in the design of PBR plans. The measurement of gas and electric distributor productivity is a company specialty. In addition to numerous studies on the MFP trends of U.S. gas distributors, we have recently measured the input price and productivity trends of several Canadian gas distributors in work for the Ontario Energy Board and the Gaz Metro Group de Travail. Work for a diverse clientele has given our practice a reputation for objectivity and dedication to regulatory science.

This document reports on our research for the CCA in this proceeding. Chapter 2 provides an introduction to input price and productivity measurement and discusses their relevance in PBR plan design. Highlights of our empirical research are presented in Chapter 3. Other plan design issues are discussed in Chapter 4. Further details of our work are provided in the Appendix.



2. INDEX RESEARCH AND INCENTIVE REGULATION

Price and productivity research has been used for at least thirty years to design the rate escalation mechanisms of PBR plans. Index logic provides the rationale for this approach. To understand the logic it is necessary to first have a high level understanding of input price and productivity indexes. We provide this in Section 2.1. There follows in Section 2.2 a discussion of the logic for using indexing in the design of rate escalation mechanisms for PBR plans.

2.1 Price and Productivity Indexes

2.1.1 An Introduction to Indexes and Index Logic

Indexes are mechanisms for making comparisons using ratios. A price trend index, for example, compares prices in one period to those in the previous period by taking price ratios. Inflation in the price of natural gas, for instance, may be calculated as

$$Inflation^{Gas} = \frac{P_t^{Gas}}{P_{t-1}^{Gas}} - 1$$

or, using natural logarithms,

$$Inflation^{Gas} = \ln \frac{P_t^{Gas}}{P_{t-1}^{Gas}}.$$

Indexes can summarize multiple comparisons by taking weighted averages of them. The indexes used to make individual comparisons are called subindexes. The weights used in summary indexes should reflect the intended use of the index. Canada's consumer price index for all items ("CPI"), for example, averages the inflation rates of numerous consumer products using the share of each product in the expenditures of a typical consumer as weights. It can be shown using calculus that, with expenditure share weights, a CPI can measure the impact of price inflation on the typical consumer's expenditures. We will call the use of calculus to design indexes used in economic research "index logic".



2.1.2 Input Price Indexes

Input price indexes can be designed to measure the trend in the input prices paid by a utility or utility industry. It can be shown using index logic that the growth in cost is the sum of the growth in an appropriately designed input price index (“Input Prices”) and input quantity index (“Inputs”).

$$\text{growth Cost} = \text{growth Input Prices} + \text{growth Inputs}. \quad [1]$$

The input price and quantity indexes summarize trends in the input prices and quantities that make up the cost. Both indexes in [1] use the cost share of each input group that is itemized in index design as weights.

Capital, labor, and miscellaneous materials and services are the major classes of base rate inputs used by gas distributors. Capital typically accounts for at least half of total cost. In an input price index for total cost the capital price index therefore has the heaviest weight.

2.1.3 Productivity Indexes

Basic Idea

A productivity index is the ratio of an output quantity index (“Outputs”) to an input quantity index.

$$\text{Productivity} = \frac{\text{Outputs}}{\text{Inputs}}. \quad [2]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services they offer. Some productivity indexes are designed to measure productivity *trends*. The growth trend of such a productivity index is the *difference* between the trends in the output and input quantity indexes.

$$\text{trend Productivity} = \text{trend Outputs} - \text{trend Inputs}. \quad [3]$$

Productivity thus measured grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity growth can be volatile due to fluctuations in output and the uneven timing of expenditures. The volatility tends to be greater for individual companies than for an aggregation of companies such as a regional industry.

Input Indexes

The calculation of input indexes for utilities is complicated by the fact that they use numerous inputs in service provisions. This problem is finessed if summary input price indexes are readily available. Rearranging the terms of [3] we obtain

$$\text{growth Inputs} = \text{growth Cost} - \text{growth Input Prices.} \quad [4]$$

This is the approach to input quantity trend calculation that is most widely used in utility productivity research. One can, for example, calculate the growth in the quantity of labor by taking the difference between salary and wage expenses and an appropriate salary and wage price index.

The scope of a productivity index depends on the array of inputs that are considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. A multifactor productivity index measures productivity in the use of several kinds of inputs.

Output Indexes

The output quantity index of a firm or industry summarizes trends in the amounts of goods and services that are produced or sold. Growth in each output dimension that is itemized is measured by a subindex. In designing an output index, choices concerning subindexes and weights depend on the manner in which the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event, the subindexes should measure trends in *billing determinants* and the weight for each itemized determinant should be its share of revenue.

Billing determinants are the quantities companies use to determine customer bills. A bill from Tim Horton's, for instance, might reflect the number of coffees and doughnuts ordered. The bills of gas distributors commonly feature customer (a/k/a "basic") charges and either volumetric charges or demand charges. The relevant billing determinants are therefore delivery volumes, peak demands, and the number of customers served. The weights appropriate for a particular utility vary and depend on the mix of customers, their average use, and the design of rates.

In this paper, we denote by $Outputs^R$ an output index that is revenue-based in the sense that it is designed to measure the impact of output on revenue. The trend in an MFP index calculated using a revenue-based output index (" MFP^R ") has the property



$$\text{trend MFP}^R = \text{trend Outputs}^R - \text{trend Inputs} . \quad [5]$$

Another possible objective of output research is to measure the impact of output growth on company *cost*. In that event, it can be shown that the subindexes should measure the dimensions of the “workload” that drive cost and the weights should reflect the relative importance of the cost elasticities that correspond to these drivers. This approach to output quantity indexation was first detailed in an influential study by three Canadian economists: Michael Denny, Melvyn Fuss, and Leonard Waverman.¹ In this paper, we denote by Outputs^C an output index that is cost-based in the sense of being designed to measure the effect of output growth on cost. The trend in an MFP index that is calculated using a cost-based output index (“*Productivity*^C”) has the property

$$\text{trend Productivity}^C = \text{trend Outputs}^C - \text{trend Inputs} . \quad [6]$$

The elasticity of cost with respect to an output quantity is the percentage change in cost that will result from a 1% change in the quantity. The requisite elasticities for utilities can be estimated econometrically using a sample of historical data on the costs and workloads of utilities. In the gas distribution industry, our research over the years has shown that salient cost drivers include the number of customers served and the extensiveness of the system (often measured by the miles of transmission lines and distribution mains). Given the cost function

$$\ln \text{Cost} = a_0 + a_1 \ln \text{Customers} + a_2 \ln \text{Line Miles} + a_3 \text{Trend} . \quad [7]$$

for example, the parameters a_1 and a_2 are the elasticities of cost with respect to the number of customers served and the line miles. A multi-category output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver.

Sources of Productivity Growth

Research by Denny, Fuss, and Waverman and others has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

¹ Michael Denny, Melvyn A. Fuss and Leonard Waverman (1981), “The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications,” in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

Economies of scale are another important source of productivity growth. These economies are available in the longer run when cost has a tendency to grow less rapidly than output (as measured by *Outputs*^C). In that event, output growth can raise productivity growth. A company's potential to achieve incremental scale economies depends on the pace of its workload growth and may also depend on its operating scale. Incremental scale economies (and thus productivity growth) will typically be greater the more rapid is output growth. The potential for scale economy realization varies by industry. Our research over the years has found that the potential is generally greater in gas distribution than in power distribution.

A third important source of productivity growth is change in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth will increase (decrease) to the extent that X inefficiency diminishes (increases). The potential of a company for productivity growth from this source is greater the lower is its current level of efficiency.

Another source of productivity growth is changes in the miscellaneous business conditions, other than input price inflation and output growth, which affect cost. A good example for an electric power distributor is the share of distribution lines that are undergrounded. An increase in the percentage of lines that is undergrounded will tend to slow MFP growth.

An important source of productivity growth in the shorter run is the intertemporal pattern of expenditures that must be made periodically but need not be made every year. Such "deferrable" expenditures include those for maintenance and the replacement of a poorly performing plant that has deteriorating performance. A surge in deferrable expenditures can slow productivity growth.

When productivity is calculated using a revenue-based output index, growth in productivity may also depend on the degree to which the output growth affects *revenue* differently from the way it affects *cost*. This can be measured by the difference in the growth rates of revenue-based and cost-based output indexes. This difference may be called the "output differential".

$$\text{Output Differential} = \text{growth } \text{Outputs}^R - \text{growth } \text{Outputs}^C \quad [8]$$



The output differential is important to the extent that output is growing but prices are not cost causative in the sense that they do not reflect the drivers of cost well. It is an important determinant of MFP^R growth in the energy distribution industry because the rate designs of energy distributors are frequently not very reflective of cost drivers.² For example, our research over the years reveals that the costs of energy distributors are commonly driven in the short and medium term chiefly by growth in the number of customers served, whereas distributor revenue is commonly driven chiefly by growth in delivery volumes to residential and small business customers. Under these circumstances, the output differential and growth in MFP^R will be sensitive to trends in delivery volumes *per customer* (a/k/a “average use”). The output differential will be negative, slowing growth in MFP^R , when average use is declining and will be positive, accelerating MFP^R growth, when average use is rising.

Declines in average use by small-volume customers have been common in the gas distribution industry for many years. Contributing factors include demand-side management (“DSM”) programs, general improvements in the technology of furnaces and other gas-fired equipment, and changes in building codes and appliance efficiency standards. In contrast, North American electric utilities often experience modest growth in average use by small volume customers when large DSM programs are not underway in their service territories.

It follows that results of productivity studies in the energy utility industry can be quite sensitive to the output specification. A study of gas distributor productivity, for instance, is apt to produce a substantially lower productivity growth estimate with a revenue-based output index than it will with a cost-based output index. Before using a productivity study in the design of a rate escalation mechanism, it is therefore advisable to first examine whether the study uses an output quantity treatment that is consistent with the kind of PBR plan under development and the rate design of the subject utility. Output indexes featuring the number of customers served will, for example, be more relevant to the extent that the utility gathers its revenues from customer charges.

In appraising the results of a productivity study that uses a revenue-based output index, it is also noteworthy that the delivery volumes which typically receive the heaviest weights in such an index are more volatile than the customer numbers and line miles that

² This phenomenon is somewhat less pronounced in Canada than in the United States.

typically receive the heaviest weights in a cost-based output index. As a consequence, productivity indexes with revenue-based output indexes tend to be more volatile than productivity indexes with cost-based output indexes. Moreover, the calculation of a long term productivity trend is more sensitive to the choice of a sample period with a revenue-based output index. For example, a sample period that ends in a period of economic decline can impart a downward bias to the estimate of the long-run productivity trend.

2.1.4 Calculating Capital Costs

Trends in the price and quantity of capital play a critical role in the measurement of trends in MFP and the prices of base rate inputs due to the typically high share of capital in total cost. A practical means must be found to calculate capital cost and to decompose it into consistent price and quantity indexes such that

$$\text{Growth Cost}^{\text{Capital}} = \text{growth Price}^{\text{Capital}} + \text{growth Quantity}^{\text{Capital}}.$$

The capital price index measures the trend in the cost of owning a unit of capital. It is sometimes called a rental or service price because in a competitive market the price of rentals would tend to reflect the unit cost of capital ownership. The components of capital cost include depreciation and the return on investment. The trend in these costs depends on trends in construction prices and the market rate of return on capital. A capital price index should be reflective of both of these price trends.

Three practical methods that have been developed for calculating capital costs using service prices merit note.

- The geometric decay (“GD”) method assumes a current valuation of capital and a constant rate of depreciation. This method has been widely used in productivity research. Although the assumptions underlying the GD method are very different from those used to compute capital cost in utility regulation, the GD method has been used on several occasions in research intended to calibrate utility X factors. The assumptions produce capital service price and quantity indexes that are mathematically elegant and easy to code and review. Current valuation of plant means that owners profit from capital gains. The net cost of plant ownership can be appreciably less than the gross. A GD capital price reflects the net cost of plant ownership, and includes the real (inflation-



adjusted) rate of return on plant ownership. This return has been remarkably volatile in recent years due to rapid growth in the price of construction that was not matched by higher lending rates.

- The one loss approach to capital costing assumes that plant does not depreciate gradually but, rather, all at once as the asset reaches the end of its service life. The plant is valued in current dollars. Although the assumptions underlying the one loss method are very different from those used to compute capital cost in utility regulation, the method has been used occasionally in research intended to calibrate utility X factors.
- 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.

Utilities have diverse methods for calculating depreciation. In calculating capital costs and quantities, it is therefore generally considered desirable to rely on the reporting companies chiefly for the value of plant additions and then use a standardized depreciation treatment. Since the quantity of capital on hand may involve plant added thirty to fifty years ago, it is desirable to have plant addition data for many years in the past. For older periods in which plant addition data are unavailable, it is customary to consider the net plant value near the end of this period and then estimate the quantity of capital it reflects using construction price indexes from earlier years and assumptions about the pattern of investment. The year in which this exercise takes place is commonly called the “benchmark

year”. Since this exercise is unlikely to be exact, it is advisable to base X factor research on a sample period that begins at least ten years after the benchmark year.

2.2 Role of Index Research in Regulation

Multi-year rate plans are the most common approach to PBR around the world. In such a plan, a moratorium is typically placed on general rate cases for several years. A rate escalation mechanism adjusts allowed rates or revenues automatically for changing business conditions between rate cases. This mechanism is predetermined in the sense that it is designed before the start of the plan and is insensitive to the costs (and possibly also the billing determinants) of the utility during the plan period. An approach to the design of rate escalation mechanisms has been developed in North America that uses input price and productivity indexes. In this section we first consider the basic logic of using index research to design price and revenue caps. We then consider in more detail the use of index research to choose the components of rate escalation mechanisms.

2.2.1 Price Cap Indexes

Index research was first used in the design of *price cap* indexes (“PCIs”). We begin our explanation of the supportive index logic by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.³ In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\text{trend Revenue} = \text{trend Cost}. \quad [9]$$

The trend in the revenue of any firm or industry can be shown to be the sum of the trends in revenue-weighted indexes of its (output) prices and billing determinants.

$$\text{trend Revenue} = \text{trend Outputs}^R + \text{trend Output Prices}^R. \quad [10]$$

Recollecting from [1] that the trend in cost is the sum of the growth in cost-weighted input price and productivity indexes, it follows that the trend in output prices that permits revenue to track cost is the difference between the trends in an input price index and an MFP index that uses a revenue-based output measure.

³ The assumption of a competitive rate of return applies to unregulated, competitively structured markets. It is also applicable to utility industries and even to individual utilities.

$$\begin{aligned} \text{trend Output Prices} &= \text{trend Input Prices} - (\text{trend Outputs}^R - \text{trend Inputs}) \\ &= \text{trend Input Prices} - \text{trend MFP}^R \end{aligned} \quad [11]$$

The result in [11] provides a conceptual framework for the design of PCIs of general form

$$\text{trend Rates} = \text{trend Inflation} - X$$

Here X, the “X factor”, can be calibrated to reflect a base productivity target. A “stretch factor”, established in advance of plan operation, is sometimes added to the formula which slows PCI growth in a manner that shares with customers the benefits of performance improvements that are expected due to the stronger performance incentives of the PBR plan.⁴

$$X = \text{Base Productivity Factor} + \text{Stretch}$$

Input price research can be used to select an appropriate inflation measure. Productivity research can be used to “calibrate” the X factor by setting the base productivity factor.

2.2.2 Revenue Cap Indexes

A revenue cap is a rate escalation mechanism designed to limit growth in a utility’s allowed *revenue* rather than its *rates*. The allowed revenue for a given year must then be converted by some means into rates. The allowed revenue cap is often, though not always, paired with a revenue “decoupling” mechanism that ensures, using variance accounts, that the allowed revenue is ultimately recovered.

Revenue caps are favored in regulation for two principle reasons. One is that they weaken the link between system use (*e.g.* energy deliveries and peak demand) and earnings, thereby mitigating the disincentive a utility has to promote demand-side management DSM.⁵ Where average use by small-volume customers has a markedly downward trend, revenue caps also sidestep the need for the very low X factors that would otherwise be needed to provide compensatory rate escalation.⁶

The mathematical research of Denny, Fuss, and Waverman implies that

⁴ Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases.

⁵ This benefit has diminished relevance to the extent that DSM is provided by other agencies. However, utilities still have some means to encourage DSM in this situation.

⁶ See, for example, the low X factor in the current PBR plan of Gaz Metro.



$$\text{growth Cost} = \text{growth Input Prices} - \text{growth Productivity}^C + \text{growth Outputs}^C \quad [12]$$

Cost growth is the difference between input price and productivity growth plus output growth, where output growth is measured using a cost-based output index.⁷

Formulas with *elasticity-weighted* output measures have been used by the Essential Services Commission (“ESC”) in the populous state of Victoria, Australia to establish multiyear O&M budgets for gas and electric distributors.⁸ In the energy distribution business, however, we have noted that the number of customers served is an especially important output variable driving cost in the short and medium term. To the extent that this is true, Outputs^C can be reasonably approximated by growth in the number of customers served and there is no need to have a multidimensional output index with elasticity weights. Relation [12] can be restated as

$$\begin{aligned} \text{growth Cost} \\ = \text{growth Input Prices} - \text{growth Productivity}^C + \text{growth Customers} \end{aligned}$$

where the productivity index uses the number of customers to measure output. Rearranging the terms of this formula we obtain

$$\begin{aligned} \text{growth Cost} - \text{growth Customers} \\ = \text{growth (Cost/Customer)} \\ = \text{growth Input Prices} - \text{growth Productivity}^C. \end{aligned} \quad [13]$$

This provides the basis for the following revenue/customer escalation formula.⁹

⁷ This formula can establish the revenue requirement for cost *components* as well as total cost. For example, the applicable formula for non-fuel O&M expenses is

$$\begin{aligned} \text{growth Cost}_{O\&M} \\ = \text{growth Input Prices}_{O\&M} - (\text{growth Outputs}^C_{O\&M} - \text{growth Inputs}_{O\&M}) \\ \quad + \text{growth Outputs}^C_{O\&M} \\ = \text{growth Input Prices}_{O\&M} - \text{growth Productivity}^C_{O\&M} + \text{growth Outputs}^C_{O\&M} \end{aligned}$$

where

$\text{Input Prices}^{O\&M}$ = Price Index for O&M inputs

$\text{Outputs}^C_{O\&M}$ = Elasticity-weighted output index applicable to O&M

$\text{Productivity}^C_{O\&M}$ = Productivity index for O&M that is calculated using $\text{Outputs}^C_{O\&M}$.

⁸ The ESC uses an approach to the design of multiyear rate caps that involves multiyear cost forecasts. This approach is popular in Australia and Britain.

⁹ The propriety of using the number of customers served as the output index to calibrate the X factor of a revenue per customer index has an alternative and simpler derivation. Assume that a revenue per customer index should be calibrated to achieve the revenue per customer growth of a typical utility. Then

$$\begin{aligned} \text{growth Revenue/Customer} \\ = \text{growth Revenue} - \text{growth Customers} \\ = \text{growth Cost} - \text{growth Customers} \end{aligned}$$



$$\text{growth Cost/Customer} = \text{growth Inflation} - X.$$

This general formula for the design of a rate escalation mechanism is currently used in the revenue caps of Enbridge and Gazifere in Canada and was previously used in a revenue cap for Southern California Gas, the largest U.S. gas distributor.^{10 11} Cost per customer escalation formulas have been used to escalate *O&M* budgets in IR plans of several companies in the U.S. and Canada.

2.2.3 Long Run Productivity Trends

Productivity research for X factor calibration commonly focuses on discerning the current *long run* productivity trend. This is the trend in productivity that is unaffected by short-term fluctuations in output or expenditures. The long run productivity trend is faster than the trend that a utility will achieve *during* a surge in expenditures or a slump in demand but also *slower* than the trend that it will achieve between expenditure surges and demand slumps.

If a utility is in a period of normal demand and system age, and is not expecting a major change in its mission (*e.g.* the construction of a gas transmission line), a base productivity factor that reflects the long run productivity trend may be sufficient to finance all capital expenditures if used in successive PBR plans. However, the utility may nonetheless experience some financial stress in periods of expenditure surges.

Care must be taken in the selection of a sample period if the goal of research is to estimate the long run productivity trend. It is customary to use a lengthy sample period for this purpose. However, a period of more than twenty years may be unreflective of the current state of technological change. The sample period can be shorter to the extent that the output measure isn't volatile. If the output index is volumetric, care should be taken not to have a start or end date in a recession year.

$$\begin{aligned} &= (\text{growth Input Prices} + \text{growth Input Quantity}) - \text{growth Customers} \\ &= \text{growth Input Prices} - (\text{growth Customers} - \text{growth Inputs}). \end{aligned}$$

¹⁰ In the Enbridge and Gazifere formulations, revenue per customer growth is capped at $\alpha\%$ of inflation. The X factor is in this case implicit and has an expected value of $(1 - \alpha/100) \times \text{Expected Inflation}$.

¹¹ If the revenue per customer index is applied to individual customer classes, the growth in the output index used to calculate productivity is ideally a revenue weighted average of the growth in the number of customers served. However, an index of this kind is difficult to calculate accurately using available data and is not expected to yield markedly different results.



2.2.4 Inflation Measure Issues

Index logic suggests that the inflation measure of a rate or revenue cap should in some fashion track the input price inflation of utilities. To strengthen performance incentives, it is preferable that the inflation measure track the input price inflation of utilities generally rather than each specific utility to which it applies. This can be achieved by using external inflation indexes and cost share weights that don't reflect the subject utility's changing input mix during the PBR plan.

Several issues in the choice of an inflation specification must still be addressed. One is whether the inflation measure should be *expressly* designed to track utility industry input price inflation as per relation [13]. There are several precedents for the use of utility-specific inflation measures in PBR rate escalation mechanisms. Such a measure was used in one of the world's first large scale PBR plans, which applied to US railroads. Such measures have also been used in PBR plans several times in California.

In Canada, the OEB used an industry-specific inflation measure in its first price cap plan for Ontario power distributors. An industry specific inflation measure has also been used to regulate the terms of grain shipments by railroads in western Canada. In Alberta, an industry-specific inflation measure is featured in the current rate escalation mechanism of ENMAX.

Notwithstanding such precedents, the majority of rate indexing plans approved worldwide do not feature industry-specific inflation measures. They instead feature measures of macroeconomic (*i.e.* economy-wide) inflation prepared by government agencies. These are usually measures of inflation in the prices of the economy's *outputs* such as CPIs and gross domestic product price indexes. In Canada, gross domestic product implicit price indexes ("GDPIPIs") and CPIs are computed on a quarterly basis by Statistics ("Stats") Canada. GDPIPIs measure inflation in the prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products and also include capital equipment and exports. A GDPIPI for final domestic demand is computed at both the national and provincial level. It excludes prices of exports, which are volatile in Canada's resource-intensive economy.

Macroeconomic inflation measures have some advantages over industry-specific measures in rate adjustment indexes. One is that they are available, at little or no cost, from



government agencies such as Statistics Canada. There is no need to go through the chore of annual index calculations. The complications of designing an industry-specific price index are sidestepped. The design of a capital price index can be an especially difficult.

Customers are more familiar with macroeconomic price indexes, and especially with CPIs.

However, the use of a macroeconomic measure in a rate escalation mechanism sometimes involves design challenges. Suppose, for example, that the inflation measure is a GDPIPI. In that event we can restate relation [13] as

$$\begin{aligned} & \text{growth Cost / Customer} \\ &= \text{growth GDPIPI} - \left[\text{trend Productivity}^C + (\text{trend GDPIPI} - \text{trend Input Prices}) + \text{Stretch Factor} \right] \end{aligned} \quad [14]$$

It follows that the PCI can still conform to index logic when a GDPIPI is the inflation measure provided that the X factor corrects for any tendency of the GDPIPI growth to differ from industry input price growth. The difference between the GDPIPI and input price trends may be usefully called the “inflation differential”.

Consider now that a GDPIPI is a measure of inflation in the economy’s *output* prices. Since, additionally, markets in the U.S. and Canada are broadly competitive, the long run trend in the GDPIPI for the economy is the difference between the trends in input price and MFP indexes for the economy.

$$\text{trend GDPIPI} = \text{trend Input Prices}^{\text{Economy}} - \text{trend MFP}^{\text{Economy}} . \quad [15]$$

This makes clear that the GDPIPI already reflects the productivity growth of the economy.

Relations [14] and [15] can be combined to produce the following formula for the design of a revenue/customer index.

$$\begin{aligned} & \text{growth Revenue / Customer} \\ &= \text{growth GDPIPI} \\ & \quad - \left[\left(\text{trend Productivity}^{\text{Industry}} - \text{trend TFP}^{\text{Economy}} \right) \right. \\ & \quad \left. + \left(\text{trend Input Prices}^{\text{Economy}} - \text{trend Input Prices}^{\text{Industry}} \right) + \text{Stretch} \right] \end{aligned} \quad [16]$$

It suggests that when a GDPIPI is employed as the inflation measure, the PCI can be calibrated to conform to index logic when the X factor has two calibration terms: a “productivity differential” and an “input price differential”.

The productivity differential is the difference between the MFP trends of the industry and the economy. The X will be larger, slowing PCI growth, to the extent that the MFP



growth of the economy is slow. The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry. This general approach to X factor design has been used in several PBR proceedings.

The decomposition of X factor calibration into a productivity differential and an input price differential is an aid to thinking about the need for an X factor adjustment when a macroeconomic inflation measure is used. The input price trends of a utility industry and the economy can differ for several reasons. One is that the industry may have a different mix of inputs than the economy. The technologies for gas and electric power distribution, are, in fact, considerably more capital intensive than the typical production process in the economy. It is therefore more sensitive to fluctuations in the price of capital, as we have seen. Another possible reason for the input price trends of the industry and the economy to differ is that the prices of certain inputs grow at a different rate in some regions than they do on average throughout the economy. This is a palpable concern in Alberta, whose resource-intensive economy sometimes experiences hiring booms that stimulate provincial inflation. This concern can be reduced by using an Alberta-specific measure of macroeconomic price inflation.

The difficulties in establishing long-term input price trends complicate identification of an appropriate input price differential. To the extent that the capital price is volatile, for example, the calculation of a long run input price trend for the utility industry is sensitive to the choice of the sample period. Even if we could establish a differential between the long term trends it could differ considerably from the trend expected over the prospective plan period. This situation invites posturing by the parties to PBR proceedings over the input price differential issue. Controversy is possible, additionally, over the method used to calculate the price of capital.

Turning now to the issue of the productivity differential, this depends greatly on the productivity trend of the economy. Studies by the U.S. government show that growth in the MFP of the US private business sector has been fairly brisk for more than a decade, and typically exceeds 100 basis points annually. Since US studies typically suggest that the input price differential is modest in the long run, a macroeconomic output price index such

as the GDPIPI tends to understate the inflation in the input prices of US utilities. Recognition of this bias has led to a downward adjustment in the X factors of some U.S. PBR plans.

In Canada, the productivity trend of the business sector has been quite slow in recent years, and close to zero. According to Statistics Canada, MFP growth was virtually unchanged from 1980 to 2010. It is then reasonable to assume that the productivity differential is roughly the same as the productivity trend of the industry. Assuming, additionally, that the input price trends of the industry and the economy are similar in the long run, there is no need for a special adjustment to the X factor when a macroeconomic inflation measure is used in a rate escalation mechanism.

2.2.5 External vs. Company-Specific Productivity Targets

Productivity research can be used in several ways to calculate base productivity factors. Using the productivity trend of the entire industry to calibrate X is tantamount to simulating the outcome of competitive markets. However, individual firms in competitive markets routinely experience windfall gains and losses. Our discussion in Section 2.1.2 of the sources of productivity growth implies that differences in the external business conditions that drive productivity growth can cause utilities to have different productivity trends. For example, gas distributors that are experiencing brisk growth in the number of gas customers served are more likely to realize economies of scale than distributors that are experiencing slower growth. There is thus considerable interest in methodologies to customize base productivity factors.

The most common approach to customizing base productivity factors has been to average the productivity trends of similarly situated (aka “peer”) utilities. In the Northeast United States, for example, X factors in index-based PBR plans have usually been calibrated using research on the productivity trends of Northeast utilities. Unfortunately, the number of utilities, for which good data are available, which face productivity growth drivers that are similar to those facing the subject utility is sometimes limited. This is a chronic problem in Canada, where standardized data that could be used to accurately measure the productivity trends of numerous utilities are not readily available and there are few potential peers for a given utility in any event.



Complications like these have occasionally prompted regulators to base X factors on a utility's *own* recent historical productivity trend. This approach will weaken a utility's incentives to increase productivity growth if used repeatedly. Furthermore, a utility's productivity growth potential in one five or ten year period may be very different from its productivity growth potential in the following five years. For example, rapid (slow) growth in productivity may be due to a reduction (increase) in X inefficiency, making it more (less) difficult to achieve rapid productivity growth in the future.

Econometric approaches to setting base productivity targets are available that can be customized to the external business conditions of a utility without using its own cost data or having to select productivity peers. One such approach is to use the mathematics that Denny Fuss and Waverman developed to decompose the drivers of productivity growth. Given the simple cost model

$$\ln Cost = a_0 + a_1 \ln Customers + a_2 Trend$$

for instance, it can be shown that, setting aside considerations of X-inefficiency,

$$\begin{aligned} trend Productivity^C &= scale\ effect + trend\ effect \\ &= (1-a_1) \times growth\ Customers + a_2. \end{aligned}$$

We might, then, estimate the parameters of the cost model (*e.g.* a_1 and a_2) using a large sample of data on gas distributor operations in the United States. A custom econometric productivity target can then be established for Alberta gas utilities using the formula:

$$Base\ Productivity\ Target^{Alberta} = (1-a_1) \times growth\ Customers^{Alberta} + a_2.$$

To the extent that Alberta utilities expect output growth that exceeds the norm for the US sample, the custom productivity growth target would be higher than the average target thus calculated for the utilities in the U.S. sample.

This general approach to establishing productivity targets has been used by PEG Research to propose base productivity targets for gas distributors in Ontario and Quebec. A paper discussing the results of our econometric productivity targeting in Ontario has been published in a respected economic journal.¹² An alternative and simpler econometric approach is to regress MFP on drivers of productivity growth, such as the number of customers that have been identified by econometric cost research.

¹²See Mark Newton Lowry and Lullit Getachew, "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry", *Review of Network Economics* Volume 8, Issue 4, December 2009.

2.2.6 Dealing With Cost Exclusions

Many multi-year rate plans recover certain costs outside of the predetermined rate escalation mechanisms. Costs that are targeted for exclusion are sometimes said to be “Y-factored”. The exclusions affect the research that is appropriate for calibrating the X factor.

Suppose, for example, that the cost of some or all capex is Y factored but the cost of existing plant is not. Unless the exempted capex is for a novel purpose (*e.g.* advanced metering infrastructure or the development of a large new storage field or transmission line), the same kind of capex will occasionally have been undertaken by sampled U.S. utilities during a sample period of some length. Note also that the removal of a portion of capital expenditures from the capital quantity index will tend to slow its growth and thereby accelerate productivity growth. That is because the removal increases the implicit cost share weight on the quantity of older plant, which cannot grow and is instead declining due to depreciation.

Evidence to this effect can be found in an examination of experience with the capex cost “trackers” that are used in the regulation of many U.S. energy utilities. According to our theory, the larger is the share of capex recovered through the tracker, the easier it will be for the utility to agree to slow escalation in the rates that recover its residual (*e.g.* O&M and older capital) cost. In Ohio, for instance, three power distributors owned by First Energy (Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison) currently operate under capex trackers that recover substantially all capex costs through a tracker. With respect to the rates that compensate the utility for other costs, all three utilities have agreed to a rate case moratorium.

The Y factoring of capex cost is sometimes advocated on the grounds that the capex in question is a one-time surge. To the extent that this is true, it should also be noted that the productivity growth of the company should accelerate once the surge is complete because the surge will cause the rate base to grow more slowly after it is completed. If PBR should accommodate a revenue surge now to help finance the capex, it should then reflect the slower revenue growth that later results and thereby improve customer finances. One way to accomplish this is to have the costs of capex (*e.g.* depreciation and return) that are excluded from one indexing plan be recovered outside of indexing in the next rate plan as well.

3. RATE ESCALATION RESEARCH

This section presents an overview of our work to develop rate escalation mechanisms for Alberta gas distributors. The discussions here are largely non-technical. Additional and more technical details of the research are provided in the Appendix.

3.1 Data

Data limitations discourage the use of Canadian data in the calibration of X factors for rate escalation mechanisms. Data collection is not standardized across Canada, and the data gathered and reported in Alberta and other individual provinces have changed over the years. Data for many years of plant additions, such as are needed to calculate accurate capital quantity trends, are generally unavailable. The best available data for calibrating the X factors of Alberta energy utilities are therefore those found in the United States. Data on U.S. productivity trends has been considered by Canadian regulators in designing rate escalation mechanisms for BC Gas, Gaz Metro, EGD, Union Gas, and Ontario's power distributors.

The primary source of the US data we use in our gas distribution productivity research has changed over time. Data for the earliest years, which are needed to accurately calculate capital costs and quantities, are drawn from the *Uniform Statistical Reports* ("USRs") that gas utilities filed with the American Gas Association. USR data for some variables of interest are aggregated and released by the Association in its annual publication *Gas Facts*¹³. The earliest year for which we have all of the requisite capital data is 1983.

USR data are still collected but have been unavailable to the public for many sampled gas distributors for many years. The development of a satisfactory sample has therefore required us to obtain cost and quantity data from alternative sources. The chief source of our more recent data on the costs incurred by gas distributors is reports to state regulators. These reports are fairly standardized since they often use as templates the Form 2 that interstate gas pipeline companies file with the Federal Energy Regulatory Commission ("FERC"). The chief source for our data on operating scale has been Form

¹³ These data are unsatisfactory for use in productivity research because the firms in the sample change over time.

EIA 176. Gas utility operating data from both of these sources are compiled by respected commercial vendors. We obtained most of our gas operating data for the sample years of this study from SNL Financial.¹⁴

Other data sources were also employed in our productivity research. These were used primarily to measure input price trends. The supplemental sources of price data were Whitman, Requardt & Associates, the Regulatory Research Associates unit of SNL Financial, the Bureau of Labor Statistics (“BLS”) of the U.S. Department of Labor, and Global Insight (formerly DRI-McGraw Hill).

Our calculations of the productivity trends of US gas distributors are based on quality data for 34 distributors. The sample includes most of the larger distributors in the United States. Some of the sampled distributors also provide gas transmission and/or storage services but all were involved more extensively in gas distribution. The sampled distributors are listed in Table 1.

3.2 Productivity Index Details

3.2.1 Scope

We calculated indexes of trends in the MFP of each sampled utility in the provision of gas services. Costs of any electric services provided by combined gas and electric utilities were excluded from the analysis. We also excluded certain costs that are itemized on U.S. data forms and that are unlikely to be subject to indexing in the PBR plans of the Alberta distributors. The excluded costs include income taxes, gas supply, transmission by others, customer service and information, sales, and customer accounts other than meter reading. The applicable total cost of these services was calculated as the corresponding O&M expenses plus the costs of gas plant ownership. Capital cost was calculated using the COS method. Our capital cost methodology is discussed further below in Appendix A.3.

Some of the excluded costs have grown rapidly in recent years for sampled US utilities and would materially slow their measured productivity trends were they to be

¹⁴ For a few of the sampled companies, the SNL data were deemed insufficient in some of the earliest years of the sample period. In such cases, we used data from sources we have used in the past such as the GasDat service of Platts.

Table 1

SAMPLED GAS DISTRIBUTORS FOR PRODUCTIVITY RESEARCH

Alabama Gas	NSTAR Gas
Baltimore Gas & Electric	Orange and Rockland Utilities
Boston Gas	Pacific Gas and Electric *
Brooklyn Union Gas	PECO Energy
Cascade Natural Gas *	Peoples Gas Light and Coke
Central Hudson Gas & Light	Peoples Natural Gas
Connecticut Natural Gas	Public Service of North Carolina
Consolidated Edison of New York	Public Service Electric and Gas
Consumers Energy	Puget Sound Energy *
East Ohio Gas	Questar Gas *
Louisville Gas and Electric	Rochester Gas and Electric
Madison Gas and Electric	San Diego Gas & Electric *
New Jersey Natural Gas	Southern California Gas *
Niagara Mohawk Power	Southern Connecticut Gas
North Shore Gas	Washington Gas Light
Northern Illinois Gas	Wisconsin Gas
Northwest Natural Gas *	Wisconsin Power and Light

Number of Companies: 34

* indicates western distributor

included. For example, the customer service and information expenses of some distributors have increased markedly in recent years due to the growth of utility DSM programs. The uncollectible bill expenses of some distributors rose rapidly in the later years of the sample period due to high field prices for natural gas and the recession.

3.2.2 Output Measure

Our output specification is intended to measure the effect of output growth on cost. The trend in the workload was measured by the number of customers served. We show in Section 2.2.2 above that this is the output specification that is relevant to the design of a revenue per customer index.

3.2.3 Input Quantity Index

The growth rate in the input quantity index of each sampled distributor was a weighted average of the growth rates in quantity subindexes for capital and O&M inputs. The weights were based on the shares of these input classes in each company's applicable gas distributor cost. The O&M input quantity was calculated as the ratio of the corresponding cost to an appropriate input price index. O&M expenses comprise expenses for labor, materials, and services. Material and service ("M&S") inputs is a residual input category that includes the O&M services of contractors, insurance, real estate rents, equipment leases, materials, and miscellaneous other goods and services.

3.2.4 Sample Period

In choosing a sample period for a productivity study it is generally desirable that the period include the latest year for which all of the requisite data are available. In the present case this year is 2009. This was a year of deep recession in the United States, but the sensitivity of our productivity results to this circumstance is lessened by our choice of the number of customers as the output measure.

It is also desirable for the sample period to reflect the long run productivity trend. We generally desire a sample period of at least 10 years to fulfill this goal. A long sample period, however, may not be indicative of the latest technology trend. Moreover, the accuracy of the measured capital quantity trend is enhanced by having starting data for research that is at least ten years after the first year that good capital cost data are available.



We attempt to balance these considerations by presenting productivity results for the fourteen year 1996 to 2009 period.

3.3 Productivity Index Results

Table 2 and Figures 1 and 2 report the average annual growth rates in the gas distributor productivity and component output and input quantity indexes for the full U.S. sample and a subset consisting of the sampled distributors in the western US. Inspecting the results it can be seen that, for the full sample and over the full sample period, the distributors averaged 1.32% annual productivity growth. Customer growth averaging 1.46% annually outpaced input quantity growth averaging only 0.14% annually. The average trend in the productivity of the western gas distributors was 1.84% growth per annum over the full sample period. By way of comparison, the MFP index that the BLS calculates for the private business sector of the U.S. economy grew at a 1.22% average annual rate over this period. Thus, the MFP trend of the US gas distribution industry was very similar to that of the private business sector as a whole.

We also calculated MFP indexes that excluded 10% of capital expenditures on the grounds that routine capex recovered outside of indexing would likely be undertaken as well by sampled utilities. We find that the average annual growth in the productivity trend of the full US sample rises from 1.32% to 1.53%. The average annual growth in the productivity trend of the sampled gas distributors in the western US rises from 1.84% to 2.05%.

3.4 Econometric Productivity Growth Projections

In Section 2.2.5 above we discussed the use of econometrics to make productivity growth projections that are customized to the local business conditions that a utility faces. This methodology makes some sense in Canada, where quality, standardized data on the productivity growth of peer utilities is unavailable. However, econometric productivity growth projections can trigger criticisms that results are somehow only true in the *long* run, and that the behavior of MFP indexes will be quite different in the short and medium term.

To anticipate such criticisms, we have developed for the CCA an econometric model of MFP growth that can be used to project base productivity factors that reflect the local



Table 2

Productivity Index Results

	Output Quantity		Input Quantity		TFP	
	Sample	Western	Sample	Western	Sample	Western
1996	2.08%	3.92%	1.06%	1.29%	1.02%	2.63%
1997	1.92%	2.40%	-1.09%	0.58%	3.01%	1.82%
1998	1.86%	2.98%	-0.34%	2.20%	2.21%	0.79%
1999	2.04%	3.91%	-0.27%	-1.71%	2.32%	5.62%
2000	1.94%	2.78%	1.88%	-0.37%	0.06%	3.16%
2001	1.70%	2.74%	-1.69%	1.36%	3.39%	1.38%
2002	1.38%	1.88%	0.26%	0.29%	1.12%	1.59%
2003	1.10%	2.29%	0.89%	3.14%	0.21%	-0.85%
2004	1.33%	2.41%	1.15%	0.27%	0.18%	2.14%
2005	1.65%	3.48%	0.76%	1.38%	0.89%	2.11%
2006	1.23%	2.42%	-1.93%	-0.04%	3.16%	2.45%
2007	1.07%	2.20%	0.78%	0.72%	0.29%	1.48%
2008	0.77%	1.35%	-0.68%	-3.06%	1.45%	4.41%
2009	0.38%	0.46%	1.13%	3.39%	-0.75%	-2.93%
1996-2009	1.46%	2.52%	0.14%	0.67%	1.32%	1.84%

Figure 1
Productivity Results - Full Sample

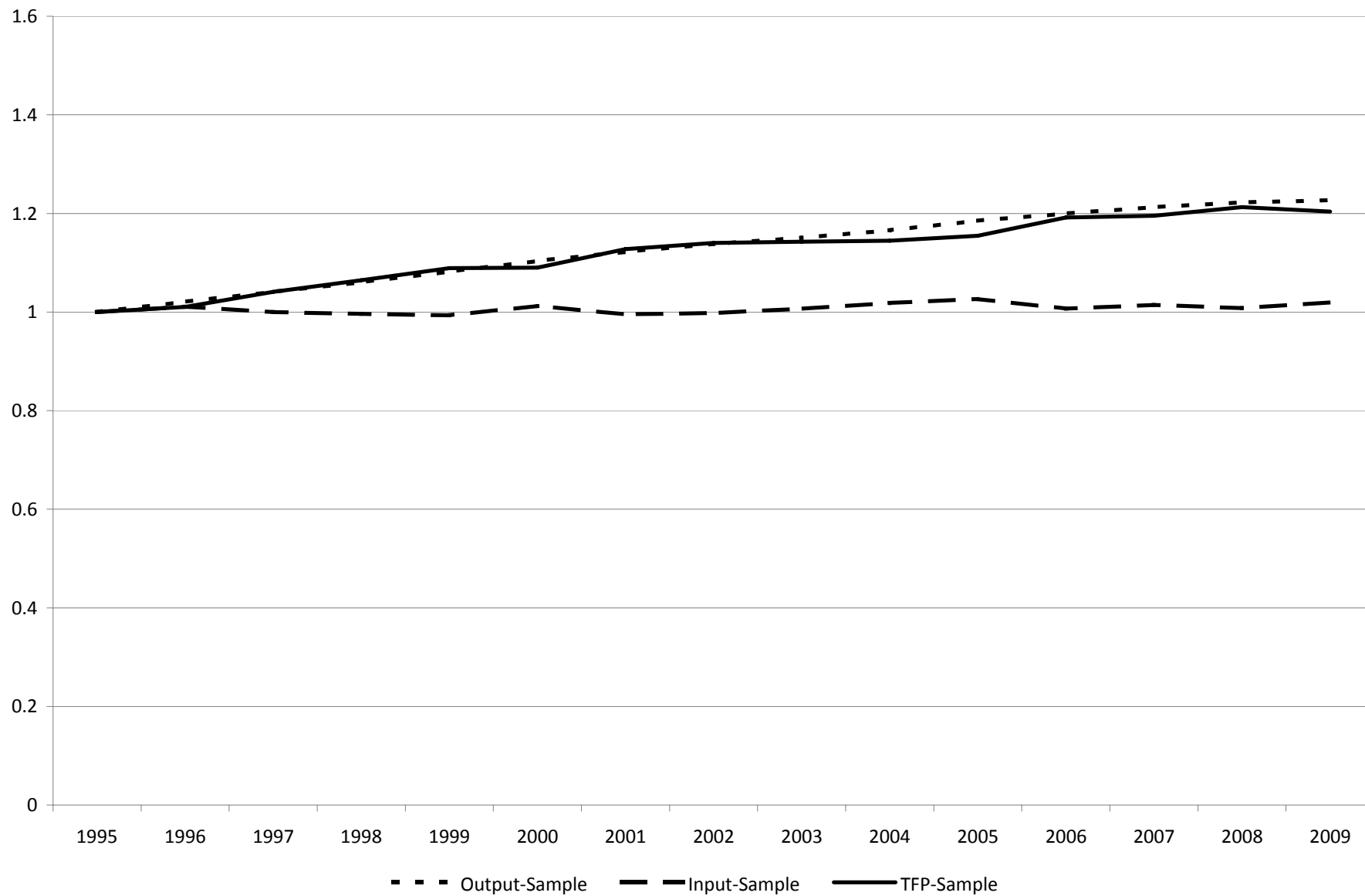
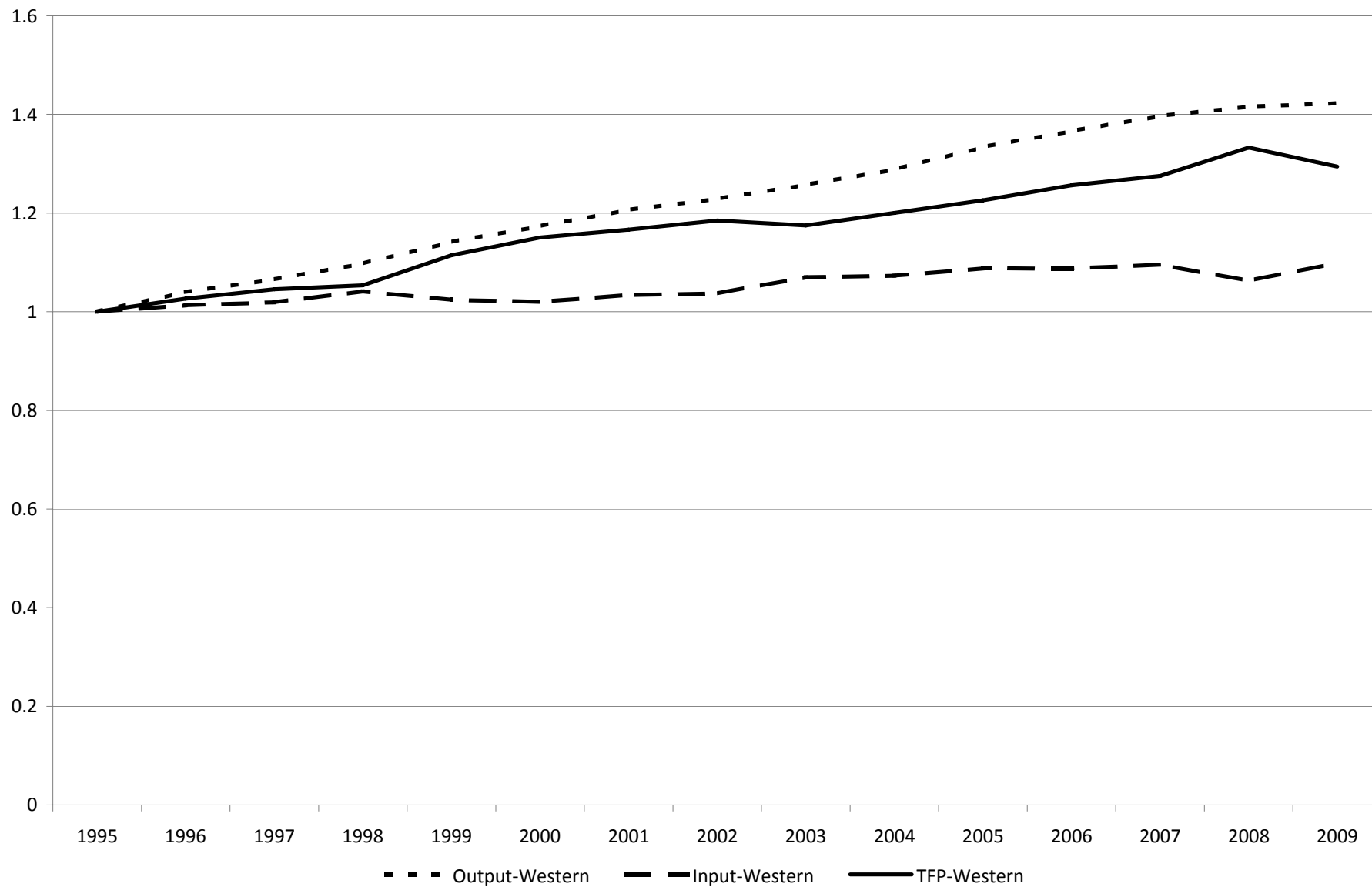


Figure 2
Productivity Results - Western LDCs



business conditions of Alberta gas utilities. The dependent variable is the MFP indexes. The explanatory or business condition variables are indexes of likely MFP growth drivers that are informed by our recent econometric cost modeling for the Gaz Metro Groupe de Travail: the number of gas customers, the number of electric customers, line miles, and a trend variable. We expect MFP growth to be more rapid the more rapid is the growth in gas and electric customers and the slower is the growth in line miles. The trend variable should reflect technological change and have a positive sign. All variables are logged, so that the parameter estimates are also estimates of cost elasticities.

Results of the econometric work can be found in Table 3. It can be seen that all of the business condition variables have sensible elasticity estimates. A 1% increase in the number of gas customers increased MFP by 0.726%. A 1% increase in the number of electric customers increased MFP by 0.128%. A 1% increase in line miles reduces MFP growth by 0.433%. The trend variable parameter estimate reveals that MFP rose by 1.1% annually for reasons not otherwise explained by the model. The adjusted R^2 of the model is 0.433.

To put this model in projection mode, we assume that Alberta gas utilities will experience 2% growth in line kilometers and the number of gas customers over the sample period. There will be no growth in the number of electric customers served. The model then forecasts MFP growth of $1.1\% + 0.726 \times 2\% - 0.433 \times 2\% = 1.686\%$. The AUC and other parties to this proceeding are free to revise this projection using more refined business condition forecasts.

3.5 Results from Other Recent Productivity Studies

3.5.1 NERA Study

Let's consider now how our research results for the CCA compare with those from other recent studies of gas and electric power distributor productivity. We begin with a discussion of the study filed by NERA in this proceeding.¹⁵ The authors calculate the MFP trend of U.S. electric utilities as providers of power distribution services. Expenses for power procurement, generation, transmission, customer accounts, customer service and

¹⁵ Jeff D. Makhholm and Agustin J. Ros, *Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative* (NERA, December 2010).

Table 3

Econometric Model of Gas Distributor MFP Trend

VARIABLE KEY

N = Number Customers
 LM = Line Miles
 NE = Number of Electric Customers
 Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.726	10.61	0.00
LM	-0.433	-5.48	0.00
NE	0.128	3.16	0.00
Trend	0.011	7.63	0.00
Constant	0.576	8.99	0.00
Rbar-Squared	0.433		
Sample Period	1995-2009		
No. of Observations	480		

information, and A&G (including pensions and benefits), which are itemized on the FERC Form 1, were excluded from the study. Taxes were included. Capital cost is measured using a one hoss shay methodology. Output is measured using a revenue-weighted volumetric output index.

Over the full 1973-2009 sample period, NERA reports 0.85% average annual MFP growth.¹⁶ Over the more recent 1999-2009 period, however, NERA reports a 0.99% average annual *decline* in MFP. The authors recommend use of the MFP trend for the full sample period.

We believe that the NERA study has flaws and natural limitations that reduce its suitability for use in the calibration of X factors for energy distributors. The problems with the study contribute to the finding of negative MFP growth in recent years. Here is an itemization of some of the most noteworthy problems with the NERA study which we have identified.

- In the early years of the sample period, the study relied on FERC Form 1 data on the number of employees to measure the labor quantity trend. This approach is unnecessary and probably inadvisable inasmuch as the number of employees is available only for aggregate company operations and may include construction workers. For years after 2001, when the employee data were no longer reported on the FERC Form 1, NERA used the escalation in labor *cost* to measure labor quantity growth.¹⁷ The growth in an input quantity index was shown in relation [4] to equal the growth in cost less the growth of the corresponding input price index. The prices of salaries and wages in the United States grew by around 3% annually on average from 2001 to 2006. Thus, NERA grossly overstated labor quantity growth in the later years of the sample period but not in the earlier years, and this is a major reason for the finding of a recent decline in productivity growth. A sharp run up in the labor quantity after 2001 is visible in Figure 7 on p. 31 of NERA's report. Four of the six years in which NERA's productivity index declined by more than 2% in a year occurred after 2001. Two of these four

¹⁶ NERA calls their MFP index a "total factor" productivity ("TFP") index.

¹⁷ NERA states on p. 9 of its report that "Beginning in 2002, the FERC Form 1 no longer contains employee data. To account for this change, we estimated the number of employees by using the previous year's payroll growth rate for the years 2002 to 2009."

outcomes did not occur in a recession year, whereas the other two large declines in productivity both occurred during recession years (1982 and 2001). We recommend that NERA recalculate the labor quantity by taking the difference between the growth in salaries and wages and the inflation in an appropriate salary and wage price index using relation [4].

- There are several problems with the NERA output specification. The authors use an entirely volumetric output index. As can be seen by an examination of the output data in Table 4 on p. 20 of the report, the volumetric index is quite volatile and falls sharply in recession years, which happen to include the last two years of the sample period. Thus, the desire for a recent sample period end date is at odds with the desire to estimate a long run MFP trend. Removal of the last two years of the sample period would alone raise the estimated MFP growth trend since 1972 to 113 basis points.¹⁸

Another problem with NERA's output treatment is that the authors rely on the FERC Form 1 for their volume data. The volumes reported on the FERC Form 1 are *sales* volumes rather than *delivery* volumes. As such, they produce spurious trends for electric utilities that were restructured to face retail power market competition and lost substantial sales to competing merchants but did not experience corresponding declines in deliveries. Restructuring of the industry commenced in the late 1990s. Data on *deliveries* of power are readily available on Form EIA 861 for years after 1990 and are routinely used by PEG Research in studies where volume data are needed. Using this data source we find, for example, that the decline in the industrial volume of Massachusetts Electric was much less precipitous than that reported in the FERC Form 1. It would be straightforward for NERA to patch FERC Form 1 data for early years of the sample period with Form EIA 861 data for the later years.

Consider also that NERA assigns a weight to the sales volume of each customer class that is based on its share of a utility's *total* sales revenue, which includes a sizable charge for energy procured. NERA reports that this approach produces a 20.51% weight for industrial sales volumes. While revenue share weighting is

usually desirable, a 20.5% share for the industrial volume is far above the typical share of industrial customers in power distribution *base* rate revenues since these customers tend to have high load factors and many take delivery of power directly from the transmission grid. NERA's approach to revenue weighting heightens the effect on measured output growth of the slow growth in industrial deliveries that occurred during the sample period and magnifies the spurious impact on measured output growth of declines in industrial sales volumes due to retail competition. NERA reports in Table 1 on p. 16 of its report that the industrial volume grew much more slowly than the more important residential and commercial volumes during the full sample period.

- NERA uses a one-hoss shay approach to the calculation of the capital cost and quantity. Under this approach, we have noted that the value of an asset does not decline gradually due to depreciation but instead is removed from the rate base abruptly when it is no longer used and useful. As in studies by PEG Research, the authors make a rough estimate of the capital stock in an early benchmark year using the *net* plant value.¹⁹ However, *gross* plant value is consistent with NERA's calculation of capital cost using the one hoss shay specification. Thus, the capital quantity is likely to have been underestimated in the benchmark year. This in principle imparts a downward bias to the measured productivity trend that is most pronounced in the early years of the sample period.
- In common with PEG Research, NERA uses a perpetual inventory approach to construct its capital quantity index. Under this approach, the quantity of capital held in a given year is a function of the size of real plant additions in numerous previous years. This approach requires cumbersome adjustments for large mergers, acquisitions, and transfers of assets between power transmission and distribution. Some of the needed adjustments were apparently not made in the NERA study.
- The authors included income taxes in the cost of capital even though income taxes are Y factored in the ATCO Gas proposal.

¹⁹ Note, however, that net plant value had to be imputed because NERA relied on electronic data.

We have demonstrated that NERA's study has flaws and limitations that reduce its relevance in the determination of X factors for Alberta power distributors. The problems are especially evident in the later years of the sample period. Results for these years should not be used in an Alberta X factor calibration. Absent extensive corrections, the interval of the NERA study that is most worthy of consideration is the 15 year period from 1981 to 1995 period. This is the period before NERA's questionable treatment of delivery volumes and labor quantities becomes material and after the impact of its questionable handling of the benchmark year diminishes. The average MFP growth in NERA's productivity index for this period is 1.43%.

Considering the problems in the NERA study it is remarkable that Dr. Carpenter and Dr. Schoech, in their testimony for ATCO Gas and AltaGas respectively, urged the Commission to focus on the NERA results for the later years of the sample period. Dr. Schoech and Dr. Carpenter responded to data requests from the CCA by saying that they had reviewed the NERA methodology and had no major problems with it. Their speculations as to why power distribution productivity might have declined in recent years and their proposals to rely selectively on NERA's negative productivity results should carry little or no evidentiary weight in the Commission's deliberations on Alberta X Factors.

Notwithstanding the questionable quality of its study of the MFP trend of *power* distributors, NERA nonetheless tenders this study as one that is also satisfactory for determining X factors for Alberta *gas* distributors. We disagree. The AUC noted the following criteria for the productivity study it commissioned from NERA.

The MFP study must

- Be applicable to Alberta gas and electric utilities;
- Compare productivity for gas and electric utilities to economy wide productivity;
- Make the comparison in a transparent manner;
- Use publicly available data;
- Be for use and testing in a regulatory proceeding and for adjusting rates for Alberta gas and electric utilities;

We believe that our study for the CCA does a better job of meeting the Commission's criteria for the development of gas distributor X factors.



- It measures the productivity trends of gas distributors rather than power distributors. This matters, since research has found that the productivity growth of gas distributors is generally more rapid than that of power distributors. The productivity trends of gas distributors tend to be especially high in rapid-growth service territories such as those found in Alberta. NERA reports that, from 1972 to 2006, the trends in the Statistics Canada MFP Indexes for the electricity and gas & water utility industries (discussed further below) are quite similar. While this is true, this particular sample period was unusual for having similar trends. For both longer and shorter sample periods, the gas & water MFP growth trend is materially more rapid than that for electric utilities.
- Our methodology is transparent and sensible and the code for the calculations is available for inspection.
- Most of the data used in our study are publicly available, including all of the data on O&M expenses, plant additions, outputs, and input prices during the 1996-2009 sample period. The older capital data are not publicly available, but were all obtained from a standardized form (the Uniform Statistical Report of the American Gas Association) and are available for scrutiny by participants in this proceeding who sign a confidentiality agreement.
- Our study is tailored to the development of revenue per customer indexes such as those proposed by Alberta gas utilities. We also consider the effect of rapid customer growth that is expected in Alberta on gas distributor productivity. Moreover, our research considers the implications for X factors of Y factoring a substantial portion of capex cost.
- NERA's rationale for not undertaking a gas productivity study seems to hinge on the fact that gas distributor data are unavailable for a "broad population of industry participants". Our study is based on data for 34 gas distributors. NERA states that it has previously presented productivity research in testimony to support X factors twice over the



years. In one case it proposed an X factor for Central Maine Power based on a study of the productivity trends of 25 Northeast power distributors. In the other, it proposed an X factor for UtiliCorp Networks Canada (d/b/a FortisAlberta) based on a study of the productivity trends of 12 power distributors in the western US.

3.5.2 Other Recent Studies

Here is a summary of some other recent energy distributor productivity studies we are aware of.

- In 2008, PEG Research prepared a study for the Ontario Energy Board on the MFP trends of U.S. power distributors. The study was used to calibrate the X factors in price cap plans for Ontario power distributors. An elasticity-weighted output index and a GD approach to capital costing were employed in the study. Over the 1989-2006 period, a 0.72% average annual MFP growth rate was reported.²⁰
- In 2010, PEG Research filed testimony in California on the recent MFP trends of US gas and electric power distributors.²¹ The work was done on behalf of two large Sempra Energy utilities: San Diego Gas & Electric and Southern California Gas. The research used the number of customers as the output quantity index and the GD approach to the calculation of capital cost. In the 1999-2008 period, a 1.18% average annual MFP growth rate was found for gas distributors and a 0.88% average annual MFP growth rate for power distributors. Thomas Renaghan, a productivity expert at the California Public Utilities Commission, replicated these results in recent testimony.²²
- In 2011, PEG Research released a report on a study of the recent MFP trends of two large Ontario gas distributors: Enbridge Gas Distribution and Union Gas.

²⁰ Kaufmann, L., *et al* (2008), *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, Report Prepared for the Ontario Energy Board, February 2008.

²¹ See, for example, the report of Mark Newton Lowry and David Hovde, "Productivity Research for San Diego Gas & Electric", in Docket A.10-12-005/006, December 2010.

²² See report of Tom Renaghan, "SDG&E and SoCalGas Total Factor Productivity Study" in A.10-12-005/006, September 2011. Mr. Renaghan states on page 2 of his report that "Based on DRA's replication of PEG's power and gas distribution TFP results and DRA's alternative output scenarios for the electric sector, DRA concludes that PEG's TFP results are reasonable".



The report was prepared for the Ontario Energy Board. The study used an elasticity-weighted output index and the COS approach to capital costing. In the 2006-2010 period, a 1.07% average annual MFP growth rate was found for EGD and a 1.65% average annual growth rate for Union Gas.²³

- Also in 2011, PEG Research released a report on a study of the recent MFP trend of Gaz Metro. The report was prepared for a Gaz Metro Groupe de Travail to aid it in the development of a new PBR plan. The study featured an elasticity-weighted output index and the COS approach to capital costing. In the 2000-2009 period, a 1.66% average annual MFP growth rate was reported.²⁴
- Also in 2011, PEG Research has filed testimony for three US power distributors on the MFP trend of power distributors in the Northeast US.²⁵ The study used the number of customers to measure output and a COS approach to capital costing. Over the 1999-2010 period, a 0.64% average annual MFP growth rate was reported.
- Statistics Canada maintains MFP indexes for the utility sector of the Canadian economy and two subsectors: “Electric power generation, transmission, and distribution” and “natural gas distribution, water, and other systems”. All three indexes are available on both a “gross output” and a “value added” basis. The gross output approach is most similar to that conventionally used in productivity studies for X factor calibration because it includes intermediate inputs like materials and services. The value added approach does not, and is intended for use in the calculation of the MFP growth of the Canadian aggregate business sector.²⁶ Only results for the value added utility MFP index are reported on a timely basis. Over the full sample period, from 1962-2010, this index has exhibited a 0.67 % average annual growth rate. Over the last twenty years, from

²³ Lawrence Kaufmann, *et al* (2011), *Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans*, Report Prepared for the Ontario Energy Board, September 2011.

²⁴ Mark Newton Lowry and David Hovde (2011), *Research for Gaz Metro's Performance Incentive Mechanism*, Report Prepared for the Gaz Metro Groupe de Travail in R-3693-2009.

²⁵ See, for example, the testimony of Mark Newton Lowry on behalf of Atlantic City Electric in New Jersey, Docket Number E011100650.

²⁶ It is difficult to use macroeconomic data to compute the MFP of the aggregate private business sector if intermediate inputs are included.

1981 to 2010, the value-added utility MFP index has averaged 0.34% average annual growth. Over the last ten years, from 2001 to 2010, this index has averaged a 0.98% average annual decline.

The results of the value-added utility MFP index are featured in the testimony of witnesses Carpenter and Schoech but are of limited relevance in setting X factors for Alberta energy distributors, for several reasons.

- It is a value-added calculation. As such, it ignores productivity in the use of intermediate inputs and is sensitive to the quality of data available on intermediate inputs.
- It is sensitive to developments in the generation sector of the electric utility industry. This has very little relevance to network industries such as gas and electric power distribution. For example, the growth in the index is slowed by Hydro Quebec projects to develop remote hydroelectric resources.
- The electric utility industry restructured in Alberta and Ontario in the last decade. It is not clear how well this has been handled by Statistics Canada.
- A volumetric output index is employed. This makes results sensitive to changing business conditions including, particularly, recessions and slowing growth in average use. Measured output fell substantially in 2008, 2009, and 2010. A very long sample period such as NERA has proposed would be necessary to smooth over the effects of this extraordinary decline.
- Measured productivity growth is doubtless slowed by growth in expenses for utility DSM programs, which are large in several Canadian provinces. Measured productivity growth may also have been slowed by a rising trend in uncollectible bills.
- Given all of the circumstances surrounding the recent decline in the index, it would certainly not make sense to combine a 2010 (or 2009) end date with a relatively recent start date such as 2000 if the long term MFP trend of the utility sector is of interest. In the ten years ending in 2007, the last year

before the recession, the value added utility MFP index averaged 1.17% annual growth.²⁷

The Statistics Canada MFP indexes for “electric power generation, transmission, and distribution” and “natural gas distribution, water, and other systems” are published, with a lag, on both a gross value and a value added basis. They are currently available only through 2007. Using the more relevant gross output approach, Statistics Canada reports a 1.13% average annual growth rate in gas and water sector productivity for the full 1962-2007 period. For the most recent 20 years, the productivity trend is 1.56%. For the most recent ten years (1998-2007), the productivity trend is 2.83%. These numbers are remarkably high when it is considered that output is measured volumetrically, and thereby reflects the material decline in average use of gas by Canadian residential and commercial customers that has been underway for many years. Statistics Canada assigns letter grades to the quality of the data on intermediate inputs it uses in its productivity work. They assign an A grade to the gas and water data.

- As for the MFP index for the “electric power generation, transmission, and distribution”, the relevance of this index to the establishment of X factors for energy distributors is questionable. Using the gross output approach, Statistics Canada reports a 0.79% average annual growth rate in utility sector productivity for the full 1962-2007 period. For the most recent 20 years (1988-2007), the productivity trend is 0.15%. For the most recent ten years (1998-2007), the productivity trend is 0.31%. Statistics Canada assigns a C grade to the electric power data on intermediate inputs.
- The Center for the Study of Living Standards (“CSLS”) retained Statistics Canada to prepare a study of productivity trends at the provincial level. A report on the research was released in 2010.²⁸ This study reported results only for value added MFP indexes. After extensive correspondence between PEG Research and

²⁷ Using the accurate *gross output* approach, Statistics Canada reports a 0.91% average annual growth rate in utility sector productivity for the full 1962-2007 period. For the most recent 20 years, the productivity trend is 0.44%. For the most recent ten years (1998-2007), the productivity trend is 0.86%.

²⁸ CSLS, *New Estimates of Labor, Capital, and Multifactor Productivity Growth and Levels for Canadian Provinces at the Three Digit NAICS Level 1997-2007*.

principles of this study, the principles conceded that the study used an experimental methodology and is not of a high enough standard to be used in X factor determination.

3.5.3 Conclusions

Our review of recent productivity studies suggests that vigorous growth in the MFP of natural gas distributors has been the norm for both the U.S. and Canada in the last fifteen years. The NERA result of declining power distribution productivity in the last decade is anomalous, and reflects flaws and limitations of the research methodology. The Canadian utility MFP index that is highlighted in the testimony of other witness is of questionable relevance. It includes power generation and DSM costs and uses a volumetric output index that is highly sensitive to the recessionary conditions at the end of the sample period. A 2007 end date for the sample period produces a better estimate of the long-run MFP trend and produces results that are quite different.

The best available estimate of the *recent* MFP growth trend of U.S. power distributors is probably that presented by PEG Research in California testimony and confirmed by an expert for the Division of Ratepayer Advocates. This places a *lower* bound on the productivity trend that is pertinent for the design of *price* cap indexes because it is based on customer growth and thereby ignores the (modest) growth in the average use of power by small-volume customers that was typical during this period. For electric utilities that, like ATCO Electric, have high customer charges the use of the number of customers as the output measure is, in any event, fairly appropriate. Should the Commission nonetheless wish to base the X factors for Alberta power distributors on the NERA research, the 1.45% growth trend for the 1981-95 period is recommended.

We conclude that the base productivity factor for ATCO Gas and AltaGas should exceed 100 basis points. Specifically, we propose that it lie in the [1.32% - 1.69%] range that is bounded by the average industry MFP trend and our customized econometric productivity projection. Should the Commission sanction recovery of the costs of certain routine capital expenditures outside the indexing mechanism, a higher base productivity factor may be warranted.



3.6 Stretch Factor

The stretch factor term of the X factor was noted in Chapter 2 to facilitate the sharing, between utilities and customers, of any benefits that are expected to result from the stronger performance incentives that are generated by an IR plan. We have relied on three sources in developing our stretch factor recommendation. One is historical precedent. The average explicit stretch factor approved for rate and revenue indexing plans of energy utilities with rate escalation mechanisms informed by productivity research is about 0.50%.

Our second substantive basis for proposing stretch factors is our incentive power research. We have developed an incentive power model that estimates the typical cost performance improvements that will be achieved by utilities under stylized regulatory systems. The use of numerical analysis permits us to consider regulatory systems of considerable relevance. Clients who have supported the development of this model have included the Ontario Energy Board and US and Canadian gas distributors.

Alberta energy distributors have been operating for several years under a two year rate case cycle. There is no earnings sharing mechanism. Suppose, now, that this is replaced with a regulatory system with a five year rate case cycle and an ESM that shares surplus and deficit earnings 75/25 between the utility and its customers. Our incentive power model suggests that the typical annual cost performance gain in the long run is 0.66% under the current system and 1.17% under the new system, a gain of 51 basis points.²⁹

Based on our experience, we believe that gas distributors in our U.S. sample held rate cases about every three years on average during the sample period we used to calculate MFP trends. Earnings sharing mechanisms were uncommon. Our incentive power model suggests that the typical cost performance gain in the long run is 0.90% under this system. Using industry average productivity growth to set the base X factor thus guarantees customers the first 24 basis points of expected productivity gains under the PBR plan. The stretch factor can be used to divide the remaining 27 basis points between the utility and customers. A stretch factor equal to *all* of the incremental acceleration in annual performance improvement is 27 basis points. A stretch factor equal to half of the

²⁹ This model has not been calibrated to reflect the latest productivity research results. However, comparisons between regulatory systems should still be meaningful.

incremental performance gains is about 13 basis points. We have traditionally advocated an equal sharing of such accelerations.

A final consideration in determining stretch factors for Alberta gas utilities is the *level* of efficiency that the Companies have already achieved. Recall from our discussion in Section 2.1 that a high level of initial efficiency reduces prospects for reductions in X-inefficiency. This is an empirical issue, and neither company has to our knowledge filed a rigorous and persuasive appraisal of its operating efficiency. However, it is noteworthy that both Companies have been filing rate cases every two years for some time. This is a regulatory system with weak incentive properties.

Dr. Carpenter presents several flawed arguments as to why ATCO Gas should have no stretch factor. He states that a stretch factor is unnecessary for an “average” utility “which has been operating under a traditional regulatory framework with significant incentives for improving productivity”. But the ATCO companies have in fact been filing frequent rate cases for many years. This is likely to have undermined the companies’ incentives for cost containment. Dr. Carpenter also argues against a stretch factor on the grounds that it would constitute asymmetric sharing. We believe that the ATCO Gas proposal would assign to the company most of the expected productivity gains since there would be no stretch factor and a wide dead band in the earning sharing mechanism.

Dr. Schoech provides some novel explanations as to why his client should have a zero stretch factor. The service territory is “unique” and the company is small and has a low ratio of customers to pipeline kilometers. As Dr. Schoech has not considered any gas productivity research in his testimony, there is no substantiation for the notion that any of these conditions slow potential productivity growth, rather than accelerating it.

All things considered, we believe that the indicated range of potential stretch factors is [0.13-0.50].

3.7 Input Price Research

3.7.1 Macroeconomic Price Indexes

We noted in Section 2.2.4 that macroeconomic output price indexes pose fewer complications in the design of an attrition relief measure in Canada than they do in the United States. The chief reason is that the productivity trend of the Canadian economy is



close to zero. Macroeconomic price indexes also merit consideration as a subindex in an industry-specific input price index.

Table 4 shows the trends in seven macroeconomic output price indexes that are sensible candidates for use in Alberta. Here are the indexes with a brief discussion of noteworthy features.

- The CPI for Canada is the inflation measure most familiar to Canadian consumers. This type of inflation measure is the norm in British and Australian PBR. It is less common in North American PBR because it places a fairly heavy weight on price-volatile consumer commodities like gasoline, natural gas, and food. These commodities make the CPI more volatile and have much more impact on the budget of a typical consumer than they do on the cost of an energy distributor's base rate inputs. CPIs also have the disadvantage of not being revised.
- The CPI for Alberta ("CPI^{Alberta}") has the drawbacks just noted for the CPI but has material advantage of being specific to the province. It should therefore be more sensitive to local business conditions than the national CPI. It is forecasted annually by Alberta Finance in its annual Economic Outlook.
- The core CPI (CPI^{core}) excludes inflation in the prices of price-volatile commodities such as gasoline and food. It is available for Canada but not for Alberta.
- GDPIs track inflation in the prices of capital equipment and net exports as well as consumer products. They are periodically updated, and are available for Alberta as well as Canada. In the United States, a gross domestic product price index has been preferred over the CPI in PBR plans because the impact of price-volatile consumer commodities is watered down. However, in Canada's economy with its sizable reliance on natural resource exports, this stabilizing benefit is offset by the impact of incorporating inflation in commodity exports.
- The GDPIs for final domestic demand (GDPI^{FDD}) remove the inflation impact of price volatile exports. They are available for Alberta as well as Canada.

Table 4

Macroeconomic Inflation Measures for Alberta and Canada

Canada									Alberta						
CPI (all items) ¹			Core CPI ^{1 2}		Gross Domestic Product Implicit Price Indexes ³				CPI (all items) ¹		Gross Domestic Product Implicit Price Indexes ³				
					Comprehensive		Final Domestic Demand				Comprehensive		Final Domestic Demand		
Year	Level	Growth Rate ⁴	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	
1980	44.0								44.1						
1981	49.5	11.8%			55.7		53.6		49.8	12.2%			55.6		
1982	54.9	10.4%			60.4	8.1%	58.7	9.1%	55.4	10.7%	71.6	9.5%	60.7	8.8%	
1983	58.1	5.7%			63.7	5.3%	61.9	5.3%	58.3	5.1%	74.4	3.8%	63.3	4.2%	
1984	60.6	4.2%	62.9		65.8	3.2%	64.4	4.0%	59.8	2.5%	76.2	2.4%	64.8	2.3%	
1985	63.0	3.9%	65.1	3.4%	67.8	3.0%	66.7	3.5%	61.6	3.0%	75.6	-0.8%	66.5	2.6%	
1986	65.6	4.0%	68.0	4.4%	69.9	3.1%	69.2	3.7%	63.7	3.4%	67.1	-11.9%	68.4	2.8%	
1987	68.5	4.3%	71.0	4.3%	73.1	4.5%	72.0	4.0%	66.3	4.0%	68.2	1.6%	70.2	2.6%	
1988	71.2	3.9%	74.0	4.1%	76.4	4.4%	74.7	3.7%	68.1	2.7%	67.2	-1.5%	72.2	2.8%	
1989	74.8	4.9%	77.2	4.2%	79.8	4.4%	77.9	4.2%	70.9	4.0%	69.8	3.8%	75.0	3.8%	
1990	78.4	4.7%	79.8	3.3%	82.4	3.2%	80.9	3.8%	75.0	5.6%	74.2	6.1%	78.4	4.4%	
1991	82.8	5.5%	82.1	2.8%	84.8	2.9%	83.7	3.4%	79.4	5.7%	73.5	-0.9%	80.9	3.1%	
1992	84.0	1.4%	83.6	1.8%	85.9	1.3%	85.1	1.7%	80.6	1.5%	74.9	1.9%	82.6	2.1%	
1993	85.6	1.9%	85.3	2.0%	87.2	1.5%	86.8	2.0%	81.4	1.0%	75.7	1.1%	84.1	1.8%	
1994	85.7	0.1%	86.9	1.9%	88.2	1.1%	88.1	1.5%	82.6	1.5%	77.3	2.1%	85.9	2.1%	
1995	87.6	2.2%	88.8	2.2%	90.2	2.2%	89.2	1.2%	84.5	2.3%	78.3	1.3%	86.7	0.9%	
1996	88.9	1.5%	90.3	1.7%	91.6	1.5%	90.2	1.1%	86.4	2.2%	82.3	5.0%	88.3	1.8%	
1997	90.4	1.7%	92.0	1.9%	92.7	1.2%	91.5	1.4%	88.1	1.9%	83.6	1.6%	90.5	2.5%	
1998	91.3	1.0%	93.2	1.3%	92.3	-0.4%	92.7	1.3%	89.2	1.2%	79.7	-4.8%	91.9	1.5%	
1999	92.9	1.7%	94.5	1.4%	93.9	1.7%	93.9	1.3%	91.4	2.4%	85.7	7.3%	93.3	1.5%	
2000	95.4	2.7%	95.7	1.3%	97.8	4.1%	96.1	2.3%	94.5	3.3%	99.9	15.3%	95.6	2.4%	
2001	97.8	2.5%	97.7	2.1%	98.9	1.1%	97.8	1.8%	96.7	2.3%	102.6	2.7%	97.4	1.9%	
2002	100.0	2.2%	100.0	2.3%	100.0	1.1%	100.0	2.2%	100.0	3.4%	100.0	-2.6%	100.0	2.6%	
2003	102.8	2.8%	102.2	2.2%	103.3	3.2%	101.5	1.5%	104.4	4.3%	109.5	9.1%	100.9	0.9%	
2004	104.7	1.8%	103.8	1.6%	106.6	3.1%	103.2	1.7%	105.9	1.4%	116.0	5.8%	103.0	2.1%	
2005	107.0	2.2%	105.5	1.6%	110.1	3.2%	105.5	2.2%	108.1	2.1%	128.6	10.3%	106.0	2.9%	
2006	109.1	1.9%	107.5	1.9%	113.0	2.6%	107.9	2.2%	112.3	3.8%	132.1	2.7%	111.1	4.7%	
2007	111.5	2.2%	109.8	2.1%	116.7	3.2%	110.4	2.3%	117.9	4.9%	139.0	5.1%	116.1	4.4%	
2008	114.1	2.3%	111.7	1.7%	121.4	3.9%	112.9	2.2%	121.6	3.1%	155.5	11.2%	120.1	3.4%	
2009	114.4	0.3%	113.6	1.7%	119.1	-1.9%	114.6	1.5%	121.5	-0.1%	135.7	-13.6%	121.3	1.0%	
2010	116.5	1.8%	115.6	1.7%	122.6	2.9%	116.0	1.2%	122.7	1.0%	143.8	5.8%	122.3	0.8%	
Average Annual Growth Rates															
1988-2007		2.44%	2.18%		2.34%		2.14%		2.88%		3.56%		2.52%		
1998-2007		2.10%	1.77%		2.30%		1.88%		2.91%		5.08%		2.49%		
1981-2010		3.25%	2.34%		2.72%		2.66%		3.41%		2.73%		2.72%		
1991-2010		1.98%	1.85%		1.99%		1.80%		2.46%		3.31%		2.22%		
2001-2010		2.00%	1.89%		2.26%		1.88%		2.61%		3.64%		2.46%		
Standard Deviation															
1985-2010		1.38%	0.37%		1.47%		0.56%		1.44%		6.26%		1.08%		

Footnotes

¹ Statistics Canada. Table 326-0021 - Consumer Price Index (CPI), 2005 basket, annual (2002=100 unless otherwise noted) (table)

² The Core CPI excludes volatile components of the all items CPI: fruit, fruit preparations and nuts; vegetables and vegetable preparations; mortgage interest cost; natural gas; fuel oil and other fuels; gasoline; inter-city transportation; and tobacco

³ Statistics Canada. Table 384-0036 - Implicit price indexes, gross domestic product (GDP), provincial economic accounts, annual (index, 2002=100)

⁴ All growth rates are calculated logarithmically.

Inspecting the numbers in Table 4, it can be seen that these indexes vary considerably in their volatility, which is measured in the last row of the table by the standard deviation of their growth rates. The CPIs and GDPIPIs for Canada and Alberta are much more volatile than the core CPI or the GDPIPIs for final domestic demand in Canada and Alberta. In 2009, for instance, the CPI (all items) for Canada and Alberta grew only 0.3% and -0.1%, and the GDPIPI for Canada and Alberta *fell* by 1.9% and 13.6%. In the same year, the core CPI grew by 1.7% and the GDPIPI^{FDD} for Canada and Alberta grew by 1.5% and 1.00%, respectively. The longer-term trends in Canada's core CPI and the GDPIPI^{FDD} are quite similar.

Comparisons between the Alberta and Canadian price indexes are also instructive. For both the CPI and the GDPIPI^{FDD}, inflation in Alberta was substantially above the Canadian norm in several years (*e.g.* 2006, 2007, and 2008) and quite a bit slower in other years (*e.g.* 1984). Note also that since 1980 inflation has tended to be modestly more rapid in Alberta than in Canada using both indexes.

Should the AUC wish to use a macroeconomic output price index as the inflation measure, we recommend on the basis of this review that it use either the CPI^{Alberta} or the GDPIPI^{FDD} for Alberta. Both of these indexes are also suitable for use as an input price subindex.

3.7.2 Custom Input Price Indexes

Suppose, now, that the AUC instead prefers a custom utility input price index as PBR inflation measure. ATCO Gas and AltaGas have each proposed simple indexes of this kind. Each averages the estimated inflation in price subindexes for two classes of inputs: labor and other. The proposed price subindex for labor is in each plan the Average Weekly Earnings ("AWE") for the Industrial Aggregate in Alberta. The proposed subindex for other inputs is CPI^{Alberta}. Both companies propose weights for the labor price that far exceed the share of direct salaries and wage expenses in the total annual cost that would be subject to recovery via the revenue per customer index. ATCO Gas, for example, proposes a labor cost share of 57%. They arrive at this share by adding to the share of direct salaries and wages the estimated share of labor in capex.

Table 5 presents alternative indexes of salary and wage prices that are available for an industry-specific input price index. The fixed weight index of the average hourly earnings (“AHE”) of all employees in Alberta have the advantage of being expressly designed to measure labor price *trends*. The average weekly earnings (AWE) for Alberta is not and is therefore prone to aggregation bias. The AWE covers a somewhat broader range of workers (*e.g.* those whose basic remuneration is not in the form of a wage rate or a salary but rather an alternative such as commissions and piece rates) and is forecasted by Alberta Finance.

Comparing the results in Tables 4 and 5, it can be seen that the inflation in all of the labor price indexes tends to rise considerably more rapidly than the CPI in Alberta and Canada as a whole. From 2001-2010, for instance, the AWE averaged 4.0% annual growth whereas the CPI^{Alberta} averaged only 2.61% annual growth. Each company therefore benefits from having a large labor cost share in its inflation measure, and a proposal for a share that is much larger than the share of direct labor in their total applicable cost is a good area for scrutiny.

We advise the Commission to reject the proposed labor price weighting of ATCO Gas and instead assign a labor price weighting that is commensurate only with the share of direct labor costs in the total costs that are subject to indexing. We tender this advice for three reasons. One is that under regulatory accounting capital cost is, as we discuss in Section 2.1.4, a function of construction prices over many years and not only of the construction price in the current year. Thus, insofar as labor prices affect the cost of capital, it is the trend in the prices over many years that is relevant and not the current price.

Another reason for rejecting the Company’s proposed weighting is that they propose to apply CPI^{Alberta} to a collection of costs that comprises materials, services, and non-labor capex. We believe that the underlying technology for the provision of consumer products is considerably more labor intensive than the underlying technology for the provision of the inputs in this residual input basket.³⁰ The Statistics Canada MFP index for the aggregate business sector, for instance, has a cost share weight for labor that is four times the weight for capital. Given the tendency of labor prices to growth more rapidly than the prices of other inputs, and the slight decline in the MFP growth for the private business sector, we

Table 5

Salary and Wage Price Indexes for Alberta and Canada

Year	Fixed weighted index of average hourly earnings (AHE) for all employees ^{1 2}								Average weekly earnings (AWE) for all employees (Industrial aggregate excluding unclassified businesses) ^{2 3}				Composite construction union wage rate index ⁴		
	Canada				Alberta				Canada		Alberta		Canada	Calgary	Edmonton
	Industrial Aggregate	Growth Rate	Utilities	Growth Rate	Industrial Aggregate	Growth Rate	Utilities	Growth Rate	Level	Growth Rate	Level	Growth Rate			
1981													39.98	40.13	40.43
1982													43.73	44.47	44.97
1983													49.21	50.51	50.96
1984													51.00	52.10	52.80
1985													52.23	52.23	52.87
1986													53.72	52.01	52.65
1987													55.17	52.05	51.64
1988													57.21	52.22	51.72
1989													59.91	52.96	52.41
1990													63.20	56.48	56.07
1991	82.03		67.29		78.84		73.98		553.15		545.19		66.98	59.34	59.28
1992	84.74	3.25%	70.06	4.03%	80.45	2.02%	77.98	5.27%	572.41	3.42%	561.55	2.96%	70.07	63.45	62.97
1993	86.44	1.99%	72.28	3.12%	82.45	2.46%	79.51	1.94%	582.87	1.81%	570.68	1.61%	71.72	65.74	64.62
1994	87.63	1.36%	73.11	1.15%	82.51	0.07%	79.87	0.45%	592.88	1.70%	573.63	0.52%	73.19	66.73	65.43
1995	89.62	2.25%	74.44	1.81%	83.08	0.69%	80.94	1.34%	598.67	0.97%	572.49	-0.20%	74.57	67.37	67.05
1996	91.74	2.34%	75.79	1.80%	87.21	4.85%	81.66	0.88%	611.01	2.04%	596.81	4.16%	75.27	67.50	67.60
1997	92.29	0.60%	77.63	2.39%	88.96	1.99%	82.78	1.36%	623.43	2.01%	618.23	3.53%	76.80	68.66	69.12
1998	93.80	1.62%	80.82	4.03%	92.18	3.55%	87.18	5.18%	632.72	1.48%	635.01	2.68%	78.38	71.42	72.23
1999	94.85	1.11%	86.17	6.41%	94.78	2.79%	90.91	4.19%	640.47	1.22%	644.07	1.42%	79.74	74.66	75.35
2000	96.78	2.01%	88.79	3.00%	96.56	1.86%	95.84	5.28%	655.55	2.33%	663.09	2.91%	81.77	79.32	80.02
2001	98.05	1.31%	94.93	6.68%	98.96	2.46%	93.45	-2.53%	657.01	0.22%	676.66	2.03%	83.79	83.33	83.81
2002	100.18	2.15%	99.91	5.12%	100.20	1.25%	100.06	6.83%	672.85	2.38%	694.05	2.54%	87.02	88.43	89.30
2003	103.13	2.90%	105.13	5.10%	104.75	4.44%	104.19	4.05%	690.87	2.64%	718.3	3.43%	89.28	91.08	92.10
2004	105.91	2.66%	107.00	1.76%	107.87	2.93%	106.28	1.99%	709.37	2.64%	742.37	3.30%	91.38	92.73	93.53
2005	109.24	3.10%	108.94	1.80%	112.16	3.90%	111.75	5.02%	737.39	3.87%	785.01	5.58%	94.09	94.61	94.90
2006	112.10	2.58%	111.23	2.07%	117.23	4.42%	116.57	4.22%	755.53	2.43%	824.07	4.86%	97.03	96.67	96.38
2007	117.25	4.49%	117.40	5.40%	124.18	5.77%	132.05	12.47%	788.18	4.23%	872.61	5.72%	100.03	100.01	100.01
2008	121.34	3.43%	118.94	1.30%	132.16	6.22%	137.61	4.12%	810.96	2.85%	924.39	5.76%	104.90	107.63	108.67
2009	125.03	3.00%	125.78	5.59%	136.40	3.16%	144.08	4.60%	823.88	1.58%	950.06	2.74%	109.20	113.82	114.92
2010	128.78	2.95%	129.78	3.13%	139.88	2.52%	139.76	-3.05%	853.19	3.50%	993.28	4.45%	112.23	120.33	121.49
Average Annual Growth Rates															
1992-2010		2.4%		3.5%		3.0%		3.3%		2.3%		3.2%	1982-2010	3.6%	3.8%
2001-2010		2.9%		3.8%		3.7%		3.8%		2.6%		4.0%	1991-2010	2.9%	3.9%

Footnotes

¹ Statistics Canada. Table 281-0039 - Fixed weighted index of average hourly earnings for all employees (SEPH), excluding overtime, unadjusted for seasonal variation. Available for selected industries classified using the North American Industry Classification System (NAICS), monthly (index, 2002=100)

² Industrial aggregate covers all industrial sectors except those primarily involved in agriculture, fishing and trapping, private household services, religious organisations, and the military personnel of the defence services.

³ Statistics Canada. Table 281-0027 - Average weekly earnings (SEPH), unadjusted for seasonal variation. Available by type of employee for selected industries classified using the North American Industry Classification System (NAICS), annual (current dollars)

⁴ Statistics Canada. Table 327-0045 - Construction union wage rate indexes, monthly (index, 2007=100)

expect that $CPI^{Alberta}$ will tend to overestimate the input price inflation of the residual cost group to which it would be applied. The $CPI^{Alberta}$ is a better match for an input group that includes all capital cost.

A third reason for rejecting the proposed approach is that the labor cost share calculation is erroneous. The total annual cost that would be subject to recovery via the revenue per customer index is not even used as the denominator in the cost share calculations. Instead they use the sum of O&M expenses and *capex*.

The Commission has stated an interest in a PBR plan that resembles the one it approved for Enmax. That plan features an inflation measure that included the annual growth rate of an electric utility construction price index (“EUCPI”). Should the Commission wish to include the EUCPI or another construction price index in the inflation measures of Alberta energy utilities, we would recommend as an alternative to this a custom index that itemizes trends in the prices of three groups of base rate inputs: labor, materials & services, and capital. Each of the three input groups would have its own subindex. The weight for each subindex would be the share of the input group in the total cost of the subject utility that will be subject to indexing.³¹ In the case of ATCO Gas, for instance, the applicable total cost used to calculate cost shares would exclude costs for pensions and income taxes. The cost shares can be drawn from each company’s pro forma cost of service in the latest year for which the company has provided rate case evidence. These can be reset when the PBR plan is updated.

With respect to the inflation subindexes, we recommend the use of the $CPI^{Alberta}$ or the $GDPI^{FDD}$ for Alberta as the proxy for the M&S input price index and the Alberta AHE or AWE for the labor price index. With respect to the capital price subindex, we noted in Section 2.2.4 that a service price approach to the design of this index is consistent with the approach taken to the measurement of the capital quantity in the productivity research. The design of a capital service price should reflect the components of capital cost. Capital cost can be calculated in different ways but commonly includes depreciation and a return on the rate base. The trends in depreciation and the return on rate base both depend on the trend in the cost of constructing a unit of plant. The return on rate base depends, additionally, on the trend in the rate of return on capital.

³¹ The average shares of a group of Alberta utilities is a reasonable alternative.

The different approaches to measuring capital cost differ with respect to their relevance for utility regulation and the volatility of the capital service price. The use of the current inflation in the construction price index in the capital service price is consistent with the assumption of a current valuation of capital. This approach differs materially from capital costing under cost of service regulation and produces capital prices (and costs) that can be quite volatile.

The alternative COS approach to measuring the capital price is much more stable and more consistent with utility regulatory accounting. The COS approach to capital costing is discussed in more detail in Appendix 2. We are interested here in the lessons of this analysis for the design of reasonably simple capital price index for use in rate escalation mechanisms in Alberta. Two lessons are salient. One is that capital cost depends on the rate of return on capital in addition to construction prices. The other lesson is that capital cost depends on a *weighted average* of past construction prices and not solely on current prices. This is noteworthy, since a weighted average of current construction prices tends to be much more stable than the current construction price.

With respect to the first lesson, we recommend that a capital price used to construct a custom input price index for Alberta PBR plans be the product of a rate of return on capital and a construction price index. The rate of return on capital can be set initially at the weighted average cost of capital established for the subject utility in its most recent rate case. It can subsequently be indexed to the trends in one or more rates of return on capital assets observed in Canadian markets. Statistics Canada tracks the trends in corporate and government long term bond yields and in the return on equity of businesses in the utility industry and all industries. With respect to the second lesson, we recommend taking a weighted average of the current and past values of an available construction price index.³²

³² A “triangularized” weighting of past values of such an index would be a one sensible simplification. This approach begins by adding up a sequence of numbers between one and a certain number N (*i.e.* 1, 2, ..., N). N can be set at the average life of utility assets. The sum of the sequence (“SUM”) becomes the denominator in the calculation of weights corresponding to each number of the sequence (*e.g.* 1/SUM, 2/SUM, ...N/SUM). The largest (smallest) of these is shares is used as the weight for the construction price index (“WKA”) for the newest (oldest) year of plant additions. This makes sense since newer plant additions are less depreciated and therefore account for a larger share of the rate base. The formula may be represented mathematically as

$$\text{Construction Price Index}^{TWA} = \frac{\text{SUM}_s (N-s)}{\text{SUM}_s (N-s)} \text{WKA}_{t-s}$$

where WKA is the construction price index. The full formula for the simplified capital price that we recommend is then



Tables 6, 7, and 8 present three groups of indexes that could serve as capex price indexes for the long-lived assets of Alberta gas utilities:

- Natural Gas Distribution, Water, and Other Systems Capital Stock Price Indexes
- Electric Utility Construction Price Indexes (“EUCPI”)
- Non-Residential Building Construction Price Indexes .

Of these, we believe that Natural Gas Distribution, Water, and Other Systems Capital Stock Price Index for engineering structures is the single most accurate measure of construction cost trends for Canadian gas distributors. Unfortunately, it is not available in a timely fashion, and has not to our knowledge been updated since 2007. It is also not Alberta specific.

A summary EUCPI is available for power distribution. It is released on a timely basis but is not Alberta-specific. Non-Residential Building construction price indexes are available on a timely basis for Calgary and Edmonton. Finance Alberta forecasts the growth in Alberta non-residential construction prices. The summary EUCPI could in principle be made more relevant to Alberta by being adjusted periodically for the difference between Alberta and Canadian non-residential building construction prices.

Figure 3 shows how alternative construction price indexes tracked the trend in the gas and water engineering price index from 1982 to 2007. It can be seen that the summary EUCPI for power distribution did a better job of tracking the gas and water index than the non-residential building construction price index in most years. However, the EUCPI veered significantly away from the gas and water index in the 2005-2007 period.

$$\begin{aligned}
 WK^{COS} &= r \times \text{Construction Price Index}^{TWA} \\
 &= r \times \frac{\sum_s (N-s)}{\sum_s (N-s)} WKA_{t-s}
 \end{aligned}$$

For an early use of a triangularized weighted average construction price index see Thomas G. Cowing, Jeffrey Small, and Rodney Stevenson, *Comparative Measures of Productivity for Electric Utilities*, in Thomas G. Cowing and Rodney Stevenson, *Productivity Measurement in Regulated Industries* (New York: Academic Press, 1981).



Table 6
Canadian Natural Gas Distribution, Water, and Other Systems Capital Stock Price Indexes

Year	Information and communication technologies machinery and equipment ¹		Non-information and communication technologies machinery and equipment ²		Building structures		Engineering structures		Land	
	Level	Growth Rate ³	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1961	3091.7		17.5		17.9		12.6		35.4	
1962	3102.6	0.4%	17.9	2.3%	17.8	-0.6%	12.7	0.8%	32.8	-7.6%
1963	3165.2	2.0%	20.1	11.6%	18.2	2.2%	13.1	3.1%	30.4	-7.6%
1964	3205.4	1.3%	18.7	-7.2%	18.4	1.1%	13.6	3.7%	28.6	-6.1%
1965	3282.6	2.4%	19.3	3.2%	19.2	4.3%	14.4	5.7%	28	-2.1%
1966	3226.8	-1.7%	19.7	2.1%	20.5	6.6%	15.2	5.4%	27.9	-0.4%
1967	3312.1	2.6%	19.5	-1.0%	21.3	3.8%	16	5.1%	27	-3.3%
1968	3325.9	0.4%	19.4	-0.5%	21.2	-0.5%	16.2	1.2%	25.8	-4.5%
1969	3353.1	0.8%	19.8	2.0%	22.2	4.6%	17.1	5.4%	25.7	-0.4%
1970	3408.4	1.6%	20.9	5.4%	23.3	4.8%	18.1	5.7%	25.6	-0.4%
1971	3505.1	2.8%	21.5	2.8%	24.6	5.4%	19.3	6.4%	26.1	1.9%
1972	3522.7	0.5%	22	2.3%	26.9	8.9%	20.5	6.0%	27.6	5.6%
1973	3564.8	1.2%	23	4.4%	29	7.5%	21.8	6.1%	31	11.6%
1974	3466.6	-2.8%	26.2	13.0%	35.4	19.9%	26.1	18.0%	36.1	15.2%
1975	3606.7	4.0%	31	16.8%	40.4	13.2%	30.8	16.6%	39.7	9.5%
1976	3213.5	-11.5%	32.8	5.6%	41.3	2.2%	33.4	8.1%	40.9	3.0%
1977	2807.1	-13.5%	36.2	9.9%	42.2	2.2%	36	7.5%	43.4	5.9%
1978	2060.2	-30.9%	40.5	11.2%	43.8	3.7%	38.8	7.5%	45.2	4.1%
1979	1826.7	-12.0%	45.2	11.0%	46.9	6.8%	42.7	9.6%	49.9	9.9%
1980	1347.4	-30.4%	50.4	10.9%	52.1	10.5%	47.1	9.8%	56.7	12.8%
1981	1139	-16.8%	56.2	10.9%	60.4	14.8%	52.2	10.3%	62.8	10.2%
1982	1108.6	-2.7%	60.7	7.7%	65.3	7.8%	57.9	10.4%	65.2	3.8%
1983	793.6	-33.4%	61.8	1.8%	64	-2.0%	60.8	4.9%	63.6	-2.5%
1984	688.1	-14.3%	64.7	4.6%	62.7	-2.1%	62.8	3.2%	64	0.6%
1985	576.5	-17.7%	68.5	5.7%	63.9	1.9%	64.6	2.8%	64	0.0%
1986	486.4	-17.0%	70.6	3.0%	66.5	4.0%	66.5	2.9%	66.2	3.4%
1987	409.9	-17.1%	70.6	0.0%	70.8	6.3%	68.2	2.5%	69.3	4.6%
1988	373.8	-9.2%	70.1	-0.7%	75.2	6.0%	71.9	5.3%	74	6.6%
1989	316.2	-16.7%	72.2	3.0%	80.4	6.7%	74.6	3.7%	78.2	5.5%
1990	286.2	-10.0%	74	2.5%	83.2	3.4%	77.5	3.8%	81	3.5%
1991	230.6	-21.6%	72	-2.7%	80.4	-3.4%	79.6	2.7%	80.3	-0.9%
1992	204.5	-12.0%	74.8	3.8%	80.4	0.0%	81	1.7%	79.8	-0.6%
1993	197.5	-3.5%	77.8	3.9%	80.6	0.2%	82.5	1.8%	81.8	2.5%
1994	185.6	-6.2%	81.5	4.6%	82.2	2.0%	85.6	3.7%	84.5	3.2%
1995	169	-9.4%	84.7	3.9%	84.7	3.0%	86.1	0.6%	87.1	3.0%
1996	146.3	-14.4%	86.3	1.9%	86	1.5%	89.2	3.5%	89.8	3.1%
1997	135.1	-8.0%	87.5	1.4%	87.7	2.0%	91.7	2.8%	91.3	1.7%
1998	122.6	-9.7%	93.3	6.4%	89.3	1.8%	94.6	3.1%	92.7	1.5%
1999	109.7	-11.1%	94.8	1.6%	91	1.9%	96.4	1.9%	94.7	2.1%
2000	105.2	-4.2%	95.7	0.9%	95.6	4.9%	98.7	2.4%	97.2	2.6%
2001	103.6	-1.5%	98.3	2.7%	98.5	3.0%	98.8	0.1%	98.1	0.9%
2002	100	-3.5%	100	1.7%	100	1.5%	100	1.2%	100	1.9%
2003	92.5	-7.8%	93.3	-6.9%	102.6	2.6%	101.1	1.1%	103.9	3.8%
2004	85.8	-7.5%	89.6	-4.0%	108.7	5.8%	107.2	5.9%	112.9	8.3%
2005	79.5	-7.6%	87.6	-2.3%	114	4.8%	113.9	6.1%	123.2	8.7%
2006	76.3	-4.1%	85.6	-2.3%	122.8	7.4%	122.1	7.0%	137	10.6%
2007	74.7	-2.1%	84.5	-1.3%	136	10.2%	128.4	5.0%	151.2	9.9%
Average Annual Growth Rates										
1962-2007		-8.1%	3.4%		4.4%		5.0%		3.2%	
1968-2007		-9.5%	3.7%		4.6%		5.2%		4.3%	
1978-2007		-12.1%	2.8%		3.9%		4.2%		4.2%	
1988-2007		-8.5%	0.9%		3.3%		3.2%		3.9%	
1998-2007		-5.9%	-0.3%		4.4%		3.4%		5.0%	

Footnotes

¹ Information and communication technologies machinery and equipment consists of computer hardware, software and telecommunication equipment

² Machinery and equipment other than computer hardware and telecommunication equipment.

³ All growth rates are calculated logarithmically.

