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").

$$growth\ Cost = growth\ Input\ Prices + growth\ Inputs. \qquad [1]$$

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.

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

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.

$$trend\ Productivity = trend\ Outputs - trend\ Inputs. \qquad [3]$$

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

growth Inputs = growth Cost - growth Input Prices. [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

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

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

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

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

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

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".

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

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

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

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 hoss shay 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 hoss shay 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.

$$trend\ Revenue = trend\ Cost. \qquad [9]$$

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.

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

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.

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

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

$$trend\ Rates = trend\ Inflation - X$$

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]

$$X = Base\ Productivity\ Factor + Stretch$$

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.

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

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

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

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

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

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

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[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

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

where

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

$\textit{Outputs}^{C}_{O\&M}$ = Elasticity-weighted output index applicable to O&M

$\textit{Productivity}^{C}_{O\&M}$ = Productivity index for O&M that is calculated using $\textit{Outputs}^{C}_{O\&M}$.

[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

$$\begin{aligned} &\textit{growth Revenue/Customer} \\ &\qquad = \textit{growth Revenue} - \textit{growth Customers} \\ &\qquad = \textit{growth Cost} - \textit{growth Customers} \end{aligned}$$

growth Cost/Customer = *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.

= (*growth Input Prices* + *growth Input Quantity*) – *growth Customers*
= *growth Input Prices* – (*growth Customers* – *growth Inputs*).

[10] In the Enbridge and Gazifere formulations, revenue per customer growth is capped at α% of inflation. The X factor is in this case implicit and has an expected value of $(1 - \alpha/100)$ *x 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

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

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.

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

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.

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

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

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

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

$$\textit{trend Productivity}^C = \textit{scale effect} + \textit{trend effect}$$

$$= (1-a_1) \text{ x } \textit{growth Customers} + a_2.$$

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:

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

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.