Sources:

Statistics Canada. Table 383-0025 - Investment, capital stock and capital services of physical assets, by North American Industry Classification System (NAICS), annual (dollars unless otherwise noted) (index, 2002=100)

Table 7
Canadian Electric Utility Construction Price Indexes

Distribution Systems							Transmission Systems		
Total							Total		
Year	Level	Growth Rate ¹	Total direct costs	Materials	Labour	Construction equipment	Construction indirects	Level	Growth Rate
1956	17.7				8.3	17.3		20.0	
1957	18.0	1.7%			8.6	18.3		20.6	3.0%
1958	17.4	-3.4%			9.3	19.0		19.5	-5.5%
1959	18.1	3.9%			9.8	24.7		20.1	3.0%
1960	18.7	3.3%			10.4	20.0		19.8	-1.5%
1961	18.7	0.0%			10.9	20.3		18.6	-6.3%
1962	19.0	1.6%			11.4	20.0		19.3	3.7%
1963	19.1	0.5%			11.9	20.2		19.7	2.1%
1964	19.5	2.1%			12.3	20.4		20.4	3.5%
1965	19.9	2.0%			12.9	20.5		21.4	4.8%
1966	20.9	4.9%			13.5	20.9	14.5	22.3	4.1%
1967	21.7	3.8%			15.1	22.0	15.6	22.5	0.9%
1968	21.5	-0.9%			16.2	22.5	16.8	22.2	-1.3%
1969	22.4	4.1%			17.5	23.3	18.1	22.9	3.1%
1970	24.1	7.3%			18.9	24.7	19.6	25.0	8.8%
1971	25.0	3.7%	25.6	29.8	20.3	26.0	21.2	26.1	4.3%
1972	26.1	4.3%	26.6	30.0	22.1	26.9	23.2	27.3	4.5%
1973	28.5	8.8%	29.1	32.6	25.0	27.9	24.7	29.3	7.1%
1974	34.3	18.5%	35.6	42.3	27.4	32.0	27.7	35.5	19.2%
1975	38.5	11.6%	39.7	45.7	32.5	34.8	31.9	41.6	15.9%
1976	40.7	5.6%	41.7	45.5	37.2	39.1	35.2	44.6	7.0%
1977	43.4	6.4%	44.4	46.7	41.4	43.3	38.3	47.0	5.2%
1978	46.6	7.1%	47.7	50.3	44.2	48.3	41.0	50.6	7.4%
1979	52.9	12.7%	54.5	60.3	47.0	54.2	44.5	56.5	11.0%
1980	60.3	13.1%	62.3	70.6	51.6	61.7	49.4	63.3	11.4%
1981	65.7	8.6%	67.8	75.0	57.5	74.0	55.2	69.7	9.6%
1982	71.8	8.9%	73.7	79.9	64.5	82.1	62.3	75.1	7.5%
1983	74.8	4.1%	76.2	79.1	71.0	86.2	67.2	77.0	2.5%
1984	78.1	4.3%	79.4	83.0	73.6	88.9	70.9	80.6	4.6%
1985	82.1	5.0%	83.7	88.7	76.0	93.0	74.1	81.6	1.2%
1986	84.0	2.3%	85.5	90.7	78.0	90.4	76.5	84.0	2.9%
1987	86.6	3.0%	87.9	93.3	80.7	91.3	79.5	89.2	6.0%
1988	91.9	5.9%	93.6	101.7	83.6	89.5	83.0	96.5	7.9%
1989	95.5	3.8%	97.3	105.0	88.0	91.9	85.7	102.6	6.1%
1990	98.5	3.1%	99.9	106.9	91.3	97.2	90.8	104.0	1.4%
1991	97.7	-0.8%	97.9	98.5	96.9	99.4	96.8	100.4	-3.5%
1992	100.0	2.3%	100.0	100.0	100.0	100.0	100.0	100.0	-0.4%
1993	102.5	2.5%	102.5	102.1	102.7	104.8	102.3	103.0	3.0%
1994	108.2	5.4%	109.1	112.5	104.3	111.0	103.3	108.1	4.8%
1995	116.7	7.6%	118.7	128.1	106.1	120.3	105.5	112.8	4.3%
1996	116.6	-0.1%	118.2	126.1	106.6	125.7	107.9	113.5	0.6%
1997	118.0	1.2%	119.3	125.0	110.1	129.8	111.1	115.7	1.9%
1998	122.8	4.0%	123.0	125.4	117.6	138.1	121.4	121.0	4.5%
1999	126.1	2.7%	126.0	126.0	123.6	141.5	126.9	122.2	1.0%
2000	128.7	2.0%	129.1	128.6	128.8	135.3	126.7	124.7	2.0%
2001	129.6	0.7%	129.8	127.7	130.7	142.0	128.9	127.0	1.8%
2002	130.5	0.7%	130.6	127.6	132.3	145.5	129.9	129.2	1.7%
2003	130.6	0.1%	130.9	127.8	132.7	145.5	129.0	126.4	-2.2%
2004	131.1	0.4%	131.3	132.5	127.2	148.0	129.9	129.0	2.0%
2005	133.6	1.9%	134.2	138.2	125.3	157.7	130.4	130.9	1.5%
2006	142.4	6.4%	144.2	155.0	127.5	160.0	132.6	136.2	4.0%
2007	148.8	4.4%	150.7	165.0	130.3	160.0	138.4	142.6	4.6%
2008	150.3	1.0%	151.9	167.6	127.7	173.8	141.4	148.8	4.3%
2009	151.1	0.5%	150.7	167.4	127.2	158.7	153.4	149.7	0.6%
2010	154.8	2.4%	154.5	169.8	132.8	163.0	156.8	150.7	0.7%
Average Annual Growth Rates									
1962-2007		4.5%	NA	NA	5.4%	4.5%	NA		4.4%
1968-2007		4.8%	NA	NA	5.4%	5.0%	5.5%		4.6%
1978-2007		4.1%	4.1%	4.2%	3.8%	4.4%	4.3%		3.7%
1988-2007		2.7%	2.7%	2.9%	2.4%	2.8%	2.8%		2.3%
1998-2007		2.3%	2.3%	2.8%	1.7%	2.1%	2.2%		2.1%
1981-2010		3.1%	3.0%	2.9%	3.2%	3.2%	3.9%		2.9%
1991-2010		2.3%	2.2%	2.3%	1.9%	2.6%	2.7%		1.9%
2001-2010		1.8%	1.8%	2.8%	0.3%	1.9%	2.1%		1.9%

Footnotes

¹ All growth rates are calculated logarithmically.

Source: Statistics Canada. Table 327-0011 - Electric utility construction price indexes (EUCPI), annual (index, 1992=100)

Table 8

Canadian Non-Residential Building Construction Price Indexes

Seven Census Metropolitan Area Composite							Calgary, Alberta						Edmonton, Alberta					
Year	Total, non-residential building construction		Total, commercial structures		Total, industrial structures		Total, non-residential building construction		Total, commercial structures		Total, industrial structures		Total, non-residential building construction		Total, commercial structures		Total, industrial structures	
	Level	Growth Rate ¹	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1981	58.3		59.8		52.5		68.4		69.3		68.3		68.9		71.1		68.6	
1982	62.8	7.4%	64.4	7.4%	56.5	7.2%	72.3	5.5%	73.2	5.5%	71.4	4.5%	73.7	6.8%	76.5	7.3%	72.6	5.8%
1983	62.0	-1.2%	63.2	-1.9%	56.4	-0.2%	67.4	-7.0%	68.3	-7.0%	66.8	-6.7%	70.6	-4.4%	72.5	-5.3%	70.0	-3.7%
1984	60.9	-1.9%	61.8	-2.3%	56.3	0.0%	63.7	-5.6%	64.5	-5.7%	63.0	-5.8%	64.2	-9.4%	65.6	-10.0%	64.2	-8.7%
1985	62.2	2.2%	63.1	2.1%	58.7	4.0%	62.5	-2.0%	63.1	-2.2%	61.7	-2.0%	63.2	-1.7%	64.5	-1.8%	62.8	-2.2%
1986	65.0	4.3%	66.0	4.5%	62.0	5.5%	63.8	2.1%	64.4	2.0%	63.1	2.2%	63.7	0.8%	64.2	-0.5%	62.6	-0.2%
1987	69.7	7.1%	71.0	7.2%	65.9	6.1%	64.2	0.6%	64.8	0.6%	63.7	0.9%	65.2	2.3%	65.7	2.3%	63.1	0.8%
1988	74.6	6.8%	76.1	7.0%	70.6	7.0%	67.8	5.4%	68.7	5.9%	65.7	3.1%	66.4	1.8%	67.2	2.4%	63.8	1.1%
1989	79.5	6.4%	81.1	6.4%	75.8	7.1%	74.8	9.9%	75.9	9.9%	72.9	10.5%	75.1	12.3%	77.0	13.6%	72.1	12.3%
1990	81.8	2.9%	83.3	2.7%	78.1	2.9%	78.5	4.8%	79.0	4.1%	76.7	5.1%	78.8	4.8%	80.2	4.1%	76.7	6.2%
1991	78.8	-3.8%	79.8	-4.3%	76.0	-2.7%	77.9	-0.8%	78.4	-0.8%	75.7	-1.3%	78.7	-0.2%	79.8	-0.6%	76.9	0.2%
1992	78.7	-0.1%	79.6	-0.2%	76.1	0.1%	78.6	1.0%	79.2	1.0%	76.5	1.0%	79.5	1.1%	80.6	1.0%	77.9	1.3%
1993	79.2	0.6%	80.0	0.5%	76.7	0.9%	78.9	0.4%	79.5	0.4%	77.3	1.0%	79.9	0.5%	80.9	0.3%	78.7	1.1%
1994	80.9	2.0%	81.5	1.9%	78.8	2.6%	80.4	1.8%	80.8	1.7%	78.9	2.0%	81.5	1.9%	82.3	1.8%	80.5	2.2%
1995	83.4	3.1%	84.0	3.0%	81.2	3.1%	83.0	3.1%	83.3	3.0%	81.4	3.2%	84.3	3.4%	85.1	3.3%	83.2	3.3%
1996	84.9	1.8%	85.3	1.5%	82.8	1.9%	84.3	1.5%	84.5	1.3%	82.7	1.6%	85.5	1.4%	86.0	1.1%	84.3	1.4%
1997	86.7	2.2%	87.0	1.9%	85.0	2.7%	86.4	2.5%	86.5	2.3%	85.3	3.1%	87.4	2.2%	87.8	2.1%	86.6	2.7%
1998	88.5	2.0%	88.8	2.1%	86.8	2.0%	88.8	2.8%	88.9	2.8%	87.4	2.4%	89.6	2.5%	90.1	2.5%	88.6	2.3%
1999	90.1	1.8%	90.4	1.8%	88.6	2.1%	90.6	2.1%	90.8	2.1%	89.1	2.0%	91.2	1.8%	91.7	1.8%	90.3	1.8%
2000	95.1	5.4%	95.3	5.3%	94.3	6.2%	94.7	4.4%	94.8	4.3%	93.8	5.1%	94.9	4.0%	95.4	3.9%	94.3	4.4%
2001	98.2	3.2%	98.3	3.1%	97.9	3.7%	97.8	3.2%	97.8	3.2%	97.5	3.9%	98.0	3.2%	98.1	2.9%	97.8	3.6%
2002	100.0	1.8%	100.0	1.7%	100.0	2.2%	100.0	2.2%	100.0	2.2%	100.0	2.5%	100.0	2.0%	100.0	1.9%	100.0	2.3%
2003	103.0	3.0%	102.9	2.9%	103.1	3.1%	103.1	3.0%	103.2	3.1%	103.1	3.0%	102.7	2.7%	102.8	2.8%	102.5	2.5%
2004	109.7	6.3%	109.4	6.1%	111.1	7.4%	110.0	6.5%	109.5	5.9%	111.8	8.2%	109.7	6.5%	109.2	6.1%	111.2	8.1%
2005	115.9	5.5%	115.5	5.4%	118.0	6.1%	117.6	6.6%	116.8	6.5%	120.3	7.3%	117.2	6.6%	116.6	6.5%	119.6	7.2%
2006	124.9	7.5%	124.6	7.6%	127.3	7.5%	132.7	12.1%	131.7	12.1%	136.5	12.6%	130.8	11.0%	130.1	11.0%	133.7	11.2%
2007	136.8	9.1%	137.3	9.6%	138.4	8.4%	156.1	16.3%	156.1	16.9%	159.0	15.3%	153.1	15.7%	153.4	16.4%	154.7	14.6%
2008	150.9	9.8%	151.3	9.8%	154.2	10.8%	177.5	12.9%	177.1	12.6%	187.9	16.7%	172.4	11.8%	172.1	11.5%	178.0	14.0%
2009	142.0	-6.0%	141.4	-6.8%	146.7	-5.0%	163.9	-8.0%	163.1	-8.2%	168.6	-10.8%	151.8	-12.7%	151.7	-12.6%	153.3	-14.9%
2010	141.5	-0.4%	140.6	-0.6%	146.2	-0.3%	160.3	-2.2%	159.5	-2.2%	162.6	-3.6%	155.0	2.1%	155.0	2.2%	155.7	1.6%
Average Annual Growth Rates																		
1988-2007		3.4%			3.3%	3.7%			4.4%	4.4%	4.6%	4.3%			4.2%	5.6%	5.8%	
1998-2007		4.6%			4.6%	4.9%			5.9%	5.9%	6.2%	5.6%			5.6%	5.6%	5.8%	
1982-2010		3.1%			2.9%	3.5%			2.9%	2.9%	3.0%	2.8%			2.7%	2.8%	2.8%	
1991-2010		2.7%			2.6%	3.1%			3.6%	3.5%	3.8%	3.4%			3.3%	3.5%	3.5%	
2001-2010		4.0%			3.9%	4.4%			5.3%	5.2%	5.5%	4.9%			4.9%	5.0%	5.0%	

Footnotes

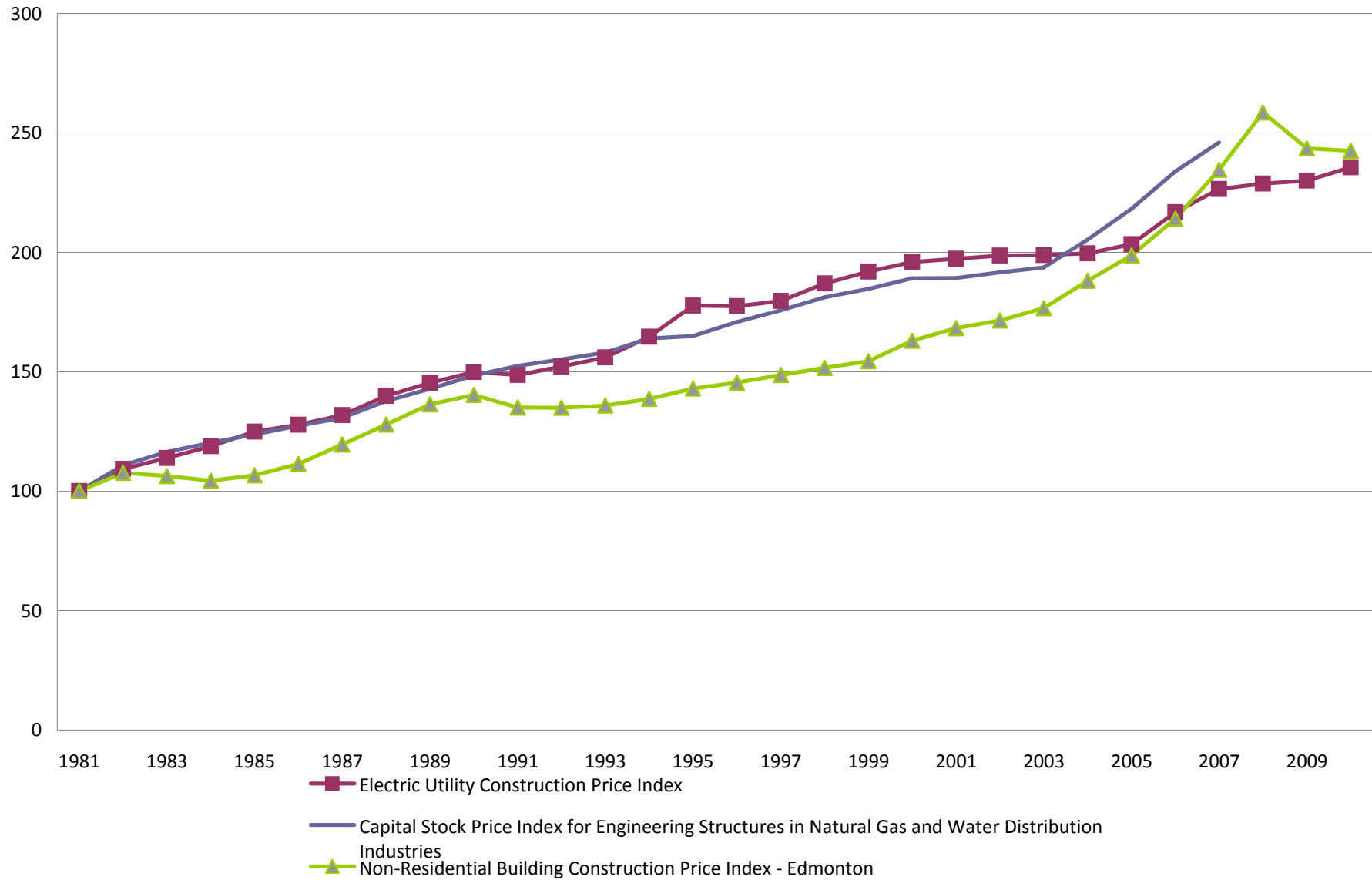
¹ All growth rates are calculated logarithmically.

Source:

Statistics Canada. Table 327-0043 - Price indexes of non-residential building construction, by class of structure, quarterly (index, 2002=100)

Figure 3

Comparison of Construction Price Indexes



4. OTHER PLAN PROVISIONS

4.1 Special Ratemaking Treatment of Capital Expenditures

ATCO Gas and AltaGas both propose special ratemaking treatments for costs of certain capital expenditures. ATCO proposes a “K Factor” that will compensate the company for higher forecasted levels of capital expenditures than are funded by the rate escalation index. ATCO Gas additionally proposes to Y-factor “material capital investment that is unique in nature”. In its testimony, ATCO cites as examples of projects whose costs might be recovered through the Y factor the construction of a South Edmonton Operating Center and a new customer information system. AltaGas proposes a major projects factor that would recover the annual cost of certain system safety and reliability projects.

Large capex surges are less common for gas and electric power distributors than they are for vertically integrated electric utilities. The reason is that distribution systems tend to grow gradually as the settled areas that they serve expand. Replacements of aging facilities are typically spread out over time for the same reason. Deferrals of maintenance expenses for a year or two can help to finance small upturns, as can the acceleration in O&M productivity that is made possible by the replacement of problematic bare steel mains. As AltaGas comments in response to CCA data request CCA.AUI.16 (d), “in general, it would be fair to expect, as older, less efficient assets are replaced, there would be a reduction in operating expenses related to those assets.” For a company operating under multiyear rate plan, occasional rate cases are another source of financial relief. Capex surges can be timed to occur when rate cases are imminent.

In contrast, vertically integrated electric utilities occasionally build large base load power plants, which may be remotely located and require sizable new transmission infrastructure. Lumpy generation investments may produce capacity considerably in excess of current requirements. Rate shock is a likely outcome when such assets enter the rate base.

Energy distributors may nonetheless occasionally need capex surges. Common triggers have included the construction of a large gas transmission line or storage field (which materially redefine the utility’s mission) and changes in metering technology or the



reliability and safety standards of government agencies. When capex surges are necessary they can subject distributors to financial stress if allowed rates do not provide a sufficient budget for the resultant increase in depreciation, the return on plant, and taxes.

The handling of capex surges under PBR is discussed in Chapter 2. For a distributor that is not far behind in making needed capital investments, a well-designed base productivity factor that captures the long run MFP trend should be sufficient to finance normal capex requirements if used routinely in X factor calibration. Budgets will be too small in some years and too large in others. This mirrors the outcome of competitive markets where, for example, an oil refiner cannot expect a higher price for gasoline when it expands its refining capacity.

To the extent that the capex excluded from indexing is sizable and involves the normal kinds of capex undertaken by sampled utilities, it may be necessary to raise the base productivity factor in the rate escalation mechanism that compensates the utility for other costs. A higher X may be needed in succeeding plans as well as the current plan. Our MFP index research in Chapter 3 provides some notion of the appropriate adjustment.

Since X factor adjustments of this kind clearly complicate the design of index-based rate escalation mechanisms, expedients should be considered. One idea is to keep the capital costs of certain large projects outside of the indexing mechanism *in subsequent plans* if they are excluded from the plan under consideration. This will tend to slow the company's future revenue growth because the rate base associated with the capex is sure to decline in subsequent plans.

Another idea is to give the Companies some flexibility in the timing of its rate escalations. For example, the Companies may be restricted only with respect to the *cumulative* pace of revenue per customer growth during the plan period. If it is allowed 8% revenue per customer growth over a four year period, for instance, it may take all 8% growth in one year to finance a "lumpy" investment provided that it "makes do" with 0% revenue/customer growth in the other three years. It is possible to extend this flexibility to multiple plans. A company could, in the example just cited, take a 10% revenue per customer hike in one year of one plan provided that it is prepared to reduce its cumulative revenue per customer hikes by 2% in the next plan.

The K factor proposal of ATCO Gas (and ATCO Electric) is set forth in the testimony of Dr. Carpenter. The K factor is rationalized in his testimony on the grounds that the basic X factor incorporates a “basic amount of capital investment equal to the average rate of capital investment of the firms in NERA’s sample”. To calculate the K factor, Dr. Carpenter computes the average growth in the net plant in service of the utilities in NERA’s sample from 1994-2009. He shows that the average annual growth rate is about 4.5% and asserts that the basic X factor “is sufficient to support approximately these rates of investment”. The proposed K factor would be an adjustment to the rate escalation mechanism that is sufficient to finance that portion of ATCO’s projected rate base growth that cannot be funded

Carpenter’s K factor analysis is flawed. Most fundamentally, a base productivity factor does not fund an average rate of rate base growth any more than it funds average growth in the use of O&M inputs. It instead ensures an average rate of capital *productivity* growth. We have shown that the growth in any cost is the difference between input price and productivity growth *plus the growth in output*. Thus, the growth in the capital stock that the rate escalation mechanism funds depends on customer growth as well as the X factor. The implicit capital budget will be larger for a company the more rapid is output growth. A major reason that ATCO Gas has greater capex needs is that it anticipates customer growth that is considerably more rapid than the US sample norm. Any calculation of the need for a K factor must thus factor out customer growth.

A second conceptual flaw with the K factor calculation is that it is based on a comparison of growth in the rate base. Rate base growth depends on escalation in construction prices as well as escalation in the capital quantity. An expectation of unusually rapid rate base growth may reflect in part an expectation of unusually rapid growth in construction prices. Yet local construction price inflation may be addressed by the inflation measure.

Consider also that it is not always true that a utility which has a high level of capex needs to increase its rates especially rapidly in order that it continue to have a reasonable opportunity to earn the target rate of return.

- Some kinds of investments produce automatic revenue growth. Any special treatment of capex costs should therefore be restricted to capex that does not



produce revenue. This would include investments that are needed to maintain or improve reliability or safety.

- In gas distribution, output growth often produces economies of scale that accelerate productivity growth. The utilities in the Western peer group have experienced an average pace of customer growth that exceeds the approximately 2% growth expected by ATCO Gas and AltaGas and have averaged productivity growth that substantially exceeds the US norm.
- Replacement of bare steel mains may, as noted above, accelerate O&M productivity growth.

4.2 Service Quality and Safety Provisions

The move from Alberta's current system of regulation to PBR is likely to strengthen incentives for cost containment substantially. There will be a stronger temptation to trim maintenance and customer service expenses and the capex for replacement of poorly-performing facilities. Service quality ("SQ") and safety can suffer, and mishaps in both areas have occurred during PBR plans. Formal award/penalty mechanisms ("APMs") can discourage SQ and safety degradation.

The Companies have proposed a continuation of Alberta's current monitoring program and oppose APMs. The fact that SQ monitoring is used instead of formal APMs in Ontario and British Columbia has been noted by the Companies in defense of their proposals. However, SQ and safety APMs are very common in PBR plans of four or more years' duration. In Quebec, Gaz Metro currently operates under an SQ APM, and the Gaz Metro Group de Travail has proposed to continue this in its new PBR plan proposal. The new proposal, to which Gaz Metro is a party, includes indicators for collection and interruption procedures, vegetation control, telephone response time, meter-reading frequency, and customer satisfaction.³³ We recommend that SQ and safety APMs be included in the PBR plans of all Alberta utilities.

³³ Gaz Metro, *Performance Incentive Mechanism: Working Paper Presented by Gaz Metro as Part of Negotiated Settlement Process* (NSP), R-3693-2009. August 2011.

4.3 Efficiency Carryover Mechanisms

Efficiency carryover mechanisms (ECMs) have growing use in PBR today. These mechanisms permit utilities to share some of the benefits of achieving long term performance gains between PBR plans. We recommend that the Commission give consideration to ECMs for Alberta energy utilities. We will have more commentary on this issue in our subsequent testimony.



5. SUMMING UP

The proposals of Alberta's two gas utilities for a revenue/customer cap is reasonable. However, the proposed indexes for escalating the revenue per customer cap are self-serving and unsupported by available evidence. The X factor should be developed using the following formula

$$X = \text{Base Productivity Factor} + \text{Stretch}.$$

The base productivity factor should be established with research on the productivity trends of North American natural gas distributors. This research should use the number of customers served as the output measure.

The Y factoring of a substantial portion of each Company's capex is a key issue in this proceeding. Our research suggests that if capex is *not* Y factored, the MFP growth target should lie in the [1.32%-1.69%] range. Should the Commission sanction the Y factoring of capex, the X factor may need to be upward for the first plan period and revenue per customer escalation in the second plan period must be slowed by some means. As an alternative to the Y factoring of capex, the Commission should consider allowing the distributors some flexibility in the annual growth in the revenue per customer allowance, subject to the constraint that the *cumulative* growth in the index-based cap cannot be exceeded. The stretch factor should lie in the [0.13%-0.50%] range.

With respect to the inflation measure, care must be taken that it strike a reasonable balance between simplicity and the ability to accurately reflect distributor input price inflation in Alberta. This is most simply achieved by using an Alberta-specific macroeconomic price index such as CPI^{Alberta} or the GDPIPI^{FDD} for Alberta. Should the Commission instead prefer a custom input price index, the weight on the labor price should reflect only the share of each Company's *direct* labor cost in the total cost subject to indexing. Should the Commission prefer an explicit capital price in the formula, it should include a rate of return term and average construction prices over the current and numerous past years.



APPENDIX

This appendix contains additional details of our research for the CCA. Section A.1 addresses the input quantity indexes. Section A.2 addresses capital cost. Section A.3 addresses our method for calculating productivity growth rates and trends.

A.1 Input Quantity Indexes

The growth rates of the input quantity indexes were defined by formulas. These formulas involved subindexes measuring growth in the usage of various kinds of inputs. Major decisions in the design of such indexes include their form, the choice of input categories, and the method for calculating quantity subindexes.

A.1.1 Index Form

The summary input quantity index for each company in the sample was of Tornqvist form.³⁴ This means that its annual growth rate was determined by the following general formula:

$$\ln\left(\frac{\text{Input Quantities}_t}{\text{Input Quantities}_{t-1}}\right) = \sum_j \frac{1}{2} \cdot (\text{sc}_{j,t} + \text{sc}_{j,t-1}) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}}\right). \quad [\text{A-1}]$$

Here in each year t ,

$\text{Input Quantities}_t$ = Input quantity index

$X_{j,t}$ = Quantity subindex for input category j

$\text{sc}_{j,t}$ = Share of input category j in applicable total cost.

It can be seen that the annual growth rate of the summary index is a weighted average of the growth rates of the input quantity subindexes. The annual growth rate of each subindex is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable total cost of the distributor provide the basis for the weights.

³⁴ For seminal discussions of this index form see Tornqvist (1936) and Theil (1965).

A.1.2 Input Quantity Subindexes

The quantity subindex for O&M expenses was calculated as the ratio of applicable O&M expenses to an O&M price index. The O&M price index was a weighted average of price subindexes for labor and the following five categories of materials and services: transmission, distribution, storage, metering, and administrative and general services.

The M&S price indexes were taken from the Global Insight *Power Planner* and are specific to these particular gas utility functions. The labor price indexes were constructed by PEG Research using data from two sources. The principal driver was BLS employment cost indexes (“ECIs”) of inflation in salaries and wages in the electric, gas, and sanitary sector (for earlier years of the sample period) and the utility sector (for later years). These national estimates were regionalized by adjusting them for differences between the trends in regional all-industry ECIs and the corresponding national ECI. The quantity subindexes for capital are discussed in Section A.1.4 below.

In calculating the M&S price index, data were unavailable for many gas distributors on the breakdown of O&M expenses between M&S expenses and salaries and wages. These breakdowns are available for combined gas and electric utilities because they are reported for gas as well as electric O&M on the FERC Form 1. For companies lacking these data, we imputed the breakdowns using the average breakdowns for combined gas and electric utilities.

A.1.3 Price Index Formulas

The summary O&M input price indexes that was used in the calculation of the input quantity subindexes were of Törnqvist form. This means that the annual growth rate of each index is determined by the following general formula:

$$\ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}}\right) = \sum_j \frac{1}{2} \cdot (sc_{j,t} + sc_{j,t-1}) \cdot \ln\left(\frac{W_{j,t}}{W_{j,t-1}}\right). \quad [A2]$$

Here in each year t ,

$Input\ Prices_t$ = O&M input price index

$W_{j,t}$ = Price subindex for input category j

$sc_{j,t}$ = Share of input category j in applicable total cost.



The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years.

A.1.4 Detailed Results

Detailed input quantity results for the full sample of gas distributors can be found in Table A-1. It can be seen that the quantity of plant grew at a 0.25% average annual rate for the full national sample whereas the quantity of O&M inputs fell at a slight 0.08% average annual rate. Since customer growth averaged 1.46%, it follows that capital productivity averaged 1.21% annual growth, whereas O&M productivity averaged 1.54% annual growth.

A.2 Capital Cost

The service price approach to the measurement of capital cost has a solid basis in economic theory and is widely used in government and scholarly empirical research.³⁵ In the application of the general method used in this study, the non-tax cost of utility plant in a given year t (CK_t) is the product of a capital service price index (WKS_t) and an index of the capital quantity at the end of the prior year (XK_{t-1}).

$$CK_t = WKS_t \cdot XK_{t-1}. \quad [A3]$$

Each capital quantity index is constructed using inflation-adjusted data on the value of utility plant. Each service price index reflects the cost of owning a unit of capital. Our data reflect the cost of facilities for local delivery, transmission, storage, and metering.

The value of the capital quantity index at the end of a given year depends on the quantities of plant added in that year and in a series of prior years that depends on the service life of the asset. The quantity of capital added in a given year $t-s$ (a_{t-s}) can be calculated as

$$a_{t-s} = \frac{VK_{t-s}^{add}}{WKA_{t-s}}$$

where VK_{t-s}^{add} is the gross value of plant additions and WKA_{t-s} is the capex (a/k/a asset) price index.

The capital quantity index also depends on the particular way that the quantities added

³⁵ See Hall and Jorgensen (1967) for a seminal discussion of the service price method of capital cost measurement.

Table A-1

Input Quantity and Partial Factor Productivity Results: Full Sample

	O&M Quantity	Capital Quantity	Output Quantity	O&M PFP	Capital PFP
1995					
1996	1.09%	0.85%	2.08%	0.99%	1.23%
1997	-4.59%	0.97%	1.92%	6.51%	0.95%
1998	-1.45%	0.04%	1.86%	3.31%	1.82%
1999	-2.30%	0.25%	2.04%	4.34%	1.80%
2000	5.61%	0.26%	1.94%	-3.67%	1.68%
2001	-6.63%	0.67%	1.70%	8.33%	1.03%
2002	0.15%	0.64%	1.38%	1.23%	0.74%
2003	0.79%	1.02%	1.10%	0.31%	0.08%
2004	3.08%	0.36%	1.33%	-1.75%	0.97%
2005	3.19%	-0.55%	1.65%	-1.55%	2.19%
2006	-5.87%	0.16%	1.23%	7.10%	1.07%
2007	3.09%	-0.40%	1.07%	-2.01%	1.47%
2008	-1.65%	-0.22%	0.77%	2.42%	0.99%
2009	4.38%	-0.57%	0.38%	-4.01%	0.95%
1996-2009	-0.08%	0.25%	1.46%	1.54%	1.21%

decline in later years due to depreciation.

Data on the gross plant additions of our sampled gas distributors are unfortunately not available before 1983. In productivity research, when estimates are needed of plant additions before a certain year, it is customary to assume that the net plant value at the end of the prior year resulted from a specific pattern of plant additions in that year and a series of prior years. A constant level of plant additions is often assumed for this purpose.

The earliest year for which a net plant value is available for all of our sampled utilities is 1983. Assuming a 45 year service life, the net plant value is based on plant additions from 1939 to 1983. We assume that plant additions were constant from 1939 to 1983.

The COS formulas for calculating capital price and quantity reflect the broad outlines of how capital cost is calculated in North American utility regulation. For each year t of the sample period we define the following terms for each asset category.

ck_t	Total non-tax cost of capital
ck_t^{Return}	Return on net plant value
$ck_t^{Depreciation}$	Depreciation expense
xk_t	Total quantity of plant
xk_t^{t-s}	Subset of plant in year t that remains from plant additions in year $t-s$
VK_t	Total (book) value of plant at the end of last year
N	Average service life of plant
r_t	Rate of return on net plant value
WKS_t	Capital (a/k/a service or rental) price

The non-tax cost of capital is the sum of depreciation and the return on net plant value.

$$ck_t = ck_t^{Return} + ck_t^{Depreciation}$$

There is a return and depreciation associated with the investment in the current year or any prior year $t-s$ that has not been fully depreciated.³⁶ Assuming straight line depreciation and book valuation of utility plant, the non-tax cost of capital can then be expressed as

$$ck_t = \sum_{s=0}^{N-1} (WKA_{t-s} \cdot xk_t^{t-s}) \cdot r_t + \sum_{s=0}^{N-1} WKA_{t-s} (1/N) \cdot a_{t-s} \quad [A4]$$

$$= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{(1/N) \cdot a_{t-s}}{xk_t}$$

The second term in the formula is a standardized approach to the calculation of depreciation that frees us from reliance on the depreciation expenses reported by utilities provided that we have many years of data on their gross plant additions.

The total quantity of capital used in each year t is the sum of the quantities of different ages in the rate base.

$$xk_t = \sum_{s=0}^{N-1} xk_{t-s}$$

Under straight line depreciation it is true that in the interval $[N-1, 0]$,

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s} \quad [A5]$$

The capital quantity in year t is thus linked to current and past plant additions by the formula

$$xk_t = \sum_{s=0}^{N-1} \frac{N-s}{N} a_{t-s} \quad [A6]$$

The size of the addition in year $t-s$ can then be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s} \quad [A7]$$

Equations [A4] and [A7] together imply that

$$ck_t = xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s}$$

$$= xk_t \cdot WKS_t \quad [A8]$$

³⁶ The analysis assumes that depreciation and the return on net plant value is incurred in year t on the amount of plant remaining at the end of year $t-1$, as well as on any plant added in year t . This is tantamount to assuming that plant additions are made at the beginning of the year. This depends in turn on the amount of plant added (a_{t-s}) and the unit cost of construction (WKA_{t-s}) in that year.

Capital is the product of a price and quantity index where the capital (service) price index has a formula

$$\begin{aligned}
WKS_t &= \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{I}{N-s} \\
&= \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \left(r_t + \frac{I}{N-s} \right)
\end{aligned}
\tag{A9}$$

It can be seen that market construction prices and the rate of return on net plant value play key roles in the COS capital service price formula. The first term in the formula pertains to the return on net plant value. The second term pertains to depreciation. Both terms depend on WKA, the capex price index, in the N most recent years and not just the costs in the current year. The importance of each value of the market construction cost index depends on the share, in the total quantity of plant, of the plant remaining from additions made in that year.

A.3 Productivity Growth Rates and Trends

The annual growth in the productivity index of each company is given by the formula

$$\ln \left(\frac{Productivity_{h,t}}{Productivity_{h,t-1}} \right) = \ln \left(\frac{Output\ Quantities_{h,t}}{Output\ Quantities_{h,t-1}} \right) - \ln \left(\frac{Input\ Quantities_{h,t}}{Input\ Quantities_{h,t-1}} \right)
\tag{A-7}$$

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PBR PLANS FOR ALBERTA

ENERGY DISTRIBUTORS

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EXECUTIVE SUMMARY

The Alberta Utilities Commission (“AUC” or “the Commission”) in February 2010 began a Rate Regulation Initiative to reform rate regulation in the province. In conformance with Commission directives, performance-based regulation (“PBR”) plans were recently proposed by several provincial gas and electric power distributors. All of the proposed plans have rate escalation mechanisms with inflation – X formulas.

Rate escalation mechanisms of PBR plans are often designed using research on utility input price and productivity trends. The AUC retained National Economic Research Associates (“NERA”) to prepare a multifactor productivity (“MFP”) study or studies that could be used to design X factors for Alberta utilities. NERA filed testimony that includes a study of the historical productivity trend of US power distributors. NERA maintains that the results of the study are applicable to Alberta gas and electric power distributors alike. The productivity index that NERA developed displays a negative trend over the last nine years of the sample period.

ATCO Gas and AltaGas (“the Companies”), the two natural gas distributors in the proceeding, have each filed testimony proposing a PBR plan. In both proposed plans, the rate escalation mechanism takes the form of a revenue/customer cap. Both escalation mechanisms also feature an index that is purported to measure distribution input price inflation and a negative X factor that is rationalized in part on the basis of the recent negative trend in the NERA productivity index. Neither proposed X factor has a stretch factor, but earnings sharing mechanisms are proposed that have broad deadbands. Each gas distributor has also proposed that rates for a substantial portion of their capital expenditures (“capex”) be established independently of the indexing mechanism. Both Companies propose that service quality be addressed by a continuation of the Commission’s current monitoring program rather than an award/penalty mechanism. ATCO Gas proposes an efficiency carryover mechanism.

The Consumer’s Coalition of Alberta (“CCA”) has retained Pacific Economics Group (“PEG”) Research LLC to provide research and testimony that would be pertinent to the design of the PBR plans for ATCO Gas and AltaGas. The scope of work includes input



price and productivity research. This document reports on our research for the CCA and provides our views on key issues in the design of PBR plans for Alberta gas utilities. Some of our commentary is relevant to the regulation of provincial power distributors as well.

Base Productivity Factor

Our productivity research for the CCA was based on a sizable sample of data on the operations of U.S. investor-owned gas distributors. All data used in the study were drawn from respected public sources. The sample period was the fourteen years from 1996 to 2009.

We calculated the trends of MFP indexes of the sampled distributors as providers of gas transmission, storage, distribution, metering, and general administration services. For all of these services the costs considered comprised operation and maintenance (“O&M”) expenses and costs of plant ownership. Expenses for gas production and purchases, customer service and information, sales, customer accounts (other than metering), pensions and other benefits, and income taxes were excluded from the costs to better match the costs that the Companies propose to recover via indexing. Output was measured by the number of customers served, as this specification is consistent with the proposed revenue per customer index.

The average trend in the productivity of all of the gas distributors in our US sample was found to be 1.32% growth per annum over the full 1996-2009 period. The average trend in the productivity of the sampled gas utilities located in the western U.S. was 1.84% growth per annum. The western companies averaged 2.52% customer growth, which was well above the sample norm and similar to that achieved by ATCO Gas in the last decade.

To obtain base productivity growth factors more customized to business conditions in Alberta, we developed an econometric model of MFP growth. MFP growth was found to be higher the more rapid was gas and electric customer growth, the slower was growth in miles of main, and the more rapid was technological change. Assuming 2% annual growth in line miles and the number of gas customers served, the model predicts 1.69% annual MFP growth. A higher productivity growth target would be warranted if expected customer growth was higher.

An adjustment to the base productivity factor may be warranted if the Commission sanctions the recovery of certain capex costs outside the indexing mechanism. To



investigate the dimension of the possible adjustment, we recalculated the productivity trends of the western and full sample groups, having excluded a fixed percentage of the plant additions used in cost computations. Excluding 10% of plant additions, we found that the productivity trend of the full sample rose from 1.32% to 1.53%. The productivity trend of the western group rose from 1.84% to 2.05%. The Commission should consider allowing the Companies flexibility in the year to year escalation of revenue per customer subject to the constraint that cumulative escalation cannot exceed that of the revenue per customer escalation index. If certain capex costs are Y factored consideration should also be paid to their ongoing Y factoring in subsequent plans so that, having accelerated revenue growth in one plan, they slow it in later plans.

Other recent studies support the notion that the productivity growth of North American gas and electric power distributors is typically substantial. PEG Research studies released this year found annual MFP growth trends exceeding 100 basis points for Enbridge Gas Distribution (“EGD”), Gaz Metro, and Union Gas. Recent PEG Research findings that the MFP trends of US power and gas distributors were 0.88% and 1.18% respectively were confirmed by the Division of Ratepayer Advocates of the California Public Utilities Commission. The Statistics Canada MFP index for the gas and water industry does not contradict the notion of brisk productivity growth. The Statistics Canada MFP index for the utility industry is less relevant for various reasons and results after 2008 should be given little weight given the sensitivity of the output index to economic conditions.

The NERA study of the MFP trend of US power distributors reaches very different results for power distributors in recent years than those produced by other recent power distribution studies. We believe that this is chiefly because the NERA study has flaws that especially compromise its estimate of the MFP trend in recent years. NERA’s results for this period do not provide a suitable basis for Alberta X factors. The NERA results are most reliable for the 1981-1995 period. In this interval MFP growth averaged 1.43% annually.

Our research using for the CCA suggests a base productivity factor for Alberta Gas utilities in the [1.32% - 1.69%] range. Witnesses for the Companies advocate much lower productivity factors despite the proposals of the Companies to exempt some capex from the indexing mechanism. We urge the Commission to base its decision on the best available research and not “split the baby” by taking the average of all proposals in this proceeding.



Stretch Factor

A stretch factor is often added to the X factor of a rate escalation mechanism. This can help guarantee customers a share of the expected benefits of any accelerated productivity growth that is expected under the stronger performance incentives generated by the PBR plan. Our research suggests that stretch factors for Alberta gas utilities should lie in the [0.13-0.50] range. The Company proposals to have zero stretch factors and earnings sharing mechanisms with broad deadbands would give the companies most of the expected productivity gains.

Inflation Measure

Some rate escalation mechanisms of PBR plans in Alberta have used an inflation measure designed to measure the input price trends of utilities. An alternative is to use a macroeconomic price index. The Consumers Price Index for Alberta and the Gross Domestic Product Implicit Price Index for Final Domestic Demand for Alberta are both serviceable for this purpose.

Should the Commission wish to use a custom input price index, the weight assigned to the labor price index should be limited to the share of direct salaries and wages in the expected total cost that will be subject to the rate escalation mechanism. Any capital price index used in the inflation measure formula should track the trend in the rate of return and a weighted average of current and historical construction prices.

Service Quality

The move from Alberta's current system of regulation to PBR is likely to strengthen incentives for cost containment substantially. Service quality and safety can suffer, and mishaps in both areas have occurred during PBR plans. Award/penalty mechanisms are commonly featured in PBR plans to forestall service quality and safety degradation. A noteworthy Canadian precedent can be found in the PBR plan of Gaz Metro. We recommend that award/penalty mechanisms be developed for all Alberta utilities.



1. INTRODUCTION

The Alberta Utilities Commission (“AUC” or “the Commission”) in February 2010 began a Rate Regulation Initiative to reform rate regulation in the province. Pursuant to Commission directives, performance-based regulation plans have been proposed by several provincial gas and electric power distributors. The Commission has indicated that it would like the PBR plans to have a design broadly similar to that which it approved for ENMAX. The ENMAX plan features a multi-year rate case moratorium and a rate escalation mechanism with an inflation – X escalation formula. The inflation measure in the formula is a custom measure of input price inflation.

In North America, the rate escalation mechanisms of PBR plans are often designed using research on the input price and productivity trends of utilities. The AUC retained NERA to prepare an MFP study or studies that would be useful in the design of X factors for Alberta distributors. In testimony filed last December, NERA presented a single study of the historical productivity trend of US power distributors and maintained that the results were applicable to Alberta gas and electric power distributors alike. The productivity index that NERA developed displays a markedly negative productivity trend in the last decade of the sample period.

ATCO Gas and AltaGas, the two natural gas distributors in the proceeding, have each filed testimony proposing a PBR plan. In both proposed plans, the rate escalation mechanism takes the form of a revenue/customer cap with an inflation – X formula. The formulas feature custom indexes of input price inflation and negative X factors that are rationalized on the basis of the negative trend in the NERA MFP index for the later years of the sample period.

Each gas distributor has also proposed that rates for a substantial portion of their capital expenditures be established independently of the indexing mechanism. ATCO Gas proposes a capital intensity factor (“K factor”) adjustment to the X factor and the Y factoring of “material capital investment that is unique in nature”. AltaGas proposes a major projects (“MP”) factor that would recover the annual cost of certain system safety and reliability projects. Both Companies propose that service quality be addressed by a



continuation of the Commission's current monitoring program rather than an award/penalty mechanism. ATCO Gas proposes an efficiency carryover mechanism.

The Consumer Coalition of Alberta has retained Pacific Economics Group Research LLC to provide research and testimony pertinent to the design of the PBR plans for ATCO Gas and AltaGas. Some of our work is relevant to the design of PBR plans for Alberta power distributors as well. The scope of work includes input price and productivity research that would be pertinent to the design of rate adjustment mechanisms for the Companies.

PEG Research personnel have decades of experience in the design of PBR plans. The measurement of gas and electric distributor productivity is a company specialty. In addition to numerous studies on the MFP trends of U.S. gas distributors, we have recently measured the input price and productivity trends of several Canadian gas distributors in work for the Ontario Energy Board and the Gaz Metro Group de Travail. Work for a diverse clientele has given our practice a reputation for objectivity and dedication to regulatory science.

This document reports on our research for the CCA in this proceeding. Chapter 2 provides an introduction to input price and productivity measurement and discusses their relevance in PBR plan design. Highlights of our empirical research are presented in Chapter 3. Other plan design issues are discussed in Chapter 4. Further details of our work are provided in the Appendix.



2. INDEX RESEARCH AND INCENTIVE REGULATION

Price and productivity research has been used for at least thirty years to design the rate escalation mechanisms of PBR plans. Index logic provides the rationale for this approach. To understand the logic it is necessary to first have a high level understanding of input price and productivity indexes. We provide this in Section 2.1. There follows in Section 2.2 a discussion of the logic for using indexing in the design of rate escalation mechanisms for PBR plans.

2.1 Price and Productivity Indexes

2.1.1 An Introduction to Indexes and Index Logic

Indexes are mechanisms for making comparisons using ratios. A price trend index, for example, compares prices in one period to those in the previous period by taking price ratios. Inflation in the price of natural gas, for instance, may be calculated as

$$Inflation^{Gas} = \frac{P_t^{Gas}}{P_{t-1}^{Gas}} - 1$$

or, using natural logarithms,

$$Inflation^{Gas} = \ln \frac{P_t^{Gas}}{P_{t-1}^{Gas}}.$$

Indexes can summarize multiple comparisons by taking weighted averages of them. The indexes used to make individual comparisons are called subindexes. The weights used in summary indexes should reflect the intended use of the index. Canada's consumer price index for all items ("CPI"), for example, averages the inflation rates of numerous consumer products using the share of each product in the expenditures of a typical consumer as weights. It can be shown using calculus that, with expenditure share weights, a CPI can measure the impact of price inflation on the typical consumer's expenditures. We will call the use of calculus to design indexes used in economic research "index logic".



2.1.2 Input Price Indexes

Input price indexes can be designed to measure the trend in the input prices paid by a utility or utility industry. It can be shown using index logic that the growth in cost is the sum of the growth in an appropriately designed input price index (“Input Prices”) and input quantity index (“Inputs”).

$$\text{growth Cost} = \text{growth Input Prices} + \text{growth Inputs}. \quad [1]$$

The input price and quantity indexes summarize trends in the input prices and quantities that make up the cost. Both indexes in [1] use the cost share of each input group that is itemized in index design as weights.

Capital, labor, and miscellaneous materials and services are the major classes of base rate inputs used by gas distributors. Capital typically accounts for at least half of total cost. In an input price index for total cost the capital price index therefore has the heaviest weight.

2.1.3 Productivity Indexes

Basic Idea

A productivity index is the ratio of an output quantity index (“Outputs”) to an input quantity index.

$$\text{Productivity} = \frac{\text{Outputs}}{\text{Inputs}}. \quad [2]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services they offer. Some productivity indexes are designed to measure productivity *trends*. The growth trend of such a productivity index is the *difference* between the trends in the output and input quantity indexes.

$$\text{trend Productivity} = \text{trend Outputs} - \text{trend Inputs}. \quad [3]$$

Productivity thus measured grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity growth can be volatile due to fluctuations in output and the uneven timing of expenditures. The volatility tends to be greater for individual companies than for an aggregation of companies such as a regional industry.



Input Indexes

The calculation of input indexes for utilities is complicated by the fact that they use numerous inputs in service provisions. This problem is finessed if summary input price indexes are readily available. Rearranging the terms of [3] we obtain

$$\text{growth Inputs} = \text{growth Cost} - \text{growth Input Prices.} \quad [4]$$

This is the approach to input quantity trend calculation that is most widely used in utility productivity research. One can, for example, calculate the growth in the quantity of labor by taking the difference between salary and wage expenses and an appropriate salary and wage price index.

The scope of a productivity index depends on the array of inputs that are considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. A multifactor productivity index measures productivity in the use of several kinds of inputs.

Output Indexes

The output quantity index of a firm or industry summarizes trends in the amounts of goods and services that are produced or sold. Growth in each output dimension that is itemized is measured by a subindex. In designing an output index, choices concerning subindexes and weights depend on the manner in which the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event, the subindexes should measure trends in *billing determinants* and the weight for each itemized determinant should be its share of revenue.

Billing determinants are the quantities companies use to determine customer bills. A bill from Tim Horton's, for instance, might reflect the number of coffees and doughnuts ordered. The bills of gas distributors commonly feature customer (a/k/a "basic") charges and either volumetric charges or demand charges. The relevant billing determinants are therefore delivery volumes, peak demands, and the number of customers served. The weights appropriate for a particular utility vary and depend on the mix of customers, their average use, and the design of rates.

In this paper, we denote by $Outputs^R$ an output index that is revenue-based in the sense that it is designed to measure the impact of output on revenue. The trend in an MFP index calculated using a revenue-based output index (" MFP^R ") has the property



$$\text{trend MFP}^R = \text{trend Outputs}^R - \text{trend Inputs} . \quad [5]$$

Another possible objective of output research is to measure the impact of output growth on company *cost*. In that event, it can be shown that the subindexes should measure the dimensions of the “workload” that drive cost and the weights should reflect the relative importance of the cost elasticities that correspond to these drivers. This approach to output quantity indexation was first detailed in an influential study by three Canadian economists: Michael Denny, Melvyn Fuss, and Leonard Waverman.¹ In this paper, we denote by Outputs^C an output index that is cost-based in the sense of being designed to measure the effect of output growth on cost. The trend in an MFP index that is calculated using a cost-based output index (“*Productivity*^C”) has the property

$$\text{trend Productivity}^C = \text{trend Outputs}^C - \text{trend Inputs} . \quad [6]$$

The elasticity of cost with respect to an output quantity is the percentage change in cost that will result from a 1% change in the quantity. The requisite elasticities for utilities can be estimated econometrically using a sample of historical data on the costs and workloads of utilities. In the gas distribution industry, our research over the years has shown that salient cost drivers include the number of customers served and the extensiveness of the system (often measured by the miles of transmission lines and distribution mains). Given the cost function

$$\ln \text{Cost} = a_0 + a_1 \ln \text{Customers} + a_2 \ln \text{Line Miles} + a_3 \text{Trend} . \quad [7]$$

for example, the parameters a_1 and a_2 are the elasticities of cost with respect to the number of customers served and the line miles. A multi-category output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver.

Sources of Productivity Growth

Research by Denny, Fuss, and Waverman and others has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

¹ Michael Denny, Melvyn A. Fuss and Leonard Waverman (1981), “The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications,” in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

Economies of scale are another important source of productivity growth. These economies are available in the longer run when cost has a tendency to grow less rapidly than output (as measured by *Outputs^C*). In that event, output growth can raise productivity growth. A company's potential to achieve incremental scale economies depends on the pace of its workload growth and may also depend on its operating scale. Incremental scale economies (and thus productivity growth) will typically be greater the more rapid is output growth. The potential for scale economy realization varies by industry. Our research over the years has found that the potential is generally greater in gas distribution than in power distribution.

A third important source of productivity growth is change in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth will increase (decrease) to the extent that X inefficiency diminishes (increases). The potential of a company for productivity growth from this source is greater the lower is its current level of efficiency.

Another source of productivity growth is changes in the miscellaneous business conditions, other than input price inflation and output growth, which affect cost. A good example for an electric power distributor is the share of distribution lines that are undergrounded. An increase in the percentage of lines that is undergrounded will tend to slow MFP growth.

An important source of productivity growth in the shorter run is the intertemporal pattern of expenditures that must be made periodically but need not be made every year. Such "deferrable" expenditures include those for maintenance and the replacement of a poorly performing plant that has deteriorating performance. A surge in deferrable expenditures can slow productivity growth.

When productivity is calculated using a revenue-based output index, growth in productivity may also depend on the degree to which the output growth affects *revenue* differently from the way it affects *cost*. This can be measured by the difference in the growth rates of revenue-based and cost-based output indexes. This difference may be called the "output differential".

$$\text{Output Differential} = \text{growth } \text{Outputs}^R - \text{growth } \text{Outputs}^C \quad [8]$$



The output differential is important to the extent that output is growing but prices are not cost causative in the sense that they do not reflect the drivers of cost well. It is an important determinant of MFP^R growth in the energy distribution industry because the rate designs of energy distributors are frequently not very reflective of cost drivers.² For example, our research over the years reveals that the costs of energy distributors are commonly driven in the short and medium term chiefly by growth in the number of customers served, whereas distributor revenue is commonly driven chiefly by growth in delivery volumes to residential and small business customers. Under these circumstances, the output differential and growth in MFP^R will be sensitive to trends in delivery volumes *per customer* (a/k/a “average use”). The output differential will be negative, slowing growth in MFP^R , when average use is declining and will be positive, accelerating MFP^R growth, when average use is rising.

Declines in average use by small-volume customers have been common in the gas distribution industry for many years. Contributing factors include demand-side management (“DSM”) programs, general improvements in the technology of furnaces and other gas-fired equipment, and changes in building codes and appliance efficiency standards. In contrast, North American electric utilities often experience modest growth in average use by small volume customers when large DSM programs are not underway in their service territories.

It follows that results of productivity studies in the energy utility industry can be quite sensitive to the output specification. A study of gas distributor productivity, for instance, is apt to produce a substantially lower productivity growth estimate with a revenue-based output index than it will with a cost-based output index. Before using a productivity study in the design of a rate escalation mechanism, it is therefore advisable to first examine whether the study uses an output quantity treatment that is consistent with the kind of PBR plan under development and the rate design of the subject utility. Output indexes featuring the number of customers served will, for example, be more relevant to the extent that the utility gathers its revenues from customer charges.

In appraising the results of a productivity study that uses a revenue-based output index, it is also noteworthy that the delivery volumes which typically receive the heaviest weights in such an index are more volatile than the customer numbers and line miles that

² This phenomenon is somewhat less pronounced in Canada than in the United States.

typically receive the heaviest weights in a cost-based output index. As a consequence, productivity indexes with revenue-based output indexes tend to be more volatile than productivity indexes with cost-based output indexes. Moreover, the calculation of a long term productivity trend is more sensitive to the choice of a sample period with a revenue-based output index. For example, a sample period that ends in a period of economic decline can impart a downward bias to the estimate of the long-run productivity trend.

2.1.4 Calculating Capital Costs

Trends in the price and quantity of capital play a critical role in the measurement of trends in MFP and the prices of base rate inputs due to the typically high share of capital in total cost. A practical means must be found to calculate capital cost and to decompose it into consistent price and quantity indexes such that

$$\text{Growth Cost}^{\text{Capital}} = \text{growth Price}^{\text{Capital}} + \text{growth Quantity}^{\text{Capital}}.$$

The capital price index measures the trend in the cost of owning a unit of capital. It is sometimes called a rental or service price because in a competitive market the price of rentals would tend to reflect the unit cost of capital ownership. The components of capital cost include depreciation and the return on investment. The trend in these costs depends on trends in construction prices and the market rate of return on capital. A capital price index should be reflective of both of these price trends.

Three practical methods that have been developed for calculating capital costs using service prices merit note.

- The geometric decay (“GD”) method assumes a current valuation of capital and a constant rate of depreciation. This method has been widely used in productivity research. Although the assumptions underlying the GD method are very different from those used to compute capital cost in utility regulation, the GD method has been used on several occasions in research intended to calibrate utility X factors. The assumptions produce capital service price and quantity indexes that are mathematically elegant and easy to code and review. Current valuation of plant means that owners profit from capital gains. The net cost of plant ownership can be appreciably less than the gross. A GD capital price reflects the net cost of plant ownership, and includes the real (inflation-



adjusted) rate of return on plant ownership. This return has been remarkably volatile in recent years due to rapid growth in the price of construction that was not matched by higher lending rates.

- The one loss approach to capital costing assumes that plant does not depreciate gradually but, rather, all at once as the asset reaches the end of its service life. The plant is valued in current dollars. Although the assumptions underlying the one loss method are very different from those used to compute capital cost in utility regulation, the method has been used occasionally in research intended to calibrate utility X factors.
- 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.

Utilities have diverse methods for calculating depreciation. In calculating capital costs and quantities, it is therefore generally considered desirable to rely on the reporting companies chiefly for the value of plant additions and then use a standardized depreciation treatment. Since the quantity of capital on hand may involve plant added thirty to fifty years ago, it is desirable to have plant addition data for many years in the past. For older periods in which plant addition data are unavailable, it is customary to consider the net plant value near the end of this period and then estimate the quantity of capital it reflects using construction price indexes from earlier years and assumptions about the pattern of investment. The year in which this exercise takes place is commonly called the “benchmark

year”. Since this exercise is unlikely to be exact, it is advisable to base X factor research on a sample period that begins at least ten years after the benchmark year.

2.2 Role of Index Research in Regulation

Multi-year rate plans are the most common approach to PBR around the world. In such a plan, a moratorium is typically placed on general rate cases for several years. A rate escalation mechanism adjusts allowed rates or revenues automatically for changing business conditions between rate cases. This mechanism is predetermined in the sense that it is designed before the start of the plan and is insensitive to the costs (and possibly also the billing determinants) of the utility during the plan period. An approach to the design of rate escalation mechanisms has been developed in North America that uses input price and productivity indexes. In this section we first consider the basic logic of using index research to design price and revenue caps. We then consider in more detail the use of index research to choose the components of rate escalation mechanisms.

2.2.1 Price Cap Indexes

Index research was first used in the design of *price cap* indexes (“PCIs”). We begin our explanation of the supportive index logic by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.³ In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\text{trend Revenue} = \text{trend Cost}. \quad [9]$$

The trend in the revenue of any firm or industry can be shown to be the sum of the trends in revenue-weighted indexes of its (output) prices and billing determinants.

$$\text{trend Revenue} = \text{trend Outputs}^R + \text{trend Output Prices}^R. \quad [10]$$

Recollecting from [1] that the trend in cost is the sum of the growth in cost-weighted input price and productivity indexes, it follows that the trend in output prices that permits revenue to track cost is the difference between the trends in an input price index and an MFP index that uses a revenue-based output measure.

³ The assumption of a competitive rate of return applies to unregulated, competitively structured markets. It is also applicable to utility industries and even to individual utilities.

$$\begin{aligned} \text{trend Output Prices} &= \text{trend Input Prices} - (\text{trend Outputs}^R - \text{trend Inputs}) \\ &= \text{trend Input Prices} - \text{trend MFP}^R \end{aligned} \quad [11]$$

The result in [11] provides a conceptual framework for the design of PCIs of general form

$$\text{trend Rates} = \text{trend Inflation} - X$$

Here X, the “X factor”, can be calibrated to reflect a base productivity target. A “stretch factor”, established in advance of plan operation, is sometimes added to the formula which slows PCI growth in a manner that shares with customers the benefits of performance improvements that are expected due to the stronger performance incentives of the PBR plan.⁴

$$X = \text{Base Productivity Factor} + \text{Stretch}$$

Input price research can be used to select an appropriate inflation measure. Productivity research can be used to “calibrate” the X factor by setting the base productivity factor.

2.2.2 Revenue Cap Indexes

A revenue cap is a rate escalation mechanism designed to limit growth in a utility’s allowed *revenue* rather than its *rates*. The allowed revenue for a given year must then be converted by some means into rates. The allowed revenue cap is often, though not always, paired with a revenue “decoupling” mechanism that ensures, using variance accounts, that the allowed revenue is ultimately recovered.

Revenue caps are favored in regulation for two principle reasons. One is that they weaken the link between system use (*e.g.* energy deliveries and peak demand) and earnings, thereby mitigating the disincentive a utility has to promote demand-side management DSM.⁵ Where average use by small-volume customers has a markedly downward trend, revenue caps also sidestep the need for the very low X factors that would otherwise be needed to provide compensatory rate escalation.⁶

The mathematical research of Denny, Fuss, and Waverman implies that

⁴ Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases.

⁵ This benefit has diminished relevance to the extent that DSM is provided by other agencies. However, utilities still have some means to encourage DSM in this situation.

⁶ See, for example, the low X factor in the current PBR plan of Gaz Metro.



$$\text{growth Cost} = \text{growth Input Prices} - \text{growth Productivity}^C + \text{growth Outputs}^C \quad [12]$$

Cost growth is the difference between input price and productivity growth plus output growth, where output growth is measured using a cost-based output index.⁷

Formulas with *elasticity-weighted* output measures have been used by the Essential Services Commission (“ESC”) in the populous state of Victoria, Australia to establish multiyear O&M budgets for gas and electric distributors.⁸ In the energy distribution business, however, we have noted that the number of customers served is an especially important output variable driving cost in the short and medium term. To the extent that this is true, Outputs^C can be reasonably approximated by growth in the number of customers served and there is no need to have a multidimensional output index with elasticity weights. Relation [12] can be restated as

$$\begin{aligned} \text{growth Cost} \\ = \text{growth Input Prices} - \text{growth Productivity}^C + \text{growth Customers} \end{aligned}$$

where the productivity index uses the number of customers to measure output. Rearranging the terms of this formula we obtain

$$\begin{aligned} \text{growth Cost} - \text{growth Customers} \\ = \text{growth (Cost/Customer)} \\ = \text{growth Input Prices} - \text{growth Productivity}^C. \end{aligned} \quad [13]$$

This provides the basis for the following revenue/customer escalation formula.⁹

⁷ This formula can establish the revenue requirement for cost *components* as well as total cost. For example, the applicable formula for non-fuel O&M expenses is

$$\begin{aligned} \text{growth Cost}_{O\&M} \\ = \text{growth Input Prices}_{O\&M} - (\text{growth Outputs}^C_{O\&M} - \text{growth Inputs}_{O\&M}) \\ \quad + \text{growth Outputs}^C_{O\&M} \\ = \text{growth Input Prices}_{O\&M} - \text{growth Productivity}^C_{O\&M} + \text{growth Outputs}^C_{O\&M} \end{aligned}$$

where

$\text{Input Prices}^{O\&M}$ = Price Index for O&M inputs

$\text{Outputs}^C_{O\&M}$ = Elasticity-weighted output index applicable to O&M

$\text{Productivity}^C_{O\&M}$ = Productivity index for O&M that is calculated using $\text{Outputs}^C_{O\&M}$.

⁸ The ESC uses an approach to the design of multiyear rate caps that involves multiyear cost forecasts. This approach is popular in Australia and Britain.

⁹ The propriety of using the number of customers served as the output index to calibrate the X factor of a revenue per customer index has an alternative and simpler derivation. Assume that a revenue per customer index should be calibrated to achieve the revenue per customer growth of a typical utility. Then

$$\begin{aligned} \text{growth Revenue/Customer} \\ = \text{growth Revenue} - \text{growth Customers} \\ = \text{growth Cost} - \text{growth Customers} \end{aligned}$$



$$\text{growth Cost/Customer} = \text{growth Inflation} - X.$$

This general formula for the design of a rate escalation mechanism is currently used in the revenue caps of Enbridge and Gazifere in Canada and was previously used in a revenue cap for Southern California Gas, the largest U.S. gas distributor.^{10 11} Cost per customer escalation formulas have been used to escalate *O&M* budgets in IR plans of several companies in the U.S. and Canada.

2.2.3 Long Run Productivity Trends

Productivity research for X factor calibration commonly focuses on discerning the current *long run* productivity trend. This is the trend in productivity that is unaffected by short-term fluctuations in output or expenditures. The long run productivity trend is faster than the trend that a utility will achieve *during* a surge in expenditures or a slump in demand but also *slower* than the trend that it will achieve between expenditure surges and demand slumps.

If a utility is in a period of normal demand and system age, and is not expecting a major change in its mission (*e.g.* the construction of a gas transmission line), a base productivity factor that reflects the long run productivity trend may be sufficient to finance all capital expenditures if used in successive PBR plans. However, the utility may nonetheless experience some financial stress in periods of expenditure surges.

Care must be taken in the selection of a sample period if the goal of research is to estimate the long run productivity trend. It is customary to use a lengthy sample period for this purpose. However, a period of more than twenty years may be unreflective of the current state of technological change. The sample period can be shorter to the extent that the output measure isn't volatile. If the output index is volumetric, care should be taken not to have a start or end date in a recession year.

$$\begin{aligned} &= (\text{growth Input Prices} + \text{growth Input Quantity}) - \text{growth Customers} \\ &= \text{growth Input Prices} - (\text{growth Customers} - \text{growth Inputs}). \end{aligned}$$

¹⁰ In the Enbridge and Gazifere formulations, revenue per customer growth is capped at $\alpha\%$ of inflation. The X factor is in this case implicit and has an expected value of $(1 - \alpha/100) \times \text{Expected Inflation}$.

¹¹ If the revenue per customer index is applied to individual customer classes, the growth in the output index used to calculate productivity is ideally a revenue weighted average of the growth in the number of customers served. However, an index of this kind is difficult to calculate accurately using available data and is not expected to yield markedly different results.

2.2.4 Inflation Measure Issues

Index logic suggests that the inflation measure of a rate or revenue cap should in some fashion track the input price inflation of utilities. To strengthen performance incentives, it is preferable that the inflation measure track the input price inflation of utilities generally rather than each specific utility to which it applies. This can be achieved by using external inflation indexes and cost share weights that don't reflect the subject utility's changing input mix during the PBR plan.

Several issues in the choice of an inflation specification must still be addressed. One is whether the inflation measure should be *expressly* designed to track utility industry input price inflation as per relation [13]. There are several precedents for the use of utility-specific inflation measures in PBR rate escalation mechanisms. Such a measure was used in one of the world's first large scale PBR plans, which applied to US railroads. Such measures have also been used in PBR plans several times in California.

In Canada, the OEB used an industry-specific inflation measure in its first price cap plan for Ontario power distributors. An industry specific inflation measure has also been used to regulate the terms of grain shipments by railroads in western Canada. In Alberta, an industry-specific inflation measure is featured in the current rate escalation mechanism of ENMAX.

Notwithstanding such precedents, the majority of rate indexing plans approved worldwide do not feature industry-specific inflation measures. They instead feature measures of macroeconomic (*i.e.* economy-wide) inflation prepared by government agencies. These are usually measures of inflation in the prices of the economy's *outputs* such as CPIs and gross domestic product price indexes. In Canada, gross domestic product implicit price indexes ("GDPIPIs") and CPIs are computed on a quarterly basis by Statistics ("Stats") Canada. GDPIPIs measure inflation in the prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products and also include capital equipment and exports. A GDPIPI for final domestic demand is computed at both the national and provincial level. It excludes prices of exports, which are volatile in Canada's resource-intensive economy.

Macroeconomic inflation measures have some advantages over industry-specific measures in rate adjustment indexes. One is that they are available, at little or no cost, from



government agencies such as Statistics Canada. There is no need to go through the chore of annual index calculations. The complications of designing an industry-specific price index are sidestepped. The design of a capital price index can be an especially difficult.

Customers are more familiar with macroeconomic price indexes, and especially with CPIs.

However, the use of a macroeconomic measure in a rate escalation mechanism sometimes involves design challenges. Suppose, for example, that the inflation measure is a GDPIPI. In that event we can restate relation [13] as

$$\begin{aligned} & \text{growth Cost / Customer} \\ &= \text{growth GDPIPI} - \left[\text{trend Productivity}^C + (\text{trend GDPIPI} - \text{trend Input Prices}) + \text{Stretch Factor} \right] \end{aligned} \quad [14]$$

It follows that the PCI can still conform to index logic when a GDPIPI is the inflation measure provided that the X factor corrects for any tendency of the GDPIPI growth to differ from industry input price growth. The difference between the GDPIPI and input price trends may be usefully called the “inflation differential”.

Consider now that a GDPIPI is a measure of inflation in the economy’s *output* prices. Since, additionally, markets in the U.S. and Canada are broadly competitive, the long run trend in the GDPIPI for the economy is the difference between the trends in input price and MFP indexes for the economy.

$$\text{trend GDPIPI} = \text{trend Input Prices}^{\text{Economy}} - \text{trend MFP}^{\text{Economy}} . \quad [15]$$

This makes clear that the GDPIPI already reflects the productivity growth of the economy.

Relations [14] and [15] can be combined to produce the following formula for the design of a revenue/customer index.

$$\begin{aligned} & \text{growth Revenue / Customer} \\ &= \text{growth GDPIPI} \\ & \quad - \left[\left(\text{trend Productivity}^{\text{Industry}} - \text{trend TFP}^{\text{Economy}} \right) \right. \\ & \quad \left. + \left(\text{trend Input Prices}^{\text{Economy}} - \text{trend Input Prices}^{\text{Industry}} \right) + \text{Stretch} \right] \end{aligned} \quad [16]$$

It suggests that when a GDPIPI is employed as the inflation measure, the PCI can be calibrated to conform to index logic when the X factor has two calibration terms: a “productivity differential” and an “input price differential”.

The productivity differential is the difference between the MFP trends of the industry and the economy. The X will be larger, slowing PCI growth, to the extent that the MFP

growth of the economy is slow. The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry. This general approach to X factor design has been used in several PBR proceedings.

The decomposition of X factor calibration into a productivity differential and an input price differential is an aid to thinking about the need for an X factor adjustment when a macroeconomic inflation measure is used. The input price trends of a utility industry and the economy can differ for several reasons. One is that the industry may have a different mix of inputs than the economy. The technologies for gas and electric power distribution, are, in fact, considerably more capital intensive than the typical production process in the economy. It is therefore more sensitive to fluctuations in the price of capital, as we have seen. Another possible reason for the input price trends of the industry and the economy to differ is that the prices of certain inputs grow at a different rate in some regions than they do on average throughout the economy. This is a palpable concern in Alberta, whose resource-intensive economy sometimes experiences hiring booms that stimulate provincial inflation. This concern can be reduced by using an Alberta-specific measure of macroeconomic price inflation.

The difficulties in establishing long-term input price trends complicate identification of an appropriate input price differential. To the extent that the capital price is volatile, for example, the calculation of a long run input price trend for the utility industry is sensitive to the choice of the sample period. Even if we could establish a differential between the long term trends it could differ considerably from the trend expected over the prospective plan period. This situation invites posturing by the parties to PBR proceedings over the input price differential issue. Controversy is possible, additionally, over the method used to calculate the price of capital.

Turning now to the issue of the productivity differential, this depends greatly on the productivity trend of the economy. Studies by the U.S. government show that growth in the MFP of the US private business sector has been fairly brisk for more than a decade, and typically exceeds 100 basis points annually. Since US studies typically suggest that the input price differential is modest in the long run, a macroeconomic output price index such

as the GDPIPI tends to understate the inflation in the input prices of US utilities. Recognition of this bias has led to a downward adjustment in the X factors of some U.S. PBR plans.

In Canada, the productivity trend of the business sector has been quite slow in recent years, and close to zero. According to Statistics Canada, MFP growth was virtually unchanged from 1980 to 2010. It is then reasonable to assume that the productivity differential is roughly the same as the productivity trend of the industry. Assuming, additionally, that the input price trends of the industry and the economy are similar in the long run, there is no need for a special adjustment to the X factor when a macroeconomic inflation measure is used in a rate escalation mechanism.

2.2.5 External vs. Company-Specific Productivity Targets

Productivity research can be used in several ways to calculate base productivity factors. Using the productivity trend of the entire industry to calibrate X is tantamount to simulating the outcome of competitive markets. However, individual firms in competitive markets routinely experience windfall gains and losses. Our discussion in Section 2.1.2 of the sources of productivity growth implies that differences in the external business conditions that drive productivity growth can cause utilities to have different productivity trends. For example, gas distributors that are experiencing brisk growth in the number of gas customers served are more likely to realize economies of scale than distributors that are experiencing slower growth. There is thus considerable interest in methodologies to customize base productivity factors.

The most common approach to customizing base productivity factors has been to average the productivity trends of similarly situated (aka “peer”) utilities. In the Northeast United States, for example, X factors in index-based PBR plans have usually been calibrated using research on the productivity trends of Northeast utilities. Unfortunately, the number of utilities, for which good data are available, which face productivity growth drivers that are similar to those facing the subject utility is sometimes limited. This is a chronic problem in Canada, where standardized data that could be used to accurately measure the productivity trends of numerous utilities are not readily available and there are few potential peers for a given utility in any event.



Complications like these have occasionally prompted regulators to base X factors on a utility's *own* recent historical productivity trend. This approach will weaken a utility's incentives to increase productivity growth if used repeatedly. Furthermore, a utility's productivity growth potential in one five or ten year period may be very different from its productivity growth potential in the following five years. For example, rapid (slow) growth in productivity may be due to a reduction (increase) in X inefficiency, making it more (less) difficult to achieve rapid productivity growth in the future.

Econometric approaches to setting base productivity targets are available that can be customized to the external business conditions of a utility without using its own cost data or having to select productivity peers. One such approach is to use the mathematics that Denny Fuss and Waverman developed to decompose the drivers of productivity growth. Given the simple cost model

$$\ln Cost = a_0 + a_1 \ln Customers + a_2 Trend$$

for instance, it can be shown that, setting aside considerations of X-inefficiency,

$$\begin{aligned} trend Productivity^C &= scale\ effect + trend\ effect \\ &= (1-a_1) \times growth\ Customers + a_2. \end{aligned}$$

We might, then, estimate the parameters of the cost model (*e.g.* a_1 and a_2) using a large sample of data on gas distributor operations in the United States. A custom econometric productivity target can then be established for Alberta gas utilities using the formula:

$$Base\ Productivity\ Target^{Alberta} = (1-a_1) \times growth\ Customers^{Alberta} + a_2.$$

To the extent that Alberta utilities expect output growth that exceeds the norm for the US sample, the custom productivity growth target would be higher than the average target thus calculated for the utilities in the U.S. sample.

This general approach to establishing productivity targets has been used by PEG Research to propose base productivity targets for gas distributors in Ontario and Quebec. A paper discussing the results of our econometric productivity targeting in Ontario has been published in a respected economic journal.¹² An alternative and simpler econometric approach is to regress MFP on drivers of productivity growth, such as the number of customers that have been identified by econometric cost research.

¹²See Mark Newton Lowry and Lullit Getachew, "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry", *Review of Network Economics* Volume 8, Issue 4, December 2009.

2.2.6 Dealing With Cost Exclusions

Many multi-year rate plans recover certain costs outside of the predetermined rate escalation mechanisms. Costs that are targeted for exclusion are sometimes said to be “Y-factored”. The exclusions affect the research that is appropriate for calibrating the X factor.

Suppose, for example, that the cost of some or all capex is Y factored but the cost of existing plant is not. Unless the exempted capex is for a novel purpose (*e.g.* advanced metering infrastructure or the development of a large new storage field or transmission line), the same kind of capex will occasionally have been undertaken by sampled U.S. utilities during a sample period of some length. Note also that the removal of a portion of capital expenditures from the capital quantity index will tend to slow its growth and thereby accelerate productivity growth. That is because the removal increases the implicit cost share weight on the quantity of older plant, which cannot grow and is instead declining due to depreciation.

Evidence to this effect can be found in an examination of experience with the capex cost “trackers” that are used in the regulation of many U.S. energy utilities. According to our theory, the larger is the share of capex recovered through the tracker, the easier it will be for the utility to agree to slow escalation in the rates that recover its residual (*e.g.* O&M and older capital) cost. In Ohio, for instance, three power distributors owned by First Energy (Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison) currently operate under capex trackers that recover substantially all capex costs through a tracker. With respect to the rates that compensate the utility for other costs, all three utilities have agreed to a rate case moratorium.

The Y factoring of capex cost is sometimes advocated on the grounds that the capex in question is a one-time surge. To the extent that this is true, it should also be noted that the productivity growth of the company should accelerate once the surge is complete because the surge will cause the rate base to grow more slowly after it is completed. If PBR should accommodate a revenue surge now to help finance the capex, it should then reflect the slower revenue growth that later results and thereby improve customer finances. One way to accomplish this is to have the costs of capex (*e.g.* depreciation and return) that are excluded from one indexing plan be recovered outside of indexing in the next rate plan as well.

3. RATE ESCALATION RESEARCH

This section presents an overview of our work to develop rate escalation mechanisms for Alberta gas distributors. The discussions here are largely non-technical. Additional and more technical details of the research are provided in the Appendix.

3.1 Data

Data limitations discourage the use of Canadian data in the calibration of X factors for rate escalation mechanisms. Data collection is not standardized across Canada, and the data gathered and reported in Alberta and other individual provinces have changed over the years. Data for many years of plant additions, such as are needed to calculate accurate capital quantity trends, are generally unavailable. The best available data for calibrating the X factors of Alberta energy utilities are therefore those found in the United States. Data on U.S. productivity trends has been considered by Canadian regulators in designing rate escalation mechanisms for BC Gas, Gaz Metro, EGD, Union Gas, and Ontario's power distributors.

The primary source of the US data we use in our gas distribution productivity research has changed over time. Data for the earliest years, which are needed to accurately calculate capital costs and quantities, are drawn from the *Uniform Statistical Reports* ("USRs") that gas utilities filed with the American Gas Association. USR data for some variables of interest are aggregated and released by the Association in its annual publication *Gas Facts*¹³. The earliest year for which we have all of the requisite capital data is 1983.

USR data are still collected but have been unavailable to the public for many sampled gas distributors for many years. The development of a satisfactory sample has therefore required us to obtain cost and quantity data from alternative sources. The chief source of our more recent data on the costs incurred by gas distributors is reports to state regulators. These reports are fairly standardized since they often use as templates the Form 2 that interstate gas pipeline companies file with the Federal Energy Regulatory Commission ("FERC"). The chief source for our data on operating scale has been Form

¹³ These data are unsatisfactory for use in productivity research because the firms in the sample change over time.

EIA 176. Gas utility operating data from both of these sources are compiled by respected commercial vendors. We obtained most of our gas operating data for the sample years of this study from SNL Financial.¹⁴

Other data sources were also employed in our productivity research. These were used primarily to measure input price trends. The supplemental sources of price data were Whitman, Requardt & Associates, the Regulatory Research Associates unit of SNL Financial, the Bureau of Labor Statistics (“BLS”) of the U.S. Department of Labor, and Global Insight (formerly DRI-McGraw Hill).

Our calculations of the productivity trends of US gas distributors are based on quality data for 34 distributors. The sample includes most of the larger distributors in the United States. Some of the sampled distributors also provide gas transmission and/or storage services but all were involved more extensively in gas distribution. The sampled distributors are listed in Table 1.

3.2 Productivity Index Details

3.2.1 Scope

We calculated indexes of trends in the MFP of each sampled utility in the provision of gas services. Costs of any electric services provided by combined gas and electric utilities were excluded from the analysis. We also excluded certain costs that are itemized on U.S. data forms and that are unlikely to be subject to indexing in the PBR plans of the Alberta distributors. The excluded costs include income taxes, gas supply, transmission by others, customer service and information, sales, and customer accounts other than meter reading. The applicable total cost of these services was calculated as the corresponding O&M expenses plus the costs of gas plant ownership. Capital cost was calculated using the COS method. Our capital cost methodology is discussed further below in Appendix A.3.

Some of the excluded costs have grown rapidly in recent years for sampled US utilities and would materially slow their measured productivity trends were they to be

¹⁴ For a few of the sampled companies, the SNL data were deemed insufficient in some of the earliest years of the sample period. In such cases, we used data from sources we have used in the past such as the GasDat service of Platts.

Table 1

SAMPLED GAS DISTRIBUTORS FOR PRODUCTIVITY RESEARCH

Alabama Gas	NSTAR Gas
Baltimore Gas & Electric	Orange and Rockland Utilities
Boston Gas	Pacific Gas and Electric *
Brooklyn Union Gas	PECO Energy
Cascade Natural Gas *	Peoples Gas Light and Coke
Central Hudson Gas & Light	Peoples Natural Gas
Connecticut Natural Gas	Public Service of North Carolina
Consolidated Edison of New York	Public Service Electric and Gas
Consumers Energy	Puget Sound Energy *
East Ohio Gas	Questar Gas *
Louisville Gas and Electric	Rochester Gas and Electric
Madison Gas and Electric	San Diego Gas & Electric *
New Jersey Natural Gas	Southern California Gas *
Niagara Mohawk Power	Southern Connecticut Gas
North Shore Gas	Washington Gas Light
Northern Illinois Gas	Wisconsin Gas
Northwest Natural Gas *	Wisconsin Power and Light

Number of Companies: 34

* indicates western distributor

included. For example, the customer service and information expenses of some distributors have increased markedly in recent years due to the growth of utility DSM programs. The uncollectible bill expenses of some distributors rose rapidly in the later years of the sample period due to high field prices for natural gas and the recession.

3.2.2 Output Measure

Our output specification is intended to measure the effect of output growth on cost. The trend in the workload was measured by the number of customers served. We show in Section 2.2.2 above that this is the output specification that is relevant to the design of a revenue per customer index.

3.2.3 Input Quantity Index

The growth rate in the input quantity index of each sampled distributor was a weighted average of the growth rates in quantity subindexes for capital and O&M inputs. The weights were based on the shares of these input classes in each company's applicable gas distributor cost. The O&M input quantity was calculated as the ratio of the corresponding cost to an appropriate input price index. O&M expenses comprise expenses for labor, materials, and services. Material and service ("M&S") inputs is a residual input category that includes the O&M services of contractors, insurance, real estate rents, equipment leases, materials, and miscellaneous other goods and services.

3.2.4 Sample Period

In choosing a sample period for a productivity study it is generally desirable that the period include the latest year for which all of the requisite data are available. In the present case this year is 2009. This was a year of deep recession in the United States, but the sensitivity of our productivity results to this circumstance is lessened by our choice of the number of customers as the output measure.

It is also desirable for the sample period to reflect the long run productivity trend. We generally desire a sample period of at least 10 years to fulfill this goal. A long sample period, however, may not be indicative of the latest technology trend. Moreover, the accuracy of the measured capital quantity trend is enhanced by having starting data for research that is at least ten years after the first year that good capital cost data are available.



We attempt to balance these considerations by presenting productivity results for the fourteen year 1996 to 2009 period.

3.3 Productivity Index Results

Table 2 and Figures 1 and 2 report the average annual growth rates in the gas distributor productivity and component output and input quantity indexes for the full U.S. sample and a subset consisting of the sampled distributors in the western US. Inspecting the results it can be seen that, for the full sample and over the full sample period, the distributors averaged 1.32% annual productivity growth. Customer growth averaging 1.46% annually outpaced input quantity growth averaging only 0.14% annually. The average trend in the productivity of the western gas distributors was 1.84% growth per annum over the full sample period. By way of comparison, the MFP index that the BLS calculates for the private business sector of the U.S. economy grew at a 1.22% average annual rate over this period. Thus, the MFP trend of the US gas distribution industry was very similar to that of the private business sector as a whole.

We also calculated MFP indexes that excluded 10% of capital expenditures on the grounds that routine capex recovered outside of indexing would likely be undertaken as well by sampled utilities. We find that the average annual growth in the productivity trend of the full US sample rises from 1.32% to 1.53%. The average annual growth in the productivity trend of the sampled gas distributors in the western US rises from 1.84% to 2.05%.

3.4 Econometric Productivity Growth Projections

In Section 2.2.5 above we discussed the use of econometrics to make productivity growth projections that are customized to the local business conditions that a utility faces. This methodology makes some sense in Canada, where quality, standardized data on the productivity growth of peer utilities is unavailable. However, econometric productivity growth projections can trigger criticisms that results are somehow only true in the *long* run, and that the behavior of MFP indexes will be quite different in the short and medium term.

To anticipate such criticisms, we have developed for the CCA an econometric model of MFP growth that can be used to project base productivity factors that reflect the local



Table 2
Productivity Index Results

	Output Quantity		Input Quantity		TFP	
	Sample	Western	Sample	Western	Sample	Western
1996	2.08%	3.92%	1.06%	1.29%	1.02%	2.63%
1997	1.92%	2.40%	-1.09%	0.58%	3.01%	1.82%
1998	1.86%	2.98%	-0.34%	2.20%	2.21%	0.79%
1999	2.04%	3.91%	-0.27%	-1.71%	2.32%	5.62%
2000	1.94%	2.78%	1.88%	-0.37%	0.06%	3.16%
2001	1.70%	2.74%	-1.69%	1.36%	3.39%	1.38%
2002	1.38%	1.88%	0.26%	0.29%	1.12%	1.59%
2003	1.10%	2.29%	0.89%	3.14%	0.21%	-0.85%
2004	1.33%	2.41%	1.15%	0.27%	0.18%	2.14%
2005	1.65%	3.48%	0.76%	1.38%	0.89%	2.11%
2006	1.23%	2.42%	-1.93%	-0.04%	3.16%	2.45%
2007	1.07%	2.20%	0.78%	0.72%	0.29%	1.48%
2008	0.77%	1.35%	-0.68%	-3.06%	1.45%	4.41%
2009	0.38%	0.46%	1.13%	3.39%	-0.75%	-2.93%
1996-2009	1.46%	2.52%	0.14%	0.67%	1.32%	1.84%

Figure 1
Productivity Results - Full Sample

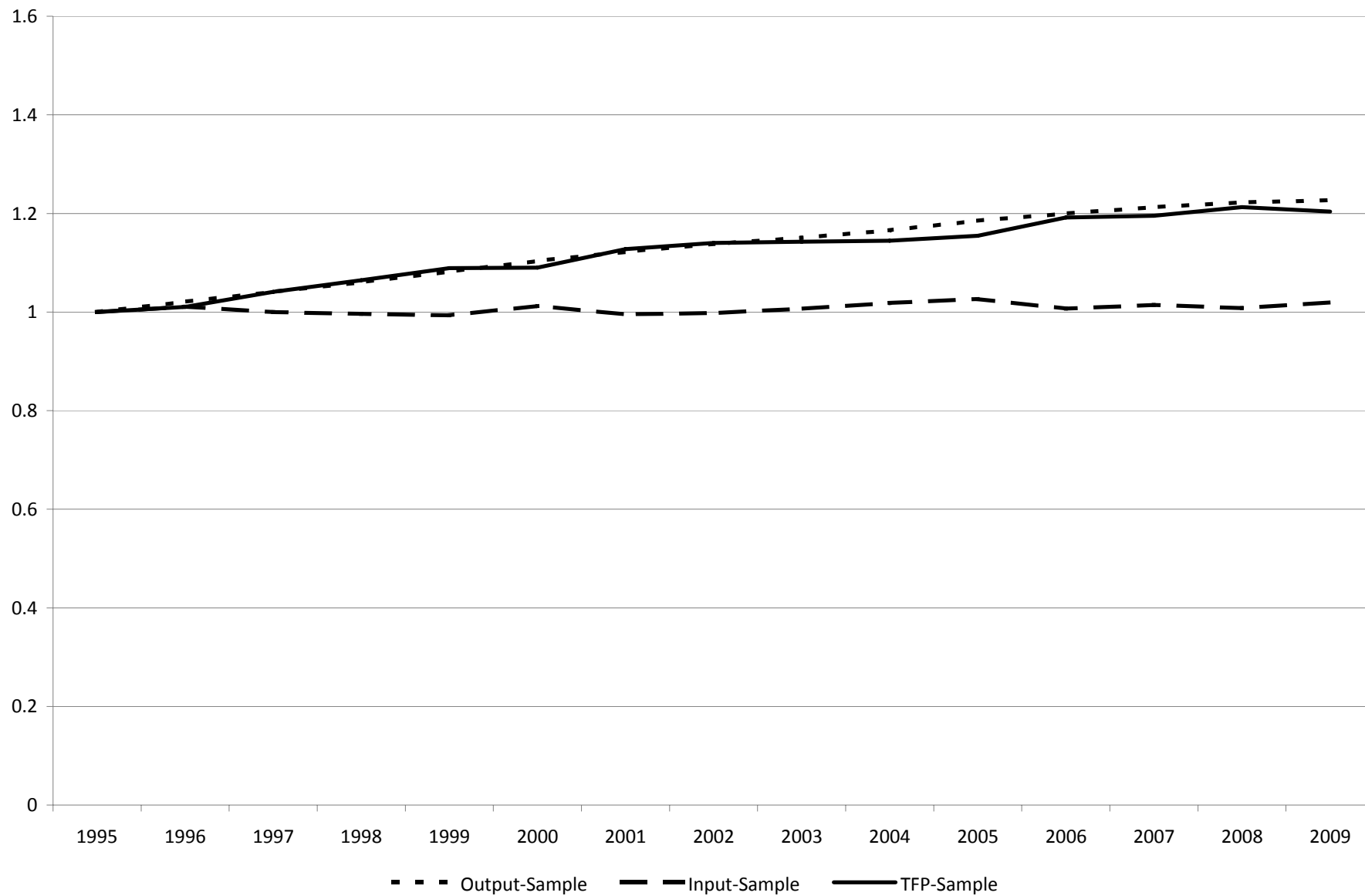
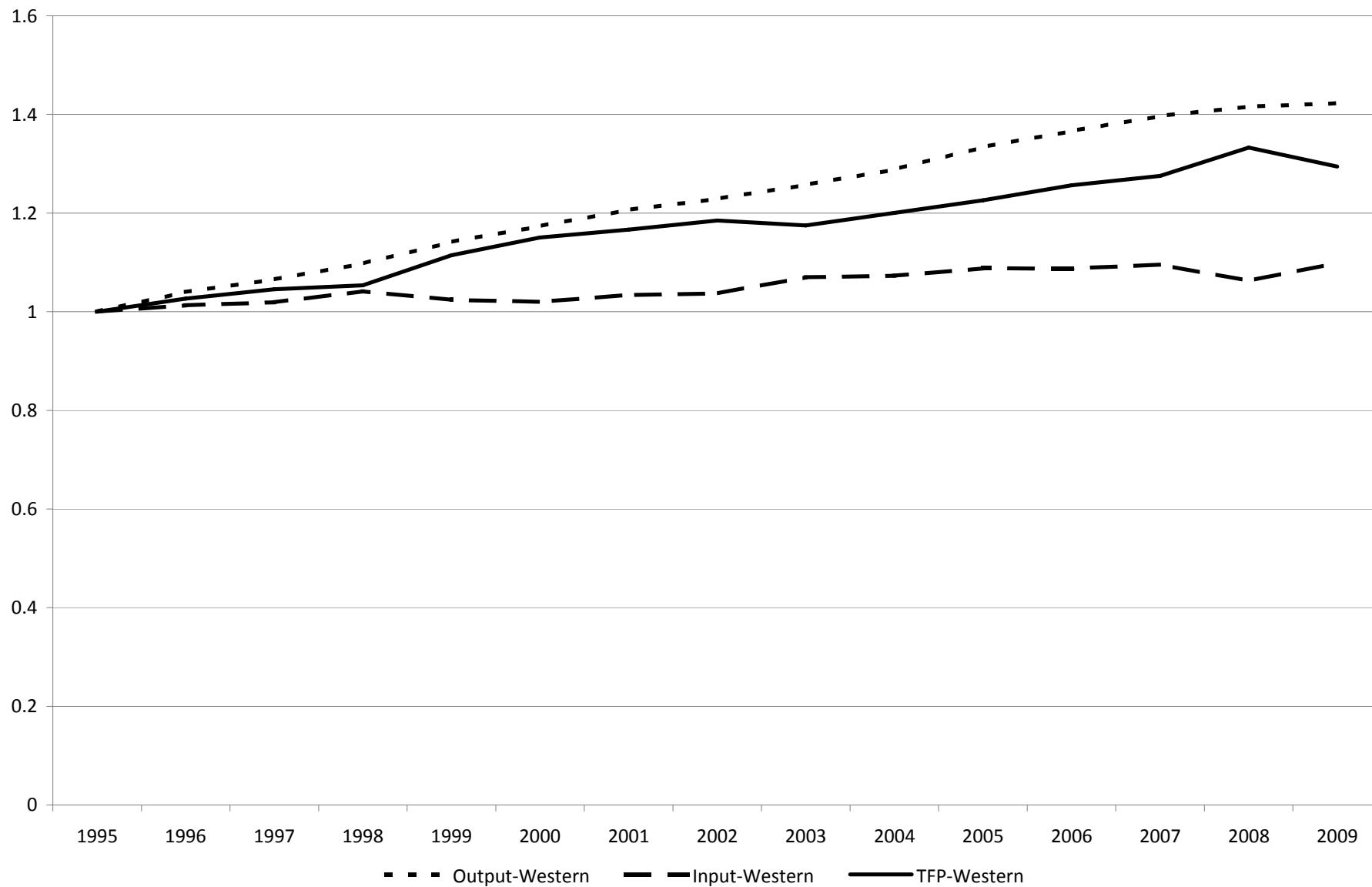


Figure 2
Productivity Results - Western LDCs



business conditions of Alberta gas utilities. The dependent variable is the MFP indexes. The explanatory or business condition variables are indexes of likely MFP growth drivers that are informed by our recent econometric cost modeling for the Gaz Metro Groupe de Travail: the number of gas customers, the number of electric customers, line miles, and a trend variable. We expect MFP growth to be more rapid the more rapid is the growth in gas and electric customers and the slower is the growth in line miles. The trend variable should reflect technological change and have a positive sign. All variables are logged, so that the parameter estimates are also estimates of cost elasticities.

Results of the econometric work can be found in Table 3. It can be seen that all of the business condition variables have sensible elasticity estimates. A 1% increase in the number of gas customers increased MFP by 0.726%. A 1% increase in the number of electric customers increased MFP by 0.128%. A 1% increase in line miles reduces MFP growth by 0.433%. The trend variable parameter estimate reveals that MFP rose by 1.1% annually for reasons not otherwise explained by the model. The adjusted R^2 of the model is 0.433.

To put this model in projection mode, we assume that Alberta gas utilities will experience 2% growth in line kilometers and the number of gas customers over the sample period. There will be no growth in the number of electric customers served. The model then forecasts MFP growth of $1.1\% + 0.726 \times 2\% - 0.433 \times 2\% = 1.686\%$. The AUC and other parties to this proceeding are free to revise this projection using more refined business condition forecasts.

3.5 Results from Other Recent Productivity Studies

3.5.1 NERA Study

Let's consider now how our research results for the CCA compare with those from other recent studies of gas and electric power distributor productivity. We begin with a discussion of the study filed by NERA in this proceeding.¹⁵ The authors calculate the MFP trend of U.S. electric utilities as providers of power distribution services. Expenses for power procurement, generation, transmission, customer accounts, customer service and

¹⁵ Jeff D. Makhholm and Agustin J. Ros, *Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative* (NERA, December 2010).

Table 3

Econometric Model of Gas Distributor MFP Trend

VARIABLE KEY

N = Number Customers
 LM = Line Miles
 NE = Number of Electric Customers
 Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.726	10.61	0.00
LM	-0.433	-5.48	0.00
NE	0.128	3.16	0.00
Trend	0.011	7.63	0.00
Constant	0.576	8.99	0.00
Rbar-Squared	0.433		
Sample Period	1995-2009		
No. of Observations	480		

information, and A&G (including pensions and benefits), which are itemized on the FERC Form 1, were excluded from the study. Taxes were included. Capital cost is measured using a one hoss shay methodology. Output is measured using a revenue-weighted volumetric output index.

Over the full 1973-2009 sample period, NERA reports 0.85% average annual MFP growth.¹⁶ Over the more recent 1999-2009 period, however, NERA reports a 0.99% average annual *decline* in MFP. The authors recommend use of the MFP trend for the full sample period.

We believe that the NERA study has flaws and natural limitations that reduce its suitability for use in the calibration of X factors for energy distributors. The problems with the study contribute to the finding of negative MFP growth in recent years. Here is an itemization of some of the most noteworthy problems with the NERA study which we have identified.

- In the early years of the sample period, the study relied on FERC Form 1 data on the number of employees to measure the labor quantity trend. This approach is unnecessary and probably inadvisable inasmuch as the number of employees is available only for aggregate company operations and may include construction workers. For years after 2001, when the employee data were no longer reported on the FERC Form 1, NERA used the escalation in labor *cost* to measure labor quantity growth.¹⁷ The growth in an input quantity index was shown in relation [4] to equal the growth in cost less the growth of the corresponding input price index. The prices of salaries and wages in the United States grew by around 3% annually on average from 2001 to 2006. Thus, NERA grossly overstated labor quantity growth in the later years of the sample period but not in the earlier years, and this is a major reason for the finding of a recent decline in productivity growth. A sharp run up in the labor quantity after 2001 is visible in Figure 7 on p. 31 of NERA's report. Four of the six years in which NERA's productivity index declined by more than 2% in a year occurred after 2001. Two of these four

¹⁶ NERA calls their MFP index a "total factor" productivity ("TFP") index.

¹⁷ NERA states on p. 9 of its report that "Beginning in 2002, the FERC Form 1 no longer contains employee data. To account for this change, we estimated the number of employees by using the previous year's payroll growth rate for the years 2002 to 2009."

outcomes did not occur in a recession year, whereas the other two large declines in productivity both occurred during recession years (1982 and 2001). We recommend that NERA recalculate the labor quantity by taking the difference between the growth in salaries and wages and the inflation in an appropriate salary and wage price index using relation [4].

- There are several problems with the NERA output specification. The authors use an entirely volumetric output index. As can be seen by an examination of the output data in Table 4 on p. 20 of the report, the volumetric index is quite volatile and falls sharply in recession years, which happen to include the last two years of the sample period. Thus, the desire for a recent sample period end date is at odds with the desire to estimate a long run MFP trend. Removal of the last two years of the sample period would alone raise the estimated MFP growth trend since 1972 to 113 basis points.¹⁸

Another problem with NERA's output treatment is that the authors rely on the FERC Form 1 for their volume data. The volumes reported on the FERC Form 1 are *sales* volumes rather than *delivery* volumes. As such, they produce spurious trends for electric utilities that were restructured to face retail power market competition and lost substantial sales to competing merchants but did not experience corresponding declines in deliveries. Restructuring of the industry commenced in the late 1990s. Data on *deliveries* of power are readily available on Form EIA 861 for years after 1990 and are routinely used by PEG Research in studies where volume data are needed. Using this data source we find, for example, that the decline in the industrial volume of Massachusetts Electric was much less precipitous than that reported in the FERC Form 1. It would be straightforward for NERA to patch FERC Form 1 data for early years of the sample period with Form EIA 861 data for the later years.

Consider also that NERA assigns a weight to the sales volume of each customer class that is based on its share of a utility's *total* sales revenue, which includes a sizable charge for energy procured. NERA reports that this approach produces a 20.51% weight for industrial sales volumes. While revenue share weighting is

usually desirable, a 20.5% share for the industrial volume is far above the typical share of industrial customers in power distribution *base* rate revenues since these customers tend to have high load factors and many take delivery of power directly from the transmission grid. NERA's approach to revenue weighting heightens the effect on measured output growth of the slow growth in industrial deliveries that occurred during the sample period and magnifies the spurious impact on measured output growth of declines in industrial sales volumes due to retail competition. NERA reports in Table 1 on p. 16 of its report that the industrial volume grew much more slowly than the more important residential and commercial volumes during the full sample period.

- NERA uses a one-hoss shay approach to the calculation of the capital cost and quantity. Under this approach, we have noted that the value of an asset does not decline gradually due to depreciation but instead is removed from the rate base abruptly when it is no longer used and useful. As in studies by PEG Research, the authors make a rough estimate of the capital stock in an early benchmark year using the *net* plant value.¹⁹ However, *gross* plant value is consistent with NERA's calculation of capital cost using the one hoss shay specification. Thus, the capital quantity is likely to have been underestimated in the benchmark year. This in principle imparts a downward bias to the measured productivity trend that is most pronounced in the early years of the sample period.
- In common with PEG Research, NERA uses a perpetual inventory approach to construct its capital quantity index. Under this approach, the quantity of capital held in a given year is a function of the size of real plant additions in numerous previous years. This approach requires cumbersome adjustments for large mergers, acquisitions, and transfers of assets between power transmission and distribution. Some of the needed adjustments were apparently not made in the NERA study.
- The authors included income taxes in the cost of capital even though income taxes are Y factored in the ATCO Gas proposal.

¹⁹ Note, however, that net plant value had to be imputed because NERA relied on electronic data.

We have demonstrated that NERA's study has flaws and limitations that reduce its relevance in the determination of X factors for Alberta power distributors. The problems are especially evident in the later years of the sample period. Results for these years should not be used in an Alberta X factor calibration. Absent extensive corrections, the interval of the NERA study that is most worthy of consideration is the 15 year period from 1981 to 1995 period. This is the period before NERA's questionable treatment of delivery volumes and labor quantities becomes material and after the impact of its questionable handling of the benchmark year diminishes. The average MFP growth in NERA's productivity index for this period is 1.43%.

Considering the problems in the NERA study it is remarkable that Dr. Carpenter and Dr. Schoech, in their testimony for ATCO Gas and AltaGas respectively, urged the Commission to focus on the NERA results for the later years of the sample period. Dr. Schoech and Dr. Carpenter responded to data requests from the CCA by saying that they had reviewed the NERA methodology and had no major problems with it. Their speculations as to why power distribution productivity might have declined in recent years and their proposals to rely selectively on NERA's negative productivity results should carry little or no evidentiary weight in the Commission's deliberations on Alberta X Factors.

Notwithstanding the questionable quality of its study of the MFP trend of *power* distributors, NERA nonetheless tenders this study as one that is also satisfactory for determining X factors for Alberta *gas* distributors. We disagree. The AUC noted the following criteria for the productivity study it commissioned from NERA.

The MFP study must

- Be applicable to Alberta gas and electric utilities;
- Compare productivity for gas and electric utilities to economy wide productivity;
- Make the comparison in a transparent manner;
- Use publicly available data;
- Be for use and testing in a regulatory proceeding and for adjusting rates for Alberta gas and electric utilities;

We believe that our study for the CCA does a better job of meeting the Commission's criteria for the development of gas distributor X factors.



- It measures the productivity trends of gas distributors rather than power distributors. This matters, since research has found that the productivity growth of gas distributors is generally more rapid than that of power distributors. The productivity trends of gas distributors tend to be especially high in rapid-growth service territories such as those found in Alberta. NERA reports that, from 1972 to 2006, the trends in the Statistics Canada MFP Indexes for the electricity and gas & water utility industries (discussed further below) are quite similar. While this is true, this particular sample period was unusual for having similar trends. For both longer and shorter sample periods, the gas & water MFP growth trend is materially more rapid than that for electric utilities.
- Our methodology is transparent and sensible and the code for the calculations is available for inspection.
- Most of the data used in our study are publicly available, including all of the data on O&M expenses, plant additions, outputs, and input prices during the 1996-2009 sample period. The older capital data are not publicly available, but were all obtained from a standardized form (the Uniform Statistical Report of the American Gas Association) and are available for scrutiny by participants in this proceeding who sign a confidentiality agreement.
- Our study is tailored to the development of revenue per customer indexes such as those proposed by Alberta gas utilities. We also consider the effect of rapid customer growth that is expected in Alberta on gas distributor productivity. Moreover, our research considers the implications for X factors of Y factoring a substantial portion of capex cost.
- NERA's rationale for not undertaking a gas productivity study seems to hinge on the fact that gas distributor data are unavailable for a "broad population of industry participants". Our study is based on data for 34 gas distributors. NERA states that it has previously presented productivity research in testimony to support X factors twice over the



years. In one case it proposed an X factor for Central Maine Power based on a study of the productivity trends of 25 Northeast power distributors. In the other, it proposed an X factor for UtiliCorp Networks Canada (d/b/a FortisAlberta) based on a study of the productivity trends of 12 power distributors in the western US.

3.5.2 Other Recent Studies

Here is a summary of some other recent energy distributor productivity studies we are aware of.

- In 2008, PEG Research prepared a study for the Ontario Energy Board on the MFP trends of U.S. power distributors. The study was used to calibrate the X factors in price cap plans for Ontario power distributors. An elasticity-weighted output index and a GD approach to capital costing were employed in the study. Over the 1989-2006 period, a 0.72% average annual MFP growth rate was reported.²⁰
- In 2010, PEG Research filed testimony in California on the recent MFP trends of US gas and electric power distributors.²¹ The work was done on behalf of two large Sempra Energy utilities: San Diego Gas & Electric and Southern California Gas. The research used the number of customers as the output quantity index and the GD approach to the calculation of capital cost. In the 1999-2008 period, a 1.18% average annual MFP growth rate was found for gas distributors and a 0.88% average annual MFP growth rate for power distributors. Thomas Renaghan, a productivity expert at the California Public Utilities Commission, replicated these results in recent testimony.²²
- In 2011, PEG Research released a report on a study of the recent MFP trends of two large Ontario gas distributors: Enbridge Gas Distribution and Union Gas.

²⁰ Kaufmann, L., *et al* (2008), *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, Report Prepared for the Ontario Energy Board, February 2008.

²¹ See, for example, the report of Mark Newton Lowry and David Hovde, "Productivity Research for San Diego Gas & Electric", in Docket A.10-12-005/006, December 2010.

²² See report of Tom Renaghan, "SDG&E and SoCalGas Total Factor Productivity Study" in A.10-12-005/006, September 2011. Mr. Renaghan states on page 2 of his report that "Based on DRA's replication of PEG's power and gas distribution TFP results and DRA's alternative output scenarios for the electric sector, DRA concludes that PEG's TFP results are reasonable".



The report was prepared for the Ontario Energy Board. The study used an elasticity-weighted output index and the COS approach to capital costing. In the 2006-2010 period, a 1.07% average annual MFP growth rate was found for EGD and a 1.65% average annual growth rate for Union Gas.²³

- Also in 2011, PEG Research released a report on a study of the recent MFP trend of Gaz Metro. The report was prepared for a Gaz Metro Groupe de Travail to aid it in the development of a new PBR plan. The study featured an elasticity-weighted output index and the COS approach to capital costing. In the 2000-2009 period, a 1.66% average annual MFP growth rate was reported.²⁴
- Also in 2011, PEG Research has filed testimony for three US power distributors on the MFP trend of power distributors in the Northeast US.²⁵ The study used the number of customers to measure output and a COS approach to capital costing. Over the 1999-2010 period, a 0.64% average annual MFP growth rate was reported.
- Statistics Canada maintains MFP indexes for the utility sector of the Canadian economy and two subsectors: “Electric power generation, transmission, and distribution” and “natural gas distribution, water, and other systems”. All three indexes are available on both a “gross output” and a “value added” basis. The gross output approach is most similar to that conventionally used in productivity studies for X factor calibration because it includes intermediate inputs like materials and services. The value added approach does not, and is intended for use in the calculation of the MFP growth of the Canadian aggregate business sector.²⁶ Only results for the value added utility MFP index are reported on a timely basis. Over the full sample period, from 1962-2010, this index has exhibited a 0.67 % average annual growth rate. Over the last twenty years, from

²³ Lawrence Kaufmann, *et al* (2011), *Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans*, Report Prepared for the Ontario Energy Board, September 2011.

²⁴ Mark Newton Lowry and David Hovde (2011), *Research for Gaz Metro's Performance Incentive Mechanism*, Report Prepared for the Gaz Metro Groupe de Travail in R-3693-2009.

²⁵ See, for example, the testimony of Mark Newton Lowry on behalf of Atlantic City Electric in New Jersey, Docket Number E011100650.

²⁶ It is difficult to use macroeconomic data to compute the MFP of the aggregate private business sector if intermediate inputs are included.

1981 to 2010, the value-added utility MFP index has averaged 0.34% average annual growth. Over the last ten years, from 2001 to 2010, this index has averaged a 0.98% average annual decline.

The results of the value-added utility MFP index are featured in the testimony of witnesses Carpenter and Schoech but are of limited relevance in setting X factors for Alberta energy distributors, for several reasons.

- It is a value-added calculation. As such, it ignores productivity in the use of intermediate inputs and is sensitive to the quality of data available on intermediate inputs.
- It is sensitive to developments in the generation sector of the electric utility industry. This has very little relevance to network industries such as gas and electric power distribution. For example, the growth in the index is slowed by Hydro Quebec projects to develop remote hydroelectric resources.
- The electric utility industry restructured in Alberta and Ontario in the last decade. It is not clear how well this has been handled by Statistics Canada.
- A volumetric output index is employed. This makes results sensitive to changing business conditions including, particularly, recessions and slowing growth in average use. Measured output fell substantially in 2008, 2009, and 2010. A very long sample period such as NERA has proposed would be necessary to smooth over the effects of this extraordinary decline.
- Measured productivity growth is doubtless slowed by growth in expenses for utility DSM programs, which are large in several Canadian provinces. Measured productivity growth may also have been slowed by a rising trend in uncollectible bills.
- Given all of the circumstances surrounding the recent decline in the index, it would certainly not make sense to combine a 2010 (or 2009) end date with a relatively recent start date such as 2000 if the long term MFP trend of the utility sector is of interest. In the ten years ending in 2007, the last year

before the recession, the value added utility MFP index averaged 1.17% annual growth.²⁷

The Statistics Canada MFP indexes for “electric power generation, transmission, and distribution” and “natural gas distribution, water, and other systems” are published, with a lag, on both a gross value and a value added basis. They are currently available only through 2007. Using the more relevant gross output approach, Statistics Canada reports a 1.13% average annual growth rate in gas and water sector productivity for the full 1962-2007 period. For the most recent 20 years, the productivity trend is 1.56%. For the most recent ten years (1998-2007), the productivity trend is 2.83%. These numbers are remarkably high when it is considered that output is measured volumetrically, and thereby reflects the material decline in average use of gas by Canadian residential and commercial customers that has been underway for many years. Statistics Canada assigns letter grades to the quality of the data on intermediate inputs it uses in its productivity work. They assign an A grade to the gas and water data.

- As for the MFP index for the “electric power generation, transmission, and distribution”, the relevance of this index to the establishment of X factors for energy distributors is questionable. Using the gross output approach, Statistics Canada reports a 0.79% average annual growth rate in utility sector productivity for the full 1962-2007 period. For the most recent 20 years (1988-2007), the productivity trend is 0.15%. For the most recent ten years (1998-2007), the productivity trend is 0.31%. Statistics Canada assigns a C grade to the electric power data on intermediate inputs. .
- The Center for the Study of Living Standards (“CSLS”) retained Statistics Canada to prepare a study of productivity trends at the provincial level. A report on the research was released in 2010.²⁸ This study reported results only for value added MFP indexes. After extensive correspondence between PEG Research and

²⁷ Using the accurate *gross output* approach, Statistics Canada reports a 0.91% average annual growth rate in utility sector productivity for the full 1962-2007 period. For the most recent 20 years, the productivity trend is 0.44%. For the most recent ten years (1998-2007), the productivity trend is 0.86%.

²⁸ CSLS, *New Estimates of Labor, Capital, and Multifactor Productivity Growth and Levels for Canadian Provinces at the Three Digit NAICS Level 1997-2007*.

principles of this study, the principles conceded that the study used an experimental methodology and is not of a high enough standard to be used in X factor determination.

3.5.3 Conclusions

Our review of recent productivity studies suggests that vigorous growth in the MFP of natural gas distributors has been the norm for both the U.S. and Canada in the last fifteen years. The NERA result of declining power distribution productivity in the last decade is anomalous, and reflects flaws and limitations of the research methodology. The Canadian utility MFP index that is highlighted in the testimony of other witness is of questionable relevance. It includes power generation and DSM costs and uses a volumetric output index that is highly sensitive to the recessionary conditions at the end of the sample period. A 2007 end date for the sample period produces a better estimate of the long-run MFP trend and produces results that are quite different.

The best available estimate of the *recent* MFP growth trend of U.S. power distributors is probably that presented by PEG Research in California testimony and confirmed by an expert for the Division of Ratepayer Advocates. This places a *lower* bound on the productivity trend that is pertinent for the design of *price* cap indexes because it is based on customer growth and thereby ignores the (modest) growth in the average use of power by small-volume customers that was typical during this period. For electric utilities that, like ATCO Electric, have high customer charges the use of the number of customers as the output measure is, in any event, fairly appropriate. Should the Commission nonetheless wish to base the X factors for Alberta power distributors on the NERA research, the 1.45% growth trend for the 1981-95 period is recommended.

We conclude that the base productivity factor for ATCO Gas and AltaGas should exceed 100 basis points. Specifically, we propose that it lie in the [1.32% - 1.69%] range that is bounded by the average industry MFP trend and our customized econometric productivity projection. Should the Commission sanction recovery of the costs of certain routine capital expenditures outside the indexing mechanism, a higher base productivity factor may be warranted.



3.6 Stretch Factor

The stretch factor term of the X factor was noted in Chapter 2 to facilitate the sharing, between utilities and customers, of any benefits that are expected to result from the stronger performance incentives that are generated by an IR plan. We have relied on three sources in developing our stretch factor recommendation. One is historical precedent. The average explicit stretch factor approved for rate and revenue indexing plans of energy utilities with rate escalation mechanisms informed by productivity research is about 0.50%.

Our second substantive basis for proposing stretch factors is our incentive power research. We have developed an incentive power model that estimates the typical cost performance improvements that will be achieved by utilities under stylized regulatory systems. The use of numerical analysis permits us to consider regulatory systems of considerable relevance. Clients who have supported the development of this model have included the Ontario Energy Board and US and Canadian gas distributors.

Alberta energy distributors have been operating for several years under a two year rate case cycle. There is no earnings sharing mechanism. Suppose, now, that this is replaced with a regulatory system with a five year rate case cycle and an ESM that shares surplus and deficit earnings 75/25 between the utility and its customers. Our incentive power model suggests that the typical annual cost performance gain in the long run is 0.66% under the current system and 1.17% under the new system, a gain of 51 basis points.²⁹

Based on our experience, we believe that gas distributors in our U.S. sample held rate cases about every three years on average during the sample period we used to calculate MFP trends. Earnings sharing mechanisms were uncommon. Our incentive power model suggests that the typical cost performance gain in the long run is 0.90% under this system. Using industry average productivity growth to set the base X factor thus guarantees customers the first 24 basis points of expected productivity gains under the PBR plan. The stretch factor can be used to divide the remaining 27 basis points between the utility and customers. A stretch factor equal to *all* of the incremental acceleration in annual performance improvement is 27 basis points. A stretch factor equal to half of the

²⁹ This model has not been calibrated to reflect the latest productivity research results. However, comparisons between regulatory systems should still be meaningful.

incremental performance gains is about 13 basis points. We have traditionally advocated an equal sharing of such accelerations.

A final consideration in determining stretch factors for Alberta gas utilities is the *level* of efficiency that the Companies have already achieved. Recall from our discussion in Section 2.1 that a high level of initial efficiency reduces prospects for reductions in X-inefficiency. This is an empirical issue, and neither company has to our knowledge filed a rigorous and persuasive appraisal of its operating efficiency. However, it is noteworthy that both Companies have been filing rate cases every two years for some time. This is a regulatory system with weak incentive properties.

Dr. Carpenter presents several flawed arguments as to why ATCO Gas should have no stretch factor. He states that a stretch factor is unnecessary for an “average” utility “which has been operating under a traditional regulatory framework with significant incentives for improving productivity”. But the ATCO companies have in fact been filing frequent rate cases for many years. This is likely to have undermined the companies’ incentives for cost containment. Dr. Carpenter also argues against a stretch factor on the grounds that it would constitute asymmetric sharing. We believe that the ATCO Gas proposal would assign to the company most of the expected productivity gains since there would be no stretch factor and a wide dead band in the earning sharing mechanism.

Dr. Schoech provides some novel explanations as to why his client should have a zero stretch factor. The service territory is “unique” and the company is small and has a low ratio of customers to pipeline kilometers. As Dr. Schoech has not considered any gas productivity research in his testimony, there is no substantiation for the notion that any of these conditions slow potential productivity growth, rather than accelerating it.

All things considered, we believe that the indicated range of potential stretch factors is [0.13-0.50].

3.7 Input Price Research

3.7.1 Macroeconomic Price Indexes

We noted in Section 2.2.4 that macroeconomic output price indexes pose fewer complications in the design of an attrition relief measure in Canada than they do in the United States. The chief reason is that the productivity trend of the Canadian economy is



close to zero. Macroeconomic price indexes also merit consideration as a subindex in an industry-specific input price index.

Table 4 shows the trends in seven macroeconomic output price indexes that are sensible candidates for use in Alberta. Here are the indexes with a brief discussion of noteworthy features.

- The CPI for Canada is the inflation measure most familiar to Canadian consumers. This type of inflation measure is the norm in British and Australian PBR. It is less common in North American PBR because it places a fairly heavy weight on price-volatile consumer commodities like gasoline, natural gas, and food. These commodities make the CPI more volatile and have much more impact on the budget of a typical consumer than they do on the cost of an energy distributor's base rate inputs. CPIs also have the disadvantage of not being revised.
- The CPI for Alberta ("CPI^{Alberta}") has the drawbacks just noted for the CPI but has material advantage of being specific to the province. It should therefore be more sensitive to local business conditions than the national CPI. It is forecasted annually by Alberta Finance in its annual Economic Outlook.
- The core CPI (CPI^{core}) excludes inflation in the prices of price-volatile commodities such as gasoline and food. It is available for Canada but not for Alberta.
- GDPIs track inflation in the prices of capital equipment and net exports as well as consumer products. They are periodically updated, and are available for Alberta as well as Canada. In the United States, a gross domestic product price index has been preferred over the CPI in PBR plans because the impact of price-volatile consumer commodities is watered down. However, in Canada's economy with its sizable reliance on natural resource exports, this stabilizing benefit is offset by the impact of incorporating inflation in commodity exports.
- The GDPIs for final domestic demand (GDPI^{FDD}) remove the inflation impact of price volatile exports. They are available for Alberta as well as Canada.

Table 4

Macroeconomic Inflation Measures for Alberta and Canada

Canada									Alberta						
CPI (all items) ¹			Core CPI ^{1 2}		Gross Domestic Product Implicit Price Indexes ³				CPI (all items) ¹		Gross Domestic Product Implicit Price Indexes ³				
					Comprehensive		Final Domestic Demand				Comprehensive		Final Domestic Demand		
Year	Level	Growth Rate ⁴	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	
1980	44.0								44.1						
1981	49.5	11.8%			55.7		53.6		49.8	12.2%	65.1		55.6		
1982	54.9	10.4%			60.4	8.1%	58.7	9.1%	55.4	10.7%	71.6	9.5%	60.7	8.8%	
1983	58.1	5.7%			63.7	5.3%	61.9	5.3%	58.3	5.1%	74.4	3.8%	63.3	4.2%	
1984	60.6	4.2%	62.9		65.8	3.2%	64.4	4.0%	59.8	2.5%	76.2	2.4%	64.8	2.3%	
1985	63.0	3.9%	65.1	3.4%	67.8	3.0%	66.7	3.5%	61.6	3.0%	75.6	-0.8%	66.5	2.6%	
1986	65.6	4.0%	68.0	4.4%	69.9	3.1%	69.2	3.7%	63.7	3.4%	67.1	-11.9%	68.4	2.8%	
1987	68.5	4.3%	71.0	4.3%	73.1	4.5%	72.0	4.0%	66.3	4.0%	68.2	1.6%	70.2	2.6%	
1988	71.2	3.9%	74.0	4.1%	76.4	4.4%	74.7	3.7%	68.1	2.7%	67.2	-1.5%	72.2	2.8%	
1989	74.8	4.9%	77.2	4.2%	79.8	4.4%	77.9	4.2%	70.9	4.0%	69.8	3.8%	75.0	3.8%	
1990	78.4	4.7%	79.8	3.3%	82.4	3.2%	80.9	3.8%	75.0	5.6%	74.2	6.1%	78.4	4.4%	
1991	82.8	5.5%	82.1	2.8%	84.8	2.9%	83.7	3.4%	79.4	5.7%	73.5	-0.9%	80.9	3.1%	
1992	84.0	1.4%	83.6	1.8%	85.9	1.3%	85.1	1.7%	80.6	1.5%	74.9	1.9%	82.6	2.1%	
1993	85.6	1.9%	85.3	2.0%	87.2	1.5%	86.8	2.0%	81.4	1.0%	75.7	1.1%	84.1	1.8%	
1994	85.7	0.1%	86.9	1.9%	88.2	1.1%	88.1	1.5%	82.6	1.5%	77.3	2.1%	85.9	2.1%	
1995	87.6	2.2%	88.8	2.2%	90.2	2.2%	89.2	1.2%	84.5	2.3%	78.3	1.3%	86.7	0.9%	
1996	88.9	1.5%	90.3	1.7%	91.6	1.5%	90.2	1.1%	86.4	2.2%	82.3	5.0%	88.3	1.8%	
1997	90.4	1.7%	92.0	1.9%	92.7	1.2%	91.5	1.4%	88.1	1.9%	83.6	1.6%	90.5	2.5%	
1998	91.3	1.0%	93.2	1.3%	92.3	-0.4%	92.7	1.3%	89.2	1.2%	79.7	-4.8%	91.9	1.5%	
1999	92.9	1.7%	94.5	1.4%	93.9	1.7%	93.9	1.3%	91.4	2.4%	85.7	7.3%	93.3	1.5%	
2000	95.4	2.7%	95.7	1.3%	97.8	4.1%	96.1	2.3%	94.5	3.3%	99.9	15.3%	95.6	2.4%	
2001	97.8	2.5%	97.7	2.1%	98.9	1.1%	97.8	1.8%	96.7	2.3%	102.6	2.7%	97.4	1.9%	
2002	100.0	2.2%	100.0	2.3%	100.0	1.1%	100.0	2.2%	100.0	3.4%	100.0	-2.6%	100.0	2.6%	
2003	102.8	2.8%	102.2	2.2%	103.3	3.2%	101.5	1.5%	104.4	4.3%	109.5	9.1%	100.9	0.9%	
2004	104.7	1.8%	103.8	1.6%	106.6	3.1%	103.2	1.7%	105.9	1.4%	116.0	5.8%	103.0	2.1%	
2005	107.0	2.2%	105.5	1.6%	110.1	3.2%	105.5	2.2%	108.1	2.1%	128.6	10.3%	106.0	2.9%	
2006	109.1	1.9%	107.5	1.9%	113.0	2.6%	107.9	2.2%	112.3	3.8%	132.1	2.7%	111.1	4.7%	
2007	111.5	2.2%	109.8	2.1%	116.7	3.2%	110.4	2.3%	117.9	4.9%	139.0	5.1%	116.1	4.4%	
2008	114.1	2.3%	111.7	1.7%	121.4	3.9%	112.9	2.2%	121.6	3.1%	155.5	11.2%	120.1	3.4%	
2009	114.4	0.3%	113.6	1.7%	119.1	-1.9%	114.6	1.5%	121.5	-0.1%	135.7	-13.6%	121.3	1.0%	
2010	116.5	1.8%	115.6	1.7%	122.6	2.9%	116.0	1.2%	122.7	1.0%	143.8	5.8%	122.3	0.8%	
Average Annual Growth Rates															
1988-2007		2.44%	2.18%		2.34%		2.14%		2.88%		3.56%		2.52%		
1998-2007		2.10%	1.77%		2.30%		1.88%		2.91%		5.08%		2.49%		
1981-2010		3.25%	2.34%		2.72%		2.66%		3.41%		2.73%		2.72%		
1991-2010		1.98%	1.85%		1.99%		1.80%		2.46%		3.31%		2.22%		
2001-2010		2.00%	1.89%		2.26%		1.88%		2.61%		3.64%		2.46%		

Footnotes

¹ Statistics Canada. Table 326-0021 - Consumer Price Index (CPI), 2005 basket, annual (2002=100 unless otherwise noted) (table)

² The Core CPI excludes volatile components of the all items CPI: fruit, fruit preparations and nuts; vegetables and vegetable preparations; mortgage interest cost; natural gas; fuel oil and other fuels; gasoline; inter-city transportation; and tobacco

³ Statistics Canada. Table 384-0036 - Implicit price indexes, gross domestic product (GDP), provincial economic accounts, annual (index, 2002=100)

⁴ All growth rates are calculated logarithmically.

Inspecting the numbers in Table 4, it can be seen that these indexes vary considerably in their volatility, which is measured in the last row of the table by the standard deviation of their growth rates. The CPIs and GDPIPIs for Canada and Alberta are much more volatile than the core CPI or the GDPIPIs for final domestic demand in Canada and Alberta. In 2009, for instance, the CPI (all items) for Canada and Alberta grew only 0.3% and -0.1%, and the GDPIPI for Canada and Alberta *fell* by 1.9% and 13.6%. In the same year, the core CPI grew by 1.7% and the GDPIPI^{FDD} for Canada and Alberta grew by 1.5% and 1.00%, respectively. The longer-term trends in Canada's core CPI and the GDPIPI^{FDD} are quite similar.

Comparisons between the Alberta and Canadian price indexes are also instructive. For both the CPI and the GDPIPI^{FDD}, inflation in Alberta was substantially above the Canadian norm in several years (*e.g.* 2006, 2007, and 2008) and quite a bit slower in other years (*e.g.* 1984). Note also that since 1980 inflation has tended to be modestly more rapid in Alberta than in Canada using both indexes.

Should the AUC wish to use a macroeconomic output price index as the inflation measure, we recommend on the basis of this review that it use either the CPI^{Alberta} or the GDPIPI^{FDD} for Alberta. Both of these indexes are also suitable for use as an input price subindex.

3.7.2 Custom Input Price Indexes

Suppose, now, that the AUC instead prefers a custom utility input price index as PBR inflation measure. ATCO Gas and AltaGas have each proposed simple indexes of this kind. Each averages the estimated inflation in price subindexes for two classes of inputs: labor and other. The proposed price subindex for labor is in each plan the Average Weekly Earnings ("AWE") for the Industrial Aggregate in Alberta. The proposed subindex for other inputs is CPI^{Alberta}. Both companies propose weights for the labor price that far exceed the share of direct salaries and wage expenses in the total annual cost that would be subject to recovery via the revenue per customer index. ATCO Gas, for example, proposes a labor cost share of 57%. They arrive at this share by adding to the share of direct salaries and wages the estimated share of labor in capex.

Table 5 presents alternative indexes of salary and wage prices that are available for an industry-specific input price index. The fixed weight index of the average hourly earnings (“AHE”) of all employees in Alberta have the advantage of being expressly designed to measure labor price *trends*. The average weekly earnings (AWE) for Alberta is not and is therefore prone to aggregation bias. The AWE covers a somewhat broader range of workers (*e.g.* those whose basic remuneration is not in the form of a wage rate or a salary but rather an alternative such as commissions and piece rates) and is forecasted by Alberta Finance.

Comparing the results in Tables 4 and 5, it can be seen that the inflation in all of the labor price indexes tends to rise considerably more rapidly than the CPI in Alberta and Canada as a whole. From 2001-2010, for instance, the AWE averaged 4.0% annual growth whereas the CPI^{Alberta} averaged only 2.61% annual growth. Each company therefore benefits from having a large labor cost share in its inflation measure, and a proposal for a share that is much larger than the share of direct labor in their total applicable cost is a good area for scrutiny.

We advise the Commission to reject the proposed labor price weighting of ATCO Gas and instead assign a labor price weighting that is commensurate only with the share of direct labor costs in the total costs that are subject to indexing. We tender this advice for three reasons. One is that under regulatory accounting capital cost is, as we discuss in Section 2.1.4, a function of construction prices over many years and not only of the construction price in the current year. Thus, insofar as labor prices affect the cost of capital, it is the trend in the prices over many years that is relevant and not the current price.

Another reason for rejecting the Company’s proposed weighting is that they propose to apply CPI^{Alberta} to a collection of costs that comprises materials, services, and non-labor capex. We believe that the underlying technology for the provision of consumer products is considerably more labor intensive than the underlying technology for the provision of the inputs in this residual input basket.³⁰ The Statistics Canada MFP index for the aggregate business sector, for instance, has a cost share weight for labor that is four times the weight for capital. Given the tendency of labor prices to growth more rapidly than the prices of other inputs, and the slight decline in the MFP growth for the private business sector, we

Table 5

Salary and Wage Price Indexes for Alberta and Canada

Year	Fixed weighted index of average hourly earnings (AHE) for all employees ^{1 2}								Average weekly earnings (AWE) for all employees (Industrial aggregate excluding unclassified businesses) ^{2 3}				Composite construction union wage rate index ⁴		
	Canada				Alberta				Canada		Alberta		Canada	Calgary	Edmonton
	Industrial Aggregate	Growth Rate	Utilities	Growth Rate	Industrial Aggregate	Growth Rate	Utilities	Growth Rate	Level	Growth Rate	Level	Growth Rate			
1981													39.98	40.13	40.43
1982													43.73	44.47	44.97
1983													49.21	50.51	50.96
1984													51.00	52.10	52.80
1985													52.23	52.23	52.87
1986													53.72	52.01	52.65
1987													55.17	52.05	51.64
1988													57.21	52.22	51.72
1989													59.91	52.96	52.41
1990													63.20	56.48	56.07
1991	82.03		67.29		78.84		73.98		553.15		545.19		66.98	59.34	59.28
1992	84.74	3.25%	70.06	4.03%	80.45	2.02%	77.98	5.27%	572.41	3.42%	561.55	2.96%	70.07	63.45	62.97
1993	86.44	1.99%	72.28	3.12%	82.45	2.46%	79.51	1.94%	582.87	1.81%	570.68	1.61%	71.72	65.74	64.62
1994	87.63	1.36%	73.11	1.15%	82.51	0.07%	79.87	0.45%	592.88	1.70%	573.63	0.52%	73.19	66.73	65.43
1995	89.62	2.25%	74.44	1.81%	83.08	0.69%	80.94	1.34%	598.67	0.97%	572.49	-0.20%	74.57	67.37	67.05
1996	91.74	2.34%	75.79	1.80%	87.21	4.85%	81.66	0.88%	611.01	2.04%	596.81	4.16%	75.27	67.50	67.60
1997	92.29	0.60%	77.63	2.39%	88.96	1.99%	82.78	1.36%	623.43	2.01%	618.23	3.53%	76.80	68.66	69.12
1998	93.80	1.62%	80.82	4.03%	92.18	3.55%	87.18	5.18%	632.72	1.48%	635.01	2.68%	78.38	71.42	72.23
1999	94.85	1.11%	86.17	6.41%	94.78	2.79%	90.91	4.19%	640.47	1.22%	644.07	1.42%	79.74	74.66	75.35
2000	96.78	2.01%	88.79	3.00%	96.56	1.86%	95.84	5.28%	655.55	2.33%	663.09	2.91%	81.77	79.32	80.02
2001	98.05	1.31%	94.93	6.68%	98.96	2.46%	93.45	-2.53%	657.01	0.22%	676.66	2.03%	83.79	83.33	83.81
2002	100.18	2.15%	99.91	5.12%	100.20	1.25%	100.06	6.83%	672.85	2.38%	694.05	2.54%	87.02	88.43	89.30
2003	103.13	2.90%	105.13	5.10%	104.75	4.44%	104.19	4.05%	690.87	2.64%	718.3	3.43%	89.28	91.08	92.10
2004	105.91	2.66%	107.00	1.76%	107.87	2.93%	106.28	1.99%	709.37	2.64%	742.37	3.30%	91.38	92.73	93.53
2005	109.24	3.10%	108.94	1.80%	112.16	3.90%	111.75	5.02%	737.39	3.87%	785.01	5.58%	94.09	94.61	94.90
2006	112.10	2.58%	111.23	2.07%	117.23	4.42%	116.57	4.22%	755.53	2.43%	824.07	4.86%	97.03	96.67	96.38
2007	117.25	4.49%	117.40	5.40%	124.18	5.77%	132.05	12.47%	788.18	4.23%	872.61	5.72%	100.03	100.01	100.01
2008	121.34	3.43%	118.94	1.30%	132.16	6.22%	137.61	4.12%	810.96	2.85%	924.39	5.76%	104.90	107.63	108.67
2009	125.03	3.00%	125.78	5.59%	136.40	3.16%	144.08	4.60%	823.88	1.58%	950.06	2.74%	109.20	113.82	114.92
2010	128.78	2.95%	129.78	3.13%	139.88	2.52%	139.76	-3.05%	853.19	3.50%	993.28	4.45%	112.23	120.33	121.49
Average Annual Growth Rates															
1992-2010		2.4%		3.5%		3.0%		3.3%		2.3%		3.2%	1982-2010	3.6%	3.8%
2001-2010		2.9%		3.8%		3.7%		3.8%		2.6%		4.0%	1991-2010	2.9%	3.9%

Footnotes

¹ Statistics Canada. Table 281-0039 - Fixed weighted index of average hourly earnings for all employees (SEPH), excluding overtime, unadjusted for seasonal variation. Available for selected industries classified using the North American Industry Classification System (NAICS), monthly (index, 2002=100)

² Industrial aggregate covers all industrial sectors except those primarily involved in agriculture, fishing and trapping, private household services, religious organisations, and the military personnel of the defence services.

³ Statistics Canada. Table 281-0027 - Average weekly earnings (SEPH), unadjusted for seasonal variation. Available by type of employee for selected industries classified using the North American Industry Classification System (NAICS), annual (current dollars)

⁴ Statistics Canada. Table 327-0045 - Construction union wage rate indexes, monthly (index, 2007=100)

expect that $CPI^{Alberta}$ will tend to overestimate the input price inflation of the residual cost group to which it would be applied. The $CPI^{Alberta}$ is a better match for an input group that includes all capital cost.

A third reason for rejecting the proposed approach is that the labor cost share calculation is erroneous. The total annual cost that would be subject to recovery via the revenue per customer index is not even used as the denominator in the cost share calculations. Instead they use the sum of O&M expenses and *capex*.

The Commission has stated an interest in a PBR plan that resembles the one it approved for Enmax. That plan features an inflation measure that included the annual growth rate of an electric utility construction price index (“EUCPI”). Should the Commission wish to include the EUCPI or another construction price index in the inflation measures of Alberta energy utilities, we would recommend as an alternative to this a custom index that itemizes trends in the prices of three groups of base rate inputs: labor, materials & services, and capital. Each of the three input groups would have its own subindex. The weight for each subindex would be the share of the input group in the total cost of the subject utility that will be subject to indexing.³¹ In the case of ATCO Gas, for instance, the applicable total cost used to calculate cost shares would exclude costs for pensions and income taxes. The cost shares can be drawn from each company’s pro forma cost of service in the latest year for which the company has provided rate case evidence. These can be reset when the PBR plan is updated.

With respect to the inflation subindexes, we recommend the use of the $CPI^{Alberta}$ or the $GDPI^{FDD}$ for Alberta as the proxy for the M&S input price index and the Alberta AHE or AWE for the labor price index. With respect to the capital price subindex, we noted in Section 2.2.4 that a service price approach to the design of this index is consistent with the approach taken to the measurement of the capital quantity in the productivity research. The design of a capital service price should reflect the components of capital cost. Capital cost can be calculated in different ways but commonly includes depreciation and a return on the rate base. The trends in depreciation and the return on rate base both depend on the trend in the cost of constructing a unit of plant. The return on rate base depends, additionally, on the trend in the rate of return on capital.

³¹ The average shares of a group of Alberta utilities is a reasonable alternative.

The different approaches to measuring capital cost differ with respect to their relevance for utility regulation and the volatility of the capital service price. The use of the current inflation in the construction price index in the capital service price is consistent with the assumption of a current valuation of capital. This approach differs materially from capital costing under cost of service regulation and produces capital prices (and costs) that can be quite volatile.

The alternative COS approach to measuring the capital price is much more stable and more consistent with utility regulatory accounting. The COS approach to capital costing is discussed in more detail in Appendix 2. We are interested here in the lessons of this analysis for the design of reasonably simple capital price index for use in rate escalation mechanisms in Alberta. Two lessons are salient. One is that capital cost depends on the rate of return on capital in addition to construction prices. The other lesson is that capital cost depends on a *weighted average* of past construction prices and not solely on current prices. This is noteworthy, since a weighted average of current construction prices tends to be much more stable than the current construction price.

With respect to the first lesson, we recommend that a capital price used to construct a custom input price index for Alberta PBR plans be the product of a rate of return on capital and a construction price index. The rate of return on capital can be set initially at the weighted average cost of capital established for the subject utility in its most recent rate case. It can subsequently be indexed to the trends in one or more rates of return on capital assets observed in Canadian markets. Statistics Canada tracks the trends in corporate and government long term bond yields and in the return on equity of businesses in the utility industry and all industries. With respect to the second lesson, we recommend taking a weighted average of the current and past values of an available construction price index.³²

³² A “triangularized” weighting of past values of such an index would be a one sensible simplification. This approach begins by adding up a sequence of numbers between one and a certain number N (*i.e.* 1, 2, ..., N). N can be set at the average life of utility assets. The sum of the sequence (“SUM”) becomes the denominator in the calculation of weights corresponding to each number of the sequence (*e.g.* 1/SUM, 2/SUM, ...N/SUM). The largest (smallest) of these is shares is used as the weight for the construction price index (“WKA”) for the newest (oldest) year of plant additions. This makes sense since newer plant additions are less depreciated and therefore account for a larger share of the rate base. The formula may be represented mathematically as

$$\text{Construction Price Index}^{TWA} = \frac{\text{SUM}_s (N-s)}{\text{SUM}_s (N-s)} \text{WKA}_{t-s}$$

where WKA is the construction price index. The full formula for the simplified capital price that we recommend is then



Tables 6, 7, and 8 present three groups of indexes that could serve as capex price indexes for the long-lived assets of Alberta gas utilities:

- Natural Gas Distribution, Water, and Other Systems Capital Stock Price Indexes
- Electric Utility Construction Price Indexes (“EUCPI”)
- Non-Residential Building Construction Price Indexes .

Of these, we believe that Natural Gas Distribution, Water, and Other Systems Capital Stock Price Index for engineering structures is the single most accurate measure of construction cost trends for Canadian gas distributors. Unfortunately, it is not available in a timely fashion, and has not to our knowledge been updated since 2007. It is also not Alberta specific.

A summary EUCPI is available for power distribution. It is released on a timely basis but is not Alberta-specific. Non-Residential Building construction price indexes are available on a timely basis for Calgary and Edmonton. Finance Alberta forecasts the growth in Alberta non-residential construction prices. The summary EUCPI could in principle be made more relevant to Alberta by being adjusted periodically for the difference between Alberta and Canadian non-residential building construction prices.

Figure 3 shows how alternative construction price indexes tracked the trend in the gas and water engineering price index from 1982 to 2007. It can be seen that the summary EUCPI for power distribution did a better job of tracking the gas and water index than the non-residential building construction price index in most years. However, the EUCPI veered significantly away from the gas and water index in the 2005-2007 period.

$$\begin{aligned}
 WK^{COS} &= r \times \text{Construction Price Index}^{TWA} \\
 &= r \times \frac{\sum_s (N-s)}{\sum_s (N-s)} WKA_{t-s}
 \end{aligned}$$

For an early use of a triangularized weighted average construction price index see Thomas G. Cowing, Jeffrey Small, and Rodney Stevenson, *Comparative Measures of Productivity for Electric Utilities*, in Thomas G. Cowing and Rodney Stevenson, *Productivity Measurement in Regulated Industries* (New York: Academic Press, 1981).



Table 6
Canadian Natural Gas Distribution, Water, and Other Systems Capital Stock Price Indexes

Year	Information and communication technologies machinery and equipment ¹		Non-information and communication technologies machinery and equipment ²		Building structures		Engineering structures		Land	
	Level	Growth Rate ³	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1961	3091.7		17.5		17.9		12.6		35.4	
1962	3102.6	0.4%	17.9	2.3%	17.8	-0.6%	12.7	0.8%	32.8	-7.6%
1963	3165.2	2.0%	20.1	11.6%	18.2	2.2%	13.1	3.1%	30.4	-7.6%
1964	3205.4	1.3%	18.7	-7.2%	18.4	1.1%	13.6	3.7%	28.6	-6.1%
1965	3282.6	2.4%	19.3	3.2%	19.2	4.3%	14.4	5.7%	28	-2.1%
1966	3226.8	-1.7%	19.7	2.1%	20.5	6.6%	15.2	5.4%	27.9	-0.4%
1967	3312.1	2.6%	19.5	-1.0%	21.3	3.8%	16	5.1%	27	-3.3%
1968	3325.9	0.4%	19.4	-0.5%	21.2	-0.5%	16.2	1.2%	25.8	-4.5%
1969	3353.1	0.8%	19.8	2.0%	22.2	4.6%	17.1	5.4%	25.7	-0.4%
1970	3408.4	1.6%	20.9	5.4%	23.3	4.8%	18.1	5.7%	25.6	-0.4%
1971	3505.1	2.8%	21.5	2.8%	24.6	5.4%	19.3	6.4%	26.1	1.9%
1972	3522.7	0.5%	22	2.3%	26.9	8.9%	20.5	6.0%	27.6	5.6%
1973	3564.8	1.2%	23	4.4%	29	7.5%	21.8	6.1%	31	11.6%
1974	3466.6	-2.8%	26.2	13.0%	35.4	19.9%	26.1	18.0%	36.1	15.2%
1975	3606.7	4.0%	31	16.8%	40.4	13.2%	30.8	16.6%	39.7	9.5%
1976	3213.5	-11.5%	32.8	5.6%	41.3	2.2%	33.4	8.1%	40.9	3.0%
1977	2807.1	-13.5%	36.2	9.9%	42.2	2.2%	36	7.5%	43.4	5.9%
1978	2060.2	-30.9%	40.5	11.2%	43.8	3.7%	38.8	7.5%	45.2	4.1%
1979	1826.7	-12.0%	45.2	11.0%	46.9	6.8%	42.7	9.6%	49.9	9.9%
1980	1347.4	-30.4%	50.4	10.9%	52.1	10.5%	47.1	9.8%	56.7	12.8%
1981	1139	-16.8%	56.2	10.9%	60.4	14.8%	52.2	10.3%	62.8	10.2%
1982	1108.6	-2.7%	60.7	7.7%	65.3	7.8%	57.9	10.4%	65.2	3.8%
1983	793.6	-33.4%	61.8	1.8%	64	-2.0%	60.8	4.9%	63.6	-2.5%
1984	688.1	-14.3%	64.7	4.6%	62.7	-2.1%	62.8	3.2%	64	0.6%
1985	576.5	-17.7%	68.5	5.7%	63.9	1.9%	64.6	2.8%	64	0.0%
1986	486.4	-17.0%	70.6	3.0%	66.5	4.0%	66.5	2.9%	66.2	3.4%
1987	409.9	-17.1%	70.6	0.0%	70.8	6.3%	68.2	2.5%	69.3	4.6%
1988	373.8	-9.2%	70.1	-0.7%	75.2	6.0%	71.9	5.3%	74	6.6%
1989	316.2	-16.7%	72.2	3.0%	80.4	6.7%	74.6	3.7%	78.2	5.5%
1990	286.2	-10.0%	74	2.5%	83.2	3.4%	77.5	3.8%	81	3.5%
1991	230.6	-21.6%	72	-2.7%	80.4	-3.4%	79.6	2.7%	80.3	-0.9%
1992	204.5	-12.0%	74.8	3.8%	80.4	0.0%	81	1.7%	79.8	-0.6%
1993	197.5	-3.5%	77.8	3.9%	80.6	0.2%	82.5	1.8%	81.8	2.5%
1994	185.6	-6.2%	81.5	4.6%	82.2	2.0%	85.6	3.7%	84.5	3.2%
1995	169	-9.4%	84.7	3.9%	84.7	3.0%	86.1	0.6%	87.1	3.0%
1996	146.3	-14.4%	86.3	1.9%	86	1.5%	89.2	3.5%	89.8	3.1%
1997	135.1	-8.0%	87.5	1.4%	87.7	2.0%	91.7	2.8%	91.3	1.7%
1998	122.6	-9.7%	93.3	6.4%	89.3	1.8%	94.6	3.1%	92.7	1.5%
1999	109.7	-11.1%	94.8	1.6%	91	1.9%	96.4	1.9%	94.7	2.1%
2000	105.2	-4.2%	95.7	0.9%	95.6	4.9%	98.7	2.4%	97.2	2.6%
2001	103.6	-1.5%	98.3	2.7%	98.5	3.0%	98.8	0.1%	98.1	0.9%
2002	100	-3.5%	100	1.7%	100	1.5%	100	1.2%	100	1.9%
2003	92.5	-7.8%	93.3	-6.9%	102.6	2.6%	101.1	1.1%	103.9	3.8%
2004	85.8	-7.5%	89.6	-4.0%	108.7	5.8%	107.2	5.9%	112.9	8.3%
2005	79.5	-7.6%	87.6	-2.3%	114	4.8%	113.9	6.1%	123.2	8.7%
2006	76.3	-4.1%	85.6	-2.3%	122.8	7.4%	122.1	7.0%	137	10.6%
2007	74.7	-2.1%	84.5	-1.3%	136	10.2%	128.4	5.0%	151.2	9.9%
Average Annual Growth Rates										
1962-2007		-8.1%	3.4%		4.4%		5.0%		3.2%	
1968-2007		-9.5%	3.7%		4.6%		5.2%		4.3%	
1978-2007		-12.1%	2.8%		3.9%		4.2%		4.2%	
1988-2007		-8.5%	0.9%		3.3%		3.2%		3.9%	
1998-2007		-5.9%	-0.3%		4.4%		3.4%		5.0%	

Footnotes

¹ Information and communication technologies machinery and equipment consists of computer hardware, software and telecommunication equipment

² Machinery and equipment other than computer hardware and telecommunication equipment.

³ All growth rates are calculated logarithmically.

Sources:

Statistics Canada. Table 383-0025 - Investment, capital stock and capital services of physical assets, by North American Industry Classification System (NAICS), annual (dollars unless otherwise noted) (index, 2002=100)

Table 7
Canadian Electric Utility Construction Price Indexes

Distribution Systems							Transmission Systems		
Total							Total		
Year	Level	Growth Rate ¹	Total direct costs	Materials	Labour	Construction equipment	Construction indirects	Level	Growth Rate
1956	17.7				8.3	17.3		20.0	
1957	18.0	1.7%			8.6	18.3		20.6	3.0%
1958	17.4	-3.4%			9.3	19.0		19.5	-5.5%
1959	18.1	3.9%			9.8	24.7		20.1	3.0%
1960	18.7	3.3%			10.4	20.0		19.8	-1.5%
1961	18.7	0.0%			10.9	20.3		18.6	-6.3%
1962	19.0	1.6%			11.4	20.0		19.3	3.7%
1963	19.1	0.5%			11.9	20.2		19.7	2.1%
1964	19.5	2.1%			12.3	20.4		20.4	3.5%
1965	19.9	2.0%			12.9	20.5		21.4	4.8%
1966	20.9	4.9%			13.5	20.9	14.5	22.3	4.1%
1967	21.7	3.8%			15.1	22.0	15.6	22.5	0.9%
1968	21.5	-0.9%			16.2	22.5	16.8	22.2	-1.3%
1969	22.4	4.1%			17.5	23.3	18.1	22.9	3.1%
1970	24.1	7.3%			18.9	24.7	19.6	25.0	8.8%
1971	25.0	3.7%	25.6	29.8	20.3	26.0	21.2	26.1	4.3%
1972	26.1	4.3%	26.6	30.0	22.1	26.9	23.2	27.3	4.5%
1973	28.5	8.8%	29.1	32.6	25.0	27.9	24.7	29.3	7.1%
1974	34.3	18.5%	35.6	42.3	27.4	32.0	27.7	35.5	19.2%
1975	38.5	11.6%	39.7	45.7	32.5	34.8	31.9	41.6	15.9%
1976	40.7	5.6%	41.7	45.5	37.2	39.1	35.2	44.6	7.0%
1977	43.4	6.4%	44.4	46.7	41.4	43.3	38.3	47.0	5.2%
1978	46.6	7.1%	47.7	50.3	44.2	48.3	41.0	50.6	7.4%
1979	52.9	12.7%	54.5	60.3	47.0	54.2	44.5	56.5	11.0%
1980	60.3	13.1%	62.3	70.6	51.6	61.7	49.4	63.3	11.4%
1981	65.7	8.6%	67.8	75.0	57.5	74.0	55.2	69.7	9.6%
1982	71.8	8.9%	73.7	79.9	64.5	82.1	62.3	75.1	7.5%
1983	74.8	4.1%	76.2	79.1	71.0	86.2	67.2	77.0	2.5%
1984	78.1	4.3%	79.4	83.0	73.6	88.9	70.9	80.6	4.6%
1985	82.1	5.0%	83.7	88.7	76.0	93.0	74.1	81.6	1.2%
1986	84.0	2.3%	85.5	90.7	78.0	90.4	76.5	84.0	2.9%
1987	86.6	3.0%	87.9	93.3	80.7	91.3	79.5	89.2	6.0%
1988	91.9	5.9%	93.6	101.7	83.6	89.5	83.0	96.5	7.9%
1989	95.5	3.8%	97.3	105.0	88.0	91.9	85.7	102.6	6.1%
1990	98.5	3.1%	99.9	106.9	91.3	97.2	90.8	104.0	1.4%
1991	97.7	-0.8%	97.9	98.5	96.9	99.4	96.8	100.4	-3.5%
1992	100.0	2.3%	100.0	100.0	100.0	100.0	100.0	100.0	-0.4%
1993	102.5	2.5%	102.5	102.1	102.7	104.8	102.3	103.0	3.0%
1994	108.2	5.4%	109.1	112.5	104.3	111.0	103.3	108.1	4.8%
1995	116.7	7.6%	118.7	128.1	106.1	120.3	105.5	112.8	4.3%
1996	116.6	-0.1%	118.2	126.1	106.6	125.7	107.9	113.5	0.6%
1997	118.0	1.2%	119.3	125.0	110.1	129.8	111.1	115.7	1.9%
1998	122.8	4.0%	123.0	125.4	117.6	138.1	121.4	121.0	4.5%
1999	126.1	2.7%	126.0	126.0	123.6	141.5	126.9	122.2	1.0%
2000	128.7	2.0%	129.1	128.6	128.8	135.3	126.7	124.7	2.0%
2001	129.6	0.7%	129.8	127.7	130.7	142.0	128.9	127.0	1.8%
2002	130.5	0.7%	130.6	127.6	132.3	145.5	129.9	129.2	1.7%
2003	130.6	0.1%	130.9	127.8	132.7	145.5	129.0	126.4	-2.2%
2004	131.1	0.4%	131.3	132.5	127.2	148.0	129.9	129.0	2.0%
2005	133.6	1.9%	134.2	138.2	125.3	157.7	130.4	130.9	1.5%
2006	142.4	6.4%	144.2	155.0	127.5	160.0	132.6	136.2	4.0%
2007	148.8	4.4%	150.7	165.0	130.3	160.0	138.4	142.6	4.6%
2008	150.3	1.0%	151.9	167.6	127.7	173.8	141.4	148.8	4.3%
2009	151.1	0.5%	150.7	167.4	127.2	158.7	153.4	149.7	0.6%
2010	154.8	2.4%	154.5	169.8	132.8	163.0	156.8	150.7	0.7%
Average Annual Growth Rates									
1962-2007		4.5%	NA	NA	5.4%	4.5%	NA		4.4%
1968-2007		4.8%	NA	NA	5.4%	5.0%	5.5%		4.6%
1978-2007		4.1%	4.1%	4.2%	3.8%	4.4%	4.3%		3.7%
1988-2007		2.7%	2.7%	2.9%	2.4%	2.8%	2.8%		2.3%
1998-2007		2.3%	2.3%	2.8%	1.7%	2.1%	2.2%		2.1%
1981-2010		3.1%	3.0%	2.9%	3.2%	3.2%	3.9%		2.9%
1991-2010		2.3%	2.2%	2.3%	1.9%	2.6%	2.7%		1.9%
2001-2010		1.8%	1.8%	2.8%	0.3%	1.9%	2.1%		1.9%

Footnotes

¹ All growth rates are calculated logarithmically.

Source: Statistics Canada. Table 327-0011 - Electric utility construction price indexes (EUCPI), annual (index, 1992=100)

Table 8

Canadian Non-Residential Building Construction Price Indexes

Seven Census Metropolitan Area Composite							Calgary, Alberta						Edmonton, Alberta					
Year	Total, non-residential building construction		Total, commercial structures		Total, industrial structures		Total, non-residential building construction		Total, commercial structures		Total, industrial structures		Total, non-residential building construction		Total, commercial structures		Total, industrial structures	
	Level	Growth Rate ¹	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1981	58.3		59.8		52.5		68.4		69.3		68.3		68.9		71.1		68.6	
1982	62.8	7.4%	64.4	7.4%	56.5	7.2%	72.3	5.5%	73.2	5.5%	71.4	4.5%	73.7	6.8%	76.5	7.3%	72.6	5.8%
1983	62.0	-1.2%	63.2	-1.9%	56.4	-0.2%	67.4	-7.0%	68.3	-7.0%	66.8	-6.7%	70.6	-4.4%	72.5	-5.3%	70.0	-3.7%
1984	60.9	-1.9%	61.8	-2.3%	56.3	0.0%	63.7	-5.6%	64.5	-5.7%	63.0	-5.8%	64.2	-9.4%	65.6	-10.0%	64.2	-8.7%
1985	62.2	2.2%	63.1	2.1%	58.7	4.0%	62.5	-2.0%	63.1	-2.2%	61.7	-2.0%	63.2	-1.7%	64.5	-1.8%	62.8	-2.2%
1986	65.0	4.3%	66.0	4.5%	62.0	5.5%	63.8	2.1%	64.4	2.0%	63.1	2.2%	63.7	0.8%	64.2	-0.5%	62.6	-0.2%
1987	69.7	7.1%	71.0	7.2%	65.9	6.1%	64.2	0.6%	64.8	0.6%	63.7	0.9%	65.2	2.3%	65.7	2.3%	63.1	0.8%
1988	74.6	6.8%	76.1	7.0%	70.6	7.0%	67.8	5.4%	68.7	5.9%	65.7	3.1%	66.4	1.8%	67.2	2.4%	63.8	1.1%
1989	79.5	6.4%	81.1	6.4%	75.8	7.1%	74.8	9.9%	75.9	9.9%	72.9	10.5%	75.1	12.3%	77.0	13.6%	72.1	12.3%
1990	81.8	2.9%	83.3	2.7%	78.1	2.9%	78.5	4.8%	79.0	4.1%	76.7	5.1%	78.8	4.8%	80.2	4.1%	76.7	6.2%
1991	78.8	-3.8%	79.8	-4.3%	76.0	-2.7%	77.9	-0.8%	78.4	-0.8%	75.7	-1.3%	78.7	-0.2%	79.8	-0.6%	76.9	0.2%
1992	78.7	-0.1%	79.6	-0.2%	76.1	0.1%	78.6	1.0%	79.2	1.0%	76.5	1.0%	79.5	1.1%	80.6	1.0%	77.9	1.3%
1993	79.2	0.6%	80.0	0.5%	76.7	0.9%	78.9	0.4%	79.5	0.4%	77.3	1.0%	79.9	0.5%	80.9	0.3%	78.7	1.1%
1994	80.9	2.0%	81.5	1.9%	78.8	2.6%	80.4	1.8%	80.8	1.7%	78.9	2.0%	81.5	1.9%	82.3	1.8%	80.5	2.2%
1995	83.4	3.1%	84.0	3.0%	81.2	3.1%	83.0	3.2%	83.3	3.0%	81.4	3.2%	84.3	3.4%	85.1	3.3%	83.2	3.3%
1996	84.9	1.8%	85.3	1.5%	82.8	1.9%	84.3	1.5%	84.5	1.3%	82.7	1.6%	85.5	1.4%	86.0	1.1%	84.3	1.4%
1997	86.7	2.2%	87.0	1.9%	85.0	2.7%	86.4	2.5%	86.5	2.3%	85.3	3.1%	87.4	2.2%	87.8	2.1%	86.6	2.7%
1998	88.5	2.0%	88.8	2.1%	86.8	2.0%	88.8	2.8%	88.9	2.8%	87.4	2.4%	89.6	2.5%	90.1	2.5%	88.6	2.3%
1999	90.1	1.8%	90.4	1.8%	88.6	2.1%	90.6	2.1%	90.8	2.1%	89.1	2.0%	91.2	1.8%	91.7	1.8%	90.3	1.8%
2000	95.1	5.4%	95.3	5.3%	94.3	6.2%	94.7	4.4%	94.8	4.3%	93.8	5.1%	94.9	4.0%	95.4	3.9%	94.3	4.4%
2001	98.2	3.2%	98.3	3.1%	97.9	3.7%	97.8	3.2%	97.8	3.2%	97.5	3.9%	98.0	3.2%	98.1	2.9%	97.8	3.6%
2002	100.0	1.8%	100.0	1.7%	100.0	2.2%	100.0	2.2%	100.0	2.2%	100.0	2.5%	100.0	2.0%	100.0	1.9%	100.0	2.3%
2003	103.0	3.0%	102.9	2.9%	103.1	3.1%	103.1	3.0%	103.2	3.1%	103.1	3.0%	102.7	2.7%	102.8	2.8%	102.5	2.5%
2004	109.7	6.3%	109.4	6.1%	111.1	7.4%	110.0	6.5%	109.5	5.9%	111.8	8.2%	109.7	6.5%	109.2	6.1%	111.2	8.1%
2005	115.9	5.5%	115.5	5.4%	118.0	6.1%	117.6	6.6%	116.8	6.5%	120.3	7.3%	117.2	6.6%	116.6	6.5%	119.6	7.2%
2006	124.9	7.5%	124.6	7.6%	127.3	7.5%	132.7	12.1%	131.7	12.1%	136.5	12.6%	130.8	11.0%	130.1	11.0%	133.7	11.2%
2007	136.8	9.1%	137.3	9.6%	138.4	8.4%	156.1	16.3%	156.1	16.9%	159.0	15.3%	153.1	15.7%	153.4	16.4%	154.7	14.6%
2008	150.9	9.8%	151.3	9.8%	154.2	10.8%	177.5	12.9%	177.1	12.6%	187.9	16.7%	172.4	11.8%	172.1	11.5%	178.0	14.0%
2009	142.0	-6.0%	141.4	-6.8%	146.7	-5.0%	163.9	-8.0%	163.1	-8.2%	168.6	-10.8%	151.8	-12.7%	151.7	-12.6%	153.3	-14.9%
2010	141.5	-0.4%	140.6	-0.6%	146.2	-0.3%	160.3	-2.2%	159.5	-2.2%	162.6	-3.6%	155.0	2.1%	155.0	2.2%	155.7	1.6%
Average Annual Growth Rates																		
1988-2007		3.4%	3.3%		3.7%		4.4%		4.4%		4.6%		4.3%		4.2%		4.5%	
1998-2007		4.6%	4.6%		4.9%		5.9%		5.9%		6.2%		5.6%		5.6%		5.8%	
1982-2010		3.1%	2.9%		3.5%		2.9%		2.9%		3.0%		2.8%		2.7%		2.8%	
1991-2010		2.7%	2.6%		3.1%		3.6%		3.5%		3.8%		3.4%		3.3%		3.5%	
2001-2010		4.0%	3.9%		4.4%		5.3%		5.2%		5.5%		4.9%		4.9%		5.0%	

Footnotes

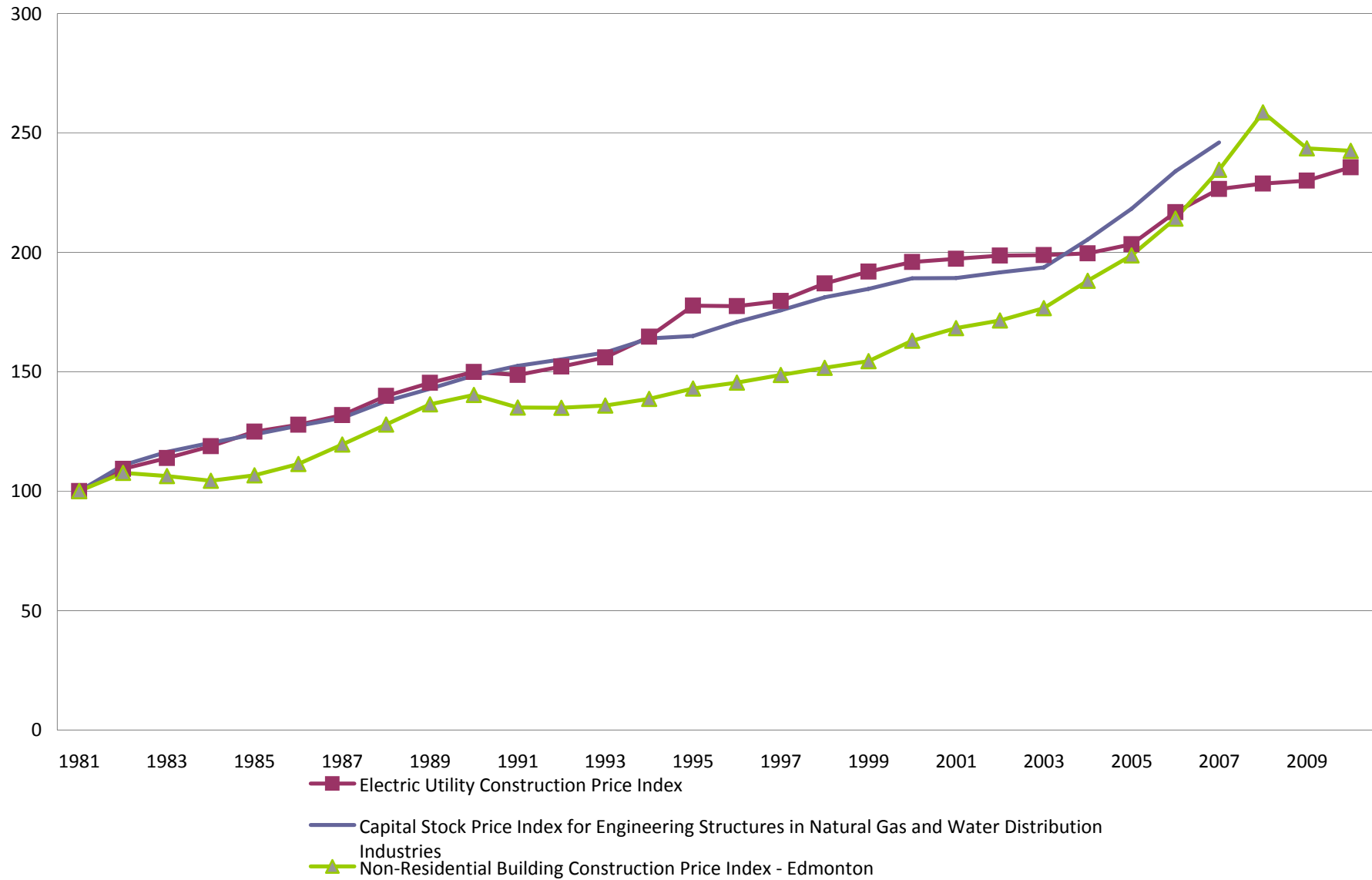
¹ All growth rates are calculated logarithmically.

Source:

Statistics Canada. Table 327-0043 - Price indexes of non-residential building construction, by class of structure, quarterly (index, 2002=100)

Figure 3

Comparison of Construction Price Indexes



4. OTHER PLAN PROVISIONS

4.1 Special Ratemaking Treatment of Capital Expenditures

ATCO Gas and AltaGas both propose special ratemaking treatments for costs of certain capital expenditures. ATCO proposes a “K Factor” that will compensate the company for higher forecasted levels of capital expenditures than are funded by the rate escalation index. ATCO Gas additionally proposes to Y-factor “material capital investment that is unique in nature”. In its testimony, ATCO cites as examples of projects whose costs might be recovered through the Y factor the construction of a South Edmonton Operating Center and a new customer information system. AltaGas proposes a major projects factor that would recover the annual cost of certain system safety and reliability projects.

Large capex surges are less common for gas and electric power distributors than they are for vertically integrated electric utilities. The reason is that distribution systems tend to grow gradually as the settled areas that they serve expand. Replacements of aging facilities are typically spread out over time for the same reason. Deferrals of maintenance expenses for a year or two can help to finance small upturns, as can the acceleration in O&M productivity that is made possible by the replacement of problematic bare steel mains. As AltaGas comments in response to CCA data request CCA.AUI.16 (d), “in general, it would be fair to expect, as older, less efficient assets are replaced, there would be a reduction in operating expenses related to those assets.” For a company operating under multiyear rate plan, occasional rate cases are another source of financial relief. Capex surges can be timed to occur when rate cases are imminent.

In contrast, vertically integrated electric utilities occasionally build large base load power plants, which may be remotely located and require sizable new transmission infrastructure. Lumpy generation investments may produce capacity considerably in excess of current requirements. Rate shock is a likely outcome when such assets enter the rate base.

Energy distributors may nonetheless occasionally need capex surges. Common triggers have included the construction of a large gas transmission line or storage field (which materially redefine the utility’s mission) and changes in metering technology or the



reliability and safety standards of government agencies. When capex surges are necessary they can subject distributors to financial stress if allowed rates do not provide a sufficient budget for the resultant increase in depreciation, the return on plant, and taxes.

The handling of capex surges under PBR is discussed in Chapter 2. For a distributor that is not far behind in making needed capital investments, a well-designed base productivity factor that captures the long run MFP trend should be sufficient to finance normal capex requirements if used routinely in X factor calibration. Budgets will be too small in some years and too large in others. This mirrors the outcome of competitive markets where, for example, an oil refiner cannot expect a higher price for gasoline when it expands its refining capacity.

To the extent that the capex excluded from indexing is sizable and involves the normal kinds of capex undertaken by sampled utilities, it may be necessary to raise the base productivity factor in the rate escalation mechanism that compensates the utility for other costs. A higher X may be needed in succeeding plans as well as the current plan. Our MFP index research in Chapter 3 provides some notion of the appropriate adjustment.

Since X factor adjustments of this kind clearly complicate the design of index-based rate escalation mechanisms, expedients should be considered. One idea is to keep the capital costs of certain large projects outside of the indexing mechanism *in subsequent plans* if they are excluded from the plan under consideration. This will tend to slow the company's future revenue growth because the rate base associated with the capex is sure to decline in subsequent plans.

Another idea is to give the Companies some flexibility in the timing of its rate escalations. For example, the Companies may be restricted only with respect to the *cumulative* pace of revenue per customer growth during the plan period. If it is allowed 8% revenue per customer growth over a four year period, for instance, it may take all 8% growth in one year to finance a "lumpy" investment provided that it "makes do" with 0% revenue/customer growth in the other three years. It is possible to extend this flexibility to multiple plans. A company could, in the example just cited, take a 10% revenue per customer hike in one year of one plan provided that it is prepared to reduce its cumulative revenue per customer hikes by 2% in the next plan.

The K factor proposal of ATCO Gas (and ATCO Electric) is set forth in the testimony of Dr. Carpenter. The K factor is rationalized in his testimony on the grounds that the basic X factor incorporates a “basic amount of capital investment equal to the average rate of capital investment of the firms in NERA’s sample”. To calculate the K factor, Dr. Carpenter computes the average growth in the net plant in service of the utilities in NERA’s sample from 1994-2009. He shows that the average annual growth rate is about 4.5% and asserts that the basic X factor “is sufficient to support approximately these rates of investment”. The proposed K factor would be an adjustment to the rate escalation mechanism that is sufficient to finance that portion of ATCO’s projected rate base growth that cannot be funded

Carpenter’s K factor analysis is flawed. Most fundamentally, a base productivity factor does not fund an average rate of rate base growth any more than it funds average growth in the use of O&M inputs. It instead ensures an average rate of capital *productivity* growth. We have shown that the growth in any cost is the difference between input price and productivity growth *plus the growth in output*. Thus, the growth in the capital stock that the rate escalation mechanism funds depends on customer growth as well as the X factor. The implicit capital budget will be larger for a company the more rapid is output growth. A major reason that ATCO Gas has greater capex needs is that it anticipates customer growth that is considerably more rapid than the US sample norm. Any calculation of the need for a K factor must thus factor out customer growth.

A second conceptual flaw with the K factor calculation is that it is based on a comparison of growth in the rate base. Rate base growth depends on escalation in construction prices as well as escalation in the capital quantity. An expectation of unusually rapid rate base growth may reflect in part an expectation of unusually rapid growth in construction prices. Yet local construction price inflation may be addressed by the inflation measure.

Consider also that it is not always true that a utility which has a high level of capex needs to increase its rates especially rapidly in order that it continue to have a reasonable opportunity to earn the target rate of return.

- Some kinds of investments produce automatic revenue growth. Any special treatment of capex costs should therefore be restricted to capex that does not



produce revenue. This would include investments that are needed to maintain or improve reliability or safety.

- In gas distribution, output growth often produces economies of scale that accelerate productivity growth. The utilities in the Western peer group have experienced an average pace of customer growth that exceeds the approximately 2% growth expected by ATCO Gas and AltaGas and have averaged productivity growth that substantially exceeds the US norm.
- Replacement of bare steel mains may, as noted above, accelerate O&M productivity growth.

4.2 Service Quality and Safety Provisions

The move from Alberta's current system of regulation to PBR is likely to strengthen incentives for cost containment substantially. There will be a stronger temptation to trim maintenance and customer service expenses and the capex for replacement of poorly-performing facilities. Service quality ("SQ") and safety can suffer, and mishaps in both areas have occurred during PBR plans. Formal award/penalty mechanisms ("APMs") can discourage SQ and safety degradation.

The Companies have proposed a continuation of Alberta's current monitoring program and oppose APMs. The fact that SQ monitoring is used instead of formal APMs in Ontario and British Columbia has been noted by the Companies in defense of their proposals. However, SQ and safety APMs are very common in PBR plans of four or more years' duration. In Quebec, Gaz Metro currently operates under an SQ APM, and the Gaz Metro Group de Travail has proposed to continue this in its new PBR plan proposal. The new proposal, to which Gaz Metro is a party, includes indicators for collection and interruption procedures, vegetation control, telephone response time, meter-reading frequency, and customer satisfaction.³³ We recommend that SQ and safety APMs be included in the PBR plans of all Alberta utilities.

³³ Gaz Metro, *Performance Incentive Mechanism: Working Paper Presented by Gaz Metro as Part of Negotiated Settlement Process* (NSP), R-3693-2009. August 2011.

4.3 Efficiency Carryover Mechanisms

Efficiency carryover mechanisms (ECMs) have growing use in PBR today. These mechanisms permit utilities to share some of the benefits of achieving long term performance gains between PBR plans. We recommend that the Commission give consideration to ECMs for Alberta energy utilities. We will have more commentary on this issue in our subsequent testimony.



5. SUMMING UP

The proposals of Alberta's two gas utilities for a revenue/customer cap is reasonable. However, the proposed indexes for escalating the revenue per customer cap are self-serving and unsupported by available evidence. The X factor should be developed using the following formula

$$X = \text{Base Productivity Factor} + \text{Stretch}.$$

The base productivity factor should be established with research on the productivity trends of North American natural gas distributors. This research should use the number of customers served as the output measure.

The Y factoring of a substantial portion of each Company's capex is a key issue in this proceeding. Our research suggests that if capex is *not* Y factored, the MFP growth target should lie in the [1.32%-1.69%] range. Should the Commission sanction the Y factoring of capex, the X factor may need to be upward for the first plan period and revenue per customer escalation in the second plan period must be slowed by some means. As an alternative to the Y factoring of capex, the Commission should consider allowing the distributors some flexibility in the annual growth in the revenue per customer allowance, subject to the constraint that the *cumulative* growth in the index-based cap cannot be exceeded. The stretch factor should lie in the [0.13%-0.50%] range.

With respect to the inflation measure, care must be taken that it strike a reasonable balance between simplicity and the ability to accurately reflect distributor input price inflation in Alberta. This is most simply achieved by using an Alberta-specific macroeconomic price index such as CPI^{Alberta} or the GDPIPI^{FDD} for Alberta. Should the Commission instead prefer a custom input price index, the weight on the labor price should reflect only the share of each Company's *direct* labor cost in the total cost subject to indexing. Should the Commission prefer an explicit capital price in the formula, it should include a rate of return term and average construction prices over the current and numerous past years.

APPENDIX

This appendix contains additional details of our research for the CCA. Section A.1 addresses the input quantity indexes. Section A.2 addresses capital cost. Section A.3 addresses our method for calculating productivity growth rates and trends.

A.1 Input Quantity Indexes

The growth rates of the input quantity indexes were defined by formulas. These formulas involved subindexes measuring growth in the usage of various kinds of inputs. Major decisions in the design of such indexes include their form, the choice of input categories, and the method for calculating quantity subindexes.

A.1.1 Index Form

The summary input quantity index for each company in the sample was of Tornqvist form.³⁴ This means that its annual growth rate was determined by the following general formula:

$$\ln\left(\frac{\text{Input Quantities}_t}{\text{Input Quantities}_{t-1}}\right) = \sum_j \frac{1}{2} \cdot (\text{sc}_{j,t} + \text{sc}_{j,t-1}) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}}\right). \quad [\text{A-1}]$$

Here in each year t ,

$\text{Input Quantities}_t$ = Input quantity index

$X_{j,t}$ = Quantity subindex for input category j

$\text{sc}_{j,t}$ = Share of input category j in applicable total cost.

It can be seen that the annual growth rate of the summary index is a weighted average of the growth rates of the input quantity subindexes. The annual growth rate of each subindex is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable total cost of the distributor provide the basis for the weights.

³⁴ For seminal discussions of this index form see Tornqvist (1936) and Theil (1965).

A.1.2 Input Quantity Subindexes

The quantity subindex for O&M expenses was calculated as the ratio of applicable O&M expenses to an O&M price index. The O&M price index was a weighted average of price subindexes for labor and the following five categories of materials and services: transmission, distribution, storage, metering, and administrative and general services.

The M&S price indexes were taken from the Global Insight *Power Planner* and are specific to these particular gas utility functions. The labor price indexes were constructed by PEG Research using data from two sources. The principal driver was BLS employment cost indexes (“ECIs”) of inflation in salaries and wages in the electric, gas, and sanitary sector (for earlier years of the sample period) and the utility sector (for later years). These national estimates were regionalized by adjusting them for differences between the trends in regional all-industry ECIs and the corresponding national ECI. The quantity subindexes for capital are discussed in Section A.1.4 below.

In calculating the M&S price index, data were unavailable for many gas distributors on the breakdown of O&M expenses between M&S expenses and salaries and wages. These breakdowns are available for combined gas and electric utilities because they are reported for gas as well as electric O&M on the FERC Form 1. For companies lacking these data, we imputed the breakdowns using the average breakdowns for combined gas and electric utilities.

A.1.3 Price Index Formulas

The summary O&M input price indexes that was used in the calculation of the input quantity subindexes were of Törnqvist form. This means that the annual growth rate of each index is determined by the following general formula:

$$\ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}}\right) = \sum_j \frac{1}{2} \cdot (sc_{j,t} + sc_{j,t-1}) \cdot \ln\left(\frac{W_{j,t}}{W_{j,t-1}}\right). \quad [A2]$$

Here in each year t ,

$Input\ Prices_t$ = O&M input price index

$W_{j,t}$ = Price subindex for input category j

$sc_{j,t}$ = Share of input category j in applicable total cost.



The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years.

A.1.4 Detailed Results

Detailed input quantity results for the full sample of gas distributors can be found in Table A-1. It can be seen that the quantity of plant grew at a 0.25% average annual rate for the full national sample whereas the quantity of O&M inputs fell at a slight 0.08% average annual rate. Since customer growth averaged 1.46%, it follows that capital productivity averaged 1.21% annual growth, whereas O&M productivity averaged 1.54% annual growth.

A.2 Capital Cost

The service price approach to the measurement of capital cost has a solid basis in economic theory and is widely used in government and scholarly empirical research.³⁵ In the application of the general method used in this study, the non-tax cost of utility plant in a given year t (CK_t) is the product of a capital service price index (WKS_t) and an index of the capital quantity at the end of the prior year (XK_{t-1}).

$$CK_t = WKS_t \cdot XK_{t-1}. \quad [A3]$$

Each capital quantity index is constructed using inflation-adjusted data on the value of utility plant. Each service price index reflects the cost of owning a unit of capital. Our data reflect the cost of facilities for local delivery, transmission, storage, and metering.

The value of the capital quantity index at the end of a given year depends on the quantities of plant added in that year and in a series of prior years that depends on the service life of the asset. The quantity of capital added in a given year $t-s$ (a_{t-s}) can be calculated as

$$a_{t-s} = \frac{VK_{t-s}^{add}}{WKA_{t-s}}$$

where VK_{t-s}^{add} is the gross value of plant additions and WKA_{t-s} is the capex (a/k/a asset) price index.

The capital quantity index also depends on the particular way that the quantities added

³⁵ See Hall and Jorgensen (1967) for a seminal discussion of the service price method of capital cost measurement.

Table A-1

Input Quantity and Partial Factor Productivity Results: Full Sample

	O&M Quantity	Capital Quantity	Output Quantity	O&M PFP	Capital PFP
1995					
1996	1.09%	0.85%	2.08%	0.99%	1.23%
1997	-4.59%	0.97%	1.92%	6.51%	0.95%
1998	-1.45%	0.04%	1.86%	3.31%	1.82%
1999	-2.30%	0.25%	2.04%	4.34%	1.80%
2000	5.61%	0.26%	1.94%	-3.67%	1.68%
2001	-6.63%	0.67%	1.70%	8.33%	1.03%
2002	0.15%	0.64%	1.38%	1.23%	0.74%
2003	0.79%	1.02%	1.10%	0.31%	0.08%
2004	3.08%	0.36%	1.33%	-1.75%	0.97%
2005	3.19%	-0.55%	1.65%	-1.55%	2.19%
2006	-5.87%	0.16%	1.23%	7.10%	1.07%
2007	3.09%	-0.40%	1.07%	-2.01%	1.47%
2008	-1.65%	-0.22%	0.77%	2.42%	0.99%
2009	4.38%	-0.57%	0.38%	-4.01%	0.95%
1996-2009	-0.08%	0.25%	1.46%	1.54%	1.21%

decline in later years due to depreciation.

Data on the gross plant additions of our sampled gas distributors are unfortunately not available before 1983. In productivity research, when estimates are needed of plant additions before a certain year, it is customary to assume that the net plant value at the end of the prior year resulted from a specific pattern of plant additions in that year and a series of prior years. A constant level of plant additions is often assumed for this purpose.

The earliest year for which a net plant value is available for all of our sampled utilities is 1983. Assuming a 45 year service life, the net plant value is based on plant additions from 1939 to 1983. We assume that plant additions were constant from 1939 to 1983.

The COS formulas for calculating capital price and quantity reflect the broad outlines of how capital cost is calculated in North American utility regulation. For each year t of the sample period we define the following terms for each asset category.

ck_t	Total non-tax cost of capital
ck_t^{Return}	Return on net plant value
$ck_t^{Depreciation}$	Depreciation expense
xk_t	Total quantity of plant
xk_t^{t-s}	Subset of plant in year t that remains from plant additions in year $t-s$
VK_t	Total (book) value of plant at the end of last year
N	Average service life of plant
r_t	Rate of return on net plant value
WKS_t	Capital (a/k/a service or rental) price

The non-tax cost of capital is the sum of depreciation and the return on net plant value.

$$ck_t = ck_t^{Return} + ck_t^{Depreciation}$$



There is a return and depreciation associated with the investment in the current year or any prior year $t-s$ that has not been fully depreciated.³⁶ Assuming straight line depreciation and book valuation of utility plant, the non-tax cost of capital can then be expressed as

$$ck_t = \sum_{s=0}^{N-1} (WKA_{t-s} \cdot xk_t^{t-s}) \cdot r_t + \sum_{s=0}^{N-1} WKA_{t-s} (1/N) \cdot a_{t-s} \quad [A4]$$

$$= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{(1/N) \cdot a_{t-s}}{xk_t}$$

The second term in the formula is a standardized approach to the calculation of depreciation that frees us from reliance on the depreciation expenses reported by utilities provided that we have many years of data on their gross plant additions.

The total quantity of capital used in each year t is the sum of the quantities of different ages in the rate base.

$$xk_t = \sum_{s=0}^{N-1} xk_{t-s}$$

Under straight line depreciation it is true that in the interval $[N-1, 0]$,

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s} \quad [A5]$$

The capital quantity in year t is thus linked to current and past plant additions by the formula

$$xk_t = \sum_{s=0}^{N-1} \frac{N-s}{N} a_{t-s} \quad [A6]$$

The size of the addition in year $t-s$ can then be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s} \quad [A7]$$

Equations [A4] and [A7] together imply that

$$ck_t = xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s}$$

$$= xk_t \cdot WKS_t \quad [A8]$$

³⁶ The analysis assumes that depreciation and the return on net plant value is incurred in year t on the amount of plant remaining at the end of year $t-1$, as well as on any plant added in year t . This is tantamount to assuming that plant additions are made at the beginning of the year. This depends in turn on the amount of plant added (a_{t-s}) and the unit cost of construction (WKA_{t-s}) in that year.

Capital is the product of a price and quantity index where the capital (service) price index has a formula

$$\begin{aligned}
WKS_t &= \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{I}{N-s} \\
&= \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \left(r_t + \frac{I}{N-s} \right)
\end{aligned}
\tag{A9}$$

It can be seen that market construction prices and the rate of return on net plant value play key roles in the COS capital service price formula. The first term in the formula pertains to the return on net plant value. The second term pertains to depreciation. Both terms depend on WKA, the capex price index, in the N most recent years and not just the costs in the current year. The importance of each value of the market construction cost index depends on the share, in the total quantity of plant, of the plant remaining from additions made in that year.

A.3 Productivity Growth Rates and Trends

The annual growth in the productivity index of each company is given by the formula

$$\ln\left(\frac{Productivity_{h,t}}{Productivity_{h,t-1}}\right) = \ln\left(\frac{Output\ Quantities_{h,t}}{Output\ Quantities_{h,t-1}}\right) - \ln\left(\frac{Input\ Quantities_{h,t}}{Input\ Quantities_{h,t-1}}\right)
\tag{A-7}$$

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PBR PLANS FOR ALBERTA:

RESPONSE TO SECOND NERA REPORT

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1. INTRODUCTION

The Alberta Utilities Commission (“AUC” or “Commission”) in February 2010 began a Rate Regulation Initiative to reform regulation in the province. Proceeding 566 was established, and gas and electric power distributors were directed to file performance-based regulation (“PBR”) plans. The Commission indicated that it would like the plans to have a design broadly similar to that which it approved in 2010 for ENMAX Power Corporation, the power distributor serving Calgary. The ENMAX plan features a multi-year rate case moratorium and a rate escalation mechanism with an inflation – X formula. The inflation measure in the formula is a custom index of Alberta input price inflation.

In North America, the rate escalation mechanisms of PBR plans are often designed using research on utility input price and productivity trends. The AUC retained National Economic Research Associates (“NERA”) to prepare a productivity study or studies that would be useful in calibrating X factors for Alberta distributors. In a report filed in December 2010, NERA presented a study of the multifactor productivity (“MFP”) trend of power distributors in the United States over the 1973-2009 sample period.¹ It maintained that the results were applicable to Alberta gas distributors as well as to power distributors. The MFP index NERA developed displays a marked slowdown in productivity growth and a negative growth trend over the last eleven years of the sample period.

In testimony filed in July 2011, most Alberta distributors filed PBR proposals. The rate escalation mechanisms in these proposals are diverse. However, all feature an escalation formula with a negative X factor that is rationalized in part by the negative trend in the NERA MFP index for the later years of the sample period. ATCO witness Carpenter and AUI witness Schoech both pronounced the methodology of the NERA MFP index to be fundamentally sound. Most utilities opposed the addition of a stretch factor to the X factor.

¹ NERA describes its index as a *total* factor productivity (“TFP”) index but it in fact excludes several classes of inputs, including those for administrative and customer care services.

With respect to other plan provisions, most utilities proposed to monitor service quality (“SQ”) but did not include an SQ award/penalty mechanism (“APM”) in their PBR plan. Three of the five utilities proposed “efficiency carryover mechanisms” (“ECMs”) that are purported to let the companies to keep a share of the benefits of long term performance gains after the first PBR plan terminated.

In December 2011, Pacific Economics Group Research LLC filed a report on behalf of the Consumers’ Coalition of Alberta (“CCA”) with its views on the design of PBR plans for Alberta energy distributors. Our report focused on the design of plans for gas distributors. We lodged several criticisms of NERA’s MFP index methodology and presented results of research, on the MFP trends of a sample of US gas distributors, which could serve as the basis for gas distributor X factors. In addition to gas distribution MFP indexes we developed companion MFP growth targets that are customized to the general operating conditions of Alberta gas distributors using an econometric model of MFP index growth. We used our Incentive Power simulation model to place the development of a stretch factor on a more objective and reasoned foundation. A general approach was outlined for the design of a custom inflation measure. It is based on the cost of service (“COS”) approach to capital cost measurement, which is designed to be compatible with regulatory accounting in Alberta. SQ APMs were recommended.

On 22 February 2012, NERA filed its second report in proceeding 566 (“Second Report”).² The report responded to the commentary of the CCA and other parties on the MFP research detailed in NERA’s first report. As commissioned by the AUC, the Second Report also discussed a survey of various provisions of approved PBR plans and compared the proposals of the Alberta utilities to the gathered precedents. NERA limited its survey to PBR plans in the United States and Canada which feature index-based rate escalation mechanisms.

The CCA has asked PEG Research to review and respond to NERA’s Second Report. This is the report on our work. Chapter 2 discusses issues in the development of

² NERA, *Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation*, 22 February 2012.

X factors. Chapter 3 discusses other PBR plan provisions. A postscript briefly discusses the history of PBR.

2. X FACTOR ISSUES

In this section we review salient issues in the design of the X factors which are raised by the second NERA Report. For each issue, we first briefly review the record prior to NERA's second report and then discuss the report and our response.

2.1 Power Distribution

2.1.1 Sample Period

Review

Utilities noted in their testimony a marked slowdown in the growth of NERA's original MFP index, which begins around 1999. The average annual growth rate in the index was 0.85% over the full sample period but -1.00% over the last eleven years (1999-2009). Various speculations were lodged by utility witnesses about why MFP growth in the industry might have slowed in these years.

The trend in NERA's output index is a revenue-weighted average of trends in retail service volumes. In our report last December, we stated a concern that such an index is quite sensitive to the extraordinary slowdown in volume growth that occurred in the last two years of NERA's full sample period due to the severe recession that occurred in the States. We recommended that the end date for NERA's MFP index should be 2007. The removal of these two years has a material impact on the MFP trend even with a 1972 start date for the sample period.

Second NERA Report

In its Second Report, NERA advocates use of the "largest time period available" to calculate MFP trends that are used to calibrate utility X factors, and NERA opposes the sample period truncations proposed by utilities. Here are some key arguments.

- The start dates proposed by utility witnesses lack an "objective basis" and reflect the analysts' "subjective judgments" (page 45).

- There is little if any commentary “from disinterested or scholarly sources” that growth in power (or gas) distributor MFP has substantially slowed in recent years (page 5).
- MFP growth may be erratic in the short term but “will eventually revert back to its long-term trend” (page 14). Any use of a shorter sample period in X factor calibration should be justified using a “statistical testing procedure along the lines of accepted research in the area of structural breaks” (page 16).
- Volumetric data can be sensitive to recessions and price shocks, but “our preference has always been to use kWh with the longest time series that Form 1 permits so as to dampen the effects of the kind of short-term or cyclical patterns that would most influence kWh sales as a measure of output” (page 23).

Response

We do not believe that the calculation of the long-term MFP trend for use in X factor calibration is always best served by mechanistically using the longest sample period available. For example, delivery volumes are well known to be volatile due to volatile business conditions such as weather and economic activity. When a volumetric output index is employed in an MFP calculation, the likelihood of identifying the long term MFP trend is therefore increased by choosing start and end dates that reflect broadly similar values for key volume drivers. A long sample period reduces the sensitivity of the trend to the start and end dates, but attention to volume drivers on the start and end dates is still warranted.

Table 1 presents data on US cooling degree days and the unemployment rate (a proxy for the business cycle) during the 1972-2009 period. It can be seen that the US unemployment rate was extraordinarily high in 2009, exceeding 9%. The unemployment rate was only 5.6% in 1972, the first year of NERA’s index. Cooling degree days were meanwhile similar in 2009 and 1972.

This evidence underlines the desirability of ending the sample period in 2007. Only two years of data are lost and the unemployment rate is much more similar to that in 1972. If a substantially shorter sample period is desired, ending the sample period in 2007 rather than 2009 is even more imperative. Any test for a recent “structural shift” in the MFP trend should therefore use a sample period ending

Table 1
HISTORICAL VOLUME DRIVERS 1972-2010

Year	Cooling Degree Days ¹	Difference from 2007	Unemployment Rate ²	Difference from 2007	Combined Impact on Volume
		[A]		[B]	[B] - [A]
1972	1,187	-15.0%	5.6%	19.7%	34.7%
1973	1,275	-7.8%	4.9%	6.3%	14.2%
1974	1,157	-17.6%	5.6%	19.7%	37.2%
1975	1,206	-13.4%	8.5%	61.4%	74.8%
1976	1,063	-26.0%	7.7%	51.5%	77.5%
1977	1,325	-4.0%	7.1%	43.4%	47.4%
1978	1,271	-8.2%	6.1%	28.2%	36.4%
1979	1,155	-17.7%	5.8%	23.2%	40.9%
1980	1,353	-1.9%	7.1%	43.4%	45.3%
1981	1,253	-9.6%	7.6%	50.2%	59.8%
1982	1,180	-15.6%	9.7%	74.6%	90.2%
1983	1,293	-6.4%	9.6%	73.6%	80.0%
1984	1,255	-9.4%	7.5%	48.9%	58.3%
1985	1,240	-10.6%	7.2%	44.8%	55.4%
1986	1,294	-6.4%	7.0%	42.0%	48.3%
1987	1,310	-5.1%	6.2%	29.8%	35.0%
1988	1,325	-4.0%	5.5%	17.9%	21.9%
1989	1,202	-13.7%	5.3%	14.2%	27.9%
1990	1,305	-5.5%	5.6%	19.7%	25.2%
1991	1,370	-0.7%	6.8%	39.1%	39.7%
1992	1,091	-23.4%	7.5%	48.9%	72.3%
1993	1,262	-8.9%	6.9%	40.5%	49.4%
1994	1,266	-8.5%	6.1%	28.2%	36.8%
1995	1,333	-3.4%	5.6%	19.7%	23.1%
1996	1,227	-11.7%	5.4%	16.0%	27.7%
1997	1,205	-13.5%	4.9%	6.3%	19.8%
1998	1,452	5.2%	4.5%	-2.2%	-7.4%
1999	1,335	-3.2%	4.2%	-9.1%	-5.9%
2000	1,276	-7.8%	4.0%	-14.0%	-6.2%
2001	1,292		4.7%		
2002	1,402		5.8%		
2003	1,296		6.0%		
2004	1,248		5.5%		
2005	1,411		5.1%		
2006	1,388		4.6%		
2007	1,379		4.6%		
2008	1,261		5.8%		
2009	1,209		9.3%		
2010	1,427		9.6%		

Footnotes:

¹ EIA-861, "Annual Electric Utility Report"

² U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

¹ National Climatic Data Center, "NNDC Climate Data Online."

² United States Department of Labor, Bureau of Labor Statistics, Series ID LNU04000000 Labor Force Statistics From the Current Population Survey. Labor Force Statistics From the Current Population Survey.

in 2007, not 2009.

With respect to the debate between NERA and the utilities concerning the merit of a shorter sample period, we believe that there is some value in a shorter period because even long term drivers of MFP growth such as technological change can change over a period of several decades. On the other hand, the utilities have provided no credible explanation of why the sample period should begin just as the period of slower productivity growth begins. As NERA points out, no credible explanation of this slowdown has been ventured and, in the absence of such an explanation, we cannot know whether the more recent sample period is more or less relevant for Alberta utilities.

Caution is further encouraged by the fact that other recent studies of power distribution MFP growth have not corroborated NERA's finding of a major MFP slowdown. A summary of recent research results is provided in Table 2. It can be seen that no recent study reports a negative MFP trend. For example, a study by Christensen Associates Energy Consulting for Kansas City Power & Light reported 0.7% average annual MFP growth for US power distributors over the 1994-2004 period.³

Should the Commission be persuaded of the need for a more recent sample period, we recommend one of intermediate length that has an objective basis. We propose one that ends in 2007 and begins in 1988, a year in which both US CDDs and the unemployment rate were similar to their 2007 levels.⁴ Using the old NERA MFP index, the average annual growth rate over the 19 years from 1989 to 2007 is 0.59%.

2.1.2 Labor Quantity Index

Review

In our filing last December we stated a concern that NERA had miscalculated the labor quantity trend for the later years of the sample period. We recommended as an alternative a residual approach to calculating the trend by taking the difference between the trends in salaries and wages and an appropriate salary and wage price index.

³See, for example, Direct Testimony of Robert J. Camfield on Behalf of Kansas City Power & Light in Docket No. 06-KCPE-828-RTS, January 2006.

⁴The first relevant productivity growth rate is then that for 1989.

Table 2
Summary of Energy Distribution MFP Research

Author	In Research for	Industry/Company	Time Period Studied	Annual Growth Trend
Gas Distribution				
PEG Research	Consumers' Counsel of Alberta	US	1996-2009	1.32%
PEG Research	San Diego Gas & Electric Co	US	1999-2008	1.18%
PEG Research	Gaz Metro	Gaz Metro	2000-2009	1.66%
PEG Research	Ontario Energy Board	Enbridge Gas Dist	2005-2010	1.07%
PEG Research	Ontario Energy Board	Union Gas	2005-2010	1.65%
PEG	Ontario Energy Board	Enbridge Gas Dist	2000-2006	0.60%
PEG	Ontario Energy Board	Union Gas	2000-2006	1.47%
PEG	Ontario Energy Board	US	1994-2004	1.61%
Industry Average				1.32%
Power Distribution				
PEG Research	San Diego Gas & Electric Co	US	1999-2008	0.88%
Economic Insights	New Zealand Commerce Commission	New Zealand	1996-2008	0.31%
PEG	Central Vermont Power Service	US	1996-2006	1.03%
PEG	Ontario Energy Board	US	1988-2006	0.72%
PEG	Central Maine Power (CMP)	Northeast US	1993-2005	1.57%
CA Energy Consulting	Kansas City Power & Light (KCPL)	US	1994-2004	0.70%
Industry Average				0.87%

Second NERA Report

NERA acknowledged its error and has upgraded its labor quantity specification. The average annual growth rate for the revised MFP index over the full sample period rose from 0.85% to 0.96% and this is now NERA's recommended MFP growth target. The average annual growth rate for the nineteen year 1989-2007 period rose more substantially, from 0.59% to 0.76%. The average annual growth rate for the eleven year 1999-2009 period rose from -1.00% to -0.65%. These and other new MFP results are summarized in Table 3.

2.1.3 Volume Data

Review

We noted in our first report that the volumes NERA used to construct its output index are commonly *sales* volumes obtained from Federal Energy Regulatory Commission ("FERC") Form 1 reports. For U.S. utilities that, like those in Alberta, have been restructured to create retail competition, sales volumes can differ materially from the volumes *delivered* in the later years of the sample period. An alternative data source, the Form EIA 861, is available from the U.S. Energy Information Administration from which it is possible to construct delivery volumes for these utilities. We use these data routinely in our power distribution productivity and econometric cost research. We proposed in our first report to "patch in" EIA 861 volume data for the later years of the sample period.

Second NERA Report

In its Second Report NERA acknowledges that the FERC Form 1 volumes are sales volumes. They note that when a patch is added to their index with the labor quantity upgrade, the MFP trend for the full sample period rises from 0.96% to 1.08%. The impact is presumably magnified considerably in the later years of the sample period but NERA does not report results for these years.

NERA nonetheless opposes the idea of an EIA 861 patch. They argue that sales volume data are problematic for only a few companies, that the effect on the long term productivity trend isn't large, and that the EIA 861 data also contain some "anomalies".

Table 3

SUMMARY OF NERA MFP RESULTS WITH CORRECTIONS AND ALTERNATIVE SPECIFICATIONS

	MFP Trend			Output Quantity Trend			Input Quantity Trend		
	1973-2009	1999-2009	1989-2007	1973-2009	1999-2009	1989-2007	1973-2009	1999-2009	1989-2007
NERA First Report	0.85%	-1.00%	0.59%	2.11%	0.80%	1.88%	1.25%	1.80%	1.29%
NERA Second Report	0.96%	-0.65%	0.76%	2.11%	0.80%	1.88%	1.15%	1.46%	1.12%
Three Category Output Index	0.93%	-0.64%	0.76%	2.08%	0.82%	1.88%	1.15%	1.46%	1.12%
Three Category with 861	1.01%	-0.53%	0.84%	2.16%	0.94%	1.96%	1.15%	1.47%	1.12%
Above with Gross Stock	1.14%	-0.37%	0.95%	2.16%	0.94%	1.96%	1.02%	1.30%	1.01%
Volume Weighted Tornqvist Index	1.20%	-0.19%	1.08%	2.20%	1.10%	2.05%	0.99%	1.29%	0.97%
Cumulative Change from First Report	0.35%	0.80%	0.49%	0.09%	0.30%	0.17%	-0.26%	-0.51%	-0.31%

Response

We feel that NERA's stated reservations about an EIA 861 patch are not appropriate grounds for reliance on FERC Form 1 sales data in the later years of the sample period. Arguments favoring the patch can be summarized as follows.

- NERA uses an all-volumetric output index and this makes it especially important to use the best volumetric data available.
- The period in which the EIA 861 data are superior is the period during which MFP growth slows, and this is the period that Alberta utilities propose to rely on in setting their X factors.
- Form EIA 861 data are clearly superior for a number of restructured utilities and tend to be very similar or identical to the sales volumes for vertically integrated utilities, as they should be.

As for NERA's contentions of problems with the EIA 861 data we have the following response. Two of the cited anomalies are related to a change in the classifications of customers into commercial (small) vs. industrial (large). Companies are generally given flexibility to classify these customers based on size or industrial classification. These classification changes happen on both the FERC Form 1 and EIA-861 and therefore we do not believe that this is evidence of the deficiency of the EIA-861 data. We would not object to an appropriate imputation or exclusion of companies that had such classification changes if it mattered for the study.

The other cited data anomalies were minor in our opinion. Other considerations such as a change in the standard deviation are not relevant because the issue is the correct measurement of output. We maintain our opinion that the EIA-861 is a superior data source because it measures the deliveries of power as opposed to only the sales of bundled power in many cases.

PEG Research has accordingly recalculated NERA's new MFP index, with its labor quantity upgrade, using our proposed EIA 861 patch. We use a three-category volumetric index in which the commercial and "other" volume categories have been consolidated. For the full sample period, the patch raises the MFP trend only slightly, from 0.96% to 1.01%. For the 19 year 1989-2007 period, the patch raises the growth trend more substantially, from 0.76% to 0.84%. For the eleven year 1999-2009 period

the patch raises the trend from -0.65% to -0.53%. It can be seen that the EIA 861 patch has a material impact in the later years of the sample period. Accordingly, any statistical test of a structural shift in the MFP trend should be based on an MFP index that uses the EIA 861 patch.

2.1.4 Benchmark Year Adjustment

Review

MFP indexes require capital costs that decompose into indexes of capital price and quantity trends. Capital quantity indexes essentially measure the trend in the inflation-adjusted (sometimes described as the “real”) value of plant. The first year of the capital quantity index is sometimes called the “benchmark year”. In this year, the value of the index is the ratio of the value of plant to a construction cost index. The inflation adjustments are complicated by the fact that reported plant values are expressed in historical dollars and therefore reflect construction costs in prior decades. In the United States, detailed regional power distribution construction cost indexes are available from Whitman, Requardt and Associates. In many MFP studies, a “triangularized” weighted average (“TWA”) of past values of these “Handy-Whitman” indexes has been employed in benchmark year calculations. This places a heavier weight on more recent values of the index.

Several operational formulas for calculating capital cost have been used in MFP research. The geometric decay and COS approaches both assume that the quantity of investment from a given capital expenditure declines gradually over time due to depreciation. The quantity of plant in a given year is then the real value of *net* plant. NERA, however, assumed a “one hoss shay” approach to capital costing in its MFP research. Under this approach, the quantity of plant from an investment does not decline gradually but instead falls to zero abruptly when it is retired, much as gross plant value is unchanged until it is removed from the books.

We stated in our December report that the benchmark year adjustment should be theoretically consistent with the basic approach to capital cost measurement. With the geometric decay and COS approaches, the quantity of plant in the benchmark year should be the inflation-adjusted value of *net* plant. With the one hoss shay approach, however,

we maintained that the quantity of plant in the benchmark year should be the inflation-adjusted value of *gross* plant. NERA's use of net plant value in the benchmark year adjustment is thus inconsistent with the one hoss shay specification and would tend to impart a downward bias to the MFP trend.

We also stated in our December report that the TWA of past values of the construction cost index that NERA used in its benchmark year adjustment was inconsistent with one hoss shay.⁵ We suggested instead that an arithmetic (even-weighted) average of past values of the construction cost index was the proper match for one hoss shay.

Second NERA Report

In its Second Report, NERA rejected our suggestions for a better benchmark year adjustment, venturing two arguments. One is that Dr. Makholm had used this approach in several past studies without challenge. The other is that net plant value and TWAs of construction cost indexes are widely used in the benchmark year adjustments of published MFP studies.

Response

We believe that NERA's arguments in defense of its benchmark year adjustment have little merit. Dr. Makholm has not done a large number of MFP studies, and in his previous (two) uses of the method in the regulatory arena he may not have had to reckon with technically competent reviewers. To our knowledge, he has published no articles using his methodology in refereed economic journals. The association of one hoss shay with gross plant value is so great that the noted Canadian productivity expert Erwin Diewert has commented that "this model is sometimes known as the gross capital stock model."⁶ It is true that net plant value and a TWA construction cost deflator are commonly used in benchmark year adjustments but that is because capital costing methods, such as geometric decay, that assume gradual depreciation are much more commonly used than one hoss shay in MFP work.

⁵ In fact, the TWA weighting that NERA used can be shown to be consistent with the assumption of COS capital costing that PEG Research uses and constant annual quantity additions.

⁶ Erwin Diewert and Denis A. Lawrence, "Progress in Measuring the Price and Quantity of Capital", presented at the Canberra Group on Capital Stock Statistics in Washington DC in November 1999.

We have recalculated NERA's MFP index using an alternative benchmark year adjustment that deflates gross plant in the benchmark year by an arithmetic average of historical construction cost index values. We find that the addition of the upgraded adjustment to our proposed EIA 861 patch raises the MFP trend for the full sample period from 1.01% to 1.14%. The trend for the nineteen year 1989-2007 period is raised from 0.84% to 0.95%. The trend for the eleven year 1999-2009 period is raised from -0.53% to -0.37%.

2.1.5 Index Form

Our development of upgraded MFP index results for NERA was complicated by the fact that they use a multilateral Tornqvist form for their input quantity index. The value of the index is a weighted average of logarithmic comparisons of the quantities of the individual companies to the corresponding sample mean values of these quantities. There are separate quantity comparisons for capital, labor, and other inputs. The weight for each subindex is an arithmetic average of the share of the corresponding cost for the company and an average of the shares for all companies over the full sample period.

The advantage of the multilateral approach is that it permits the input quantities of individual utilities to be compared on both a trend and a levels basis. We could, for example, use such an index to compare the input quantity levels of the utilities in the US sample. However, this capability has no benefit in an X factor calibration exercise, where the focus is exclusively on quantity *trends*. Moreover, it is well established in the economics literature that the multilateral form is not ideal for measuring trends due to the problem of "characteristicity."⁷ To calculate trends it is preferable to instead use "chain-weighted" input quantity trend indexes. The growth in such an index is a weighted average of the logarithmic annual growth rates of the quantities. The weights for the quantity subindexes are entirely company specific and change from year to year as cost shares change. If labor productivity is growing rapidly, for example, labor cost will decline and the weight on labor quantity growth will diminish in the later years of the sample period. Another problem with the multilateral approach is that sample means must be changed when the sample period changes. We have spoken above, for example,

⁷ See, for example, the discussion in L. Dreschler, "Weighting of Index Numbers in Multilateral International Comparisons", *Review of Income and Wealth*, Vol. 19, 1973 pp. 17-34.

of the trends in MFP indexes for the last eleven years. We did not recalculate NERA's index to use different sample means in reporting these calculations

We have recalculated NERA's MFP index with the upgrade to the labor quantity index using the 861 patch, our upgrade to the benchmark year adjustment, and chain-weighted input quantity indexes of Tornqvist form. We find that the MFP growth trend for the full sample period rises from 1.14% to 1.20%. The MFP growth trend for the nineteen year 1989-2007 period rises from 0.95% to 1.08%. The MFP growth trend for the eleven year 1999-2009 period rises from -0.37% to -0.19% (close to zero).

2.1.6 Customization of Productivity Targets

Review

Most parties to the proceeding criticized NERA for not considering special features of the Alberta operating environment in establishing MFP growth targets.

Second NERA Report

NERA restated in its Second Report its objection to using custom productivity targets in X factor calibration. Its arguments included the following.

- The theory of PBR calls for the X factor to reflect “the sort of long-term, underlying industry productivity trend that a competitive firm would face in their own industries” (page 18).
- “The theory underlying the kind of PBR *sought by the AUC* seeks to inject the type of incentives experienced by company managements in competitive industries where benchmark prices move according to the productivity of the industry in question rather than to the particular costs of one company” (page 19, italics added).
- The issue in X factor calibration is the MFP *trend*. Many conditions that cause utility cost *levels* to vary between service territories may not have much effect on cost trends.

- NERA used regional peer groups in *both* of its MFP studies for X factor calibration, including a western peer group in work for Utilicorp Alberta. It stated in the Second Report that it did not calculate results for such a peer group because data were available for fewer companies and results could be unstable.

Response

Index theory reveals that the trend in the prices of a *firm or industry* earning a competitive rate of return is the difference between the trends in the corresponding input prices and total factor productivity. The *revenue* of a firm or industry earning a competitive rate of return is the difference between the trends in its input prices and total factor productivity plus the growth in output.

One possible use of these results is to invoke a “competitive market paradigm” in which a rate or revenue cap escalator is based on industry input price and productivity research. However, firms in competitive markets can experience substantial windfall gains and losses. Wheat farmers in Saskatchewan, for instance, can have a good year if drought conditions in the States (which reduce productivity there and thereby raise prices) do not cross the border. Since participants in utility regulation are generally not keen on windfall gains and losses, it is understandable that index logic could be placed at the service of developing rate and revenue caps more tailored to local business conditions. Performance incentives can be still be strong provided that the escalators are sensitive only to local *external* business conditions such as the opportunity to realize scale economies and not to the productivity growth of the subject utility.

We do not agree with NERA that customized productivity growth targets are inconsistent with the seminal works of PBR theory. William Baumol, for example, devised an early statement of index-based regulation in collaboration with Arthur Okun.⁸ The guiding principle is to recreate market pressures that exist under competition using an inflation – X formula. While inflation and productivity targets should be constructed

⁸ William J. Baumol, “Productivity Incentive Clauses and Rate Adjustments for Inflation”, *Public Utilities Fortnightly*, July 22 1982, at 11.

so that they can not be changed by the companies' actions, the productivity trend target should reflect "the prospective rate of growth of the company's productivity."

E. Fred Sudit was another early proponent of index based regulation for public utilities that are based on productivity performance.⁹ Nothing in his method precludes a customized approach in calculating the productivity trend. He notes the potential for business conditions that are cost drivers outside the company's control.

As NERA acknowledges in its responses to a data request from the CCA, Denny, Fuss and Waverman ("DF&W") undertook a decomposition of MFP growth in a classic 1981 paper.¹⁰ The authors show that MFP *growth*, and not just cost *levels*, depends on diverse external business conditions and these can vary between service territories. Econometric analysis can quantify the relative importance of these business conditions, and this can guide the search for an MFP growth peer group or the development of an econometric MFP growth target. PEG Research used the DF&W analysis to project productivity targets for Union Gas and Enbridge Gas Distribution in work for the Ontario Energy Board. An article discussing this research has been published in the *Review of Network Economics*.¹¹

As for NERA's contention that the AUC does not seek custom productivity targets, its April 2010 commentary in proceeding 566 states that

While the Commission is satisfied that the bases for the inflation and productivity factors in the ENMAX formula are acceptable for electric utilities, the inflation and productivity factors will need to be determined for the gas distribution utilities. The rate structures (fixed/variable charges), geographic territories served and sizes of the various companies may, for example, need to be considered in determining the values of

⁹ E. Fred Sudit, "Automatic Rate Adjustments Based on Total Factor Productivity Performance in Public Utility Regulation" in *Problems in Public Utility Economics and Regulation* 55 (Michael A. Crew ed. Lexington Books, 1979).

¹⁰ Michael Denny, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowling and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

¹¹ Mark Newton Lowry and Lulitt Getachew, "Econometric TFP Targets, Incentive Regulation, and the Ontario Gas Distribution Industry", *Review of Network Economics* Vol. 8 Issue 4, December 2009.

various factors in the formula. In addition, there may be other matters specific to individual companies that will need to be considered before a PBR formula is determined and applied.