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

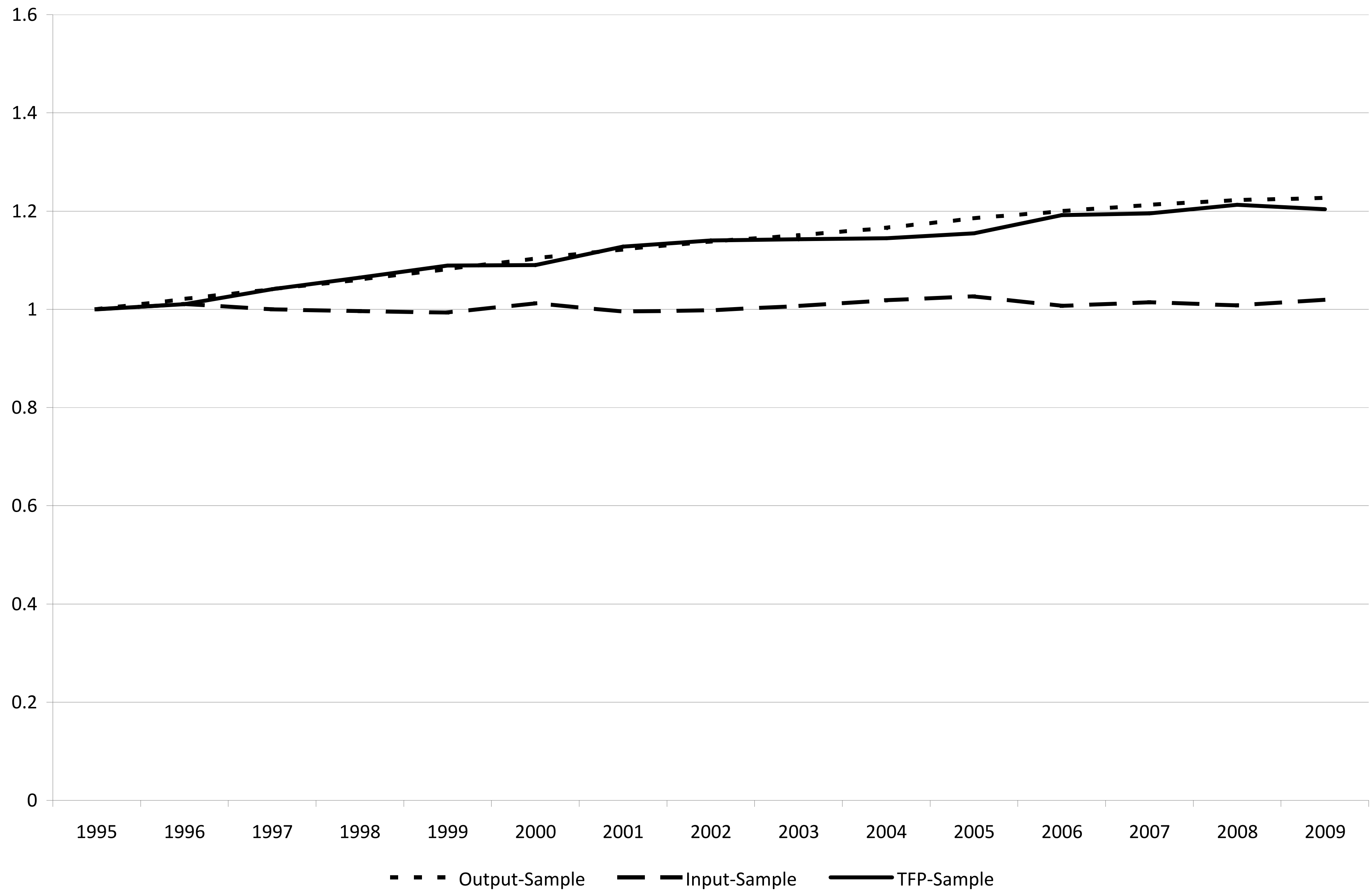
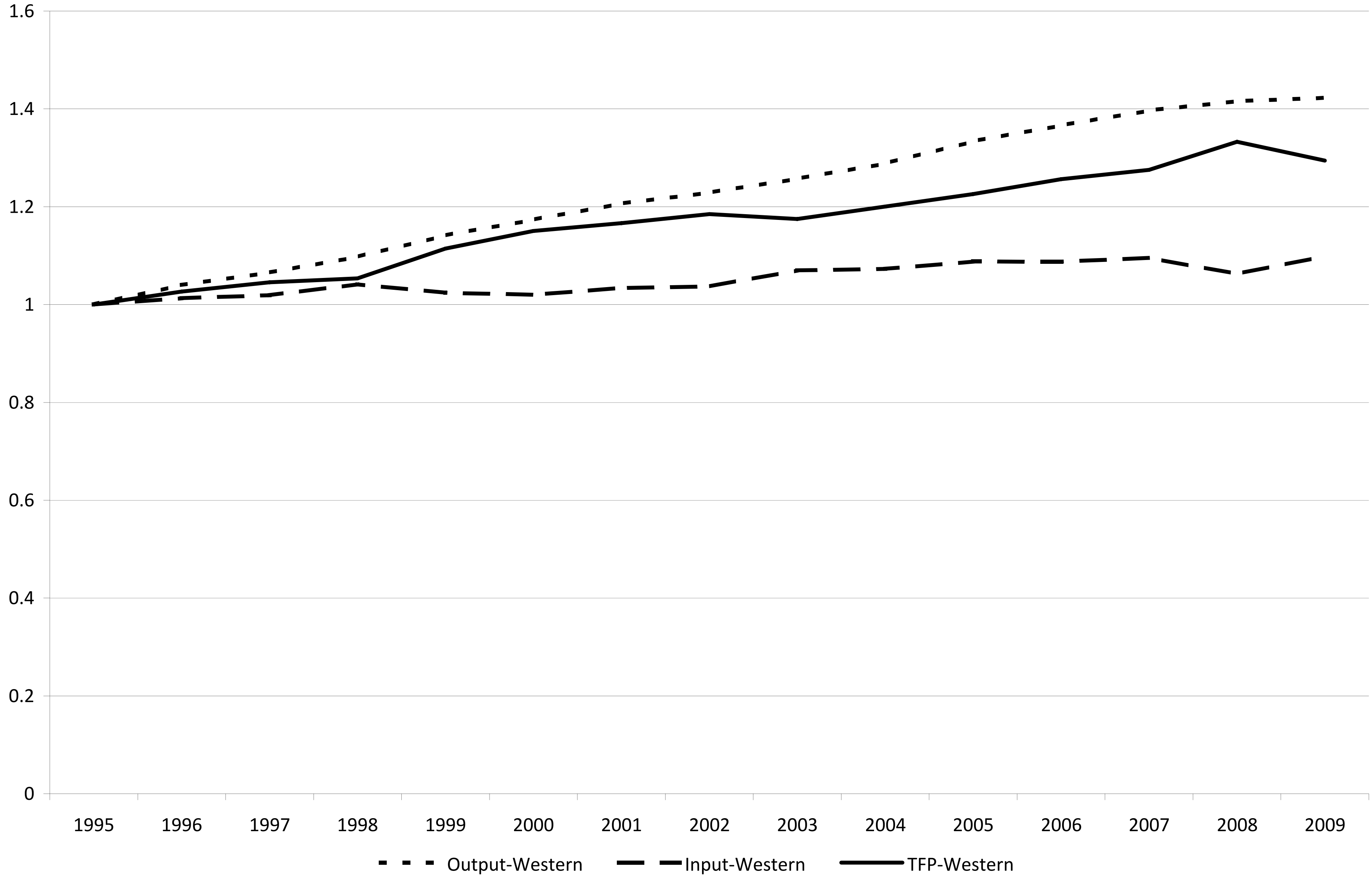