While it is possible that the AUC gave NERA different directions in retaining them for a productivity study, NERA states in their response to data request CCA-NERA-19 that they have had no supplemental correspondence with the Commission concerning its research preferences.

2.2 Gas Distribution

2.2.1 Second NERA Report

NERA supports the methodology used by PEG Research in its MFP index study (page 46). This is a noteworthy finding, since utilities may in their follow-up testimony dispute some details of this methodology. NERA goes on to say on this page that “the X factor that Dr. Lowry recommends is in the range that one would consider acceptable given experience for other energy utilities in North America.” NERA does express concern about the use of proprietary data in our study.

Concerning the econometric TFP growth model that we developed, NERA states that it has value in peer-reviewed scholarly research but may be ineffective in an adversarial proceeding “where every element of subjective or expert choice (and in a complex econometric analysis there are many) opens the door to esoteric debate amongst experts” (page 24). NERA recommends against the use of such methods in X factor determinations.

2.2.2 Response

Concerning the proprietary nature of the data in our gas study, only the older capital cost data, which are used to improve the accuracy of the capital quantity indexes and corresponding cost weights, are not drawn from sources that are entirely public. These data were drawn from Uniform Statistical Reports (“USRs”) that gas utilities file with the American Gas Association (“AGA”). These data are “quasi-public” inasmuch as the forms are standardized and were developed by the AGA; industry-level data from USRs are published periodically by the AGA in *Gas Facts*; some companies have shared

(and may continue to share) their USRs with the public; and the data we have obtained are freely available for use in this proceeding to witnesses prepared to sign a confidentiality agreement. All of our other data are in the public domain but much of it has been purchased from a respected commercial vendor (SNL Financial) and there are contractual limits on our ability to freely share these. Any other purchaser of these quality data would face the same restrictions.

To allay concern about this data issue, we recomputed the MFP trend of the industry using data that are entirely in the public domain in our response to data request ATCO-CCA-32. We used 1994 as the benchmark year for the capital quantity index. The sample consists of the same 34 companies used in our previous calculations. Growth rates are calculated and averaged for the fourteen year 1996-2009 period.

Results of this research are reported in Tables 4 and 5. It can be seen in Table 4 that with the new benchmark year the average MFP trend of the sampled utilities for the full sample period fell modestly, from 1.32% to 1.19% for the full sample. Output growth averaging 1.46% annually outpaced input growth averaging 0.27%. The MFP trend for the western distributors in the sample fell from 1.84% to 1.59%. Table 5 provides details of the input quantity subindexes and associated partial factor productivities.

2.3 Stretch Factor

2.3.1 Review

EPCOR proposed a stretch factor of 0.2% for its PBR plan. Other utilities opposed the addition of a stretch factor to the X factors. PEG Research noted that 0.5% stretch factors are typical in PBR plans designed using productivity research. We also enunciated the principle that the stretch factor should share the expected acceleration in productivity growth that results from PBR. Our Incentive Power simulation model indicated a stretch factor of only 0.13% because the base MFP growth factor already reflects the incentive power of regulatory systems with more incentive power than that currently used in Alberta. The Incentive Power model producing these results had been calibrated to produce MFP growth similar to that of the industry under normal regulatory conditions. However, the results reflected an MFP growth trend somewhat slower than

Table 4
Gas Productivity Index Results

Year	Output Quantity		Input Quantity		MFP	
	Full Sample	Western Sample	Full Sample	Western Sample	Full Sample	Western Sample
1996	2.08%	3.92%	1.24%	1.63%	0.84%	2.29%
1997	1.92%	2.40%	-1.11%	0.44%	3.03%	1.96%
1998	1.86%	2.98%	-0.20%	2.60%	2.07%	0.38%
1999	2.04%	3.91%	-0.20%	-1.75%	2.24%	5.66%
2000	1.94%	2.78%	2.08%	-0.14%	-0.14%	2.92%
2001	1.70%	2.74%	-1.67%	1.50%	3.37%	1.24%
2002	1.38%	1.88%	0.45%	0.62%	0.93%	1.26%
2003	1.10%	2.29%	1.09%	3.59%	0.01%	-1.30%
2004	1.33%	2.41%	1.32%	0.50%	0.01%	1.91%
2005	1.65%	3.48%	0.95%	1.89%	0.70%	1.59%
2006	1.23%	2.42%	-1.88%	0.00%	3.11%	2.41%
2007	1.07%	2.20%	0.94%	1.04%	0.13%	1.16%
2008	0.77%	1.35%	-0.58%	-2.93%	1.35%	4.28%
2009	0.38%	0.46%	1.32%	3.91%	-0.94%	-3.45%
1996-2009	1.46%	2.52%	0.27%	0.92%	1.19%	1.59%

Table 5

Gas Input Quantity and Partial Factor Productivity Results: Full Sample

Year	O&M Quantity	Capital Quantity	Output Quantity	O&M PFP	Capital PFP
1996	1.09%	1.15%	2.08%	0.99%	0.93%
1997	-4.59%	1.24%	1.92%	6.51%	0.68%
1998	-1.45%	0.28%	1.86%	3.31%	1.59%
1999	-2.30%	0.45%	2.04%	4.34%	1.59%
2000	5.61%	0.51%	1.94%	-3.67%	1.43%
2001	-6.63%	0.92%	1.70%	8.33%	0.78%
2002	0.15%	0.95%	1.38%	1.23%	0.42%
2003	0.79%	1.32%	1.10%	0.31%	-0.22%
2004	3.08%	0.57%	1.33%	-1.75%	0.75%
2005	3.19%	-0.37%	1.65%	-1.55%	2.02%
2006	-5.87%	0.41%	1.23%	7.10%	0.82%
2007	3.09%	-0.19%	1.07%	-2.01%	1.26%
2008	-1.65%	-0.01%	0.77%	2.42%	0.78%
2009	4.38%	-0.36%	0.38%	-4.01%	0.74%
1996-2009	-0.08%	0.49%	1.46%	1.54%	0.97%

that resulting from our new gas MFP trend research.

2.3.2 Second NERA Report

NERA's survey revealed that stretch factors are a common addition to the X factors in North American index-based PBR plans. By our count, stretch factors are noted in roughly a third of the plans that NERA reports. One reason they are not more common is that X factors have frequently been a feature of settlements in which base productivity trend and stretch factor components of the X factor were not itemized.

NERA did not comment on the specific stretch factor proposed by EPCOR or on the range of stretch factors proposed by PEG Research for Alberta's gas utilities. By way of general commentary, NERA noted that stretch factors reflect "subjective judgments" concerning the opportunity for a PBR plan to spur productivity growth.

2.3.3 Response

We believe that our incentive power model takes important steps in the direction of making the calculation of stretch factors more objective. We recalibrated the model to reflect our new gas MFP growth trend estimate in our supplemental response to data request ATCO-CCA-59. With the incentive power model recalibrated, the indicated stretch factor rises six basis points, from 0.13% to 0.19%.

3. OTHER PLAN DESIGN ISSUES

3.1 Inflation Measure

3.1.1 Review

The PBR plan approved by the AUC for ENMAX featured a custom inflation measure. The “I Factor” is a weighted average of the growth in Alberta Average Hourly Earnings and the Canadian Electric Utility Construction Price Index (“EUCPI”). The weighting on the two input price subindexes is apparently 50/50. ATCO Gas and AltaGas have both proposed I Factors featuring two subindexes: average weekly earnings in Alberta (“AWE”) and the comprehensive Consumer Price Index for Alberta. The 57% weight for ATCO is apparently the estimated share of labor in the sum of O&M and capital expenditures, where the labor component of contract services has been extracted from the other cost categories. AltaGas also proposes a 57% labor index weight.

PEG Research acknowledged in its December report the general desirability of an Alberta-specific inflation measure given the unusual inflation activity that is generated by the large natural resource extraction and processing industry in the province. We further commented that in the construction of such a measure the EUCPI should not be used in its *raw form a la* ENMAX because the capital price index that is implicit in cost of service regulation is a function of a weighted average of a lengthy series of past values of a construction cost index and also of a rate of return on capital. We criticized the I Factor design proposed by ATGO Gas for placing an excessive weight on the AWE, which is likely to grow more rapidly. The theoretically appropriate weight for labor is the share of direct labor O&M expenses in the total cost of base rate inputs. We also recommended Alberta’s Gross Domestic Product Implicit Price Index for final domestic demand (GDPIPI-FDD) as the most pertinent measure of general price inflation in the province.

3.1.2 Second NERA Report

NERA observes in its survey that although most PBR plans surveyed use rate escalation mechanisms with macroeconomic inflation measures, there are precedents in both the US and Canada for industry-specific measures. The most common

macroeconomic price indexes employed in the surveyed PBR plans were gross domestic product price indexes. As a matter of principle, NERA states that “an inflation index should be exogenous, reasonably reflecting the cost behavior facing the industry” (page 44). NERA says little concerning the inflation measure proposals of the Alberta utilities, noting that they seem to be constructed from “objective and reliable price indexes.” In response to data request ATCO-NERA-03, NERA stated that it “sees nothing problematic about Dr. Lowry’s discussion of inflation indexes, even though it requires more time to process than those proposed by the other parties.”

3.1.3 Response

We believe that the design of an appropriate inflation measure for a PBR plan depends on much more than whether they are constructed from objective and reliable component price indexes. The subindexes should have appropriate cost share weights and, in the case of capital prices, should ideally be consistent with way that capital cost is calculated in rate cases. We developed a workable industry-specific input price index for Alberta in response to data request ATCO-CCA-63. An index of this kind is potentially applicable to both gas and electric power distributors.

Highlights of this work can be found in Tables 6-10. Table 6 shows some details of index construction. The labor price index employed was the fixed-weight index of average hourly earnings for all workers in Alberta. The GDPIPI-FDD for Alberta was used as the proxy for the materials and services price index. The capital price index is the product of a rate of return and a triangularized-weighted moving average of an Alberta-adjusted EUCPI. The weights for this index were based on the cost shares for O&M expenses and capital (*not* capital expenditures) reported in recent ATCO Gas and AltaGas rate filings. In this calculation, the O&M expense cost share was divided 50/50 between labor and materials & services. The resultant cost shares for the input price index were about 42% for capital and about 29% each for labor and material & service O&M expenses.

Table 7 shows how we calculated a custom Alberta EUCPI by adding to the annual growth rate of the national EUCPI the difference between the annual growth rates in industrial structure construction price indexes for Alberta and Canada. Table 8 shows

Table 6
Calculation of the PEG Research Custom Alberta Input Price Index

Year	Labor			Materials & Services			Capital			PEG Research Custom Alberta Input Price Index	
	Fixed Weight Index of Average Hourly Earnings for all employees, Industrial Aggregate ¹²	Annual Growth Rate	Weight	GDPPI-FDD Alberta ³	Annual Growth Rate	Weight	Custom Alberta Capital Price Index	Annual Growth Rate	Weight	Index	Annual Growth Rate
1995	83.08		29.3%	86.70		29.3%	27.70		41.5%	1.000	
1996	87.21	4.8%	29.3%	88.30	1.8%	29.3%	27.72	0.1%	41.5%	1.020	1.98%
1997	88.96	2.0%	29.3%	90.50	2.5%	29.3%	26.93	-2.9%	41.5%	1.021	0.10%
1998	92.18	3.6%	29.3%	91.90	1.5%	29.3%	26.09	-3.2%	41.5%	1.023	0.17%
1999	94.78	2.8%	29.3%	93.30	1.5%	29.3%	27.27	4.4%	41.5%	1.055	3.10%
2000	96.56	1.9%	29.3%	95.60	2.4%	29.3%	28.17	3.3%	41.5%	1.083	2.61%
2001	98.96	2.5%	29.3%	97.40	1.9%	29.3%	29.17	3.5%	41.5%	1.113	2.71%
2002	100.20	1.2%	29.3%	100.00	2.6%	29.3%	29.90	2.5%	41.5%	1.137	2.15%
2003	104.75	4.4%	29.3%	100.90	0.9%	29.3%	30.04	0.5%	41.5%	1.157	1.75%
2004	107.87	2.9%	29.3%	103.00	2.1%	29.3%	30.42	1.3%	41.5%	1.180	1.98%
2005	112.16	3.9%	29.3%	106.00	2.9%	29.3%	29.66	-2.5%	41.5%	1.191	0.94%
2006	117.23	4.4%	29.3%	111.10	4.7%	29.3%	30.34	2.3%	41.5%	1.235	3.61%
2007	124.18	5.8%	29.3%	116.10	4.4%	29.3%	31.57	4.0%	41.5%	1.293	4.62%
2008	132.16	6.2%	29.3%	120.10	3.4%	29.3%	32.14	1.8%	41.5%	1.340	3.54%
2009	136.40	3.2%	29.3%	121.30	1.0%	29.3%	32.75	1.9%	41.5%	1.367	2.00%
2010	139.88	2.5%	29.3%	122.30	0.8%	29.3%	33.11	1.1%	41.5%	1.387	1.43%
Average Annual Growth Rates											
2001-2010		3.7%			2.5%			1.6%			2.5%
1996-2010		3.5%			2.3%			1.2%			2.2%
Standard Deviation 1996-2010		1.4%			1.2%			2.4%			1.3%

¹ Statistics Canada. Table 281-0039 - Fixed weighted index of average hourly earnings for all employees (SEPH), excluding overtime, unadjusted for seasonal variation. Available for selected industries classified using the North American Industry Classification System (NAICS), monthly (index, 2002=100)

² Industrial aggregate covers all industrial sectors except those primarily involved in agriculture, fishing and trapping, private household services, religious organisations, and the military personnel of the defence services.

³ Statistics Canada. Table 384-0036 - Implicit price indexes, gross domestic product (GDP), provincial economic accounts, annual (index, 2002=100)

Table 7

Canadian Electric Utility Construction Price Index Adjustment for Alberta

Year	EUCPI ¹		Industrial Structure Construction Price Index ³ / CPI							Adjustment		Alberta Adjusted EUCPI	
	Canada		Metropolitan Area		Calgary, Alberta		Edmonton, Alberta		Alberta	Alberta - Composite		Level	Growth Rate
	Level	Growth Rate ²	Composite										
			Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Growth Rate				
		[A]		[B]		[C]		[D]	[E] ⁴				[F] ⁵
1956	17.7		na		na	na	na	na				100.0	
1957	18.0	1.68%	na	3.16%	na	na	na	na	2.73%	-0.43%		101.3	1.25%
1958	17.4	-3.39%	na	2.65%	na	na	na	na	2.13%	-0.52%		97.4	-3.91%
1959	18.1	3.94%	na	1.10%	na	na	na	na	1.31%	0.21%		101.5	4.16%
1960	18.7	3.26%	na	1.22%	na	na	na	na	0.91%	-0.31%		104.6	2.95%
1961	18.7	0.00%	na	0.94%	na	na	na	na	0.64%	-0.29%		104.2	-0.29%
1962	19	1.59%	na	1.19%	na	na	na	na	0.89%	-0.30%		105.6	1.29%
1963	19.1	0.52%	na	1.70%	na	na	na	na	1.14%	-0.56%		105.6	-0.04%
1964	19.5	2.07%	na	1.80%	na	na	na	na	0.50%	-1.30%		106.4	0.78%
1965	19.9	2.03%	na	2.39%	na	na	na	na	1.49%	-0.90%		107.6	1.13%
1966	20.9	4.90%	na	3.66%	na	na	na	na	3.27%	-0.39%		112.6	4.52%
1967	21.7	3.76%	na	3.53%	na	na	na	na	3.86%	0.33%		117.3	4.08%
1968	21.5	-0.93%	na	3.97%	na	na	na	na	4.38%	0.41%		116.7	-0.52%
1969	22.4	4.10%	na	4.45%	na	na	na	na	3.98%	-0.47%		121.0	3.63%
1970	24.1	7.32%	na	3.24%	na	na	na	na	2.91%	-0.33%		129.7	6.98%
1971	25	3.67%	na	2.84%	na	na	na	na	2.43%	-0.41%		134.0	3.26%
1972	26.1	4.31%	na	4.59%	na	4.43%	na	4.49%	4.46%	-0.14%		139.7	4.17%
1973	28.5	8.80%	na	7.50%	na	6.44%	na	7.33%	6.88%	-0.61%		151.6	8.18%
1974	34.3	18.52%	na	10.29%	na	9.56%	na	9.83%	9.69%	-0.59%		181.4	17.93%
1975	38.5	11.55%	na	10.23%	na	10.95%	na	10.29%	10.62%	0.39%		204.4	11.94%
1976	40.7	5.56%	na	7.20%	na	7.85%	na	7.70%	7.77%	0.57%		217.3	6.13%
1977	43.4	6.42%	na	7.70%	na	8.22%	na	8.67%	8.45%	0.75%		233.5	7.17%
1978	46.6	7.11%	na	8.59%	na	7.95%	na	8.67%	8.31%	-0.28%		250.0	6.83%
1979	52.9	12.68%	na	8.73%	na	8.32%	na	8.46%	8.39%	-0.34%		282.8	12.34%
1980	60.3	13.09%	na	9.68%	na	9.88%	na	9.69%	9.78%	0.10%		322.7	13.20%
1981	65.7	8.58%	52.5	11.6%	68.3	12.5%	68.6	11.8%	12.16%	0.52%		353.5	9.09%
1982	71.8	8.88%	56.5	7.21%	71.4	4.48%	72.6	5.77%	5.13%	-2.08%		378.3	6.80%
1983	74.8	4.09%	56.4	-0.18%	66.8	-6.70%	70.0	-3.68%	-5.19%	-5.01%		374.9	-0.92%
1984	78.1	4.32%	56.3	-0.04%	63.0	-5.82%	64.2	-8.73%	-7.27%	-7.23%		364.1	-2.91%
1985	82.1	4.99%	58.7	4.04%	61.7	-2.04%	62.8	-2.21%	-2.13%	-6.17%		359.8	-1.18%
1986	84.0	2.29%	62.0	5.51%	63.1	2.24%	62.6	-0.24%	1.00%	-4.51%		351.9	-2.22%
1987	86.6	3.05%	65.9	6.06%	63.7	0.87%	63.1	0.76%	0.81%	-5.25%		344.2	-2.20%
1988	91.9	5.94%	70.6	6.97%	65.7	3.09%	63.8	1.06%	2.08%	-4.89%		347.9	1.05%
1989	95.5	3.84%	75.8	7.11%	72.9	10.47%	72.1	12.31%	11.39%	4.28%		377.3	8.13%
1990	98.5	3.09%	78.1	2.93%	76.7	5.08%	76.7	6.15%	5.62%	2.69%		399.8	5.78%
1991	97.7	-0.82%	76.0	-2.66%	75.7	-1.34%	76.9	0.23%	-0.56%	2.10%		405.0	1.29%
1992	100.0	2.33%	76.1	0.07%	76.5	1.02%	77.9	1.29%	1.16%	1.09%		419.1	3.42%
1993	102.5	2.47%	76.7	0.85%	77.3	1.04%	78.7	1.05%	1.05%	0.20%		430.4	2.67%
1994	108.2	5.41%	78.8	2.64%	78.9	2.02%	80.5	2.23%	2.12%	-0.51%		452.0	4.90%
1995	116.7	7.56%	81.2	3.09%	81.4	3.18%	83.2	3.33%	3.26%	0.16%		488.3	7.72%
1996	116.6	-0.09%	82.8	1.92%	82.7	1.61%	84.3	1.37%	1.49%	-0.43%		485.8	-0.51%
1997	118.0	1.19%	85.0	2.65%	85.3	3.07%	86.6	2.66%	2.86%	0.21%		492.7	1.41%
1998	122.8	3.99%	86.8	2.01%	87.4	2.43%	88.6	2.31%	2.37%	0.36%		514.6	4.35%
1999	126.1	2.65%	88.6	2.14%	89.1	1.95%	90.3	1.82%	1.89%	-0.25%		527.1	2.40%
2000	128.7	2.04%	94.3	6.18%	93.8	5.11%	94.3	4.39%	4.75%	-1.43%		530.3	0.61%
2001	129.6	0.70%	97.9	3.72%	97.5	3.89%	97.8	3.62%	3.76%	0.03%		534.2	0.73%
2002	130.5	0.69%	100.0	2.17%	100.0	2.51%	100.0	2.28%	2.39%	0.22%		539.1	0.91%
2003	130.6	0.08%	103.1	3.08%	103.1	3.00%	102.5	2.47%	2.74%	-0.34%		537.7	-0.26%
2004	131.1	0.38%	111.1	7.40%	111.8	8.17%	111.2	8.14%	8.16%	0.75%		543.8	1.14%
2005	133.6	1.89%	118.0	6.09%	120.3	7.31%	119.6	7.24%	7.27%	1.18%		560.8	3.07%
2006	142.4	6.38%	127.3	7.55%	136.5	12.62%	133.7	11.17%	11.89%	4.35%		624.2	10.72%
2007	148.8	4.40%	138.4	8.36%	159.0	15.29%	154.7	14.57%	14.93%	6.57%		696.6	10.97%
2008	150.3	1.00%	154.2	10.83%	187.9	16.68%	178.0	14.03%	15.36%	4.53%		736.2	5.53%
2009	151.1	0.53%	146.7	-5.00%	168.6	-10.84%	153.3	-14.92%	-12.88%	-7.88%		684.1	-7.35%
2010	154.8	2.42%	146.2	-0.32%	162.6	-3.64%	155.7	1.55%	-1.04%	-0.72%		695.8	1.70%
Average Annual Growth Rates													
1957-2010		4.02%		4.19%		4.43%		4.33%	3.77%	-0.42%			3.59%
1973-2010		4.68%		4.84%		4.43%		4.33%	4.38%	-0.46%			4.23%
1990-2007		2.46%		3.34%		4.33%		4.24%	4.29%	0.94%			3.41%
2000-2010		1.86%		4.55%		5.46%		4.96%	5.21%	0.66%			2.52%

Sources:

¹ Statistics Canada. Table 327-0011 - Electric utility construction price indexes (EUCPI), annual (index, 1992=100)

³ Statistics Canada. Table 327-0043 - Price indexes of non-residential building construction, by class of structure, quarterly (index, 2002=100). For years prior to 1982 the CP for cities in Alberta was used. Prior to 1972 the cities were not reported separately.

Notes:

² All growth rates calculated logarithmically.

⁴ [E]= ([C]+[D])/2

⁵ [F]= [A]+ ([E]-[B])

Table 8

Computation of Triangularized Weighted Moving Average Construction Cost Index

	Alberta Adjusted		40 year TW Moving		Undepreciated Years	Triangular
Year	EUCPI	Growth Rate	Average	Growth Rate	of Plant Remaining	Weight
1956	100.0				1	0.12%
1957	101.3	1.25%			2	0.24%
1958	97.4	-3.91%			3	0.37%
1959	101.5	4.16%			4	0.49%
1960	104.6	2.95%			5	0.61%
1961	104.2	-0.29%			6	0.73%
1962	105.6	1.29%			7	0.85%
1963	105.6	-0.04%			8	0.98%
1964	106.4	0.78%			9	1.10%
1965	107.6	1.13%			10	1.22%
1966	112.6	4.52%			11	1.34%
1967	117.3	4.08%			12	1.46%
1968	116.7	-0.52%			13	1.59%
1969	121.0	3.63%			14	1.71%
1970	129.7	6.98%			15	1.83%
1971	134.0	3.26%			16	1.95%
1972	139.7	4.17%			17	2.07%
1973	151.6	8.18%			18	2.20%
1974	181.4	17.93%			19	2.32%
1975	204.4	11.94%			20	2.44%
1976	217.3	6.13%			21	2.56%
1977	233.5	7.17%			22	2.68%
1978	250.0	6.83%			23	2.80%
1979	282.8	12.34%			24	2.93%
1980	322.7	13.20%			25	3.05%
1981	353.5	9.09%			26	3.17%
1982	378.3	6.80%			27	3.29%
1983	374.9	-0.92%			28	3.41%
1984	364.1	-2.91%			29	3.54%
1985	359.8	-1.18%			30	3.66%
1986	351.9	-2.22%			31	3.78%
1987	344.2	-2.20%			32	3.90%
1988	347.9	1.05%			33	4.02%
1989	377.3	8.13%			34	4.15%
1990	399.8	5.78%			35	4.27%
1991	405.0	1.29%			36	4.39%
1992	419.1	3.42%			37	4.51%
1993	430.4	2.67%			38	4.63%
1994	452.0	4.90%	296.7		39	4.76%
1995	488.3	7.72%	309.4	4.20%	40	4.88%
1996	485.8	-0.51%	321.4	3.80%		
1997	492.7	1.41%	333.3	3.62%		
1998	514.6	4.35%	345.7	3.67%		
1999	527.1	2.40%	358.3	3.57%		
2000	530.3	0.61%	370.5	3.35%		
2001	534.2	0.73%	382.4	3.15%		
2002	539.1	0.91%	393.9	2.98%		
2003	537.7	-0.26%	404.9	2.75%		
2004	543.8	1.14%	415.7	2.62%		
2005	560.8	3.07%	426.7	2.62%		
2006	624.2	10.72%	440.3	3.13%		
2007	696.6	10.97%	456.8	3.68%		
2008	736.2	5.53%	474.5	3.81%		
2009	684.1	-7.35%	488.9	2.99%		
2010	695.8	1.70%	503.2	2.88%		
Average Annual Growth Rate						
1995-2010		2.70%		3.30%		
Standard Deviation of Growth Rates						
1995-2010		4.51%		0.48%		
1957-2010		4.73%		na		

the construction of a triangularized weighted moving average construction cost index from the raw Alberta Adjusted EUCPI. It can be seen to be far more stable than the raw EUCPI. Table 9 shows the calculation of the rate of return from data on Canada long bond yields and an authorized return on equity.

Table 10 compares the growth in the PEG Research custom input price index to that of the Alberta Gross Domestic Product Implicit Price Index for final domestic demand and a custom inflation measure similar to those proposed by ATCO Gas and AltaGas. It can be seen that the year to year growth rates in the two indexes differed considerably. The longer term trends in the GDPIPI and the PEG Research Custom Alberta Input Price Index were quite similar. However, this is due to a material decline in the allowed rate of return that may not be repeated prospectively. The ATCO Gas-style inflation measure grew much more rapidly than the other two indexes.

In response to data request CCA-NERA-22 NERA stated concerning this research that

NERA believes that the added complexity to which Dr. Lowry refers in AUC-CCA-20, and as shown in Attachment ATCO-CCA-63, would not be a barrier to an “objective and reliable” inflation index as long as all parties generally found that the added complexity was easily understood and acceptable, both for the current proceeding and for the intervals at which the PBR plan is re-set.

3.2 Service Quality Provisions

3.2.1 Second NERA Report

NERA notes that most of the PBR plans it surveyed contain SQ award penalty mechanisms. NERA advocates the use of SQ APMs with both awards and penalties for Alberta utilities.

3.2.2 Response

We believe that the limitation of NERA’s survey to index-based North American PBR plans may actually have understated the frequency with which SQ APMs are featured in PBR generally. When it comes to these mechanisms, there is no need to ignore other PBR precedents because they involve alternative rate escalation mechanisms or a country with different institutional arrangements. SQ APMs are common in many

Table 9

Calculation of the Weighted Average Cost of Capital

Year	Bond Yield Long-term	20 Year Moving Average	Imputed Utility Bond Yield ¹	Authorized Return on Equity ²	Weighted Average Cost of Capital
1976	9.61				
1977	9.15				
1978	9.57				
1979	10.50				
1980	12.82				
1981	15.59				
1982	14.75				
1983	12.08				
1984	13.00				
1985	11.20				
1986	9.30				
1987	9.75				
1988	10.05				
1989	9.66				
1990	10.69				
1991	9.72				
1992	8.68				
1993	7.86				
1994	8.69				
1995	8.41	10.55	11.28	9.50	8.95
1996	7.75	10.46	11.18	9.50	8.62
1997	6.66	10.34	11.05	9.50	8.08
1998	5.59	10.14	10.84	9.50	7.55
1999	5.72	9.90	10.58	9.50	7.61
2000	5.71	9.54	10.20	9.50	7.60
2001	5.76	9.05	9.68	9.50	7.63
2002	5.68	8.60	9.19	9.50	7.59
2003	5.34	8.26	8.83	9.50	7.42
2004	5.14	7.87	8.41	9.50	7.32
2005	4.40	7.53	8.05	9.50	6.95
2006	4.28	7.28	7.78	9.50	6.89
2007	4.32	7.01	7.49	9.50	6.91
2008	4.05	6.70	7.17	9.50	6.77
2009	3.90	6.42	6.86	9.50	6.70
2010	3.66	6.06	6.48	9.50	6.58
Average 1999-2009	-3.85%			0.00%	-1.28%

¹ The imputed bond utility bond yield uses the actual average debt rate for ATCO in 2010 and then imputes the earlier values using the change in the 20 year moving average of the long bond yield.

² The return on equity used is a modest discount from that proposed by ATCO and is held constant.

Table 10
Inflation Differential Calculations for Alberta

GDIPI Final Domestic Demand - Alberta ¹				PEG Research Custom Alberta						Inflation Differentials			
				ATCO Input Price Index			Input Price Index						
Year	Level	Growth Rate	Average Growth Rate Ending in 2010	Level	Growth Rate	Average Growth Rate Ending in 2010	Level	Growth Rate	Average Growth Rate Ending in 2010	PEG - GDIPI	Average Growth Rate Ending in 2010	PEG-ATCO	Average Growth Rate Ending in 2010
1995	86.7			1.000			1.000						
1996	88.3	1.83%	1.83%	1.034	3.33%	3.16%	1.020	1.98%	2.18%	0.15%	-0.11%	-1.35%	-0.98%
1997	90.5	2.46%	2.46%	1.064	2.85%	3.15%	1.021	0.10%	2.19%	-2.36%	-0.13%	-2.74%	-0.96%
1998	91.9	1.54%	1.54%	1.086	2.06%	3.17%	1.023	0.17%	2.36%	-1.37%	0.04%	-1.89%	-0.82%
1999	93.3	1.51%	1.51%	1.106	1.86%	3.27%	1.055	3.10%	2.54%	1.58%	0.16%	1.24%	-0.73%
2000	95.6	2.44%	2.44%	1.141	3.09%	3.40%	1.083	2.61%	2.49%	0.17%	0.01%	-0.48%	-0.92%
2001	97.4	1.87%	1.87%	1.166	2.14%	3.43%	1.113	2.71%	2.47%	0.84%	0.00%	0.57%	-0.95%
2002	100.0	2.63%		1.200	2.89%		1.137	2.15%		-0.48%		-0.73%	
2003	100.9	0.90%		1.246	3.81%		1.157	1.75%		0.85%		-2.06%	
2004	103.0	2.06%		1.278	2.49%		1.180	1.98%		-0.08%		-0.51%	
2005	106.0	2.87%		1.331	4.07%		1.191	0.94%		-1.93%		-3.13%	
2006	111.1	4.70%		1.391	4.41%		1.235	3.61%		-1.09%		-0.79%	
2007	116.1	4.40%		1.467	5.35%		1.293	4.62%		0.22%		-0.73%	
2008	120.1	3.39%		1.537	4.61%		1.340	3.54%		0.16%		-1.07%	
2009	121.3	0.99%		1.560	1.53%		1.367	2.00%		1.00%		0.47%	
2010	122.3	0.82%		1.607	2.96%		1.387	1.43%		0.61%		-1.53%	
Average Annual Growth Rates													
1996-2010		2.29%			3.16%			2.18%		-0.11%		-0.98%	
2001-2010		2.46%			3.43%			2.47%		0.01%		-0.95%	

¹Statistics Canada. Table 384-0036 - Implicit price indexes, gross domestic product (GDP), provincial economic accounts, annual (index, 2002=100).

PBR plans overseas and in the many PBR plans approved in the United States that do not involve index-based rate escalators. A good example of the latter are the numerous PBR plans in New York state that are not covered by the NERA survey because they have “stairstep” allowed revenue escalators.¹²

3.3 Efficiency Carryover Mechanisms

3.3.1 Second NERA Report

NERA’s survey of index-based North American PBR plans found that ECMs were “uncommon in North America” (page 52) and, more generally, “unprecedented in PBR.” NERA spoke disapprovingly of ECMs, stating on page 9 that “we have seen no evidence demonstrating that that particular innovation to PBR – a partial lengthening of regulatory lag – is worth the additional complications it would pose for the periodic future rate cases.”

3.3.2 Response

We believe that this is another area where a broader survey would have been more helpful to the AUC. There has in fact been considerable experimentation with ECMs in recent years, but it has mostly occurred overseas or in US PBR plans that don’t involve index-based rate escalation mechanisms. ECMs have, for example, been a feature of PBR plans approved in the United States for AmerenUE, Granite State Electric, Massachusetts Electric, and Narragansett Electric. Overseas, they have been used several times, for both gas and electric utilities, by the Essential Services Commission in Victoria State of Australia. The ESC has emphasized the value of ECMs in discouraging an opportunistic timing of O&M expenses.

We believe that ECMs merit consideration for the Alberta utilities in this proceeding. However, this is one area where resolution through settlement would be preferable given the lack of a record in this proceeding that would direct the AUC to ECMs that share benefits fairly between the companies and their customers.

¹²For an example of a New York gas utility SQ APM please see the joint proposal filed in New York PSC Case 09-G-0796. For an example of a New York electric SQ APM please see the joint proposal in New York PSC Case 09-E-0428.

4. POSTSCRIPT: PBR HISTORY

As a closing note, we would like to make some corrections to the brief history of PBR that NERA presents on pages 25-27 of their Second Report. PBR in North America is characterized in these pages as an outgrowth of experiments in regulation that attended the privatization of utility industries in Britain in the 1980s. Although PBR in Britain is not based on input price and productivity research, we are nonetheless led to believe that PBR based on index research somehow evolved in North America from British precedent.¹³

In point of fact, the approach to index-based PBR that is popular in North America developed independently of British precedents and during a contemporaneous time period.¹⁴ As noted in Section 2.16 above, economists in the US were considering in the late 1970s and early 1980s how input price and productivity research could be used to regulate utilities. An entire book on the use of productivity research in utility regulation was published in 1981. The first large-scale use of indexing in North American regulation began in the early 1980s in the US railroad industry where a rail cost adjustment factor (“RCAF”) was established that featured a railroad industry input price index and a productivity offset based on the industry productivity trend. About the same time, California gas and electric utilities began filing rate cases at three year intervals in accordance with the California commission’s “rate case plan” and began escalating the O&M portion of their allowed revenue using inflation indexes. By the early 1990s industry-specific input price indexes were used for this purpose. Price cap indexes based on input price and productivity were first approved for use in US telecommunications in the late 1980s and PBR based on index research subsequently spread to the US oil pipeline industries, to gas and electric utilities in New England, and to railroad, telecommunications, and energy distribution utilities in Canada.

¹³ NERA notes correctly on page 27 that “In current practice in both the UK and Australia, the *X factor* does not come from a TFP growth study but rather is a way to synchronize current prices (or revenues) with long-term economic forecasts ... of capital and operating costs.”

¹⁴ The early history of PBR in the United States is discussed in Lawrence Kaufmann and Mark Newton Lowry, “Performance-Based Regulation of Utilities”, *Energy Law Journal*, Vol. 23, No. 2, 2002.

Most American PBR plans today use rate and revenue caps with “stairstep trajectories.” Canada has emerged as the leading North American practitioner of what is now properly called the “North American” approach to PBR indexing. This approach has also been adopted in several countries overseas.



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

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Website: www.auc.ab.ca

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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.

time⁴), 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 board⁷ 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. Makhholm.

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 letter¹⁵ 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 2010-20²² 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. Intervenors filed their PBR evidence on December 16, 2011.

33. The Commission received a wide range of proposals from the companies and the intervenors. 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.

Consumer Advocate (UCA) expressed concerns about moving to PBR at this time.²⁴ The UCA's position was that the companies are performing well under the current cost of service framework and that more company-specific information is needed to implement the type of PBR plan that the UCA envisions. The Industrial Power Consumers Association of Alberta (IPCAA) recommended a limited adoption of PBR until two types of performance metrics (quality of service and asset condition metrics) are available and the necessary quality and reliability safeguards are implemented.²⁵ EPCOR proposed a PBR plan that excludes all capital-related costs from the application of an I-X mechanism.²⁶ The other parties (ATCO Electric,²⁷ ATCO Gas,²⁸ Fortis,²⁹ AltaGas,³⁰ the Consumers' Coalition of Alberta (CCA)³¹ and The City of Calgary (Calgary)³²) proposed or accepted plans that applied an I-X mechanism to all categories of costs. Each of these parties also argued for or accepted some type of provision to deal with some capital costs outside of the I-X mechanism and proposed or accepted the need for certain new or existing deferral accounts and rate riders.

34. In seeking to develop a PBR mechanism that can best achieve the Commission's objectives while being consistent with all of its principles to the maximum extent possible, the Commission has carefully considered all of the submissions of the companies and interveners. The Commission is employing an I-X mechanism and a five-year term as part of its PBR plan in order to create the same efficiency incentives as those that are present in competitive markets to the greatest extent possible for the electric and gas distribution companies. The inclusion of an efficiency carry-over mechanism will further enhance these incentives. In doing so, the Commission is also making provision for the exclusion of some capital costs from application of the I-X mechanism where necessary in order to accommodate the unique circumstances of each regulated company. The Commission is employing a revenue-per-customer cap for natural gas distribution companies and a price cap for electric distribution companies in order to recognize the differences between those two industries. The Commission is also making provision for the treatment of necessary deferral accounts and flow-through mechanisms for each company as part of its PBR plan.

35. In making its determinations, the Commission has considered the effect of the combination of the I-X mechanism with the treatment of some capital-related costs outside of the I-X mechanism, the Z factor adjustments and the provision for deferral accounts and flow-throughs to protect the companies from significant unforeseen events that are outside their control. In addition, the Commission has considered the statements of a number of witnesses regarding the incentives to over-forecast capital expenditures, the observation of Dr. Lowry that the companies have considerable flexibility in the timing of capital replacements³³ and the views of Dr. Weisman that with the incentives created by the plan, the companies will discover new ways to conduct their businesses.³⁴ Having considered the statements of the parties and

²⁴ Exhibit 299.02, Cronin and Motluk UCA evidence, pages 12-13.

²⁵ Exhibit 306.01, IPCAA Vidya Knowledge Systems evidence.

²⁶ Exhibit 103.02, EPCOR application.

²⁷ Exhibit 98.02, ATCO Electric application.

²⁸ Exhibit 99.01, ATCO Gas application.

²⁹ Exhibit 100.01, Fortis application.

³⁰ Exhibit 110.01, AltaGas application.

³¹ Exhibit 307.01, CCA evidence.

³² Exhibit 298.02, Calgary evidence.

³³ Exhibit 307.01, CCA evidence of PEG, Section 4.1, page 59; Exhibit 636.01, CCA argument, Section 8.1, paragraph 118.

³⁴ Exhibit 103.03, EPCOR application, Appendix A, page 20, paragraph 49.

witnesses, and the full record of the proceeding, the Commission is satisfied that the PBR plans approved in this decision will provide 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. With regard to earning a fair rate of return, there was general agreement³⁵ among the experts and the parties that the opportunity to earn a fair rate of return should be considered over the term of the PBR plan and not on a year-by-year basis.

36. Customers will share the benefits from the improved efficiency incentives under PBR through the inclusion of an X factor and a stretch factor in the plan. Customers will be protected against earnings significantly above the approved ROE, and the companies will be protected against earnings significantly below the approved ROE, by the incorporation of a re-opener in the plan. If the ROE of a company meets the conditions for a plan re-opener to take effect, this will afford an opportunity for the Commission to re-examine the parameters of the plan and, if required, to adjust them.

37. The Commission is also making provision for enhanced quality of service rules and measures to address the incentive that companies might have to reduce their costs in such a way that service quality declines in the short and long term.

38. The Commission has sought to make the PBR plans as easy to understand, implement and administer as possible given the structure of the electric and natural gas industries in Alberta, the need to accommodate the unique circumstances of each company and the recognition that this is the first time PBR has been adopted for all of the distribution companies. The Commission is confident that as the parties become more familiar with PBR and as the companies discover new ways to adapt their businesses to the opportunities PBR offers, it will be possible to further streamline the regulatory framework to achieve the Commission's objectives.

39. Finally, the Commission is satisfied that the PBR plans meet the objectives for PBR described in its February 26, 2010 letter. Furthermore, the Commission has taken particular note of the five PBR principles articulated in Bulletin 2010-20. The Commission is satisfied that the PBR plans overall, and each of the elements of the plans, are consistent, to the maximum extent possible, with all five principles.

40. The Commission intends to review PBR as it comes to the end of the first term and to consider extending the plans or incorporating other approaches if those can be demonstrated to better balance regulatory efficiency and regulatory effectiveness in a way that achieves the Commission's objectives and satisfies the Commission's principles.

2 Approaches to rate regulation

41. The UCA (Office of the Utilities Consumer Advocate), IPCAA (Industrial Power Consumers Association of Alberta), and EPCOR each proposed alternatives to the Commission's preferred approach to PBR (performance-based regulation) stated in its letter of February 26, 2010 and Bulletin 2010-20. These proposals affected either the time at which PBR could be implemented in Alberta for the electric and gas distribution companies, the nature of PBR, or the

³⁵ Transcript, Dr. Carpenter, Volume 3, pages 565-566; Transcript, Mr. Camfield, Volume 8, page 1373; Transcript, Mr. Gerke and Dr. Weisman, Volume 10, pages 1828-1829; Transcript, Ms. Frayer, Volume 11, page 2190.

costs to which PBR would apply. In this section, the Commission addresses each of these alternative proposals. The Commission also addresses specific elements of these proposals throughout this decision.

2.1 The UCA's proposal

42. The UCA proposed a delay in the implementation of PBR. The UCA developed its own objectives for PBR and then used those objectives, in combination with its view of what a PBR plan should be like, to justify the delay.

43. The UCA's objectives were expressed as follows:

- Better economic incentives in order to achieve productivity improvements, which will result in lower customer rates than under cost of service regulation,
- Clearly defined performance standards with penalties for failure to achieve specified performance targets, and
- A reduction in the overall regulatory burden by improving the efficiency of the regulatory framework.³⁶

44. The UCA stated that if PBR would not meet its three over-arching objectives, then the move to PBR at this time must be reassessed. The UCA also submitted that based on the available information, there is no compelling reason to switch to PBR. Three principal reasons were given for this position:

- 1) The evidence of Dr. Cronin [expert witness for the UCA] that regulatory burden does not go down under PBR;
- 2) The large capital forecasts upon which the applicants' PBR plans are based, and, in the case of EDTI the complete exclusion of capital from its PBR plan; and
- 3) The lack of information presently available about the applicants: (i) comparative performance; (ii) present efficiency levels, and (iii) potential for efficiency improvements.³⁷

Commission findings

45. The Commission has considered the UCA's objectives for PBR and its reasons for reassessing the move to PBR at this time. The Commission agrees with the objectives that PBR should provide better economic incentives and result in lower rates than under cost of service regulation. The Commission also agrees that PBR should reduce the regulatory burden by improving the efficiency of the regulatory framework. The Commission considers that clearly defined performance standards and the imposition of penalties to achieve performance targets is a good approach to addressing service quality issues, and, therefore, the Commission has included maintaining service quality as an integral part of its first PBR principle. Service quality issues and the Commission's approach to maintaining service quality are addressed in Section 14 of this decision.

46. The Commission acknowledges the UCA's concerns about the capital forecasts filed by the companies in this proceeding and has addressed these concerns in this decision.

³⁶ Exhibit 634.01, UCA argument, paragraph 20, page 4.

³⁷ Exhibit 634.01, UCA argument, paragraph 28, page 5.

47. The Commission considers the UCA's first and third reasons for reconsidering and delaying implementation of PBR at this time to be closely related. Dr. Cronin argued that the regulatory burden does not go down under PBR and cites the Ontario PBR plans as an example. In the Commission's view, the type of PBR plan envisioned by Dr. Cronin would not decrease the overall regulatory burden because significant effort would still be required, although on different matters than under cost of service regulation. Dr. Cronin expressed his view that PBR plans require collecting significant amounts of information in order to carry out comparisons of the productivity and efficiency performance of various individual companies in Alberta with each other and with other North American companies. Dr. Cronin requires this information in order to determine how close those companies are to the "efficiency frontier"³⁸ and, therefore, their potential for efficiency improvements.³⁹ In addition, Dr. Cronin argued for the use of company-specific total factor productivity studies (which is also a data-intensive undertaking) to establish company-specific X factors. Dr. Cronin further suggested that comparisons of companies could be made at even more disaggregated levels, such as individual cost types or cost centres.⁴⁰

48. In the Commission's view, adopting this type of an approach to PBR might very well increase the regulatory burden. Indeed, Dr. Cronin, in describing the approach used in Great Britain (one that appears to require the same type of information as that proposed by Dr. Cronin), stated that the regulator there "busies hundreds of analysts"⁴¹ to give effect to its regulatory approach.

49. It is not the Commission's intention to build a PBR regulatory framework that requires or invites the Commission to manage the companies through analysis of and distinct incentive schemes for lower level cost data provided in company-specific TFP studies. Nor is it the Commission's intention to benchmark companies against each other or against an estimated efficiency frontier. In the ENMAX proceeding, Dr. Cronin expressed similar views to those expressed in this proceeding, and the Commission rejected them in Decision 2009-035, dealing with the ENMAX FBR proposal.⁴² The Commission's objective is to provide incentives for improved efficiencies, both in the short run and the long run, as well as opportunities for the companies, without Commission direction and control, to discover and implement those efficiencies over longer time periods than they would have under the current regulatory framework. In the Commission's view, the PBR approach envisioned by the UCA would not achieve the objective of improving the efficiency of the regulatory process, nor would it satisfy the principle that, to the greatest extent possible, a PBR plan should create the same efficiency incentives as those experienced by companies in a competitive market. It would also not satisfy the principle that a PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

50. The Commission has also considered the UCA's view that PBR need not be implemented at this time because "based on the limited information available, it appears very likely the applicant utilities have superior performance, their rates are below or equal to other jurisdictions; their reliability is higher; and ROE is much higher than other jurisdictions."⁴³ The UCA's

³⁸ For further discussion on the efficiency frontier approach please refer to Section 6.2.

³⁹ Exhibit 634.01, UCA argument, paragraph 40, page 7.

⁴⁰ Transcript Volume 18, page 3420, line 8 to page 3422, line 7.

⁴¹ Transcript, Volume 17, pages 3227, lines 15-16; Transcript, Volume 18, pages 3430-3431.

⁴² Decision 2009-035, paragraph 175.

⁴³ Exhibit 634.01, UCA argument, paragraph 48, page 9.

conclusion is based on a benchmarking of the Alberta companies to a number of U.S. local distribution companies selected by Dr. Cronin.⁴⁴ These comparisons show that ENMAX's and EPCOR's local distribution rates are at the lower end of the range of rates of the selected companies and that Fortis is in the range of two local distribution companies in the northern states.⁴⁵ Information provided in response to an undertaking showed that ATCO Electric's local distribution rates are much higher than the other companies in the UCA's comparison group.⁴⁶

51. The Commission is not satisfied that these comparisons can justify a decision to delay PBR until more information can be provided and analysed. ENMAX's rates are already regulated under a PBR plan. EPCOR has explained that a great deal of its local distribution network is in need of replacement. As a result, its rates can be expected to be lower because its capital-related costs included in rates will be lower than if the local network had already been substantially replaced. Indeed, as discussed in Section 7.3, the Commission's observation in this proceeding is that differences among the companies' capital proposals under PBR can be explained to some degree by where those companies are in the long term cycle of capital investment and replacement. Furthermore, this observation makes suspect the results of benchmarking across different regulated companies, whether Canadian companies or, as in the UCA analysis, U.S. companies. There may also be significant differences among the companies that cannot be accounted for in benchmarking studies.

52. Accordingly for all of the reasons stated above, the Commission is not persuaded by the UCA to reconsider or delay implementation of PBR for Alberta distribution companies.

53. The UCA has proposed that if the Commission proceeds at this time with PBR, it should engage in benchmarking and, if not benchmarking, then it should use a menu approach to PBR. If the menu approach is not employed by the Commission, the UCA recommended that the Commission adopt the ENMAX FBR model. The UCA's proposal for benchmarking and its menu approach to PBR are both addressed Section 6.2.

2.2 IPCAA's proposal

54. IPCAA objected to the full implementation of PBR at this time. IPCAA proposed the use of an I-X mechanism only for general and administrative (G&A) costs and the retention of cost of service regulation for the remaining costs (O&M (operating and maintenance) as well as capital-related costs). IPCAA's concern is that PBR creates incentives to reduce costs and that the Commission's current quality of service rules are not sufficient to protect service quality and asset condition. IPCAA, therefore, recommended a limited adoption of PBR until specific quality of service and asset condition performance metrics are implemented.⁴⁷

Commission findings

55. The Commission understands IPCAA's concerns about the potential effects of the incentives created by PBR on service quality and the condition of the companies' capital assets. The Commission also recognizes that its own current quality of service rules may not be sufficient to properly address IPCAA's concerns or, indeed, the Commission's concerns under PBR. However, the Commission does not agree that these concerns must be addressed before a

⁴⁴ Exhibit 299.02, Cronin and Motluk UCA evidence, page 27.

⁴⁵ Exhibit 299.02, Cronin and Motluk UCA evidence, page 27; Exhibit 614.01, UCA undertaking.

⁴⁶ Exhibit 614.01, undertaking response given by Dr. Cronin.

⁴⁷ Exhibit 304.01, IPCAA policy evidence.

PBR plan can begin. The Commission is confident that its plans to address service quality and asset condition issues early in the PBR term will be sufficient to allow PBR to proceed. The Commission has taken into account IPCAA's concerns in its quality of service determinations and plans described in Section 14.

56. Furthermore, the Commission notes that IPCAA's proposal to include only G&A expenses in PBR would result in a negative effect on incentives because of the exclusion of a significant portion of the operations of a company from the I-X mechanism. Such an effect is well documented in this proceeding.⁴⁸ Therefore, based on all of the above, the Commission does not accept IPCAA's suggestion to limit the PBR plans to G&A expenses only.

2.3 EPCOR's proposal to exclude capital

57. EPCOR has proposed to exclude all capital-related costs from the application of the I-X mechanism.⁴⁹ The reason given by EPCOR is that it must embark on a major capital replacement program to address its aging local distribution system. EPCOR argued that, in its case, including all current capital-related expenses under the I-X mechanism and making provision for its significant capital additions outside of the I-X mechanism would be too complex to implement and could prevent EPCOR from making efficient capital decisions because of the way in which a capital mechanism outside of the I-X mechanism might be structured.

Commission findings

58. The Commission understands EPCOR's concerns but is itself concerned that excluding all capital from the I-X mechanism will not create new incentives to more optimally make efficient trade-offs between capital and maintenance and may serve to exacerbate the already significant incentives under a rate base rate-of-return framework to prefer capital investment over O&M expenses. In addition, the Commission is not satisfied that there is any acceptable way to create an X factor suitable for use for non-capital-related costs only. Therefore, the Commission does not accept EPCOR's proposal to exclude all capital-related costs from application of the I-X mechanism. However, the Commission does address EPCOR's concerns about how its capital program can be treated outside of the I-X mechanism in Section 7.3.2.4 of this decision.

2.4 EPCOR's transmission proposal

59. In its February 26, 2010 letter, the Commission indicated that reform of rate regulation for electricity and natural gas transmission services would not be undertaken at that time because:

The electricity transmission system is entering a period of significant change with substantial planned expansions while natural gas transportation rates are one subject of more extensive negotiations between the province's two largest regulated natural gas transportation service providers.⁵⁰

⁴⁸ Transcript, Volume 1, page 143, Dr. Makholm.

⁴⁹ Exhibit 103.02, EPCOR application, pages 10-18.

⁵⁰ Exhibit 1.01, AUC letter dated February 26, 2010, Rate regulation initiative round table.

60. Nonetheless, on July 15, 2010, the Commission released Bulletin 2010-20, which stated that “those distribution companies that are also transmission facility owners may choose to include their transmission components in the PBR plan if that is their preference.”⁵¹

61. Of the Alberta distribution companies affected by the bulletin that also had an integrated transmission function, EPCOR was the only company that proposed to include its transmission component in its PBR plan. EPCOR explained that the highly integrated nature of its distribution and transmission functions allowed for economies of scale and scope and that a single, joint rate application for the two business operations reduced regulatory burden.⁵²

62. As further outlined in the subsequent sections of this decision, EPCOR proposed that in its PBR plan, the I-X mechanism would apply only to the company’s O&M and other non-capital costs, with capital expenditures treated as a flow-through item. EPCOR proposed this type of PBR plan for both its distribution and transmission functions.⁵³ In these circumstances, as discussed in Section 6.4.3, Dr. Cicchetti noted that an X factor for EPCOR should reflect the changes in O&M productivity only. Furthermore, because the O&M costs of EPCOR’s distribution and transmission functions were similar in nature, Dr. Cicchetti offered that his recommended X factor was relevant to both functions:

The two functions are highly integrated and interdependent, with shared management and staff, who utilize the same offices and other assets. There are common union settlements and the primary O&M input for both functions is labour. Accordingly, my recommendations apply to both functions.⁵⁴

63. In its proposed PBR plan, EPCOR included four service quality performance measures and proposed targets for each of these measures along with a penalty adjustment in its formula for non-compliance with the performance targets. The four service quality performance measures were: Total Recordable Injury Frequency Rate (TRIF), System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Service Connection Time (SCT).⁵⁵ For three of these measures, TRIF, SAIDI and SAIFI, EPCOR proposed to report combined distribution and transmission results.⁵⁶ During the hearing, EPCOR witnesses testified that there are no service quality issues that are unique to transmission.⁵⁷ As such, EPCOR concluded that its proposed service quality measures that combine distribution and transmission are “reasonable and workable.”⁵⁸

64. No party to this proceeding opposed the inclusion of EPCOR’s transmission function in the company’s PBR plan. However, the CCA and IPCAA expressed their concerns with the lack of relevant reliability metrics for transmission in Alberta to be used as service quality performance measures in PBR plans for electric transmission operations.

65. In argument and reply, IPCAA pointed to the absence of standard province-wide service quality measures for electric transmission services in Alberta. In IPCAA’s view, a PBR

⁵¹ Exhibit 64.01, AUC Bulletin 2010-20, page 3.

⁵² Exhibit 103.02, EPCOR application, paragraph 14.

⁵³ Exhibit 103.02, EPCOR application, paragraph 3.

⁵⁴ Exhibit 103.05, Cicchetti evidence, pages 20-21.

⁵⁵ Exhibit 630.02, EPCOR argument, paragraph 292.

⁵⁶ Exhibit 630.02, EPCOR argument, paragraph 309.

⁵⁷ Transcript, Volume 10, page 1813, lines 17-21.

⁵⁸ Exhibit 646.02, EPCOR reply argument, paragraph 283.

mechanism for transmission facilities would be “far more complex and have much greater impact than at the distribution level,” since the consequences of service quality degradation for transmission are much more severe than for distribution:

Reductions in customer service quality at a POD [point-of-delivery where the distribution system connects to the transmission system] level will have an order of magnitude larger impact as transmission level outages affect either thousands of smaller customers at a [distribution company] point of delivery or large industrial facilities such as gas plants, refineries and oil sands facilities.⁵⁹

66. Accordingly, IPCAA asserted that transmission service quality measures should be considered in a province-wide process. In IPCAA’s view:

Applying PBR to EDTI’s transmission function could result in a piecemeal approach to transmission regulation, which is managed and delivered on a province-wide basis, and typically consists of large, capital intensive projects, the costs of which are flowed through to customers.⁶⁰

67. The CCA expressed concern over the lack of data that EPCOR proposed to report in relation to transmission reliability and proposed that the Commission direct EPCOR to also report additional reliability measures such as energy not supplied, average interruption time and overhead line maintenance cost index for its transmission reliability. The CCA indicated that these measures are being used by other transmission companies.⁶¹

Commission findings

68. The Commission has two concerns with EPCOR’s proposed inclusion of its transmission function under its PBR plan.

69. First, EPCOR’s proposed X factor, which would be applicable to both its distribution and transmission functions under its PBR plan, is only for non-capital costs. Dr. Cicchetti stated that because the O&M costs of EPCOR’s distribution and transmission functions were similar in nature, his recommended X factor (calculated using the O&M data for the distribution component of NERA’s sample) was relevant to both functions.⁶² In the Commission’s view, it is uncertain whether the same conclusion can be reached when the X factor is calculated based on the entirety of the costs (both O&M and capital) of the company.

70. In its productivity study, NERA measured the TFP of the distribution component of 72 U.S. electric and combination electric/gas companies from 1972 to 2009. Costs related to power generation and transmission, as well as general overhead costs, were not included in the study.⁶³

71. As explained above, the Commission has not accepted EPCOR’s proposal to exclude capital and apply the I-X mechanism only to the O&M and other non-capital costs in its PBR plan. No evidence was filed in this proceeding on what the relevant X factor for the electric transmission function should be if the I-X mechanism is applied to both O&M and capital costs.

⁵⁹ Exhibit 635.01, IPCAA argument, paragraph 75.

⁶⁰ Exhibit 642.01, IPCAA reply argument, paragraph 38.

⁶¹ Exhibit 636.01, CCA argument, paragraphs 363-365.

⁶² Exhibit 103.04, Cicchetti evidence, pages 20-21.

⁶³ Exhibit 80.02, NERA report, page 6.

Accordingly, the Commission cannot set an X factor for EPCOR if the transmission function is included in the plan.

72. Second, EPCOR's proposed measures, targets and penalties to ensure service quality were proposed in the context of a PBR plan that excludes capital-related costs from the rates subject to the I-X mechanism. It is unclear whether these measures, targets and penalties would be adequate to ensure transmission service quality for a PBR plan that is not restricted in this manner. EPCOR's proposals for service quality measures are further discussed in Section 14.

73. The creation of reliability standards and performance targets for transmission is still under development. Unlike transmission, the Commission has been monitoring service quality performance through AUC Rule 002⁶⁴ for electric utilities and gas distributors. While further measures and performance targets will be developed as part of AUC Rule 002, as discussed in Section 14, there has been a history of measuring and reporting performance for the distribution function with which companies and industry stakeholders are familiar. There is no similar starting point for transmission.

74. In light of the above considerations, the Commission finds that transmission services should not be a part of EPCOR's PBR plan. EPCOR's transmission services will continue to be regulated under cost of service regulation.

3 Going-in rates

3.1 Purpose and background

75. Going-in rates are the starting rates for the implementation of a PBR (performance-based regulation) plan. The going-in rates are sometimes referred to as "year zero rates." They are the rates to which the approved PBR formula is applied to determine the rates to be charged to customers during the first year of the PBR term. Thereafter, the current year's rates are adjusted by the PBR formula to determine the upcoming year's rates until the end of the PBR term.

76. In Decision 2009-035,⁶⁵ the Commission determined that ENMAX's going-in rates were to be based on the company's revenue requirement as determined in a forecast cost of service rate setting proceeding.⁶⁶ The Commission directed that the going-in rates for ENMAX would be its approved 2006 rates, adjusted to include previously disallowed short term incentive plan costs. With respect to adjustments to going-in rates proposed by ENMAX and interveners to reflect certain actual 2006 costs, the Commission stated that it would "not accept adjustments to the going-in rates to account for 2006 actual results."⁶⁷ The Commission further stated that: "[a]djustments to account for actual results should not be made selectively but, rather, should only be made in the context of a full rate case which would consider the forecast costs for a subsequent time period."⁶⁸ The Commission accepted a single adjustment to going-in rates to include previously disallowed short term incentive plan costs. This adjustment was approved on

⁶⁴ AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*, effective July 1, 2010 (Rule 002).

⁶⁵ Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID. 12, March 25, 2009.

⁶⁶ Decision 2009-035, paragraph 72.

⁶⁷ Decision 2009-035, paragraph 73.

⁶⁸ Decision 2009-035, paragraph 74.

the basis that ENMAX had addressed the concerns that had led to the original disallowance of these costs from inclusion in the 2006 revenue requirement and that the revised short term incentive plan had been designed to incent “operational efficiency improvements and, as such, complements the incentives created by a formula based regulation plan.”⁶⁹

77. In a December 16, 2010 letter granting deadline extensions for the filing of the companies’ PBR proposals in this proceeding, the Commission determined that the forthcoming rate decisions for the 2012 test year will be used by the Commission to establish the going-in rates for the companies.

3.2 Proposals for going-in rates

78. All of the companies proposed that their 2012 approved rates be used as the basis for their going-in rates. In addition, all of the companies, with the exception of EPCOR, proposed adjustments to their 2012 approved rates in setting going-in rates for the PBR term. The companies collectively proposed a total of nine individual adjustments to their going-in rates. Like ATCO Electric and ATCO Gas, AltaGas stated that its adjustments were necessary to earn a fair rate of return during the PBR plan.⁷⁰

79. EPCOR pointed to Decision 2009-035 in proposing that its 2012 approved distribution and transmission tariffs be used as the going-in rates for the company’s PBR plan⁷¹ without adjustment. In UCA-EDTI-10(b) EPCOR stated:

The approved distribution rates and transmission revenue requirement will form EDTI’s going-in rates and revenue requirement and, for many of the same reasons stated by the Commission in Decision 2009-35 [sic.], no adjustments to those rates for PBR purposes will be necessary or warranted. If the rates and revenue requirement are just and reasonable for 2012, they will also be just and reasonable as EDTI’s going-in rates and revenue requirement. As the Commission indicated in Decision 2009-035, costs and financial results will fluctuate from year to year over the PBR Term. In some years, costs will be higher than expected and in other years lower, EDTI will be incented to improve its efficiency and productivity and under EDTI’s PBR Plan, some of these gains will be shared with customers and some will be retained by EDTI.⁷²

80. AltaGas requested that its going-in rates be based on its 2012 distribution rates approved in response to its 2010 to 2012 GRA (general rate application) subject to certain adjustments. ATCO Electric and ATCO Gas proposed to use their 2012 final distribution rates as the basis for the going-in rates for the PBR term subject to certain adjustments.⁷³ Fortis also proposed to use its 2012 approved rates as the basis for its going-in rates but requested that the rates be adjusted to reflect its 2013 opening rate base balance, which would recognize 2012 actual capital expenditures.⁷⁴

⁶⁹ Decision 2009-035, paragraph 79.

⁷⁰ Exhibit 628.01, AltaGas argument, page 81; Exhibit 628.01, AltaGas argument, page 80; Exhibit 389.01, ATCO Gas update, page 4, paragraph 7.

⁷¹ Exhibit 103.02, EPCOR application, page 2.

⁷² Exhibit 238.01, EPCOR information responses, pages 25 and 26.

⁷³ Exhibit 98.02, ATCO Electric application, paragraph 208 and Exhibit 99.01, ATCO Gas application, paragraph 10.

⁷⁴ Exhibit 100.02, Fortis application, page 11.

81. There were no objections by interveners to the companies' proposals that the 2012 approved rates be used as the starting point for going-in rates in the PBR term. The CCA stated that, for the purposes of going-in rates, the approved revenue requirements have been set by rigorous cost of service regulatory oversight. However, the CCA stated that it was uncertain of the finality of these revenue requirements because of placeholders or the potential impact of other adjustments for outstanding appeals or applications.⁷⁵

82. The UCA recommended that the "going-in rates must include recognition of efficiency gains achieved in the last cost of service test period."⁷⁶ IPCAA and the CCA did not provide argument on going-in rates but agreed with the UCA that efficiency gains achieved under cost of service regulation should be recognized in going-in rates.⁷⁷

Commission findings

83. Prior to initiating the current proceeding, the Commission considered two alternatives for establishing the going-in rates at the commencement of the PBR term. The first alternative was to use the actual results for the immediately preceding year, in this case 2012, and adjust the 2012 approved rates to reflect the actual 2012 results to form the basis for the going-in rates for PBR. This approach would account for any expenses that were not forecast in the 2012 revenue requirement and any unaccounted for efficiency gains realized in 2012, all subject to a prudence review. However, the Commission recognized that the actual results for 2012 would not be available until well into 2013 and that a prudence review of these results would require a significant regulatory process. The Commission did not adopt this approach because it is inconsistent with the Commission's objective to implement PBR effective January 1, 2013 as set out in the Commission's letter of December 16, 2010.⁷⁸

84. The other alternative was to adopt the approach approved in Decision 2009-035 which uses rates approved in the most recent revenue requirement proceeding as the basis for establishing the going-in rates.

85. In an effort to promote regulatory efficiency, and so as not to delay the commencement of PBR, the Commission in its December 16, 2010 letter, adopted the approach approved in Decision 2009-035 and directed that the companies' approved rates for 2012 would be used as the basis for establishing going-in rates. Accordingly, rates that will form the basis for the going-in rates for PBR will have been established in the context of a full rate case, or in the case of Fortis, on the basis of a negotiated settlement approved by the Commission.

86. With respect to proposed adjustments to going-in rates, the Commission again has two alternatives. The first alternative is to consider making adjustments to include certain costs that were either not forecast or otherwise approved for inclusion in the 2012 revenue requirement, as proposed by certain of the companies. In this context, the Commission could also consider an adjustment to going-in rates to reflect efficiency gains that may have occurred in 2012 that were not already reflected in 2012 approved rates, as proposed by interveners.

⁷⁵ Exhibit 636.01, CCA argument, paragraph 11.

⁷⁶ Exhibit 634.01, UCA argument, page 72.

⁷⁷ Exhibit 642.01, IPCAA reply argument, paragraph 62.

⁷⁸ Exhibit 79.01, AUC letter dated December 16, 2010, Request for deadline extensions.

87. The second alternative is to again adopt the approach followed in Decision 2009-035. In that decision the Commission rejected the adjustments to going-in rates proposed by ENMAX and interveners to reflect certain actual 2006 costs. The Commission stated that it would “not accept adjustments to the going-in rates to account for 2006 actual results.”⁷⁹ The Commission further stated that: “[a]djustments to account for actual results should not be made selectively but, rather, should only be made in the context of a full rate case which would consider the forecast costs for a subsequent time period.”⁸⁰ The Commission did accept however, a single adjustment to going-in rates to include previously disallowed short term incentive plan costs. This adjustment was accepted on the basis that ENMAX had addressed the concerns that had led to the original disallowance of these costs from inclusion in the 2006 revenue requirement and that the revised short term incentive plan had been designed to incent “operational efficiency improvements and, as such, complements the incentives created by a formula based regulation plan.”⁸¹ The Commission found that an adjustment of this kind “is qualitatively different from rate adjustments made after the fact to reflect actual results.”⁸²

88. The Commission considers the second alternative is in keeping with the decision to use 2012 approved rates rather than 2012 actual costs as the basis for going-in rates. The 2012 rates have been tested and approved by the Commission as just and reasonable for 2012. Accordingly, the 2012 approved rates are the correct starting point on which to base going-in rates. The Commission confirms the findings in Decision 2009-035 that adjustments to going-in rates should not be made to reflect actual results. Further, adjustments should not be made selectively but, rather, should only be made in the context of a full rate case. Adjustments may be made in exceptional situations, however, like the case of the short term incentive plan adjustment approved in the ENMAX decision.

89. Accordingly, the Commission will consider adjustments that are in the nature of a correction to the going-in rates, and which are not rate adjustments made after-the-fact to reflect actual results. This approach is consistent with the Commission’s finding in Section 7.4.4 that differences between placeholder amounts and final approved amounts will be treated as Y factor adjustments or adjustments to rates that will be subject to the I-X mechanism, depending on the circumstances of the adjustment.

90. The Commission will consider each of the proposals of the companies and interveners to include adjustments to going-in rates.

91. Given the above findings, the Commission directs the companies to use their respective approved 2012 distribution rates as the going-in rates for the PBR term, subject to the specific adjustments allowed below.

3.3 Requests for adjustments to going-in rates

3.3.1 UCA requested adjustment for efficiency gains

92. The UCA recommended that efficiencies achieved by the companies prior to the commencement of the PBR term should be reflected in going-in rates. The UCA stated that prior to the implementation of PBR, the utilities had undertaken projects that will create new

⁷⁹ Decision 2009-035, paragraph 73.

⁸⁰ Decision 2009-035, paragraph 74.

⁸¹ Decision 2009-035, paragraph 79.

⁸² Decision 2009-035, paragraph 81.

efficiencies. However, none of the applications included any “mechanism or adjustment to allow customers to benefit from these efficiencies in going-in rates.”⁸³

93. The UCA identified two specific adjustments for ATCO Gas to account for efficiency gains: one to remove the costs of old facilities from going-in rates and one to remove certain costs for meter reading to account for the adoption of automated meter reading in 2012.⁸⁴

94. IPCAA and the CCA agreed with the UCA that efficiency gains achieved under cost of service regulation should be recognized in going-in rates.⁸⁵

95. EPCOR disagreed with the UCA’s proposed adjustments to going-in rates for efficiencies achieved under cost of service regulation and pointed to its actual return on equity being close to or below the target ROE.⁸⁶ The ATCO companies argued that the 2011 to 2012 distribution rates proceedings included a forecast of anticipated productivity improvements. The ATCO companies argued, “there is a danger that any adjustment could be giving customers the benefit of those productivity improvements twice, because they have already been incorporated into the 2012 going-in revenue for PBR.”⁸⁷

Commission findings

96. As stated in Section 3.2 above, it is the Commission’s view that adjustments to going-in rates should not be made to reflect actual costs incurred in the test year which form the basis for the going-in rates. Adjustments should only be made in the context of a full rate case. Accordingly, the Commission denies adjustments to reflect possible efficiency gains in a prior period that are not captured in the going-in rates. This finding is consistent with the Commission’s determination in Decision 2009-035 which denied the UCA’s request to reduce going-in rates by an amount to reflect actual costs incurred in the test year just as it disallowed ENMAX’s request for increases to the going-in rates to reflect higher actual costs.⁸⁸

3.3.2 Company proposals

3.3.2.1 Proposals to move from mid-year to end-of-year for rate base purposes

97. ATCO Electric requested an adjustment to its 2012 distribution rates to move from a mid-year calculation of rate base to an end-of-year calculation of rate base to reflect the full impact of its 2012 capital investment.⁸⁹ ATCO Electric submitted that the Commission has approved the full amount of the costs relating to its 2012 capital investment, totalling \$367 million, in the company’s revenue requirement in its 2011 to 2012 General Tariff Application.⁹⁰ ATCO Electric’s mid-year rate base was \$1.392 billion compared to its end-of-year rate base of \$1.508 billion. The capital related costs include financing costs, income tax, and depreciation.⁹¹ Based on the evidence of Dr. Carpenter, ATCO Electric submitted that NERA’s TFP study to be used for calculating X does not compensate ATCO Electric for the full year impact of

⁸³ Exhibit 634.01, UCA argument, page 72.

⁸⁴ Exhibit 300.02, UCA evidence of Russ Bell, pages 87 to 89.

⁸⁵ Exhibit 642.01, IPCAA reply argument, paragraph 62 and Exhibit 636.01, CCA argument, paragraph 375.

⁸⁶ Exhibit 646.02, EPCOR reply argument, paragraph 302.

⁸⁷ Exhibit 647.01, ATCO Electric reply argument, paragraph 246 and Exhibit 648.02, ATCO Gas reply argument, paragraph 518.

⁸⁸ Decision 2009-035, paragraph 83.

⁸⁹ Exhibit 98.02, ATCO Electric application, paragraphs 215 to 220.

⁹⁰ Exhibit 98.02, ATCO Electric application, paragraphs 215 and 216 and Decision 2011-134.

⁹¹ Exhibit 98.02, ATCO Electric application, paragraphs 217 and 218.

2012 additions that were not incorporated in the 2012 rates. Dr. Carpenter's evidence purported to show that NERA's study is based on a rate base growth of peer group utilities of 4.5 per cent and the company had an approximate rate base growth of 17 per cent in 2012.⁹²

98. ATCO Gas also proposed to use end-of-year values rather than applying the mid-year convention for its rate base calculations in order to reflect the full impact of its 2012 capital investments.⁹³ ATCO Gas submitted that the mid-year convention is used in order to recognize that not all investments occur on the first day of January. In employing the mid-year convention, the revenue requirement is adjusted to reflect the full year costs including depreciation, income tax, and carrying costs for the prior year's investment⁹⁴ but an adjustment for capital investments is required to fully recognize the investments in going-in rates.

99. Interveners disagreed with the proposal to use end-of-year investment values to determine rate base. Calgary stated that the effect of moving from the mid-year convention to the end-of-year is to increase the baseline revenue requirement. Calgary argued that, "AG's approach has the effect of increasing the baseline revenue requirement – the starting point for the revenue trajectory – over and above the point at which the Commission has already deemed reasonable from the approved revenue requirement."⁹⁵ It would also be inconsistent with its proposed use of average number of customers in ATCO Gas's PBR formula.⁹⁶

100. The CCA supported Calgary's position and argued that ATCO Gas' request should not be approved.⁹⁷

Commission findings

101. The mid-year rate base convention is the accepted method for approximating the cost of capital investments in the year, and for the purposes of calculating other capital related costs. The mid-year convention uses an arithmetical average of a utility's investments to account for capital related costs uniformly over the entire year, recognizing that assets are added to rate base throughout the year. It is commonly used in regulatory jurisdictions in North America.

102. Had a cost of service rate application been filed for 2013, it would have accounted for 2012 capital expenditures in opening plant balances for rate base and an entire year's operating expenses for the use of those assets. However, 2013 capital expenditures would still be subject to the mid-year convention. In its December 16, 2010 letter, the Commission determined that the forthcoming rate decisions for the 2012 test year will be used to establish the going-in rates for the companies. Therefore, PBR will take these going-in rates and will in effect apply the I-X mechanism to the mid-year rate base. Carrying forward the mid-year forecast balance of rate base in the 2012 rates into the going-in rates continues to reflect the fact that new capital assets are put into service throughout the year. The Commission finds that the introduction of PBR does not require a departure from the use of the mid-year convention. No evidence was provided that other regulators employ this practice in adopting a PBR plan.

⁹² Exhibit 476.01, ATCO Electric rebuttal evidence, paragraph 76.

⁹³ Exhibit 99.01, ATCO Gas application, page 45-46.

⁹⁴ Exhibit 99.01, ATCO Gas application, paragraph 132.

⁹⁵ Exhibit 298.02, Calgary evidence, page 49, paragraph 176.

⁹⁶ Exhibit 629.01, Calgary argument, page 69.

⁹⁷ Exhibit 636.01, CCA argument, paragraphs 230 and 231.

103. The Commission finds no compelling reason to depart from the use of the mid-year convention. Accordingly, the Commission denies ATCO Electric's and ATCO Gas' proposal to use 2012 end-of-year forecast values rather than applying the mid-year convention for the rate base calculations included in going-in rates.

3.4 Individual adjustments to going-in rates requested by the companies

3.4.1 Fortis

104. Fortis proposed to update its 2013 opening values to reflect 2012 actual capital expenditures and related effects.⁹⁸ Fortis also proposed two adjustments to account for the full cost of a distribution control centre and one for depreciation rates.

105. At the hearing, Fortis requested a one-time adjustment to going-in rates to reflect the full cost of a distribution control center.⁹⁹ This adjustment was required because the timing of the distribution control centre implementation changed and now falls between 2012 and 2013.

106. With respect to the depreciation rates, Fortis proposed an adjustment to the depreciation rates established in its negotiated settlement. The negotiated settlement was signed on November 7, 2011 and approved by the Commission on April 18, 2012 in Decision 2012-108.¹⁰⁰ Fortis argued that "going-in rates for depreciation costs alone are fine on a going in basis" but due to Fortis' PBR assumptions the going-in rates should recognize "\$60 million more of rate base compared to the plan assumptions when we set our PBR proposal."¹⁰¹

3.4.2 ATCO Electric

107. ATCO Electric requested two adjustments: one to include the final 2012 costs for three buildings and an adjustment for capitalized pension costs.

108. ATCO Electric proposed adjustments to its 2012 distribution rates to recognize full forecast costs and property taxes for three buildings with in-service dates falling in the second half of 2012.¹⁰² The three buildings are located in Grande Prairie, Lloydminster, and Stettler.

109. ATCO Electric also proposed an adjustment to remove the cash basis current year recovery of its capitalized pension costs from going-in rates.¹⁰³ ATCO Gas removed the cash basis current year recovery of capitalized pension costs in its 2011 to 2012 general rate application¹⁰⁴ and ATCO Electric sought a similar change to ensure distribution pension costs were treated in the same manner by both ATCO companies. ATCO Electric therefore is no longer seeking cash basis current year recovery of capitalized pension costs.¹⁰⁵ Consequently, an

⁹⁸ Exhibit 100.02, Fortis application, paragraph 42.

⁹⁹ Exhibit 633, Fortis argument, page 122.

¹⁰⁰ Decision 2012-108: FortisAlberta Inc, Application for Approval of a Negotiated Settlement Agreement in respect of 2012 Phase I Distribution Tariff Application, Application No. 1607159, Proceeding ID No. 1147, April 18, 2012.

¹⁰¹ Testimony of Mr. Lorimer, Transcript, Volume 11, pages 2184-2188 as quoted in Fortis argument, Exhibit 633.01, pages 121-122.

¹⁰² Exhibit 98.02, ATCO Electric application, paragraphs 210-214.

¹⁰³ Exhibit 98.02, ATCO Electric application, paragraphs 221 and 222.

¹⁰⁴ Decision 2011-450 ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.) 2011-2012 General Rate Application Phase I, Application No, 1606822, Proceeding ID. No, December 5, 2011, paragraph 5, Table 2 shows capital pension – removal of immediate collection: costs of \$13,257,000 were removed for 2012.

¹⁰⁵ Exhibit 98.02, ATCO Electric application, paragraphs 221 and 222.

adjustment to going-in rates is required to reflect the change in recovery of these costs. In Application No. 1608750 (Proceeding ID No. 2078, the ATCO Utilities Compliance with Decision 2012-166¹⁰⁶) filed on August 15, 2012, the Commission has been requested to determine the adjustment required to reflect the removal of the cash basis current year recovery of capitalized pension costs from the 2012 revenue requirement for ATCO Electric. ATCO Electric stated that the adjustment of capitalized pension costs was not commented on by interveners and it should be approved.¹⁰⁷

3.4.3 ATCO Gas

110. ATCO Gas proposed an adjustment to going-in rates to account for the actual 2011 to 2012 urban mains replacement (UMR) capital expenditures in excess of the forecasts approved in Decision 2011-450.¹⁰⁸ ATCO Gas requested the opportunity to file a future application for an adjustment to its 2012 going-in revenue requirement for its actual 2011 to 2012 UMR expenditures. ATCO Gas submitted this approach is consistent with the mid-year convention and the effect on 2012 capital investment is consistent with what would occur under a cost of service rates application had one been filed to set rates for 2013.¹⁰⁹ ATCO Gas stated:

The findings of the Commission on this matter are similar to the findings of the AEUB in Decision 2003-072, where the Board held ATCO Gas' UMR expenditures at approximately \$7 million per year for the years 2003 and 2004.¹ In the 2005 –2007 GRA, ATCO Gas was able to support the prudence of the actual UMR projects undertaken in 2003 and 2004, at a total cost of approximately \$22 million, rather than the \$14 million that had been approved.¹¹⁰

111. ATCO Gas stated that “[i]t is not reasonable to expect ATCO Gas to carry the cost of these prudent investments over the full term of its PBR Plan.”¹¹¹ It further stated with respect to the ability to recover these UMR costs: “[t]o not provide ATCO Gas with this ability increases the risk to the utility, and it prevents ATCO Gas from having a reasonable opportunity to recover its prudently incurred costs, including a fair return.”¹¹²

3.4.4 AltaGas

112. AltaGas proposed four adjustments to going-in rates: annualization of costs associated with monthly meter reading, income tax timing differences between 2012 and 2013, including losses carried forward, impacts of changes in pension expense from 2012 to 2013, and recovery of 2013 Natural Gas System Settlement Code (NGSSC) capital forecasts and annualization of capital and O&M expenses related to NGSSC costs.¹¹³ AltaGas stated that its proposed annualized adjustments for metering and NGSSC costs are required in order for it to earn a fair return.¹¹⁴

¹⁰⁶ Decision 2012-166: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2011 Pension Common Matters Compliance Filing, Application No. 1607949, Proceeding ID No. 1599, June 14, 2012.

¹⁰⁷ Exhibit 631.01, ATCO Electric argument, paragraph 318.

¹⁰⁸ Exhibit 389.01, ATCO Gas update, page 5 and 6.

¹⁰⁹ Exhibit 389.01, ATCO Gas application update, paragraph 8.

¹¹⁰ Exhibit 389.01, ATCO Gas update, page 2, paragraph 4.

¹¹¹ Exhibit 389.01, ATCO Gas update, page 3, paragraph 5.

¹¹² Exhibit 389.01, ATCO Gas update, page 4, paragraph 7.

¹¹³ Exhibit 628.01, AltaGas argument, pages 80 and 81.

¹¹⁴ Exhibit 628.01, AltaGas argument, paragraph 273.

113. AltaGas proposed its 2012 distribution rates be adjusted to reflect changes in income taxes and depreciation.¹¹⁵ The adjustment for income taxes is intended to recognize changes in income tax timing differences between 2012 and 2013, including losses carried forward.¹¹⁶ AltaGas has requested an adjustment to account for a forecast change from 2012 to 2013 related to income taxes. This adjustment would be for book to tax timing differences.¹¹⁷ In the hearing, AltaGas was asked about its proposal to adjust taxes to reflect a reduced level of capital cost allowance. The AltaGas witness responded:

Well, our proposal is that the going-in rates be adjusted to allow for the increase in the income taxes, the cash income tax, expense the company will be incurring as a result of the -- of its ability to claim an equivalent CCA amount as it had in 2012. In other words, in 2012 because AUI was able to claim maximum CCA at the direction of the Commission, it effectively reduces its cash taxes to zero. So there is in fact zero dollars for income taxes sitting in the revenue requirement, which would drive the going-in rates. So we're simply asking that the company be allowed to have a component for income taxes in its going-in rates, which would be the equivalent of what it would require under normal circumstances.¹¹⁸

114. AltaGas also proposed an adjustment for the impact of changes in pension expenses from 2012 to 2013.¹¹⁹ On April 18, 2012, AltaGas provided corrections and updates to its application.¹²⁰ AltaGas stated, with respect to meter reading that, due to the timing of Decision 2012-091, AltaGas "will not be able to commence the additional readings until July 1, 2012. As AltaGas' intention is to adjust its 2012 revenue requirement in its compliance filing to reflect only a half year of the additional costs, it will be necessary to make an adjustment to going-in rates to reflect the full year of costs."¹²¹ AltaGas also asked to reserve the right to apply for a going-in adjustment for the NGSSC capital cost forecast for adjustments not included in its 2012 compliance filing.¹²²

Commission findings

115. The Commission considers that each of the individual adjustments to going-in rates except for the those items specifically referred to below are requests to adjust approved 2012 revenue requirements for after-the-fact events or circumstances and are therefore denied. The Commission has confirmed the position taken in Decision 2009-035 that it will not accept adjustments to the going-in rates to account for 2012 actual results. As noted in that decision: "[a]djustments to account for actual results should not be made selectively but, rather, should only be made in the context of a full rate case which would consider the forecast costs for a subsequent time period."¹²³

116. However, the Commission will allow the ATCO Electric requested adjustment to going-in rates to remove its cash basis current year recovery of capitalized pension costs. In

¹¹⁵ Exhibit 110.01, AltaGas application, page 12, paragraph 44.

¹¹⁶ Exhibit 628.02, AltaGas argument, page 80.

¹¹⁷ Exhibit 110.01, AltaGas application, paragraph 44.

¹¹⁸ Transcript, Volume 9, page 1610, lines 10 to 23, AltaGas witness Mr. Mantei in response to cross-examination by CCA counsel.

¹¹⁹ Exhibit 628.01, AltaGas argument, pages 80-81.

¹²⁰ Exhibit 529, AltaGas corrections and amendments to AltaGas' application.

¹²¹ Exhibit 529, AltaGas corrections and amendments to AltaGas' application, pages 4 and 5.

¹²² Exhibit 529, AltaGas corrections and amendments to AltaGas' application, pages 4 and 5.

¹²³ Decision 2009-035, paragraph 74.

Decision 2012-166¹²⁴ the Commission approved the request of the ATCO Utilities to no longer collect the capital component of pension costs in the current year on a cash basis and to fund it as part of each utility's invested capital.¹²⁵ Given this decision and ATCO Gas' removal of similar costs in its general rate application, the Commission considers that this adjustment provides for consistent treatment between the ATCO distribution companies for the purpose of setting going-in rates for PBR. The requested adjustment is similar in nature to the adjustment to going-in rates permitted in Decision 2009-035 for the inclusion of ENMAX short term incentive plan costs. It is also similar to the replacement of a placeholder, and is not a rate adjustment made after-the-fact to reflect actual results. The Commission grants ATCO Electric's removal of its cash basis current year recovery of capitalized pension costs for the purposes of establishing going-in rates. The necessary adjustment to 2012 revenue requirement will be determined by the Commission in Proceeding ID. 2078. With respect to AltaGas' NGSSC costs for 2012, the Commission determined in Decision 2012-091, that the evaluation of AltaGas' 2012 forecast costs for NGSSC will be determined in AltaGas' compliance filing to its general rate application.¹²⁶ The Commission's decision on AltaGas' compliance filing to its general rate application will establish the final rates for 2012. These rates will form the basis for the going-in rates for PBR and, as a result, recovery of NGSSC costs in 2013 are already accounted for, adjusted by I-X. Accordingly, there is no need for an adjustment for NGSSC costs in AltaGas' going-in rates. With respect to AltaGas' request for a going-in rates adjustment for tax timing differences, the Commission has addressed this issue in Section 7.4.2.3.5 by indicating that book-to-tax timing differences should be the subject of a Y factor application.

3.5 Other adjustments to going-in rates

117. Certain parties to this proceeding requested removal of all deferral accounts and other Y factor adjustments from their 2012 revenue requirements. For instance, ATCO Gas requested removing the amounts included 2012 approved revenue requirement corresponding to deferral accounts treated as Y factor adjustments under PBR.¹²⁷

Commission findings

118. The removal from going-in rates of amounts corresponding to approved Y factor items from going-in rates is discussed in Section 7.4.4 of this decision.

¹²⁴ Decision 2012-166: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) 2011 Pension Common Matters Compliance Filing, Application No. 1607949, Proceeding ID No. 1599, June 14, 2012.

¹²⁵ Decision 2012-166, paragraph 70.

¹²⁶ AltaGas Utilities Inc. Compliance Filing Proceeding ID No. 1921 and Decision 2012-091, AltaGas Utilities Inc, 2010 to 2012 General Rate Application – Phase I, Application No. 1606694, Proceeding ID No. 904, April 9, 2012.

¹²⁷ Exhibit 99.01, ATCO Gas application paragraph 135 and Exhibit 632.01, ATCO Gas argument, paragraph 330.

4 Price cap or revenue cap

119. The electric distribution companies (ATCO Electric, EPCOR and Fortis) proposed that their PBR (performance-based regulation) plans take the form of a price cap. Under a price cap plan, a company is allowed to change its customer rates according to an indexing formula that is typically comprised of an inflation measure, known as the I factor, and a productivity offset, commonly referred to as the X factor. An illustrative generic formula describing a typical price cap plan can be written as follows:

For each customer class:

$$\text{Rates}_t = \text{Rates}_{t-1} * (1 + I - X) \pm \text{Other Adjustments}$$

120. As the formula above illustrates, the current year's customer rates for each class are derived by adjusting the previous year's rates by a percentage equal to the difference between the relevant I and X factors (as well as any other allowed or mandated adjustments discussed in other sections of this decision).

121. A price cap plan establishes annual customer rates regardless of the amount of energy transported through a company's system. Accordingly, under price cap plans the company ordinarily bears the risk of a change in energy volumes transported through its system. An increase in the amount of energy transported would lead to an increase in the company's revenues, and a decrease in the amount of energy transported would lead to a decrease in the company's revenues. As a result, parties to this proceeding pointed out that the use of price caps can be problematic when there is expected to be a continuing decline in sales per customer.

122. ATCO Gas and AltaGas both presented evidence that average gas deliveries per customer had been declining for most customer classes in Alberta and for several years and were expected to continue to decline. The average decline rate for ATCO Gas and AltaGas was approximately 1.5 per cent per year.¹²⁸ No party took issue with this evidence. Dr. Lowry, on behalf of the CCA, also confirmed that declines in average use by small-volume customers have been common in the gas distribution industry for many years. Contributing factors include demand side management (DSM) programs, general improvements in the technology of furnaces and other gas-fired equipment, and changes in building codes and appliance efficiency standards.¹²⁹ None of the electric distribution companies indicated a similar trend in declining use per customer.¹³⁰

123. Because the rates charged by ATCO Gas and AltaGas are composed of fixed and variable components, a significant portion of revenue for both companies is determined by actual deliveries. The gas distribution companies submitted that a price cap plan would result in chronic revenue shortfalls in an environment of declining deliveries per customer.¹³¹ To address this issue, both gas distributors, ATCO Gas and AltaGas, proposed that their PBR plans take form of a revenue-per-customer cap.

124. A revenue-per-customer cap is similar to the price cap plans discussed above. However, instead of limiting the change in customer rates from one year to the next, it limits the change in

¹²⁸ Transcript, Volume 3, page 553, lines 18-22 and Exhibit 212.02, AUC-ATCOGas-1(c) and (d); Transcript, Volume 8, pages 1356-1357 and Exhibit 248.03, AUC-AltaGas-8(c) and (e).

¹²⁹ Exhibit 307.01, PEG evidence, page 17.

¹³⁰ Transcript, Volume 3, pages 557-559; Exhibit 103.05, Cicchetti evidence, page 14.

¹³¹ Exhibit 632, ATCO Gas argument, paragraph 141 and Exhibit 628, AltaGas argument, page 35.

a company's revenue per customer on a class by class basis, as illustrated by the following general formula:

For each customer class:

$$\text{Revenue per customer}_t = \text{Revenue per customer}_{t-1} * (1 + I - X) \pm \text{Other Adjustments}$$

125. Under a revenue-per-customer cap plan, the approved revenue per customer from the previous year is adjusted by the I-X index on a class by class basis to arrive at the upcoming year's revenue-per-customer cap. However, to calculate actual customer rates, the indexed revenue must be divided by the forecast consumption per customer on a class by class basis. Consequently, unlike in a price cap plan, forecast billing determinants represent an integral part of the revenue cap mechanism, regardless of any other adjustments outside of the I-X indexing mechanism.

126. Both gas distribution companies indicated that a revenue cap plan is common for natural gas distribution companies in Canada because it allows the company to update its billing determinants and adjust its rates to account for the effect of the declining use per customer that is common to the natural gas industry.¹³² ATCO Gas highlighted the fact that PBR plans in the form of revenue cap plans were previously approved by the regulators for other Canadian gas distribution companies, including Enbridge Gas, Gaz Métro and Terasen Gas.¹³³

127. As AltaGas explained in its evidence, PBR plans designed in the form of price caps are not consistent with the underlying cost structure of gas distribution companies. AltaGas pointed out that the total cost of gas distribution largely depends on the capacity required to provide for maximum daily throughput (peak loads) and transport distances (or the length of distribution line), and is largely unrelated to total energy use. However, these predominately fixed costs are mostly recovered through variable charges, for example dollars per gigajoule delivered. As a result, while changes in use per customer have virtually no impact on cost, they have a direct impact on the company's total revenues.¹³⁴

128. This effect is further amplified by the economies of density¹³⁵ in the gas distribution industry, with the result that the price charged for an additional unit of gas delivered to customers is typically above the marginal cost of delivery. In such circumstances, increases in use per customer will increase revenue more rapidly than costs and, conversely, decreases in use per customer will decrease revenue more rapidly than costs. Consequently, unexpected changes in use per customer may lead to "windfall profits or extraordinary losses."¹³⁶ More importantly in the context of Alberta gas distribution companies, when use per customer is expected to decline on a continuing basis, the revenue decline will be fairly certain. By focusing on revenue per customer as opposed to the price per unit of gas delivered, the revenue cap approach to PBR is designed to account for the revenue decline associated with declining use per customer.

¹³² Exhibit 99.01, ATCO Gas application, paragraph 19 and Transcript, Volume 8, page 1364, lines 18-20.

¹³³ Transcript, Volume 3, page 551, line 2 to page 552, line 2.

¹³⁴ Exhibit 477.01, AltaGas rebuttal evidence, paragraph 18.

¹³⁵ As AltaGas explained in its evidence, economies of density exist when an increase in usage to a customer on the network leads to a less than proportional increase in total costs. In gas distribution, costs are primarily related to connecting a customer to the network and are not related to the customer's use, leading to economies of density. (Exhibit 110.01, footnote 1 on page 2).

¹³⁶ Exhibit 110.01, Christensen Associates evidence, paragraph 7.

129. The CCA stated that revenue caps sidestep the need for the very low X factors that would otherwise be needed to provide compensatory rate escalation in the circumstances where average use by small-volume customers has a markedly downward trend.¹³⁷ This view was shared by Calgary.¹³⁸

130. With respect to the incentive properties of the proposed PBR plans, parties to this proceeding agreed that both price cap and revenue cap formulas create similar incentives to minimize costs.¹³⁹ In fact, both gas companies pointed out that they would be indifferent as between a price cap plan and a revenue cap plan if there were a deferral account or some other revenue adjustment mechanism to account for changes in use per customer under the price cap plan. However, neither company favoured the use of a price cap plan with the adjustment mechanism due to the increased complexity and administrative burden of such approach as compared to the proposed revenue-per-customer cap plans.¹⁴⁰

131. At the same time, NERA pointed out that price caps and revenue caps differ with regard to their potential impact on sales (either in total or on a per-customer basis) and in the incentive to maintain quality. NERA explained that a firm under a price cap plan has an incentive to increase sales if its additional revenues from new sales exceed its incremental costs. Firms under a revenue cap plan do not have such an incentive. Additionally, NERA noted that service quality can be more of a concern under revenue caps than price caps because, under a revenue cap, if poor service quality leads to fewer sales, the lost revenue can be made up through the price increases for remaining customers that arise from application of the formula.¹⁴¹

132. Parties also observed that a revenue-per-customer cap plan would diminish the disincentive a company has to promote the DSM measures. AltaGas noted that, because the price it charges for the delivery of gas is typically greater than the marginal cost for the service, any reduction in gas consumption will have a greater impact on revenues than costs. Thus, under a price cap plan, it is in the financial interest of the company to limit the reduction in customer use and, instead, encourage increased consumption, if possible.¹⁴² The CCA experts reached a similar conclusion and pointed out that revenue cap plans mitigate the disincentive to promote DSM plans by weakening the link between changes in system use (e.g., energy deliveries and peak demand) and changes in earnings.¹⁴³ However, Ms. Frayer on behalf of Fortis pointed out that revenue caps may create distorted incentives for companies to act like monopolists, raising prices while reducing output in order to maximize profit margins, giving rise to the so-called “Crew-Kleindorfer effect.”¹⁴⁴

133. AltaGas submitted that, unlike a revenue cap formula that applies to a firm’s overall revenue, the proposed revenue-per-customer cap approach provides an incentive to continue connecting new customers because customer growth drives revenue growth. In contrast, a straight revenue cap formula would not provide such an incentive because under a revenue cap

¹³⁷ Exhibit 307.01, PEG evidence, page 16.

¹³⁸ Transcript, Volume 15, page 2926, lines 23-35 and page 2927, lines 1-11.

¹³⁹ Exhibit 195.01, AUC-NERA-13; Exhibit 628, AltaGas argument, page 35; Exhibit 629, Calgary argument, page 37.

¹⁴⁰ Exhibit 632.01, ATCO Gas argument, page 44 and Exhibit 628.01, AltaGas argument, page 35.

¹⁴¹ Exhibit 195.01, AUC-NERA-13.

¹⁴² Exhibit 110.01, Christensen Associates evidence, paragraph 8.

¹⁴³ Exhibit 307.01, PEG evidence, page 16.

¹⁴⁴ Exhibit 100.02, Frayer evidence, page 23.

approach the company can raise prices to meet the revenue cap without having to connect new customers.¹⁴⁵

134. Finally, ATCO Gas and AltaGas pointed out that their respective revenue-per-customer cap plans do not contemplate an adjustment if the forecast PBR revenue or consumption per customer deviates from the actual values. However, the two PBR plans differ with regard to their treatment of forecast customer growth. ATCO Gas proposed that the forecast of the average number of customers be reconciled with the actual number of customers when it becomes available, while AltaGas' plan does not provide for such a true-up.¹⁴⁶

Commission findings

135. A price cap plan sets customer rates in accordance with the established I-X index, regardless of the company's actual costs and the amount of energy transported. A revenue cap also employs an I-X index. However, under the latter approach, it is the revenue of the company and not its rates that is adjusted by the I-X index. Consequently, customer rates may fluctuate so long as revenue does not exceed the revenue cap.

136. The PBR plans proposed by ATCO Gas and AltaGas demonstrate that under a revenue-per-customer cap plan, customer rates are calculated on a class by class basis by dividing the revenue-per-customer cap derived from the formula by the forecast use per customer for the upcoming year. For example, if the actual billing determinants from the previous year were used for calculating customer rates in the upcoming year, the declining use per customer would lead to a systematic under-recovery of revenues by the companies. Under the proposed revenue-per-customer cap plans, customer rates will go down if the company forecasts an increase in energy consumption per customer in the upcoming year. Likewise, customer rates will go up if a decrease in energy consumption per customer is projected for the coming year. In either case, a company's revenue per customer will not exceed the value established by the PBR formula.

137. Under a price cap plan, the company ordinarily bears the risk of changes in energy volumes delivered, while under a revenue cap plan the company is largely protected from volumetric risk. Parties to this proceeding pointed out that the volumetric risk may become too great to bear when there is an expected continuing decline in use per customer.¹⁴⁷ In this circumstance, the use of a price cap may be problematic as it may expose the company to significant reductions in revenues resulting from declines in use per customer.

138. Both ATCO Gas and AltaGas indicated that, despite the overall sales growth, they are experiencing a continuing decline in use per customer, averaging approximately 1.5 per cent per year.¹⁴⁸ This rate of decline in average customer use is forecast to continue into the future. Furthermore, the companies noted that overall customer growth and increased consumption by some existing customers does not completely offset overall declines in the average use per customer.¹⁴⁹ The Commission accepts the average usage per customer decline rates forecasted by ATCO Gas and AltaGas and accepts the position that a price cap plan would result in significant

¹⁴⁵ Exhibit 243.01, AUI-CCA-2(g) and (h).

¹⁴⁶ Exhibit 99.01, ATCO Gas application, paragraphs 43-44; Transcript, Volume 8, page 1370, line 25 to page 1371, line 6 (AltaGas).

¹⁴⁷ Exhibit 632, ATCO Gas argument, paragraphs 141-143 and Exhibit 628, AltaGas argument, page 35.

¹⁴⁸ Transcript, Volume 3, page 553, lines 18-22 and Exhibit 212.02, AUC-ATCOGas-1(c) and (d); Transcript, Volume 8, pages 1356-1357 and Exhibit 248.03, AUC-AltaGas-8(c) and (e).

¹⁴⁹ Transcript, Volume 3, page 554, lines 12-15 and Volume 8, page 1356, lines 2-9.

revenue reductions under existing rate structures due to declining gas usage if such declines in revenue were not otherwise adjusted for.

139. The Commission also agrees with AltaGas' argument that the revenue-per-customer cap approach to PBR is consistent with the underlying cost structure of gas distribution utilities. A large proportion of gas distributors' costs are fixed, while a significant amount of these costs is recovered through variable charges. As a result, unexpected changes in use per customer may lead to significant variations in the revenues of gas distribution companies that are not offset by cost changes. By focusing on revenue per customer as opposed to price per unit of gas delivered, the revenue-per-customer cap PBR plans proposed by ATCO Gas and AltaGas account for the impact of changes in use per customer on the companies' revenues.

140. Given the above, the Commission considers that forecasting use per customer for the upcoming year is warranted in this case since it accounts for the declining use per customer.

141. The Commission agrees with the parties to this proceeding that the incentive properties of both price cap and revenue-per-customer cap plans are largely the same. Both types of plans rely on an I-X indexing mechanism that decouples revenues from the costs of service, thus creating efficiency incentives. Additionally, both price cap and revenue-per-customer cap formulas use customer growth as a driver for revenue growth, thus providing incentives to continue connecting new customers. The Commission also acknowledges that, by making companies indifferent to volume changes, revenue-per-customer caps provide incentives to promote DSM plans.¹⁵⁰

142. The Commission also accepts NERA's proposition that diminished service quality can be more of a concern under revenue caps than price caps. However, the Commission considers that concerns with respect to the maintenance of service quality can be addressed through service quality monitoring and reporting measures under both price cap and revenue cap PBR plans. Service quality is discussed in Section 14 of this decision.

143. Overall, the Commission agrees with ATCO Gas and AltaGas that the revenue-per-customer cap approach to PBR adequately addresses the issues associated with declining usage per customer without decreasing the intended efficiency incentives of performance-based regulation. The Commission observes that Calgary and the CCA supported the use of revenue-per-customer cap plans for ATCO Gas and AltaGas.¹⁵¹

144. Regarding the issue of a true-up to the actual number of customers, as proposed by ATCO Gas, the Commission notes that the focus of the PBR plans proposed by the gas distribution companies in this proceeding is on indexing the revenue per customer for each customer class, not the overall revenue of a company. Accordingly, the correct measure to true up, if any, is the forecast use per customer.

¹⁵⁰ The commission has denied certain types of demand side management programs proposed by the gas distribution companies as being inconsistent with the legislative framework. For example see, Decision 2011-450: ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.), 2011-2012 General Rate Application Phase I, Application No. 1606822, Proceeding ID No. 969, December 5, 2011, paragraph 683 and Decision 2012-091: AltaGas Utilities Inc., 2010-2012 General Rate Application Phase I, Application No. 1606694, Proceeding ID No. 904, April 9, 2012, paragraph 625.

¹⁵¹ Exhibit 329, Calgary argument, page 37; Exhibit 636, CCA argument, page 2 and Transcript, Volume 13, page 2534, lines 13-17 (Lowry).

145. In the interest of regulatory efficiency, the Commission considers that no true up for the actual weather normalized use per customer is required. The Commission directs the gas companies to use the actual average change in weather normalized use per customer (per class) for the preceding three years as their forecast percentage change in weather normalized use per customer for the upcoming year. This percentage change is to be applied to weather normalized use per customer (actual and projected per class) for the current year to determine the forecast for the upcoming year. The Commission is satisfied that the rate of change in weather normalized use per customer over the preceding three year period will result in a reasonable forecast of weather normalized use per customer for the upcoming year.

146. With respect to the PBR plans of ATCO Electric, EPCOR and Fortis, these companies indicated that a declining use per customer or other types of volumetric risk are not an issue for them.¹⁵² As well, Dr. Lowry pointed out that North American electric utilities often experience modest growth in average use by small volume customers when large DSM programs are not underway in their service territories.¹⁵³ Consequently, the Commission has no concerns with the use of a price cap approach in the PBR plans for the electric distribution companies.

5 I factor

5.1 Characteristics of an I factor

147. The inflation factor, also referred to as an I factor or an input price index, is the component of a price cap or revenue cap PBR (performance-based regulation) plan that reflects the expected changes in the prices of inputs that the companies use. As the companies' experts explained, a PBR formula should be designed to produce rates that reflect inflationary pressures on input prices that a company is expected to experience from year to year during the term of the plan.¹⁵⁴ The purpose of the inflation factor is to pass on to customers the increases in the costs of goods and services purchased by the company (for example, cost of the materials and supplies, salaries of the company's staff, etc.) that are driven by macro-economic forces and are beyond the control of the company's management.¹⁵⁵

148. The UCA noted that, by setting an automatic adjustment for the company's cost changes, an input price index obviates the need to hold frequent cost of service proceedings. The UCA pointed out that, in effect, the I factor mirrors the process of reviewing a company's costs and adjusting rates on a prudence basis, in effect using the selected inflation measure as a prudence test.¹⁵⁶

149. In their respective PBR submissions, parties outlined a number of considerations for choosing the relevant I factor. Specifically, parties proposed the following selection criteria for establishing an inflation index:¹⁵⁷

¹⁵² Transcript, Volume 3, pages 557-559; Exhibit 103.05, Cicchetti evidence, page 14.

¹⁵³ Exhibit 307.01, PEG evidence, page 17.

¹⁵⁴ Exhibit 110.01, Christensen Associates evidence, paragraph 29; Exhibit 98.02, Carpenter evidence, page 15.

¹⁵⁵ Exhibit 100.02, prepared testimony of Julia Frayer, page 33.

¹⁵⁶ Exhibit 299.02, Cronin and Motluk UCA evidence, page 182, A87.

¹⁵⁷ Exhibit 631.01, ATCO Electric argument, paragraph 38; Exhibit 632.01, ATCO Gas argument, paragraph 34; Exhibit 628.01, AltaGas argument, pages 11-12; Exhibit 633.01, Fortis argument, paragraph 63; Exhibit 636.01, CCA argument, paragraph 48.

- The I factor must be indicative of the change in input prices that the company expects to experience over the term of the PBR plan.
- The inflation index must be published by a reputable, independent agency and made readily available on at least an annual basis.
- The I factor should be transparent, simple to calculate and easy to understand.
- The selected I factor should not be overly volatile.
- The I factor should reflect a broad measure of inflation rather than the experience of the specific company to which the PBR plan is to apply, so that the company cannot significantly affect the index.

150. In addition to these criteria, Dr. Ryan on behalf of EPCOR indicated that, in conducting his analysis and recommending an inflation index, he considered the Commission's findings in Decision 2009-035. In particular, EPCOR's expert recommended using an input-based index, thus avoiding the need for making adjustments to the productivity factor, which would be the case if an output-based price index were used.¹⁵⁸ This recommendation was also supported by the UCA.¹⁵⁹

151. Additionally, in setting out his proposed criteria, Dr. Ryan recommended that if the inflation factor was composed of different component indexes, the weighting of these should be fixed rather than vary year to year, so that the company's incentives are not influenced by relative rates of inflation in the component indexes.¹⁶⁰

152. The CCA pointed out that the I factor selection criteria are often in conflict and that there is "considerable art in developing an index that sensibly balances simplicity and accuracy."¹⁶¹

Commission findings

153. The I factor provides a mechanism to adjust the companies' prices¹⁶² (in the case of a price cap plan) or revenues (in the case of a revenue-per-customer cap plan) year over year to reflect changes in the prices of inputs that the companies use.

154. As the ATCO companies pointed out in their arguments, a PBR plan should provide incentives for the company to undertake efficiency improvements to manage and minimize the costs that are within its control. However, changes in a company's input prices due to inflation are not within its ability to control, although the company may be able to use those inputs more efficiently than its competitors.¹⁶³ In competitive markets, when faced with a universal, economy-wide increase in input prices (such as an increase in salaries and wages, higher fuel prices, etc.), 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 in the market forces the companies to lower their prices. The I factor in the PBR plans is intended to mimic this characteristic of competitive markets.

¹⁵⁸ Exhibit 103.04, Dr. Ryan evidence, paragraph 8.

¹⁵⁹ Exhibit 634.02, UCA argument, paragraph 76.

¹⁶⁰ Exhibit 103.04, Dr. Ryan evidence, paragraph 8.

¹⁶¹ Exhibit 636, CCA argument, paragraph 49.

¹⁶² Utility output prices are most commonly referred to as rates. In the context of a price cap plan they are referred to as prices.

¹⁶³ Exhibit 631, ATCO Electric argument, paragraph 37.

155. All parties agreed that the selected I factor should be indicative of the change in input prices that the companies are expected to experience, be transparent, simple to calculate and easy to understand. In addition, parties recommended that the inflation factor should not be overly volatile, must be published on a regular basis by a reputable independent agency and should not be overly influenced by the company itself. The Commission agrees.

156. The choice between input and output inflation indexes, the use of a single index or a composite I factor consisting of multiple indexes and the weights to be assigned to the elements of a composite I factor are discussed in the subsequent sections of this decision.

5.2 Selecting an I factor

5.2.1 The rationale behind a composite I factor

157. In Decision 2009-035, dealing with ENMAX's 2007-2016 FBR (formula-based ratemaking) application, the Commission approved a composite I factor that includes the distribution construction price index as measured by the Canadian Electric Utility Construction Price Index (EUCPI) and the Alberta Average Hourly Earnings (AHE) index with a 50:50 fixed weighting throughout the PBR term.¹⁶⁴

158. The companies argued that, in general, no single measure of inflation can explain all the cost trends facing a utility, and they maintained that greater accuracy can be achieved by constructing a composite index composed of published indexes, weighted according to the average relationship among the company's various inputs.

159. Specifically, AltaGas' experts explained that a utility primarily purchases two types of inputs, employee time and goods and services from other firms. The prices that a company in Alberta must pay for these inputs will be affected primarily by economic conditions within the province of Alberta.¹⁶⁵ This position was supported by the other companies with each proposing that their respective I factors consist of two inflation indexes, one reflecting labour cost and the other reflecting the cost of non-labour items. Such a blended I factor would generally be calculated each year using the following weighted-average formula:

$$I \text{ factor} = w_l * \text{Labour Price Index} + w_n * \text{Other Costs Price Index}$$

160. For labour costs, the companies preferred to use either Average Hourly Earnings (AHE) or Average Weekly Earnings (AWE) for Alberta. For non-labour costs, the companies preferred to use either the EUCPI adjusted for Alberta inflation or the Alberta Consumer Price Index (CPI). These sub-indexes would be weighted based on the companies' historical proportions of labour (w_l) and non-labour (w_n) costs. The following table summarizes the proposed I factors as outlined in the electric distribution companies' respective PBR applications:

¹⁶⁴ Decision 2009-035, paragraphs 144 and 149.

¹⁶⁵ Exhibit 110.01, Christensen Associates evidence, paragraph 30.

Table 5-1 Summary of electric distribution companies' I factor proposals

	ENMAX¹⁶⁶ (distribution)	ATCO Electric (distribution)	Fortis	EPCOR (distribution)
Labour costs	Alberta AHE	Alberta AWE	Alberta AHE	Alberta AHE
Non-labour costs	EUCPI (no adjustment)	EUCPI (adjusted for Alberta)	EUCPI (adjusted for Alberta)	Alberta CPI
Weights (labour/non-labour)	50:50	65:35	61:39	80:20

161. Table 5-2 below presents the I factors proposed by the gas distribution companies in their respective PBR plans:

Table 5-2 Summary of gas distribution companies' I factor proposals

	ATCO Gas	AltaGas
Labour Costs	Alberta AWE	Alberta AWE
Other Costs	Alberta CPI	Alberta CPI
Weights (labour/non-labour)	57:43	57:43

162. The UCA supported the use of a composite I factor and indicated that the Commission should use the input price index approved for ENMAX in Decision 2009-035 for all the companies in this proceeding.¹⁶⁷

163. The CCA also acknowledged the need for an inflation measure that reflects the “special inflationary conditions that sometimes occur in Alberta.” The CCA pointed out that inflation can be much more rapid in Alberta than in Canada as a whole in some periods (for example, 2006 to 2008) and appreciably lower in other periods (2009 to 2010), since the province’s economy can experience “booms and busts” because it is largely influenced by the production of price-volatile commodities.¹⁶⁸

164. The CCA recommended that the I factor consist of either a single macroeconomic measure of Alberta price inflation or an appropriately designed custom index of Alberta utility input price inflation. With respect to macroeconomic inflation measures, the CCA recommended using either the Alberta gross domestic product implicit price index for final domestic demand (GDP-IPI-FDD) or the Alberta CPI.

165. PEG on behalf of the CCA, developed an index that tracks the prices of three categories of input costs: labour, materials and services, and capital. Specifically, PEG recommended using either CPI or GDP-IPI-FDD for Alberta as the proxy for the materials and supplies input price index and the Alberta AHE or AWE for the labour price index. For the capital cost category, PEG constructed this element as the product of a rate of return on capital (set initially at the weighted average cost of capital established for the subject utility in its most recent rate case)

¹⁶⁶ As approved in Decision 2009-035. ENMAX was included in this table for comparison purposes.

¹⁶⁷ Exhibit 634.02, UCA argument, paragraph 73.

¹⁶⁸ Exhibit 636, CCA argument, paragraph 44.

and a triangularized weighted average of past values of the EUCPI, with an adjustment to reflect Alberta construction market conditions.¹⁶⁹

166. Calgary also recommended using the Alberta GDP-IPI-FDD index and indicated that it did not support the adoption of a composite I factor consisting of several weighted indexes because such an inflation measure would not be consistent with the simplicity principle.¹⁷⁰

Commission findings

167. A number of parties pointed out that, because the Alberta economy is influenced by the production of price-volatile commodities such as oil and natural gas, it can experience wider swings in economic activity than the rest of the Canadian economy. As a result, inflation in the province can be quite different from inflation in the Canadian economy as a whole.

168. The companies also highlighted the fact that the presence of large scale capital-intensive oil and gas activity in Alberta leads to strong competition for labour resources, especially those involved in technical and engineering services, as well as capital-intensive projects. Accordingly, the companies were particularly concerned that the I factor be able to capture the effect of the tight labour market in Alberta.¹⁷¹ As Dr. Cicchetti on behalf of EPCOR explained:

But high oil prices and high gas prices, although those are now falling, but high oil prices at least have the effect of making the demand in the job market tighter, and the demand for people who are engineers of whatever kind who can be employed by electric distribution companies is tighter.¹⁷²

169. The Commission agrees with these observations. Because of the relatively tight labour market in Alberta, salaries and wages have been rising faster than the national average during petroleum industry booms and have declined more rapidly or risen less quickly during economic slowdowns, as compared to the rest of Canada. Therefore, the Commission will include an Alberta-specific labour inflation component in the I factor of the companies' PBR plans to reflect labour inflation in the province.

170. The Commission agrees with the companies that all-encompassing macroeconomic inflation measures, such as Alberta GDP-IPI-FDD or Alberta CPI proposed by the CCA and Calgary, when used as the only measure of inflation, do not reflect the input price inflation faced by the companies. As ATCO Gas pointed out, using a single macroeconomic index for the I factor may result in a significant revenue shortfall due to the under-recovery of its labour-related costs.¹⁷³ Furthermore, the CCA agreed that both CPI and GDP-IPI-FDD in this context are output price indexes, thus requiring adjustments to the productivity measure (in this case a TFP (total factor productivity) study) in determining an X factor as explained in Section 6.4.1 below.¹⁷⁴ In the Commission's view, the need for such an adjustment more than offsets any simplicity and transparency benefits of using a single macroeconomic inflation measure.

¹⁶⁹ Exhibit 307.01, PEG evidence, pages 52-54 and Exhibit 376.18, ATCO-CCA-63 attachment.

¹⁷⁰ Exhibit 629.01, Calgary argument, page 22.

¹⁷¹ Transcript, Volume 7, page 1291, lines 13-16, Volume 11, page 2137, line 24 to page 2138, line 1.

¹⁷² Transcript, Volume 11, page 2061, lines 19-24.

¹⁷³ Exhibit 632, ATCO Gas argument, paragraph 49.

¹⁷⁴ Exhibit 636, CCA argument, paragraph 51.

171. Accordingly, for the reasons above the Commission finds that the use of a composite I factor in the PBR plans of Alberta utilities is warranted.

172. The Commission considers that the composite I factors proposed by the companies generally conform to the input price index selection criteria outlined in Section 5.1. The proposed sub-indexes for labour and non-labour costs are published by Statistics Canada on a regular basis and, as explained in further sections of this decision, do not require any subjective modifications. The Commission considers that these indexes are sufficiently broad-based to avoid potential concerns about the activities of the companies significantly influencing these measures.

173. In addition, as explained in Section 6.4.1 below, since all the components of the I factors proposed by the companies can be considered input price indexes for the Alberta electric and gas distribution companies, using such a composite I factor does not require an adjustment to TFP in determining an X factor in order to account for an input price differential and a productivity differential.

174. With respect to the customized index for labour, capital and materials proposed by the CCA, the Commission notes that a similar index was proposed by the UCA in the ENMAX FBR proceeding, as outlined in Decision 2009-035. In that decision, it was noted that this type of I factor was more data intensive and more complex than the Commission considered desirable for the purposes of a PBR plan.¹⁷⁵ Indeed, in this proceeding, the CCA pointed out that the selection of an inflation measure for a PBR plan is difficult because greater accuracy comes at the cost of greater complexity.¹⁷⁶ ATCO Gas pointed out that the CCA's index needed a 15 page spreadsheet with a number of significant, complex calculations.¹⁷⁷ During the hearing, Dr. Lowry concurred that the calculation of the proposed customized index would likely require a Ph.D.'s expertise.¹⁷⁸ As such, the Commission considers that the customized index proposed by the CCA suffers from the same data intensity and complexity drawbacks as did the UCA's proposal for ENMAX. Furthermore, similar to the proposed I factors of ATCO Gas and Fortis, the CCA's customized inflation factor involves a modification to EUCPI to attempt to better reflect Alberta inflation. The Commission discusses the shortcomings of such adjustments in Section 5.2.3 below.

175. Finally, the CCA contended that the added complexity of a customized inflation index was warranted because it better tracked input price inflation. However, when the CCA compared its proposed customized I factor to a GDP-IPI-FDD index, the results were within 0.01 percentage points of each other over the 2001 to 2010 period.¹⁷⁹

176. In light of the above considerations, the Commission is not persuaded that the customized index proposed by the CCA is superior to the types of I factors proposed by the companies.

177. Similar to the findings in Decision 2009-035, the Commission recognizes that the blended I factors proposed by the companies do not specifically account for changes in the cost

¹⁷⁵ Decision 2009-035, paragraph 139.

¹⁷⁶ Exhibit 636, CCA argument, paragraph 49.

¹⁷⁷ Exhibit 472.02, ATCO Gas rebuttal evidence, paragraph 164.

¹⁷⁸ Transcript, Volume 13, page 2587, lines 1-6.

¹⁷⁹ Exhibit 372.01, AUC-CCA-20(c).

of capital.¹⁸⁰ Although there was some debate at the proceeding as to whether financing rates in the economy as a whole may be reflected sufficiently in the rate of inflation, it is the Commission's view that financing rates are a function of interest rates in the economy as a whole, which themselves are ultimately reflected in the rate of inflation. As Dr. Lowry stated:

But the one that raises an eyebrow to me in this category is the financing of – financing rate changes. I have never seen a plan involving an index that also involves an adjustment for financing rate changes. You would think that the – there is a danger of double-counting of that since [if] there is a change in interest rates eventually it will have an effect on general inflation rates. And this is particularly so inasmuch as the other – the second inflation measure proposed by ATCO Gas is the CPI for Alberta...¹⁸¹

178. On the issue of whether changes in the cost of capital are reflected in the selected I factor, AltaGas stated in its rebuttal evidence:

The inflation factor, like the X-factor, is designed to mirror the way prices change in a competitive economy. In a competitive economy, the price of capital inputs is determined by the real rate of return on assets, their rate of economic depreciation and the price of acquiring and installing capital. In much of productivity research, including previous productivity research conducted by us [Christensen Associates Energy Consulting] and PEG, the real rate of return has been computed using the current year's nominal rate of return and the rate of inflation in recent years. This produced significant year-over-year volatility in the real rate of return, which, in turn, led to significant year-over-year volatility in the price of capital services. With this volatility, researchers were unable to determine the trend rates of price inflation with any degree of accuracy. In recent years, researchers have noted the real rate of return fluctuates around a constant value and have taken the approach of using a fixed, real rate of return when computing capital price inflation. Fixing the real rate of return at a constant value implies the price of capital services moves in proportion to the price of acquiring and installing that capital. Thus, the relatively straight forward way of computing the inflation factor proposed by AUI is also theoretically sound.¹⁸²

179. The theory supported by the AltaGas experts implies that changes in the cost of capital (both debt and equity) are sufficiently reflected in the company's selected inflation measure. AltaGas' proposed I factor is similar to what the Commission has adopted.

180. Accordingly, the Commission considers that a composite I factor consisting of two broad-based indexes for labour and non-labour costs captures changes in the cost of capital (both debt and equity). In addition, including a separate adjustment for the company's actual cost of capital in the I factor would require accounting for other cost items such as rate base and depreciation to determine the weighting of the capital cost component of such an I factor. In Decision 2009-035, the Commission expressed its concerns with an I factor that appeared to be an effort to move closer to an inflation index that tracked the experience of a specific company to which the PBR plan would apply rather than a broader industry inflation measure.¹⁸³ The more the selected inflation measure tracks the actual performance of an individual company, the more it resembles cost of service regulation and the more the incentive properties of PBR are

¹⁸⁰ Decision 2009-035, paragraphs 139-140.

¹⁸¹ Transcript, Volume 14, pages 2660, line 18 to page 2661, line 2.

¹⁸² Exhibit 477, Christensen Associates rebuttal evidence filed on behalf of AltaGas, paragraph 56.

¹⁸³ Decision 2009-035, paragraph 141.

diminished. For all these reasons, the Commission finds that no adjustments for company-specific capital costs should be incorporated in the I factor.

181. Overall, the Commission is satisfied that a composite I factor consisting of two indexes (one for labour and the other for non-labour costs), represents a reasonable balance between the need for transparency and the need for accuracy in establishing an input price inflation measure for the Alberta electric and gas distribution companies.

182. The individual components of a composite I factor are discussed below.

5.2.2 Labour input price indexes (AHE vs. AWE)

183. Some of the companies proposed using the Alberta AHE as the labour price index component of their I factors, while others preferred using the Alberta AWE instead. Both of these indexes are published by Statistics Canada. However, since the agency produces many variations of the AWE and AHE indexes, careful attention must be paid to the definition of a particular inflation measure when evaluating it.

184. In their respective PBR applications, Fortis and EPCOR proposed using the AHE index, defined as average hourly earnings for salaried employees (paid a fixed salary), including overtime and unadjusted for seasonal variation, which is published for selected industries classified using the North American Industry Classification System (NAICS).¹⁸⁴ ATCO Electric, ATCO Gas and AltaGas proposed to use the AWE, defined as average weekly earnings, including overtime and seasonally adjusted for all employees in selected industries classified using the NAICS.¹⁸⁵

185. The broadest measure for both AHE and AWE indexes is the aggregate index or industrial aggregate, which includes all NAICS industries (including utilities), except for those industries that are unclassified. As Dr. Ryan explained in his evidence, it is preferable to use either AHE or AWE for the industrial aggregate, since the weights of the individual industries in these two labour inflation indexes are not known. Further, an Alberta AHE or AWE for the utilities sector would be influenced by the companies.¹⁸⁶ Consequently, all the companies proposed using the AHE or AWE labour input price indexes at the industrial aggregate level.

186. In response to the Commission's information request (IR) as to whether there would be material differences in the inflation rates used for the PBR formulas if AHE or AWE were employed to calculate an I factor, the companies agreed that even though the two inflation measures may differ from each other substantially in a single year, over an extended period, both measures of labour costs increase at a similar rate. For example, Fortis pointed out that, over the period from 1999 to 2009, Alberta AHE grew by an average of 3.7 per cent annually, while Alberta AWE grew by an average of 3.8 per cent annually.¹⁸⁷ A similar conclusion was reached by Dr. Ryan.¹⁸⁸ Based on the inflation data filed by the parties, the Commission has produced the following table which compares the Alberta AHE and AWE growth rates over the period of 1999 to 2010:

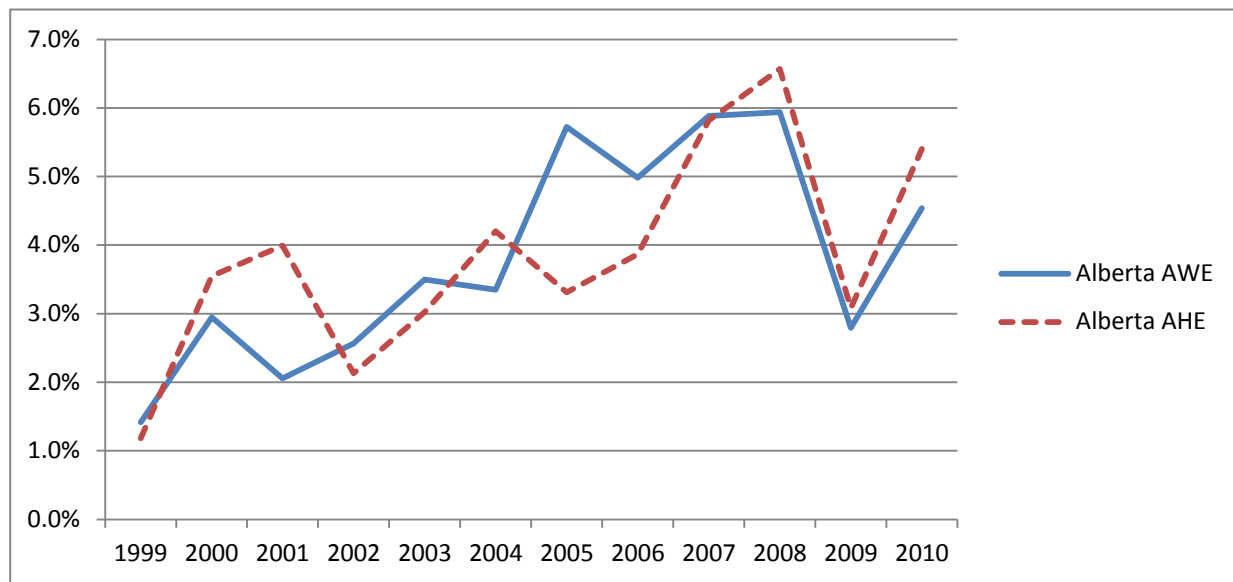
¹⁸⁴ Statistics Canada Table 281-0036, data vector V1808689.

¹⁸⁵ Statistics Canada Table 281-0028, data vector V1597350.

¹⁸⁶ Exhibit 103.04, Dr. Ryan evidence, paragraph 13.

¹⁸⁷ Exhibit 219.02, AUC-ALLUTILITIES-FAI-4.

¹⁸⁸ Exhibit 233.01, AUC-ALLUTILITIES-EDTI-4.

Table 5-3 Alberta AHE and Alberta AWE, 1999-2010 (in per cent)¹⁸⁹

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average 1999-2010
Alberta AWE	1.4	2.9	2.1	2.6	3.5	3.4	5.7	5.0	5.9	5.9	2.8	4.5	3.8%
Alberta AHE	1.2	3.6	4.0	2.1	3.0	4.2	3.3	3.9	5.8	6.6	3.1	5.4	3.8%

187. However, the companies restated their preferences for the labour index set out in their PBR applications. ATCO Electric and ATCO Gas argued that the AWE index more accurately represents their labour input costs as compared to the AHE index and therefore better meets AUC PBR Principle 4.¹⁹⁰ Fortis proposed to use the Alberta AHE for the labour component of the I factor, arguing that approximately 75 per cent of its employee compensation is based on an hourly rate of pay.¹⁹¹ AltaGas argued that, because many of its employees and its contractors' employees are wage employees, it preferred to use the AWE index, which takes both hourly and salary compensation into account.¹⁹² EPCOR concluded that, for the purpose of calculating an I factor to use in the PBR formulas, it is immaterial which measure is used.¹⁹³

Commission findings

188. As EPCOR explained, both the AWE and AHE indexes are obtained from the same Statistics Canada survey¹⁹⁴ and therefore are based on the same underlying data. Table 5-3 above demonstrates that, over the period from 1999 to 2010, the two series yielded essentially the same overall average inflation rate.

¹⁸⁹ For AWE, see Exhibit 540.02. For AHE, see Exhibit 233.01, AUC-ALLUTILITIES-EDTI-4.

¹⁹⁰ Exhibit 203.01, AUC-ALLUTILITIES-AE-4 and Exhibit 204.02, AUC-ALLUTILITIES-AG-4.

¹⁹¹ Exhibit 219.02, AUC-ALLUTILITIES-FAI-4.

¹⁹² Exhibit 248.02, AUC-ALLUTILITIES-AUI-4.

¹⁹³ Exhibit 233.01, AUC-ALLUTILITIES-EDTI-4.

¹⁹⁴ Survey of Employment, Payrolls and Hours (SEPH).

189. The Commission observes that there is no significant difference between the Alberta AWE and Alberta AHE over an extended period of time at the industrial aggregate level and accordingly, for the purposes of establishing an I factor, either measure can be adopted.

190. Parties to this proceeding pointed out that, based on the Statistics Canada definitions of the two indexes, the main difference is that the AWE index includes both salaried employees and those paid an hourly wage while the AHE index referenced in this proceeding includes salaried employees only. In that regard, the Commission agrees with Fortis' explanation that year-to-year differences between the two measures can be explained by the fact that the adjustment of labour utilization in response to variations in economic activity are made through the number of hours worked in the short term, while salaries are slower to adjust to economic booms and slowdowns.¹⁹⁵

191. In the Commission's view, using the AWE index which includes both salaried employees and those paid an hourly wage would capture the inflationary trends in labour costs more quickly than an index which includes salaried employees only. Further, given that the AWE reflects variations in economic activity sooner than the AHE, using the AWE in the composite I factor would mitigate somewhat the effect of the inflation lag resulting from using the actual inflation from the preceding 12-month period for the upcoming year's I factor, as further discussed in Section 5.3 below. In addition, the Commission observes that unlike the AWE index (from Statistics Canada Table 281-0028) that is published monthly, the AHE index (from Statistics Canada Table 281-0036) proposed by Fortis and EPCOR is published on an annual basis. As such, using the Alberta AHE index for January 1st rate changes will effectively result in a 24-month lag between the I factor used in the PBR plan and the actual labour inflation experienced by the provincial economy in any given year.

192. The other difference between the two indexes is that the proposed AWE index is seasonally adjusted, while the AHE is not. Taking into account the fact that the purpose of the seasonal adjustment is to adjust for patterns that occur within a year, the Commission agrees with the ATCO companies' view¹⁹⁶ that the adjustment for seasonal variation is not relevant in this case, since the companies will be using the inflation indexes over a 12-month period. Accordingly, seasonal adjustment is not a reason to choose one index over the other.

193. Finally, the Commission is satisfied that the Alberta AWE index, at the industrial aggregate level which includes all industries in the Alberta economy, is sufficiently broad-based to avoid potential concerns about the companies' actual experience significantly influencing these measures.

194. For all these reasons, the Commission considers that using the Alberta AWE index from Statistics Canada Table 281-0028, data vector V1597350 as a labour cost component of the I factor for the Alberta companies provides a reasonable overall reflection of labour price changes.

5.2.3 Non-labour input price indexes

195. In Decision 2009-035, the Commission approved the use of EUCPI as a component of ENMAX's composite I Factor. Having analyzed its recent experience under the PBR plan,

¹⁹⁵ Exhibit 219.02, AUC-ALLUTILITIES-FAI-4.

¹⁹⁶ Exhibit 203.01, AUC-ALLUTILITIES-AE-4 and Exhibit 204.02, AUC-ALLUTILITIES-AG-4.

ENMAX noted that, because the EUCPI portion of its I factor is a Canada-wide index, it may not be sufficiently aligned with actual cost increases faced by an electric distribution company in Alberta.¹⁹⁷ The CCA also objected to the use of the unadjusted national EUCPI index in the PBR plans of the Alberta electric distribution companies.¹⁹⁸

196. EPCOR, ATCO Gas and AltaGas proposed to use the all items Alberta CPI for the non-labour component of their I factors.¹⁹⁹ The CPI for all items is the broadest measure of the consumer price inflation, and reflects the prices of a wide variety goods and services in the economy. EPCOR, ATCO Gas and AltaGas argued that the Alberta CPI is perhaps the best index to reflect changes in their non-labour input prices. Furthermore, these companies indicated that they have traditionally used, and the Commission has adopted, the Alberta CPI in the past to forecast general supply-related costs in their cost of service rate applications. In addition, AltaGas noted that the use of the Alberta CPI reflected the fact that most of its non-labour inputs are sourced within the province.²⁰⁰

197. The proponents of the Alberta CPI generally agreed that this index may be regarded as an output rather than an input-based price index and, as such, could be influenced by the economy-wide productivity. However, as AltaGas observed, economy-wide outputs also serve as inputs in the form of goods and services purchased by companies. Additionally, Dr. Ryan, Dr. Carpenter and Dr. Schoech explained that, in the context of a composite I factor, the Alberta CPI will be used only to track changes in the prices of their non-labour inputs. Accordingly, the companies generally agreed that the Alberta CPI could be regarded as a proxy for an input price index for the purposes of their composite I factors, obviating the need for an adjustment to the TFP to calculate the X factor.²⁰¹

198. In turn, ATCO Electric and Fortis proposed using the EUCPI for distribution systems as a price index for their non-labour input costs.²⁰² In her evidence, Ms. Frayer pointed out that, since the EUCPI is a national indicator, an adjustment factor was necessary to capture the differences in inflationary trends between Alberta and the Canadian average. To develop such an adjustment factor, Ms. Frayer proposed using the ratio of the Alberta to Canada GDP implicit price index (GDP-IPI) as a proxy for the inflation differential between the province and the rest of Canada.

199. After comparing the 10-year average of Alberta and Canada GDP-IPI trends for the period of 2000 to 2009, Fortis' expert recommended an adjustment factor of 29 per cent (or 1.29) per year to the national EUCPI to reflect Alberta inflation.²⁰³ Using similar logic, and by taking a mid-point of the 10-year (2000 to 2009) and 15-year (1995 to 2009) ratios of Alberta to Canada GDP-IPI, ATCO Electric recommended an adjustment to the national EUCPI of 23 per cent (or 1.23) per year.²⁰⁴

200. The CCA supported an adjustment to EUCPI to account for the difference between Alberta and Canada inflation; however, it did not agree with ATCO Electric's and Fortis'

¹⁹⁷ Exhibit 297.01, ENMAX evidence, page 15.

¹⁹⁸ Exhibit 636, CCA argument, paragraph 46.

¹⁹⁹ Monthly Alberta CPI is reported in Statistics Canada Table 326-0020, data vector V41692327.

²⁰⁰ Exhibit 628, AltaGas argument, page 16.

²⁰¹ Transcript, Volume 4, page 612, line 25 to page 614, line 10; Volume 8, page 1415, line 12 to page 1416, line 3. See also Exhibit 103.04, Ryan evidence, paragraph 32.

²⁰² Statistics Canada Table 327-0011, data vector V735224.

²⁰³ Exhibit 100.02, prepared testimony of Julia Frayer, pages 41-43.

²⁰⁴ Exhibit 98.01, ATCO Electric application, Schedule 3-3.

proposal for an adjustment. Specifically, the CCA expressed its opinion that GDP-IPI is an improper basis for comparing inflation in Alberta and Canada as a whole because price inflation in Alberta is especially sensitive to the prices of oil and gas exports, which are volatile. In PEG's view, the GDP-IPI-FDD index was more suitable for this purpose because it is less volatile than the GDP-IPI index.²⁰⁵ In addition, the CCA argued that, by using the most recent period of 10 to 15 years to compare price trends and adjust the Alberta EUCPI, the companies would lock in the favourable inflation differential observed in that period.²⁰⁶

201. The UCA stated that the EUCPI is more likely to represent the input capital costs of the Alberta companies because the CPI is an output measure for consumers and is wholly inappropriate for determining the I factor for the companies.²⁰⁷ The UCA also contended that the EUCPI is a relevant index for gas distribution companies as well because many materials and services used in capital construction for gas distribution companies are similar to those used by electric distribution companies.²⁰⁸

202. Calgary also objected to the use of the Alberta CPI and observed that the cost components included in this index have little relevance to the cost of gas and electric distribution activities. Further, in Calgary's view, using Alberta CPI in conjunction with AWE could lead to double counting of labour costs.²⁰⁹

Commission findings

203. The Commission recognizes that using the EUCPI presents a number of problems. First, the EUCPI is a national indicator. Statistics Canada does not produce an Alberta-specific version of this index. Therefore, an adjustment to the EUCPI to account for Alberta-specific inflation must be considered. However, making such an adjustment introduces issues associated with comparing inflation in Alberta to Canada. These include whether to use levels or growth rates as the best indicator of the difference in inflation rates, whether to keep an adjustment constant or permit it to change during the PBR term and selecting an appropriate time period for such a comparison, among others.²¹⁰

204. The ATCO companies, when commenting on an adjustment to the EUCPI proposed by PEG, submitted that such a complicated customization of the EUCPI would add complexity and confusion to a PBR plan.²¹¹ In the Commission's view, adjusting the EUCPI introduces a high degree of subjectivity and makes the resulting I factor less transparent and more difficult to understand.

205. Additionally, as ATCO Gas and AltaGas pointed out, no construction price index similar to the EUCPI is available for gas distribution companies. The UCA contended that the EUCPI is relevant for gas companies. However, as the gas companies submitted in their arguments, it is not clear why an index covering electric distribution capital relating to substations, wires, conductors and transformers is applicable to gas distribution companies with capital costs

²⁰⁵ Exhibit 372.01, AUC-CCA-19(c).

²⁰⁶ Exhibit 372.01, AUC-CCA-19(c).

²⁰⁷ Exhibit 634.02, UCA argument, paragraph 81.

²⁰⁸ Exhibit 361.02, AUC-UCA-10.

²⁰⁹ Exhibit 629, Calgary argument, pages 21-22.

²¹⁰ For more discussion on this issue, see Exhibit 226.01, AUC-FAI-4 and Exhibit 372.01, AUC-CCA-19.

²¹¹ Exhibit 631, ATCO Electric argument, paragraph 50 and Exhibit 632, ATCO Gas argument, paragraph 53.

relating to pipe, distribution compressors, regulators and meter stations.²¹² The Commission agrees that the EUCPI should not be used as part of an I factor in a PBR plan for the gas distribution companies.

206. In the previous section of this decision the Commission agreed that the substantial influence of the oil and gas sectors on inflationary pressures in Alberta can lead to substantially different inflationary pressures than in the Canadian economy as a whole with respect to labour costs. The Commission considers that the same is true for non-labour costs. Accordingly, the Commission finds that it would be more accurate to use an Alberta measure of non-labour input price inflation.

207. If EUCPI without adjustment to reflect the Alberta environment is undesirable given the differences in inflationary pressure between Alberta and Canada as a whole, and if adjusting EUCPI to Alberta is problematic, then the Commission must consider other available indexes to adjust non-labour costs for inflation.

208. Dr. Lowry recommended using the Alberta GDP-IPI-FDD as the inflation measure for materials and services, since this index is less volatile than the Alberta CPI. However, Dr. Lowry discussed the benefits of using the GDP-IPI-FDD in the context of a customized I factor which also includes separate capital and labour components.²¹³ The Commission dismissed in Section 5.2.1 PEG's customized approach to setting the I factor. It is unclear whether the same benefits would be realized when this index is used for a two part I factor consisting only of labour and non-labour components.

209. Unlike the Alberta GDP-IPI-FDD, the CPI for Alberta is readily available from Statistics Canada on a regular basis and does not require any subjective adjustments or modifications. As a result, this index is easily understood by customers. While it may be argued that the Alberta CPI is less relevant to the electric and gas companies' business when used as the only inflation measure in a PBR plan, the Commission agrees with the proponents of Alberta CPI that it adequately reflects the price changes for the non-labour expenditures of Alberta companies to which it will apply. The Commission notes that the Alberta distribution companies (both gas and electric) have used the Alberta CPI as an escalator index for the non-labour items in their cost of service general tariff applications.²¹⁴

210. The Commission agrees with the companies' experts that, because the CPI is a proxy for changes in the companies' non-labour input prices, it may be considered an input price index for the purposes of calculating a composite I factor, obviating the need for any further adjustments to TFP in deriving an X factor, as discussed in Section 6.4.1 of this decision.

211. Finally, during the hearing, the Commission inquired whether there would be a material difference to the I factors if the Alberta CPI were used instead of the adjusted EUCPI proposed by ATCO Electric and Fortis. The provided undertakings demonstrate that over the recent 10-year period, the Alberta CPI tracks very closely to the proposed adjusted EUCPI.²¹⁵

²¹² Exhibit 632, ATCO Gas argument, page 12 and Exhibit 628, AltaGas argument, page 16.

²¹³ Exhibit 307.01, PEG evidence, page 52.

²¹⁴ Exhibit 472.02, ATCO Gas rebuttal evidence, paragraph 173; Transcript, Volume 4, page 614, lines 17-19 (ATCO Electric); Transcript, Volume 11, page 2137, lines 11-18 (Fortis).

²¹⁵ Exhibit 540 and Exhibit 592.

212. In light of the above considerations, the Commission is not persuaded that either the Alberta GDP-IPI-FDD or the adjusted EUCPI, with its increased complexity and subjectivity, represent a better alternative to the Alberta CPI. Accordingly, the Commission finds that the all-items Alberta CPI (from Statistics Canada Table 326-0020, data vector V41692327) should be used as a non-labour input price index in the composite I factor in the PBR plans of each of the Alberta gas and electric distribution companies.

5.2.4 Weighting of the I factor components

213. In Decision 2009-035, the Commission approved a 50:50 ratio for the components of the ENMAX's I factor by examining the company's historical cost ratios for capital and operating expenses. For the purpose of the ENMAX's I factor, the EUCPI was used to track changes in capital related costs while the AHE index was used to track changes in all O&M (operating and maintenance) expenses.²¹⁶

214. In this proceeding, the companies have not split their costs into capital-related and O&M components for the purposes of calculating an I factor, but rather they have split them into costs driven by labour inflation and costs driven by non-labour inflation. The companies proposed that the labour and non-labour components of their I factors be weighted based on their historical proportion of labour expenditures in total combined operating and capital expenditures for the (three to five-year) period immediately preceding the PBR term.

215. The companies contended that this proposed weighting better reflects the changes in input prices that they expect to experience over the term of the PBR plan. As the ATCO companies explained:

All labour, regardless of whether it is for capital or for O&M activities, has [the] same inflationary pressures. All workers employed by ATCO Electric or retained by ATCO Electric through a contractor exist in the same labour market here in Alberta. Labour inflation does not discriminate by whether or not the worker's pay is charged to capital or O&M. Indeed, many of ATCO Electric's staff will work on a capital project one day and an O&M project the next.²¹⁷

216. Likewise, the companies noted that inflationary pressures on non-labour costs were likely to be the same regardless of whether they relate to O&M or capital.²¹⁸ As a result, the companies grouped their expenditures into labour costs (primarily consisting of salaries, wages and contract labour), and non labour costs (primarily consisting of materials and services) to arrive at the proportional shares for the components of their respective I factor proposals set out in Table 5-1 and Table 5-2 above.

217. The UCA supported the 50:50 weighting approved for ENMAX in Decision 2009-035 because, in Dr. Cronin and Mr. Motluk's view, this weighting reflects the capital shares in Ontario and other jurisdictions internationally.²¹⁹

218. The CCA submitted that three weighting issues are salient in this proceeding: the denominator in the cost share calculations, the weight assigned to labour, and whether company-

²¹⁶ Decision 2009-035, paragraph 148.

²¹⁷ Exhibit 631, ATCO Electric argument, paragraph 47.

²¹⁸ Exhibit 628, AltaGas argument, page 13 and Exhibit 631, ATCO Electric argument, paragraph 48.

²¹⁹ Exhibit 634.02, UCA argument, paragraph 87.

specific costs should be used to establish weightings.²²⁰ With respect to the first issue, the CCA did not agree with the companies using the sum of O&M and capital expenditures as the denominator in the calculation of the I factor weights. The CCA indicated that the correct denominator to be used in the composite I factor is the sum of O&M and administration expenses and capital costs, which include depreciation, return on rate base, as well as income and property taxes. The inclusion of these additional non-labour items in the total amount of costs would reduce the weight of the labour component.

219. Regarding the second issue, the CCA submitted that the weight assigned to the labour component should reflect only the share of direct labour O&M expenses in total company costs. Specifically, the CCA did not agree with the approach of including contractor expenses and capitalized labour in the labour component. The CCA pointed out that contractor expenses do not consist entirely of labour expenses. In addition, since the EUCPI and the Alberta CPI already reflect labour cost trends, the CCA argued that using these indexes for the non-labour component would result in a double counting of labour inflation. Furthermore, the CCA submitted that capitalized labour does not have the same effect on a utility's earnings as O&M expenses.²²¹ Dr. Lowry provided the following explanation on this subject:

[T]he way that construction labour prices affect a utility's accounting is different from the way that the direct labour price does. The direct labour price -- let's say there's a big run-up in the price because they discovered another big oilfield or something in northern Alberta. Then by the way the O&M expenses go up. But as for the capitalized piece, that's going to be recovered over 40 years, so it does not give -- and of course the reverse is true too. If there was suddenly the price of oil collapsed [...] and all of a sudden there was lower labour prices in Alberta, it immediately lowers your O&M expenses, but it does not have that much of an affect on your capital cost.²²²

220. Finally, the CCA noted that using company-specific costs to establish the weights for the I factor in the subsequent PBR plans could weaken cost containment incentives, stating that the I factor should reflect the industry-wide proportions of the relevant costs in order to provide the strongest competitive incentives. The CCA submitted that it has no objection to using company specific costs to establish the weights for the I factor in this proceeding only, provided it is clearly understood that in any future plan the cost shares will not be company-specific.²²³

Commission findings

221. The Commission explained in Section 5.2.1 of this decision that a relatively tight labour market in Alberta warrants the inclusion of a separate I factor component to reflect the unique labour inflation experience in the province. The Commission agrees with the companies that all workers employed by the companies or retained through a contractor are generally in the same Alberta labour market and subject to the same compensation inflation trends regardless of whether their work is accounted for as O&M or capital related labour.

222. Accordingly, the Commission considers that an I factor with a labour and a non-labour cost component represents an improvement over an I factor with an O&M and a capital

²²⁰ Exhibit 636, CCA argument, paragraph 52.

²²¹ Exhibit 636, CCA argument, paragraph 54.

²²² Transcript, Volume 13, page 2593, line 15 to page 2594, line 4.

²²³ Exhibit 636, CCA argument, paragraph 55 and Exhibit 372.01, AUC-CCA-18(a).

component, as previously approved in the ENMAX FBR plan, because it provides for a better tracking of inflation in prices of inputs that the companies use.

223. Dr. Lowry and Calgary pointed out that because both the EUCPI and the Alberta CPI include some labour, using these indexes along with the AWE or AHE indexes can result in a potential double-counting of labour inflation if all capitalized labour is removed from the non-labour category.²²⁴ The Commission agrees. However, because no evidence was provided on the share of labour in either CPI or EUCPI,²²⁵ correcting for any possible double-counting is problematic. One possible approach would be to adjust the weightings proposed by the companies by removing all capitalized labour as well as contractor expenses from the labour component. However, because capitalized labour and contractor expenses would comprise between 30 and 50 per cent of this component (based on the data for ATCO Electric, AltaGas and Fortis),²²⁶ making this adjustment is tantamount to assuming that the share of labour in the Alberta CPI is between 30 and 50 per cent as well. In the absence of any information on the size of the labour component in the Alberta CPI, the Commission is not prepared to adopt this approach.

224. The CCA observed that contractor expenses do not consist entirely of labour expenses. However, as the ATCO companies pointed out, the contractors do not supply materials, and as such, their costs relate mostly to labour.²²⁷ Similarly, Fortis also indicated that its contractor costs are “primarily labour, almost all labour.”²²⁸ AltaGas explained that because contractor costs consist of labour and services related to the use of contractor machinery, these costs tend to be driven by labour cost escalation, rather than general inflation.²²⁹ The Commission agrees with this explanation.

225. With regard to the other concerns expressed by the CCA, such as the effect of capitalized labour on a company’s earnings and whether it is necessary to include depreciation and return on rate base in the calculation of the I factor weights, the Commission observes that these proposals rely on the same rationale as the proposal to include a separate I factor component for the cost of capital. As explained in Section 5.2.1 of this decision, the Commission considers that no specific adjustments for the cost of capital need to be incorporated into the inflation index. Accordingly, the Commission accepts the companies’ approach of using the sum of O&M and capital expenditures when calculating the weights for their respective I factors.

226. Finally, the Commission agrees with the CCA that, ideally, the weightings for the components comprising the I factor should reflect the industry-wide proportions of the relevant costs in order to provide the strongest competitive incentives. However, in this proceeding, the Commission was presented with no data to assess an alternative to examining the companies’ own historical cost ratios relative to labour and non-labour components. For this reason, the Commission will rely on the weights calculated on the basis of the companies’ historical costs, as provided in their PBR applications.

²²⁴ Transcript, Volume 13, page 2593, lines 11-14 and Exhibit 636, CCA argument, paragraph 54.

²²⁵ For example, Dr. Ryan pointed out that Statistics Canada does not report the share of labour in the EUCPI (Exhibit 103.04, paragraph 21).

²²⁶ Estimates calculated by the Commission’s staff based on the cost information provided in Exhibit 224.01; Exhibit 110.01, Appendix III, Composite I factor calculation; Exhibit 539 and referenced Rule 005 filings.

²²⁷ Exhibit 647, ATCO Electric reply argument, paragraph 76 and Exhibit 648.02, ATCO Gas reply argument, paragraph 117.

²²⁸ Transcript, Volume 11, page 2146, lines 15-18.

²²⁹ Exhibit 650, AltaGas reply argument, paragraphs 23 and 42.

227. In light of the above considerations, the Commission accepts the companies' method of calculating the weights for the I factor components. The Commission has examined the companies' historical ratios of labour to non-labour expenditures in recent years, as provided in the PBR applications and presented in tables 5-1 and 5-2 above. ATCO Electric's estimates resulted in a 65 per cent weighting of the labour component, although this ratio reflects the fact that ATCO Electric was the only company to apply a 50 per cent multiplier to its contractor costs.²³⁰ The Commission does not agree with this adjustment. The Commission observes that the historical cost ratios are approximately 60 per cent labour and 40 per cent non-labour for the other companies (not including EPCOR). Accordingly, the Commission finds that a 60:40 weighting of the labour and non-labour components is a reasonable estimate of the balance of labour and non-labour costs for all companies, including ATCO Electric.

228. Nevertheless, the Commission has decided in the previous section of this decision to use Alberta CPI for non-labour costs. The Commission observed earlier in this section that the CPI includes some embedded labour. Therefore, using this index for the non-labour component together with the AWE index for the labour component may lead to a double-counting of labour costs. In this case, the 60:40 weighting would overstate the companies' input price inflation in years when growth in the Alberta AWE exceeds the growth in the Alberta CPI. Conversely, the companies' input price inflation would be understated in years when growth in the AWE is lower than the growth in the Alberta CPI. Accordingly, to temper the possibility that inflation in the companies' input prices will be overstated or understated, the Commission considers that a 55:45 ratio of labour to non-labour expenditures should be used for calculating the I factors in the companies' PBR plans.

229. Consistent with the findings in Decision 2009-035, in order to ensure that the companies' incentives will not be influenced by the relative rates of inflation between the components in the I factor, the Commission also finds that the 55:45 ratio of labour to non-labour expenditures should be held constant throughout the PBR term.²³¹

230. EPCOR's proposed 80:20 labour to non-labour weighting reflects the company's proposal that the I-X mechanism be applied only to its non-capital related costs. As discussed in Section 2.3 of this decision, the Commission does not accept EPCOR's proposal to exclude all capital-related costs from the I-X mechanism. As such, the Commission directs EPCOR to use the 55:45 weighting in the calculation of its I factor.

5.3 Implementing the I factor

231. As the ATCO companies' expert Dr. Carpenter pointed out in his evidence, one of the difficulties in using the current year's inflation in the PBR formula is that the actual inflation indexes become available for each calendar year only in the first half of the following year, and there may not be any independent forecasts for the selected input price measures. To address this problem, Dr. Carpenter indicated that several methods could be used in practice. One method would be to accept a lag, either with or without a subsequent true up for the difference between the inflation actually experienced in a given year and the lagged inflation factor used to

²³⁰ Exhibit 98.02, ATCO Electric application, Schedule 3-1.

²³¹ Decision 2009-035, paragraphs 147-148.

determine rates for that year. Alternatively, a forecast of expected inflation could be used with or without a subsequent true up to the actual inflation rate.²³²

232. ENMAX's FBR plan approved in Decision 2009-035 uses actual inflation from the previous year to set rates in a current year.²³³ Specifically, ENMAX uses its selected input price indexes for the 12-month period ending December 31st of the previous year to set the I factor in the PBR formula and arrive at rates to be implemented on July 1st of the current year and to remain in effect until June 30th of the next year.²³⁴

233. Furthermore, in Decision 2010-146, the Commission recognized that the I factor indexes used by ENMAX may be periodically revised by Statistics Canada and ordered that these revisions be handled as a flow-through adjustment not subject to the materiality limit.²³⁵

234. The companies proposed two different approaches to implementing the I factor. AltaGas and EPCOR proposed to use an I factor mechanism similar to the one used by ENMAX. To accommodate the planned January 1st rate changes, AltaGas proposed that the inflation factor be calculated by computing annual price indexes for the 12-month period ending in June of the previous year. For example, in calculating rates for January 1, 2013, the AWE component of the I factor would be based on the change in the actual average AWE for the 12 months ending June 2012, as compared with the actual average AWE for the 12 months ending July 2011.²³⁶ The UCA and Calgary agreed with this concept.²³⁷

235. An alternative method was put forward by ATCO Electric, ATCO Gas and Fortis and supported by the CCA. These companies proposed adopting a forecast inflation rate for the upcoming year with a subsequent revenue adjustment to true up to the actual inflation for that year. In supporting the I factor true-up approach, ATCO Gas argued that the 18-month lag between the inflation index used in the PBR formula and the actual inflation experienced by the companies could have a significant impact on its revenues, further amplified by the compounding effect of indexing. ATCO gas argued that, as a result, the inflation lag can cause windfall gains or losses, possibly triggering earnings sharing or a PBR re-opener.²³⁸

236. The ATCO companies also pointed out that the proposed I factor true-up does not amount to a true-up to actual companies' costs. Rather, it improves the accuracy of the inflation component of the indexing mechanism by truing up the I factor to the actual inflation index results.²³⁹ Dr. Lowry on behalf of the CCA agreed that the use of a true-up for the actual inflation index results will produce a more accurate inflation adjustment and is warranted, particularly in light of the volatility of price inflation in Alberta.²⁴⁰

237. In contrast, AltaGas submitted that the lagged approach will be reasonably reflective of the company's input cost changes in the upcoming year and will provide a fair balance between accuracy and regulatory efficiency. As such, AltaGas argued that no I factor true-up was

²³² Exhibit 98.02, written evidence of Paul R. Carpenter, page 15.

²³³ In other words, in year t the I factor will be based on the actual inflation indexes from year $t-1$.

²³⁴ Proceeding ID No. 12, Exhibit 15, EPC amended application, page 52.

²³⁵ Decision 2010-146, paragraphs 167-168.

²³⁶ Exhibit 110.01, Appendix I - Christensen Associates report, paragraphs 32-33.

²³⁷ Exhibit 634.02, UCA argument, paragraph 88; Exhibit 629, Calgary argument, page 22.

²³⁸ Exhibit 632, ATCO Gas argument, paragraphs 60-61.

²³⁹ Exhibit 631, ATCO Electric argument, paragraph 55 and Exhibit 632, ATCO Gas argument, paragraphs 58-59.

²⁴⁰ Exhibit 372.01, AUC-CCA-21(a).

necessary as it introduces an unnecessary level of complexity to the PBR plan and results in additional adjustments to future rates and additional regulatory filing requirements.²⁴¹

238. EPCOR's expert, Dr. Ryan, also commented on the redundancy of the inflation correction procedure currently employed by ENMAX which requires recalculating the previous year's inflation factor if revised data are released.²⁴² Dr. Ryan noted that, since Statistics Canada series revisions can extend several years into the past, this could involve substantial recalculation and subsequent adjustments of prices in previous years without any obvious overall effect, except for allocating some part of price changes to a previous or subsequent year.

239. In Dr. Ryan's opinion, the periodic revision of inflation indexes by Statistics Canada need not affect the calculation of the I factor, provided that the unrevised value is used as the basis for subsequent calculations. Dr. Ryan illustrated this concept with the following example:

For example, if a series was 100 in Year 1 and 105 in Year 2, the inflation component for this series from Year 1 to Year 2 (to be used as part of the I factor in Year 3) would be 0.05 (or 5%). Now, if Statistics Canada was to revise the Year 2 series value to 104, and release the Year 3 series value of 107, then the inflation component for this series from Year 2 to Year 3 (to be used as part of the I factor in Year 4) would simply be calculated as $(107 - 105)/105$, and no adjustment because of the change from 105 to 104 would be needed, since this effect (from 104 to 105) has already been included in the previous year's inflation component. Similarly, if the Year 2 series value was revised to 106 (rather than 105), the inflation component for this series from Year 2 to Year 3 (to be used as part of the I factor in Year 4) would still be calculated as $(107 - 105)/105$ and no adjustment because of the change from 105 to 106 in Year 2 would be needed, as this effect (from 105 to 106) would be automatically included in the subsequent year's inflation component.²⁴³

240. At the same time, Dr. Ryan cautioned that more substantial revisions to a component data series would need to be examined on a case-by-case basis to determine whether other adjustments would be needed. Dr. Ryan proposed that, if a termination, substantial revision or modification to a Statistics Canada data series impacted the company's inflation factor, EPCOR would be able to apply for an appropriate amendment to its inflation factor in its first annual rate adjustment filing following the termination, substantial revision or modification.²⁴⁴

Commission findings

241. EPCOR and AltaGas proposed to use the actual inflation results for the most recent 12-month period to calculate the I factor for the upcoming year with no subsequent true-up, while the ATCO companies and Fortis proposed to forecast the I factor for the upcoming year, followed by a true-up to reflect the actual inflation in that year.

242. In the Commission's view, both approaches would eventually achieve the same purpose of reflecting the inflationary pressures on the companies' input prices. Under a forecast and true-up method, the forecast I factor is reconciled to the actual inflation indexes and rates are adjusted through a regulatory proceeding. Under the alternative approach, the true-up occurs automatically by virtue of using the actual inflation indexes from the preceding year; however,

²⁴¹ Exhibit 628, AltaGas argument, page 15.

²⁴² Exhibit 103.04, Dr. Ryan evidence, paragraph 37.

²⁴³ Exhibit 103.04, Dr. Ryan evidence, paragraph 37.

²⁴⁴ Exhibit 103.02, EPCOR application, paragraphs 74-75.

the true up is implemented after a longer period of regulatory lag. Both approaches represent a true-up to the inflation indexes and do not imply a true-up to the actual costs of the company, thus preserving the incentive properties of the PBR regime.

243. The main difference between the two methods is that the approach preferred by the ATCO companies and Fortis ensures that the impact of actual inflation in any given year is reconciled soon after the year's end, while the alternative approach of using the actual inflation from the previous year involves a certain lag for such a true-up to occur. In this proceeding, parties' concerns with the lagged approach seemed to be centered on the fact that the lag between the inflation index used in the PBR formula and the actual inflation experienced in the economy would expose the companies to windfall gains or losses, although these would be transitory.²⁴⁵

244. The Commission considers that if inflation is higher in some years and lower in other years, as appears to be the general case in the economy,²⁴⁶ then using the most recent historical inflation rate will average out the effect of any regulatory lag over the PBR period. Indeed, as ATCO Gas observed in its argument, in the absence of a true-up, the I factor in 2009 would be higher than actual inflation. The opposite would have occurred in 2010, where the I factor without the true-up would be lower than actual inflation.²⁴⁷ As such, inflation will tend to balance out over the PBR term, obviating the need to true-up the I factor through a separate regulatory proceeding.

245. When discussing the benefits of the two approaches, it is important to distinguish between the fact that inflation is generally positive (in other words, prices are increasing most of the time) and the fact that the actual inflation rate will increase year-over-year in some cases and will decline in others, although prices are still increasing. For example, as Table 5-3 above demonstrates, although the level of labour prices has been increasing consistently year over year from 1999 to 2010, the rate of change in salaries and wages (i.e., labour price inflation) went up and down during this period.

246. In order for the companies to be concerned with the lagged approach and the compounding effect to take place, the rate of inflation in each year would have to be consistently higher (or lower) than in the previous year. If it is higher in some years and lower in other years, as appears to be the general case in the economy, then using the most recent past inflation rate will average out the effect of the lags over the PBR period.

247. With respect to the concern that gains or losses resulting from the inflation lag may trigger earnings sharing or a re-opener, the Commission explained in Section 10 of this decision that in order to maximize the incentive properties of the PBR plans, ESM (earnings sharing mechanism) should not be part of the companies' PBR plans. As well, as set out in Section 8 below, the Commission will examine the need for re-openers on a case by case basis. Where relevant, the consequences of the inflation lag would be considered as part of any such review.

248. In light of these considerations, the Commission finds that the lagged approach currently used by ENMAX and proposed by AltaGas and EPCOR in this proceeding represents a better alternative as compared to the forecast and true-up method proposed by the ATCO companies and Fortis. For the purposes of clarity, based on the availability of Statistics Canada indexes, the

²⁴⁵ Transcript, Volume 4, pages 629-630.

²⁴⁶ See, for example, the inflation indexes chart in Exhibit 512.02, AUC-Fortis-7 attachment.

²⁴⁷ Exhibit 632.01, ATCO Gas argument, paragraph 61.

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 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:

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

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 reports²⁵⁸ 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 experts²⁶⁹

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 a 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., efficiency²⁷⁶) 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. Makhholm 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. Makhholm 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 companies 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 earnings 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's 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 period³²⁴

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 for 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 late 1990s 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 to 15 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 different 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. Makhholm pointed out that NERA's previous TFP study for Alberta from 2000³⁵¹ 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, line 19 to page 396, line 20.

³⁵¹ Evidence of Jeff D. Makhholm 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. Makhholm'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, line 16 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. Makhholm 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's 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. Schoech⁴⁵¹ on behalf of AltaGas and Dr. Cicchetti⁴⁵² 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's⁴⁵⁶ and Ms. Frayer's⁴⁵⁷ 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. Frayer⁴⁶⁵ and Dr. Carpenter⁴⁶⁶ 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 CCLS 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 AltaGas⁴⁹¹ 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.

process. A labour cost index such as AWE or AHE represents an example of an input price index since they track the changes in the wages and salaries of company's employees and contracted labour services. In contrast, output-based measures reflect the change in the prices of the basket of goods and services that are outputs of the economy and are typically purchased by final consumers rather than by companies as inputs. The CPI (consumer price index) would usually be an example of this type of measure.⁴⁹³

422. Given that the purpose of the I factor in a PBR plan is to track the prices of the inputs used by the electric or gas distribution industries (and therefore, the companies), the use of an input-based price index is preferred. However, on many occasions, the desired input price index may not be readily available or may not exist at all.⁴⁹⁴ As a result, PBR plans may need to use output-based measures that are readily available, widely known and easy to explain to consumers, stakeholders and regulators.⁴⁹⁵ NERA pointed out that the CPI is the most common inflation measure in PBR plans in Canada, while the GDP price index (also an output-based measure) is dominant in the United States.⁴⁹⁶

423. Nevertheless, using an output-based inflation index in a PBR plan may be problematic. Because the measure of output inflation already incorporates the effects of economy-wide productivity gains, such an index would not necessarily be indicative of the input price inflation likely to be experienced by the industry and, accordingly, the companies during the plan term. As a result, it may be necessary to adjust the TFP estimate when determining the X factor to correct for the difference between the output inflation included in the inflation factor and the industry input inflation.⁴⁹⁷

424. NERA and Dr. Carpenter explained that for practical purposes this adjustment consists of two adjustments to TFP to arrive at the X factor: a productivity differential and an input price differential.⁴⁹⁸ In its evidence, PEG explained the logic behind those two adjustments as follows:

The productivity differential is the difference between the MFP trends of the industry and the economy. The X will be larger, slowing the [I-X index] growth, to the extent that the MFP growth of the economy is slow. The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry.⁴⁹⁹

425. As Fortis' expert pointed out, in this case an X factor based on TFP with these two adjustments may be interpreted as the difference between the productivity growth rate of the industry and the productivity growth rate included in the output inflation measure used. On the other hand, if an input price index is used for the I factor, no adjustment to TFP is required. In this case, the resulting X factor would reflect the productivity growth of the industry.⁵⁰⁰

⁴⁹³ Exhibit 476.01, Carpenter rebuttal evidence, page 67; Exhibit 100.02, Frayer evidence, page 33.

⁴⁹⁴ Exhibit 476.01, Carpenter rebuttal evidence, page 67.

⁴⁹⁵ Exhibit 100.02, Frayer evidence, pages 33-34.

⁴⁹⁶ Exhibit 391.02, NERA second report, paragraph 65.

⁴⁹⁷ Exhibit 476.01, Carpenter rebuttal evidence, page 67; Exhibit 100.02, Frayer evidence, page 54; Exhibit 628, AltaGas argument, pages 12-13.

⁴⁹⁸ Exhibit 461.02, AUC-NERA-17(b) and Exhibit 476.01, Carpenter rebuttal evidence, page 67.

⁴⁹⁹ Exhibit 307.01, PEG evidence, pages 20-21.

⁵⁰⁰ Exhibit 100.02, Frayer evidence, page 52.

Commission findings

426. The interaction between the I factor and the X factor described above is based on a well-established theoretical foundation, as demonstrated by the agreement of parties on the need to adjust TFP in determining an X factor if an output-based inflation measure is chosen for the purpose of the PBR plan.⁵⁰¹ Consequently, the parties advised that, when possible, it is preferable to use input-based price indexes for the I factor of the PBR plan, since using such indexes avoids the need for an input price differential and a productivity differential adjustment to TFP.

427. As set out in Section 5 of this decision, the Commission approved a composite I factor consisting of AWE and CPI indexes for Alberta. While the AWE index represents an example of an input-based measure, the CPI is generally regarded as an output rather than an input price index. However, as the Commission explained in Section 5.2.3 above, in the context of this proceeding, the Alberta CPI will be used only to monitor price trends for the companies' non-labour inputs. EPCOR, AltaGas and ATCO Gas submitted that because the Alberta CPI is a good proxy for the price changes for that particular group of expenditures, it may be considered an input price index for the purpose of their composite I factors.⁵⁰² The Commission agrees.

428. Accordingly, 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.

6.4.2 Productivity gap adjustment

429. As discussed in Section 6.3.1 above, NERA's study used a population of 72 U.S. electric and combination electric/gas companies. In these circumstances, Dr. Carpenter indicated that to the extent that utilities in Canada have different productivity expectations than utilities in the U.S., an adjustment to the NERA's TFP number would be required in a Canadian PBR context.⁵⁰³

430. Dr. Carpenter observed that there is a well-documented productivity gap between the Canadian and the U.S. economies, with Canadian productivity growth rates consistently lower than productivity growth in the U.S. For example, Dr. Carpenter pointed to a Statistics Canada study that found that average annual MFP growth was 0.9 percentage points lower in Canada than in the United States from 1961 to 2008.⁵⁰⁴ In addition, Dr. Carpenter observed that in its TFP analysis, NERA showed that on average, productivity in the U.S. economy grew 0.95 percentage points per year faster than productivity in the Canadian economy over the 1972 to 2009 period.⁵⁰⁵

431. At the same time, the ATCO companies' expert acknowledged that while the existence of the economy-wide productivity gap has been documented by government statistics and academic studies, the specific causes of the gap are not well understood and it is not clear whether a similar

⁵⁰¹ Transcript, Volume 1, pages 141-142; Transcript, Volume 4, pages 611-612; Transcript, Volume 8, page 1415; Transcript, Volume 11, pages 2133-2134; Transcript, Volume 13, page 2589.

⁵⁰² Exhibit 630.02, EPCOR argument, paragraph 31; Exhibit 628, AltaGas argument, pages 12-13; Exhibit 648.02, ATCO Gas reply argument, paragraph 94.

⁵⁰³ Exhibit 98.02, Carpenter evidence, pages 25-26.

⁵⁰⁴ Baldwin, John and Wulong Gu, *Productivity Performance in Canada, 1961 to 2008: An Update on Long-term Trends*, Statistics Canada, August 2009.

⁵⁰⁵ Exhibit 98.02, Carpenter evidence, page 29.

productivity gap exists in the electric and gas utility sector. For example, Dr. Carpenter noted that studies relying on the Statistics Canada data typically define the utility sector more broadly, including power generation and transmission in the electric sector and water and sewage utilities in the gas sector.⁵⁰⁶ Thus, these studies may not provide an accurate estimate of productivity growth for electric or gas distribution companies. As a result, Dr. Carpenter conceded that there is no evidence to permit a direct comparison of Canadian and U.S. productivity growth rates for electric or gas distribution companies.⁵⁰⁷

432. Despite the lack of direct empirical evidence, Dr. Carpenter concluded that it is likely that the economy-wide productivity gap between Canada and the U.S. persists at the utility sector level. Dr. Carpenter arrived at this conclusion as a result of following considerations.⁵⁰⁸

- First, Dr. Carpenter indicated that he was not aware of any evidence that differences in the composition of the two economies drive the different rates of productivity growth. For example, Dr. Carpenter noted that the proportion of total GDP generated by the various sectors of the Canadian and the U.S. economies is not very different.
- Second, Dr. Carpenter noted that he was not aware of any compelling evidence that there is one sector or a group of sectors in the Canadian and the US economies that drives the productivity gap. According to Dr. Carpenter, there is evidence that the productivity gap occurs in a wide range of sectors, which is likely to include the utility sector.
- Third, Dr. Carpenter observed that while there is some disagreement among researchers as to the possible explanations for the U.S.-Canada gap, he had seen no reason to believe that the productivity gap is unlikely to affect the utility sector.

433. As a result of these considerations, Dr. Carpenter indicated that NERA's TFP estimate for the U.S. companies needed to be adjusted for the observed U.S.-Canada productivity gap. Using the economy-wide productivity estimates from Statistics Canada and the U.S. Bureau of Labour Statistics presented in NERA's report, Dr. Carpenter proposed an adjustment of approximately -1.5 percentage points to NERA's TFP.⁵⁰⁹

434. Furthermore, Dr. Carpenter expressed his view that the recommended productivity gap adjustment was conservative for Alberta. The ATCO companies' expert noted that the CSLS report⁵¹⁰ and another productivity study⁵¹¹ show a Canada-Alberta productivity gap, with Alberta having slower productivity growth in the utility sector and in the business sector in general. However, because ATCO Electric and ATCO Gas make up a significant part of the utility sector in Alberta, Dr. Carpenter indicated that adjustment for a Canada-Alberta productivity gap may not be appropriate since the resulting X factor would be "ATCO-specific" rather than reflective of the industry productivity trends.⁵¹²

435. AltaGas agreed with Dr. Carpenter that in the case that the TFP analysis "did not focus on the Canadian gas distribution industry, an adjustment for the U.S.-Canada productivity gap

⁵⁰⁶ Transcript, Volume 6, page 1004, lines 4-25.

⁵⁰⁷ Exhibit 98.02, Carpenter evidence, pages 26-27.

⁵⁰⁸ Exhibit 98.02, Carpenter evidence, pages 27-29.

⁵⁰⁹ Exhibit 98.02, Carpenter evidence, page 30, Tables 2 and 3.

⁵¹⁰ The CSLS report was discussed in Section 6.3.7 of this decision.

⁵¹¹ Rao, Someshwar, Andrew Sharpe and Jeremy Smith, *An Analysis of the Labour Productivity Growth Slowdown in Canada since 2000*, International Productivity Monitor, Spring 2005.

⁵¹² Exhibit 98.02, Carpenter evidence, pages 33-34.

would generally be appropriate.⁵¹³ With respect to the Canada-Alberta productivity gap, AltaGas observed that the CSLs report (from which the existence of such a gap was inferred) was conducted on an experimental basis. As such, AltaGas did not propose to make an adjustment for differences in productivity growth between Alberta and Canada.⁵¹⁴

436. EPCOR submitted that neither the company itself nor its expert Dr. Cicchetti have proposed an adjustment for the productivity differences between the U.S. and Canada or between Canada and Alberta. During the hearing, Dr. Cicchetti explained that the data for Canadian companies do not exist in a fashion that would allow anyone to have an authoritative opinion on the difference in productivity between Canadian and U.S. electric distribution utilities.⁵¹⁵ At the same time, when establishing the components of EPCOR's PBR plan, Dr. Cicchetti urged the Commission to recognize that the actual trend in input prices for labour in Alberta are likely to be above the past trends in the U.S. reflected in NERA's data.⁵¹⁶ As a result, EPCOR submitted that the Commission should not increase the X factor "to something more than -1.0 per cent" that Dr. Cicchetti recommended for the company, given the difference in U.S. and Alberta labour economics.⁵¹⁷

437. Fortis noted that the company did not ground its X factor approach or recommendation on the basis of a productivity gap. Furthermore, Fortis submitted that the relevant Canada to Alberta considerations in the company's proposal were with respect to the I factor, where the appropriate "Albertasizing" of input price measures was undertaken.⁵¹⁸

438. The CCA did not believe that any adjustment to the X factor to account for the U.S.-Canada productivity gap was necessary. Having examined the analysis of MFP conducted in several papers by Statistics Canada, PEG found that productivity growth differences between the United States and Canada "vary so widely by industry as to render economy-wide differences in productivity growth useless in quantifying differences in productivity growth between specific industries in the two countries."⁵¹⁹ In addition, PEG observed that the productivity gap between the U.S. and Canada was largely due to differences in sectors that do not include utilities, such as mining and oil extraction and manufacturing.⁵²⁰

439. In a similar vein, NERA indicated that it was not aware of any evidence to point to a productivity gap between U.S. and Canadian utilities:

NERA has seen no evidence to point to a productivity gap between US and Canadian utilities. The existence of a macroeconomic productivity gap between the US and Canada does not necessitate the existence of a productivity gap between US and Canadian utilities – or even suggest such a gap for companies, which operate as regulated utilities in markets subject to highly similar sets of accounting, administrative and legal institutional arrangements in the US and Canada.⁵²¹

⁵¹³ Exhibit 628, AltaGas argument, page 30.

⁵¹⁴ Exhibit 628, AltaGas argument, page 31.

⁵¹⁵ Transcript, Volume 11, page 2009, lines 16-24.

⁵¹⁶ Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).

⁵¹⁷ Exhibit 630.02, EPCOR argument, paragraphs 74-75.

⁵¹⁸ Exhibit 633, Fortis argument, paragraphs 130-131.

⁵¹⁹ Exhibit 376.01, ATCO-CCA-42(c).

⁵²⁰ Exhibit 376.01, ATCO-CCA-42(c).

⁵²¹ Exhibit 291.02, Calgary-NERA I-9(c), Exhibit 195.01, AUC-NERA-7.

440. Calgary stated that there is fundamentally little if any difference between the productivity of the U.S. and Canadian distribution utilities.⁵²² Similarly, the UCA expressed its concerns with establishing the existence of a productivity gap between U.S. and Canadian distribution companies based on the difference in productivity in the overall Canadian economy compared to the overall U.S. economy. In their evidence, Dr. Cronin and Mr. Motluk presented the results of various studies of Canadian electric and gas distribution utilities showing that the TFP growth rates of Canadian distribution companies were “notably higher” than for the U.S. distribution companies as measured by NERA’s TFP growth rate.⁵²³ As such, the UCA’s experts argued that there was a reverse productivity gap between U.S. and Canadian distribution companies.⁵²⁴

Commission findings

441. Parties did not dispute the fact that there presently exists a well-recognized difference between the rate at which the U.S. and the Canadian economies have been able to improve productivity (referred to as a “productivity gap”). Using macroeconomic productivity data from Statistics Canada and the U.S. Bureau of Labour Statistics, NERA showed that, on average, productivity in the U.S. economy grew 0.95 percentage points per year faster than productivity in the Canadian economy over the 1972 to 2009 period.⁵²⁵

442. At the same time, parties could not agree on whether the same productivity gap exists between the U.S. and Canadian electric and gas distribution industries. Little direct evidence on whether a gap exists is available. Dr. Carpenter and Dr. Cicchetti pointed to the fact that it is not possible to directly review the productivity gap in the electric and gas utility sectors, as no data on productivity growth for Canadian electric and gas companies exist.⁵²⁶ The UCA experts proposed examining TFP growth estimates of Canadian utilities obtained from various regulatory proceedings for this purpose. However, in the Commission’s view, because the TFP estimates introduced by Dr. Cronin and Mr. Motluk represent a variety of sources, methods, samples and time periods, it is uncertain whether these estimates can be directly compared to NERA’s TFP calculation to make a judgment on the existence of a productivity gap for the electric and gas distribution industries between the two countries.⁵²⁷ As such, the Commission will proceed with evaluating the indirect evidence of a productivity gap between U.S. and Canadian utilities.

443. On a conceptual level, the Commission agrees with NERA’s and the interveners’ proposition that the existence of a macroeconomic productivity gap between the U.S. and Canada does not mean that there is a productivity gap between U.S. and Canadian utilities. As Dr. Lowry explained:

And also the thrust of my evidence is that if you look under the hood of the Canadian economy and go sector by sector, it's nothing, you know, remotely true that all the sectors are behind their American counterparts. The numbers are just all over the place. So there's very bad predictive value by saying that for a given industry just because the Canadian economy's productivity trend is slower that therefore a given sector should be slower.⁵²⁸

⁵²² Exhibit 629, Calgary argument, page 28.

⁵²³ Exhibit 299.02, Cronin and Motluk UCA evidence, pages 76-79 and 86-87.

⁵²⁴ Exhibit 634.02, UCA argument, paragraphs 134-135.

⁵²⁵ Exhibit 80.02, NERA report, page 20, Table 4.

⁵²⁶ Exhibit 476.01, Carpenter rebuttal evidence, page 41; Transcript, Volume 11, page 2009, lines 16-24 (Cicchetti).

⁵²⁷ Exhibit 299.02, Cronin and Motluk UCA evidence, pages 78-79.

⁵²⁸ Transcript, Volume 13, page 2562, lines 11-19.

444. To examine which particular sectors of the Canadian economy contribute to a productivity gap, parties relied on a number of government and academic studies. For example, Dr. Carpenter observed that one Statistics Canada study⁵²⁹ found evidence of the labour productivity gap in six of the nine industries examined, including utilities and transportation, manufacturing, retail trade, information and cultural industries; and finance, insurance, and real estate. Another study⁵³⁰ that Dr. Carpenter relied on identified a U.S.-Canada productivity gap in 20 of 33 categories, including electric utilities, gas utilities, mining, food, textiles, printing, and electrical machinery.⁵³¹

445. However, the Statistics Canada study⁵³² referenced by the CCA's experts, PEG, did not support this conclusion and showed that "the MFP trend of the engineering sector of the economy which includes energy utilities actually exceeded that of the U.S. over a recent sample period."⁵³³ Another study by Statistics Canada⁵³⁴ quoted by PEG showed that in the 2000 to 2008 period, the decline in the business sector MFP growth rate was due chiefly to declining productivity in two industrial classifications: mining and oil and gas extraction, and manufacturing.⁵³⁵ The UCA also presented the results of an academic study⁵³⁶ showing that for the period from 1961 to 1995, Canada was "significantly more productive than the United States in coal mining, construction, tobacco, petroleum refining, electric utilities, and gas utilities."⁵³⁷

446. Without engaging in a debate on the methodology, time period and relevance of the academic studies discussed in this proceeding,⁵³⁸ the Commission observes that there is no consensus in the literature on whether a productivity gap exists for the utility sector in general or for the electric and gas distribution sectors in particular. On a related issue, Dr. Carpenter pointed out that there remains a disagreement among the researchers as to the possible explanations for the U.S.-Canada productivity gap.⁵³⁹

447. Furthermore, as Dr. Carpenter indicated, some of the academic studies on productivity referenced by the parties in this proceeding refer to the Canadian utility sector in general, which includes power generation and transmission in the electric utilities sector and water and sewage systems in the natural gas utilities sector.⁵⁴⁰ As such, it is uncertain whether the productivity of the utilities sector reported in the studies is an accurate reflection of the electric and gas distribution companies' TFP growth.

⁵²⁹ Baldwin, John and Wulong Gu, *Productivity Performance in Canada, 1961 to 2008: An Update on Long-term Trends*, Statistics Canada, August 2009 (No. 25), Statistics Canada.

⁵³⁰ Gu, Wulong and Mun Ho, *A Comparison of Industrial Productivity Growth in Canada and the United States*, Published in *Industry-level Productivity and International Competitiveness between Canada and the United States*, 2001.

⁵³¹ Exhibit 98.02, Carpenter evidence, page 28.

⁵³² Baldwin, Gu and Yan, *Relative Multifactor Productivity Levels in Canada and the United States: A Sectoral Analysis*, The Canadian Productivity Review, June 2008 (No. 19), Statistics Canada.

⁵³³ Exhibit 636, CCA argument, paragraph 102.

⁵³⁴ Baldwin and Gu, *Productivity Performance in Canada, 1961 to 2008: An Update on Long-term Trends*, The Canadian Productivity Review, August 2009 (No. 25), Statistics Canada.

⁵³⁵ Exhibit 636, CCA argument, paragraph 102.

⁵³⁶ Lee, Frank C., and Jianmin Tang. 2000. *Productivity Levels and International Competitiveness between Canadian and U.S. Industries*. American Economic Review, 90(2): 176-179.

⁵³⁷ Exhibit 634.02, UCA argument, paragraphs 136-138.

⁵³⁸ Exhibit 476.01, Carpenter rebuttal evidence, pages 42-46; Exhibit 650, AltaGas reply argument, paragraph 87.

⁵³⁹ Exhibit 98.02, Carpenter evidence, page 29.

⁵⁴⁰ Exhibit 98.02, Carpenter evidence, page 26; Exhibit 476.01, Carpenter rebuttal evidence, page 45.

448. In light of the conflicting evidence from the government and academic research, and the uncertainty of whether the results of such research can be used for establishing the existence of a productivity gap between U.S. and Canadian distribution utilities, the Commission considers that no definitive conclusion can be reached on the existence of such a gap. Further, the Commission finds it to be significant that parties observed the business, operational and regulatory similarities between utilities in both jurisdictions. For example, NERA commented on the similarity of the institutional frameworks in which the Canadian and U.S. utilities operate. As NERA explained:

[F]rom the constitutional foundation through to administrative practices, accounting practices and judicial review, Canada and the United States have virtually indistinguishable regulatory environments – so much so that the US *Hope* and *Bluefield* decisions are even cited in Canadian rate cases.⁵⁴¹

449. Dr. Cicchetti also pointed to similarities in the business environment between the utilities in the two countries by observing that electric and gas distribution companies in both the United States and Canada “are certainly the last remaining holdout in the U.S. context of unionized employees.”⁵⁴²

450. In light of these considerations, the Commission finds that no adjustment to NERA’s TFP is necessary to account for the observed economy-wide productivity gap between the U.S. and Canada. The Commission observes that Dr. Carpenter was not aware of any jurisdiction in Canada that has adjusted a TFP estimate in setting the X factor in recognition of the productivity gap between the two countries.⁵⁴³

451. With respect to a Canada-Alberta productivity gap, the Commission notes that Dr. Carpenter’s conclusions as to the existence of such a gap were largely derived from the examination of the CSLS study.⁵⁴⁴ However, as the Commission explained earlier in this section and in Section 6.3.7, because the CSLS study used the same methodology and underlying data that Statistics Canada employed in calculating its MFP indexes, it is not clear to what degree the results of this study are reflective of the productivity trends in the electric and gas distribution industries.

452. More importantly, the Commission explained in Section 6.2 of this decision that the X factor should reflect the average rate of productivity growth in the industry. Accordingly, the Commission agrees with Dr. Carpenter’s observation about the size of the ATCO companies and concludes that because the companies in this proceeding make up a large part of the utility sector in Alberta, an adjustment for a Canada-Alberta productivity gap (in the utility sector) would result in an X factor that would reflect the companies’ own experience rather than industry productivity trends.⁵⁴⁵

453. Dr. Cicchetti proposed that when setting the X factor for Alberta companies, some recognition be given to the fact that the actual trend of input prices for labour in Alberta is likely to be above the past trends in the U.S. that are reflected in NERA’s TFP estimates.⁵⁴⁶ In

⁵⁴¹ Exhibit 391.02, NERA second report, page 20.

⁵⁴² Transcript, Volume 11, page 2071, lines 3-6.

⁵⁴³ Transcript, Volume 4, page 635, lines 7-11.

⁵⁴⁴ Exhibit 98.02, Carpenter evidence, page 33.

⁵⁴⁵ Exhibit 98.02, Carpenter evidence, pages 33-34.

⁵⁴⁶ Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).

EPCOR's view, the consequence of this would be that NERA's TFP growth rate would be higher than the actual TFP growth rate for Alberta.⁵⁴⁷

454. The Commission has a number of concerns with the EPCOR proposition. First of all, Dr. Cicchetti did not provide any information on the relative labour inflation in Alberta and the United States for NERA's study period to support his conclusion that labour inflation in Alberta has been consistently higher than labour inflation in the U.S. over this entire period.

455. Furthermore, the actual impact of labour inflation on the TFP estimate is not so direct as to warrant an immediate upward adjustment to NERA's estimates. NERA explained that its overall input index (in the form of a Tornqvist-Theil volume index) primarily captures changes in input volume.⁵⁴⁸ Because NERA used the number of employees as a labour quantity measure,⁵⁴⁹ the resulting TFP estimate is largely, but not completely, insulated from the effect of labour inflation. NERA explained that its overall input index "is affected by input prices to the extent that the input expenses are the shares by which the input volumes are weighted."⁵⁵⁰ Since NERA used nominal dollars to construct the input price shares,⁵⁵¹ adjusting for higher labour inflation (assuming that the labour inflation in Alberta was consistently higher than in the United States) would result in a higher share of labour in NERA's input index. However, a higher share of labour in the overall input index does not necessarily lead to a reduction to TFP. For example, if the rate of growth in the labour index (i.e., labour quantity) were lower than the rate of growth of the capital and materials indexes (quantities of capital and materials), assigning more weight to the labour index would actually result in a lower overall input index. Holding the output index constant, this would result in a higher TFP growth.

456. In the absence of any analysis on how historical Alberta labour inflation would affect NERA's TFP estimate, the Commission cannot accept EPCOR's proposition that an adjustment to the TFP factor is necessary to account for the difference in U.S. and Alberta labour economics.

6.4.3 Effect on the X factor of excluding capital from the application of the I-X mechanism

457. Because EPCOR's proposed PBR plan indexes only operating costs and excludes capital costs, Dr. Cicchetti noted that a PFP (partial productivity factor) measuring only changes in O&M productivity was a relevant measure to use instead of TFP as a basis for EPCOR's X factor.⁵⁵² The ATCO companies agreed with this logic and submitted that if all capital expenditures were to be excluded from indexing under the PBR plan, a different X factor would likely be required based on the PFP associated with O&M.⁵⁵³

⁵⁴⁷ Exhibit 630.02, EPCOR argument, paragraphs 74-75.

⁵⁴⁸ Exhibit 195.01, AUC-NERA-3(a) and (d).

⁵⁴⁹ As NERA explained in its second report, before 2002, NERA used number of employees for labour quantity. Because FERC Form 1 no longer contains employee data after 2002, NERA estimated the number of employees using the inflation-adjusted distribution payroll growth for the years 2002 to 2009. (Exhibit 391.02, NERA second report, page 10). In either period, labour quantity is measured by a number of employees, and is not reflective of labour inflation.

⁵⁵⁰ Exhibit 195.01, AUC-NERA-3(d).

⁵⁵¹ Exhibit 195.01, AUC-NERA-3(b).

⁵⁵² Exhibit 103.05, Cicchetti evidence, page 20.

⁵⁵³ Exhibit 631, ATCO Electric argument, paragraph 102 and Exhibit 632, ATCO Gas argument, paragraph 112.

458. The UCA argued that the same reasoning applies to the exclusion from indexing of a portion of capital expenditures. Because NERA's TFP estimate was based on the entirety of the distribution companies' inputs (i.e., capital, labour and materials), the UCA argued that the exclusion of some or all capital from the I-X mechanism would require an adjustment to NERA's TFP and the resulting X factor.⁵⁵⁴ At the same time, the UCA observed that the issue of what the relevant X factor should be in this case was not addressed in this proceeding, and a separate process was required:

However, if the Commission determines that there is need for a capital adjustment outside of the I-X mechanism, then a separate proceeding is definitely required. The proceeding would have to examine the appropriate X factor having regard to the exclusion of a material portion of capital from the I-X mechanism. This alternative creates additional regulatory burden. It would create uncertainty for the Applicants and the ratepayers. The UCA does not recommend this alternative.⁵⁵⁵

459. PEG observed that to the extent that the capital expenditures excluded from indexing are sizable and involve the "normal kinds of [capital expenditures] undertaken by the sampled utilities," it may be necessary to raise the TFP estimate.⁵⁵⁶ To support its view, PEG showed that for its sample of companies, excluding 10 per cent of capital expenditures causes TFP growth to increase from 1.32 per cent to 1.53 per cent.⁵⁵⁷

460. In response, the ATCO companies submitted that based on the structure of their PBR plans, there is no need to adjust the TFP (and the resulting X factor). Specifically, the ATCO companies noted that while some capital expenditures were included as flow-through factors under the companies' respective plans, the vast majority (approximately 85 per cent for ATCO Electric and 95 per cent for ATCO Gas) of their revenues were covered under the I-X portion of the plan. As such, the ATCO companies argued that their PBR plans were comprehensive, and thus no adjustment to the X factor was required.⁵⁵⁸

461. Similarly, AltaGas indicated that under the revenue-per-customer cap proposed by the company, the impact of capital expenditures removed from the I-X mechanism and included in the proposed flow-through factor represented only around five per cent of the company's total revenue requirement. AltaGas argued that given the relative size, scope and the effective isolation of the projects included in the flow-through factor from other elements of the company's plan, there was no reason to adjust the X factor for the exclusion of some part of capital.⁵⁵⁹

Commission findings

462. The Commission agrees in principle with the CCA's and the UCA's view that because NERA's study measures changes in output compared to changes in all of the companies' inputs (that is, labour, materials and capital), NERA's TFP estimate may not be precisely applicable to PBR plans that exclude all or a part of capital from the application of the I-X mechanism. However, for the reasons explained below, the Commission has not made any adjustment to

⁵⁵⁴ Exhibit 634.02, UCA argument, paragraph 204.

⁵⁵⁵ Exhibit 634.02, UCA argument, paragraph 205.

⁵⁵⁶ Exhibit 307.01, PEG evidence, page 60.

⁵⁵⁷ Exhibit 307.01, PEG evidence, page 29.

⁵⁵⁸ Exhibit 631, ATCO Electric argument, paragraph 103 and Exhibit 632, ATCO Gas argument, paragraph 113.

⁵⁵⁹ Exhibit 628, AltaGas argument, pages 31-32.

NERA's TFP estimate to account for capital that is excluded from the application of the I-X mechanism.

463. With respect to excluding all capital from the application of the I-X mechanism, the Commission explained in Section 2.3 that it did not accept EPCOR's proposal to exclude capital and apply the I-X mechanism only to the O&M and other non-capital costs. As such, no consideration of the partial productivity factors of the type proposed by Dr. Cicchetti is required in determining the X factor for EPCOR's proposed PBR plan.

464. With respect to the exclusion of some capital, as further discussed in Section 7.3.2.4 of this decision, the Commission's preferred method of dealing with companies' concerns regarding unusual capital expenditures is through the use of capital trackers. The Commission acknowledges that, in theory, because the capital expenses subject to these trackers will be not be subject to the I-X mechanism, NERA's TFP number may need to be adjusted.

465. However, the Commission observes that the direction of any TFP adjustment to account for the exclusion of some of the capital is not clear, as demonstrated by the parties' conflicting evidence on this subject. Dr. Cicchetti's analysis showed that excluding capital from NERA's TFP estimate results in a more negative PFP trend, and therefore the X factor when capital is excluded from the application of the I-X mechanism should be lower than if capital were included.⁵⁶⁰ In contrast, PEG showed that for its sample of companies, excluding 10 per cent of capital expenditures causes TFP to rise. Accordingly, to the extent that the capital expenditures excluded from indexing are sizable, the CCA experts advocated a higher X factor.⁵⁶¹

466. Additionally, the Commission indicated in Section 7.3.4 below that it is not approving any of the capital factors proposed by the companies as part of this decision. In Section 7.3.4, the Commission has invited the companies to file their capital proposals in their first capital tracker filing on or before November 2, 2012. In its submissions, the UCA was referring to the exclusion of a "material portion of capital" from the application of the I-X mechanism.⁵⁶² AltaGas and the ATCO companies argued that their proposed capital flow-through factors (which, in AltaGas' view were of a nature similar to NERA's definition of a capital tracker) would not have a large effect on the overall revenue requirement.⁵⁶³

467. In light of this conflicting evidence and the resulting uncertainty as to the materiality and the direction of any adjustment to account for the exclusion of some capital from the I-X mechanism, the Commission will not be making any adjustments to TFP during the PBR term to account for the fact that some capital may be excluded from the application of the I-X mechanism.

⁵⁶⁰ Exhibit 103.05, Cicchetti evidence, pages 22-24.

⁵⁶¹ Exhibit 307.01, PEG evidence, pages 29 and 60.

⁵⁶² Exhibit 634.02, UCA argument, paragraph 205.

⁵⁶³ Exhibit 628, AltaGas argument, page 32; Exhibit 631, ATCO Electric argument, paragraph 103; Exhibit 632, ATCO Gas argument, paragraph 113.

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 UCA⁵⁶⁹ 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 Pfeifenger, 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.

Table 6-2 Summary of the X factor proposals

	ATCO Electric/ ATCO Gas⁶²¹	EPCOR⁶²²	Fortis⁶²³	AltaGas⁶²⁴	CCA⁶²⁵
Starting point	-0.28 to -1.09	-1.0	-1.0	-1.0 to -1.7	1.32 for gas companies 1.08 to 1.23 for electric companies
Productivity research relied upon	NERA's TFP	PFP based on NERA's data	Statistics Canada MFP index and NERA TFP	Statistics Canada MFP index and NERA TFP	PEG's TFP for gas companies NERA's TFP for electric companies
Time period	1994-2009 and 1999-2009	1999-2009	2000-2009	2000-2009	1996-2009 (PEG data) 1989-2007 (NERA data)
Adjustment for the U.S.-Canada productivity gap	-1.31 to -1.73	--	--	--	--
Stretch factor ⁶²⁶	No	0.2	No	0.1 to 0.2	0.19
Proposed X factor (in per cent)	-2.0	-1.0	-1.0	-1.3	1.08 to 1.32

Note: Numbers do not add up due to a number of assumptions and qualifications that parties incorporated in their X factor proposals (for example, choice of a mid-point value for a range of X, application of a stretch factor only if an ESM was excluded from the plan, etc.).

502. Calgary recommended an X factor in the range of 1.0 to 1.7 per cent based on the results of NERA's and PEG's productivity studies.⁶²⁷ As well, 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.⁶²⁸

503. IPCAA did not make a specific recommendation on the X factor except to mention that a negative X factor unduly increases the risk of the companies over-earning.⁶²⁹

504. The UCA's experts, Dr. Cronin and Mr. Motluk, recommended using the X factor and ROE menu discussed in the Ontario Energy Board's *2000 Draft Rate Handbook*.⁶³⁰ As set out in Section 6.2, the Commission did not accept the UCA's menu approach. The UCA also indicated that if the menu approach to the X factor is not adopted, it recommends stretch factors for the

⁶²¹ Exhibit 98.02, Carpenter evidence, page 32, Table 3.

⁶²² Exhibit 103.05 Cicchetti evidence, page 16.

⁶²³ Exhibit 100.02, Frayer evidence, pages 78-79.

⁶²⁴ Exhibit 110.01, Christensen Associates evidence, pages 13-15.

⁶²⁵ Exhibit 636, CCA argument, paragraphs 60-62.

⁶²⁶ Exhibit 631, ATCO Electric argument, paragraph 106; Exhibit 632, ATCO Gas argument, paragraph 116; Exhibit 630.02, EPCOR argument, paragraph 81; Exhibit 633, Fortis argument, paragraph 142; Exhibit 628, AltaGas argument, page 33; Exhibit 636, CCA argument, paragraph 106.

⁶²⁷ Exhibit 629, Calgary argument, page 24.

⁶²⁸ Exhibit 629, Calgary argument, page 33.

⁶²⁹ Exhibit 635, IPCAA argument, pages 2-3 and Exhibit 642, IPCAA reply argument, paragraphs 5-6.

⁶³⁰ <http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/handbook0.html>.

companies of between 0.2 and 0.6 per cent based on the current Ontario third generation PBR plan approach.⁶³¹

Commission findings

505. As noted earlier in this section, the parties' X factor proposals were based on a variety of productivity indexes, approaches, and sample periods that they considered to be the most relevant in determining the X factor.

506. There was some discussion about whether the X factor to be used in a PBR plan necessarily has to be positive. The companies contended that there is nothing inherently wrong with a negative X factor. All companies proposed negative X factors in their respective PBR applications. Calgary did not agree with this conclusion and argued that a negative X factor does not provide the proper incentives to reduce costs.⁶³² IPCAA observed that a lower X factor would lead to a higher risk of company over-earning.⁶³³

507. On this issue, the Commission agrees with the companies' argument that, in theory, the X factor does not necessarily have to be always positive. As NERA's and EPCOR's experts explained during the hearing, a negative TFP (and the resulting X factor) just means that a particular industry grows more slowly in its productivity than the economy as a whole or that input costs are growing faster in the industry than in the economy.⁶³⁴ Because the economy-wide productivity represents the average productivity of different industries comprising the national economy, some of the industries must be below average and some above. For instance, Dr. Makholm and Dr. Schoech pointed to the construction industry as an example of a sector with slower productivity growth.⁶³⁵

508. In Section 6.2 of this decision, the Commission reiterated its preference for an approach to setting the X factor based on the long-term rate of productivity growth in the industry. The Commission dismissed the alternative approaches to determining the X factor, such as the building blocks approach proposed by Fortis and the efficiency benchmarking and menu approaches proposed by the UCA.

509. In Section 6.3 of this decision, the Commission examined multiple aspects of the parties' TFP recommendations and determined that the results of NERA's TFP study represent a reasonable starting point for establishing a productivity estimate for Alberta electric and gas distribution companies. Based on the results of NERA's study, the Commission determined 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 and gas distribution companies. In this proceeding, parties discussed several potential adjustments to TFP to arrive at the X factor, some of which would have resulted in a negative X factor.

510. Specifically, NERA explained that the theory behind PBR plans may require an input price differential and a productivity differential adjustment to TFP if an output-based measure is used for the I factor.⁶³⁶ However, the Commission explained in Section 6.4.1 above that because

⁶³¹ Exhibit 634.02, UCA argument, paragraph 146.

⁶³² Exhibit 629, Calgary argument, page 30.

⁶³³ Exhibit 304.01, IPCAA evidence, page 2.

⁶³⁴ Transcript, Volume 3, page 487, lines 20-22 and Volume 11, page 1987, line 17 to page 1988, line 11.

⁶³⁵ Transcript, Volume 3, page 488, lines 24-25, Volume 9, page 1678, lines 17-25.

⁶³⁶ Exhibit 461.02, AUC-NERA-17(a) and (b).

both components of the approved I factors can be considered input-based price indexes, no adjustment to TFP is required.

511. Additionally, Dr. Carpenter on behalf of the ATCO companies indicated that NERA's TFP analysis based on U.S. data needed to be adjusted for a productivity gap between the U.S. and Canadian economies.⁶³⁷ Dr. Schoech on behalf of AltaGas also noted that this productivity gap warrants consideration.⁶³⁸ As well, Dr. Carpenter and Dr. Cicchetti urged the Commission to consider the possible adjustment for the productivity performance of the Alberta economy when setting the X factor for the companies.⁶³⁹ The Commission has reviewed the issue of productivity gap in Section 6.4.2 of this decision and determined that no adjustment to NERA's TFP is necessary to account for the differences in the economy-wide productivity growth between the U.S. and Canada, or Canada and Alberta.

512. The Commission has considered IPCAA's suggestion that a stretch factor be used to adjust for 2012 rates for historical over-earning. Give the approach the Commission has taken to the requested adjustments to going-in rates requested by the companies (see Section 3.4), the Commission will not make an adjustment to the stretch factor for that purpose. In Section 3.4, the Commission rejected adjustments to going-in rates to reflect selected actual results on 2012 because those adjustments could not be made without concurrently reviewing all actual results for 2012. The Commission will not assume what the results of such a review might be and seek to capture assumed 2012 productivity gains through an increased stretch factor.

513. Parties also discussed the effect on X of excluding all or part of capital from the I-X mechanism, as set out in Section 6.4.3. In that regard, because the Commission did not accept EPCOR's proposal to exclude capital from its PBR plan, no consideration of the partial productivity factors, of the type proposed by Dr. Cicchetti, is required in determining the X factor for the companies. With respect to the exclusion of only some capital, the Commission determined that no adjustments to TFP will be made during the PBR term to account for the possible exclusion of some capital from the I-X mechanism.

514. Based on the above, the Commission finds that no adjustments to the industry TFP growth rate are required when establishing the X factors for the companies. Accordingly, the Commission finds that the X factor to be used in the PBR plans of the electric and gas distribution companies prior to consideration of a stretch factor is 0.96 per cent.

515. Furthermore, as set out in Section 6.5 of this decision, the Commission determined that a stretch factor of 0.2 per cent will apply to the companies' PBR plans for the duration of the PBR term. Accordingly, the Commission finds that the total X factor for the electric and gas distribution companies, inclusive of a stretch factor, will be 1.16 per cent.

⁶³⁷ Transcript, Volume 4, pages 595-596.

⁶³⁸ Transcript, Volume 8, page 1414, lines 9-25.

⁶³⁹ Exhibit 98.02, Carpenter evidence, pages 33-34; Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).

7 Adjustment to rates outside of the I-X mechanism

7.1 Introduction

516. The Commission recognizes the need to make provision for recovery of a limited number of costs outside of the I-X mechanism. It is common for PBR plans to make special provision to reflect the cost impact of significant unforeseen events that are outside the ability of the regulated entity to control. Approved costs of this nature are recovered through a Z factor rate adjustment. In addition, the companies have proposed a capital factor for the recovery of certain specific capital project costs as well as Y factor rate adjustments to permit the flow through to customers of third party charges that are beyond the control of the companies, Commission directed costs, deferral accounts and certain other costs. This section will review each of the proposals to deal with costs outside of the I-X mechanism.

7.2 Z factors

517. A Z factor is ordinarily included in a PBR plan to provide for exogenous events. The Z factor allows for an adjustment to a company's rates to account for a significant financial impact (either positive or negative) of an event outside of the control of the company and for which the company has no other reasonable opportunity to recover the costs within the PBR formula.

518. The Commission considered the criteria for when the impact of an exogenous event would qualify for a Z factor adjustment to rates in Decision 2009-035 and accepted the following proposal put forward by Dr. Cronin:⁶⁴⁰

With respect to exogenous events, the Commission considered the evaluation criteria proposed by Dr. Cronin, and has determined that the following criteria for an exogenous adjustment should be adopted.

- 1) The impact must be attributable to some event outside management's control;
- 2) The impact of the event must be material. It must have a significant influence on the operation of the utility otherwise the impact should be expensed or recognized as income, in the normal course of business;
- 3) The impact of the event should not have a significant influence on the inflation factor in the FBR formulas; and
- 4) All costs claimed as an exogenous adjustment must be prudently incurred.

519. Applying these criteria, if an exogenous event has an economy-wide impact, the cost of that impact will be reflected in and recovered through the I factor. Providing the company with additional revenues through a Z factor adjustment in circumstances where the event has economy-wide impacts would result in a double-counting of the impact of the exogenous event. The criteria adopted by the Commission in Decision 2009-035 also speak to the recovery of costs after they have been incurred and subsequently found by the Commission to have been prudently incurred.

520. All of the companies' proposed plans include Z factors and generally agreed with the continued use of the criteria established in Decision 2009-035.⁶⁴¹

⁶⁴⁰ Decision 2009-035, Section 9.3, paragraph 247, page 54.

521. NERA stated that generally PBR plans have Z factors to permit “[u]tilities to recover the costs of unforeseeable events with material impacts.”⁶⁴² However, NERA also suggested that Z factors should be limited to exogenous factors that impact the entire industry “like a tax change, or a change in investment tax credit, or something else that would lift or lower the price that the industry would have to compete against if we were talking about a competitive business.”⁶⁴³ A Z factor should not be used to address the impact of an exogenous event which affected the company alone.⁶⁴⁴

522. All interveners accepted that Z factors are a necessary component of a PBR plan.⁶⁴⁵ The primary concern of interveners was to limit the use of Z factors by having clearly defined criteria and appropriate materiality thresholds. The UCA suggested the continued use of the criteria from Decision 2009-035 because those criteria were working well in the ENMAX plan, and there is no evidence to the contrary.⁶⁴⁶ Calgary proposed an alternative set of criteria that were substantially similar to the four criteria adopted in Decision 2009-035, and added a criterion requiring the company to promptly report the event when first discovered.⁶⁴⁷

Commission findings

523. The Commission considers it necessary to include a Z factor in the PBR plan to account for the impact of material exogenous events for which the company has no other reasonable cost recovery or refund mechanism within the PBR plan. The Commission continues to support the criteria established in Decision 2009-035 to determine if the impacts of an exogenous event qualify for Z factor treatment, with one clarification. The Commission considers that for the negative impact of an exogenous event to qualify for cost recovery, the extent of the impact must, by necessary implication, be unforeseen prior to the occurrence of the event. This criterion is necessary to distinguish the cost impacts of exogenous events that are not foreseeable from the cost impacts of other events that are beyond the company’s control but are foreseeable and therefore may qualify for Y factor treatment as discussed in Section 7.4 below. In Decision 2009-035 the Commission also made a distinction between exogenous adjustments and flow-through items by stating:⁶⁴⁸

With respect to flow-through rate adjustments, the Commission considers that flow-through rate adjustments arise from cost elements that are not unforeseen one time events. Flow-through items arise in the normal course of business, but are such that the company has no control over them.

⁶⁴¹ Exhibit 628.01, AltaGas argument, Section 9.1, page 47; Exhibit 630.02, EPCOR argument, Section 9.1, paragraph 159, page 59; Exhibit 631.02, ATCO Electric argument, Section 9.2, paragraph 205, page 54; Exhibit 632.01, ATCO Gas argument, Section 9.2, paragraph 214, page 70; Exhibit 100.02, Fortis application, Section 7, paragraph 118, page 34.

⁶⁴² Exhibit 391.02, NERA second report, Section IV-C-3, paragraph 71, page 35.

⁶⁴³ Transcript, Dr. Makhholm, Volume 1, page 179, lines 5-9.

⁶⁴⁴ Transcript, Dr. Makhholm, Volume 1, pages 179-180.

⁶⁴⁵ Exhibit 634.02, UCA argument, Section 9.1, paragraph 209, page 38; Exhibit 636.02, CCA argument, Section 9.1, paragraph 145, page 59; Exhibit 942.01, IPCAA reply argument, Section 9.0, paragraph 12, page 2; Exhibit 629.01, Calgary argument, Section 9.1, page 42.

⁶⁴⁶ Exhibit 634.02, UCA argument, Section 9.2, paragraph 214, page 38.

⁶⁴⁷ Exhibit 629.01, Calgary argument, Section 9.2, page 43.

⁶⁴⁸ Decision 2009-035, Section 9.3, paragraph 251, page 55.

524. Accordingly, the Commission considers that the following criteria will apply when evaluating whether the impact of an exogenous event qualifies for Z factor treatment:

- (1) The impact must be attributable to some event outside management's control.
- (2) The impact of the event must be material. It must have a significant influence on the operation of the company otherwise the impact should be expensed or recognized as income, in the normal course of business.
- (3) The impact of the event should not have a significant influence on the inflation factor in the PBR formulas.
- (4) All costs claimed as an exogenous adjustment must be prudently incurred.
- (5) The impact of the event was unforeseen.

525. The Commission considers that all of the above criteria must be met in order for an item to qualify for a Z factor rate adjustment.