Figure 2

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 than forecasts MFP growth of 1.1% + 0.726 x 2% - 0.433 x 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. Makholm 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.
- GDPIPIs 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 GDPIPIs for final domestic demand ($GDPIPI^{FDD}$) 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%**
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

	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					
Year	Industrial Aggragate	Growth Rate	Utilities	Growth Rate	Industrial Aggregate	Growth Rate	Utilities	Growth Rate	Level	Growth Rate	Level	Growth Rate		Canada	Calgary	Edmonton
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%**	**3.8%**
2001-2010		**2.9%**		**3.8%**		**3.7%**		**3.8%**		**2.6%**		**4.0%**	**1991-2010**	**2.9%**	**3.8%**	**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 usin(
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 dollar:

[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 $GDPIPI^{FDD}$ 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]

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[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

$$\text{Construction Price Index}^{TWA} = SUM_s \frac{(N-s)}{SUM_s\,(N-s)} WKA_{t-s.}$$

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.

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

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

	Information and communication technologies machinery and equipment[1]		Non-information and communication technologies machinery and equipment[2]		Building structures		Engineering structures		Land	
Year	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-Residental Building Construction Price Indexes

	Seven Census Metropolitan Area Composite					
	Total, non-residential building construction		Total, commercial structures		Total, industrial structures	
Year	Level	Growth Rate[1]	Level	Growth Rate	Level	Growth Rate
1981	58.3		59.8		52.5	
1982	62.8	7.4%	64.4	7.4%	56.5	7.2%
1983	62.0	-1.2%	63.2	-1.9%	56.4	-0.2%
1984	60.9	-1.9%	61.8	-2.3%	56.3	0.0%
1985	62.2	2.2%	63.1	2.1%	58.7	4.0%
1986	65.0	4.3%	66.0	4.5%	62.0	5.5%
1987	69.7	7.1%	71.0	7.2%	65.9	6.1%
1988	74.6	6.8%	76.1	7.0%	70.6	7.0%
1989	79.5	6.4%	81.1	6.4%	75.8	7.1%
1990	81.8	2.9%	83.3	2.7%	78.1	2.9%
1991	78.8	-3.8%	79.8	-4.3%	76.0	-2.7%
1992	78.7	-0.1%	79.6	-0.2%	76.1	0.1%
1993	79.2	0.6%	80.0	0.5%	76.7	0.9%
1994	80.9	2.0%	81.5	1.9%	78.8	2.6%
1995	83.4	3.1%	84.0	3.0%	81.2	3.1%
1996	84.9	1.8%	85.3	1.5%	82.8	1.9%
1997	86.7	2.2%	87.0	1.9%	85.0	2.7%
1998	88.5	2.0%	88.8	2.1%	86.8	2.0%
1999	90.1	1.8%	90.4	1.8%	88.6	2.1%
2000	95.1	5.4%	95.3	5.3%	94.3	6.2%
2001	98.2	3.2%	98.3	3.1%	97.9	3.7%
2002	100.0	1.8%	100.0	1.7%	100.0	2.2%
2003	103.0	3.0%	102.9	2.9%	103.1	3.1%
2004	109.7	6.3%	109.4	6.1%	111.1	7.4%
2005	115.9	5.5%	115.5	5.4%	118.0	6.1%
2006	124.9	7.5%	124.6	7.6%	127.3	7.5%
2007	136.8	9.1%	137.3	9.6%	138.4	8.4%
2008	150.9	9.8%	151.3	9.8%	154.2	10.8%
2009	142.0	-6.0%	141.4	-6.8%	146.7	-5.0%
2010	141.5	-0.4%	140.6	-0.6%	146.2	-0.3%
Average Annual Growth Rates						
1988-2007		**3.4%**		**3.3%**		**3.7%**
1998-2007		**4.6%**		**4.6%**		**4.9%**
1982-2010		**3.1%**		**2.9%**		**3.5%**
1991-2010		**2.7%**		**2.6%**		**3.1%**
2001-2010		**4.0%**		**3.9%**		**4.4%**

	Calgary, Alberta					
	Total, non-residential building construction		Total, commercial structures		Total, industrial structures	
Year	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1981	68.4		69.3		68.3	
1982	72.3	5.5%	73.2	5.5%	71.4	4.5%
1983	67.4	-7.0%	68.3	-7.0%	66.8	-6.7%
1984	63.7	-5.6%	64.5	-5.7%	63.0	-5.8%
1985	62.5	-2.0%	63.1	-2.2%	61.7	-2.0%
1986	63.8	2.1%	64.4	2.0%	63.1	2.2%
1987	64.2	0.6%	64.8	0.6%	63.7	0.9%
1988	67.8	5.4%	68.7	5.9%	65.7	3.1%
1989	74.8	9.9%	75.9	9.9%	72.9	10.5%
1990	78.5	4.8%	79.0	4.1%	76.7	5.1%
1991	77.9	-0.8%	78.4	-0.8%	75.7	-1.3%
1992	78.6	1.0%	79.2	1.0%	76.5	1.0%
1993	78.9	0.4%	79.5	0.4%	77.3	1.0%
1994	80.4	1.8%	80.8	1.7%	78.9	2.0%
1995	83.0	3.2%	83.3	3.0%	81.4	3.2%
1996	84.3	1.5%	84.5	1.3%	82.7	1.6%
1997	86.4	2.5%	86.5	2.3%	85.3	3.1%
1998	88.8	2.8%	88.9	2.8%	87.4	2.4%
1999	90.6	2.1%	90.8	2.1%	89.1	2.0%
2000	94.7	4.4%	94.8	4.3%	93.8	5.1%
2001	97.8	3.2%	97.8	3.2%	97.5	3.9%
2002	100.0	2.2%	100.0	2.2%	100.0	2.5%
2003	103.1	3.0%	103.2	3.1%	103.1	3.0%
2004	110.0	6.5%	109.5	5.9%	111.8	8.2%
2005	117.6	6.6%	116.8	6.5%	120.3	7.3%
2006	132.7	12.1%	131.7	12.1%	136.5	12.6%
2007	156.1	16.3%	156.1	16.9%	159.0	15.3%
2008	177.5	12.9%	177.1	12.6%	187.9	16.7%
2009	163.9	-8.0%	163.1	-8.2%	168.6	-10.8%
2010	160.3	-2.2%	159.5	-2.2%	162.6	-3.6%
Average Annual Growth Rates						
1988-2007		**4.4%**		**4.4%**		**4.6%**
1998-2007		**5.9%**		**5.9%**		**6.2%**
1982-2010		**2.9%**		**2.9%**		**3.0%**
1991-2010		**3.6%**		**3.5%**		**3.8%**
2001-2010		**5.3%**		**5.2%**		**5.5%**