526. Inclusion of a Z factor based on clearly defined criteria is consistent with the Commission's PBR principles. The Commission observes that when an exogenous event occurs within a competitive industry that is not generally felt within the economy as a whole, the companies within the industry will generally adjust their prices in response to the event. A Z factor will permit the regulated distribution companies in Alberta to do the same. The Commission notes that Dr. Makholm agreed with this characterization.⁶⁴⁹

527. With respect to the opinion of Dr. Makholm that a Z factor should not be available to deal with the impacts of a company specific exogenous factor because it would not parallel competitive markets, the Commission notes that no such restriction was imposed in Decision 2009-035. Further, the Commission considers that allowing a company specific exogenous factor to potentially qualify for Z factor treatment is in keeping with the fourth Commission PBR principle which states that the design of PBR plans should recognize the unique circumstances of each regulated company. Also, allowing recovery of the costs of a company specific exogenous event is consistent with providing the company with a reasonable opportunity to recover its prudently incurred costs. Accordingly, the impact of company specific exogenous events will not be excluded from consideration for Z factor treatment.

528. The Commission considers that Z factors should be symmetrical in that they should apply to exogenous events with both additional costs that the company needs to recover and also reductions to costs that need to be refunded to customers. The Commission agrees with the CCA and considers it necessary to allow the Commission and interveners to apply for Z factor adjustments to rates where circumstances warrant.

7.2.1 Z factor materiality

529. Materiality may be considered on an event-by-event basis or cumulatively. Under the ENMAX FBR plan, materiality is evaluated on an event-by-event basis.⁶⁵⁰ Most of the companies in this proceeding proposed that materiality be evaluated on a cumulative basis. That is, if the sum of the effects of a number of exogenous events in a year would have a material impact on the company, they should be considered as though they were one event for Z factor purposes.

⁶⁴⁹ Transcript, Dr. Makholm, Volume 1, page 179, lines 5-9.

⁶⁵⁰ Decision 2009-035, Section 9.3, paragraph 231, page 51.

530. The following table sets out the materiality thresholds of the Z factor as approved for ENMAX in Decision 2009-035 and as proposed by each of the companies in this proceeding:

Table 7-1 Summary of companies Z factor materiality proposals

	ENMAX ⁶⁵¹	AltaGas ⁶⁵²	ATCO Electric ⁶⁵³	ATCO Gas ⁶⁵⁴	EPCOR ⁶⁵⁵	Fortis ⁶⁵⁶
Threshold	\$1.0 million	Variable (approx. \$0.2 million) ⁶⁵⁷	\$0.5 million	\$0.5 million	\$1.0 million distribution \$0.5 million transmission	\$0.5 million
Basis for determining the threshold	Size of revenue requirements	Annual impact on ROE \geq +/- 25 basis points	Rule 005 variance threshold criteria	Rule 005 variance threshold criteria	Rule 005 variance threshold criteria	Rule 005 variance threshold criteria ⁶⁵⁸
Cumulative	No	Yes	Yes	Yes	Yes	No

531. Concerns were raised by interveners over having materiality thresholds set too low, particularly when materiality is measured on a cumulative basis, because it allows companies to qualify for Z factor adjustments on too frequent a basis. It was suggested by Calgary's witness, Mr. Matwchuk that AUC Rule 005⁶⁵⁹ is not the appropriate source for finding the criteria to determine the materiality thresholds for Z factor adjustments, and if comparisons to PBR plans in other jurisdictions are made, a higher threshold would be used.⁶⁶⁰ The UCA suggested that the materiality thresholds should be established by taking 0.25 per cent of net assets, which would result in significantly higher threshold levels.⁶⁶¹

532. The CCA stated that it is appropriate to address the materiality of Z factors on an individual event basis in order to achieve consistency with the process established in Decision 2009-035.⁶⁶² Dr. Lowry submitted that having low materiality thresholds that could result in frequent Z factor applications is contrary to the spirit of PBR. Dr. Lowry stated the following at the oral hearing:

I can tell you too that, you know, in some jurisdictions, including the Ontario Energy Board, they're not very encouraging to the utilities to come in even for Z factor proposals as violating the spirit of the PBR.⁶⁶³

Commission findings

533. Setting a Z factor threshold too low invites parties to submit applications on too frequent a basis, and undermines the regulatory efficiency that PBR seeks to achieve. Setting a Z factor

⁶⁵¹ Decision 2009-035, Section 9.3, paragraph 248, page 54.

⁶⁵² Exhibit 110.01, AltaGas application, Section 7.2, paragraph 84, page 26.

⁶⁵³ Exhibit 98.02, ATCO Electric application, Section 7, paragraph 206, page 7-1.

⁶⁵⁴ Exhibit 99.01, ATCO Gas application, Section 2.6, paragraph 112, page 40.

⁶⁵⁵ Exhibit 103.02, EPCOR application, Section 2.3.4.1, paragraphs 134-140.

⁶⁵⁶ Exhibit 219.02, AUC-ALLUTILITIES-FAI-19.

⁶⁵⁷ Transcript, Mr. Mantei, Volume 8, page 1487.

⁶⁵⁸ Transcript, Mr. Lorimer, Volume 12, page 2238.

⁶⁵⁹ Rule 005: *Annual Reporting Requirements of Financial and Operational Results* (Rule 005).

⁶⁶⁰ Transcript, Mr. Matwchuk, Volume 15, page 2953.

⁶⁶¹ Exhibit 634.02, UCA argument, Section 9.2, paragraph 217, page 39.

⁶⁶² Exhibit 636.01, CCA argument, Section 9.3.1, paragraph 152, page 61.

⁶⁶³ Transcript, Dr. Lowry, Volume 14, page 2673.

threshold too high may limit a company's reasonable opportunity to recover prudently incurred costs, or conversely may prevent customers from realizing the benefit of a reduction in costs.

534. Exogenous events may occur during the PBR term but by definition they are exceptional occurrences which may either add costs to, or remove costs from, the provision of utility service. Additionally, not all events beyond the control of the company will qualify under other Z factor criteria, thereby further reducing the number of already rare events that could result in a rate adjustment outside of the I-X mechanism. Given the exceptional nature of a qualifying exogenous event and the equally exceptional measure of authorizing a recovery outside of the I-X mechanism, the Commission considers that the PBR principles require a relatively high threshold and that this threshold should apply to each event unless otherwise permitted in exceptional circumstances.

535. The Commission considers that the approach to establishing a materiality threshold based on the impact to ROE as proposed by AltaGas is reasonable. However, the Commission finds that the materiality threshold should be higher. In order to establish the threshold the Commission has calculated the impact on ROE that the dollar threshold established for ENMAX represented in 2006 (going-in rates). Accordingly, the Commission establishes the threshold as the dollar value of a 40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established (2012). This dollar amount threshold is to be escalated by I-X annually. The companies are directed to calculate and file the 2012 threshold amount along with supporting calculations in the compliance filing to this proceeding.

7.2.2 Process for considering a Z factor application

536. Having separate Z factor applications from the PBR annual filings may result in a need for more applications, and therefore may increase the administrative burden. However, if separate Z factor applications can be completed prior to the PBR annual filings, the annual filing process will not be complicated with potentially contentious Z factor items.

537. The companies generally agreed that addressing Z factors as part of the annual PBR rate adjustment filing process, rather than through a separate regulatory process, would be in the best interests of regulatory efficiency.⁶⁶⁴ Fortis raised concerns that a Z factor application may require a protracted review, and as such, including Z factors as part of the annual PBR rate adjustment filing process may not be optimal.⁶⁶⁵

538. The UCA stated that "[t]o maximize regulatory efficiency, Z factor applications should be made at the same time as deferral and other PBR filings."⁶⁶⁶ Calgary addressed the issue of how to process Z factor applications when it included a new criterion for Z factors that "the utility will be required to report promptly at the first discovery of an event and then apply for disposition of the accumulated savings or costs at the time of annual reporting."⁶⁶⁷ In addition,

⁶⁶⁴ Exhibit 632.01, ATCO Gas argument, Section 9.3, paragraph 219, page 71; Exhibit 631.01, ATCO Electric argument, Section 9.3, paragraph 210, page 55; Exhibit 630.02, EPCOR argument, Section 9.3, paragraph 168, page 63; Exhibit 628.01, AltaGas argument, Section 9.3, page 48.

⁶⁶⁵ Exhibit 633.01, Fortis argument, Section 9.3, paragraph 180, page 83.

⁶⁶⁶ Exhibit 634.02, UCA argument, Section 9.3, paragraph 220, page 40.

⁶⁶⁷ Exhibit 629.01, Calgary argument, Section 9.2, page 43.

the CCA stated that “the utilities and stakeholders should both be eligible to file Z factor proposals.”⁶⁶⁸

539. The Commission outlined the process for Z factor applications in Decision 2009-035.

In order to ensure fairness to all stakeholders, EPC or other parties are directed to notify the Commission of all proposed exogenous adjustments as soon as possible after the event that gives rise to them is identified. The Commission also directs that the impact of any proposed exogenous adjustment be initially captured in a separate account pending a ruling from the Commission. The impact of any proposed adjustment is to be measured from the time the event occurred. The disposition of the account would follow the Commission's ruling on the proposed adjustment.⁶⁶⁹

Commission findings

540. The Commission finds that the process established in Decision 2009-035 is satisfactory. Accordingly, companies are directed to notify the Commission of all proposed exogenous adjustments as soon as possible after the event that gives rise to them is identified. Further, Z factor applications should be submitted as soon as possible after the costs associated with the exogenous event have been incurred or the savings have been realized.

541. A party may file a Z factor application at any time. However, in order to minimize the number of rate adjustments during the year, unless otherwise permitted, the Commission directs that Z factor rate adjustment applications be filed as part of the annual PBR rate adjustment filing. Please see Section 15.1.2 for a more detailed explanation of how the inclusion of Z factor amounts will be included in the annual PBR rate adjustment filing process.

542. In Decision 2009-035 the Commission recognized that some Z factors may result from changes in circumstances that carry forward into future periods.

The Commission recognizes that, in some cases, a “Z” adjustment for an extraordinary event will be transitory and will not be subject to the I minus X adjustment. In other cases, the extraordinary event may require a “Z” adjustment that is subject to the I minus X adjustment going forward. The Commission will make this determination on a case by case basis.⁶⁷⁰

543. The Commission recognizes that some approved Z factor applications may generate costs or savings that can be fully recovered or refunded over a single year or portion thereof while other events will generate costs or savings requiring treatment over a longer term. The nature of the required Z factor rate adjustment will be considered by the Commission on a case-by-case basis.

7.3 Capital factors

7.3.1 Need for a capital factor

544. All of the companies argued that they are experiencing some cost pressures on capital expenditures that will require special treatment under PBR. There was some agreement among NERA and the experts representing the companies and interveners that certain types of unusual

⁶⁶⁸ Exhibit 636.01, CCA argument, Section 9.1, paragraph 145, page 59.

⁶⁶⁹ Decision 2009-035, Section 9.3, paragraph 250, page 55.

⁶⁷⁰ Decision 2009-035, Section 9.3, paragraph 249, page 54.

capital expenditures may require capital factors as part of a PBR plan to provide for sources of revenue in addition to the revenue generated by the I-X mechanism.

545. The companies offered several reasons why capital factors are required, including the costs being outside of the control of the company, the costs to build capital being significantly higher than historic norms, the need to build specific large projects, and high growth rates of the system. Another reason that was cited by several of the companies was a surge in replacement activities requiring an unusually high level of capital expenditures during the PBR term.⁶⁷¹ Because of the long term nature of utility assets, the cycles in which the companies purchase capital assets are much longer than the length of the PBR term. The evidence and testimony indicated that installation of large amounts of facilities during high growth periods in the past creates an echo effect when those facilities come to the end of their useful lives and must be replaced in current dollars with large replacement projects. Consequently, the companies submitted that if a utility is at a stage where it must invest more than the historical rate of capital asset growth or capital asset replacement assumed in the X factor, a special capital factor may be required.⁶⁷²

546. Experts representing the interveners acknowledged that under some circumstances special treatment of capital may be required, although most of the interveners took issue with the extent to which special capital treatment had been proposed.⁶⁷³ There was concern expressed that double-counting may occur in circumstances where the companies should be able to recover the capital expenditures through the I-X mechanism, but are also provided with relief through a capital factor.⁶⁷⁴ The double-counting may occur because the I-X mechanism already provides funding for capital projects and the addition of a capital factor outside of the formula would provide that funding again. The CCA also argued that companies have some flexibility in the timing of replacement expenditures without affecting safety or reliability, so utilities may have the ability to defer some replacement capital expenditures instead of seeking a capital factor adjustment.⁶⁷⁵

547. One of the concerns with approving capital factors is that the efficiency incentives created by a PBR plan may be reduced because the incentives to find efficiencies by substitution among various types of inputs (expenses and capital) may be lessened. In an exchange with Commission counsel, Dr. Makholm addressed how significant of a concern this is.

Q. If the Commission was to accept company proposals that excluded significant capital components, does that mean that the X factor, if it was the same as your TFP estimate, would be wrong?

A. DR. MAKHOLM: It wouldn't mean that the TFP growth number that we've calculated, that's then used for the X factor, would be wrong. It would call into question

⁶⁷¹ Exhibit 636.01, CCA argument, Section 8.1, paragraph 117, page 46; Exhibit 630.02, EPCOR argument, Section 8.2, paragraph 97, page 36; Exhibit 631.01, ATCO Electric argument, Section 8.3, paragraph 146, page 40; Exhibit 628.01, AltaGas argument, Section 5.4, page 32.

⁶⁷² Exhibit 98.02, ATCO Electric application, Section 5, paragraph 46, page 5-1; Exhibit 99.01, ATCO Gas application, Section 2.4, paragraph 45, page 20; Exhibit 628.01, AltaGas argument, Section 8.2, pages 38 to 39; Exhibit 630.02, EPCOR argument, Section 8.2, paragraph 96, page 35

⁶⁷³ Exhibit 629.01, Calgary argument, Section 8.3, page 40, Exhibit 636.01, CCA argument, Section 8.2, paragraph 122, page 49, Exhibit 634.02, UCA argument, Section 8.3, paragraph 182, page 33.

⁶⁷⁴ Transcript, Dr. Makholm, Volume 1, page 162.

⁶⁷⁵ Exhibit 636.01, CCA argument, Section 8.1, paragraph 118, page 46.

the basis for the PBR regime itself because, as you just recounted as our answer, the use of a total factor productivity study embraces the idea that different factors of production are substitutable and the substitution of different factors of production over time constitute one of the areas of TFP growth.

The theory upon which this kind of PBR formula is based doesn't apply to a kind of regime that would only target, for instance, O&M costs. So in that respect, the formula is wrong. The application of PBR in this context, drawing upon a competitive paradigm, is wrong; not the calculation of the TFP growth itself.⁶⁷⁶

548. The UCA agreed with NERA's opinion with respect to the impact on PBR incentives that results from the use of capital factors.

The creation of a flow-through shifts the risk to customers and is in violation of AUC Principle 1, that a PBR plan should incent behavior similar to a competitive market. For the examples listed, the factors affecting the forecast are not beyond the utility's control, in fact the decision to proceed is entirely a utility management decision. Management must weigh the costs and benefits of all options, including the status quo, and decide on a course of action.²¹³ If there is flow-through treatment, the incentive to examine alternatives will be eliminated.⁶⁷⁷

²¹³ Exhibit 0300.02, Evidence of Russ Bell at A26.

Commission findings

549. The Commission recognizes that the TFP study used to determine the X factor adopted by the Commission in this proceeding measures the rate of productivity change of the distribution industry over time necessarily reflecting input costs including the types of capital expenditures and all of the types of year to year fluctuations in the need for capital referred to by the companies. Nevertheless, the Commission acknowledges that there are circumstances in which a PBR plan would need to provide for revenues in addition to the revenues generated by the I-X mechanism in order to provide for some necessary capital expenditures. The way in which this is accomplished is through a capital factor (K factor) in the PBR plan. The capital proposals of the companies were all quite different. Some companies asked for considerably more capital to be treated outside of the I-X mechanism than others.

550. The Commission shares the concerns raised by NERA and interveners that a capital factor must be carefully designed in order to maintain the efficiency incentives of PBR, and also to avoid double-counting. At issue are the types and levels of capital expenditures that can reasonably be expected to be recovered through the I-X mechanism. The Commission finds that a mechanism that permits the recovery of specific types of capital outside of the I-X mechanism should be included in a PBR plan. In the sections of this decision that follow, the Commission addresses these issues by adopting a capital factor that, to the greatest extent possible, seeks to maintain the incentive properties of PBR and avoids double-counting.

7.3.2 Methodologies for addressing capital

551. A number of alternatives for a capital factor were explored during the proceeding. These included determining the average rate of capital growth in the TFP study and providing for

⁶⁷⁶ Transcript, Volume 1, page 143.

⁶⁷⁷ Exhibit 634.02, UCA argument, Section 8.3, paragraph 196, pages 35-36.

capital in addition to that amount as required, modifying the X factor in consideration of a need for higher capital spending, excluding all capital from going-in rates and the I-X mechanism, and providing compensation for capital needs outside of the normal course of the company's operations by way of a capital tracker.

7.3.2.1 The average rate of capital growth in the TFP study

552. Dr. Carpenter approached the issue of identifying the amount of capital expenditures that the I-X mechanism can support by proposing that the capital factor be calibrated by comparing the capital requirements of the company to a benchmark level established by the median level of growth in plant observed in the utilities in the NERA TFP study.⁶⁷⁸ Dr. Carpenter examined capital investment information about the companies in NERA's TFP study to estimate that the median level of annual growth in plant was 4.5 per cent over the relevant time period of the NERA TFP study that he used to determine the X factor he proposed.⁶⁷⁹

553. There were several issues identified with respect to the approach suggested by Dr. Carpenter.

554. Dr. Makholm commented on Dr. Carpenter's analysis as follows:

Simple trends from past data series not having to do with our type of TFP growth study is what he is proposing as a way of creating -- I can't remember whether it was his Y or K factor, I'm not sure, one of those two. I think in our evidence and in responses to data request responses -- data requests, we drew a line between those types of things and the specific ring fenced engineering-based justified capital expenditures that consumed our 15 or 20 minutes before the break. For our purposes, at least for my purposes, using that kind of trend to project capital input over the course of a PBR plan is not very reliable. I wouldn't do it.⁶⁸⁰

555. NERA also stated:

Under this logic additional adjustments would need to be made to account for the fact that the regulated firm's labor input and material input may be growing at different trend rates than the 72 utilities in the NERA sample. If, however, adjustments are made to each input to account for the differences between the trend rates of the regulated firm and the 72 utilities the result would be that regulated prices would be tied to actual productivity changes of the regulated firm rather than the industry's productivity. This means that the PBR incentive properties would be similar to the incentive properties under cost of service regulation. An important linchpin of performance based regulation and price cap regulation is that the X factor represents the productivity of the industry and not the productivity of the regulated company.⁶⁸¹

556. NERA also calculated a different capital growth rate of 1.32 per cent for 1972 to 2009 based on the capital index used in its TFP study.⁶⁸² NERA stated "[w]e deal with capital quantity inputs measured in a very idiosyncratic way with one hoss shay techniques, and I think what you'll find in response to AUC NERA 15 that we're trying to dissuade anybody from taking the

⁶⁷⁸ Transcript, Dr. Carpenter, Volume 4, page 643.

⁶⁷⁹ Transcript, Dr. Carpenter, Volume 4, page 643.

⁶⁸⁰ Transcript, Dr. Makholm, Volume 1, page 155.

⁶⁸¹ Exhibit 195.01, AUC-NERA-8(a).

⁶⁸² Exhibit 195.01, AUC-NERA-8(b).

trends in capital quantity input we use to arrive at TFP growth analysis from being used to project new investments in whatever over the course of PBR planning.”⁶⁸³ Dr. Ros went on to explain:

Can I just add productivity growth is the change in outputs and change in the three different inputs. So what Dr. Carpenter has observed is investment, net investment, which is not an input in the TFP study. And your question doesn't follow in the sense you're not mentioning anything about what's going on with output or other input at the same time. But in addition to that, it seems to be implying that in order for a TFP [PBR] plan to be effective you have to track exactly the type of changes that the utilities are likely to experience over the next five years, which does away with the incentive properties of performance-based ratemaking.⁶⁸⁴

557. Dr. Lowry also explained the impact that customer growth has on capital, and that customer growth for the Alberta utilities is more rapid than it is for the typical utility.⁶⁸⁵ In theory, a company could be experiencing significantly higher capital growth than 4.5 per cent, but if the capital expenditures are required to add new customers and additional load to the system, there would be offsetting impacts to outputs in the calculation of TFP, and productivity growth would not necessarily be significantly impacted.⁶⁸⁶

558. ATCO Electric employed Dr. Carpenter’s analysis to develop the ATCO K factor proposal. That proposal was based on a three plank approach. The first plank was intended to include the level of capital expenditures the I-X mechanism can support, which ATCO Electric determined to be 4.9 per cent annual growth.⁶⁸⁷ The second plank was comprised of the remaining amount of capital growth in its current four year capital forecast, which was to be funded by the ATCO K factor. ATCO K factor programs were selected on the basis that they were stable and predictable and could be forecast for a four year period. The third plank was comprised of capital projects that do not occur on a routine basis and, therefore, could not be accurately forecasted. The end result of the three plank approach was that ATCO Electric prepared an overall capital forecast, and proposed a method by which that forecast could be recovered in the PBR plan. Mr. Freedman explained the ATCO Electric approach as follows:

When we did our forecast of the rate base growth on its own, that showed us that we were closer to 10 percent. So when we were designing the planks, we were just looking at that. We tested the results and the outcomes of all of that afterwards, after we designed the planks to see it was in. What the results were going to give us with these planks was still in the area of reasonableness, and we showed those results in section 16 of the application.⁶⁸⁸

559. Mr. Freedman further explained in a discussion with Commission counsel how the determination of the 4.9 per cent that could be funded from application of the I-X mechanism was determined:

⁶⁸³ Transcript, Dr. Makhholm, Volume 1, page 154.

⁶⁸⁴ Transcript, Dr. Ros, Volume 1, page 157.

⁶⁸⁵ Transcript, Dr. Lowry, Volume 13, page 2605.

⁶⁸⁶ Exhibit 307.01, CCA evidence of PEG, Section 4.1, page 61.

⁶⁸⁷ Dr. Carpenter had calculated a 4.5 per cent median annual investment growth rate for the companies in the NERA TFP study. ATCO Electric chose 4.9 per cent for its first plank because of the types of capital projects it could identify.

⁶⁸⁸ Transcript, Mr. Freedman, Volume 7, page 1263.

So when we looked at the capital maintenance programs and the programs that fell within that definition, we looked at the dollar impact of that. We looked at the results that were arising from that through -- and we would see that through -- in Section 16 of our application. And given that the 4.5 percent was part of a range and that was considered. We could have gone more aggressive but we didn't want to -- we didn't want to gray it up with putting some programs in that may be not quite as stable and predictable and readily factorable. So it could have been more aggressive to get it down to the 4 1/2 percent, but looking at the results that were being generated with the overall plan, ATCO Electric believed that it could put forward the programs as we've selected.

Q. The 4.9 fell out of that analysis; is that right?

A. MR. FREEDMAN: Correct.⁶⁸⁹

560. Under its approach ATCO Electric forecasted a total amount of revenue requirement first, and then developed rates (in this case using a PBR formula) to ensure that it is collecting the amount of revenue requirement needed to fund the forecasted amounts over the PBR term.

561. With particular reference to the ATCO Electric K factor, the UCA pointed out that the requirement for business cases for capital spending would have been subject to extensive review under cost of service regulation, and that the same level of testing would be required under PBR if the ATCO Electric K factor approach were used.⁶⁹⁰

Commission findings

562. The Commission finds that the evidence of capital investment growth of the companies included in NERA's total factor productivity study can not be used to determine the average amount of capital expenditures that could be recovered through the I-X mechanism because the Commission agrees with Dr. Makholm's, Dr. Ros' and Dr. Lowry's criticisms that such an approach does not account for the variability of capital investments and other inputs in relation to outputs from year to year. In addition, the Commission agrees with Dr. Makholm's observation that a simple trend analysis of average capital investment is an unreliable predictor of the amount of capital that can be funded through the I-X mechanism. Accordingly, the Commission rejects Dr. Carpenter's approach to determining the amount of capital growth that should be recovered through the I-X mechanism.

563. Because the ATCO Electric approach forecasts the total amount of capital revenue requirement over the PBR term to ensure that it is collecting the amount of revenue needed to fund its forecast capital expenditures, the Commission considers that the adoption of the ATCO Electric proposal would amount to retaining cost of service regulation for all capital but with a four year forecast. The Commission would not only be required to test the projects that comprise the ATCO Electric K factor, but it would also need to test the projects covered by the 4.9 per cent. If the projects that make up the 4.9 per cent were not tested, ATCO Electric could select which projects and types of capital expenditures should be included in the 4.9 per cent thereby avoiding scrutiny of possible double-counting of costs already in the K factor. If the Commission were to direct ATCO Electric to provide details for all capital projects including those captured by the 4.9 per cent, it would represent a return to cost of service regulation for all capital for a four year forecast term, reducing the efficiency incentives that PBR creates and failing to reduce the regulatory burden.

⁶⁸⁹ Transcript, Mr. Freedman, Volume 4, pages 685-686.

⁶⁹⁰ Exhibit 634.02, UCA argument, Section 8.2, paragraph 180, page 32.

7.3.2.2 Modifying the X factor to accommodate the need for higher capital spending

564. There was some discussion that the X factor could be modified to provide sufficient revenues to cover a higher level of capital investment growth than provided for in the I-X mechanism.

565. In the view of Dr. Carpenter, when developing the X factor from a TFP study it is necessary to take into account the forecasted investment needs of the specific company for which the PBR plan is being designed.⁶⁹¹ As such, Dr. Carpenter appeared to suggest that a smaller X factor was required for the companies that expect a higher than usual level of capital expenditures during the PBR term. At the same time, Dr. Carpenter explained that he did not recommend this adjustment, since the ATCO companies proposed to deal with higher than usual capital expenditures by means of their K factor:

DR. CARPENTER: ...And I think we also would have to take into account whether or not unusually high [capital expenditures] growth requirements over the plan term would require an X adjustment. Now, in ATCO's case X is not being adjusted for [capital expenditures]. Instead in ATCO Electric's case a K factor has been employed to deal with that issue.

Q. And in the absence of the K factor you would be recommending an adjustment to the X in addition to the productivity gap?

A. DR. CARPENTER: One may have to, yes.⁶⁹²

566. Fortis and AltaGas stated that if the Commission were to decide not to include capital flow-through factors in the PBR formula, it would be necessary to adjust the X factor to allow the financing of these capital projects under the I-X mechanism.⁶⁹³ The CCA stated that it would be open to experimentation with such an approach because it has been used in PBR plan designs in other jurisdictions.⁶⁹⁴

567. At the same time, AltaGas acknowledged that this approach would be a “British-style building blocks” approach to developing the X factor, and would unnecessarily complicate the derivation of the formula.⁶⁹⁵ Similar to the ATCO Companies, EPCOR, Fortis and AltaGas preferred to deal with unusual capital expenditures by way of flow-through factors, and not by adjusting the X factor.⁶⁹⁶

568. NERA explained that under this approach, the X factor 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.⁶⁹⁷ In Dr. Makholm's view, forecasts that extend as far into the future as the length of a PBR term become vague, and undermine the effectiveness of a PBR plan.⁶⁹⁸ Dr. Makholm concluded:

⁶⁹¹ Exhibit 476.01, Carpenter rebuttal evidence, page 10.

⁶⁹² Transcript, Volume 3, page 592, lines 4-13.

⁶⁹³ Exhibit 628, AltaGas argument, page 32 and Exhibit 633, Fortis argument, paragraph 138.

⁶⁹⁴ Exhibit 636.01, CCA argument, Section 8.4, paragraph 136, page 55

⁶⁹⁵ Exhibit 628, AltaGas argument, page 32 and Exhibit 247.01, AUC-ALLUTILITIES-AUI-7(a).

⁶⁹⁶ Exhibit 233.01, AUC-ALLUTILITIES-EDTI-7(b); Exhibit 628, AltaGas argument, page 32 and Exhibit 633, Fortis argument, paragraph 139.

⁶⁹⁷ Exhibit 391.02, NERA second report, pages 27-28.

⁶⁹⁸ Transcript, Volume 1, page 160 and Volume 3, page 502, lines 9-17.

I think as I've -- as we have tried to distinguish between adjustments to X -- that is, Y factors or K factors -- cognizant of what goes on in Britain, where X is a true-up measure for long-term forecasts, it's our conclusion that it is better to leave X to do what X is designed in North America to do, which is to reflect total factor productivity growth and let other elements of ratemaking reflect unusual or special-case or needed capital expenditures.⁶⁹⁹

Commission findings

569. The companies acknowledged that any attempt to adjust the X factor for the investment needs of a specific company requires a detailed forecast of a company's capital expenditures and the associated revenue requirement, billing determinants, and even inflation over the PBR term.⁷⁰⁰ As NERA and AltaGas pointed out, this approach essentially amounts to adopting the building blocks method employed by the regulators in the U.K.⁷⁰¹

570. In Section 6.2 above, the Commission rejected the use of a building blocks approach and restated its preference for an approach to setting the X factor based on the long term average rate of productivity growth in the industry. Accordingly, the Commission finds that the X factor should not include any adjustments to deal with company-specific forecast capital expenditures.

7.3.2.3 Exclude all capital from going-in rates and the I-X mechanism

571. Due to the complexities of establishing what capital spending should be included and excluded from the I-X mechanism, EPCOR recommended that, in its case, all capital should be excluded from going-in rates and consequently not be subject to the I-X mechanism. Such an approach essentially splits the revenue requirement of the company so that capital is dealt with in a traditional cost of service manner, and the remainder of the revenue requirement is subject to the I-X mechanism and other PBR formula variables. The K factor proposed by EPCOR encompasses all capital.

572. EPCOR was unique amongst the companies in its proposal to exclude all capital from the I-X mechanism. The other companies proposed a limited number of capital factors that were more targeted at specific types of projects. EPCOR argued that it is faced with unique circumstances in that it must replace a more significant portion of its system during the PBR term.⁷⁰² While EPCOR considered the options of including all capital within the I-X mechanism and using capital trackers for special circumstances, EPCOR concluded that the regulatory burden would be significantly reduced if it excluded all of its capital from the I-X mechanism because there are too many projects that have complex interrelationships requiring capital tracker treatment.⁷⁰³

573. NERA expressed the view that the negative impact on incentives that excluding a significant portion of capital has is significant enough to bring into question whether PBR should

⁶⁹⁹ Transcript, Volume 1, page 119, lines 9-17.

⁷⁰⁰ Exhibit 233.01, AUC-ALLUTILITIES-EDTI-7(a), Exhibit 201.01, AUC-ALLUTILITIES-AE-7(a), Exhibit 633, Fortis argument, paragraph 78.

⁷⁰¹ Exhibit 247.01 AUC-ALLUTILITIES-AUI-7(a).

⁷⁰² Exhibit 630.02, EPCOR argument, Section 8.2.1, paragraphs 105-107, pages 39-41.

⁷⁰³ Exhibit 630.02, EPCOR argument, Section 8.2.1, paragraph 102, page 38.

be allowed to proceed. Several interveners supported the opinion of NERA.⁷⁰⁴ Dr. Makholm addressed the issue saying:

It would call into question the basis for the PBR regime itself because, as you just recounted as our answer, the use of a total factor productivity study embraces the idea that different factors of production are substitutable and the substitution of different factors of production over time constitute one of the areas of TFP growth.⁷⁰⁵

Commission findings

574. The Commission has previously considered the EPCOR approach for the complete exclusion of capital from its PBR plan, and rejected this approach for the reasons set out in Section 2.3. The Commission is concerned that excluding all capital or a large portion of the company's capital expenditures from going-in rates and the I-X mechanism would significantly dampen the efficiency incentives of a PBR plan.

7.3.2.4 Capital trackers

575. In its second report and in response to the capital factor proposals made by the companies, NERA referred the Commission to the growing use by some U.S. regulators of capital trackers that allow a regulated firm to track and begin to recover the costs associated with certain capital projects more quickly and more efficiently than in a normal rate case.⁷⁰⁶ NERA indicated that capital trackers are "used in various situations where the typical regulatory rate case provides an inadequate mechanism to adjust rates in response to increased investment in infrastructure."⁷⁰⁷ NERA indicated that capital trackers could be used in conjunction with a PBR plan to deal with certain special capital requirements. NERA described the purpose and use of capital trackers as follows:

Capital trackers are used to recover the costs of a classified, pre-approved set of infrastructure investments. The tracker does not include all infrastructure investments, rather only infrastructure investments that meet the classifications set at the on-set of the tracker; all other infrastructure investments are recovered in the company's next rate case proceeding. A "qualified investment" is an investment that meets the pre-set conditions for inclusion in the asset tracker. Typically, the proposed accounts included in a capital tracker go beyond the scope of routine investments required to support existing infrastructure. Qualified investments are specific, non-routine investments recovered outside of the normal rate case proceeding.⁷⁰⁸

576. NERA favoured an approach that did not rely on calculating the dollar amount of capital that could or could not be accommodated by the I-X mechanism. Rather, it focused on the nature of the projects and whether those projects are consistent with the past practices of the company. NERA said that unusual projects may need special capital treatment, but "because everybody's rates are based on their own books and records in base rates, and if the company has been doing

⁷⁰⁴ Exhibit 629.01, Calgary argument, Section 8.6, page 41; Exhibit 636.01, CCA argument, Section 8.6, paragraph 138, page 56; Exhibit 634.02, UCA argument, Section 8.2, paragraph 175, page 31.

⁷⁰⁵ Transcript, Dr. Makholm, Volume 1, page 143.

⁷⁰⁶ Exhibit 391.02, NERA second report, Section 4, paragraphs 86-91, pages 41-43.

⁷⁰⁷ Exhibit 391.02, NERA second report, Section 4, paragraph 88, page 42.

⁷⁰⁸ Exhibit 391.02, NERA second report, Section 4, paragraph 90, page 43.

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."⁷⁰⁹

577. NERA described the capital tracker mechanism by stating that "the basic idea of a capital tracker is to recover the costs of qualified infrastructure investments incurred between rate cases through an asset tracker."⁷¹⁰ This means that once a capital project has been identified as a capital tracker the costs associated with the project are tracked and a cost of service revenue requirement calculation is performed for the project to determine the amount of revenue the company requires. That revenue requirement is collected by the company through rate adjustments outside of the I-X mechanism.

578. When asked why a capital tracker is any better than any other exclusion of capital from the I-X mechanism, and in particular a PBR plan which excludes capital entirely, Dr. Makhholm stated:

That's a fair question. Capital trackers are there because there's not an administrative and practical way in the commission's judgment to deal with certain kinds of aged infrastructure any other way than to have a rate base case. That issue of capital affects PBR jurisdictions as much as it affects any other jurisdiction.

The difference between that kind of targeted engineering-based approach to particular kinds of aged infrastructure or lumpy prospective capital and the proposals from one of the utilities to do an O&M only rate cap plan I think are large and manifest.

One takes a piece of prospective capital expense and subjects it to the microscope of justification and engineering so that the public is well served through the efficient replacement of infrastructure that the public needs. That is specific and targeted.

The other type, which is apply PBR only to O&M, is neither specific nor targeted, it's general. And for practical purposes, I think observers can distinguish between those two kinds of methods of regulation.⁷¹¹

579. NERA stated that one of the main benefits of the capital tracker approach is that, by limiting the trackers to a few very specific items it maintains the incentive properties of PBR for most of the plan, while still recognizing that some relief may be required for companies to handle lumpy investments.⁷¹²

580. The capital tracker approach was supported by several other parties.⁷¹³ In addition, most of the parties agreed that a capital tracker approach is reasonable for inclusion in a PBR plan. Even EPCOR, which discarded capital trackers as a viable option for its own plan, acknowledged that the incentive properties of capital trackers are superior to the exclusion of all capital from the I-X mechanism it proposed.⁷¹⁴

⁷⁰⁹ Transcript, Volume 1, page 162.

⁷¹⁰ Exhibit 391.02, NERA second report, Section 4, paragraph 89, page 42.

⁷¹¹ Transcript, Dr. Makhholm, Volume 1, pages 146-147.

⁷¹² Transcript, Dr. Makhholm, Volume 1, pages 146-147.

⁷¹³ Transcript, Dr. Weisman, Volume 10, pages 1906-1907; Transcript, Mr. Camfield, Volume 8, page 1457; Transcript, Ms. Frayer, Volume 12, page 2395; Transcript, Dr. Lowry, Volume 13, page 2627; Transcript, Mr. Bell, Volume 18, pages 3274-3275.

⁷¹⁴ Exhibit 646.02, EPCOR reply argument, Section 8.1, paragraph 106, page 33.

581. While agreeing with the underlying premise for a capital tracker, ATCO Electric expressed its concern about the inability to determine the amount of capital that can be funded outside of the I-X mechanism.⁷¹⁵ EPCOR raised a related concern when it argued that its analysis had shown that a capital tracker approach “proved unworkable due to the complex interrelationships between baseline capital and new capital and the lack of any credible basis upon which to separate the two in a well-defined, defensible manner.”⁷¹⁶ EPCOR concluded that the issues around splitting capital costs were substantial enough to warrant excluding all capital from the I-X mechanism.

582. ATCO Electric stated that the capital tracker approach is an alternative it could work with.

However, if ATCO Electric’s approach is not acceptable to the Commission then a well defined tracker mechanism that encompasses ATCO Electric’s programs currently included in ATCO Electric’s K factor would be an alternative that ATCO Electric could work with.⁷¹⁷

583. Some companies proposed to deal with some capital expenditures through capital Y factors on the basis that the level of expenditures was so significant that the I-X mechanism could not handle them. The ATCO Electric and ATCO Gas material-capital-unique-in-nature Y factors and the AltaGas AMR (automated meter reading) implementation Y factor are examples of this. There was some recognition by ATCO Gas,⁷¹⁸ ATCO Electric⁷¹⁹ and AltaGas,⁷²⁰ that their proposed Y factor capital costs may not meet the typical criteria for assessing capital trackers or Y factors but they argued that the significance of the costs is so substantial that the projects can be justified on the basis of materiality alone given that there is an assumption that the projects are in the public interest.

584. The UCA recommended that these types of capital Y factors not be allowed on the basis that “[t]he creation of a flow-through shifts the risk to customers and is in violation of AUC Principle 1, that a PBR plan should incent behavior similar to a competitive market.”⁷²¹ The CCA also expressed concern with the impact of these capital Y factors on the incentive properties of PBR, saying that “to the extent these costs are recovered as incurred, the de-linking of revenues from costs, being one of the foundations of any PBR plan, is weakened.”⁷²²

585. Several companies requested capital Y factors for capital expenditures that are outside of the control of the company. Examples of this are the Fortis externally driven capital Y factor,⁷²³ the ATCO Electric distribution contributions to transmission,⁷²⁴ and the ATCO Gas transmission driven costs.⁷²⁵ One of the arguments used to support the flow-through treatment of these particular capital costs was that utility companies have unique obligations to undertake such

⁷¹⁵ Exhibit 631.01, ATCO Electric argument, Section 8.2, paragraph 125, page 35.

⁷¹⁶ Exhibit 630.02, EPCOR argument, Section 8.2.1, paragraph 102, page 38.

⁷¹⁷ Exhibit 631.01, ATCO Electric argument, paragraph 163, page 49.

⁷¹⁸ Exhibit 632.01, ATCO Gas argument, Section 8.3, paragraph 190, page 61.

⁷¹⁹ Exhibit 211.01, NERA-AE-17.

⁷²⁰ Exhibit 247.01, AUC-ALLUTILITIES-AUI-10.

⁷²¹ Exhibit 634.02, UCA argument, Section 8.3, paragraphs 193 and 196, page 35.

⁷²² Exhibit 636.01, CCA argument, Section 10.2.1, paragraph 167, page 69.

⁷²³ Exhibit 100.02, Fortis application, Section 6.2, paragraphs 103-105, pages 29-30.

⁷²⁴ Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 104-112, pages 6-6 to 6-7.

⁷²⁵ Exhibit 99.01, ATCO Gas application, Section 2.5.2.2, paragraphs 93-102, pages 34-36.

projects that a competitive firm would not encounter. Fortis explained that “as a result of its obligation to serve, FortisAlberta does not have the discretion to decline or delay such expenditures, unlike competitive firms.”⁷²⁶

Commission findings

586. The Commission has determined that a mechanism to fund certain capital-related costs outside of the I-X mechanism through a capital factor is required. In the preceding sections the Commission has generally rejected the methodologies proposed by the companies for addressing this requirement. The Commission considers that the potential erosion of the incentive properties of PBR that arise from adopting the approaches to capital factors proposed by the companies are significant enough to warrant the use of the capital tracker approach to address special capital funding requirements. The Commission considers that the targeted criteria-based nature of a capital tracker limits the number of projects that are outside of the I-X mechanism, and as a result, the incentive properties of PBR are preserved to the greatest extent possible. Therefore, the Commission accepts that the use of capital trackers, as proposed by NERA and as recognized by several other parties as a viable option, is the best of the alternatives proposed for dealing with capital expenditures outside of the I-X mechanism. Accordingly, the Commission will include a capital tracker mechanism in the PBR plans.

587. A capital tracker mechanism in a PBR plan is warranted in circumstances where the company can demonstrate that a necessary capital replacement project or capital project required by an external party cannot reasonably be expected to be recovered through the I-X mechanism. The Commission concludes that a structured criteria-based approach provides the most objective method for assessing whether projects qualify as capital trackers.

588. Many of the proposals for capital factors in the form of K factors, the AltaGas MP factor, or Y factored capital expenditures are PBR plan variables that attempt to track the costs and corresponding revenue requirement of specific assets, and recover the revenue requirement outside of the I-X mechanism. Regardless of what a company originally called the capital factor variable, as long as the variable isolates the revenue requirement impact of the underlying qualifying assets (including depreciation, return on equity, cost of debt and income tax) to be incorporated into the PBR plan outside of the I-X mechanism, the factor is in the nature of a capital tracker and will be considered and tested as a capital tracker. The non-specific K factor proposed by EPCOR⁷²⁷ is an obvious exception because it does not involve tracking specific capital assets. For consistency, all capital trackers will be recovered through a K factor variable in the PBR formula for all companies.

589. Dr. Makholm discussed the types of considerations the Commission should take into account in establishing the criteria for a capital tracker:

Q Well, the incentive formula will produce a certain revenue stream and the incentives that result from the imposition of this regime will create savings through efficiencies through the company. So the effective revenue that a utility would have would be a mixture of the I minus X portion of the formula; it would be a function of growth in revenues, growth in customers, growth in revenues; a function of depreciation that has fallen off -- assets that are fully depreciated but yet the depreciation expense remains in rates. It would also be a function of all the efficiencies that can be achieved throughout

⁷²⁶ Exhibit 474.01, Fortis rebuttal evidence, Section 2.5, paragraph 76, page 14.

⁷²⁷ Exhibit 630.02, EPCOR argument, Section 8.1, paragraph 91, page 34.

the term. How does a regulator know when a ring fenced proposal for a tracker comes to them whether or not there's sufficient resources available through the operation of the PBR formula with all the incentives that are instilled through to it to cover the costs of that and how will they know when there isn't enough revenue to cover that?

A. DR. MAKHOLM: They'll know if the company can make good enough case that the derogation from a plan inherent in employing a tracker is genuine and worth the effort. And we have seen cases where that is the case, and one of them, a prime one, is cast iron pipe.

Q. We're all kind of dancing around the same question, but it's a very interesting discussion, so I'll try to advance it a bit further. So assume with me for a moment that a utility is able to put together the state of the art capital tracker application, ring fenced, engineering data to support it, and it has been doing that same type of activity for many years.

A. DR. MAKHOLM: Well, why then would they require a tracker if they've been doing that activity for many years? If they have been -- I don't mean to butt in, but if they have done, then that activity will be reflected in their base rates.

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?

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.⁷²⁸

590. In an exchange with Calgary's counsel, Dr. Makholm clarified several qualifying criteria for capital trackers:⁷²⁹

Q. There was discussion yesterday with Mr. McNulty that these kinds of trackers would not -- would not be or were not included in the base or the going-in rates; correct?

A. DR. MAKHOLM: Yes.

Q. And that they were idiosyncratic in nature. Yes?

A. DR. MAKHOLM: Yes.

Q. That, again referencing the between-rate-cases aspects, they were outside -- or were incurred outside of a rate case proceeding. Yes?

A. DR. MAKHOLM: Yes.

Q. They were incurred outside the ordinary course of business of the utility?

A. DR. MAKHOLM: Yes.

⁷²⁸ Transcript, Volume 1, pages 160-163.

⁷²⁹ Transcript, Volume 2, page 339.

Q. And they were incurred outside of or unrelated to past practices of the utility. Did I hear that right yesterday?

A. DR. MAKHOLM: Yes.

Q. Are there any others that I've missed?

A. DR. MAKHOLM: No, not that I can recall.

591. In addition to the criteria identified above, there was some discussion of other characteristics that should be exhibited by projects that qualify for special capital treatment. For projects to be considered atypical, NERA stated that the costs associated with the projects should be substantial.⁷³⁰ NERA also suggested that any projects should be supported by an engineering analysis.⁷³¹ In addition, as stated by the CCA “investments to meet customer and load growth trigger revenue growth and are largely self-funding,”⁷³² therefore these projects should not be eligible for capital tracker treatment if they result in customer and load growth because the incremental costs should be funded by other features of the PBR formula.

592. Based on the foregoing, the Commission adopts the following criteria for capital trackers:

- (1) The project must be outside of the normal course of the company’s ongoing operations.
- (2) Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party.
- (3) The project must have a material effect on the company’s finances.

593. The Commission considers that the party recommending the capital tracker must demonstrate that all of the criteria have been satisfied in order for a capital project to receive consideration as a capital tracker. Accordingly, the Commission rejects the proposals to permit capital factors on the basis of materiality alone or on the basis that the project is externally driven alone, as was suggested by some of the companies proposing capital-related Y factors.

The project must be outside of the normal course of the company’s ongoing operations

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.⁷³³ 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.

⁷³⁰ Transcript, Dr. Makhholm, Volume 1, page 171.

⁷³¹ Transcript, Dr. Makhholm, Volume 1, page 147.

⁷³² Exhibit 636.01, CCA argument, Section 8.1, paragraph 117, page 46.

⁷³³ Exhibit 634.02, UCA argument, Section 8.3, paragraph 196, page 36.

Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party

595. The second criterion generally limits the scope of eligible capital projects to those required for replacement of aged infrastructure that has come to the end of its useful life and those that are required by third parties, such as projects ordered by government agencies. It excludes projects required to accommodate customer or demand growth because a certain amount of capital growth is expected to occur as the system grows and system growth generates new sources of revenue that offset the costs of the new capital. The new sources of revenue can come in the form of increased customers and load growth,⁷³⁴ and also through contributions in aid of construction as prescribed by maximum investment level (MIL) policies.⁷³⁵

596. NERA stated that just because a capital expenditure is externally driven is not sufficient to justify a separate capital factor for it. Dr. Makholm identified the fact that even though it may be externally driven, the items may already be covered by the I-X mechanism if a similar level of costs is reflected in going-in rates.

I would have to agree only on the condition that I've stated before, which is they're not reflected in the normal course of business reflected in the revenue requirement. They are specific and unusual enough to carve out and deal with separately. You have to appreciate our perspective, that for a distribution company everything is externally driven in one fashion or another. It's driven by the public services need for lights, and that the quantity of service that a utility provides isn't up to it; it's up to what the public requires, because all these distributors are set up to serve all-comers. So just saying externally driven doesn't do it for me. You would have to say externally driven, unusual enough not to be reflected in the cost of service as a going-forward exercise, and capable of being carved out as a limited feature so as not to disrupt unnecessarily the basic features of the PBR plan, which is to provide some regulatory lag and incentives.⁷³⁶

597. The UCA stated that externally driven capital expenditures do not meet the test of a capital tracker on the basis that the projects are not limited in nature, externally driven capital is included in going-in rates, the projects are not outside the ordinary course of utility business, and externally driven capital is related to the past practices of a utility.⁷³⁷

598. The CCA argued that supplemental capital expenditure funding may be required if it can be substantiated by solid evidence for investments “due to events beyond the utility’s control such as highway relocations or the construction of a new transmission line.”⁷³⁸

599. The Commission is aware that some of the capital costs for distribution utilities would otherwise not be required were it not for the activities of transmission or system operator entities or other external parties, and that the costs to the distribution utilities can be material and can vary significantly from year-to-year. Due to a company’s obligation to provide service there is no opportunity for the company to turn down the project on the basis that company could not recover its costs because the project may not meet the capital tracker criteria, and therefore the company would be exposed to not receiving adequate compensation for undertaking the project.

⁷³⁴ Exhibit 636.01, CCA argument, Section 8.1, paragraph 117, page 46.

⁷³⁵ Transcript, Volume 7, page 1310.

⁷³⁶ Transcript, Dr. Makholm, Volume 2, page 330.

⁷³⁷ Exhibit 634.02, UCA argument, Section 8.3, paragraph 199, page 36.

⁷³⁸ Exhibit 636.01, CCA argument, Section 8.2, paragraph 122, page 50

600. Fortis indicated that the expenditures included in its Y factor for externally driven capital arise in the normal course of business.⁷³⁹ While the obligations to perform the work exist for the companies, the Commission considers that a company must demonstrate that such costs are significantly different than historical trends to qualify for capital tracker treatment, otherwise there is a likelihood for double-counting.

The project must have a material effect on the company's finances

601. The third criterion is required to limit the use of capital trackers. NERA stated that the costs associated with capital trackers should be substantial due to the regulatory burden associated with the administration of the tracker.⁷⁴⁰ The Commission considers that a utility may be frequently undertaking a number of small projects that may have the appearance of being atypical. However, the fact that the utility is undertaking a certain level of atypical projects on a consistent basis may result in that level of small unique projects being considered to be in the normal course of operations. The Commission also considers that it would not be suitable to group together several dissimilar projects into a single large project to give the appearance of materiality. However, a number of smaller related items required as part of a larger project might qualify for capital tracker treatment.

7.3.3 Implementation of capital trackers

7.3.3.1 Isolation of capital trackers from other fixed assets

602. The inclusion of capital trackers in the PBR plan presents a potential for double-counting if capital costs that should be funded by the I-X mechanism are also funded by the revenue provided through a capital tracker. To avoid the possibility of double-counting some parties proposed a method whereby the revenue requirement associated with historical costs (depreciation, return on capital and taxes) are removed from the going-in rates, thereby eliminating any possible impact of dealing with the capital tracker-related expenditures outside of the I-X mechanism.

603. Some of the proposed PBR plans proposed to isolate historical capital costs associated with certain capital expenditures for the PBR term. Fortis proposed to isolate the historical AESO contributions from going-in rates, and then take the revenue requirement associated with all AESO contributions to calculate that portion of its externally driven capital expenditures Y factor.⁷⁴¹ Fortis stated that it is not able to isolate the historical costs for the other types of capital expenditures that comprise the externally driven capital expenditures Y factor, due to the level of detail available in its asset ledgers.⁷⁴² AltaGas proposed a different form of adjustment to its major projects factor with the same underlying purpose, to avoid double-counting. To achieve this AltaGas proposed a reduction to the annual major projects factor calculation to exclude the revenue requirement impact associated with similar capital expenditures made between December 31, 2009 and December 31, 2012.⁷⁴³

604. Because capital trackers typically represent a surge in capital spending that will be followed by a period of slower than average capital spending, and therefore the company's future revenue requirements should be less than they otherwise would have been in the absence of the

⁷³⁹ Exhibit 474.01, Fortis rebuttal evidence, Section 2.5, paragraph 73, page 14.

⁷⁴⁰ Transcript, Dr. Makhholm, Volume 1, page 171.

⁷⁴¹ Exhibit 100.02, Fortis application, Section 6.2, paragraph 105, page 30.

⁷⁴² Exhibit 222.17, CCA-FAI-8(b).

⁷⁴³ Exhibit 110.01, AltaGas application, Section 6.0, paragraph 69, page 19.

capital tracker, there were some concerns raised over how long the projects should remain outside of the I-X mechanism. PEG suggested that if certain capital expenditures are excluded from the I-X mechanism in a PBR plan, then those capital expenditures should remain outside of the I-X mechanism in the next rate plan as well. PEG explained:

The Y factoring of capex cost is sometimes advocated on the grounds that the capex in question is a one-time surge. To the extent that this is true, it should also be noted that the productivity growth of the company should accelerate once the surge is complete because the surge will cause the rate base to grow more slowly after it is completed. If PBR should accommodate a revenue surge now to help finance the capex, it should then reflect the slower revenue (requirement) growth that later results and thereby improve customer finances. One way to accomplish this is to have the costs of capex (e.g. depreciation and return) that are excluded from one indexing plan be recovered outside of indexing in the next rate plan as well.⁷⁴⁴

605. Other parties generally objected to this suggestion by PEG because it creates unnecessary complexity in subsequent PBR plans. These parties recommended that, the capital expenditures associated with the capital tracker should be included with the rest of rate base in the rebasing process.⁷⁴⁵

Commission findings

606. The Commission considers that the reduction to the capital tracker to eliminate the impact of similar expenditures included in going-in rates as proposed in the AltaGas major projects factor may be a reasonable method for addressing the issue of double-counting. However, the merits of any such proposal would need to be assessed as part of the approval process for individual capital trackers.

607. The Commission does not find that a company should remove the impact of historical costs associated with expenditures similar in nature to approved capital trackers from going-in rates as proposed by Fortis for its AESO contributions. The Commission considers that it is necessary to maintain the incentive properties of PBR to the greatest extent possible by keeping the maximum amount of capital expenditures subject to the I-X mechanism.

608. The Commission accepts the arguments that the complexity of isolating certain capital expenditures in perpetuity beyond the PBR term outweighs the benefits suggested by PEG. Therefore, the Commission requires that the revenue requirement impact of the capital tracker expenditures be recorded outside of the I-X mechanism only during the course of the current PBR term.

7.3.3.2 Method for determining capital tracker amounts

609. Some parties have objected to the use of capital trackers on the basis that they result in too much regulatory burden.⁷⁴⁶ On the other hand, capital trackers are a reasonable method for retaining the efficiency incentive properties of PBR as discussed in Section 7.3.2.4.

⁷⁴⁴ Exhibit 307.01, PEG evidence, Section 2.2.6, page 24.

⁷⁴⁵ Exhibit 631.01, ATCO Electric argument, Section 8.5, paragraphs 201-202, page 53; Exhibit 632.01, ATCO Gas argument, Section 8.5, paragraph 212, page 68; Exhibit 628.01, AltaGas argument, Section 8.5, page 43.

⁷⁴⁶ Exhibit 646.02, EPCOR reply argument, Section 8.1, paragraph 108, page 34; Exhibit 634.02, UCA argument, Section 8.4, paragraph 205, page 37.

Dr. Makholm stated that if a capital tracker is required to address the legitimate concerns of a company, the negative impact on administrative burden should not be a concern.⁷⁴⁷ Given the criteria outlined for capital trackers in Section 7.3.2.4 it is clear that a relatively rigorous testing of capital trackers must occur.

610. Some of the companies have suggested that it would be administratively more efficient to not review the forecast for capital factors on an annual basis. The ATCO Electric K factor proposed to use forecasts at the outset of the PBR term that remain unchanged for the duration of the plan.⁷⁴⁸ ATCO Electric and ATCO Gas suggested that not truing up the forecasts for capital factors introduces some superior incentive properties by allowing the companies to beat their approved forecasts.⁷⁴⁹ The CCA supported the use of fixed forecasts on the basis that fixing the forecast would provide strong capital expenditure containment incentives. However, the CCA acknowledged that there would be an incentive for the companies to exaggerate their capital needs and therefore there would need to be a strong evidentiary record supporting the capital forecasts.⁷⁵⁰

611. Some of the companies suggested that their capital factors be reforecast periodically. Examples of this include the ATCO material-investments-unique-in-nature,⁷⁵¹ the Fortis externally-driven-capital Y factor,⁷⁵² and the AltaGas system reliability projects component of the major projects factor.⁷⁵³ AltaGas also proposed a formulaic annual adjustment mechanism for the system safety projects component of its major projects factor.⁷⁵⁴

612. Another approach proposed to avoid the regulatory burden of reviewing forecasts is to only deal with capital trackers on a retrospective basis after the company has decided to proceed with the project and has made the capital expenditure. ATCO Gas proposed that this approach be used for its urban mains replacement (UMR) Y factor project.⁷⁵⁵ Dr. Makholm suggested that a capital tracker should be based on items that are known and measurable rather than general forecasts to ensure that the tracker is specifically targeted.⁷⁵⁶ Dr. Makholm suggested that if a tracker is limited to costs that are truly required to be recovered outside of the I-X mechanism, the efficiency incentives of a PBR formula will be lost.⁷⁵⁷ Dr. Makholm explained one of the shortcomings of relying on capital forecasts is the incentive to overstate capital forecasts in saying:

The other way is to find a formula that perhaps has incentives that are like the incentives in the UK that I described, that leave rise five years from now to the commission feeling that it's been hoodwinked with forecasts that haven't turned out to be what was actually spent. They may not have been hoodwinked, but how are you going to tell?⁷⁵⁸

⁷⁴⁷ Transcript, Dr. Makholm, Volume 3, page 506.

⁷⁴⁸ Exhibit 476.01, ATCO Electric rebuttal evidence, paragraph 39, page 13.

⁷⁴⁹ Transcript, Ms. Wilson, Volume 7, page 1280.

⁷⁵⁰ Exhibit 636.01, CCA argument, Section 8.3.2, paragraph 127, page 52.

⁷⁵¹ Transcript, Ms. Wilson, Volume 4, page 759.

⁷⁵² Transcript, Mr. Delaney, Volume 11, pages 2152-2154.

⁷⁵³ Exhibit 110.01, AltaGas application, Section 6.3, paragraph 78, page 22.

⁷⁵⁴ Exhibit 110.01, AltaGas application, Section 6.2, paragraphs 75-76, pages 21-22.

⁷⁵⁵ Exhibit 389.01, ATCO Gas application updates, Section 2.3, paragraph 12, page 7.

⁷⁵⁶ Transcript, Dr. Makholm, Volume 1, page 175.

⁷⁵⁷ Transcript, Dr. Makholm, Volume 1, page 168.

⁷⁵⁸ Transcript, Dr. Makholm, Volume 3, page 506.

Commission findings

613. The Commission acknowledges that a reduction in the frequency of capital reviews would achieve a reduction in administrative burden. In addition, the Commission acknowledges that the use of long term forecasts as proposed by ATCO Electric for its K factor does create some efficiency incentives. However, in the absence of a true-up, the Commission considers the incentives for a company to exaggerate its capital needs, as identified by the CCA, to be a major drawback to such an approach, and accordingly on that basis long term forecasts will not be used for capital trackers.

614. The Commission recognizes that superior efficiency incentives would be created if the companies were required to make capital investment decisions and undertake the investment prior to applying for recovery of their costs by way of a capital tracker. However, the Commission recognizes that parties and the Commission have very little experience with capital trackers and, therefore, will not require that this approach be used by the companies during the first PBR term.

615. Accordingly, unless a company chooses to undertake investment prior to applying for recovery of its costs by way of a capital tracker, the company will be expected to provide a forecast with its capital tracker application. The company will only be permitted to collect the forecast amounts for the capital tracker on an interim basis, and a true-up to the actual amount of the capital tracker will occur after the capital expenditures have been made. As a result, these companies will still have some efficiency incentives due to the risk of regulatory disallowances in the true-up process if expenditures are not prudently incurred.

7.3.4 Commission findings on the capital factors proposed by the companies

616. The capital projects proposed by the companies for capital factor or capital Y factor treatment may or may not satisfy the criteria for a capital tracker established by the Commission in this decision. Neither the companies nor other parties have had the opportunity to evaluate whether these projects satisfy the Commission's criteria. Accordingly, the Commission makes no finding as to whether any of the capital projects proposed by the companies satisfy the Commission's criteria. The companies may file, as separate applications at the time of their compliance filing on November 2, 2012, applications for approval of specific 2013 projects as capital trackers, including projects that were included in their PBR filings. The companies need not re-file the information already on the record of this proceeding with respect to those capital projects included in their PBR filings. The companies may specifically refer to the record of this proceeding and supplement that information with additional information or explanations to address the Commission's capital tracker criteria

7.4 Y factor

617. In a PBR plan, Y factor costs are those costs that do not qualify for capital tracker treatment or Z factor treatment and that the Commission considers should be directly recovered from customers or refunded to them. Y factor costs in turn, could either be costs the company is required to pay to a third party (such as the AESO) or other Commission-approved costs incurred by the company for flow through to customers.

618. In Decision 2009-035 the Commission approved the flow-through of certain costs incurred by ENMAX along with the established collection of these costs outside the I-X mechanism. The Commission stated:⁷⁵⁹

With respect to flow-through rate adjustments, the Commission considers that flow-through rate adjustments arise from cost elements that are not unforeseen one time events. Flow-through items arise in the normal course of business, but are such that the company has no control over them. The Commission approves the following three items for flow-through treatment.

- SAS rates in the distribution tariff
- TAC Deferral Account
- AESO load settlement costs

619. In Decision 2010-146⁷⁶⁰ (the ENMAX compliance filing decision), the Commission approved the addition of the Commission's own administrative fee as a flow-through cost. Although not considered material, the Commission found it to be similar in nature to other flow-through amounts approved by the Commission.⁷⁶¹

620. As a result of these criteria, under the ENMAX FBR plan, a cost might qualify to be collected as a flow-through cost outside of the I-X mechanism if the amount was foreseeable and regularly incurred in the normal course of business but the quantum and requirement to pay the cost was outside of the control of management. In addition, the amounts approved by the Commission should be material.

621. In this proceeding, each of the companies proposed the treatment of several accounts outside of the I-X mechanism. The companies designated all of these costs as Y factors. The Y factor accounts proposed by the companies substantially exceeded the number of flow-through items approved in Decision 2009-035.

622. The proposed Y factor costs included existing flow-through accounts similar to those approved in the ENMAX decision, deferral accounts that had been approved under cost of service rate regulation, new deferral accounts and unusual capital expenditures. The companies argued that all of these costs should be recovered as Y factors because these costs are highly volatile, recurring or have previously been approved by the Commission for flow-through treatment. More importantly, all of these costs were considered by the companies to be outside the funding capacity of the I-X mechanism.

623. In its review of these companies' Y factor proposals, NERA commented that the inclusion of a comprehensive set of deferral accounts was unusual in PBR plans,⁷⁶² and that an

⁷⁵⁹ Decision 2009-035, Section 9.3, paragraph 251, page 55.

⁷⁶⁰ Decision 2010-146: ENMAX Power Corporation, Decision 2009-035 Formula Based Ratemaking Compliance Application, Application No. 1604999, Proceeding ID. 191, April 22, 2010

⁷⁶¹ Decision 2010-146, Section 9.1.1, paragraph s 97-100, page 16.

⁷⁶² Exhibit 391.02, NERA second report, Section IV-D-2, paragraph 83, page 40.

overly broad set of Y factor accounts reduces efficiency incentives under PBR.⁷⁶³ Interveners generally agreed with NERA's observations.

624. The CCA noted "that some utilities (most notably AE and AG) propose excessive use of Y factors."⁷⁶⁴ The UCA recommended "that the ENMAX type flow-through items, like system access charges, AESO load settlement costs, transmission costs from upstream pipelines, the UCA assessment, the AUC assessment should continue as flow-through"⁷⁶⁵ but objected to the wide use of deferral accounts. The UCA submitted that the Commission should not approve a number of the proposed Y factor accounts, stating that the Commission has previously ruled that deferral accounts should be approved only when they are demonstrably necessary.⁷⁶⁶ IPCAA generally supported the recommendations of the UCA with respect to Y factors.⁷⁶⁷ Calgary suggested that the ATCO Gas PBR plan should "retain the integrity of PBR through the reliance on the (I – X) mechanism, to the greatest extent possible."⁷⁶⁸

625. All of the companies commented that changes to their risk profiles could occur if deferral accounts that exist under cost of service were not continued as Y factors under PBR.⁷⁶⁹ IPCAA also identified this as a factor to be considered.⁷⁷⁰ The companies also expressed a preference for the use of Y factors instead of Z factors because of the greater uncertainty associated with approval of Z factors.⁷⁷¹

626. Several parties suggested that the exogenous adjustment criteria approved in Decision 2009-035 could also be used to evaluate the deferral accounts proposed as Y factors under PBR.⁷⁷² While parties acknowledged the suitability of utilizing a set of criteria for evaluating Y factors, there was some discrepancy regarding how to apply the criteria. Some companies argued that Y factors should be approved if some, but not necessarily all, of the Y factor criteria were met. The criterion suggested by some of the companies as not needing to apply in all circumstances is the "outside-of-management-control" criterion.⁷⁷³ Some interveners disagreed with the companies, and argued that items that are within management's control should not be eligible for Y factor treatment.⁷⁷⁴

⁷⁶³ Exhibit 391.02, NERA second report, Section IV-E-7, paragraph 113, page 51.

⁷⁶⁴ Exhibit 636.01, CCA argument, Section 10.1, paragraph 159, page 64.

⁷⁶⁵ Exhibit 634.02, UCA argument, Section 10.1, paragraph 231, page 41.

⁷⁶⁶ Exhibit 300.02, UCA evidence of Russ Bell, A20, page 23.

⁷⁶⁷ Exhibit 642.01, IPCAA reply argument, Section 10.0, paragraph 13, page 2.

⁷⁶⁸ Exhibit 629.01, Calgary argument, Section 10.1, page 46.

⁷⁶⁹ Exhibit 476.01, ATCO Electric rebuttal evidence, paragraph 35, page 11; Exhibit 472.02, ATCO Gas rebuttal evidence, paragraphs 28-29, page 8; Exhibit 473.02, EPCOR rebuttal evidence, A19, page 25; Exhibit 477.01, AltaGas rebuttal evidence, Section 7, paragraph 82, page 29; Exhibit 633.01, Fortis argument, Section 1.0, paragraph 36, page 9.

⁷⁷⁰ Exhibit 369.01, AUC-IPCAA-4.

⁷⁷¹ Exhibit 633.01, Fortis argument, Section 10.5, paragraph 207, page 96; Exhibit 631.01, ATCO Electric argument, Section 10.4, paragraph 244, page 61; Exhibit 632.01, ATCO Gas argument, Section 10.5, paragraph 271, page 84; Transcript, Mr. Mantei, Volume 9, page 1550; Transcript, Mr. Gerke, Volume 11, page 1792.

⁷⁷² Exhibit 219.02, AUC-ALLUTILITIES-FAI-11; Exhibit 233.01, AUC-ALLUTILITIES-EDTI-11(a); Exhibit 248.02, AUC-ALLUTILITIES-AUI-11(a); The CCA suggests similar criteria in Exhibit 636.01, CCA argument, Section 10.2.1, paragraph 163, page 67.

⁷⁷³ Exhibit 211.01, NERA-AE-17; Exhibit 204.02, AUC-ALLUTILITIES-AG-11; Exhibit 248.02, AUC-ALLUTILITIES-AUI-10.

⁷⁷⁴ Exhibit 629.01, Calgary argument, Section 10.2, page 47; Exhibit 634.02, UCA argument, Section 10.1, paragraph 230, page 41.

Commission findings

627. There was no dispute among the parties that certain third party costs similar to those approved in Decision 2009-035 should qualify to be flowed through to customers. As well, most parties supported the flow through of costs similar to the Commission's administration fee.

628. The Commission agrees that the criteria approved in Decision 2009-035 should apply to Y factor costs in this decision. The Commission agrees with parties that the types of third party flow-through costs approved in Decision 2009-035 should also be approved on a flow-through basis in this proceeding.

629. For Y factor costs that are not third party flow-through costs, some parties suggested that the deferral account criteria set out by the EUB in Decision 2003-100⁷⁷⁵ be used as the criteria for approval.⁷⁷⁶ In Decision 2003-100 the EUB stated:⁷⁷⁷

The Board does not consider there to be a definitive Board policy regarding the use of deferral accounts. Rather, the Board's practice has been to evaluate the use of a deferral account on a case-by-case basis, on its own merit. The Board notes that ATCO Pipelines and the interveners suggested several criteria for the Board to consider in this situation including:

- Materiality of the forecast amount,
- Uncertainty regarding the accuracy and ability to forecast the amount,
- Whether or not the factors affecting the forecast are beyond the utility's control,
- Whether or not the utility is typically at risk with respect to the forecast amount.

The Board notes that the criteria were suggested to address differing views with respect to risk, rate fluctuations, intergenerational inequity, and the Board's historical approach to deferral accounts. The Board considers that the suggested criteria are reasonable...

630. The criteria in Decision 2003-100 are similar to the exogenous adjustment criteria approved by the Commission in Decision 2009-035.⁷⁷⁸ In both decisions the lists included criteria related to materiality and the events being beyond management's control. There was recognition from several parties that the exogenous adjustment criteria from Decision 2009-035 could be used to evaluate the deferral accounts proposed as Y factors under PBR.⁷⁷⁹

631. The ability to recover costs outside of the I-X mechanism should be an extraordinary remedy for cost recovery. If however, the company has no ability to influence the amount of certain costs and those costs are material in nature and not otherwise recoverable under the I-X mechanism, incentives are unaffected. Accordingly, the Commission adopts and clarifies the criteria established in Decision 2009-035 for the identification of eligible Y factor costs as follows:

⁷⁷⁵ Decision 2003-100: ATCO Pipelines, 2003/2004 General Rate Application – Phase I, Application No. 1292783, December 2, 2003.

⁷⁷⁶ Exhibit 632.01, ATCO Gas argument, Section 10.2, paragraph 226, page 73; Exhibit 300.02, UCA evidence of Russ Bell, A20, page 22.

⁷⁷⁷ Decision 2003-100, Section 7.2.1, pages 115-116.

⁷⁷⁸ Decision 2009-035, Section 9.3, paragraph 247, page 54.

⁷⁷⁹ Exhibit 219.02, AUC-ALLUTILITIES-FAI-11; Exhibit 233.01, AUC-ALLUTILITIES-EDTI-11(a); Exhibit 248.02, AUC-ALLUTILITIES-AUI-11(a). The CCA suggests similar criteria in Exhibit 636.01, CCA argument, Section 10.2.1, paragraph 163, page 67.

- 1) The costs must be attributable to events outside management's control.
- 2) The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.
- 3) The costs should not have a significant influence on the inflation factor in the PBR formulas.
- 4) The costs must be prudently incurred.
- 5) All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.

632. The Commission considers that all criteria must ordinarily be satisfied before a cost will be considered for Y factor treatment. In addition to those Y factors that meet the above criteria, the Commission will allow companies to recover as Y factor rate adjustments specific costs incurred at the direction of the Commission and flow-through costs that are similar in nature to the flow-through items approved for ENMAX in Decision 2009-035. The Commission considers that having fewer Y factor accounts will make the PBR plans easier to administer. Y factors will only be approved in circumstances where there is a demonstrable need for them.

633. The Commission acknowledges the arguments made by some parties that denying certain Y factor accounts could impact the risk profiles of the companies. The Commission addresses consideration of the potential for risk impacts of PBR in Section 7.4.2.6.1 of this decision.

7.4.1 Materiality of Y factors

634. The UCA recommended the disallowance of several Y factor accounts on the basis that the amounts associated with the accounts are not material. The UCA suggested that "only if a proposed deferral account is to account for the potential of an error in forecasting that could produce a gain or loss of substantial magnitude, should the Commission then use the other criteria to determine if deferral treatment is warranted."⁷⁸⁰

635. While most parties acknowledged that assessing the materiality of Y factors is appropriate, EPCOR disagreed stating that:

EDTI's proposed Y factor does not include a materiality threshold limit. Such a threshold limit is not required as the deferral accounts and reserve accounts included in EDTI's Y factor are related to costs that are material. These deferral and reserve accounts have already been approved by the Commission using materiality as one of the criteria for approval. Generic proceedings do not require a materiality threshold as, if the subject matter of the proceeding were not material, the Commission would not hold a generic proceeding in relation to it.⁷⁸¹

Commission findings

636. Due to the high degree of similarity in the purpose and assessment of Y factors and Z factors, unless otherwise determined by the Commission, the Commission considers that the materiality threshold established in Section 7.2.1 for Z factors should also apply to Y factors.

⁷⁸⁰ Exhibit 300.02, UCA evidence, A20, page 23.

⁷⁸¹ Exhibit 237.01, CCA-EDTI-5.

7.4.2 Specific proposed Y factors

637. The companies proposed a variety of different Y factor accounts in this proceeding, some of which existed, as flow-through accounts and deferral accounts, prior to the implementation of PBR and others which are new. Interveners raised many concerns over the proposed Y factor accounts. In general, the objections raised by interveners were raised on the basis that the proposed accounts did not meet certain eligibility criteria.

638. The UCA provided many recommendations with respect to specific Y factor accounts in its evidence. Specifically the UCA recommended the denial of the following Y factors accounts proposed by the companies:⁷⁸²

- Variable Pay Program
- Expansion of Defined Benefit Pension plan
- Changes in Weather Deferral Account
- Changes in Load Balancing Deferral Account
- Production Abandonment Costs
- Distribution to Transmission Contributions
- Vegetation Management
- Head Office Cost Allocation Percentages
- AUC Rule 026 Deferrals-IFRS
- Exchange Rate Deferral
- Design, Development and implementation of a Demand Side Management (DSM) Program.
- ATCO Centre Calgary Lease.

639. Calgary only commented on ATCO Gas' accounts, and had a more general approach of only recommending the continued use of two deferral accounts with the belief that all other accounts are not appropriate to be used under PBR. Calgary recommended that only transmission costs and income tax deductible capital costs should be allowed.⁷⁸³

640. IPCAA recommended "that only those deferral accounts considered in the recent GCOC proceeding should be approved in this proceeding, in order to maintain consistency between the Commission's findings in the GCOC decision and the risk profile of the utilities."⁷⁸⁴ In addition, in reply argument, IPCAA stated that it generally supported the UCA's arguments concerning all matters related to Y factor accounts (such as deferral accounts, reserves and flow-through items).⁷⁸⁵

641. The CCA provided a number of specific recommendations in its argument,⁷⁸⁶ however several companies objected to the inclusion of the recommendations in argument on the grounds that the recommendations could not be properly tested due to the lateness of their introduction to the proceeding.⁷⁸⁷ The Commission will only give weight to the CCA recommendations it

⁷⁸² Exhibit 634.02, UCA argument, Section 10.1, paragraph 228, page 41.

⁷⁸³ Exhibit 629.01, Calgary argument, Section 10.1, page 46.

⁷⁸⁴ Exhibit 369.01, AUC-IPCAA-4.

⁷⁸⁵ Exhibit 642.01, IPCAA reply argument, Section 10.0, paragraph 13, page 2.

⁷⁸⁶ Exhibit 636.01, CCA argument, Section 10, pages 64-110.

⁷⁸⁷ Exhibit 644.01, Fortis reply argument, Section 1.0, paragraph 19, page 3; Exhibit 648.02, ATCO Gas reply argument, Section 10.2, paragraph 327, page 93; Exhibit 647.01, ATCO Electric reply argument, Section 1, paragraph 31, page 10.

determines are based on the prior record of the proceeding, and will not consider new proposals or supporting evidence that were introduced for the first time in argument.

Commission findings

642. The Commission has reviewed the various Y factor accounts requested by the companies, and has grouped the accounts into seven different categories:

- (1) Accounts that should be approved for flow-through treatment on the basis that they are similar to the flow-through items approved for ENMAX based on the Commission's findings in Section 7.4 above.
- (2) Accounts that are a result of Commission directions, and therefore are eligible for flow-through treatment even though they may not satisfy certain criteria for Y factors.
- (3) Accounts that meet the Y factor criteria, and therefore are eligible for flow-through treatment.
- (4) Events where the impacts are unforeseen, and therefore are better to be assessed as Z factors.
- (5) Accounts that are not eligible for Y factor treatment because they do not satisfy the outside-of-management-control criterion.
- (6) Accounts that are not eligible for Y factor treatment because they do not satisfy the inflation criterion.
- (7) Accounts that involve capital expenditures and are therefore better to be assessed as capital trackers.

643. The Commission considers that in many cases companies have asked for Y factors that are common amongst them. Because these accounts can be grouped together, the Commission will assess groupings of similar Y factor accounts for several companies in the sections that follow.

644. Some of the companies withdrew their requests for certain Y factor accounts during the course of the proceeding.⁷⁸⁸ Accounts that the companies have removed have not been included in the assessments in the following sections because it is assumed that the accounts will not be utilized during PBR.

⁷⁸⁸ Exhibit 389.01, ATCO Gas application updates, Section 2.4, paragraph 16, page 8 (withdrew deferral account for production abandonment costs and short term deferral accounts for IFRS implementation, NGTL/AP integration, Calgary head office lease); Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4 (withdrew deferral accounts for demand side management and natural gas system settlement code); Exhibit 633.01, Fortis argument, Section 10.2, paragraph 193, page 89 (withdrew exchange rate deferral account).

7.4.2.1 Accounts that are similar in nature to flow-through items approved for ENMAX

7.4.2.1.1 AESO flow-through items

645. All electric distribution companies accessing the electric transmission system in the province are charged by the AESO⁷⁸⁹ for transmission services provided in relation to customers in their distribution service area. Accordingly, the distribution tariff of the electric distribution companies in this proceeding includes two components:⁷⁹⁰

- the distribution component, designed to recover the costs of owning and operating the distribution system; and
- the transmission component, designed to recover the AESO tariff charges to the distribution company.

646. ATCO Electric, Fortis and EPCOR indicated that while the rates covering the distribution component will be determined by the I-X mechanism, the AESO transmission access charges should be treated as flow-through items. The companies pointed out that the AESO charges have been subject to deferral account treatment under cost of service rate regulation and they proposed to continue using the existing deferral account mechanisms (with one modification, as further discussed below) to recover these costs under PBR. Historically, the companies used slightly different names for deferral accounts for the AESO charges, but the purposes for the costs are essentially the same:

Table 7-2 AESO flow-through items for electric distribution utilities

ENMAX ⁷⁹¹	ATCO Electric	EPCOR	Fortis
AESO load settlement costs	AESO load settlement costs ⁷⁹²	AESO load settlement deferral account ⁷⁹³	AESO load settlement cost reserve ⁷⁹⁴
SAS rates in the distribution tariff	System access service payments ⁷⁹⁵	System access service rates ⁷⁹⁶	AESO system access service ⁷⁹⁷
TAC deferral account		Transmission charge deferral account ⁷⁹⁸	AESO charges deferral account ⁷⁹⁹
Balancing Pool allocation refund rider	Balancing Pool adjustment ⁸⁰⁰	Balancing Pool rider	Balancing Pool adjustment rider ⁸⁰¹

⁷⁸⁹ The AESO is a not-for-profit organization that plans and operates the transmission system in Alberta.
<http://www.aeso.ca/index.html>.

⁷⁹⁰ Exhibit 633, Fortis argument, page 142.

⁷⁹¹ Decision 2009-035, Section 9.3, paragraph 251, page 55.

⁷⁹² Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 119-122, page 6-10.

⁷⁹³ Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51.

⁷⁹⁴ Exhibit 100.02, Fortis application, Section 6.1.1, page 26.

⁷⁹⁵ Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 92-103, pages 6-2 to 6-6.

⁷⁹⁶ Exhibit 103.02, EPCOR application, Section 3.3, paragraphs 254-255, pages 81-82.

⁷⁹⁷ Exhibit 100.02, Fortis application, Section 13.1, paragraph 160, page 45.

⁷⁹⁸ Exhibit 103.02, EPCOR application, Section 3.3, paragraphs 254-255, pages 81-82.

⁷⁹⁹ Exhibit 100.02, Fortis application, Section 13.1, paragraphs 163-165, pages 46-47.

⁸⁰⁰ Exhibit 98.02, ATCO Electric application, Section 14, paragraph 265-266, page 14-2.

⁸⁰¹ Exhibit 100.02, Fortis application, Section 13.1, paragraphs 166-168, page 47.

Commission findings

647. In Decision 2009-035, the Commission agreed with ENMAX that the company has no control over the AESO charges and approved flow-through treatment of these costs for the purposes of ENMAX's FBR plan.⁸⁰² All of the electric distribution companies are subject to the same types of costs and therefore the Commission considers that these costs satisfy the Y factor criteria enumerated above. The Commission also considers that achieving consistency with the flow-through items approved in the ENMAX FBR plan is fair and reasonable. Accordingly, the Commission finds that the AESO related cost items, as presented in Table 7-2 above, will be treated as flow-through items for the purposes of the PBR plans of Fortis, EPCOR and ATCO Electric.

648. To the extent that the companies have existing rider mechanisms to pass through these costs to customers, for billing consistency those existing mechanisms will continue under PBR.

7.4.2.1.2 Inclusion of volume variance in the transmission access charge deferral accounts

649. In their PBR proposals, the electric distribution companies proposed one modification to their existing transmission access charge deferral accounts. Currently, these deferral accounts reconcile only forecast to actual variances related to the AESO price changes. The companies bear the risk of forecast to actual variances related to transmission volumes (as measured by certain billing determinants such as metered energy, customer load, peak demand, etc.). In other words, if the AESO were to change its rates, the companies would be kept whole across its forecast volumes through a deferral account. However, the companies accept the risk of the actual volumes being lower or higher than forecast.⁸⁰³ This arrangement can be generally represented as:

$$\text{Transmission Access Deferral} = \text{Forecast volume} \times (\text{Actual AESO prices} - \text{Forecast AESO prices})$$

650. The companies indicated that they do not have any meaningful control over transmission volumes as they are completely driven by customer load requirements that can vary from year to year and month to month.⁸⁰⁴ IPCAA agreed that the companies have "little if any control over customer loads."⁸⁰⁵ IPCAA also observed that the only practical option to control transmission volumes can create risks that customer loads will be interrupted:

Since utilities have and should have no direct control over customer load, their only practical option is to shift load between summer and winter peaking PODs [points of delivery] to minimize AESO tariff demand ratchets. Since distribution is largely radial in nature [Exhibit 306.01 page 2], this is rarely possible; urban utilities, with their denser service areas, are the only entities with meaningful substation switching options. However such switching creates significant risks that customer loads will be interrupted.⁸⁰⁶

651. Furthermore, the companies indicated that transmission volumes have become increasingly difficult to forecast due to a more complex AESO tariff structure. ATCO Electric

⁸⁰² Decision 2009-035, paragraph 251.

⁸⁰³ Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 95-97.

⁸⁰⁴ Exhibit 98.02, ATCO Electric application, Section 6, paragraph 98; Exhibit 633, Fortis argument, page 142.

⁸⁰⁵ Exhibit 635, IPCAA argument, paragraph 99.

⁸⁰⁶ Exhibit 635, IPCAA argument, paragraph 102.

noted that the structure of the AESO's tariff has changed over the years shifting from energy related costs to demand-related costs which are more difficult to forecast.⁸⁰⁷ In particular, ATCO Electric observed that the change in demand-related costs has increased from 42 per cent of the total AESO costs in 2004 to 78 per cent of the total system access service (SAS) costs.⁸⁰⁸ Fortis shared these concerns.⁸⁰⁹

652. ATCO Electric and Fortis also expressed their view that the complexity of forecasting the transmission volumes will be more pronounced under PBR, since the companies will be forecasting billing determinants over longer periods of time (i.e., over the PBR term).⁸¹⁰ In that regard, Fortis submitted that in the absence of volume true-up, the company would need to update its transmission volumes forecast annually to effectively attempt to manage this transmission risk. In Fortis' view, this annual update was not consistent with "regulatory streamlining envisioned for PBR."⁸¹¹

653. Fortis also observed that one of the reasons the Commission relied upon for imposing volume risk on Fortis in Decision 2012-108⁸¹² was that it might provide an additional incentive for the company to more accurately forecast its distribution billing determinants. In that regard, Fortis submitted that this determination was made in the context of a cost of service regime and would be less applicable to PBR. In Fortis' view, under PBR, forecasting of transmission volumes will be less critical in terms of sharing any risks between customers and the company.⁸¹³ ATCO Electric also agreed that the "circumstances associated with forecasting risk under PBR are significantly different than under cost of service regulation."⁸¹⁴

654. Based on these considerations, EPCOR, ATCO Electric and Fortis proposed that their transmission access charge deferral accounts include both price and volume variances under PBR.⁸¹⁵ In other words, the companies requested that the AESO charges be treated as a full dollar-for-dollar flow-through item in their PBR plans. Under this arrangement, the actual transmission costs incurred will equal the actual transmission revenues received. This arrangement can be generally represented as:

$$\text{Transmission Access Deferral} = (\text{Actual volume} - \text{Forecast volume}) \times (\text{Actual AESO prices} - \text{Forecast AESO prices})$$

655. The CCA noted that in two recent decisions, Decision 2011-375⁸¹⁶ and Decision 2012-108, the Commission determined that volume variances should not be included in the transmission cost deferral accounts in a cost of service rate design regime. In the CCA's

⁸⁰⁷ Transcript, Volume 4, pages 728-729.

⁸⁰⁸ Exhibit 631, ATCO Electric argument, paragraph 336.

⁸⁰⁹ Transcript, Volume 12, page 2243, lines 5-23.

⁸¹⁰ Exhibit 98.02, ATCO Electric application, Section 6, paragraph 99; Exhibit 633, Fortis argument, pages 143-144.

⁸¹¹ Exhibit 633.01, Fortis argument, pages 143-144.

⁸¹² Decision 2012-108: FortisAlberta Inc. Application for Approval of a Negotiated Settlement Agreement in respect of 2012 Phase I Distribution Tariff Application, Application No. 1607159, Proceeding ID No. 1147, April 18, 2012.

⁸¹³ Transcript, Volume 12, page 2242, lines 5-16 and page 2244, lines 7-14.

⁸¹⁴ Exhibit 639, ATCO Electric reply argument, paragraph 369.

⁸¹⁵ Transcript, Volume 10, page 1874, lines 19-21 (EPCOR); Exhibit 633, Fortis argument, pages 143-144; Exhibit 631, ATCO Electric argument, paragraph 337.

⁸¹⁶ Decision 2011-375: EPCOR Distribution & Transmission Inc. 2010-2011 Phase II Distribution Tariff Application, Application No. 1606833, Proceeding ID No. 980, September 15, 2011.

view, the Commission's determinations "apply as much in a cost of service environment as they do in the PBR regime."⁸¹⁷ Accordingly, the CCA argued that the companies' transmission access charge deferral accounts should continue to include price variance only.⁸¹⁸

656. The UCA noted that in Decision 2012-108, the Commission indicated that it will "consider the merits of volume reconciliation for distribution utilities under the PBR regime in due course, following the issuance of a decision on Proceeding ID No. 566."⁸¹⁹ As such, the UCA recommended that the Commission continue with a generic proceeding for examining the issue of volume true-up as referenced in Decision 2012-108.⁸²⁰

657. IPCAA also noted the Commission's determination in Decision 2012-108 referenced by the UCA and recommended that the implementation of comprehensive PBR be delayed until incentives are developed that will encourage the distribution companies "to prudently minimize the transmission and distribution facilities installed in their service area."⁸²¹

Commission findings

658. As observed by the UCA and IPCAA, in Decision 2012-108 the Commission reaffirmed its intention to consider the issues related to volume reconciliation under the PBR framework on a consistent basis for all distribution companies following the issuance of a decision in this proceeding.⁸²² However, having considered the evidence filed by the parties, the Commission agrees with Fortis' and ATCO Electric's view that a determination on volume reconciliation under PBR can be made in this proceeding.⁸²³

659. The Commission agrees with ATCO Electric's and Fortis' explanation that transmission volumes are driven by customer load requirements. Furthermore, as stated in a number of recent decisions, the Commission agrees with the electric distribution companies' assessment that they have no meaningful control over transmission volumes due to the specifics of the current structure of the AESO system access rates (more heavily oriented to demand-related charges versus energy-related charges) and the companies' limited ability to undertake seasonal switching of loads between points of delivery.⁸²⁴ IPCAA came to the same conclusion.⁸²⁵

660. Nevertheless, analysing EPCOR's and Fortis' cost of service rate applications, the Commission concluded that these companies were able to forecast transmission volumes with reasonable accuracy, as demonstrated by relatively small volume variances in their respective deferral accounts.⁸²⁶ However, in that case the companies were updating their billing determinants forecasts every two years, in their rate applications. The Commission agrees with ATCO Electric's and Fortis' arguments that the same level of precision will not likely be attainable if the companies will be forecasting their billing determinants for the duration of the

⁸¹⁷ Exhibit 636, CCA argument, paragraph 402.

⁸¹⁸ Exhibit 636, CCA argument, paragraphs 404-405.

⁸¹⁹ Decision 2012-108, paragraph 127.

⁸²⁰ Exhibit 634.02, UCA argument, paragraph 433.

⁸²¹ Exhibit 635, IPCAA argument, paragraph 104 and Exhibit 642, IPCAA reply argument, paragraph 608.

⁸²² Decision 2012-108, paragraph 127.

⁸²³ Exhibit 644, Fortis reply argument, paragraphs 182-183; Exhibit 639, ATCO Electric reply argument, paragraph 368.

⁸²⁴ Decision 2011-375, paragraph 188 and Decision 2012-108, paragraph 115.

⁸²⁵ Exhibit 635, IPCAA argument, paragraphs 99 and 102.

⁸²⁶ Decision 2011-375, paragraph 189 and Decision 2012-108, paragraph 117.

PBR term. Therefore, the Commission will require the companies to file forecast billing determinants for the following year as part of their annual PBR rate adjustment filings.

661. More importantly, the Commission explained in recent decisions dealing with EPCOR's and Fortis' rate applications, that under a cost of service regulatory framework, the distribution revenue requirement established in Phase I applications is divided by the forecast billing determinants for the test period to design customer rates. In other words, the accuracy of customer rates and the companies' ability to recover their approved revenue requirement is highly dependent on the accuracy of their billing determinants forecasts.

662. Furthermore, under the current regulatory framework, the electric distribution companies accept the risk related to the difference between the forecast and actual billing determinants when recovering their approved distribution revenue requirement. In these circumstances, the Commission determined that under a cost of service rate making framework, the absence of volume true-up on transmission charges would provide a stronger financial incentive to the companies to accurately forecast their billing determinants to ensure reasonable recovery of both the distribution tariff revenue and transmission access charges. Overall, taking into account the impact of forecast billing determinants on customer rates and the companies' revenues, the Commission considers that under cost of service rate making, regulatory efficiencies stemming from a more rigorous billing determinants forecast outweigh the potential disadvantages of the companies bearing risk on transmission volumes.⁸²⁷

663. In contrast, under PBR, the companies' costs will not be driving their revenues. As set out in Section 4 of this decision, under the price cap plans approved for ATCO Electric, EPCOR and Fortis, customer rates for each year will be established by way of the I-X mechanism, regardless of a company's actual costs and the amount of energy transported through a company's system. In these circumstances, forecasting of billing determinants will have a minimal impact on customer rates.⁸²⁸ As Fortis observed:

And we would note that under PBR that all falls away. Under PBR we essentially have rates for the distribution component of costs increasing I minus X. We have billing determinant volumes growing on an actual basis, and the product of those two things are really the revenues that FortisAlberta will receive for its distribution service.⁸²⁹

664. Accordingly, the Commission agrees with Fortis' view that under PBR, there is no purpose for maintaining the true-up of transmission flow-through accounts of electric distribution companies limited to price-only.

665. IPCAA expressed concerns that the current deferral account mechanism creates "unnecessary cost uncertainty, delay, and administrative costs."⁸³⁰ In that regard, as outlined in Bulletin 2012-04,⁸³¹ the Commission had initiated a review of the electric distribution companies'

⁸²⁷ Decision 2011-375, paragraph 191 and Decision 2012-108, paragraphs 120-121.

⁸²⁸ As set out in Section 4, under a price cap plan, billing determinants will be used nonetheless to apportion to customers other components of the PBR formula, outside of the (I-X) mechanism such as flow-through items, capital trackers, Z factors, etc.

⁸²⁹ Transcript, Volume 12, page 2242, lines 5-16.

⁸³⁰ Exhibit 635, IPCAA argument, paragraph 103.

⁸³¹ Bulletin 2012-04, Commission-initiated electric transmission quarterly rider process review, Proceeding ID No. 1678, March 29, 2012.

transmission quarterly rider mechanisms.⁸³² As part of that review, ATCO Electric, ENMAX, EPCOR and Fortis filed their applications to standardize their respective transmission access charge rider mechanisms. In the Commission's view, these applications address, among other things, the types of issues identified by IPCAA in this proceeding. For example, the companies are proposing to move to a prospective approach to setting their quarterly riders. Under this method, the transmission component of the companies' rates in any quarter will be reflective of the AESO charges in that particular quarter. As such, it will no longer be the case that transmission charges will be based on a calculation "whose results are unknowable until the utility releases them months after the fact."⁸³³ Furthermore, the companies are proposing to standardize and simplify their quarterly riders, so that these applications can be reviewed with minimal scrutiny, reducing time delay and the administrative cost of dealing with these riders.⁸³⁴ The Commission intends to address IPCAA's concerns in Proceeding ID No. 1678.

666. In light of the above considerations, the Commission approves the inclusion of volume variance in the transmission flow-through accounts of the electric distribution companies for the purposes of their PBR plans. The Commission expects that with this modification, the AESO related cost items will be dollar-for-dollar flow-through items in the companies' PBR plans. At the time of their annual transmission deferral reconciliation, the companies must ensure that the actual transmission revenues received equal the actual transmission costs incurred. As noted in the previous section of this decision, subject to this modification, the Commission directs Fortis, EPCOR and ATCO Electric to use their existing deferral mechanisms to flow through the transmission access costs to customers under PBR.

667. As indicated in Decision 2012-108, the Commission is committed to considering the issues related to volume reconciliation under the PBR regime on a consistent basis for all electric distribution companies.⁸³⁵ The Commission considers that the same reasoning for including volume variances in ATCO Electric's, EPCOR's and Fortis' transmission charge deferral accounts under PBR applies to ENMAX as well. As such, the Commission directs ENMAX to bring this matter forward to the Commission as part of the next application dealing with the company's transmission access charge deferral account.

7.4.2.1.3 Transmission flow-through for gas utilities

668. The Commission considers that certain flow-through items requested by the gas companies serve a similar purpose, and have similar mechanisms to the AESO flow-through items approved for the electric distribution utilities. The transmission costs deferral account requested by ATCO Gas⁸³⁶ falls into this category. ATCO Gas simply flows through the transmission rates charged by the transmission service provider to customers. ATCO Gas has requested volume variances to be included in this account under PBR for reasons that are similar to the electric distribution companies' requests to include volume variances in the transmission flow-through accounts. The Commission approves flow-through treatment using the existing rider mechanism for the transmission costs deferral account, and also approves the inclusion of volume variances in the account. AltaGas has also proposed to continue to address its gas procurement function and costs related to transportation by third parties separately from the

⁸³² Proceeding ID No. 1678.

⁸³³ Exhibit 635, IPCAA argument, paragraph 103.

⁸³⁴ Proceeding ID No. 1678, Exhibit 23.02, Exhibit 24.01, Exhibit 25.01 and Exhibit 26.02.

⁸³⁵ Decision 2012-108, paragraph 127.

⁸³⁶ Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.4, pages 24-25.

I-X mechanism through its existing gas costs recovery rate and third party transportation rate mechanisms.⁸³⁷ The Commission approves AltaGas' treatment.

7.4.2.1.4 Farm transmission costs

669. Fortis intends to continue its existing practice of flowing through farm transmission costs to the AESO based on a prescribed formula.⁸³⁸ Other flow-through items associated with AESO transactions have been approved as part of this decision, and it is therefore suitable for these costs to receive flow-through treatment.

7.4.2.2 Accounts that are a result of Commission directions

670. All of the companies included Y factor accounts or indicated the requirement for future Z factors related to future decisions issued by the Commission. The UCA acknowledged the need for a utility to have the opportunity to recover the costs related to changes in regulation.⁸³⁹ As discussed in Section 7.4, an exemption to certain Y factor criteria will be permitted for certain cost items that have been incurred by a company in compliance with a direction of the Commission.

7.4.2.2.1 AUC assessment fees

671. In Decision 2010-146, the Commission approved flow-through treatment of AUC assessment fees for ENMAX under its FBR plan.⁸⁴⁰ AUC assessment fees are common to all of the companies, and all of them asked for deferral or flow-through treatment of these fees.⁸⁴¹ Some of the companies did not request a specific flow-through account for these costs, as they had grouped these costs together with their hearing costs deferral account. The Commission will continue with flow-through treatment of AUC assessment fees. For those companies that included these fees in another deferral account with other types of costs, these companies are directed to separately identify the AUC assessment fees component in their Y factor calculations.

7.4.2.2.2 Effects of regulatory decisions

672. Several companies requested Y factors to flow through the impacts of regulatory decisions.⁸⁴² The Commission finds that regulatory efficiency would be achieved if the companies are able to treat the financial impact of items the Commission has already determined to be necessary as Y factor adjustments. The Commission therefore finds that the financial effects to companies that are clearly identified in a Commission direction may, with approval of the Commission, be included as Y factor adjustments in the annual PBR rate adjustment filings process. Specific changes related to generic cost of capital proceedings are discussed in Section 7.4.2.6.1 below.

⁸³⁷ Exhibit 110.01, AltaGas application, Section 1.1, paragraph 9, page 3.

⁸³⁸ Exhibit 100.02, Fortis application, Section 6.3, paragraphs 106-108, page 30.

⁸³⁹ Exhibit, 300.02, UCA evidence of Russ Bell, A21, page 33.

⁸⁴⁰ Decision 2010-146, Section 9.1.1, paragraph 100, page 16.

⁸⁴¹ Exhibit 98.02, ATCO Electric application, Section 6, paragraph 152, page 6-16; Exhibit 100.02, Fortis application, Section 6.1.3, paragraph 95, page 27; Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51; Exhibit 110.01, AltaGas application, Section 7.1.1, paragraph 81, page 23; ATCO Gas includes AUC administration costs in hearing costs according to Transcript, Volume 6, pages 918-919.

⁸⁴² Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 200-203, page 6-28; Exhibit 99.01, ATCO Gas application, Section 2.5.2.6, paragraph 108-109, page 38; Exhibit 100.02, Fortis application, Section 6.4.4, paragraphs 114-115, page 32; Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-2, page 51.

7.4.2.2.3 Hearing costs

673. All of the companies requested Y factor treatment for hearing costs presently collected through their hearing cost deferral accounts.⁸⁴³ The Commission considers that intervenor costs approved to be paid pursuant to AUC cost decisions are a result of directions from the Commission, and therefore are eligible for collection through a Y factor adjustment. The Commission considers that management has a reasonable level of control over its internal hearing costs, and therefore the company portion of hearing costs will be subject to the I-X mechanism.

674. The company portion of the hearing costs that will be subject to the I-X mechanism will be the average awarded company hearing costs for the years 2009, 2010 and 2011. This amount will be included in going-in rates for the purpose of determining the rates for 2013 replacing the amounts presently included in the revenue requirement for 2012 for the hearing cost deferral account. Intervenor costs will be treated as a flow-through Y factor account to be reconciled in the annual PBR rate adjustment filings.

7.4.2.2.4 AUC tariff billing and load settlement initiatives

675. EPCOR included a Y factor for AUC tariff billing and load settlement initiatives.⁸⁴⁴ The Commission considers that because these costs are a result of Commission directions they will be approved as a flow-through Y factor account to be reconciled in the annual PBR rate adjustment filings.

7.4.2.2.5 UCA assessment fees

676. The gas companies are required to make payments for UCA assessment fees. These are similar in nature to the AUC assessment fees and accordingly the Commission considers flow-through treatment to be warranted. The Commission understands that ATCO Gas included UCA fees as part of its hearing costs⁸⁴⁵ and that AltaGas has requested a PBR deferral account that includes both AUC and UCA assessments.⁸⁴⁶ To the extent that ATCO Gas and AltaGas included these fees in another deferral account with other types of costs, these companies are directed to separately identify the UCA assessment fees component in their Y factor calculations.

7.4.2.3 Accounts that meet the Y factor criteria and are eligible for flow-through treatment

677. The Commission has examined the following proposed Y factor accounts and finds that they satisfy the Y factor criteria established in Section 7.4 and therefore are eligible for flow-through treatment.

7.4.2.3.1 Municipal fees

678. Several companies indicated that they intend to continue with either a deferral account or flow-through treatment for franchise fees and property taxes. Fortis requested that its municipal

⁸⁴³ Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 152-155, page 6-16 to 6-17; Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.1, paragraph 58, page 23; Exhibit 100.02, Fortis application, Section 6.1.3, paragraphs 95-96, pages 27-28; Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51; Exhibit 110.01, AltaGas application, Section 7.1.1, paragraph 81, page 23.

⁸⁴⁴ Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51.

⁸⁴⁵ Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.1, paragraph 58, page 23.

⁸⁴⁶ Exhibit 110.01, AltaGas application, Section 7.1.1, paragraph 81, page 23.

franchise fee riders and its Rider A-1 municipal assessment riders continued.⁸⁴⁷ Continuation of existing rider mechanisms to collect municipal fees was also proposed by ATCO Electric⁸⁴⁸ and ATCO Gas.⁸⁴⁹ In addition, EPCOR requested a property, business and linear tax deferral account.⁸⁵⁰ Because these costs satisfy the Y factor criteria they will be treated as a flow-through item. Where there is an existing rider mechanism the companies are directed to use that mechanism and, in the absence of an existing rider mechanism, the companies will dispose of balances in a deferral account as part of the annual PBR rate adjustment filings process.

7.4.2.3.2 Load balancing

679. ATCO Gas requested continuation of its load balancing deferral account (LBDA). The UCA recommended the continued use of the load balancing deferral account, but recommended that ATCO Gas' suggestion to true-up the account every year instead of waiting until the account exceeds specified threshold levels should be denied.⁸⁵¹ Because the account meets the Y factor criteria, the Commission determines that ATCO Gas may continue to use its load balancing deferral account in its current form. The Commission considers that the continued use of a threshold approach, as proposed by the UCA, is necessary to minimize the regulatory burden of reviewing applications. Therefore, during the PBR term, the existing process for dealing with the load balancing deferral account will continue as described by ATCO Gas where "the recovery or refund of the LBDA balance is triggered if either of the North or South accounts exceeds \$5 million (receivable or payable) for six consecutive months, or if either account exceeds \$10 million in any one month."⁸⁵² ATCO Gas is directed to use a separate rider outside of the PBR formula to settle balances with customers.

7.4.2.3.3 Weather deferral

680. ATCO Gas requested continuation of its weather deferral account (WDA). The reduction to the risk that ATCO Gas faces with respect to weather was recognized in a previous GCOC proceeding in the form of a 100 basis points reduction to the equity thickness of ATCO Gas.⁸⁵³ The weather deferral account not only protects ATCO Gas in years when its earnings would otherwise be negatively impacted by warmer than normal weather, but it also protects customers in years when colder than normal weather would require them to pay higher utility bills. The UCA recommended the continued use of the weather deferral account, but recommended that ATCO Gas' suggestion to true up the account every year instead of waiting until the account exceeds specified threshold levels should be denied.⁸⁵⁴ Because the adjustment to risk has already been reflected in going-in rates, because the account meets the Y factor criteria, and because the account can have benefits for both the company and customers, ATCO Gas may continue to use its weather deferral account in its current form without annual true-ups. ATCO Gas described the current process as follows: "a WDA rate rider application is triggered to recover or refund the balance if and when either the North or South accounts is at or greater than \$7 million

⁸⁴⁷ Exhibit 100.02, Fortis application, Section 13.1, paragraph 149, page 41.

⁸⁴⁸ Exhibit 207.01, AUC-BOTHATCO-AE-6.

⁸⁴⁹ Exhibit 206.02, AUC-BOTHATCO-AG-6.

⁸⁵⁰ Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51.

⁸⁵¹ Exhibit 634.02, UCA argument, Section 10.1, paragraph 249, page 45.

⁸⁵² Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.7, paragraph 72, page 28.

⁸⁵³ Transcript, Ms. Wilson, Volume 7, page 1321.