	Edmonton, Alberta					
	Total, non-residential building construction		Total, commercial structures		Total, industrial structures	
Year	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1981	68.9		71.1		68.6	
1982	73.7	6.8%	76.5	7.3%	72.6	5.8%
1983	70.6	-4.4%	72.5	-5.3%	70.0	-3.7%
1984	64.2	-9.4%	65.6	-10.0%	64.2	-8.7%
1985	63.2	-1.7%	64.5	-1.8%	62.8	-2.2%
1986	63.7	0.8%	64.2	-0.5%	62.6	-0.2%
1987	65.2	2.3%	65.7	2.3%	63.1	0.8%
1988	66.4	1.8%	67.2	2.4%	63.8	1.1%
1989	75.1	12.3%	77.0	13.6%	72.1	12.3%
1990	78.8	4.8%	80.2	4.1%	76.7	6.2%
1991	78.7	-0.2%	79.8	-0.6%	76.9	0.2%
1992	79.5	1.1%	80.6	1.0%	77.9	1.3%
1993	79.9	0.5%	80.9	0.3%	78.7	1.1%
1994	81.5	1.9%	82.3	1.8%	80.5	2.2%
1995	84.3	3.4%	85.1	3.3%	83.2	3.3%
1996	85.5	1.4%	86.0	1.1%	84.3	1.4%
1997	87.4	2.2%	87.8	2.1%	86.6	2.7%
1998	89.6	2.5%	90.1	2.5%	88.6	2.3%
1999	91.2	1.8%	91.7	1.8%	90.3	1.8%
2000	94.9	4.0%	95.4	3.9%	94.3	4.4%
2001	98.0	3.2%	98.1	2.9%	97.8	3.6%
2002	100.0	2.0%	100.0	1.9%	100.0	2.3%
2003	102.7	2.7%	102.8	2.8%	102.5	2.5%
2004	109.7	6.5%	109.2	6.1%	111.2	8.1%
2005	117.2	6.6%	116.6	6.5%	119.6	7.2%
2006	130.8	11.0%	130.1	11.0%	133.7	11.2%
2007	153.1	15.7%	153.4	16.4%	154.7	14.6%
2008	172.4	11.8%	172.1	11.5%	178.0	14.0%
2009	151.8	-12.7%	151.7	-12.6%	153.3	-14.9%
2010	155.0	2.1%	155.0	2.2%	155.7	1.6%
Average Annual Growth Rates						
1988-2007		**4.3%**		**4.2%**		**4.5%**
1998-2007		**5.6%**		**5.6%**		**5.8%**
1982-2010		**2.8%**		**2.7%**		**2.8%**
1991-2010		**3.4%**		**3.3%**		**3.5%**
2001-2010		**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
300
250
200
150
100
50
0
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
Electric Utility Construction Price Index
Capital Stock Price Index for Engineering Structures in Natural Gas and Water Distribution Industries
Non-Residential Building Construction Price Index - Edmonton

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 is 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 = Base Productivity Factor + 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:

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

Here in each year *t*,

$Input\ Quantities_t$ = Input quantity index

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

$sc_{j,t}$ = 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:

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

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}).

$$\mathrm{CK}_t = \mathrm{WKS}_t \cdot \mathrm{XK}_{t-1}. \qquad [A3]$$

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

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

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

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

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

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 $\left[N-1, 0\right]$,

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

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

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

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

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

Equations [A4] and [A7] together imply that

$$ck_t = xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \qquad \text{[A8]}$$

$$= xk_t \cdot WKS_t$$

[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

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

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

$$
\begin{aligned}
\ln\left(\frac{Productivity_{h,t}}{Productivity_{h,t-1}} \right) &= \ln\left(\frac{Output\ Quantities_{h,t}}{Output\ Quantities_{h,t-1}} \right) - \\
&\quad \ln\left(\frac{Input\ Quantities_{h,t}}{Input\ Quantities_{h,t-1}} \right)
\end{aligned}
\qquad .[A\text{-}7]
$$

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