⁸⁵⁴ Exhibit 634.02, UCA argument, Section 10.1, paragraph 249, page 45.

(receivable or payable) on April 30 of each year.”⁸⁵⁵ ATCO Gas is directed to use a separate rider outside of the PBR formula to settle balances with customers.

7.4.2.3.4 Production abandonment

681. ATCO Gas withdrew its request for this account in its application update subject to the results of the review and variance on Decision 2011-450.⁸⁵⁶ The issue is currently under consideration in other proceedings, and the Commission considers that in the interim this deferral account will continue as a Y factor. Pending the results of other proceedings reviewing the recoverability of production abandonment costs, the Commission will reassess whether the continuation of this Y factor under PBR is necessary. In the interim, while the issues around this deferral account are being addressed in other proceedings, ATCO Gas is directed to continue to track the balance associated with this deferral account. The settlement of the balance will not occur until the other proceedings have determined the proper treatment.

7.4.2.3.5 Income tax impacts other than tax rate changes

682. Several companies requested various income tax Y factor accounts. These accounts include:

- The income tax deductible capital cost deferral account and the deduction of deferrals for income taxes requested by ATCO Electric.⁸⁵⁷
- The income tax deductible capital costs requested by ATCO Gas.⁸⁵⁸
- The CRA re-assessment deferral and the income tax payable flow-through requested by Fortis.⁸⁵⁹
- The income tax timing differences flow-through account requested by AltaGas.⁸⁶⁰

683. The Commission will address the portion of the Y factor account relating to income tax rate changes in Section 7.4.2.6.2. All of the remaining income tax Y factor accounts relate to the treatment of temporary tax differences or the reassessment of prior income tax returns. The Commission understands that these types of adjustments only affect the earnings of regulated entities due to the use of the flow-through income tax method, and that most companies in other industries normalize their income tax expenses to reflect the impact of changes to future income tax liabilities and assets.

684. Calgary proposed that ATCO Gas should continue with deferral treatment for income tax deductible capital costs on the basis “that utility management cannot manage the level of expenditure for these items despite bona fide, competent and good faith efforts.”⁸⁶¹ The UCA suggested that the continuation of income tax deferral accounts is appropriate, and noted that in

⁸⁵⁵ Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.6, paragraph 69, pages 27-28.

⁸⁵⁶ Exhibit 389.01, ATCO Gas application updates, Section 2.4, paragraph 16, page 8.

⁸⁵⁷ Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 123-145, pages 6-10 to 6-15, and paragraph 147, page 6-15.

⁸⁵⁸ Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.8, paragraph 75, page 29.

⁸⁵⁹ Exhibit 100.02, Fortis application, Section 6.1.5, paragraphs 99-100, page 28 and Section 6.4.3, paragraph 113, page 32.

⁸⁶⁰ Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.

⁸⁶¹ Exhibit 629.01, Calgary argument, Section 10.2, page 48.

Decision 2009-214,⁸⁶² the Commission expressed its intention to initiate a proceeding which will address consistent income tax methodologies for all utilities.⁸⁶³

685. As noted by the UCA, the Commission, in Decision 2009-214, indicated that it intends to initiate a proceeding which will address consistent income tax methodologies for all utilities. The Commission confirms its intention to initiate a generic income tax proceeding following the release of this decision. In the interim, the Commission considers that material changes in income tax expenses that result from the treatment of temporary tax differences or the reassessment of prior income tax returns should be passed on to customers until such time as any change in income tax methodology may be directed by the Commission. Accordingly, the income tax Y factor accounts respecting the treatment of temporary tax differences or the reassessment of prior income tax returns requested by ATCO Gas, ATCO Electric, Fortis and AltaGas are approved. These changes will be addressed through Y factor adjustments as part of the annual PBR rate adjustment filings.

7.4.2.4 Accounts that are unforeseen events, and therefore should be assessed as Z factors instead

686. The discussion on specific items in this section is not intended to obligate the Commission to approve Z factor treatment in future proceedings for any of the items discussed. This section simply identifies the types of items that have been proposed as Y factors by the companies, but which should be tested as Z factors because of their unforeseen and infrequent nature. When Z factor applications are submitted the merits of each item will be tested in detail as to whether or not they actually qualify. The following accounts fall into this category.

7.4.2.4.1 Self-insurance/reserve for injuries and damages

687. Fortis,⁸⁶⁴ EPCOR,⁸⁶⁵ ATCO Electric⁸⁶⁶ and ATCO Gas⁸⁶⁷ all requested that their self-insurance deferral accounts be continued as Y factors. While there may be some activity in these accounts on an annual basis, the primary purpose of these accounts is to capture the effects of major events that are not covered by insurance. The Commission considers that during the PBR term the significant events that the companies are concerned about could be addressed as Z factors while the non-significant events should be covered by the I-X mechanism. The Commission will allow the companies to include a provision in their going-in rates calculated as follows. The provision will be equal to the average value of each event that was included in their deferral account or as an adjustment to their reserve account for the most recent five-year period. This amount is to be reflected in the companies going-in rates. The companies are directed to identify this adjustment to going-in rates in their compliance filings and the Commission will make a determination in the compliance filing decision as to whether or not the adjustment is reasonable.

⁸⁶² Decision 2009-214: ATCO Gas, 2008-2009 General Rate Application Phase I, Income Tax Module, Application No. 1553052, Proceeding ID. 11, November 12, 2009.

⁸⁶³ Exhibit 300.02, UCA evidence of Russ Bell, A21, page 30.

⁸⁶⁴ Exhibit 100.02, Fortis application, Section 6.1.4, paragraphs 97-98, page 28.

⁸⁶⁵ Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-2, page 51.

⁸⁶⁶ Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 156-162, pages 6-17 to 6-18.

⁸⁶⁷ Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.2, paragraph 59, page 24.

7.4.2.4.2 Depreciation rate changes

688. Fortis,⁸⁶⁸ ATCO Electric,⁸⁶⁹ ATCO Gas⁸⁷⁰ and AltaGas⁸⁷¹ all requested Y factors related to depreciation changes. The companies requesting these Y factors indicated that depreciation studies do not occur on an annual basis. However, even when new depreciation studies are performed, it is not certain that significant changes in depreciation rates will result. If a substantial change does occur, the change may be a result of changes in management assumptions, which would cause the change to not be eligible for flow-through treatment in the form of either a Y factor or Z factor. However, if the change results from some circumstance that is outside of management control, the change may be eligible for Z factor treatment. Due to the unforeseeable nature of depreciation changes, the infrequent occurrence, and the uncertainty as to whether the changes would be eligible for flow-through treatment, depreciation changes will not be treated as a Y factor.

7.4.2.4.3 International Financial Reporting Standards (IFRS)/accounting changes

689. Fortis⁸⁷² and AltaGas⁸⁷³ requested Y factor treatment for accounting changes. The Commission considers that impacts associated with major changes to accounting standards, whether it is the initial adoption of IFRS or any other modifications to accounting standards, should be infrequent. Other than the initial adoption of IFRS, it is unforeseeable when subsequent major changes to accounting standards will occur. In addition, Fortis recognized that the majority of the AUC Rule 026⁸⁷⁴ changes it would need to make are required for financial reporting purposes, and that regulatory reporting would likely not be affected.⁸⁷⁵ As a result, the Commission determines that because of the infrequent and unforeseeable nature of accounting changes, they should be assessed as Z factors.

7.4.2.4.4 Acquisitions

690. ATCO Electric,⁸⁷⁶ ATCO Gas⁸⁷⁷ and AltaGas⁸⁷⁸ all requested several different types of acquisitions to be treated as Y factors including: REA acquisitions, gas co-op acquisitions, and municipal annexations. The UCA objected to the flow-through treatment of these accounts on the basis that a company should only make an acquisition when it is economically beneficial for the company to do so, and therefore allowing flow-through treatment is not necessary.⁸⁷⁹ The Commission considers that under certain circumstances it may not actually be left to the discretion of management as to whether or not the acquisition is made. In those circumstances, it may be necessary to assess the impact of an acquisition through a Z factor application. Acquisitions within the control of management would not generally qualify as either a Z factor or a Y factor.

⁸⁶⁸ Exhibit 100.02, Fortis application, Section 6.4.1, paragraph 110, page 31

⁸⁶⁹ Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 194-195, pages 6-26 to 6-27.

⁸⁷⁰ Exhibit 99.01, ATCO Gas application, Section 2.5.2.4, paragraph 104, page 37.

⁸⁷¹ Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4.

⁸⁷² Exhibit 100.02, Fortis application, Section 6.1.2, paragraph 92-94, pages 26-27.

⁸⁷³ Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.

⁸⁷⁴ Rule 026: *Rule Regarding Regulatory Account Procedures Pertaining to the Implementation of the Internal Financial Reporting Standards*, effective December 20, 2012 (Rule 026).

⁸⁷⁵ Transcript, Mr. Lorimer, Volume 11, page 2161.

⁸⁷⁶ Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 191-191, page 6-26.

⁸⁷⁷ Exhibit 99.01, ATCO Gas application, Section 2.5.2.3, paragraph 103, page 37.

⁸⁷⁸ Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.

⁸⁷⁹ Exhibit 634.02, UCA argument, Section 10.1, paragraphs 277-282.

7.4.2.4.5 Defined benefit pension plan

691. In its 2010 Pension Common Matters application the ATCO utilities (ATCO Gas, ATCO Electric and ATCO Pipelines) applied for deferral account treatment for their pension expenses. In Decision 2010-189,⁸⁸⁰ the Commission approved a deferral account for each ATCO utility to recover the special payments required to amortize an unfunded liability associated with the defined benefit portion of the Canadian Utilities Limited defined benefit pension plan.⁸⁸¹ In Decision 2010-553,⁸⁸² the Commission further explained that the purpose of the special payment deferral accounts is to capture the impact of timing differences that may arise between when special payment amounts are approved by the Alberta Superintendent of Pensions and consequently paid by the ATCO utilities and when amounts are approved by the Commission for inclusion in revenue requirement.⁸⁸³ These differences were captured in a deferral account to keep both customers and shareholders whole.

692. ATCO Gas and ATCO Electric requested an expansion of their special payment deferral accounts by way of Y factor treatment associated with their defined benefit pensions plans.⁸⁸⁴ AltaGas requested the creation of a pension deferral account with respect to their defined benefit pension plan costs.⁸⁸⁵ These companies argued that when actuarial evaluations are made they can result in significant changes to the funding of the plan. Further, it is not simple to isolate changes resulting from special payment requirements resulting from an under funding of the plan from current service or other funding requirements.

693. The UCA recommended denial of the expansion of existing pension deferral accounts. The UCA referenced Decision 2010-189 where the Commission recognized the difference between special payments and current service pension costs, and the Commission determined that current service pension costs are no different than other compensation costs and therefore should not receive deferral treatment.⁸⁸⁶

694. The Commission agrees with the UCA that current service pension costs are no different from other compensation costs and accordingly denies the requested expansion of the ATCO Gas and ATCO Electric special payment deferral accounts and the creation of a pension deferral account for AltaGas.

695. With respect to the existing special payment deferral accounts of ATCO Gas and ATCO Electric distribution, the Commission considers that under a PBR environment there is no need to monitor the timing differences for which the deferral accounts were created. Accordingly, the existing special payment deferral accounts for ATCO Gas and ATCO Electric distribution will be discontinued upon implementation of PBR.

⁸⁸⁰ Decision 2010-189: ATCO Utilities, Pension Common Matters, Application No. 1605254, Proceeding ID. 226, April 30, 2010.

⁸⁸¹ Decision 2010-198, paragraph 94.

⁸⁸² Decision 2010-553: ATCO Utilities, Compliance Filing Pursuant to Decision 2010-189, ATCO Utilities Pension Common Matters, Application No. 1606289, Proceeding ID. 693, December 1, 2010.

⁸⁸³ Decision 2010-553, Section 3.1, paragraph 17, page 4.

⁸⁸⁴ Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 113-118, pages 6-8 to 6-10; Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.5, paragraphs 65-68, pages 26-27.

⁸⁸⁵ Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4.

⁸⁸⁶ Exhibit 634.02, UCA argument, Section 10.1, paragraph 244, page 44.

696. In the event of a material change to a company's special payment obligations (either positively or negatively), a Z factor application would be available to address this change.

7.4.2.4.6 Insurance proceeds

697. ATCO Gas proposed a deferral account for insurance proceeds in compliance with AUC Rule 026.⁸⁸⁷ The Commission considers that if an event involving insurance proceeds that would have a material impact on operating costs occurs, then ATCO Gas may apply for flow-through treatment as a Z factor.

7.4.2.5 Accounts that do not meet the outside-of-management-control criterion

7.4.2.5.1 Variable pay

698. ATCO Gas⁸⁸⁸ and ATCO Electric⁸⁸⁹ proposed the continued use of deferral accounts for variable pay and AltaGas proposed the continued use of its short term incentive plan deferral account as Y factors.⁸⁹⁰ The UCA argued that variable pay is only one component of compensation and is subject to the same management control as all other components of compensation.⁸⁹¹ The Commission considers that companies should be left to develop employee compensation programs that will have the best impact on their performance, and therefore Y factor accounts related to variable pay are not approved. The Commission considers that such an approach complies with PBR Principle 1 that states that "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."⁸⁹²

7.4.2.5.2 Vegetation management

699. ATCO Electric requested Y factor treatment for vegetation management costs on the basis that the costs are outside of the control of management because there are a limited number of contractors that do the work, and that competition for services significantly increases the rates that the contractors charge.⁸⁹³ The UCA indicated that "the creation of a Vegetation Management deferral account reduces the incentive to find creative and innovative ways to manage this function, and reduce costs."⁸⁹⁴ The Commission does not accept ATCO Electric's argument. Vegetation management costs are entirely within the control of management.

7.4.2.5.3 Head office allocation changes

700. ATCO Gas⁸⁹⁵ and ATCO Electric⁸⁹⁶ requested Y factor treatment for changes to head office allocation percentages. The UCA expressed concern about the possibility of cost shifting under PBR between affiliates and the companies and proposed that significant changes in corporate structure and affiliate agreements should be reviewed by the Commission and, if approved, the effects of the change should be flowed through to customers.⁸⁹⁷ Several of the

⁸⁸⁷ Exhibit 389.01, ATCO Gas application updates, Section 2.4, paragraph 16, page 8.

⁸⁸⁸ Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.3, paragraph 60, page 24.

⁸⁸⁹ Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 148-151, page 6-16.

⁸⁹⁰ Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4.

⁸⁹¹ Exhibit 634.02, UCA argument, Section 10.1, paragraph 243, page 44.

⁸⁹² Bulletin 2010-20, Rate Regulation Initiative, Section 3, page 2.

⁸⁹³ Transcript, Mr. Freedman, Volume 4, page 755.

⁸⁹⁴ Exhibit 634.02, UCA argument, Section 10.1, paragraph 261, page 48.

⁸⁹⁵ Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 171-176, pages 6-20 to 6-22.

⁸⁹⁶ Exhibit 99.01, ATCO Gas application, Section 2.5.1.3.1, paragraphs 79-80, page 30.

⁸⁹⁷ Exhibit 634.02, UCA argument, Sections 11.3 and 11.4, paragraphs 299-309, pages 55-56.

companies indicated that they would be willing to apply for Commission approval of material changes to affiliate agreements.⁸⁹⁸

701. The Commission finds that head office allocations are not outside of the control of the companies' management or that of their parent company and do not qualify as a Y factor.

702. EPCOR's witness, Dr. Weisman, indicated that the exclusion of earnings sharing mechanisms from a PBR plan should eliminate the need for strict monitoring of affiliate transactions because the incentive to shift costs to affiliates to avoid sharing earnings is eliminated.⁸⁹⁹ The Commission agrees. As the Commission has not approved earnings sharing mechanisms in this decision, the need to isolate changes to affiliate agreements in a Y factor account has been substantially mitigated. However, the Commission has approved re-opener provisions and an efficiency carry-over mechanism that rely on the calculation of a return on equity. Therefore, the companies are directed to file all new material affiliate agreements, material changes to affiliate agreements and significant changes to corporate structure that have a substantial impact on the operating costs of the company.

7.4.2.5.4 AMR implementation

703. AltaGas requested Y factor treatment for the implementation of AMR (automated meter reading). AltaGas believes that if it were to implement AMR during the PBR term that the payoff for the investment would not be possible during a single PBR term. The UCA objected to the inclusion of an AMR deferral account indicating that "[t]he type of innovation covered by AMR is the same type of efficiency gains that is intended by PBR Principle 1, that a PBR should provide the same incentives as a competitive market."⁹⁰⁰ The Commission agrees. AMR should be undertaken only if it will achieve efficiencies that will outweigh the costs. This decision is not outside of management control. Therefore there is no need for Y factor treatment.

7.4.2.6 Accounts that do not meet the inflation factor criterion

7.4.2.6.1 Changes in the cost of capital

704. Some of the companies asked for a Y factor adjustment to rates to account for changes to the Commission approved rate of return on equity.⁹⁰¹ Fortis,⁹⁰² ATCO Gas⁹⁰³ and ATCO Electric⁹⁰⁴ requested a Y factor adjustment to recover the impacts of changes in financing rates (i.e., cost of debt).

705. In its GCOC decisions, the Commission establishes an approved ROE for the companies under its jurisdiction. As well, it has been the Commission's practice to account for the differences in risk among the individual companies by adjusting their capital structures (i.e., the

⁸⁹⁸ Transcript, Ms. Wilson, Volume 4, page 780; Exhibit 384.02, AUC-ALLUTILITIES-FAI-25(b); Exhibit 381.01, AUC-ALLUTILITIES-AUI-25(a).

⁸⁹⁹ Transcript, Dr. Weisman, Volume 9, page 1765.

⁹⁰⁰ Exhibit 634.02, UCA argument, page 35, paragraph 193.

⁹⁰¹ Exhibit 98.02, ATCO Electric application, page 6-28, paragraph 202; Exhibit 99.01, ATCO Gas application, page 38, paragraph 109; Exhibit 100.02, Fortis application, page 32, paragraph 114; Exhibit 103.02, EPCOR application, page 51, table 2.3.5-2; Exhibit 110.01, AltaGas application, page 24, paragraph 82.

⁹⁰² Exhibit 100.02, Fortis application, Section 6.4.2, paragraphs 111-112, pages 31-32.

⁹⁰³ Exhibit 99.01, ATCO Gas application, Section 2.5.2.5, paragraphs 105-107, pages 37-38.

⁹⁰⁴ Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 196-199, page 6-27.

ratio of equity to debt).⁹⁰⁵ Under cost of service regulation, the Commission approves a forecast of the company's cost of debt in its revenue requirement.

706. Both the I and the X in the PBR formula apply to the companies' distribution rates that are established through a cost of service proceeding. All of the distribution costs that are recovered through those rates, including the cost of debt and the cost of equity, are included in the going-in rates. In Section 5.2.1 of this decision the Commission determined that changes in the cost of capital (both debt and equity) are captured in the approved I factor. This means that the approved I factor in the I-X mechanism reflects changes in all of the companies' costs over time, including the cost of debt and equity. Therefore, the Commission finds that no specific changes to customer rates should be made to take into account changes in the Commission's approved generic ROE or changes in the cost of debt during the PBR term.

707. The Commission agrees with Dr. Lowry when he stated:

But the one that raises an eyebrow to me in this category is the financing of – financing rate changes. I have never seen a plan involving an index that also involves an adjustment for financing rate changes. You would think that the – there is a danger of double-counting of that since [if] there is a change in interest rates eventually it will have an effect on general inflation rates. And this is particularly so inasmuch as the other – the second inflation measure proposed by ATCO Gas is the CPI for Alberta...⁹⁰⁶

708. It follows that including a separate flow-through component for changes in the ROE would also amount to double-counting.

709. The Commission recognizes that the conclusions it has reached with respect to the treatment of the cost of equity in the PBR framework are different than the approach taken by the Commission in the ENMAX FBR framework. The Commission has benefited from the evidence and testimony on this matter that was not available to it in the ENMAX FBR proceeding.

710. The Commission understands that a change to the risk profile of the companies may result from the transition to PBR. The Commission will consider this issue in the upcoming GCOC proceeding. If the Commission determines that there is a change to the risk profile of the companies as a result of the transition to PBR, the Commission will make a one-time adjustment to the companies' rates to reflect any adjustment to the companies' capital structure.

7.4.2.6.2 Income tax rates

711. ATCO Electric⁹⁰⁷ proposed Y factor treatment to recover any changes to income tax rates. AltaGas' witness, Mr. Retnanandan, discussed why AltaGas would not try to recover the impact of tax rate changes from customers, stating "potentially on the PBR, the changes in tax rates would be covered under something like the inflation factor. So that would be duplicating, if you would, to recognize the income tax rate changes as part of the AUI Z factors."⁹⁰⁸ The Commission considers that major changes to the calculation of income tax payments, such as a change in income tax rates, should impact the entire economy, and as such, should be captured

⁹⁰⁵ See for example, Decision 2011-474: 2011 Generic Cost of Capital, Application No. 1606549, Proceeding ID No. 833, December 8, 2011, paragraph 169.

⁹⁰⁶ Transcript, Volume 14, pages 2660, line 18 to page 2661, line 2.

⁹⁰⁷ Exhibit 98.02, ATCO Electric application, Section 6, paragraph 146, page 6-15.

⁹⁰⁸ Transcript, Mr. Retnanandan, Volume 9, page 1614.

by the I factor. To the extent that a change could occur that only impacts a select group of companies, and therefore not be captured by the I factor, it may be warranted to consider the change as a Z factor. However, due to the infrequent nature of such changes, it is not necessary to establish a Y factor account.

7.4.2.7 Requested capital project Y factors

712. Some items classified as Y factors by the companies relate to specific capital programs that may or may not proceed at some point during the PBR term that the companies considered to fall outside of the revenues that would be available to fund the project through the application of the I-X mechanism and customer growth. These proposed Y factors are listed in the following table.

Table 7-3 Capital-related flow-through items requested by utilities

AltaGas	ATCO Electric	ATCO Gas	EPCOR	Fortis
n/a	Material investments unique in nature	Material investments unique in nature	n/a	Externally driven capital expenditures
n/a	Distribution to transmission contributions	Transmission driven costs (capital component)	n/a	n/a
n/a	n/a	Urban mains replacement expenditures	n/a	n/a

713. The Commission considers that eligibility for these capital-related items should be assessed by way of a capital tracker application. See Section 7.3.2.4.

7.4.3 Collection mechanism for third party flow-through items

714. For flow-through items that have existing rider mechanisms in place, the companies generally suggested the continuation of the existing mechanisms. The changes to the rate riders associated with these mechanisms are separate from the rate adjustments resulting from the I-X mechanism. Due to the material nature of costs and the processes that are already in place for certain flow-through items, true-ups may be required more frequently than the annual PBR filings. One example is quarterly applications for SAS (system access service) riders. Some other flow-through items have traditionally been structured to have less than annual true-up mechanisms to avoid frequent true-up applications. Examples include the load balancing deferral account and weather deferral account for ATCO Gas. These deferral accounts have historically relied on a threshold triggering mechanism to determine when applications are submitted.

715. The companies proposed the continuation of several existing riders outside of the I-X mechanism:

- Fortis proposed to continue to use its transmission adjustment rider to flow through AESO charges, Rider A-1 Municipal Assessment Rider, Municipal Franchise Fee Riders, and the Balancing Pool Allocation Rider.⁹⁰⁹
- EPCOR proposed to continue to deal with its SAS rates and its transmission charge deferral account through separate applications.⁹¹⁰

⁹⁰⁹ Exhibit 100.02, Fortis application, Section 13.1, paragraphs 148-149, page 41.

⁹¹⁰ Exhibit 103.02, EPCOR application, Section 3.3, paragraph 255, page 82.

- ATCO Electric proposed continued use of its Rider S for its SAS deferral account.⁹¹¹
- ATCO Gas proposed to recover its transmission costs through its existing Rider T mechanism.⁹¹²
- AltaGas proposed to continue to address its gas procurement function and costs related to transportation by third parties through its existing gas costs recovery rate and third party transportation rate mechanisms.⁹¹³

Commission findings

716. The Commission considers that to the extent there are existing processes in place that are working well for addressing changes to the approved flow-through items, and those processes do not correspond to the timing of the annual PBR rate adjustment proceedings, these applications should continue to be dealt with as they are today.

7.4.4 Collection mechanism for other Y factor amounts

717. Unless otherwise directed, all Y factor costs incurred by a company other than the flow-through accounts that are collected through separate rate riders addressed in sections 7.4.2.1 and 7.4.2.3 above should be tracked and settled as a Y factor adjustment in its annual PBR rate adjustment filings.

718. The Y factor portion of the annual PBR rate adjustment filings will be comprised of two parts, the first being a provision for the Y factor amounts to be included in rates for the upcoming year, and the second being a true-up between the provision included in rates for the Y factor in the prior year and the actual amounts incurred in the prior year.

719. The provision for the first year of the PBR term which will be included in the compliance filing to this decision will generally be based on the amount that would have been approved for the 2012 test year of the GTA or GRA proceeding that forms the going-in rates (unless a different amount is specified elsewhere in this decision). Because these items will not be subject to the I-X indexing, the companies are directed to remove the amounts included in the 2012 revenue requirement from going-in rates in their compliance filing.

720. The Commission recognizes that addressing the impact of certain Commission directions impacting rates may be better suited to an adjustment to the rates that will be subject to the I-X mechanism rather than through a Y factor. The Commission will make the determination of how to incorporate the result of any directed rate adjustment at the time it makes the relevant decision.

721. The Commission also recognizes that some of the companies may have placeholders in place for certain expenses as part of the GTA or GRA proceedings that form the going-in rates for PBR. To the extent that other proceedings in front of the Commission will establish the approved expenses, and the companies will need to adjust their going-in revenue requirements, the Commission considers that the differences that exist between the placeholder amounts and the final approved amounts will be treated as Y factor adjustments or adjustments to rates that will be subject to the I-X mechanism, depending on the circumstances of the adjustment.

⁹¹¹ Exhibit 98.02, ATCO Electric application, Section 6, paragraph 101, page 6-5.

⁹¹² Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.4, paragraph 64, page 25.

⁹¹³ Exhibit 110.01, AltaGas application, Section 1.1, paragraph 9, page 3.

7.4.5 Other existing deferral accounts, reserve accounts or flow-through mechanisms

722. Companies may not have identified all of the items they plan to flow through to customers in their PBR plans. For example ATCO Gas and ATCO Electric did not mention the continued use of existing riders to collect franchise fees and property taxes in their applications, but clarified that the existing treatment would continue in IR (information request) responses.⁹¹⁴ Similar omissions may have occurred for other PBR proposals because of assumptions made by the companies that the existing treatments will continue. Therefore, the Commission directs the companies to identify all of the riders that they intend to utilize during the PBR term that are outside of the I-X mechanism, describe the costs that are being collected on the riders, and explain why it is reasonable to continue to flow through the costs. Any items that have not been approved as a Y factor in this decision or are not identified as separate riders outside of the I-X mechanism by the companies in their compliance filings will be subject to the I-X mechanism.

8 Re-openers and off-ramps

723. A re-opener serves as a safeguard against unexpected results in the event that there is a problem with the design or operation of the plan that makes its continued operation untenable. All of the companies proposed that their PBR plans include a re-opener. As well, Calgary proposed a re-opener for ATCO Gas.⁹¹⁵

724. An off-ramp is likewise intended to provide a safeguard against unexpected results in the operation of the PBR plan. Proponents of an off-ramp distinguished it from other forms of re-openers; arguing that once triggered, an off-ramp allows for the whole of the PBR plan to be examined and possibly terminated, whereas a re-opener is generally intended to provide an opportunity to investigate and modify a particular component in the operation or design of the PBR plan.⁹¹⁶ NERA stated that re-openers and off-ramps are common features of incentive plans and recommended their inclusion.⁹¹⁷

725. As with the ENMAX FBR plan, EPCOR and AltaGas distinguished between unforeseen events that impact one or more elements of a PBR plan (to be considered by way of a re-opener) from events that jeopardize the PBR plan in its entirety (to be considered by way of an off-ramp) and accordingly both proposed separate re-opener and off-ramp. The UCA and the CCA simply urged the Commission to adopt the off-ramp that was approved for ENMAX in Decision 2009-035.

726. Fortis, ATCO Electric and ATCO Gas did not include specific off-ramp proposals in their respective PBR plans.⁹¹⁸ They instead proposed that provisions for a re-evaluation of their entire PBR plans be addressed as part of the process for re-opening and reviewing a PBR plan, if necessary. Fortis also noted that any “event material enough to merit consideration as to plan

⁹¹⁴ Exhibit 207.01, AUC-BOTHATCO-AE-6; Exhibit 206.02, AUC-BOTHATCO-AG-6

⁹¹⁵ Exhibit 298.02, Calgary evidence, page 29.

⁹¹⁶ Exhibit 103.02, EPCOR application, page 77; Exhibit 634, UCA argument, page 58 (taken from Exhibit 228.01, page 55).

⁹¹⁷ Exhibit 391.02, NERA second report, page 48, paragraph 104.

⁹¹⁸ Exhibit 631.01, ATCO Electric argument, paragraph 265; Exhibit 632.01, ATCO Gas argument, paragraph 290; Exhibit 633.01, Fortis argument, paragraphs 228-229

change or potential termination could be brought forward under a Z factor application.”⁹¹⁹ The UCA, the CCA and IPCAA all supported the inclusion of a re-opener. With respect to off-ramps, Calgary⁹²⁰ agreed with the approach advanced by ATCO Gas.

Commission findings

727. A re-opener is commonly included in a PBR plan in order to address specific problems with the design or operation of a PBR plan that may arise or come to light as the term of the PBR plan unfolds, and which may have a material impact on either the company or its customers which cannot be addressed through other features of the plan. No party recommended proceeding with a PBR plan without including the facility for a re-opening and review of the plan if it is determined that there may be a problem with the plan. The Commission agrees that a facility to re-open and review the plan is a necessary element of any PBR plan.

728. However, the Commission agrees with Fortis, ATCO Electric and ATCO Gas that a specific facility for an off-ramp, as distinct from a re-opener, is not required in a PBR plan. All that is required, in the Commission’s view, is an opportunity to re-open and review a PBR plan if a design or application flaw comes to light during the term of the PBR plan.

729. Accordingly, the Commission finds that any party, including the Commission on its own motion, will be permitted to bring an application to re-open and review a PBR plan, if there is sufficient evidence that there is a problem that cannot be resolved through another avenue available under the plan. In this regard, the Commission has approved in the PBR plans a number of mechanisms, including Z factors, K factors and various Y factors that allow for adjustments to rates outside of the adjustments required by the application of the I-X mechanism.

8.1 Specific proposals for re-openers

730. Parties to the proceeding proposed a number of events that should, in their view, lead to a re-opening and review of a PBR plan. The Commission has considered each of these events and made a determination as to whether each constitutes sufficient evidence that there is a problem with a PBR plan that can only be remedied by re-opening and review the plan.

731. Both the UCA and the CCA recommended that the Commission adopt a re-opener and proposed that the events leading to a re-opener as approved for ENMAX in Decision 2009-035 be adopted in this decision. In Decision 2009-035, the Commission accepted that the following events would generally require a re-opening of the ENMAX plan: if circumstances changed in a substantial or unforeseen manner; changes in regulatory status; changes to ENMAX’s controlling ownership; or a misrepresentation by ENMAX.⁹²¹ With regard to specific events that would require a re-opening and review of the ENMAX plan, the Commission accepted the following: a failure to meet a specific performance standard for two consecutive years; material changes in accounting standards that have an annual impact greater than \$5 million; expansion of ENMAX’s service area where more than 10,000 customers are included within the expanded area; ROE results that are more than 300 basis points above or below the approved ROE for two

⁹¹⁹ Exhibit 633.01, Fortis argument, page 102.

⁹²⁰ Exhibit 629.01, Calgary argument, page 54.

⁹²¹ Decision 2009-035, page 50

consecutive years; and an actual ROE result that is 500 basis points above or below the approved ROE for one year.⁹²²

732. Additionally, the CCA requested that, in the event that EPCOR's parent acquired additional businesses which had an impact on the amount of shared services allocated to EPCOR, a deferral account should be established and that it should not be included as a re-opener.⁹²³ IPCAA specifically proposed that a re-opener should address any material degradation in customer service and urged the Commission to establish service quality standards in advance of any implementation of a PBR plan.

733. For ease of reference, the events that were proposed by each distribution company and by Calgary as evidence that a PBR plan should be re-opened and reviewed are set out in the table below:

Table 8-1 Summary of proposed re-opener mechanisms

	Fortis⁹²⁴	EPCOR⁹²⁵	ATCO Electric	AltaGas⁹²⁶	ATCO Gas	Calgary
ROE Re-opener	ROE before ESM is +/- 300 basis points above or below approved ROE.*	ROE is +/- 300 basis points* above/below approved ROE in two consecutive years. OR Actual ROE is +/- 500 basis points above/below approved ROE for one year.	If ESM, ROE before ESM is +/- 300 basis points above/below approved ROE. OR If no ESM, actual ROE is +/- 300 basis points above/below approved ROE.* ⁹²⁷	Actual weather normalized ROE is +/- 300 basis points above/below approved ROE in two consecutive years. OR Actual ROE is +/- 400 basis points above approved ROE for one year.	If ESM, actual ROE after ESM is +/- 300 basis points above/below approved ROE. OR If no ESM, actual ROE is +/- 300 basis points above/below approved ROE. Actual ROE will be normalized. If no weather deferral account or if weather deferral account is a Z factor, then use actual ROE. ⁹²⁸	Actual ROE is 300 basis points below approved ROE.
Default supplier Re-opener			Directed to resume role of default energy supplier. ⁹²⁹	Material change in the default supply regulations.	Directed to resume role of default energy supplier. ⁹³⁰	

⁹²² Decision 2009-035, page 50.

⁹²³ Exhibit 636.01, CCA argument, at paragraphs 331-333.

⁹²⁴ Exhibit 100.02, Fortis application, page 35, paragraphs 126.

⁹²⁵ Exhibit 103.02, EPCOR application, page 79, paragraph 241.

⁹²⁶ Exhibit 110.01, AltaGas application, page 27, paragraph 87.

⁹²⁷ Exhibit 292.01, AUC-ALLUTILITIES-AE-16.

⁹²⁸ Exhibit 632.01, ATCO Gas argument, page 88, paragraph 285.

⁹²⁹ Exhibit 98.02, ATCO Electric application, page 10-1, paragraph 234.

	Fortis ⁹²⁴	EPCOR ⁹²⁵	ATCO Electric	AltaGas ⁹²⁶	ATCO Gas	Calgary
Customer size/service area Re-opener		Expansion of service area of more than 10,000 additional customers in expansion area.	Loss of a franchise resulting in loss of 20,000 or more customers. ⁹³¹	Loss of 1000 service sites, excluding service site additions.	Loss of a franchise resulting in loss of 20,000 or more customers. ⁹³²	
Accounting standard Re-opener		Material changes in accounting standards causing an annual impact on total revenue or expenses of >\$2.5 million in aggregate in any one year.				
Service quality Re-opener		Failure to meet service quality performance target for two consecutive years.				
Cost of debt Re-opener				Spread between the embedded cost of debt and the I factor is ≥ 400 basis points.		
Z factor Re-opener				Cumulative, net, annual impact of Z factors on actual weather normalized ROE is $\geq \pm 75$ basis points in a single year.		
Management structure Re-opener				Material change in the management structure of AltaGas.		

* Approved ROE is the ROE approved by the Commission, generally in a generic cost of capital decision; most recently in Decision [2011-474](#).

⁹³⁰ Exhibit 99.01, ATCO Gas application, page 43, paragraph 124.

⁹³¹ Exhibit 98.02, ATCO Electric application, page 10-1, paragraph 234.

⁹³² Exhibit 99.01, ATCO Gas application, page 43, paragraph 124.

734. Additionally, and for ease of reference, the specific events that were proposed to initiate an off-ramp proposed by EPCOR, AltaGas, the UCA and the CCA are set out in the table below:

Table 8-2 Summary of proposed off-ramp mechanisms

Proposed off-ramp	EPCOR⁹³³	AltaGas	ENMAX off-ramps supported by CCA⁹³⁴ / UCA⁹³⁵
Substantial change in circumstances	Substantial and unforeseen change in circumstance that renders continuation of PBR unjust or unreasonable. A substantial change in circumstance is defined as a change that increases distribution or transmission costs by \$1 million or \$0.50 million, respectively and these costs cannot be addressed as a Z factor.		Circumstances change in a substantial or unforeseen manner.
Regulatory status	Change in regulatory status if EPCOR no longer regulated by the Commission or a successor of the Commission.		Change in regulatory status.
Change in tax status	Change that results in a change in EPCOR'S taxable status.		
Change in control		Sale in controlling interest of AltaGas shares or disposition of all assets. ⁹³⁶	Change in control.

Commission findings

735. In keeping with the Commission's finding that a specific facility for an off-ramp (as distinct from a re-opener) is not required in a PBR plan, the Commission will consider together the proposals made by parties for events that would result in either a re-opener or an off-ramp and determine whether each of these is sufficient to result in a re-opening and review of a PBR plan.

8.1.1 Return on equity

736. Common among the companies and the interveners were proposals to re-open and review a PBR plan if the actual ROE earned by a company exceeded the approved ROE by more than a pre-determined amount and, in some cases, fell below the approved ROE by a pre-determined amount.⁹³⁷ It was generally argued that earning an actual ROE that is 300 basis points above or below the approved ROE is a sufficient indication that the PBR plan should be re-opened and reviewed. However, the parties differed as to whether the 300 basis point variance needed to be

⁹³³ Exhibit 103.02, EPCOR application, page 77.

⁹³⁴ Exhibit 636.01, CCA argument, page 115.

⁹³⁵ Exhibit 634.01, UCA argument, page 57, paragraph 320.

⁹³⁶ Exhibit 628.01, AltaGas argument, page 64.

⁹³⁷ Exhibit 98.02, ATCO Electric application, page 10-1, paragraph 233; Exhibit 99.01, ATCO Gas application, page 42, paragraph 123; Exhibit 100.02, Fortis application, page 36, paragraph 126; Exhibit 103.02, EPCOR application, page 79, paragraph 241; Exhibit 110.01, AltaGas application, page 27, paragraph 87; Exhibit 298.02, Calgary evidence, page 48, paragraph 169; Exhibit 634.02, UCA argument, page 58, paragraph 321; Exhibit 636.01, CCA argument, pages 112-113, paragraph 326.

recurring and whether the application of the measure should be symmetrically applied to both over and under-earning. EPCOR also proposed that a 500 basis point variance in one year should result in a re-opening of a PBR plan.⁹³⁸

Commission findings

737. The Commission finds that a material variance in the actual ROE achieved by a company when compared to the approved ROE may be an indicator that a PBR plan should be reviewed. The Commission expects that earnings may fluctuate from year to year and therefore finds that an earned ROE 300 basis points above or below the approved ROE in a single year is not sufficient evidence, on its own, that a PBR plan should be reviewed. However, the Commission does agree with the proposal of the CCA and EPCOR that an earned ROE that is 500 basis points above or below the approved ROE in a single year is sufficient to warrant consideration of a re-opening and review of a PBR plan. The Commission also agrees with the CCA, EPCOR and AltaGas that an earned ROE that is 300 basis points above or below the approved ROE for two consecutive years would constitute sufficient evidence to warrant consideration of a re-opening and review of a PBR plan. Both of the gas distribution companies have indicated that weather normalized ROE should be used in the assessment of re-openers. The Commission considers that the fluctuations in earnings caused by variations from normal weather typically experienced by the gas distribution companies would not be an indication that the operation of a PBR plan needs reconsideration. Therefore, the Commission accepts the use of a weather normalized ROE, as proposed by the gas distribution companies, to eliminate the possibility that variations in weather might trigger a re-opener.

738. The Commission has considered whether the rate of return on equity to be used for the purposes of determining if a company's earnings exceed the +/-300 or +/-500 basis point thresholds should be the ROE included in the going-in rates or the approved generic ROE for the year(s) in which the need for a re-opener is to be considered. Consistent with the Commission's determinations in Decision 2009-035⁹³⁹ and Decision 2010-146,⁹⁴⁰ dealing with the ROE used for the purpose of the ENMAX earning sharing mechanism, the Commission will utilize the Generic Cost of Capital ROE which may be determined from time to time by the Commission, as the ROE from which to calculate the +/-300 or +/-500 basis point re-opener thresholds.

739. The actual ROE of the companies to be used to determine whether a re-opener is warranted, will be the calculated in the same way as the ROE reported in the companies' annual AUC Rule 005 filings.

8.1.2 Change in service area

740. All of the companies, with the exception of Fortis, proposed that a material change to their service area or the number of customers to be served in their service area should result in a re-opening and review of their PBR plans. In this regard, EPCOR expressed concern with the potential for an unanticipated expansion in its service territory, while ATCO Electric, ATCO Gas and AltaGas were concerned with the potential for a material loss of customers.

741. Although a material change in service territory or number of customers may not signal that there is something wrong with the design or operation of a PBR plan, the Commission

⁹³⁸ Exhibit 103.02, EPCOR application, page 79, paragraph 241.

⁹³⁹ Decision 2009-035, paragraphs 418-419.

⁹⁴⁰ Decision 2010-146, paragraphs 118-119.

agrees that such an event may warrant a re-opening and review of the affected company's PBR plan because the event may have a material impact on the company. The Commission considers that both a material contraction and expansion of customers or service territories may indicate that a re-opening and review of a PBR plan is required. With regard to the materiality thresholds proposed for the expansion or contraction of a company's service territory or customer base, the Commission considers that it is preferable to determine materiality on a case by case basis because materiality will vary from company to company and over time. However, in some cases a Z factor application may be sufficient, see Section 7.4.2.4.4.

8.1.3 Default supply obligations

742. ATCO Electric, ATCO Gas and AltaGas all identified, as events that would result in a re-opening and review of their respective plans, changes to the default supply regulation or a regulatory direction with respect to the assumption of default supply obligations in the case of ATCO Gas and ATCO Electric. The Commission has approved the creation of a Z factor in the PBR plans as more particularly set out in Section 7.2 of this decision. The Commission considers matters related to a change in law or a regulatory direction requiring a company to assume default supply obligations are best dealt with by way of an application for a Z factor adjustment, rather than as a re-opener. Nevertheless, if the event is such that it cannot be dealt with through a Z factor or other mechanism in the plan, an application for consideration of a re-opener could be filed.

8.1.4 Accounting standards

743. EPCOR proposed that material changes in accounting standards be included as an event that would signal the requirement for a re-opening and review of a PBR plan. Fortis⁹⁴¹ and AltaGas⁹⁴² identified material changes in accounting standards as a matter that should be addressed through a Y factor. The Commission agrees that material accounting changes may require an adjustment to rates under a PBR plan, but the impact of accounting changes should properly be considered in a Z factor application and do not necessarily signal that there is a problem with the design or operation of a PBR plan. Accordingly, the Commission finds that any rate adjustments required in response to material changes to accounting standards should be dealt with by way of a Z factor application.

8.1.5 Quality

744. IPPCA recommended that any material degradation in customer service should require a re-opening and review of a PBR plan. As well, EPCOR proposed that failure to meet service quality performance targets for two consecutive years should also require a re-opening and review of the company's PBR plan. These matters have been addressed in Section 14 of this decision in the Commission's findings regarding service quality.

8.1.6 Change of control

745. AltaGas proposed two events with respect to a change of ownership or control that would warrant a re-opening and review of its PBR plan leading, in its view, to an end to its PBR plan. These events are the sale of a controlling interest in AltaGas shares or the disposal of all or substantially all of its assets. The Commission considers that any change in controlling interest in AltaGas shares or the disposal of all or substantially all of the AltaGas assets is within the

⁹⁴¹ Exhibit 100.02, Fortis application, Section 6.1.2, paragraphs 92-94, pages 26-27.

⁹⁴² Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.

control of the AltaGas shareholder, the companies' parent business entities or the management of AltaGas. That is, the owners or management of AltaGas have a choice with respect to transactions of this nature. The Commission does not consider that the PBR plan should be terminable as a result of a voluntary event of this nature. Further, it is expected that any new share or asset purchaser would, as part of its due diligence, be aware of the PBR plan and would take that into consideration as part of its purchase decision. There is no obvious correlation between a change in the ownership structure of a company or the sale of its assets, and a design or operational failure of a PBR plan. In any event, for rate setting purposes, the assets of a company must be transferred at net book value and the same assets would continue to be used to provide utility service both before and after the share or asset transfer. Accordingly, the proposal to end the PBR plan in the event of a change of ownership or control is denied

8.1.7 Change in regulatory status

746. EPCOR proposed that a change in regulatory status should result in a re-opening of the PBR plan, leading to an end to the plan. It is not clear to the Commission why a change in regulatory status would indicate a failure of the operation of the PBR plan. In any event, any issues arising from a change in regulator would, in the Commission's view, be a matter for the regulator of jurisdiction to consider.

8.1.8 Change in taxable status

747. EPCOR also proposed that a change in the taxable status of the company should result in a re-opening of the company's PBR plan with a view to ending the plan. It is also unclear to the Commission why such a change in the taxable status of the company would require the abandonment of the entire PBR plan. In the Commission's view, a change in taxable status would be a matter for consideration pursuant to a Z factor application.

8.1.9 Spread between debt costs and the I factor

748. AltaGas proposed that a material change in the spread between the cost of debt and the I factor should warrant a re-opening of its PBR plan. The Commission understands that, generally, any material changes in the spread between the cost of debt and the I factor should be occasioned by changes in interest rates in the economy and would therefore be eventually reflected in the indexes that make up the I factor, as discussed in Section 7.4.2.6.1. Otherwise, any company-specific changes to debt costs that are not a result of changes to interest rates in the economy as a whole are the result of actions taken by management and should not be the subject of a re-opener. Accordingly, the Commission does not agree with AltaGas that a material change in the spread between the cost of debt and the I factor should be an event that occasions a re-opening of the PBR plan.

8.1.10 Cumulative impact of Z factors

749. AltaGas also proposed that the cumulative impact of Z factors may warrant a re-opening of a PBR plan. The Commission considers that each Z factor application must be considered on its own merits and, if warranted, rates will be adjusted accordingly. The fact that there may be many Z factors approved for a company under its PBR plan is not, in and of itself, an indication that the PBR plan should automatically be re-opened and reviewed.

8.1.11 Organizational structure changes

750. AltaGas also proposed that changes to a company's organizational structure should result in a re-opening of a PBR plan. However, the Commission considers that changes to the organizational structure of the company are within the control of the company or its shareholder and would not, in the Commission's view, signal the need for the PBR plan to be re-opened and reviewed.

8.1.12 Material misrepresentation

751. The CCA and the UCA proposed that a PBR plan should be re-opened and reviewed with a view to ending the plan in the face of a deliberate material misrepresentation by management. The Commission has not been persuaded that this circumstance would signal a failure of the PBR plan that cannot be remedied. Accordingly, the Commission considers that a re-opening and review of the plan may be warranted in this circumstance, but the Commission cannot conclude that such an event would warrant ending the plan. In any event, the Commission considers that, if faced with such a misrepresentation, there are other remedies available to the Commission through the plan itself as well as the imposition of an administrative penalty pursuant to Section 63 of the *Alberta Utilities Commission Act*, SA 2007, c. A-37.2, which can be imposed to address such a serious matter.

8.1.13 Substantial change in circumstances

752. EPCOR proposed that a substantial change in circumstances should result in a re-opening and review of a PBR plan, leading in the company's view to an end to the plan. The Commission observes that a Z factor application is generally intended to consider a substantial change in circumstances. The Commission considers that, in the interests of regulatory efficiency and easing of the regulatory burden, the number of occasions for adjustments to rates by way of a Z factor or a re-opening and review of a PBR plan should be limited so as to allow the plans to generate the incentives that they are intended to create.

753. Nonetheless, the Commission recognizes that it is not possible to predict every circumstance that might legitimately be the subject of a re-opening and review of a PBR plan. Accordingly, should a substantial change in circumstances occur that does not, in the applicant's view, qualify for a Z factor application (as defined in Section 7.2 this decision) then an applicant may bring a re-opener application before the Commission for consideration. In this regard, the Commission is cognizant that, given a material event that is completely unforeseen and cannot be accommodated within the parameters of the PBR plan, it would be incumbent upon the Commission to re-open and review the plan.

8.2 Implementation

754. Several parties proposed that a re-opening of the PBR plan should be automatic following any of the events designated by the Commission as warranting a re-opening and review of a plan.

755. Calgary argued that "the design for re-openers contemplates a formulaic approach, once the utility is able to conclusively demonstrate that the achieved ROE is 300 basis points or more below the approved ROE, then the re-opener would be triggered automatically and parties would

begin discussions regarding potential changes to the existing PBR plan (either one-time or prospective or ongoing).’’⁹⁴³

756. ATCO Electric and ATCO Gas stated that a re-opener should be automatic, once a triggering event is identified. Moreover, they suggested that, because the company is in the best position to be aware of an event that would signal the need for a re-opening of the PBR plan, it is the company that should notify the Commission that a re-opener of the PBR plan had been triggered.⁹⁴⁴ Likewise, Fortis also proposed the automatic triggering of a re-opener if the upper or lower bounds of the earnings sharing mechanism it had proposed were exceeded.⁹⁴⁵

Commission findings

757. The Commission does not consider that a re-opening of the PBR plans should be automatic. As with any other matter before the Commission, any re-opening of a PBR plan must be on application to the Commission and the onus is on the applicant to demonstrate that a re-opening is warranted.

758. As noted above, the Commission finds that any party, including the Commission on its own motion, should be permitted to bring an application to re-open and review a PBR plan if there is sufficient evidence that there is a problem that cannot be resolved without re-opening and reviewing the plan. The Commission will consider applications to re-open and review a PBR plan and make a determination on the merits of the application as to whether a re-opening of the plan is warranted. In order to ensure fairness to all parties, parties are directed to notify the Commission of all events that they consider signal the need for a re-opener as soon as possible after they have been identified. The Commission also directs that the financial impact of any such event be captured in a separate account pending a ruling from the Commission. Any proposed financial impact is to be measured from the time the event occurred. The disposition of the balance in that account (positive or negative) would follow the Commission’s ruling.⁹⁴⁶

9 Efficiency carry-over mechanism

9.1 Purpose and rationale for an efficiency carry-over mechanism

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

760. The CCA described an ECM as “a ratemaking mechanism designed to strengthen incentives for cost containment in the later years of a PBR period by permitting the utility to carry over some of the benefits of efficiency gains achieved in one PBR plan to the subsequent plan.”⁹⁴⁷ EPCOR, ATCO Gas and ATCO Electric proposed an ECM as part of their PBR plans.

⁹⁴³ Exhibit 629.01, Calgary argument, page 53.

⁹⁴⁴ Exhibit 631.01, ATCO Electric argument, paragraph 262 and Exhibit 632.01, ATCO Gas argument, paragraph 286.

⁹⁴⁵ Exhibit 633.01, Fortis argument at paragraph 226 citing the evidence of Lorimer at Transcript, Volume 11, page 2173.

⁹⁴⁶ Decision [2009-035](#), ENMAX FBR contains a similar provision in paragraph 257.

⁹⁴⁷ Exhibit 636.01, CCA argument, paragraph 344.

To support the inclusion of an ECM, ATCO Electric and ATCO Gas explained that "...the incentive for identifying and implementing efficiency measures is strongest in the earlier years of the PBR Plan as the utility will then have several years in which to take advantage of the efficiency improvements."⁹⁴⁸ EPCOR's witness Dr. Weisman explained that "[t]he regulated firm will have less than ideal incentives to innovate and discover efficiencies if it believes that the regulator will simply claw back these efficiency gains at the end of the PBR regime and pass them on to consumers in the form of lower rates. These adverse incentives are particularly pronounced toward the end of the PBR regime."⁹⁴⁹ AltaGas stated it "recognizes the purpose of such a mechanism is to maintain incentives for investment in efficiency initiatives throughout the IR [incentive regulation] term, particularly where the benefits are not expected to be recovered during that term."⁹⁵⁰

9.1.1 ATCO Electric's capital efficiency carry-over mechanism

761. ATCO Electric proposed two forms of efficiency carry-over mechanisms, one based on rate of return and one for capital. ATCO Electric's K factor efficiency incentive mechanism (KFEI) was also initially requested by ATCO Gas,⁹⁵¹ but ATCO Gas subsequently withdrew its request for a KFEI mechanism in its updated filing.⁹⁵²

762. ATCO Electric's KFEI is calculated as any positive difference between the forecast cost of a capital project qualifying for a K factor (discussed in Section 7.3.3.2) and the actual cost of the capital project at the end of the term. Under its proposal, ATCO Electric would carry forward one-half of this positive difference into the first year following the end of the PBR term and one-third of the difference into the second year following the end of the PBR term.⁹⁵³ The proposed KFEI is intended to ensure that the company has an incentive to look for efficiencies in its K factor capital programs over the course of the entire PBR term.⁹⁵⁴

763. The UCA did not support ATCO Electric's request for a KFEI "[a]s the UCA is not supporting the inclusion of any Capital adjustments outside specific Capital Trackers."⁹⁵⁵

Commission findings

764. The Commission considers that the KFEI proposed by ATCO Electric does not promote additional efficiency. The Commission finds that the structure of ATCO Electric's KFEI would provide an incentive for the company to over forecast its capital programs. When its actual costs are subsequently less than the over-forecast amount, the company would benefit, but not necessarily as a result of efficiency gains. For this reason, ATCO Electric's KFEI is denied.

9.1.2 Return on equity (ROE) efficiency carry-over mechanisms

765. EPCOR, ATCO Gas and ATCO Electric proposed ECMs based on ROE as part of their PBR plans. EPCOR explained that its ECM would be balanced. This means that it would carry

⁹⁴⁸ Exhibit 98.02, ATCO Electric application, page 11-1, paragraph 236, Exhibit 99.01, ATCO Gas application, page 43, paragraph 127.

⁹⁴⁹ Exhibit 103.03, written evidence of Dr. Weisman, paragraph 60.

⁹⁵⁰ Exhibit 628.01, AltaGas argument, page 74.

⁹⁵¹ Exhibit 99.01, ATCO Gas application, Section 2.10.1, paragraph 128, page 44.

⁹⁵² Exhibit 389.01, ATCO Gas updated filing, Section 2.8, paragraph 20, page 10.

⁹⁵³ Exhibit 98.02, ATCO Electric application, Section 11, paragraph 237, page 11-1.

⁹⁵⁴ Transcript, Volume 7, page 1280, Ms. Wilson.

⁹⁵⁵ Exhibit 634.01, UCA argument, paragraph 352.

over half of any earnings above its approved ROE for a period of two years following the end of the PBR term. It would also receive 100 per cent of any shortfall below the approved ROE for a period of two years following the end of the PBR term.⁹⁵⁶ EPCOR also linked the size of its rate of return adjustment to its service quality measures, with lower service quality leading to a lower percentage adjustment.⁹⁵⁷ EPCOR did not indicate whether there was a limit on the amount of the earnings or losses to be carried over.

766. In contrast to EPCOR's ROE ECM, the ATCO companies did not include an adjustment for earnings deficiencies in their ECM proposals and did not link their ECM to service quality measures. ATCO Electric and ATCO Gas described their proposed ROE ECM 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

767. Some parties noted that it does not appear that ECMs are common in North America. Very few examples of existing ECMs were cited or discussed in the hearing.⁹⁵⁹ NERA indicated that ECMs are uncommon in PBR plans and stated that ECMs appear to be a desire to have the profit incentives of a PBR plan transcend to some degree beyond the end of the PBR term, "when rates would otherwise be squared with costs and profitable innovations capitalized for ratepayers."⁹⁶⁰ Dr. Makhholm suggested that in order to strengthen incentives, the term should be extended rather than including an ECM in a PBR plan.⁹⁶¹ NERA indicated that it has not seen evidence that adopting ECMs, as a partial lengthening of regulatory lag, "is worth the additional complications it would pose for the periodic future base rate cases."⁹⁶²

768. Some of the companies argued that ECMs provide a strengthening of incentives that outweigh any of the shortcomings of ECMs identified by NERA.⁹⁶³ In addition, Dr. Lowry, the CCA and the ATCO companies submitted that an ECM is a deterrent to the gaming that might be associated with the timing of capital investments.⁹⁶⁴

769. Intervenors, with the exception of Calgary, supported the general concept of ECMs, but they did not support the specific ECMs proposed by EPCOR and the ATCO companies.⁹⁶⁵ The

⁹⁵⁶ Exhibit 630.02, EPCOR argument paragraph 264.

⁹⁵⁷ Exhibit 103.02, EPCOR application, paragraph 46 and Exhibit 630.02, EPCOR argument, paragraph 265.

⁹⁵⁸ Exhibit 98.02, ATCO Electric application, page 11-2, paragraph 238 and Exhibit 99.01, ATCO Gas application, page 44, paragraph 129.

⁹⁵⁹ Exhibit 391.02, NERA second report, paragraph 65. In its survey of PBR plans, NERA identified two that had an ECM. Exhibit 199.02, Cal-ATCO Gas I-32 identified one plan.

⁹⁶⁰ Exhibit 391.02, NERA second report, page 9, paragraph 13.

⁹⁶¹ Transcript, Volume 1, Dr. Makhholm's evidence, pages 194 and 195.

⁹⁶² Exhibit 391.02, NERA second report, paragraph 13.

⁹⁶³ Exhibit 630.02, EPCOR argument, paragraph 270; Exhibit 631.01, ATCO Electric argument, paragraph 281; Exhibit 632.01, ATCO Gas argument, paragraph 303.

⁹⁶⁴ Transcript, Volume 13, Dr. Lowry, page 2642; Exhibit 631.01, ATCO Electric argument, page 70; Exhibit 648.02, ATCO Gas argument, page 131, paragraph 480; Exhibit 636.01, CCA argument, paragraphs 342-347.

⁹⁶⁵ Exhibit 634.01, UCA argument, paragraphs 356 to 359; Exhibit 642.01, IPCAA reply, paragraph 21. IPCAA states that it concurs with the UCA argument for ECMs and Exhibit 636.01, CCA argument, paragraph 342.

UCA argued that ATCO Gas and ATCO Electric have achieved ROEs prior to PBR that are in excess of approved levels. Therefore, the UCA recommended that the average of the actual ROE for the 2009 to 2012 period be used as the basis for the ECMs rather than the approved ROE for the PBR plan period because this level of ROE “represents the current level of efficiency.”⁹⁶⁶ The UCA stated, “[b]y basing the target on the actual achievement, the intent of the PBR to incent greater efficiency is maintained. If a lower target is used, the incentive to improve efficiency is lessened.”⁹⁶⁷

770. While supporting the concept of an ECM based on actual ROE performance, the UCA also suggested that there must be recognition of any efficiency gains achieved prior to the commencement of PBR that are not reflected in the going-in rates. The UCA stated, “[s]ince there are identified efficiency gains coming out of the COS environment, there should be an ECM for both going-in-rates and for the end of term.”⁹⁶⁸ The UCA proposed addressing the going-in portion of its proposed ECM through an adjustment to going-in rates. If no efficiency gains are recognized in going-in rates, the UCA argued that there should be no ECM included in the PBR plans.⁹⁶⁹

771. The CCA stated that it supports a Commission directed “generic ECM module, preferably by negotiation, in the early part of the PBR term.”⁹⁷⁰ The CCA also stated that the record was insufficient to approve an alternative ECM.⁹⁷¹

772. Calgary also rejected the inclusion of an ROE ECM in ATCO Gas’ PBR plan, providing among its reasons that there is no evidence that lengthening the period for recovery guarantees incentives or results in improved efficiencies, that there is no guarantee that efficiencies are passed on to ratepayers and that an ECM only spreads the incentives over a longer period but does not strengthen the incentives.⁹⁷²

773. Dr. Weisman discussed that alternatively an open-ended term operates as an efficiency carry-over mechanism because rates are not reset.⁹⁷³ AltaGas stated that “its proposal to include an option to extend the term of its IR [incentive regulation] Plan may be considered a form of ECM, as it potentially allows AUI to continue operating under the approved IR [incentive regulation] Plan for an additional two years.”⁹⁷⁴

Commission findings

774. In Decision 2009-035, the Commission recognized “that the longer the term of an FBR plan, the stronger the incentives for utilities to improve their efficiency.”⁹⁷⁵ In recognition of this issue the Commission stated in its February 26, 2010 letter initiating the PBR initiative that:

The Commission will initiate a proceeding during the first PBR term to consider how the success of the PBR plan should be judged and how it might be re-initiated, or rates re-

⁹⁶⁶ Exhibit 634.01, UCA argument, paragraph 359.

⁹⁶⁷ Exhibit 634.01, UCA argument, paragraph 357.

⁹⁶⁸ Exhibit 634.01, UCA argument, paragraph 346.

⁹⁶⁹ Exhibit 634.01, UCA argument, paragraph 360.

⁹⁷⁰ Exhibit 636.01, CCA argument, page 120 of 152, paragraph 343.

⁹⁷¹ Exhibit 636.01, CCA argument, page 120 of 152, paragraph 343.

⁹⁷² Exhibit 629.01, Calgary argument, pages 61 to 62.

⁹⁷³ Transcript, Volume 10, Dr. Weisman, page 1827, lines 2 to 5.

⁹⁷⁴ Exhibit 628.01, AltaGas argument, page 74.

⁹⁷⁵ Decision 2009-035, paragraph 116.

based, at the end of the initial five-year term in a way that minimizes potential distortions to economic efficiency incentives

775. The Commission agrees that ECMs are an innovative mechanism that will allow for a strengthening of incentives in the later years of the PBR term and may discourage gaming regarding the timing of capital projects. The Commission finds that the incentive properties of an ECM encourage companies to continue to make cost saving investments near the end of the PBR term.⁹⁷⁶ The Commission agrees with ATCO's proposal for an upper limit for earnings that can be carried over and finds the limit of 0.5 per cent to be reasonable. Accordingly, the Commission approves the ATCO companies' ROE ECM for inclusion in the ATCO companies' PBR plans. If any of the other companies wish to submit the same ECM in their PBR plans, they may do so in their compliance filings.

776. EPCOR's proposed ECM includes adjustments for both over- and under-earnings in the two years following the end of the PBR term. The UCA did not support EPCOR's ECM because it compensates for under-earning which would dampen incentives and shield the utility from the full impact of its decisions.⁹⁷⁷ The Commission agrees. As discussed above, the Commission supports a 0.5 per cent limit to the amount of earnings which may be carried over. Accordingly, the Commission finds that EPCOR's ECM should not include an adjustment for under-earning and should limit the amount of earnings which can be carried over to a maximum of 0.5 per cent.

777. With respect to EPCOR's proposal to include service quality as part of its ECM, the Commission will be relying on AUC Rule 002 along with administrative penalties under Section 63 of the *Alberta Utilities Commission Act* to ensure that service quality is maintained. In Section 14, the Commission has determined that these measures are sufficient to address service quality. Accordingly, EPCOR's proposed service quality adjustments to its ECM formula are not required.

778. The Commission rejects the UCA's recommendation that the average of the actual ROE for the 2009 to 2012 period be used as the basis for the ECMs rather than the approved ROE for the PBR plan period. The Commission has already made its determinations on the 2012 going-in rates in Section 3 of this decision. The purpose of the ECM is to provide an incentive to the companies to continue to achieve efficiencies in the latter part of the PBR term. If the Commission were to adopt the UCA's proposal, this incentive would be distorted because it would require the assessment of the efficiencies gained during the PBR term against financial results from the past and under a different regulatory framework.

779. In the Commission's view, the correct ROE to use for the purposes of calculating the amount of the ECM is the average approved generic ROE in place for each year during the PBR term.

⁹⁷⁶ Exhibit 636.01, CCA argument, paragraph 344; Transcript, Volume 13, pages 2647-2648; Exhibit 103.03, evidence of Dr. Weisman, paragraphs 59 and 60; Transcript Volume 10, page 1820; Exhibit 628.01, AltaGas argument, page 74; Exhibit 647.01, ATCO Electric reply argument, page 70, paragraph 281; Exhibit 648.02, ATCO Gas reply argument, page 95, paragraph 303; Exhibit 630.02, EPCOR argument, paragraph 270.

⁹⁷⁷ Exhibit 634.01, UCA argument, paragraphs 358-359.

780. The actual ROE of the companies to be used for the purposes of calculating the amount of the ECM, will be the calculated in the same way as the ROE reported in the companies' annual AUC Rule 005 filings.

9.1.3 Authority to approve an ECM

781. In its argument, Calgary questioned whether ECMs comply with the statutory framework in Alberta and raised issues of jurisdiction. Calgary stated that the equitable allocation or sharing with customers of benefits from incentives to be approved by the Commission is a matter of jurisdiction. Calgary argued that the Commission does not have jurisdiction to approve ATCO Gas' ECM as it is not a sharing of benefits from incentives and it is contrary to law. Calgary referenced AUC PBR Principle 5,⁹⁷⁸ Section 120(2)(d) of the *Electric Utilities Act* and Section 45(1)(a) of the *Gas Utilities Act*, RSA 2000, c. G-5, in support of the equitable sharing of benefits derived from utility incentives being required for ESMs (earnings sharing mechanism) and ECMs (efficiency carry-over mechanism).⁹⁷⁹ Calgary also argued that ATCO Gas' ECM will operate outside of the five-year PBR plan term. Calgary stated:

There is no rate base determined for such post PBR term as part of this Proceeding, and as a result, the Commission's approval of ATCO's ECM will be contrary to Section 37 (1) of the GUA, which requires the Commission to determine the rate base of the gas utility and fix a fair return on that rate base at the same time. Since the rate base to which the ECM would apply will be determined at the ti[m]e of rebasing, there is obviously a time disconnect between setting ROE elements today (in this Proceeding) and determining the rate base in the future to which the ECM would apply.⁹⁸⁰

782. Section 45(1) of the *Gas Utilities Act* states:

45(1) Instead of fixing or approving rates, tolls or charges, or schedules of them, under sections 36(a), 37, 40, 41, 42 and 44, the Commission, on its own initiative or on the application of a person having an interest, may by order in writing fix or approve just and reasonable rates, tolls or charges, or schedules of them,

- (a) that are intended to result in cost savings or other benefits to be allocated between the owner of the gas utility and its customers, or
- (b) that are otherwise in the public interest.

783. Section 120(2)(d) of the *Electric Utilities Act* reads:

120(2) A tariff may provide

....

- (d) for incentives for efficiencies that result in cost savings or other benefits that can be shared in an equitable manner between the owner of the electric utility and customers.

784. ATCO Gas responded to Calgary's questioning of whether ECMs comply with the statutory framework in Alberta. ATCO Gas stated that its ROE ECM is a sharing of benefits

⁹⁷⁸ Bulletin 2010-20, page 3, Principle 5: "Customers and the regulated companies should share the benefits of a PBR plan."

⁹⁷⁹ Exhibit 629.01, Calgary argument, pages 56 and 62.

⁹⁸⁰ Exhibit 629.01, Calgary argument, page 62.

from incentives of 50 per cent of the difference between the average ROE and the approved ROE over the plan term, if the difference is positive.⁹⁸¹ Section 45(1)(a) of the *Gas Utilities Act* does not indicate when the intended cost savings or other benefits are to be allocated to customers. This section only addresses that cost savings or other benefits are intended to result in cost savings or other benefits to be allocated between the owner of a gas utility and its customers.⁹⁸² ATCO Gas pointed out that this is also the case for Section 120(2)(d) of the *Electric Utilities Act*⁹⁸³ and both of these sections do not indicate that benefits have to be shared equally. Additionally, the Commission has been determining the fair rate of return for Alberta gas and electric utilities distinctly from determining rate base since Decision 2004-052,⁹⁸⁴ which established a generic formula for the establishment of ROE. ATCO Gas argued that Section 37(1) has not been an issue since Decision 2004-052, and it will not be an issue under PBR.

785. With respect to the approval of its ROE ECM, ATCO Gas stated that the ROE ECM establishes the way in which a potential increase to a future ROE will be calculated. It does not establish the ROE for the utility. There is no inconsistency for the ROE ECM as the application of the effect of the ROE ECM will occur at the same time as the future ROE will be applied.⁹⁸⁵

Commission findings

786. Upon review of the legislation as well as the arguments of Calgary and ATCO Gas, the Commission finds that Section 45(1)(a) of the *Gas Utilities Act* and Section 120(2)(d) of the *Electric Utilities Act* allow for the approval of rates and tariffs that result in cost savings and other benefits to be allocated between utilities and their customers. Further, Section 5(h) of the *Electric Utilities Act* states that one of the purposes of the Act is “to provide for a framework so that the Alberta electric industry can, where necessary, be effectively regulated in a manner that minimizes the cost of regulation and provides incentives for efficiency.” Section 102(2)(d) of the *Electric Utilities Act* specifically refers to incentives for efficiencies and allows the Commission to include incentives for efficiencies that result in cost savings or other benefits, which is consistent with PBR. In addition, Section 121(3) of the *Electric Utilities Act* provides that “[a] tariff that provides incentives for efficiency is not unjust or unreasonable simply because it provides those incentives.”

787. By Order of the Lieutenant Governor in Council, the Commission has the authority under Section 45(1) of the *Gas Utilities Act* “to proceed to fix or approve just and reasonable rates, tolls or charges, or schedules of them, that may be charged by ATCO Gas and Pipelines Ltd. or AltaGas Utilities Inc. under section 45 of the Gas Utilities Act.”⁹⁸⁶

788. ATCO Gas has correctly indicated that its ROE ECM would result in a sharing of any differences between its average ROE over the plan term and approved ROE, in the case where the average ROE over the term is higher than the approved ROE. Any benefits of a higher ROE

⁹⁸¹ Exhibit 648.02, ATCO Gas reply argument, page 131 of 152, paragraph 482.

⁹⁸² Exhibit 648.02, ATCO Gas reply argument, page 123 of 152, paragraph 455.

⁹⁸³ Exhibit 648.02, ATCO Gas reply argument, page 124 of 152, paragraph 456.

⁹⁸⁴ Decision 2004-052: Generic Cost of Capital, AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks), Nova Gas Transmission Ltd., Application No. 1271597, July 2, 2004.

⁹⁸⁵ Exhibit 648.02, ATCO Gas reply argument, page 132 of 152, paragraph 483.

⁹⁸⁶ O.C. 235/2011 June 1, 2011.

would be shared with customers under ATCO Gas' ECM proposal. Further, the entire rationale for an ECM is to incent the company to pursue additional cost savings particularly through capital investment that it might not be otherwise inclined to do in the latter part of the PBR term. Customers will directly benefit from these additional cost savings when utility costs and revenues are next reviewed and rates are adjusted.

789. The Commission has considered the ECMs proposed by the companies in light of the legislative requirements under the *Electric Utilities Act* and the *Gas Utilities Act*. The ECMs as approved above provide for incentives for efficiencies, or are intended to result in cost savings or other benefits to be allocated between the owner of the utility and its customers.

790. Calgary argued Section 37(1) of the *Gas Utilities Act* requires that rate base and rate of return be approved at the same time. Section 37(1) stated that the Commission shall determine a rate base and "upon determining a rate base it shall fix a fair return on the rate base." Section 45(1) of the *Gas Utilities Act* states that instead of fixing or approving rates, tolls or charges, or schedules of them, under sections 36(a), 37, 40, 41, 42 and 44 of the Act, the Commission may approve rates that are intended to result in cost savings or other benefits to be allocated between the owner of the gas utility and its customers. This includes the jurisdiction to approve the provisions of an incentive plan that are intended to create incentives during the PBR term to achieve cost savings or other benefits to be allocated between the owner of the gas utility and its customers in a period beyond the initial plan term.

791. The Commission concludes that ECMs are consistent with the governing legislation and it is within the Commission's jurisdiction to consider ECMs as part of the PBR plan under Section 45(1) of the *Gas Utilities Act* and under sections 5(h), 120(2)(d) and 121(3) of the *Electric Utilities Act*.

10 Earnings sharing mechanism

792. An ESM (earnings sharing mechanism) is intended to address the potential that a regulated company will earn a return significantly above or below the approved ROE (return on equity) during the PBR term. An ESM generally establishes a formula for sharing with the company's customers earnings in excess of a designated amount and may provide for a sharing of any shortfall below a designated amount. The implementation of an ESM generally requires annual filings of ROE results and sharing calculations and some form of verification of these filings. An ESM is a common feature of first generation PBR plans.

793. The Commission approved an ESM in Decision 2009-035 as part of ENMAX's FBR plan. ENMAX's approved ESM provides for an annual sharing mechanism equal to 50 per cent of ENMAX's earnings that are over 100 basis points above the approved ROE established by the Commission. Sharing of these earnings is given effect by way of a reduction in rates in the year following the year in which the excess earnings were realized. The ENMAX ESM provides for a sharing of earnings above the approved ROE but not for a sharing of any earning below the approved ROE.

794. In approving the ESM for ENMAX, the Commission acknowledged that an ESM blunts efficiency incentives but recognized that performance-based regulation was a relatively new

development in Alberta utility regulation and considered that, in the circumstances, it provided a useful safeguard in the early stages of a PBR plan.⁹⁸⁷

795. Fortis and the ATCO companies proposed including an ESM in their PBR plans. Additionally, the UCA, the CCA and Calgary supported the inclusion of ESMs in the companies' PBR plans.

796. Fortis proposed a symmetrical deadband range of 100 basis points above and below the approved ROE. Any return within 100 basis points of the approved ROE would not be shared with customers, and any shortfall up to 100 basis points below the approved ROE would not be recovered through a subsequent rate adjustment. However, any return above the 100 basis point threshold would be shared equally with customers by way of a rate reduction in the following year, while any shortfall below the 100 basis point threshold would be shared equally with customers by way of a rate increase in the following year. Under the Fortis proposal, the PBR plan would be re-opened and reviewed if the achieved ROE is more than 300 basis points above or below the approved ROE in one year.⁹⁸⁸

797. Fortis stated that "given that this is the first time that FortisAlberta is applying for a PBR plan, an ESM will serve as a safeguard to buffer the earnings results during PBR implementation, in a manner beneficial to both customers and the Company."⁹⁸⁹

798. When asked by the Commission how its PBR proposal would need to change if its ESM were eliminated, Fortis stated:

FortisAlberta's PBR Proposal would not otherwise change if the ESM component were eliminated. The proposed re-opener mechanism is based on the actual ROE before the ESM is applied.⁹⁹⁰

799. ATCO Electric and ATCO Gas proposed an ESM in each of their plans similar to the Fortis proposal. However, the ATCO companies proposed a symmetrical deadband range of 200 basis points above and below the approved ROE. Any return within 200 basis points of the approved ROE would not be shared with customers, and any shortfall up to 200 basis points below the approved ROE would not be recovered through a subsequent rate adjustment. Actual results beyond the 200 basis point threshold would be shared equally with customers by way of a rate reduction or rate increase in the following year, as required.

800. Under the ATCO companies' proposals,⁹⁹¹ the PBR plan would be re-opened and reviewed if the achieved ROE is more than 300 basis points above or below the approved ROE, after accounting for the implementation of the ESM. Ms. Wilson for the ATCO companies described the relationship between the companies' ESM and the re-opener proposal as follows, "[g]enerally earnings-sharing mechanisms and reopener clauses are viewed more as ensuring that if some of the parameters in the plan haven't been completely specified correctly or if something unexpected comes out of the PBR plan that was not -- the plan somehow doesn't have the ability

⁹⁸⁷ Decision 2009-035, paragraphs 280 and 281.

⁹⁸⁸ Exhibit 100.02, Fortis application, paragraph 126.

⁹⁸⁹ Exhibit 100.02, Fortis application, page 35, paragraph 121.

⁹⁹⁰ Exhibit 219.02, Fortis, AUC-ALLUTILITIES-FAI-16.

⁹⁹¹ Exhibit 98.02, ATCO Electric application, paragraph 233; Exhibit 99.01, ATCO Gas application, paragraph 123.

to address, those mechanisms ensure that the plan will not result in extreme outcomes for either customers or the utility.”⁹⁹²

801. In addition to the above, ATCO Gas added the following caveat regarding its ESM and weather deferral account:

In the event that ATCO Gas no longer has a Weather Deferral Account (WDA) during the course of the PBR Plan, the ROE to be used [for earnings sharing] will be the actual utility ROE, including the effects of deviations from normal weather.⁹⁹³

802. ATCO Electric and ATCO Gas submitted in argument that their ESMs have sufficiently wide deadbands to address any blunting of efficiency incentives that an ESM might cause.⁹⁹⁴ The ATCO companies did not propose any changes to their PBR plans if ESMs were not approved. Specifically, the ATCO companies indicated that, if their plans were not to include an ESM, the 300 basis point threshold for re-openers would remain unchanged.⁹⁹⁵

803. Initially, AltaGas proposed an ESM as part of its PBR plan.⁹⁹⁶ AltaGas proposed a symmetrical ESM with 50/50 sharing of earnings between 100 and 200 basis points above and below the approved ROE and 60(company)/40(customer) sharing of earnings over 200 basis points above and below the approved ROE.⁹⁹⁷ AltaGas also submitted that, if achieved earnings are significantly greater than the approved ROE (i.e., above or below 300 basis points for two consecutive years or above or below 400 basis points in a single year), customers or AltaGas may apply for a re-opening of the PBR plan.⁹⁹⁸

804. AltaGas initially indicated that, if there was no ESM, three adjustments to the PBR formula would be required. First, the rates at the beginning of the PBR period would need to be adjusted upward. Second, the Y and Z factors might need to be carefully evaluated, and perhaps more broadly defined, given the potential effect of higher risks on the willingness of AltaGas to fund capital and commit resources. Third, AltaGas stated that “provided the rate of return reflects the impacts of higher financial risks, the Company faces stronger incentives to increase efficiency, without a provision for earnings sharing. Under these circumstances, it would be appropriate to consider a stretch component to the X Factor.”⁹⁹⁹ During the hearing, AltaGas confirmed that it is prepared to dispense with an ESM in its PBR plan with the addition of a stretch factor of between 0.1 and 0.2 per cent.¹⁰⁰⁰

805. EPCOR did not propose an ESM as part of its PBR plan. EPCOR argued that ESMs are not consistent with AUC PBR principles 1, 3, and 5.¹⁰⁰¹ As part of its application, EPCOR stated that a pure price cap approach has several advantages over a price cap plan with an ESM,

⁹⁹² Transcript, Volume 3, page 568, Ms. Wilson.

⁹⁹³ Exhibit 99.01, ATCO Gas application, page 41, paragraph 118.

⁹⁹⁴ Exhibit 631.01, ATCO Electric argument, paragraph 267 and Exhibit 632.01, ATCO Gas argument, paragraph 292; Dr. Carpenter, Transcript, Volume 7, page 1308, lines 17 to 22.

⁹⁹⁵ Exhibit 631.01, ATCO Electric argument, paragraph 269 and Exhibit 632.01, ATCO Gas argument, paragraph 294.

⁹⁹⁶ Exhibit 110.01, AltaGas application, paragraph 89.

⁹⁹⁷ Exhibit 110.01, AltaGas application, paragraph 89.

⁹⁹⁸ Exhibit 628.01, AltaGas argument, page 67.

⁹⁹⁹ Exhibit 247.01, AltaGas, AUC-ALLUTILITIES-AUI-16.

¹⁰⁰⁰ Exhibit 529.01, AltaGas letter on corrections and amendments to its incentive regulation application, 2012-04-18, page 4.

¹⁰⁰¹ Exhibit 630.02, EPCOR argument, paragraph 238.

because a pure price cap plan provides for greater incentives for efficiency that are more aligned with those in a competitive market.¹⁰⁰²

806. EPCOR pointed to Dr. Weisman's evidence, stating that the gains from a pure price cap plan should exceed those from a PBR plan with earnings sharing. A plan without an ESM would also largely eliminate concerns with respect to gaming. Dr. Weisman stated:

First, consumers bear less risk under pure price cap regulation than under a PBR with earnings sharing because prices do not vary directly with either the costs or the earnings of the regulated firm. Second, at least as a theoretical matter, because the incentives for cost reducing innovation are more pronounced under pure price cap regulation, the X factor should be higher than under a PBR regime that incorporates earnings sharing, *ceteris paribus*. Third, the incentives for strategic cost shifting, cost misreporting and abuse are mitigated under a pure price cap regime and this further lessens consumer exposure to prices that may reflect higher costs associated with such inefficiencies. As a corollary to this third observation, the pure PBR framework obviates the need for regulatory intervention with respect to cost allocations under a shared services model as rates are invariant to changes in such allocations over the course of the PBR regime. Finally, as the ongoing administration of a pure price regime economizes on both Commission and company resources, consumers benefit from the flow through of such efficiencies in the form of lower prices over time.¹⁰⁰³

807. When questioned by the Commission about how its PBR plan would change if an ESM were adopted, EPCOR stated:

At a minimum, if an earnings sharing mechanism were added to EDTI's PBR Plan, EDTI's proposed stretch factor would need to be eliminated, EDTI's proposed X factor would need to be reduced (i.e., made more negative) and the proposed timeline for the annual rate adjustment process would need to be adjusted due to the significant regulatory burden that earnings sharing mechanisms entail.¹⁰⁰⁴

808. Dr. Schoech for AltaGas argued that the determination of earnings to be shared would result in a situation akin to cost of service regulation. Dr. Schoech stated:

The earnings-sharing formulas introduce a bit of cost of service – I emphasize a bit of cost of service back into the regulation because earnings sharings looks [sic.] at the actual rates of return that the company achieves which, in turn, are based upon the company's costs. A pure revenue per customer cap with no earnings sharing completely decouples rates from the utility costs. And it's the disincentive or the reduced incentives, I guess I should say, arise from that reintroduction of an element of cost of service.¹⁰⁰⁵

809. The interveners generally supported ESMs as part of PBR plans. The UCA indicated that its proposed menu approach for the X factor, which has been described in Section 6.2, has an ESM embedded into the menu options. However, if the menu approach is not adopted for the X factor, the UCA supported adoption of the ESM approved for ENMAX,¹⁰⁰⁶ including

¹⁰⁰² Exhibit 103.02, EPCOR application, paragraph 16.

¹⁰⁰³ Exhibit 103.03, EPCOR application, Appendix A: The EDTI PBR Framework: Commission Principles and Economic Foundations, paragraph 78.

¹⁰⁰⁴ Exhibit 233.01, EPCOR, AUC-ALLUTILITIES-EDTI-16, page 49.

¹⁰⁰⁵ Transcript, Volume 8, page 1376, lines 6 to 15.

¹⁰⁰⁶ Exhibit 634.02, UCA argument, paragraphs 329 and 330.

independent verification of the ROE with attestation by an officer of the company, with the same filing requirements as established for ENMAX.¹⁰⁰⁷

810. The CCA also recommended that the PBR plans include ESMs similar to ENMAX's asymmetrical ESM¹⁰⁰⁸ and that a corporate sign-off be required on any data relied upon for the calculation of the earnings to be shared.¹⁰⁰⁹

811. Calgary recommended adoption of an ESM for ATCO Gas but proposed that it be asymmetrical, providing for a sharing only of earnings above the approved ROE. Calgary questioned whether an ESM with a deadband is genuinely a sharing with ratepayers that would meet AUC Principle 5 and the legislative requirements of the *Electric Utilities Act*. Calgary argued that the equitable sharing or allocation of benefits derived from utility incentives with customers is required under Section 120(2)(d) of the *Electric Utilities Act* and Section 45(1)(a) of the *Gas Utilities Act*.¹⁰¹⁰

812. ENMAX did not take a position on the inclusion of ESMs in the proposed PBR plans of the companies, other than to state that an ESM should be symmetrical. However, ENMAX commented on the operation of the ESM in its FBR plan. In its evidence, ENMAX stated that although the ENMAX ESM has benefited customers, it has not benefited the company due to the unexpectedly high costs to establish, review and independently verify its ESM calculations. This verification process resulted in additional filing requirements over and above the requirements under AUC Rule 005.

813. Parties also pointed to concerns with gaming in ascertaining the actual returns to be shared.¹⁰¹¹ ENMAX proposed that, if the Commission approves an ESM for the companies, the Commission should determine in advance the necessary information required to ensure customers are receiving their share of the benefits.¹⁰¹² In this regard, most parties agreed that AUC Rule 005 would be the best vehicle to measure annual earnings sharing.¹⁰¹³ ATCO Electric and ATCO Gas stated that the Commission's current safeguards in AUC Rule 005 are sufficient to address any concerns with administration and gaming.¹⁰¹⁴

814. Ms. Frayer, in her evidence for Fortis, noted that ESMs have other benefits to counter the weakening of incentives. These include the avoidance of unscheduled regulatory interventions, such as windfall profit taxes or other forms of claw-back, which distort patterns of investment and return.¹⁰¹⁵

815. IPCAA stated that an annual sharing of benefits would not be necessary as "[a]n annual benefit-sharing calculation based on net income would require a review of all revenues and costs, since net income is a comprehensive financial calculation. This in turn would require detailed variance analysis by management and extensive review, knowing that litigation is a possibility. It

¹⁰⁰⁷ Exhibit 634.02, UCA argument, paragraph 338.

¹⁰⁰⁸ Exhibit 636.01, CCA argument, paragraph 337.

¹⁰⁰⁹ Exhibit 636.01, CCA argument, paragraph 341.

¹⁰¹⁰ Exhibit 629.01, Calgary argument, pages 55 and 56.

¹⁰¹¹ Exhibit 298.02, Calgary evidence, paragraph 165; Exhibit 630.02, EPCOR argument, paragraph 13,

¹⁰¹² Exhibit 297.01, EPCOR evidence, paragraphs 41 to 45.

¹⁰¹³ Exhibit 100.02, Fortis application, page 35, paragraphs 122-123; Exhibit 98.02, ATCO Electric application, pages 9-1-9-2, paragraph 228; Exhibit 629.01, Calgary argument, page 59 of 72.

¹⁰¹⁴ Exhibit 631.01, ATCO Electric argument, paragraph 272 and Exhibit 632.01, ATCO argument, paragraph 297.

¹⁰¹⁵ Exhibit 100.02, Fortis application, Performance Based Regulation Evidence attachment, page 82, lines 17 to 21

thus appears that annual benefits sharing could perpetuate the regulatory burden.”¹⁰¹⁶ IPCAA made no specific recommendations with respect to the structure of earnings sharing except to state that “any sharing calculations should occur at the end of the PBR period rather than annually” and that the scope of review should be clearly defined in advance.¹⁰¹⁷

Commission findings

816. The Commission generally agrees with Dr. Weisman and Dr. Schoech that PBR plans with an ESM provide weaker incentives for efficiency gains, in part because costs and rates are no longer completely decoupled. The Commission notes Dr. Weisman’s concerns with respect to ESMs.

And when I say that earnings sharing has problems, it has problems I think on both sides. I don't think, as I mentioned in my rebuttal testimony, it brings forth the best behaviour on the part of regulators or the firms they regulate. I think that there are incentives for cost misreporting; cost shifting; the incentives are blunted with regard to managerial effort, and the reason for that is that the firm bears the entire costs of its effort at reducing costs but only retains a share of the fruits from those efforts.¹⁰¹⁸

817. The Commission agrees with EPCOR, AltaGas, ENMAX and IPCAA that increased scrutiny on an annual basis would be required for earnings sharing and would result in a greater regulatory burden. Accordingly, the Commission is concerned that including an ESM in the PBR plans of the companies would not be consistent with the objectives of Principle 3 to reduce the regulatory burden over time.

818. In the Commission’s view, the safeguards offered by an ESM do not outweigh the negative efficiency incentives that would be re-introduced into the PBR plan as a result of the incorporation of an ESM.

819. The Commission has approved safeguards in Section 8 of this decision that provide for a re-opening and review of the companies’ PBR plans if the reported ROE of a company significantly exceeds the approved ROE or if the company experiences a significant shortfall in earnings. These safeguards are comparable to those provided for by an ESM but do not, in the Commission’s view, exhibit the disincentives that arise with ESMs. The Commission finds that the safeguards set out in Section 8 are adequate to protect both the companies and consumers.

820. In addition, the Commission notes that the companies’ reported earnings will generally vary, sometimes significantly, from year to year during the PBR term. The effect of this variability in earnings coupled with an ESM was demonstrated by the operation of ENMAX’s ESM for transmission and distribution:

EPC’s customers benefited from \$0.331 million of earnings sharing for Transmission in 2008 and \$0.563 million of earnings sharing for Distribution in 2009. As EPC is forecasting that it will earn below the AUC approved ROE for the remainder of the FBR term for both Distribution and Transmission, EPC expects that there will be no earnings sharing payments for the period 2011 to 2013.¹⁰¹⁹

¹⁰¹⁶ Exhibit 306.01, IPCAA Vidya Knowledge Systems Corp. direct evidence, page 10, lines 23-26.

¹⁰¹⁷ Exhibit 306.01, IPCAA Vidya Knowledge Systems Corp. direct evidence, page 10, lines 23-29.

¹⁰¹⁸ Transcript, Volume 9, page 1765, Dr. Weisman.

¹⁰¹⁹ Exhibit 297.01, ENMAX evidence, paragraph 41.

821. The Commission finds that this volatility of earnings argues against the introduction of ESMs. This is because the company may have sufficient earnings in one year to trigger a sharing with customers and then experience earnings below the approved ROE in subsequent years but not sufficient to trigger a sharing of the shortfall with customers. This deprives the company of a reasonable opportunity to earn its approved ROE over the PBR term. Conversely, the company may have insufficient earnings in one year, triggering a sharing of the shortfall with customers and then experience earnings above the approved ROE in subsequent years but not sufficient to trigger sharing with customers. This results in customers paying rates higher than necessary to give the company a reasonable opportunity to earn its approved ROE over the PBR term.

822. Accordingly, the Commission finds that ESMs, as proposed by the parties, are not warranted as an additional safeguard and the disincentives they will introduce are inconsistent with the objectives of PBR.

11 Term

823. The PBR term establishes the period over which a company must operate under the parameters of the formula in the PBR plan.

824. All of the parties recognized that, in setting the term of a PBR plan, the Commission must achieve a balance between two competing interests, namely, ensuring that the term is long enough to permit the company to achieve and capture efficiencies but not so long that the company's revenues are substantially out of sync with costs. As NERA stated, "ultimately we base rates for North American ratepayers on cost, and while we want to -- while it is a praise-worthy pursuit to want to avoid a disruption of frequent base rate cases, it is hard over the course of years to base rates on cost if you don't once in a while look at the costs."¹⁰²⁰

825. The Commission noted this relationship in Decision 2009-035, when it rejected ENMAX's application for a 10-year term as too long and approved a seven-year term which, given the passage of time, resulted in a five-year operational FBR term.¹⁰²¹

826. Each of the distribution companies, with the exception of ATCO Electric, proposed a PBR plan with a five-year term. ATCO Electric proposed a term of four years; stating, among other reasons, that staggering the filing of a second generation PBR plan with other companies would ease the regulatory workload for both the company and the Commission.¹⁰²² In addition, ATCO Electric,¹⁰²³ ATCO Gas¹⁰²⁴ and AltaGas¹⁰²⁵ also proposed an optional two-year extension to the term, exercisable at the companies' election. Fortis stated in argument that it was open to an extension if the plan was working well.¹⁰²⁶

827. Some of the companies, in proposing the terms for their PBR plans, also requested some form of rebasing or adjustment for capital expenditures during the PBR term.¹⁰²⁷ The

¹⁰²⁰ Transcript, Volume 1, page 197, lines 11-16.

¹⁰²¹ Decision 2009-035, paragraph 118.

¹⁰²² Exhibit 205.01, AUC-AE-13(a).

¹⁰²³ Exhibit 632.01, ATCO Gas argument, page 9, paragraph 28.

¹⁰²⁴ Exhibit 205.01, AUC-AE-13(b); Exhibit 0212.02, AUC-AG-3(a).

¹⁰²⁵ Exhibit 110.01, AltaGas application, page 15, paragraph 54.

¹⁰²⁶ Exhibit 633.01, Fortis argument, page 12, paragraphs 50 and 51.

¹⁰²⁷ See Section 7.3.3.2.

Commission has addressed the treatment of capital expenditures and adjustments in Section 7.3 of this decision.

828. The CCA supported the companies' applied-for terms but stated that, if the Commission preferred a shorter term such as three or four years, the CCA would not be opposed. In its view, a shorter term could reduce or eliminate some of the requests for supplemental capital budgets with less concern about untoward safety or reliability consequences during the PBR term. Nonetheless, the CCA stated that, whatever term is determined by the Commission, the length of the plans should be consistent among all companies.¹⁰²⁸ With regard to the proposals from ATCO Electric, ATCO Gas, and AltaGas to include an extension option to their plans' term, the CCA stated that "extensions should be allowed only with the consent of most parties"¹⁰²⁹ and that, if the plan is viewed as a success by all parties, there could potentially be an extension for up to five years.¹⁰³⁰

829. Calgary supported a term of five years¹⁰³¹ for ATCO Gas and indicated that a five-year term coincides with the Commission's efficiency, fair return and simplicity principles.¹⁰³² However, Calgary did not support a unilateral extension of the ATCO Gas five-year term proposal.¹⁰³³

830. The UCA did not support pursuing PBR because it considered that the risks of implementation outweigh the benefits of doing so.¹⁰³⁴ However, accepting that the Commission may nonetheless move forward with PBR, the UCA recommended that, as a first generation plan, the Commission adopt a term of three years.¹⁰³⁵ A period of four years was proposed for the second generation. In both cases, the UCA also recommended the imposition of a mid-term assessment to examine the PBR plans to date and to structure the design of the next term.¹⁰³⁶ Dr. Cronin, on behalf of the UCA, also opposed term extensions.¹⁰³⁷

831. IPCAA submitted that it is too early for the Commission to implement a full PBR plan, and limited its recommendation to what it considered would be a suitable term for its limited G&A PBR plan. IPCAA stated that its limited G&A PBR plan "could run for a two-year term so that a comprehensive plan could be initiated when the limited plan expires."¹⁰³⁸

Commission findings

832. One of the purposes of PBR is to start with cost of service-based rates and then sever the link between revenues and costs as a means of strengthening incentives for the companies to seek productivity improvements, and achieve lower costs than would otherwise be realized under cost of service regulation. PBR regulation allows regulated prices to change without a review of the company's costs, thereby lengthening regulatory lag. This better exposes the companies to the types of incentives faced by competitive firms. However, periodic review of the plans will be

¹⁰²⁸ Exhibit 636.01, CCA argument, page 12, paragraph 33-38.

¹⁰²⁹ Exhibit 636.01, CCA argument, page 12, paragraph 35.

¹⁰³⁰ Exhibit 636.01, CCA argument, page 14-15, paragraphs 42-43.

¹⁰³¹ Exhibit 298.02, Calgary evidence, page 29.

¹⁰³² Exhibit 64.01, PBR Principles Bulletin 2010-20.

¹⁰³³ Exhibit 629.01, Calgary argument, PDF page 20.

¹⁰³⁴ Exhibit 634.01, UCA argument, paragraphs 28-53.

¹⁰³⁵ Exhibit 299.02, Cronin and Motluk UCA evidence page 14, lines 15-23.

¹⁰³⁶ Exhibit 634.01, UCA argument, page 12, paragraphs 68-71.

¹⁰³⁷ Transcript, Volume 17, page 3322, lines 1-17.

¹⁰³⁸ Exhibit 635.16, IPCAA argument, page 2, paragraphs 8-9.

required. What the correct timing of a review will be and what the nature of the review should be will depend on the circumstances at the time.

833. The length of a typical PBR term in North America is from three to five years after which there is typically a rebasing and a recalculation of rates.¹⁰³⁹

834. During the proceeding, the Commission asked parties to explore options for establishing a term.¹⁰⁴⁰ One option which was considered was whether it was possible to implement an open-ended term where there is no fixed date for the end of the PBR plan. The utilities and interveners were asked whether or not they supported an open-ended term during the hearing.

835. While most parties agreed that an open-ended term would have a positive impact on incentives,¹⁰⁴¹ they also considered this proposal to be problematic.¹⁰⁴² No party supported such a proposal, particularly for a first generation PBR plan.¹⁰⁴³ Dr. Weisman, on behalf of EPCOR, stated, “I think you, more generally, see that [open-ended term] in second and third-generation plans than you do the initial ones.”¹⁰⁴⁴ As well, NERA concluded that such a proposal would be impractical and in their experience, they had not seen such a proposal implemented by other North American regulators.¹⁰⁴⁵ The Commission agrees that an open-ended term for the first generation PBR plans is not warranted.

836. The Commission considers that a five-year fixed term for each of the PBR plans is reasonable. The Commission has chosen this period recognizing that some of the elements approved in the PBR plans in this decision are novel and this term is consistent with the typical term for PBR plans in North America. Although a shorter term tends to blunt the incentives for companies to identify and implement productivity improvements, the Commission has approved the inclusion of an efficiency carry-over mechanism to mitigate this effect.

837. The Commission does not approve the recommendation of the UCA for a mid-term review half-way through the PBR term because doing so effectively shortens the term to two years, thereby eliminating the benefits achieved from lengthening the regulatory lag.

838. In order to ensure that all utilities are treated consistently, the Commission rejects ATCO Electric’s four-year term proposal and directs all companies to proceed with a five-year fixed term. The Commission denies the proposals of ATCO Gas, ATCO Electric and AltaGas for a unilateral option to extend their plan term.

839. The Commission will not make a determination at this stage as to how it will go forward following the end of the five-year term. As the Commission noted in its February 26, 2010 letter; “[t]he Commission will initiate a proceeding during the first PBR term to consider how the

¹⁰³⁹ Exhibit 100.02, LEI evidence, pages 31-32, PDF page 97; Exhibit 103.02, EPCOR application, page 19, paragraph 45; Exhibit 205.01, AUC-AE-13(a); Exhibit 391.02, NERA second report, Table 3, page 30 for a comprehensive list of PBR term lengths in Canada and the United States; Exhibit 629.01, Calgary argument, calculated the NERA example plan average as 4.9 years.

¹⁰⁴⁰ Exhibit 80.02, NERA first report, PDF page 8.

¹⁰⁴¹ Dr. Carpenter, Transcript, Volume 5, page 832; Ms. Frayer, Transcript, Volume 11, pages 2188-2189.

¹⁰⁴² Ms. Frayer, Transcript, Volume 11, pages 2188-2189.

¹⁰⁴³ Dr. Carpenter, Transcript, Volume 5, page 832; Dr. Makholm, NERA, Transcript, Volume 1, page 197; Exhibit 636.01, CCA argument, page 15, paragraph 42.

¹⁰⁴⁴ Transcript, Volume 10, page 1826.

¹⁰⁴⁵ Transcript, Volume 1, page 197 at lines 9 and 22.

success of the PBR plan should be judged and how it might be re-initiated, or rates ‘re-based,’ at the end of the initial five-year term in a way that minimizes potential distortions to economic efficiency incentives.”¹⁰⁴⁶

12 Maximum investment levels

840. The customer and retailer terms and conditions of electric distribution service form part of the distribution tariffs of the electric distribution companies. Over the PBR term, it is expected that there may be changes required to these terms and conditions of service. Among the elements in the terms and conditions of service of the electric distribution companies which may change are the maximum investment levels (MILs) and the service fee schedule. MILs are the maximum amounts of money that an electric distribution company can invest in a new service for a customer. This investment level is added to the electric distribution company’s rate base. The remaining cost of a new connection, if any, must be supplied by the customer as a contribution.

841. Recently, the electric distribution companies, with the participation of stakeholder groups, developed a common approach to managing changes to MILs. This common approach was approved for Fortis,¹⁰⁴⁷ ATCO Electric,¹⁰⁴⁸ and EPCOR.¹⁰⁴⁹

842. Gas distribution companies do not have MILs but do have specified customer contribution levels. The specified customer contribution levels for ATCO Gas can be found in Schedule C to its terms and conditions of service. AltaGas also provides for specific customer contribution levels as part of its terms and conditions of service.

843. Each of the distribution companies proposed an automatic adjustment to their MILs/customer contribution levels during the term of the PBR. AltaGas proposed that its customer contribution levels be adjusted annually by the I-X mechanism. With the exception of the residential and street lighting customer groups, Fortis also proposed that its MILs be indexed annually by the I-X mechanism. For the residential and street lighting customer groups, Fortis proposed an increase of I-X plus 10 per cent.¹⁰⁵⁰ EPCOR proposed that the MILs would be included in its annual capital forecast in its capital factor (K factor) stating that its MILs would be based on the historical actual costs, adjusted to keep pace with forecast construction costs.¹⁰⁵¹ ATCO Electric proposed that its MILs be adjusted by the I factor only because it considered that the I-X mechanism would not offset the effect of the company’s investment. Rather, AE argued that increasing MILs by the I factor ensures future customers receive equitable company investment and mitigates intergenerational equity issues.¹⁰⁵² Similarly, ATCO Gas proposed that its specified customer contributions be adjusted only by the I factor. Both ATCO Electric and ATCO Gas submitted that changes to MILs or customer contribution policies could have a material impact on whether future capital expenditures can reasonably be expected to be covered

¹⁰⁴⁶ Exhibit 1.01.

¹⁰⁴⁷ Decision 2010-309: FortisAlberta Inc., 2010-2011 Distribution Tariff – Phase I, Application No. 1605170, Proceeding ID No. 212, July 6, 2010.

¹⁰⁴⁸ Decision 2011-134: ATCO Electric Ltd., 2011-2012 Phase I Distribution Tariff, Application No. 1606228, Proceeding ID No. 650, April 13, 2011.

¹⁰⁴⁹ Decision 2010-505: EPCOR Distribution & Transmission Inc., 2010-2011 Phase I Distribution Tariff, Application No. 1605759; Proceeding ID No. 437, October 28, 2010.

¹⁰⁵⁰ Exhibit 100.02, Fortis application, page 53, paragraph 187-188.

¹⁰⁵¹ Exhibit 238.01, UCA-EDTI-08 b).

¹⁰⁵² Exhibit 631.01, ATCO Electric argument, page 64, paragraph 256.

by the I-X mechanism.¹⁰⁵³ Both utilities also argued that this proceeding is not the proper forum to address changes to MILs and customer contribution policies.

844. The UCA opposed ATCO Gas and ATCO Electric's proposals to adjust its specified customer contributions/MILs by I only and recommended that any adjustment be made by the I-X mechanism as, in its view, these costs should be subject to the same efficiency incentives as any other utility cost.¹⁰⁵⁴ Calgary also rejected ATCO Gas' proposal and recommended that ATCO Gas adjust its specified customer contributions by I-X. Neither the CCA nor IPCAA provided any specific comments or recommendations regarding customer contributions/MILs.

845. For ease of reference, a summary of the proposed treatment for adjusting MILs/customer contributions is provided in the table below:

Table 12-1 Summary of proposed maximum investment levels

Category	Fortis ¹⁰⁵⁵	ATCO Electric/Gas ^{1056 1057}	AltaGas ¹⁰⁵⁸	EPCOR ¹⁰⁵⁹	UCA ¹⁰⁶⁰	Calgary ¹⁰⁶¹
Residential	I-X+10%	I	I-X	Part of K factor adjustments	I-X	I-X
Street lighting	I-X + 10%	I	I-X	Part of K factor adjustments	I-X	I-X
All other customers	I-X	I	I-X	Part of K factor adjustments	I-X	I-X

Commission findings

846. It is evident from the submissions that the electric distribution companies want to continue to manage changes to their MILs in accordance with the common approach that was reached among the companies and stakeholders. However, this common approach was developed and approved by the Commission under cost of service rate regulation.

847. The Commission has considered the submissions of ATCO Electric and ATCO Gas regarding changes to MILs or customer contribution policies and agrees that this is not the forum to determine such a policy. Customer contribution policy considerations will be addressed in a future generic proceeding as directed by the Commission.

848. However, with regard to providing for the automatic escalation of MILs and specific customer contributions during the PBR term, the Commission considers that these contributions should be escalated by I-X.

849. In Decision 2000-01,¹⁰⁶² the Commission's predecessor, the Alberta Energy and Utilities Board stated "an appropriate contribution policy ... provides a suitable balance to an unlimited

¹⁰⁵³ Exhibit 631.01, ATCO Electric argument, page 64, paragraph 256; Exhibit 648.02, ATCO Gas reply argument, page 149, paragraphs 540-543.

¹⁰⁵⁴ Exhibit 300.02, UCA evidence of Russ Bell at page 56, A52.

¹⁰⁵⁵ Exhibit 100.02, Fortis application, page 53, paragraph 188.

¹⁰⁵⁶ Exhibit 476.01, ATCO Electric rebuttal evidence, page 66, paragraphs 203-204.

¹⁰⁵⁷ Exhibit 632.01, ATCO Gas argument, page 87, paragraph 282.

¹⁰⁵⁸ Exhibit 628.01, AltaGas argument, page 60.

¹⁰⁵⁹ Exhibit 238.01, UCA-EDTI-08 b).

¹⁰⁶⁰ Exhibit 634.01, UCA argument, page 57, paragraph 314.

¹⁰⁶¹ Exhibit 629.01, Calgary argument, page 52.

obligation to service by imposing economic discipline on siting decisions.”¹⁰⁶³ The Commission agrees. As MILs increase, so do the capital costs of the companies. Therefore, MILs should be subject to the same incentives as other capital costs faced by the companies. As such, the Commission considers that to escalate MILs by I only removes incentives to seek additional efficiencies. This would be contrary to Principle 1 as incentives to seek efficiencies in the competitive market would be effectively lessened by escalating MILs by I only. Therefore, subject to the discussion of Fortis’ MILs proposal below, the Commission directs that MILs be escalated by I-X throughout the PBR term.

850. Fortis proposed to escalate the MILs of residential (Rate 11) and street lighting (Rate 31) classes by an additional 10 per cent per year of the PBR term. The Commission finds that this proposal is consistent with Fortis’ approach to MILs which was approved in Decision 2012-108 and necessary to bring its MILs in line with the other electric distribution companies.¹⁰⁶⁴ Therefore, the Commission directs that Fortis’ MILs for these two classes be escalated by I-X plus 10 per cent per year throughout the PBR term.

13 Financial reporting requirements

851. Each utility proposed to file a copy of its [Rule 005](#)¹⁰⁶⁵ report in its annual PBR filing.¹⁰⁶⁶ AUC Rule 005 requires a utility to file schedules of financial and operational information including return on equity, detailed explanations of variances and audited financial statements complete with notes and an audit report. Under AUC Rule 005, all utilities are required to file their financial results by either May 1 for electric utilities or May 15 for gas utilities.

852. The UCA in its evidence noted that the minimum filing requirement (MFR)¹⁰⁶⁷ and general rate application (GRA) schedules, respectively filed by electric and gas utilities in their GRAs, provide much more detail than the Rule 005 schedules.¹⁰⁶⁸ Therefore, the UCA proposed that electric utilities be ordered to provide MFR schedules as part of their annual PBR filing, and that each gas utility file all the schedules included in its last GRA.¹⁰⁶⁹ The UCA argued that, if only the Rule 005 schedules were to be filed throughout a utility’s PBR term, rebasing at the end

¹⁰⁶² Decision [2000-01](#): ESBI Alberta Ltd., 1999/2000 General Rate Application Phase I and Phase II, Application No. 990005, File Nos. 1803-1, 1803-3, February 2, 2000.

¹⁰⁶³ Decision 2000-01, page 270.

¹⁰⁶⁴ Decision 2012-108, paragraphs 104-105.

¹⁰⁶⁵ Rule 005: *Annual Reporting Requirements of Financial and Operational Results* (Rule 005).

¹⁰⁶⁶ Exhibit 110.01, AltaGas PBR application, paragraphs 109 and 122; Exhibit 631.02, ATCO Electric argument, paragraph 328 and Exhibit 476.02, ATCO Electric rebuttal evidence, paragraphs 208-213; Exhibit 632.01, ATCO Gas argument, paragraph 343 and Exhibit 472.02, ATCO Gas rebuttal evidence, paragraphs 152-154; Exhibit 633.02, Fortis argument, paragraph 288(88); Exhibit 103.02, EPCOR PBR application, paragraph 256.

¹⁰⁶⁷ The minimum filing requirements were approved in Decision [2007-017](#): EUB Proceeding, Implementation of the Uniform System of Accounts and Minimum Filing Requirements for Alberta’s Electric Transmission and Distribution Utilities, Application No. 1468565, March 6, 2007. This decision was the culmination of a consultation to determine a uniform system of accounts for electric utilities to implement, and the minimum filing requirements electric utilities must comply with in their general rate applications. See [USA & MFR](#) on the AUC’s website under Items of Interest.

¹⁰⁶⁸ Exhibit 300.02, UCA evidence, Question 60.

¹⁰⁶⁹ Exhibit 634.02, UCA argument, paragraphs 417 to 421.

of the term would be far more difficult and it would be far more difficult to return to cost of service regulation.¹⁰⁷⁰

853. The UCA further argued that the continuity of actual data would be lost over a utility's PBR term if the companies were not required to file annually the more detailed MFR and GRA schedules. This is because companies subject to the MFR are required to provide only two years of actual data in a cost of service general rate application.¹⁰⁷¹

854. Fortis and the ATCO companies argued being required to file the MFR and GRA schedules on an annual basis would increase regulatory burden.¹⁰⁷² The UCA responded that the additional cost to provide the extra detail in the MFR and GRA schedules would be minimal.¹⁰⁷³ IPCAA stated that customers have paid and are paying for data collection in the USA/MFR format and should be afforded the right to receive all such data on an ongoing basis.¹⁰⁷⁴

855. The UCA also recommended that "all utilities continue to exclude costs previously disallowed from the calculation of actual results and ROE during the PBR term."¹⁰⁷⁵ The UCA proposed that, to address its concern with respect to excluding disallowed costs, companies should file the two tables it had provided in ENMAX's FBR proceeding and which ENMAX was subsequently directed to provide in its annual rate applications. These two tables consist of a reconciliation of financial and utility returns, and a summary of disallowed and inappropriate costs.¹⁰⁷⁶

13.1 Audits and senior officer attestation

856. AUC Rule 005 requires a reconciliation of the utility's financial results to its audited financial statements. Audited financial statements are intended to provide independent assurance on the accuracy and completeness of a utility's financial results. AUC Rule 005 does not require an audit of the Rule 005 schedules themselves. Because of disallowed costs, non-regulated operations, changes in accounting policies and other factors, the financial results reported by a utility in its audited financial statements may be different than those reported in AUC Rule 005 or may differ over several years.

857. AltaGas, in its application, proposed that as part of its annual rate application it would provide a senior officer attestation, in addition to a copy of its Rule 005 filing (which includes audited financial statements).¹⁰⁷⁷ AltaGas' proposed senior officer attestation appears to be based on the nine issues that the Commission directed ENMAX to have reviewed and commented on by an independent auditor in Decision 2010-146.¹⁰⁷⁸ The attestation by an AltaGas senior officer would provide assurance as to the veracity of the reported numbers and the calculations used, and transparency with respect to any changes in methods, policies or parameters affecting the reported results.

¹⁰⁷⁰ Exhibit 634.02, UCA argument, paragraph 420.

¹⁰⁷¹ Exhibit 634.02, UCA argument, paragraph 419.

¹⁰⁷² Exhibit 644.01, Fortis reply argument, paragraphs 174 and 175; Exhibit 648.02, ATCO Gas reply argument, paragraphs 529 and 530; Exhibit 647.01, ATCO Electric reply argument, paragraph 354.

¹⁰⁷³ Exhibit 300.02, UCA evidence, Question 65 on page 67.

¹⁰⁷⁴ Exhibit 642.01, IPCAA reply argument, paragraph 19.

¹⁰⁷⁵ Exhibit 634.02, UCA argument, paragraph 422.

¹⁰⁷⁶ Exhibit 300.02, UCA evidence, Question 69 and Question 70.

¹⁰⁷⁷ Exhibit 110.01, AltaGas Incentive Regulation application, paragraph 123.

¹⁰⁷⁸ Decision 2010-146: ENMAX Power Corporation, Decision 2009-035 Formula Based Ratemaking Compliance Application, Application No. 1604999, Proceeding ID. 191, April 22, 2010, paragraph 132.

858. The Commission in Decision 2009-035 directed ENMAX as follows:

... to have its reported ROE independently verified and to have an officer of the company attest to its validity. The Commission also directs EPC to include in its annual filings the reconciliation tables proposed by UCA.¹⁰⁷⁹

859. Subsequently, in Decision 2011-260, the Commission directed ENMAX to provide attestations and certifications by one of its senior officers for the following matters:¹⁰⁸⁰

- that the numbers, assumptions and presentation of the numbers in the application are accurate, complete, and proper
- regarding the accuracy and/or completeness of the nine issues identified
- that the numbers, assumptions and proposed rates are reasonable, fair and accurate

Commission findings

860. The Commission agrees that the utilities' proposal to include the AUC Rule 005 schedules in their annual PBR filings is reasonable and accordingly directs each company to include in its annual PBR filing a copy of its AUC Rule 005 filing.

861. To maintain transparency and consistency, the Commission agrees with the UCA that disallowed costs should continue to be identified and excluded from a company's ROE. The Commission directs each utility to include in its annual PBR rate adjustment filing a schedule including the two UCA tables put forth by the UCA.¹⁰⁸¹

862. The Commission directs each company to include in its annual PBR rate adjustment filing an attestation signed by a senior officer of the company as proposed by AltaGas. The senior officer attestation should include, as applicable, not only those items proposed by AltaGas, but also certifications on the accuracy, completeness and reasonableness of the numbers and assumptions included in the company's application. The required attestations and certifications by a senior officer of each company are as follows:

- confirm the reported ROE used to determine if a re-opener exists, either actual or weather normalized
- describe any changes in accounting methods, including assumptions respecting capitalization of labour and overhead and associated impacts
- describe any changes in the depreciation parameters and associated impacts
- describe any changes in the allocation of shared services costs and associated impacts
- confirm the inflation parameters used, including calculation and application of the rates formula to rates
- confirm the calculation of flow-through costs (Y factors) and associated riders conform to Commission directions
- confirm the calculation of exogenous (Z factor) adjustments and associated riders conform to Commission directions

¹⁰⁷⁹ Decision 2009-035, paragraph 283.

¹⁰⁸⁰ Decision 2011-260: ENMAX Power Corporation, 2011 Formula Based Ratemaking Annual Rates and Technical Report, Application No. 1607203, Proceeding ID No. 1169, June 20, 2011, paragraph 58(5).

¹⁰⁸¹ Exhibit 300.02, UCA evidence, page 74.

- confirm the calculation of capital trackers (K factor) and associated riders conform to Commission directions
- identify any material changes in the components of costs or revenues
- confirm that the numbers, assumptions and presentation of the numbers in the application are accurate, complete, and proper
- confirm that the numbers, assumptions and proposed rates are reasonable, fair and accurate

863. For a company under PBR, the requirement to file the AUC Rule 005 schedules in both its annual PBR rate adjustment filing and a separate AUC Rule 005 application, does not exempt the company from its obligation to maintain detailed accounts in accordance with the acts, regulations, Commission rules, or Commission decisions applicable to the company. Therefore, unless otherwise directed or exempted by the Commission, the companies are directed to maintain the ability to file a complete set of MFR and GRA schedules with actual results for all years within the term of the company's PBR plan. The companies are not required, however, to file a complete set of MFR and GRA schedules annually.

14 Service quality

864. 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. 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 when needed.

865. The Commission has the legislative authority under both the *Electric Utilities Act*¹⁰⁸² and the *Gas Utilities Act*¹⁰⁸³ to make rules respecting service standards for electric utilities and for gas distributors. The Commission is also authorized to investigate compliance with the rules respecting service standards and, if necessary, is empowered to take steps to enforce them. This authority exists regardless of the type of ratemaking regime in operation, be it cost of service or performance-based regulation.

866. The first of the five principles (Principle 1) states, "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." All of the companies provided assurances in their submissions that service quality would not decline with the adoption of their proposed PBR plans. Notwithstanding these assurances, each of the interveners identified service quality degradation as a significant risk under PBR.¹⁰⁸⁴

¹⁰⁸² *Electric Utilities Act*, Section 129.

¹⁰⁸³ *Gas Utilities Act*, Section 28.3.

¹⁰⁸⁴ Exhibit 634.01, UCA argument, paragraph 368; Exhibit 307.01, PEG evidence for CCA, PDF page 65; Exhibit 635.01, IPCAA argument, paragraph 53; Exhibit 629.01, Calgary argument, PDF page 64.

867. In his evidence submitted on behalf of the UCA, Dr. Cronin reported the results of a study where he compared reliability statistics from Alberta electric distribution companies with selected companies in Ontario and the United States. Of the 22 companies Dr. Cronin described as higher density, ENMAX and EPCOR ranked first and third respectively for reliability. Among the lower density companies, Dr. Cronin described ATCO Electric and Fortis as having “superior reliability” compared to the 10 companies he examined. Dr. Cronin concluded from this analysis that “the AUC must be careful that the gains achieved to date are not put at risk for what could be limited potential gains under PBR.”¹⁰⁸⁵

Commission findings

868. The Commission has reviewed the service quality and reliability annual reports of the companies and agrees with the UCA that the service levels currently provided by the companies are acceptable.¹⁰⁸⁶ The Commission will require the companies to maintain their current levels of service quality throughout the PBR term.

14.1 Mechanism to monitor and enforce service quality

869. Currently, the Commission monitors service quality performance through AUC Rule 002.¹⁰⁸⁷ AUC Rule 002 sets out the service quality reporting requirements for electric utilities and gas distributors. Pursuant to this rule, all gas distributors and electric utilities under the jurisdiction of the Commission are required to file quarterly and annual performance reports.

870. Parties were divided as to whether the Commission should continue to use AUC Rule 002 for monitoring service quality along with an enforcement mechanism such as administrative monetary penalties, or whether the Commission should implement a performance standard mechanism within the PBR plan itself that also includes penalty adjustments for non-compliance in the formula. This latter approach, which is often referred to as a “Q factor” in the PBR formula, was adopted by the Commission in Decision 2009-035 for the ENMAX FBR plan. In the ENMAX FBR, the service standards were set out for the FBR plan and the penalties for failure to meet the standards were included as an adjustment to the formula.¹⁰⁸⁸

871. ATCO Electric, ATCO Gas, AltaGas and Fortis favoured continued use of AUC Rule 002 for service quality reporting.¹⁰⁸⁹ The UCA stated that “Rule 002 should form the basis for service quality reporting under PBR.”¹⁰⁹⁰ The CCA supported this approach.¹⁰⁹¹

872. EPCOR was in favour of the approach approved for the ENMAX FBR plan. In its view, AUC Rule 002 has significant limitations including the fact that it did not set out specified penalties, and it used the All Injury Incidence Frequency Rate metric instead of the Total Recordable Injury Frequency Rate metric that EPCOR proposed. EPCOR also argued in favour of its proposal because AUC Rule 002 applies only to owners of electric distribution systems and

¹⁰⁸⁵ Exhibit 299.02, Cronin and Motluk UCA evidence, PDF pages 11-12.

¹⁰⁸⁶ Service quality and reliability annual reports on [AUC website](#).

¹⁰⁸⁷ [AUC Rule 002: Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors](#), effective date July 1, 2010 (Rule 002).

¹⁰⁸⁸ Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID. 12, March 25, 2009, paragraphs 302-304.

¹⁰⁸⁹ Exhibit 631.01, ATCO Electric argument, paragraph 284; Exhibit 632.01, ATCO Gas argument, paragraph 306; Exhibit 628.01, AltaGas argument, PDF page 80; Exhibit 474.01, Fortis rebuttal evidence, paragraph 58.

¹⁰⁹⁰ Exhibit 634.01, UCA argument, paragraph 369.

¹⁰⁹¹ Exhibit 636.01, CCA argument, paragraph 357.

to gas distributors but not to transmission, whereas, EPCOR's proposal, like that of ENMAX, included metrics for transmission.¹⁰⁹² EPCOR's proposal to adopt the approach approved for the ENMAX FBR aligned with EPCOR's proposal to include transmission in its PBR plan.

873. IPCAA was also critical of adopting AUC Rule 002 as, in its view:¹⁰⁹³

Traditional service quality metrics such as those contained in AUC Rule 002 have been accepted in the context of traditional rate-base regulation. For example, SAIDI [System Average Interruption Duration Index] and SAIFI [System Average Interruption Frequency index] provide a broad sense of "position in the pack," relative to other utilities across Canada (and elsewhere), but that is all the precision that they can potentially provide. [T16:3039.3]. They are biased metrics, which over-report some phenomena and under-report other phenomena. [T16:3061.22]

...

Since these metrics are based on number of customers affected, they can lead to poor incentives. For example, a utility might have two projects to reduce these metrics: one to trim trees around ten summer cottages and one to maintain ten large sites' high voltage equipment. If optimizing to cost and CAIDI [Customer Average Interruption Duration Index] was the goal, the cottage project might seem far superior even though the social and economic costs of outages to the large sites are much greater. [T16:3039.6]

...

AUC Rule 002 does not provide for any financial incentives, and the penalties provided by the EUA [sic. AUCA] at section 63 do not allow for a performance bonus. A symmetrical incentive plan would therefore have to be incorporated into the PBR plans. [T06, p.1090.22]

874. Calgary also rejected the use of AUC Rule 002, because it generally requires ATCO Gas to report its operations, rather than requiring the company to meet "specific performance criteria or standards."¹⁰⁹⁴

Commission findings

875. The Commission has considered the advantages and the disadvantages of each of the two alternative proposals for monitoring and enforcing service quality: to continue to use AUC Rule 002 for monitoring service quality along with an enforcement mechanism such as administrative monetary penalties, or to implement a performance standard mechanism within the PBR plan itself that also includes penalty adjustments for non-compliance in the formula.

¹⁰⁹² Exhibit 630.02, EPCOR argument, paragraph 296.

¹⁰⁹³ Exhibit 635.01, IPCAA argument paragraphs 50, 51 and 93.

¹⁰⁹⁴ Exhibit 629.01, Calgary argument, PDF page 65.

876. The following table sets out the metrics that are currently required to be reported by electric distribution utilities under AUC Rule 002 and indicates whether or not each metric has a defined target:

Table 14-1 Current AUC Rule 002 metrics for electric distribution utilities

Performance category	Metric	Defined targets
Billing and meter reading performance measures	Monthly billing and meter reading performance	No
	Cumulative meters not read within six months	Yes
	Identified meter errors	No
	Monthly tariff billing performance	Yes
Work completion performance measures	Energizing sites	No
	De-energizing sites	No
	Performing off-cycle meter reads	No
Worker safety performance measures	All injury/illness frequency rate	No
	Motor vehicle incident frequency	No
Reliability performance measures	System average interruption frequency index (SAIFI)	No
	Customer average interruption duration index (CAIDI)	No
	System average interruption duration index (SAIDI)	No
	SAIDI of worst-performing circuits on the system	No
Post-final adjustment mechanism (PFAM) adjustments processed	Post-final adjustment mechanism (PFAM) adjustments processed	No
Customer satisfaction measures	Percentage of customer satisfaction following customer-initiated contact with the owner	Yes
	Overall customer satisfaction measures	Yes
	Complaint response	Yes

877. The following table sets out the metrics that are currently required to be reported by gas distributors under AUC Rule 002 and indicates whether or not each metric has a defined target:

Table 14-2 Current AUC Rule 002 metrics for gas distributors

Performance category	Metric	Defined targets
Billing and meter reading performance measures	Cumulative meters not read within four months and one year	No
	Monthly tariff billing performance	Yes
Worker safety performance measures	All injury/illness frequency rate	No
	Motor vehicle incident frequency	No
Customer satisfaction measures	Percentage of customer satisfaction following customer-initiated contact with the owner	Yes
	Overall customer satisfaction measures	Yes
	Complaint response	Yes

878. The Commission also monitors call centre statistics, such as call answer time and abandon rates, in AUC Rule 003: *Service Quality and Reliability Performance Monitoring and Reporting for Regulated Rate Providers and Default Supply Providers* (Rule 003) because, in Alberta, call centre and billing functions are performed by competitive retailers, regulated rate providers and default supply providers. The electric utilities and gas distributors generally only field emergency calls from customers or calls from retailers.

879. In addition to filing quarterly and annual performance reports, another AUC Rule 002 requirement is for the company to meet with the Commission at least once annually after submission of its AUC Rule 002 annual report to discuss:

- service quality issues
- trends in service quality data reported by the owner, including any corrective action plans proposed by the owner to remedy failing performance standards
- issues raised by customer complaints filed with the Commission
- other policy issues related to customer service¹⁰⁹⁵

880. In the Commission's view, using AUC Rule 002 together with a penalty provision has the following advantages:

- As a rule, the performance metrics already included in AUC Rule 002 were developed and updated in consultation with industry stakeholders.
- Continuity of the metrics and how they are reported will allow for trend analysis, especially for those metrics which have been in place since 2004. The Commission can rely upon historical databases to identify any negative trends in service quality and take corrective action if service levels decline.
- Companies may make decisions and take actions during the PBR term which may have consequences not readily apparent during the term. Using AUC Rule 002 will enable the

¹⁰⁹⁵ AUC Rule 002, Section 2.3.

Commission to monitor the consequences of those actions after the PBR term expires, regardless of the rate-setting mechanism in place after the end of the term.

- As is discussed further in Section 14.2, if AUC Rule 002 is accompanied by a penalty provision rather than including penalties as an adjustment to the PBR formula, unexpected and potentially undesirable impacts to consumer behaviour can be avoided. For example, if rates were lowered because of a penalty that adjusted the formula, certain price sensitive consumers may react by choosing to consume more energy which, in turn, could potentially increase revenues for the company. In such an event, incurring a penalty may result in a financial benefit to the company.

881. Having considered both the advantages and disadvantages of the two mechanisms proposed, the Commission finds that adopting AUC Rule 002 to determine performance standards and targets, and applying penalties in the event of non-compliance with the performance targets established, is the best approach for ensuring that the companies have an adequate incentive to maintain service quality under PBR.

882. The Commission is satisfied that, with the addition of new metrics and with the establishment of defined targets for those metrics currently without them, AUC Rule 002 will satisfactorily address the requirement for service quality measurement and reporting under PBR. As the Commission has determined in Section 2.4 of this decision that it will not include transmission as part of any PBR plan, it will, therefore, not be necessary to develop any performance measures for transmission at this time.

883. Accordingly, the Commission will initiate a consultation process before the end of 2012 to review and revise AUC Rule 002 in a timely manner. The companies and interveners will be invited to participate in the consultation process.

14.2 Penalties and rewards

884. AUC Rule 002 does not include provisions for penalties in the event that performance standards are not met. All parties agreed that some kind of enforcement mechanism is necessary. None of the companies argued against penalties for failure to meet service quality targets, when the failure was within their control.¹⁰⁹⁶

885. Calgary recommended penalties and stated “the PBR plan should include direct fines paid by the utility for specific infractions; the fines should be treated as an addition to the next ESM payment or at the end of the PBR term.”¹⁰⁹⁷

886. The UCA recommended specified penalties of 10 per cent of earnings and stated:

In a competitive market, poor performance is met with a lawsuit or more likely the loss of a customer, without any process to explain the reason for poor performance. As customers of a regulated utility have no choice to change suppliers, a specified penalty, with certainty as to the impact of poor performance is simpler to administer. Also, there

¹⁰⁹⁶ Exhibit 219.02, Fortis response to AUC-FAI-020 ALLUTIL (b), PDF page 35; Exhibit 628.01, AltaGas argument, PDF page 84; Exhibit 103.02, EPCOR PBR application, paragraph 91; Exhibit 631.01, ATCO Electric argument, paragraph 308; Exhibit 632.01, ATCO Gas argument, paragraph 326.

¹⁰⁹⁷ Exhibit 629.01, Calgary argument, page 63.

is no evidence that customers want or are willing to pay for improved service levels, so the concept of a reward is not supported by the evidence.¹⁰⁹⁸

887. IPCAA recommended a symmetrical approach to address service quality issues. That is, IPCAA proposed that penalties for degradations to service quality be instituted but also, if service quality improves, that a performance bonus plan be instituted.¹⁰⁹⁹

888. EPCOR stated in its application that it “will explain the reasons for failing to meet the target as well as any future corrective actions EDTI proposes to take.”¹¹⁰⁰ While EPCOR only implied that the penalty would not apply if it adequately justified the failure, the other companies clearly argued for an opportunity to have their failures reviewed prior to a penalty being administered.¹¹⁰¹

889. ATCO Electric and ATCO Gas expressed concerns that they would be penalized for events outside of their control and, therefore, recommended that, if they would be subject to penalties for events outside of their control, they should also be entitled to receive rewards where service targets are exceeded due to events outside their control in order to balance the increased risk, if penalties were automatic without opportunity for review.¹¹⁰² Fortis, in its application, did not request rewards for higher than standard service quality¹¹⁰³ but on cross-examination recommended an approach with both penalties and rewards.¹¹⁰⁴ AltaGas submitted that higher than required service quality levels should be met with rewards if a system of penalties is in place.¹¹⁰⁵

890. EPCOR proposed a reward for meeting its service quality standards throughout the five-year PBR term, to be specifically included in an efficiency carry-over mechanism for two years after the end of the PBR term.¹¹⁰⁶

891. Regarding the size of the penalties, ATCO Electric stated:

The Commission makes the determination of whether a penalty is required and the appropriate amount would be commensurate with the benefit gained by the utility as a result of its actions.¹¹⁰⁷

892. ATCO Gas made a statement similar to the one made by ATCO Electric¹¹⁰⁸ and continued:

The magnitude of 10% of earnings recommended by the UCA is unreasonable. As ATCO Gas has already stated, there is a realistic likelihood that it will be penalized for events

¹⁰⁹⁸ Exhibit 649.02, UCA reply argument, paragraph 246.

¹⁰⁹⁹ Exhibit 635.01, IPCAA argument, paragraph 93.

¹¹⁰⁰ Exhibit 103.02, EPCOR PBR application, paragraph 93.

¹¹⁰¹ Exhibit 628.01, AltaGas argument, PDF page 83; Exhibit 631.01, ATCO Electric argument, paragraph 306; Exhibit 632.01, ATCO Gas argument, paragraph 324; Exhibit 100.02, Fortis PBR application, paragraph 131.

¹¹⁰² Exhibit 647.01, ATCO Electric reply argument, paragraph 330; Exhibit 648.02, ATCO Gas reply argument, paragraph 502.

¹¹⁰³ Exhibit 100.02, Fortis PBR application, paragraph 138.

¹¹⁰⁴ Transcript Volume 11, page 2182.

¹¹⁰⁵ Exhibit 650.01, AltaGas reply argument, paragraph 265.

¹¹⁰⁶ Exhibit 103.02, EPCOR PBR application, paragraph 272.

¹¹⁰⁷ Exhibit 647.01, ATCO Electric reply argument, paragraph 331.

¹¹⁰⁸ Exhibit 648.02, ATCO Gas reply argument, paragraph 503.

that were not within its ability to control. A penalty of 10% of earnings, which is in the order of \$6 million for ATCO Gas, related to something ATCO Gas could not control is absurdly confiscatory. Penalties must not be so great as to have a significant negative impact on ATCO Gas' ability to recover its prudently incurred costs, including a Fair Return on its investments. The penalty should be commensurate with the benefit gained...¹¹⁰⁹

893. ATCO Electric, too, had concerns with having penalties as high as 10 per cent of earnings.¹¹¹⁰ Fortis and AltaGas did not discuss the size of the penalties in their final arguments or reply arguments.

894. EPCOR, however, proposed that a failure to reach any one service quality metric should result in a \$250,000 penalty per year. Under EPCOR's proposed PBR plan, it would be penalized \$1 million in 2013 if it failed to reach all four of its proposed metrics, and the \$1 million would be escalated by I-X in subsequent years.¹¹¹¹ However, EPCOR indicated that it would be applying to the Commission for an adjustment to two of its four performance targets and for relief from those targets for 12 months after implementation of its Outage Management System/Distribution Management System.¹¹¹²

895. The UCA, in its reply argument, expressed concerns over EPCOR's proposal to be penalized \$250,000 per failed target, stating:

Further, having the penalty split between four measures, means that failing to meet one measure would result in a penalty of only \$0.25 million, which is not material, and may not be sufficient to deter the conduct. It may well lead to the concern raised by the Chair that the utility will simply factor the fine into the economics of their decisions.¹¹¹³

Commission findings

896. Section 129(3) of the *Electric Utilities Act* and Section 28.3(3) of the *Gas Utilities Act* provide the legislative authority for the Commission to take any or all of the following actions when the Commission is of the opinion that an owner of an electric utility or a gas distributor has failed or is failing to comply with its rules respecting service standards. These provisions state as follows:

Electric Utilities Act

129(3) If the Commission is of the opinion that the owner of an electric utility has failed or is failing to comply with the rules respecting service quality standards, the Commission may by order do all or any of the following:

- (a) direct the owner to take any action to improve services that the Commission considers just and reasonable;
- (b) direct the owner to provide the customer with a credit, of an amount specified by the Commission, to compensate the customer for the owner's failure to comply with the rules respecting service quality standards;

¹¹⁰⁹ Exhibit 648.02, ATCO Gas reply argument, paragraph 509.

¹¹¹⁰ Exhibit 647.01, ATCO Electric reply argument, paragraph 337.

¹¹¹¹ Exhibit 630.02, EPCOR argument, paragraph 316.

¹¹¹² Exhibit 630.02, EPCOR argument, paragraph 294.

¹¹¹³ Exhibit 649.02, UCA reply argument, paragraph 258.

- (c) prohibit the owner from engaging in any activity or conduct that the Commission considers to be detrimental to customer service;
- (d) impose an administrative penalty under section 63 of the *Alberta Utilities Commission Act*.

Gas Utilities Act

28.3(3) If the Commission is of the opinion that the gas distributor or default supply provider has failed or is failing to meet the service standards rules, the Commission may by order do all or any of the following:

- (a) direct the gas distributor or default supply provider to take any action to improve services that the Commission considers just and reasonable;
- (b) direct the gas distributor or default supply provider to provide the customer with a credit, in an amount specified by the Commission, to compensate the customer for the gas distributor's or default supply provider's failure to meet the service standards rules;
- (c) prohibit the gas distributor or default supply provider from engaging in any activity or conduct that the Commission considers to be detrimental to customer service;
- (d) impose an administrative penalty under section 63 of the *Alberta Utilities Commission Act*.

897. An administrative penalty under Section 63 of the *Alberta Utilities Commission Act* may require the person to whom it is directed to pay either or both of the following:

- (a) An amount not exceeding \$1 million for each day or part of a day on which the contravention occurs or continues.
- (b) A one-time amount to address economic benefit where the Commission is of the opinion that the person has derived an economic benefit directly or indirectly as a result of the contravention.

898. The Commission considers that these legislative remedies provide the following benefits in dealing with a failure to maintain service quality standards during the PBR term:

- The potential size of the penalties under Section 63 along with the power to direct disgorgement of any economic benefits discourages service quality degradation.
- If service quality failures occur, the size of the penalty can be tailored to match the benefit gained by the company as a result of its action.
- The review process in administering the penalty allows the company the opportunity to explain the source or cause of the failure and argue that a penalty is not warranted or should be lessened.

899. The Commission rejects any proposal that a performance bonus should be available to the companies in the event that service quality targets are exceeded. As noted throughout this decision, the objective of a PBR plan is to incent behaviour that would be similar to that of a company in a competitive market. But, in a competitive market, a company may increase its service quality and charge a higher price, but risks losing customers. For monopoly utility companies, there is no risk of losing customers. Customers have no choice but to pay the higher

price for a service quality level that they may not want or cannot afford.¹¹¹⁴ Further, if the industrial customers that IPCAA represents want a higher level of service quality, they can elect to contract directly with the companies for that purpose at a negotiated price.

900. For the above reasons, the Commission will continue to rely on these legislative provisions, including the imposition of penalties, to address enforcement issues should service quality degrade.

14.3 Consultation process

901. The Commission in this decision is setting out directions for the AUC Rule 002 consultation for the following issues to assist parties participating in the consultation process:

- a. Annual review meetings
- b. Additional service quality metrics
- c. Setting targets and penalties
- d. Asset management reporting
- e. Line losses (electric distribution companies only)

14.3.1 Annual review meetings

902. Parties provided their views on the format and content of the AUC Rule 002 annual review meetings. With respect to format, parties discussed the inclusion of interveners at the meetings, which previously only included the Commission and company staff. While some parties had no objection to including customer groups at the meetings,¹¹¹⁵ others expressed concern that such a change would be better addressed in a consultative process.¹¹¹⁶

903. With respect to content, Fortis proposed expanding the scope of the review meetings to include an evaluation of outage causes and a discussion of asset management programs.¹¹¹⁷

Commission findings

904. The Commission is not opposed to the inclusion of interveners at the annual review meetings. Proposed changes to the process and scope of the annual review meetings, including intervener attendance, will be further discussed in the upcoming AUC Rule 002 review consultative process referenced in Section 14.1, at which the roles of parties in the annual review meeting will be established.

14.3.2 Additional service quality performance metrics

905. Several interveners urged the Commission to adopt additional service quality performance metrics beyond those already identified under AUC Rule 002.

¹¹¹⁴ See discussion at Transcript, Volume 14, page 2892 to 2894.

¹¹¹⁵ Exhibit 628.01, AltaGas argument, page 79, Exhibit 631.01, ATCO Electric argument, paragraph 309, Exhibit 633.01, Fortis argument, paragraph 274.

¹¹¹⁶ Exhibit 629.01, Calgary argument, PDF page 68, Exhibit 648.02, ATCO Gas reply argument, paragraph 510, Exhibit 635.01, IPCAA argument, paragraph 94.

¹¹¹⁷ Exhibit 633.01, Fortis argument, paragraph 274.

906. The UCA recommended three new service quality performance metrics:

- service appointments met/time
- response time for emergency calls
- reconnect after cut off for nonpayment (CONP) response time¹¹¹⁸

907. The CCA recommended that line losses be monitored and that additional metrics be put in place for transmission.¹¹¹⁹

908. IPCAA was interested in having the following metrics or data sources included in the reporting requirements:

- system-level outage data
- outage information sent to customers as a part of the interval meter data set
- transmission measures¹¹²⁰

909. Calgary recommended that the Commission look to other jurisdictions for best practices and referenced the Gaz Métro Performance Incentive Mechanism Decision and Analysts' Presentation. The referenced document contains the following metrics:¹¹²¹

- preventive maintenance
- emergency response time
- telephone response time
- meter reading frequency
- ISO 14001 (environmental management systems)
- greenhouse gas emissions
- customer satisfaction by customer class
- collection & service interruption procedure

910. EPCOR, ATCO Electric, ATCO Gas and Fortis did not favour the addition of the new metrics proposed by the UCA.¹¹²² AltaGas was not opposed to the addition of the metrics proposed by the UCA but indicated that any additions should be accomplished through a consultation process.¹¹²³

911. Fortis,¹¹²⁴ ATCO Electric¹¹²⁵ and EPCOR¹¹²⁶ also opposed the addition of the metrics proposed by IPCAA.

¹¹¹⁸ Exhibit 634.01, UCA argument, paragraph 383.

¹¹¹⁹ Exhibit 636.01, CCA argument, paragraphs 358-360.

¹¹²⁰ Exhibit 635.01, IPCAA argument, paragraph 59-75.

¹¹²¹ Exhibit 546.01, undertaking Carpenter to McNulty, PDF page 25.

¹¹²² Exhibit 630.02, EPCOR argument, paragraphs 305 and 306; Exhibit 631.01, ATCO Electric argument, paragraph 294; Exhibit 632.01, ATCO Gas argument, paragraph 316; Exhibit 633.01, Fortis argument, paragraph 263.

¹¹²³ Exhibit 650.01, AltaGas reply argument, paragraph 259.

¹¹²⁴ Exhibit 644.01, Fortis reply argument, paragraphs 158 and 161.

¹¹²⁵ Exhibit 647.01, ATCO Electric reply argument, paragraph 321.

¹¹²⁶ Exhibit 473.02, EPCOR rebuttal evidence, page 32.

Commission findings

912. The Commission has considered the recommendations of the parties as well as information they provided on the record of the proceeding with respect to the practices in other jurisdictions. Based on this review, the Commission considers that there is insufficient evidence for the Commission to make a determination as to whether it is in the public interest to impose the new metrics proposed by the parties. Therefore, the Commission will be seeking further information on the metrics proposed as additions to AUC Rule 002 in the upcoming AUC Rule 002 consultation process.

14.3.3 Target setting and penalties

913. Several parties recommended that the Commission adopt a specific approach to set targets for those metrics under AUC Rule 002 that do not currently have defined performance targets.

914. In his evidence for the UCA, Dr. Cronin recommended the use of a willingness-to-pay study to set a socially optimal level of reliability or, as Dr. Cronin explained, “the level of reliability where the marginal benefits from improvements equal the marginal costs of implementation.”¹¹²⁷ In testimony, Dr. Cronin described it as “trying to elicit from, say customers in this instance, how they value the reliability they receive from the company.”¹¹²⁸ Dr. Cronin also indicated in testimony that different customer classes would be willing to pay differing amounts for reliability improvements and that customers’ willingness to pay would change over time.¹¹²⁹

915. In his rebuttal testimony on behalf of EPCOR, Dr. Weisman expressed his concerns with Dr. Cronin’s recommendation:

...this approach would seem to be ruled out by AUC PBR 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. With this principle, the Commission has seemingly carved out a special exception for service quality. To wit, the AUC wishes to implement PBR regimes that replicate the incentive structure of a competitive market, “while maintaining service quality.” Hence, even if service quality for Alberta utilities is currently over-provisioned from a social welfare perspective—service quality is “too good”—the Commission does not wish to see any fall off in the level of service quality that Albertans currently enjoy.¹¹³⁰

916. ATCO Electric also commented on Dr. Cronin’s recommendation stating:

ATCO Electric notes that the costs associated with providing the current level of service quality and reliability have been incurred and approved as prudent by the AUC, and cannot simply be undone if a WTP [willingness-to-pay] study indicates that the “socially optimal” level of service is something lower than the current level. While the results of these kinds of studies might be interesting, ATCO Electric is unsure of how they might actually be used and it is unclear as to how the costs of these studies will be addressed.¹¹³¹

¹¹²⁷ Exhibit 299.02, Cronin and Motluk UCA evidence, page 205.

¹¹²⁸ Transcript, Volume 17, pages 3293-3296.

¹¹²⁹ Transcript, Volume 17, pages 3293-3296.

¹¹³⁰ Exhibit 473.09, rebuttal testimony of Dennis L. Weisman, Ph.D., pages 13-14.

¹¹³¹ Exhibit 631.01, ATCO Electric argument, paragraph 292.

917. For the interim period, prior to completion of the proposed willingness-to-pay research, the UCA proposed the following approach for setting targets:

...the target for service levels should be based on current levels achieved. These are the levels included in going-in rates, and are the levels that customers are paying for. A five year average of actual achieved performance prior to the start of PBR is the best indication of the current level of performance achieved.¹¹³²

918. EPCOR,¹¹³³ ATCO Gas¹¹³⁴ and ATCO Electric¹¹³⁵ argued that a target based on a simple five-year average would require improvements in service quality to avoid penalties half the time, and therefore the companies proposed setting a threshold of one standard deviation above the average to account for the volatility of the measurements due to factors outside of their control. In addition, EPCOR was concerned that the reporting of annual numbers against the five-year average plus one standard deviation would incent a company to further reduce its costs in years where it had no hope of achieving a performance target, since the poor measurement in one year would not impact future years' measurements. EPCOR, therefore, proposed that it report a five-year rolling average against the target so that "poor performance in one year would be reflected in the rolling average for the next four years, incenting the utility to continue to take steps and spend dollars to minimize the extent of its poor performance in the original year."¹¹³⁶

919. The UCA expressed concern over EPCOR's proposal to report a five-year rolling average, stating, "While I understand that an average will allow the impact of anomalies to be minimized, it will also mask any trends in degradation of service levels."¹¹³⁷ In final argument, the UCA suggested that the removal of major events from the average would resolve the problem of volatility in the data and the likelihood of a penalty being imposed while service quality remained the same.¹¹³⁸

920. ATCO Gas and ATCO Electric rejected the UCA's suggestion to remove major events stating that removing " 'major events' just means that there is a requirement to make improvements over the current level on all other events."¹¹³⁹ EPCOR provided a similar response and indicated that "service quality can be significantly impacted in a given year by varying volumes of smaller outages that, just like MEDs [major event days], are beyond EDTI's ability to control."¹¹⁴⁰

921. For the new service measures that the UCA wanted introduced, it stated that the measures should be tracked initially to establish a performance history because without history "there can

¹¹³² Exhibit 634.01, UCA argument, paragraph 381.

¹¹³³ Exhibit 473.02, EPCOR rebuttal evidence, PDF page 21.

¹¹³⁴ Exhibit 648.02, ATCO Gas reply argument, paragraph 493.

¹¹³⁵ Exhibit 647.01, ATCO Electric reply argument, paragraph 316.

¹¹³⁶ Exhibit 473.02, EPCOR rebuttal evidence, A12, PDF page 23.

¹¹³⁷ Exhibit 300.02, UCA evidence of Russ Bell, A9, PDF page 14.

¹¹³⁸ Exhibit 634.01, UCA argument, paragraph 382.

¹¹³⁹ Exhibit 648.02, ATCO Gas reply argument, paragraph 494; Exhibit 647.01, ATCO Electric reply argument, paragraph 317.

¹¹⁴⁰ Exhibit 646.02, EPCOR reply argument, paragraph 296.

be no meaningful targets set and therefore no penalties should be associated with the measures at this time.”¹¹⁴¹

922. The CCA, like the UCA, did not support setting a target with a standard deviation above average and recommended that “the performance measure, in each of the PBR test years, simply be the rolling average of the last 5 years of actual reported data.”¹¹⁴² In other words, the target would change every year as the average changes over time.

923. In addition to concerns with the lack of a threshold above the average, EPCOR also argued that the CCA recommended approach “could result in degradation of service quality over time contrary to PBR Principle 1, as the targets could degrade as performance degrades.”¹¹⁴³ Fortis, ATCO Electric, ATCO Gas and AltaGas did not comment on the CCA’s recommended approach.

924. Calgary in argument stated:

There is no evidence on the record that ratepayers are seeking service levels superior to the existing service, particularly for residential and general commercial customers. Moreover, as was recognized by an AltaGas witness, the marginal cost of improving quality of service may well exceed the benefit.¹¹⁴⁴

925. IPCAA recommended “a consultative process be initiated to disclose what system-level outage data is retained by each utility, and explore efficient ways of using that data to set reliability targets and incentives.”¹¹⁴⁵

926. An additional concern was raised by ATCO Electric,¹¹⁴⁶ Fortis and EPCOR¹¹⁴⁷ regarding how adjustments were to be made to setting targets as a result of the more accurate and detailed level of reporting that would be made available as a result of the implementation of their respective outage management systems. Fortis stated in testimony:

So FortisAlberta is now implementing an outage management system. So whereas before we had 350 PLTs [power line technicians] independently inputting data manually, we will now move to a centralized process that will give us much better data, and that will cause SAIDI and SAIFI to increase, which if we'd stuck with the statistic itself, would imply the reliability has gotten worse, but reliability hasn't changed.¹¹⁴⁸

927. Similarly, EPCOR indicated that it would be applying for revisions to its SAIDI and SAIFI performance targets after it implements its outage management system.¹¹⁴⁹

¹¹⁴¹ Exhibit 634.01, UCA argument, paragraph 384.

¹¹⁴² Exhibit 636.01, CCA argument, paragraph, 371.

¹¹⁴³ Exhibit 646.02, EPCOR reply argument, paragraph 297.

¹¹⁴⁴ Exhibit 629.01, Calgary argument, PDF page 67.

¹¹⁴⁵ Exhibit 635.01, IPCAA argument, paragraph 60.

¹¹⁴⁶ Exhibit 631.01.AE-566, ATCO Electric argument, paragraph 297.

¹¹⁴⁷ Exhibit 630.02, EPCOR argument, paragraph 294.

¹¹⁴⁸ Transcript, Volume 11, pages 2179-2180.

¹¹⁴⁹ Exhibit 630.02, EPCOR argument, paragraph 294.

Commission findings

928. The Commission has evaluated the various proposals put forward by the parties to set targets. With respect to the willingness-to-pay study proposed by the UCA, the Commission does not consider that such a proposal is necessary. Although a willingness-to-pay study may provide valuable information if the Commission were trying to ascertain whether Alberta distribution companies were providing a socially optimal level of reliability, at this time, the evidence on the record of this proceeding demonstrates that reliability standards are acceptable. Customer satisfaction scores are already provided by the companies on an annual basis as a part of the AUC Rule 002 results. The Commission is of the view that declining customer satisfaction scores will be a timely indicator of problems. For all of these reasons, the Commission rejects the UCA's proposal to use a willingness-to-pay study to set target measures at this time.

929. With respect to specific proposals of parties for setting service quality targets, the Commission will consider these proposals in the upcoming AUC Rule 002 consultative process.

930. In addition to establishing new measures and setting targets for those metrics currently without targets, the Commission considers that it is important that companies and Alberta customers understand the consequences that could result from a company's failure to meet service quality targets. This is particularly critical if a pattern of consistent failure arises. Therefore, through the upcoming AUC Rule 002 consultation process, the Commission will develop a penalty structure for these metrics as part of the administrative penalty scheme authorized under Section 129(3) of the *Electric Utilities Act* and Section 28.3(3) of the *Gas Utilities Act*. The Commission expects that this penalty structure will include escalating penalty amounts commensurate with repeated violations of the targets up to and including the maximum administrative penalty set out in Section 63 of the *Alberta Utilities Commission Act*.

931. Following the completion of the consultative process the Commission will issue a bulletin indicating the process to be followed with respect to the adjudication of penalties including a hearing or other proceeding.

14.3.3.1 Asset condition monitoring

932. Service quality and the physical condition of assets are linked. Companies cannot provide consistently reliable service without a well-functioning physical infrastructure. Parties suggested that the Commission must determine whether it is sufficient to monitor only the resulting service quality or whether it is necessary to also monitor the actions of the companies to ensure that the companies do not maintain service quality during the PBR term, but reduce their costs by allowing certain assets to degrade as a result of aging and deterioration, to then be replaced in capital programs that have been delayed to the post-PBR period.

933. In the proceeding, a number of approaches were proposed that ranged from companies simply reporting their current practices for increased transparency to recommendations that advocated Commission and intervenor involvement in the development of policies and best practices for the companies.

934. The UCA proposed that the Commission "direct utilities to develop and file an asset management framework using the asset management discipline as envisioned by The Woodhouse Partnership Limited (TWPL)."¹¹⁵⁰ The UCA was not in support of the type of asset

¹¹⁵⁰ Exhibit 634.01, UCA argument, paragraph 387.

management study being conducted by EPCOR, which the UCA classified as a study of asset condition.¹¹⁵¹

935. IPCAA proposed to exclude power system assets from PBR until such a time as service quality and asset condition metrics can be developed¹¹⁵² through a Commission-led consultation process.¹¹⁵³ IPCAA's proposal is to include only general and administration costs in PBR.

936. In response to IPCAA's proposal, the CCA stated:

In our view, if the AUC is not inclined to adopt IPCAA's recommendation, the AUC should convene a consultative process which would review the existing practices and lead to a determination of appropriate asset-condition metrics with the goal the metrics so determined would be applicable for the balance of the PBR term.¹¹⁵⁴

937. Calgary stated that asset management and data disclosure should be addressed in a collaborative process.¹¹⁵⁵

938. All of the distribution companies were opposed to the increased regulatory burden that could result with having asset management as a part of PBR. AltaGas submitted that "the monitoring of asset condition may be of limited value, particularly given the different vintages and terrains applicable to different service territories which may impact the results of such surveys."¹¹⁵⁶

939. ATCO Gas indicated in its final argument that asset management metrics would hamper its ability to be innovative:

How can ATCO Gas try to find innovative, efficient ways of doing things like valve inspections, for example, if it is required to meet a standard that specifies exactly how it will undertake those valve inspections? ATCO Gas agreed with Dr. Makhholm that the measures need to be objective and measurable and focus more on the output of the utility.¹¹⁵⁷

940. In EPCOR's opinion, "a process to review and assess asset condition data would be extremely complex, time consuming and costly resulting in substantial additional costs being borne by rate payers."¹¹⁵⁸

941. ATCO Electric stated in its final reply argument:

IPCAA recommends a consultative process be initiated to identify key asset condition data which should be provided by the utility to customers and the regulator. ATCO Electric views this request to be without merit as the provision of the data by itself is without value as it requires an engineering analysis and assessment within an overall

¹¹⁵¹ Exhibit 634.01, UCA argument, paragraph 388.

¹¹⁵² Exhibit 306.01, VIDYA Knowledge Systems evidence on behalf of IPCAA, PDF page 3.

¹¹⁵³ Exhibit 306.01, VIDYA Knowledge Systems evidence on behalf of IPCAA, PDF page 13.

¹¹⁵⁴ Exhibit 645.01, CCA reply argument, paragraph 216.

¹¹⁵⁵ Exhibit 629.01, Calgary argument, page 66.

¹¹⁵⁶ Exhibit 650.01, AltaGas argument, page 77.

¹¹⁵⁷ Exhibit 632.01, ATCO Gas argument, paragraph 321.

¹¹⁵⁸ Exhibit 630.02, EPCOR argument, paragraph 313.

asset management program as was described by Ms. Bayley during testimony. This is completely contrary to the AUC principle of reducing regulatory burden.”¹¹⁵⁹

942. In an excerpt from Fortis’ testimony, Mr. Delaney stated:

We have a million poles, 100,000 kilometres of line. Coming from that, we've developed a number of programs. We have a pole management program where we do life extension of poles, and we are embarking on an effort to get 1940s and 1950s vintage poles out of our system that have 30 percent or more failure rates. We have an underground cable management program where we rejuvenate and extend the life of underground cables, pad mount transformer maintenance program with predicted maintenance, oil sampling. Well, I can go on. We have switch maintenance. We have a number of programs associated with all of our assets... And I understand certainly the Commission's point of view on this that -- but it's a tough thing to regulate without, you know, violating Principle 3, given the complexity of all these things. Now, there are avenues. There is envisioned an annual meeting, whether it's under Rule 2 or some other aspect that could be sort of a technical conference thing could be added on where utilities can give -- well, probably give things like a breakdown of what's happened in reliability over the past year, which we kind of do right now under Rule 2 in terms of what happened. Another -- but it's going to be a very, very complex exercise to establish input measures and then what do you make of them once you've established them. The utility must have the flexibility to move within its asset maintenance program to do what needs to be done prudently. And if we were to introduce process that involves information responses and thousands of -- a big process like that, then my engineers and people that were looking to find innovation and find good things to do to reduce our costs will be -- we'll take that regulatory burden.”¹¹⁶⁰

Commission findings

943. While the companies are opposed to the increased regulatory burden from the introduction of asset management monitoring practices, the Commission sees potential benefits from asset management reporting. The purpose of asset management monitoring is to provide increased visibility into the asset management practices of the companies. It is not to replace the management of assets by the companies. Indeed, IPCAA’s witness, Mr. Cowburn, acknowledged that this was not the purpose of asset condition disclosure.¹¹⁶¹ Rather, regular reporting of asset condition will give the Commission and stakeholders some insight into the condition of the companies’ assets. Information about asset condition will improve the Commission’s ability to develop quality of service metrics as well as assess capital tracker applications as discussed in Section 7.3.

944. Having determined that some asset management monitoring will be required, the Commission is of the view that stakeholders and the Commission would benefit from an AUC consultative process to develop reporting requirements. This consultation will be separate from the process discussed above with respect to AUC Rule 002. The Commission anticipates that it will conduct a distribution company round-table on this matter after the commencement of the PBR term.

¹¹⁵⁹ Exhibit 647.01, ATCO Electric reply argument, paragraph 326.

¹¹⁶⁰ Transcript, Volume 11, pages 2177-2179.

¹¹⁶¹ Transcript, Volume 16, pages 3131 to 3132

945. The Commission will, after consultation with stakeholders, develop an asset management monitoring process to report on the condition of distribution assets with the intention of providing transparency while allowing the companies to manage their assets and operations. In so doing the Commission will seek to limit any additional regulatory burden.

14.3.3.2 Line losses

946. Electricity retailers are charged for all electricity entering the distribution system from the transmission system. Some electricity is lost as a result of the transfer of energy across electric distribution systems, including distribution lines, transformers and regulators. This lost electricity is referred to as technical losses.¹¹⁶² Other electricity may be consumed but not recognized as used or sold for a variety of reasons, such as meter reading errors, meters not read, unmetered sites incorrectly estimated and energy theft. This type of loss is referred to as unaccounted-for-energy or non-technical losses.¹¹⁶³

947. ENMAX filed a line loss proposal as a complement to its FBR plan. This proposal had been developed in discussion with a number of interveners and was approved by the Commission in Decision 2009-226. The proposal created an incentive for ENMAX to reduce levels of line losses and assume the risk from investments made to reduce the losses. If there were savings from the reduction in line losses, ENMAX and the customers shared equally in those benefits.¹¹⁶⁴ ENMAX reported that, as a result of this incentive plan, \$0.854 million has been saved by its consumers in 2009 and 2010.¹¹⁶⁵

948. On behalf of the UCA, Dr. Cronin stated that for line losses “we find that the Alberta LDCs again compare very well” to the Ontario LDCs.¹¹⁶⁶ However, IPCAA, the UCA and the CCA all expressed concerns regarding the potential risk that line losses could increase from current levels under PBR.¹¹⁶⁷

949. IPCAA recommended that the way to address the potential risk that line losses may increase under PBR was to “mitigate the potential drivers of such increases.” IPCAA elaborated by stating:

If asset management processes are made available and equipment selection criteria can be reviewed in an open, consultative process, any changes in utility equipment specifications leading to higher losses will be known and understood as they occur... Information transparency is preferred over blanket requirements in order to maintain line losses at a specific level [CCA-Exhibit 636, page 123], as there may be a good economic justification for the selection of different equipment.”¹¹⁶⁸

¹¹⁶² Exhibit 218.01, ATCO Electric IR responses to UCA, UCA-ALLUTIL-AE-4(II), PDF page 35.

¹¹⁶³ Exhibit 218.01, ATCO Electric IR responses to UCA, UCA-ALLUTIL-AE-4(II), PDF page 35.

¹¹⁶⁴ Exhibit 297.01, ENMAX evidence, PDF page 16.

¹¹⁶⁵ Exhibit 297.01, ENMAX evidence, PDF page 16.

¹¹⁶⁶ Exhibit 299.02, Cronin and Motluk UCA evidence, PDF page 11.

¹¹⁶⁷ Exhibit 642.01, IPCAA reply argument, paragraph 60; Exhibit 299.02, Cronin and Motluk UCA evidence, PDF pages 183-185; Exhibit 636.01, CCA argument, paragraph 360.

¹¹⁶⁸ Exhibit 642.01, IPCAA reply argument, paragraphs 60-61.

950. The UCA recommended that each applicant should develop a line loss proposal which should either involve a mechanism to adjust the rates or a set of incentives similar to the ENMAX approach.¹¹⁶⁹

951. The CCA submitted that EPCOR's plan should include:

...a specific provision that its line losses during the PBR Term will not be any lower than that observed for the 3-year average period prior to the start of the PBR term i.e. average of 2.633% for the period 2009-2011, inclusive, per X239.01, UCA-ALLUTILITIES-4 (mm).¹¹⁷⁰

952. Fortis, EPCOR and ATCO Electric rejected the inclusion of a line loss proposal as suggested by the interveners. Fortis stated that it already "has ongoing system design and standards programs in place that focus on loss minimization, as well as an ongoing capital project that looks for loss reductions on specific lines. Any incremental line loss program would be duplicative and unnecessary."¹¹⁷¹ EPCOR expressed concern that it is already operating near the low end of what is physically achievable, that theft is outside of the direct control of the company and non-technical losses are already monitored by the AESO in support of AUC [Rule 021: Settlement System Code Rules \(Rule 021\)](#).¹¹⁷²

953. In its rebuttal evidence, ATCO Electric explained its engineering processes and the difficulty in isolating changes related to the reduction in line losses:

ATCO Electric is not proposing to introduce a line loss module as it is unable to distinguish investments required to maintain the optimal operation of its distribution system from those that may provide a benefit to its line loss, which is a consequence of all the actions ATCO Electric undertakes. As the distribution network expands, ATCO Electric will continue to implement and deliver the appropriate types of distribution investment that considers all important aspects of ensuring a safe and reliable distribution system is in place. Failure of its duty will result in power quality and reliability degradation that will impact ATCO Electric's customers' ability to operate and connect to the distribution system. In addition, current Settlement System Code Rules under Rule 021 ensure utilities are aware and comply with specific unaccounted for energy tolerances that are monitored by the AESO.

Commission findings

954. The Commission considers that line losses are currently within acceptable levels. Nonetheless, the Commission has concerns about how PBR may provide incentives that have an adverse impact on line losses.

955. As a part of the consultative process to review and revise AUC Rule 002, the Commission will consider metrics for monitoring line losses and the establishment of targets for ensuring companies maintain their current levels of line loss performance. The Commission is also prepared to consider other approaches that parties may propose.

¹¹⁶⁹ Exhibit 299.02, Cronin and Motluk UCA evidence, PDF pages 184-185.

¹¹⁷⁰ Exhibit 636.01, CCA argument, paragraph 360.

¹¹⁷¹ Exhibit 644.01, Fortis reply argument, paragraph 178.

¹¹⁷² Exhibit 646.02, EPCOR reply argument, paragraphs 268-270.

14.4 Re-openers for failure to meet service quality targets

956. The UCA, the CCA, IPCAA and EPCOR each proposed that a re-opening of the PBR plan should be undertaken in the event that there is a dramatic decline in service quality.

957. In argument, both the UCA and the CCA recommended that failure to meet a specific performance standard for two consecutive years would be an issue that could trigger a re-opener.¹¹⁷³ In the case of the CCA, the re-opener would be automatic or “alternatively at the request of an interested party or the AUC.”¹¹⁷⁴ IPCAA considered that if “customer service is materially degraded by any utility, the PBR plan should be re-opened or even terminated by an off-ramp.”¹¹⁷⁵ EPCOR’s submission included a re-opener for failure to meet the same service quality target for two consecutive years and stated that adjustments to the PBR plan “could include such things as a change to the performance target, a change to the performance measure, or the termination of the measure.”¹¹⁷⁶

958. Conversely, ATCO Gas and ATCO Electric were of the opinion that a re-opener clause that is linked to not achieving specific performance standards is not required, especially if service quality is addressed under AUC Rule 002¹¹⁷⁷ while Fortis’ proposed PBR plan did not include any provisions for re-openers or off-ramps as a result of service quality degradation.¹¹⁷⁸

Commission findings

959. The Commission has the ability under both the *Electric Utilities Act* and the *Gas Utilities Act* to make rules regarding service quality and to monitor and enforce those rules. If it should become apparent that the ways in which the companies are implementing their PBR plans are having a detrimental impact on service quality performance, the Commission can take whatever steps are necessary under the legislation to direct a change in behaviour without having to re-open the PBR plan. Accordingly, the Commission does not accept the proposal to include degradation in service quality as an event that would necessitate a re-opening of the PBR plans.

15 Annual filing requirements

960. The companies recognized a requirement for periodic filings to deal with various rate or capital factor applications during the PBR term. The proposals differed with respect to the number, content and frequency of applications. The companies were also in favour of maintaining existing application processes in respect of certain deferral accounts and flow-through accounts. In addition, some sections of this decision refer to PBR related annual filings under AUC Rule 002 and AUC Rule 005.

15.1 Annual PBR rate adjustment filing

961. Companies generally preferred an annual filing for the setting of the following year’s rates. Some of the companies requested a second annual filing with respect to the true-up of

¹¹⁷³ Exhibit 634.01, UCA argument, paragraph 321; Exhibit 636.01, CCA argument, paragraph 326.

¹¹⁷⁴ Exhibit 636.01, CCA argument, paragraph 327.

¹¹⁷⁵ Exhibit 635.01, IPCAA argument, paragraph 38.

¹¹⁷⁶ Exhibit 103.02, EPCOR submission, paragraph 243.

¹¹⁷⁷ Exhibit 648.02, ATCO Gas reply argument, paragraph 432; Exhibit 647.01, ATCO Electric reply argument, paragraph 278.

¹¹⁷⁸ Exhibit 633.01, Fortis argument, paragraphs 221-233.

certain factors or amounts that would be included on a forecast basis in the annual rate application so as to adjust rates more than once each year. The Commission has determined above that a second rate adjustment adds unnecessary administrative complexity and is not required.

962. The Commission determines that the effective date for annual rate changes will be January 1st each year. In order to accommodate this date, a number of items will need to be considered leading up to the annual rate change. The annual PBR rate adjustment filing to establish the rates to be in effect on January 1st of the upcoming year is to be made by September 10th of each year.

963. The annual PBR rate adjustment filings for electric distribution companies will calculate rates to be effective on January 1st of the upcoming year based on the following:

$$R_t = \underbrace{BR_{t-1}(1 + (I - X))}_{\text{Base rates (BR}_t\text{)}} +/- Z +/- K +/- Y$$

964. The annual PBR rate adjustment filings for gas distribution companies will calculate rates to be effective on January 1st of the upcoming year based on the following:

$$RPC_t = \underbrace{BRPC_{t-1}(1 + (I - X))}_{\text{Base revenue per customer class}} +/- Z +/- K +/- Y$$

$$R_t = RPC_t / BDC_t$$

Where:

R_t	=	upcoming year's rates for each class
RPC_t	=	upcoming year's revenue per customer for each class
BR_{t-1}	=	current year's base rates for each class
$BRPC_{t-1}$	=	current year's base revenue per customer for each class
BDC_t	=	billing determinants for each class for the upcoming year
I	=	inflation factor
X	=	productivity factor
Z	=	exogenous adjustments
Y	=	flow-through items, collected through Y factor rate adjustments (not including Y factors collected through separate riders)
K	=	capital trackers collected through K factor rate adjustments

965. The items to be included in the annual PBR rate adjustment filings will therefore be:

- base rates from the current year by rate class that will be the starting point for the upcoming year's rates
- I factor calculation as described in Section 15.1.1 with supporting backup

- Z factors approved during the previous 12 months calculated as described in Section 15.1.2
- K factor adjustment related to approved capital trackers calculated as described in Section 15.1.3
- Y factor adjustment to collect Y factors that are not collected through separate riders calculated as described in Section 15.1.4
- billing determinants for each rate class for gas applications
- billing determinants that will be used to allocate items that are not subject to the I-X mechanism to rate classes as described in Section 15.1.5
- backup showing the application of the formula by rate class and resulting rate schedules
- a copy of the Rule 005 filing filed in the current year
- any other material relevant to the establishment of current year rates

15.1.1 I factor

966. As discussed in Section 5.4, the I factor to be included in the annual PBR rate adjustment filings will be calculated using the Alberta AWE (average weekly earnings) from July of the prior year to June of the current year and the Alberta CPI (consumer price index) from July of the prior year to June of the current year. The companies will be required to provide Statistics Canada data for each index and show how the I factor was calculated.

15.1.2 Z factors

967. As noted in Section 7.2.2 some approved Z factor applications may generate costs or savings that can be fully recovered or refunded over a single year or portion thereof while other events will generate costs or savings requiring treatment over a longer term. The nature of the required Z factor rate adjustment will be considered by the Commission on a case-by-case basis in response to a Z factor application.

968. Where a Z factor adjustment has been directed to be included in rates as an adjustment to base rates, the company will make the required adjustment and provide details of the calculation as part of the annual PBR rate adjustment filing.

969. Where a Z factor adjustment has been directed to be included in rates but not as an adjustment to base rates and therefore outside of the I-X mechanism, each company will calculate a Z factor amount to be included in the annual PBR rate adjustment filing. All these Z factor amounts approved by the Commission since the last annual PBR rate adjustment filing will be aggregated as a single rate adjustment and included with the rate adjustment in the next annual PBR rate adjustment filing.

970. Parties should be aware of the Commission's performance standards for processing rate-related applications as prescribed by Bulletin [2010-16](#).¹¹⁷⁹

971. The most recent forecast of billing determinant information along with the Phase II methodologies in place, as discussed in Section 15.1.5 below, will establish the Z factor rate adjustments associated with the Z factor revenue requirements by rate class.

¹¹⁷⁹ AUC Bulletin 2010-16, Performance Standards for Processing Rate-Related Applications, Table 1.

972. Due to the time lag that may occur between the occurrence of a Z factor event and implementation of the necessary rate adjustments, the companies will be permitted to record carrying charges calculated using an interest rate equal to the Bank of Canada's Bank Rate plus 1½ per cent, subject to any previously approved Commission procedure for awarding interest. This interest rate is consistent with AUC [Rule 023](#),¹¹⁸⁰ however the regulatory lag and materiality requirements of Rule 023 will not apply.

15.1.3 Capital trackers

973. The complexity of capital tracker applications will require that these applications be submitted earlier. To promote regulatory efficiency the Commission considers that a single annual capital tracker application filing for each company will be made by March 1st each year.

974. A single application must be filed by March 1st of the current year with respect to all projects which may qualify for capital tracker treatment to be commenced in the upcoming year. The timing of the application is intended to provide sufficient time for processing of the application and inclusion of approved amounts as a K factor in the September 10th annual PBR rate adjustment filing. All of the capital trackers for each company will be collected in a pool that comprises a single K factor in the PBR formula for the company. As discussed in Section 7.3.3.2, the process for filing upcoming projects and associated K factor amounts is only to establish interim K factor rate adjustments. Interim amounts will be subject to true-up to actual costs as part of a prudence review following completion of the project.

975. The annual March 1st capital tracker filing must include a business case with respect to each proposed capital tracker. The business case will include forecast costs, being the amount proposed to be collected on an interim basis through the K factor in the upcoming year. If a project is expected to carry into future years, forecasts for the future years should also be included in order to assess the scope and scale of the project including the materiality of the entire project to be considered. Multi-year forecasts will be updated each year in the capital tracker application so that the forecast amounts to be included that year's K factor will reflect the most recent information available. In addition, the March 1st capital tracker application shall true-up the costs of projects that have been completed since the prior year's capital tracker filing together with sufficient information to permit a prudence review of these completed projects. To facilitate a prudence review of a project, the company must submit information showing that it has completed the project in the most cost effective manner possible. This information will include the results of competitive bidding processes, comparisons of in-house resources to external resources, and any other evidence that may be of assistance in demonstrating the prudence of the expenditures.

976. The results of the prudence review and cost true-up will be an adjustment to the K factor included in the following year's rates. The companies will calculate the revenue requirements resulting from the actual capital tracker expenditures, and compare those to the forecast amounts that were collected on an interim basis in the prior year. The difference between the approved revenue requirements and the forecast revenue requirements for the prior year will form the basis for the K factor true-up rate adjustment. In addition, because the capital expenditures will remain in the tracker for the duration of the PBR term, the amounts to include in the capital tracker revenue requirement calculations in subsequent years during the PBR term will be based on the actual approved expenditures rather than the initial forecasts.

¹¹⁸⁰ AUC Rule 023: *Rules Respecting Payment of Interest* (Rule 023), Section 3, paragraph 2, page 2.

977. The calculation of the K factor rate adjustments will be similar to revenue requirement calculations under cost of service, except that the calculation will be limited to the depreciation, taxes and return associated with the incremental rate base for the expenditures that form the capital tracker. The weighted average cost of capital rate to be used in calculating the revenue requirements associated with capital trackers will be based on current rates established in the most recent GCOC proceeding rather than using the rates that were in place at the start of the PBR term. The most recent forecast of billing determinant information along with the Phase II methodologies in place, as discussed in Section 15.1.5 below, will establish the K factor rate adjustments associated with revenue requirements by rate class.

978. As discussed in Section 7.3.4, the companies may file, as separate applications at the time of their compliance filing on November 2, 2012, applications for approval of specific 2013 projects as capital trackers, including projects that were included in their PBR filings. The companies need not re-file the information already on the record of this proceeding with respect to those capital projects included in their PBR filings. The companies may specifically refer to the record of this proceeding and supplement that information with additional information or explanations to address the Commission's capital tracker criteria.

15.1.4 Y factor rate adjustments

979. The forecasts for the provision for each Y factor item to be included in the upcoming year's rates will be included in the annual PBR rate adjustment filing. As discussed in Section 7.4.4 the provisions will generally be based on the 2012 test year of the general tariff application or general rate application proceeding that forms the going-in rates. The true-up of the Y factor accounts, being the difference between the prior year provision and the prior year actual result, will also be identified in the September 10th PBR annual filing.

980. For any Commission directed items (e.g., AUC assessment fees, intervener portion of hearing costs, etc.) and the UCA assessment fees, the basis for determining the true-up to be included in the annual PBR rate adjustment filing will be the actual amounts that were incurred from August 1 of the prior year to July 31 of the current year.

981. The true-up process will also capture the impact of any Commission directed items that occurred from September 1 of the prior year to August 31 of the current year that were new and for which there was no provision in the Y factor for the current year.

982. All of the Y factor accounts that are not subject to flow-through treatment and collected by way of a separate rate rider will be collected in a pool that comprises a single Y factor in the PBR formula for the company. The most recent forecast of billing determinants along with the Phase II methodologies in place, as discussed in Section 15.1.5 below, will establish the Y factor rate adjustments associated with Y factor revenue requirements by rate class.

983. Carrying charges on balances that are subject to true up will be calculated using an interest rate equal to the Bank of Canada's Bank Rate plus 1½ per cent, subject to any previously approved Commission procedure for awarding interest on accounts that existed prior to implementation of PBR. This interest rate is consistent with AUC Rule 023,¹¹⁸¹ however the regulatory lag and materiality requirements of Rule 023 will not apply.

¹¹⁸¹ AUC Rule 023, Section 3, paragraph 2, page 2.

15.1.4.1 Flow-through items

984. As discussed in Section 7.4.3, flow-through items currently collected by way of separate rider will be collected using the existing methodology and rider mechanism outside of the annual PBR rate adjustment filing process to recognize that these flow-through items are currently processed throughout the year. As a result, applications related to flow-through items may be submitted throughout the year.

15.1.4.2 Clearing balances in deferral accounts that are not permitted to continue under PBR

985. To the extent that the companies had deferral accounts under cost of service regulation that have not been approved to continue under PBR in this decision, the Commission recognizes that the companies may have residual balances in the deferral accounts that need to be disposed of. The Commission determines that the companies will submit an application identifying the outstanding balances as of December 31, 2012 as part of their annual PBR rate adjustment filing for 2013.

15.1.5 Billing determinants and Phase II implications

986. Under PBR, the portion of electric distribution rates subject to the I-X mechanism is not impacted by changes to billing determinants. The portion of gas distribution rates subject to the I-X mechanism is impacted by changes in usage per customer. Rate adjustments outside of the I-X mechanism (Z factors, K factors and Y factors) for both electric and gas distribution companies will involve calculating a total amount of revenue requirement associated with the underlying items, and then allocating that revenue requirement to rate classes to determine the necessary rate adjustments. This will require the use of billing determinants and Phase II rate class allocation methodologies. In addition, a number of the companies identified the possibility of Phase II applications to revise the rate class allocation methodologies that may be required during the PBR term, which would also require the use of billing determinants.

987. Fortis proposed to use to a method consistent with that used in previous cost of service filings to establish its billing determinants under PBR. Fortis provided a forecast of the billing determinants to be used for the entire PBR term, and indicated that it will accept the risk on any variances between forecasts and actual.¹¹⁸² Fortis identified the potential for a Phase II application to transition towards 100 per cent revenue-to-cost ratios by rate class, and the billing determinant forecast would be used for this purpose.¹¹⁸³

988. ATCO Electric also provided a forecast for billing determinants for the entire PBR term. ATCO Electric followed the same methodology for preparing the billing determinants and load forecasts used in its 2011 to 2012 GTA. In addition, if a Phase II application is determined to be necessary during the PBR term, ATCO Electric proposed to use the billing determinant forecast provided in its PBR application for input into the cost of service and rate design.¹¹⁸⁴

989. EPCOR proposed that billing determinants be reforecast annually using a calculation methodology that relies on readily available historical billing determinants.¹¹⁸⁵ EPCOR identified that Phase II rate rebalancing adjustments may be required as a result of the implementation of a

¹¹⁸² Exhibit 100.02, Fortis application, Section 2, paragraph 37, page 10.

¹¹⁸³ Exhibit 100.02, Fortis application, Section 13.2, paragraph 181, pages 50-51.

¹¹⁸⁴ Exhibit 98.02, ATCO Electric application, Section 16, paragraphs 290-291, page 16-3.

¹¹⁸⁵ Exhibit 103.02, EPCOR application, Section 2.3.7.1, paragraphs 156-158, pages 53-54.

new geographic information system (GIS).¹¹⁸⁶ Aside from the aforementioned adjustment from the implementation of GIS, as a result of the characteristics of its PBR plan, EPCOR identified that Phase II applications will no longer be required in the normal course.¹¹⁸⁷

990. ATCO Gas indicated that it would be providing a billing determinants forecast each year. ATCO Gas proposed to use the principles outlined in its Phase II negotiated settlement approved in Decision 2010-291 to determine the rates for each year. ATCO Gas proposed to use the same methodology as long as the negotiated settlement remains in place. In the event that the negotiated settlement is terminated for any reason, ATCO Gas proposed that a new Phase II application be filed, with the expectation that the determination of rates for the remainder of the PBR term would be governed by the outcome of that proceeding.¹¹⁸⁸ Calgary supported the Phase II proposal of ATCO Gas.¹¹⁸⁹

991. AltaGas proposed that its billing determinants be reforecast annually in order to capture any declining usage per customer.¹¹⁹⁰ AltaGas anticipated filing a Phase II application for its 2013 to 2017 PBR plan that will involve preparation of a revised cost of service study and rate design based on the revenue requirement approved for 2012, and adjusted pursuant to the proposed PBR formula to collect the forecast 2013 revenue cap amount.¹¹⁹¹

992. The UCA proposed that each utility should be required to file a Phase II application by the end of 2015 or at the latest 2016. The UCA noted that several of the companies are in the process of performing an analysis on cost allocations and that there are also previous Commission directions that are still outstanding, and as a result it will be necessary to realign rates in the middle of the PBR term.¹¹⁹² The CCA generally supported the position of the UCA.¹¹⁹³ IPCAA stated that “[c]ustomers deserve just, fair and reasonable rates, and a Phase II rates review should not be delayed or deferred by PBR.”¹¹⁹⁴

Commission findings

993. The Commission considers that billing determinants will have limited use during the PBR term for electric distribution companies because the I-X mechanism results in rate changes that are separated from the costs of the company, therefore there is no revenue requirement that needs to be allocated to rate classes using billing determinants as was the case under cost of service regulation. The revenue-per-customer cap plans approved for the gas distribution utilities will, however, require usage-per-customer forecasts based on current billing determinants to perform the annual customer rates calculations. In addition, both electric and gas distribution companies will be required to allocate items outside of the I-X mechanism including Z factors, K factors and Y factors to rate classes, and those allocations will require billing determinant forecasts and Phase II methodologies.

¹¹⁸⁶ Exhibit 103.02, EPCOR application, Section 4.3, paragraph 264, page 84.

¹¹⁸⁷ Exhibit 103.02, EPCOR application, Section 3.0, paragraph 232, page 77.

¹¹⁸⁸ Exhibit 99.01, ATCO Gas application, Sections 5.1.2-5.1.3, paragraphs 152-153, pages 53-54.

¹¹⁸⁹ Exhibit 629.01, Calgary argument, Section 18.1, page 71.

¹¹⁹⁰ Exhibit 110.01, AltaGas application, Section 2.3, paragraph 42, page 11.

¹¹⁹¹ Exhibit 110.01, AltaGas application, Section 13.0, paragraph 125, page 40.

¹¹⁹² Exhibit 634.02, UCA argument, Section 18.1, paragraphs 424-427, pages 75-76.

¹¹⁹³ Exhibit 636.01, CCA argument, Section 18.2, paragraph 385, page 133.

¹¹⁹⁴ Exhibit 635.01, IPCAA argument, Section 18.1, paragraph 96, page 15.

994. The Commission determines that long-term forecasts of billing determinants as proposed by Fortis and ATCO Electric are not necessary. As identified by Fortis, the use of long-term forecasts introduces forecasting risk into the PBR plan with respect to billing determinants. Because the billing determinants are generally used to allocate items that have been determined to be exceptions to the incentive properties of PBR, the Commission considers that it is necessary to achieve a greater degree of accuracy. The Commission does not consider that the company or its customers should benefit from, or be negatively impacted by, forecasting inaccuracies that may result from using forecasts that extend well into the future. Utilizing a shorter term for the forecasts will reduce the possibility for material forecasting inaccuracies. For this reason the companies will provide a revised forecast of their billing determinants annually as part of the September 10th annual PBR rate adjustment filings. In addition, the companies will provide the billing determinants forecast to be utilized for January 1, 2013 rates as part of their compliance filings to this decision.

995. Companies will be expected to utilize forecasting methodologies that are logical and easy to understand, and in most cases this will involve the continued use of forecasting methodologies utilized prior to PBR. Companies should utilize consistent billing determinant forecasting methodologies during the PBR term unless the Commission orders otherwise. Companies will describe the methodology they plan to use for the duration of the PBR term as part of their compliance filings to this decision.

996. The Commission considers that PBR is unrelated to the requirement to periodically update rates through a Phase II process. However, during the PBR term the companies may file applications for Phase II adjustments to their rate design and cost allocation methodologies and the Commission will make a determination at that time as to whether the adjustments are warranted. For purposes of a cost of service study, the companies shall use the revenue requirement resulting from going-in rates adjusted by the PBR formula (including the I-X mechanism, K factors, Y factors and Z factors) and the latest updated billing determinants.

15.2 AUC Rule 002 and AUC Rule 005 annual filings

997. As discussed in Section 13, annual AUC Rule 005 filings will continue to be filed by the companies on May 1st for electric distribution utilities and May 15th for gas distribution utilities. In addition, a copy of the prior year AUC Rule 005 filings will be included with the September 10th annual PBR rate adjustment filing.

998. As discussed in Section 14.1, the service quality of the companies will continue to be monitored using the AUC Rule 002 process. Annual service quality filing requirements are set out in the provisions of the rule.

15.3 Summary of annual filing dates

999. Below is a summary of the key annual filing dates under the PBR plans.

Table 15-1 Summary of key PBR annual filing requirements

Date	Action
March 1	Submission of capital tracker applications
May 1 or 15	AUC Rule 005 annual filings (May 1 for electric utilities, May 15 for gas utilities)
September 10	Companies to file annual PBR rate adjustment filings
January 1	Effective date for approved rates that are subject to the PBR formula

16 Generic proceedings

1000. During the first PBR term, the Commission will conduct a number of generic proceedings to deal with issues that arose out of the cost of service regulatory regime, some of which are still relevant to the companies under PBR. These proceedings are “generic” because the issues affect more than one company, including issues such as the recognition of debt costs or the treatment of certain income tax expenses. These generic proceedings are intended to make regulation in Alberta, including regulation of those companies that remain under cost of service regulation, more efficient and more predictable.

1001. To the extent that the decisions coming out of these generic proceedings will impact the companies under PBR, prior to the end of the PBR term, the Commission will consider any necessary rate adjustments using the mechanisms set out in Section 15.1.4 of this decision, as matters arise.

1002. The Commission will shortly issue bulletins to commence a proceeding on the generic cost of capital and to either continue Proceeding ID No. 20 with respect to Utility Asset Dispositions or initiate a generic proceeding regarding asset disposition and stranded assets. Additionally, the Commission will initiate other generic proceedings and will seek input from interested parties on additional matters parties may wish to have considered in generic proceedings, the scope of the issues to be considered, and the format for these proceedings. With regard to the latter, the Commission expects that many of these generic proceedings can take the form of consultations.

17 Order

1003. It is hereby ordered that each of AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc. and FortisAlberta Inc. shall file a compliance filing in accordance with the directions set out in this decision by November 2, 2012. The compliance filing shall include proposed distribution rate schedules to be effective January 1, 2013 with supporting documentation including:

- base rates for going-in rates by rate class that will be the starting point for 2013 rates
- I factor calculation as described in Section 15.1.1 with supporting backup
- provision component of the Y factor adjustment to collect Y factors that are not collected through separate riders calculated as described in Section 15.1.4
- billing determinants for each rate class for gas applications
- billing determinants that will be used to allocate Y factor provisions to rate classes
- backup showing the application of the formula by rate class and resulting rate schedules
- any other material relevant to the establishment of current year rates

Dated on September 12, 2012.

The Alberta Utilities Commission

(original signed by)

Willie Grieve, QC
Chair

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Moin A. Yahya
Commission Member

Appendix 1 – Proceeding participants

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Graves Engineering Corporation J. T. Graves
Industrial Gas Consumers Association of Alberta (IGCAA) G. Sproule
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster T. Clarke R. Mikkelsen S. Fulton V. Bellissimo
City of Lethbridge M. Turner O. Lenz
National Economic Research Associates (NERA) J. Cusano L. Aufricht J. Markholm
The City of Red Deer M. Turner L. Gan
South Alta Rural Electrification Association D. Evanchuk B. Bassett

**Name of organization (abbreviation)
counsel or representative**

Office of the Utilities Consumer Advocate (UCA)
C. R. McCreary
S. Mattuli
W. Taylor
R. Bell

The Alberta Utilities Commission

Commission Panel

W. Grieve, QC, Chair
M. Kolesar, Vice-Chair
M. A. Yahya, Commission Member

Commission Staff

B. McNulty (Commission counsel)
C. Wall (Commission counsel)
A. Sabo (Commission counsel)
J. Thygesen
O. Vasetsky
B. Miller
L. Ou
D. Mitchell
K. Schultz
D. Ward
B. Clarke
S. Karim
P. Howard
J. Olsen
B. Whyte
W. Frost
G. Scotton
S. L. Levin, Emeritus Professor of Economics
Department of Economics and Finance
School of Business
Southern Illinois University Edwardsville

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Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
National Economic Research Associates, Inc (NERA) J. Cusano L. Aufricht	J. Makholm A. Ros
AltaGas Utilities Inc. (AltaGas or AUI) N. J. McKenzie	P. Schoech R. Camfield G. Johnston A. Mantei R. Retnanandan
ATCO Electric Ltd. and ATCO Gas (ATCO) L. Smith, QC K. Illsey	P. Carpenter M. Bayley D. Wilson D. Freedman B. Goy J. Cummings N. Palladino
The City of Calgary (Calgary) D. I. Evanchuk E. W. Dixon	G. Matwichuk H. Johnson
Consumers Coalition of Alberta (CCA) J. Wachowich	M. Lowry
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) J. Liteplo C. Bystrom	Panel 1 (PRB principles and structure) D. Weisman D. Gerke D. Cole J. Elford H. Haag Panel 2 (PBR inflation, productivity and formula issues) D. Ryan D. Gerke J. Baraniecki C. Cicchetti
FortisAlberta Inc. (Fortis or FAI) T. Dalgleish, QC	I. Lorimer P. Delaney M. Stroh J. Frayer
ENMAX Power Corporation (ENMAX or EPC) D. Wood L. Cusano	K. Hildebrandt G. Weismiller R. Lawton

Name of organization (abbreviation) counsel or representative	Witnesses
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster	R. Cowburn V. Bellissimo R. Mikkelsen
Office of the Utilities Consumer Advocate (UCA) C. R. McCreary N. Parker	F. Cronin S. Motluk R. Bell

<p>The Alberta Utilities Commission</p> <p>Commission Panel</p> <p>W. Grieve, QC, Chair M. Kolesar, Vice-Chair M. A. Yahya, Commission Member</p> <p>Commission Staff</p> <p>B. McNulty (Commission counsel) C. Wall (Commission counsel) A. Sabo (Commission counsel) J. Thygesen O. Vasetsky B. Miller S. L. Levin, Emeritus Professor of Economics Department of Economics and Finance School of Business Southern Illinois University Edwardsville</p>

Appendix 3 – Major procedural steps in rate regulation initiative: performance-based regulation

[\(return to text\)](#)

1. On February 26, 2010, the Commission wrote in a letter (Exhibit 1.01) sent to interested parties that it was “beginning an initiative to reform utility rate regulation in Alberta.”
2. The Commission established a roundtable meeting of interested parties, which took place March 25, 2010 in the AUC hearing room in Edmonton. At the roundtable, the distribution companies said they could file PBR proposals by the end of the first quarter of 2011: March 31, 2011.
3. In an April 9, 2010 letter (Exhibit 6.01) to interested parties, the Commission outlined the discussions at the roundtable and notified them it had contracted the Van Horne Institute to organize a PBR workshop May 26 and May 27 in Edmonton.
4. On May 14, 2010, the Commission issued a letter (Exhibit 27.01) to interested parties on the process for development of guiding PBR principles, which the Commission planned to release via AUC bulletin on July 8, 2010. That letter established a process schedule to receive submissions on which specific incentive-based proposals would be evaluated, with initial submissions to be provided by June 10, 2010 and comments on the submissions to be provided by June 17, 2010.
5. The PBR workshop took place in Edmonton on May 26 and May 27, 2010. Material on the legal dimensions and regulatory evolution of PBR were distributed to roundtable participants ahead of the roundtable, on May 20, 2010.
6. On June 15, 2010, AltaGas Utilities Inc. (AltaGas) proposed a one-week extension to the June 17, 2010 deadline. In a letter (Exhibit 53.01) dated June 16, 2010, the Commission agreed to the request and adjusted the date for its PBR bulletin issuance to July 15, 2010.
7. On July 15, 2010, the Commission issued Bulletin 2010-20 (Exhibit 64.01). In that bulletin the Commission stated the five principles that would guide its examination of specific PBR proposals from regulated utilities.
8. In August, 2010, the Commission hired National Economic Research Associates Inc. (NERA) as an independent consultant to conduct a total factor productivity study or studies.
9. In a letter (Exhibit 71.01) to interested parties dated September 8, 2010, the Commission set out the terms of reference for NERA’s engagement.
10. In letters (exhibits 76.01 and 78.01) to the Commission dated November 12 and November 25, 2010, respectively, ATCO Gas and ATCO Electric (jointly ATCO), and AltaGas requested extensions to both the previously established date for filing their PBR proposals of March 31, 2011 and the previously established date for implementation of PBR plans of July 1, 2012. Both requested implementation be delayed to January 1, 2013.

11. By correspondence (Exhibit 79.01) to interested parties on December 16, 2010, the Commission agreed to postpone ATCO and AltaGas' PBR plan filing dates to May 31, 2011 and their PBR implementations to January 1, 2013.
12. NERA filed its expert report (Exhibit 80.02) on total factor productivity with the Commission on December 30, 2010.
13. On February 7, 2011, the Consumers Coalition of Alberta (CCA) expressed concerns about the proposed proceeding schedule, including the May 31, 2011 deadline for filing of PBR plans, due to a heavy regulatory agenda (Exhibit 86.02).
14. On March 24, 2011 EPCOR Distribution & Transmission Inc. (EPCOR), AltaGas, FortisAlberta Inc. (Fortis), ATCO Electric and ATCO Gas submitted a joint letter (Exhibit 89.01) to the Commission requesting a further deadline extension.
15. In a letter (Exhibit 90.01) to the parties dated March 29, 2011, the Commission agreed to certain proceeding schedule changes, including proposing the postponement of filing of utility PBR plans to July 22, 2011. In the same letter the Commission proposed a simplified compliance filing process to ensure that PBR plans could be implemented by January 1, 2013.
16. Following responses from parties, the Commission in a letter (Exhibit 94.01) dated April 13, 2011 set a new proceeding schedule, with utility PBR plans to be submitted July 22, 2011 and a hearing scheduled to begin March 5, 2012.
17. On June 1, 2011, the Lieutenant Governor in Council issued an Order in Council, in which it authorizes the Commission:
 - (a) to proceed to fix or approve just and reasonable rates, tolls or charges, or schedules of them, that may be charged by ATCO Gas and Pipelines Ltd. or AltaGas Utilities Inc. under section 45 of the Gas Utilities Act
 - (i) pursuant to an application filed within the period from June 1, 2011 to December 31, 2013 with the Commission by ATCO Gas and Pipelines Ltd. or AltaGas Utilities Inc. pursuant to, or related to the provisions of, section 45 of the Gas Utilities Act, or
 - (ii) on the Commission's own motion or initiative commenced within the period from June 1, 2011 to December 31, 2013,and
 - (b) to approve any related, ancillary, compliance or subsequent application arising out of an approval granted, or a direction issued, by the Commission pursuant to an application filed under clause (a)(i) or a motion or initiative of the Commission referred to in clause (a)(ii).
18. On July 22, 2011 PBR submissions and applications were filed by each of ATCO Electric, ATCO Gas, Fortis, EPCOR, and AltaGas.

19. Also on July 22, 2011, AltaGas submitted a letter (Exhibit 102.01) to the Commission requesting approval to negotiate its PBR application with its customer groups.
20. On July 26, 2011 the Commission issued a notice of proceeding (Exhibit 105.01), acknowledging the receipt of the PBR applications and soliciting statements of intention to participate (SIPs) from any party not already registered in the proceeding that wished to intervene or participate. The Commission also re-iterated the proceeding schedule it had issued in its letter to parties of April 13, 2011.
21. On August 12, 2011 the Commission wrote to registered parties in regard to AltaGas' request to negotiate a settlement of its PBR application with its customers (Exhibit 112.01). The Commission requested comment from AltaGas on its rationale for the request by August 19, 2011 and comment from other companies and interveners by August 26, 2011. AltaGas was afforded an opportunity to then reply to other companies' and interveners' forthcoming comments by August 30, 2011.
22. On August 25, 2011, the Commission informed proceeding parties by letter (Exhibit 114.01) that it had chosen to expand the role of NERA "to undertake the preparation of a second report to provide parties and the Commission with an independent, expert critical analysis and evaluation of the material aspects of the utility applications and intervener evidence in Proceeding ID No. 566."
23. On August 31, 2011, the Commission began Round 1 of information requests (IRs) related to the proceeding with questions circulated to all of the companies registered as parties and to NERA.
24. On September 30, 2011 in correspondence (Exhibit 181.01) to all parties, the Commission denied AltaGas' request to negotiate a settlement of its PBR application with its customers.
25. On the same day, ATCO Electric filed a letter (Exhibit 182.01) with the Commission objecting to the IRs filed by The City of Calgary (Calgary) directed to ATCO Electric and to Dr. Carpenter relating to the ATCO Electric application.
26. By letter (Exhibit 183.01) dated October 3, 2011, the Commission requested Calgary's comments on the ATCO Electric objection by October 5, 2011 and ATCO Electric's reply by October 6, 2011.
27. In its letter (Exhibit 186.01) to the parties dated October 11, 2011, the Commission allowed the Calgary IRs to stand and directed ATCO Electric and Dr. Carpenter to answer the IRs.
28. On November 9 and November 10, 2011, the Commission received several motions from each of the UCA, Calgary, and the CCA, requesting for full, responsive and adequate answers to certain IRs from the NERA, AltaGas, Fortis, EPCOR, Dr. Carpenter, and ATCO.

29. The Commission established a process by letter (Exhibit 263.01) dated November 10, 2011, to deal with the motions, which requested NERA and each of the companies or their experts to respond to the motions on November 16, 2011, and concluded with reply comments from the UCA, the CCA and Calgary on November 18, 2011.
30. On November 23, 2011, the Commission wrote to registered parties and provided its rulings on each of the individual motion items (Exhibit 282). In the same letter the Commission set a revised proceeding schedule, with intervenor evidence to be submitted December 16, 2011 and a hearing scheduled to begin April 16, 2012.
31. On January 16 and 26, 2012, the Commission issued Round 2 and Round 3 of IRs.
32. On February 22, 2012, NERA filed its second report (Exhibit 391.02): *Update, reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative*.
33. Also on February 22, 2012, ATCO Electric and ATCO Gas filed updates (exhibits 389 and 390) to their respective PBR applications.
34. In a letter (Exhibit 392.01) to registered parties dated February 24, 2012, the Commission provided for a further evidentiary process to allow for information requests, responses and supplemental intervenor evidence with respect to ATCO's application updates.
35. On February 29, 2012, the UCA filed a letter (Exhibit 395.01) objecting to the application update filed by ATCO Gas on various grounds and requesting the Commission to undertake certain steps, including the striking of portions of that evidence from the record of the proceeding.
36. On March 1, 2012, the Commission issued a letter (Exhibit 399.01) indicating that it would treat the UCA letter as a motion requiring a Commission decision following a reply to the ATCO response by the UCA not later than March 5, 2012.
37. On March 7, 2012 in correspondence (Exhibit 416.01) to the parties, the Commission permitted the amendment of the ATCO application updates and denied the UCA motion.
38. Also on March 7, 2012, the Commission began Round 4 of IRs in regard to NERA second report.
39. On March 8, 2012, the Commission issued Round 5 of IRs to ATCO in respect of its application updates.
40. By letter (Exhibit 470.01) dated April 4, 2012, the Commission advised parties of the details of oral hearing scheduled to commence April 16, 2012.
41. On April 12 and 13, 2012, the Commission issued Round 6 and Round 7 of IRs.
42. An oral hearing was held in the Commission's Calgary hearing room from April 16, 2012 to May 8, 2012. At the close of the hearing, the Commission directed parties to submit argument by June 8, 2012, and reply argument by July 6, 2012.

43. On June 5, 2012, multiple parties requested an extension of the deadline for filing argument from June 8, 2012 to June 13, 2012. In a letter (Exhibit 627.01) dated June 7, 2012, the Commission agreed to the request and adjusted the date for filing reply argument to July 11, 2012.
44. On July 6, 2012, ATCO proposed a two-day extension to the July 11, 2012 deadline. By letter (Exhibit 640.01) issued on the same day, the Commission agreed to postpone reply argument filing dates to July 13, 2012 for all parties.
45. On July 13, reply argument was received.

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Appendix 4 – Abbreviations

Abbreviation	Name in full
AESO	Alberta Electric System Operator
AG	ATCO Gas
AHE	average hourly earnings
AltaGas or AUI	AltaGas Utilities Inc.
AMR	automated meter reading
ATCO	ATCO Electric and ATCO Gas
ATCO Electric or AE	ATCO Electric Ltd.
AWE	average weekly earnings
CAIDI	customer average interruption duration index
capex	capital expenditures
Calgary	The City of Calgary
CCA	Consumers' Coalition of Alberta
CPI	consumer price index
CSLS	Center for the Study of Living Standards
DSM	demand side management
ECM	efficiency carry-over mechanism
ENMAX or EPC	ENMAX Power Corporation
EPCOR or EDTI	EPCOR Distribution & Transmission Inc.
ESM	earnings sharing mechanism
EUCPI	electric utility construction price index
FBR	formula-based ratemaking
FERC	Federal Energy Regulatory Commission
Fortis or FAI	FortisAlberta Inc.
G&A	general and administrative expenses
GCOC or GCC	generic cost of capital
GDP-IPI	gross domestic product implicit price index
GDP-IPI-FDD	gross domestic product implicit price index for final domestic demand
G factor	growth factor
GRA	general rate application
GTA	general tariff application
I factor	inflation factor
IPCAA	Industrial Power Consumers Association of Alberta
IR	information request

Abbreviation	Name in full
KFEI	K factor efficiency incentive
kWh	kilowatt hours
LBDA	load balancing deferral account
LDC	local distribution company
MFP	multifactor productivity
MIL	maximum investment levels
MP factor	major projects factor
NAICS	North American Industry Classification System
NERA	National Economic Research Associates Inc.
NGSSC	Natural Gas System Settlement Code
O&M	operating and maintenance
PBR	performance-based regulation
PEG	Pacific Economics Group
PFAM	post-final adjustment mechanism
PFP	partial productivity factor
ROE	return on equity
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SAS	(transmission) system access service
SQR	service quality regulation
TAC	transmission access charge
TFO	transmission facility owner
TFP	total factor productivity
TRIF	total recordable injury frequency rate
UCA	Office of the Utilities Consumer Advocate
UMR	urban mains replacement
USA/MFR	uniform system of accounts/minimum filing requirements
WDA	weather deferral account
X factor	productivity factor
Z factor	exogenous factor

Appendix 5 – Company descriptions

AltaGas Utilities Inc.

AltaGas Utilities Inc. is a Leduc-based provider of natural gas distribution services in more than 90 Alberta communities.¹¹⁹⁵

The company operates 20,000 line km of gas distribution pipelines serving more than 72,000 residential, rural and commercial customers in Alberta and employs 200 people. The company's roots stretch back to 1947 and operations in the Athabasca, St. Paul and Leduc areas. Today the company serves communities that also include Barrhead, Bonneyville, Drumheller, Hanna, Three Hills, Grande Cache, High Level, Morinville, Pincher Creek, Dunmore, Stettler, Two Hills, Elk Point and Westlock.

AltaGas Utilities also offers natural gas service for customers with annual load requirements of more than 20,000 gigajoules anywhere in Alberta, an alternative to communities that have existing natural gas service from another supplier, and provides natural gas service proposals to communities that do not currently have natural gas service.

AltaGas Utilities is a unit of AltaGas Ltd., a Calgary-based energy infrastructure company that among other things also operates natural gas utilities in British Columbia, Nova Scotia and has a one-third interest in a Northwest Territories utility. Together, the natural gas utility firms serve 115,000 customers.

¹¹⁹⁵ All information in this summary was derived from company filings and the AltaGas Utilities (<http://www.altagasutilities.com/>) and AltaGas Ltd. (<http://www.altagas.ca/>) websites, accessed on August 16, 2012.

ATCO Electric Ltd.

ATCO Electric Ltd. is an Edmonton-based developer and operator of regulated electricity distribution and transmission infrastructure.¹¹⁹⁶ In Alberta, the company operates in the northern and east-central regions of the province through 38 offices in its service area, which covers 245 Alberta communities and includes almost 213,000 customers. It has two divisions: capital projects and operations, with capital projects overseeing construction of major transmission projects and operations overseeing construction of large distribution projects and the management and operation of the company's existing transmission, distribution and technology assets.

Along with larger communities such as Grande Prairie, Fort McMurray, Jasper and Lloydminster, ATCO Electric's service area includes many rural and energy-rich areas of the province and covers the northern half of Alberta, an area west and north of Lloydminster and an area east of Calgary. This is about two-thirds of the geographic area of Alberta.

The company is a unit of publicly-listed ATCO Ltd. through ATCO Ltd. affiliates Canadian Utilities Ltd. and CU Inc. ATCO Ltd. is controlled by ATCO Ltd. Chairman Ron Southern through the Southern family holding company, Sentgraf Ltd. Along with its core operations in Alberta, which stretch back 85 years, ATCO Electric also operates in the Canadian north, principally the Yukon and the Northwest Territories, through subsidiaries Yukon Electrical Company Limited, Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited.

ATCO Electric has an employee count of more than 2,000 people and operates approximately 10,000 km of transmission lines and 62,000 km of distribution lines. The company also operates roughly 10,000 km of distribution lines on behalf of 24 rural electrification associations (REAs) that are within its service territory. In fiscal 2011, the members of six REAs voted to sell their electric system assets to ATCO Electric. In the same year, the company experienced what it described as large-scale growth in transmission development and a similar level of distribution growth related to distribution extension and construction.

Major projects in fiscal 2011 included work on the proposed Eastern Alberta Transmission Line, which is the subject of an application currently before the AUC; the Hanna region transmission development project; and the northeast transmission development projects in the Fort McMurray area. Internally, the company was focused on customer service; operational excellence, talent attraction, development and retention and responding to a changing regulatory environment. The latter work centred around the AUC's Rate Regulation Initiative on Performance-Based Regulation.

¹¹⁹⁶ All information in this summary is derived from the ATCO Ltd. 2011 annual report and the ATCO Ltd. (<http://www.atco.com/>), Canadian Utilities Ltd. (<http://www.canadianutilities.com/>) and ATCO Electric (<http://www.atcoelectric.com/default.asp>) websites accessed on August 16, 2012.

ATCO Gas

ATCO Gas is an Edmonton-based distributor of natural gas with more than one million customers in about 300 communities throughout Alberta.¹¹⁹⁷ It operates approximately 38,000 km of distribution pipes and employs about 2,000 Albertans at its headquarters and across its province-wide network of more than 60 district offices.

The company is celebrating its 100th anniversary of founding in 2012. The roots of the company go back to the origins of natural gas service in the province of Alberta in 1912 with Canadian Western Natural Gas in southern Alberta and the Calgary area, and Northwestern Utilities Limited in northern Alberta and the Edmonton area in 1923.

Along with natural gas distribution, ATCO Gas provides expert advice to consumers through ATCO EnergySense and the ATCO Blue Flame Kitchen. It is the largest natural gas distribution utility in Alberta and serves municipal, residential, business and industrial customers.

The company is a division of ATCO Gas and Pipelines Ltd., which is in turn part of the publicly-listed ATCO Ltd. corporate group. ATCO Ltd. is controlled by ATCO Ltd. Chairman Ron Southern through the Southern family holding company, Sentgraf Ltd.

In 2011 ATCO Gas spent more than \$287 million on capital projects it said enhanced system integrity and reliability and ensured public safety.

¹¹⁹⁷ All information in this summary is derived from company filings, the ATCO Ltd. 2011 annual report and the ATCO. Ltd. (<http://www.atco.com/>) and ATCO Gas (<http://www.atcogas.com/>) websites, accessed on August 16, 2012.

EPCOR Distribution & Transmission Inc.

EPCOR Distribution and Transmission Inc. (EDTI) provides electricity distribution service through aerial and underground distribution lines and related facilities to its service area in the city of Edmonton.¹¹⁹⁸

The company is a wholly owned subsidiary of EPCOR Utilities Inc., a provider of electricity and water services to customers in Canada and the United States, and is owned by the City of Edmonton. Both EDTI and its corporate parent are based in Edmonton. The parent was founded in October 1891 as the Edmonton Electric Lighting and Power Company and became municipally owned in 1902.

EDTI provides electricity distribution services to more than 308,000 residential and 35,000 commercial consumers in Edmonton, distributing roughly 14 per cent of Alberta's electricity consumption. The company operates 72-kV, 138-kV, 240-kV and 500-kV lines and cables. It distributes electricity in Edmonton through a network of eight distribution substations, 287 distribution feeders and approximately 5,000 circuit km of primary distribution lines.

Along with distribution services, EDTI also operates high-voltage substations and high-voltage transmission lines in the Edmonton area, including 203 circuit km of transmission lines and 29 transmission substations. These form part of the Alberta interconnected electric system. EDTI also provides services to the Alberta Electric System Operator, provides the distribution tariff and settlement services in Edmonton for the competitive electric market. It also manages and collects load data in the Edmonton area through meter reading, data collection and management.

The company employs approximately 629 people in its distribution arm and 139 individuals in its transmission operations.

¹¹⁹⁸ All information in this summary is derived from company filings and the EPCOR Utilities Inc. website (<http://corp.epcor.com/Pages/home.aspx>) accessed on August 16, 2012.

FortisAlberta Inc.

FortisAlberta Inc. distributes electricity to nearly half-a-million Albertans living in 200 communities across central and southern Alberta.¹¹⁹⁹

The company's origins are as the distribution arm of TransAlta Corp., which TransAlta sold in 2000, and it operates 115,000 km of power lines across a 225,000-km service area that represents more than 60 per cent of Alberta's low-voltage distribution network.

Based in Calgary, FortisAlberta employs 1,000 people working at its headquarters and 52 service points in its service territory. The company operates a 24-hour outage repair and emergency response capability, builds, maintains and upgrades power lines and facilities, installs and reads electricity meters, provides consumption data to retailers that bill customers and promotes electrical safety in the communities it serves.

FortisAlberta is a subsidiary of publicly-listed Fortis Inc., Canada's largest investor-owned distribution utility and which among other things operates regulated electric utilities in five Canadian provinces and a natural gas utility in British Columbia. Fortis Inc. is based in St. John's, Newfoundland and Labrador and its shares trade on the Toronto Stock Exchange.

¹¹⁹⁹ All information in this summary was derived from company filings, AUC records, and the FortisAlberta Inc. (<http://www.fortisalberta.com/home.aspx>) and Fortis Inc. (<http://www.fortisinc.com/>) websites, accessed on August 16, 2012.