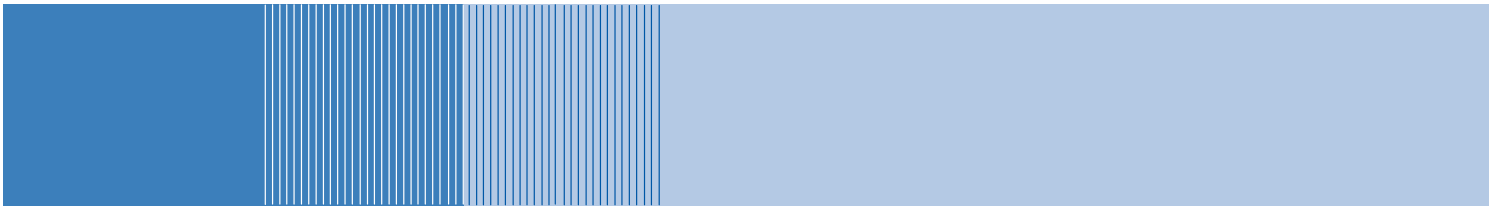
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Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative



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I. Introduction

1. The Alberta Utilities Commission (AUC) has asked NERA to participate as an independent expert in two ways in its performance-based regulation (PBR) initiative: (1) to undertake, explain and defend a total factor productivity (TFP) study that NERA considers useful for this PBR initiative in Alberta; and (2) to assess the PBR plans proposed by the Utilities, and the alternatives and modifications proposed by the interveners, against NERA's experience with relevant PBR regulatory practices in other relevant jurisdictions. NERA delivered a TFP study (along with the complete data set and computational spreadsheets), designed to be useful for electric and gas utilities in Alberta, in December 2010. In July 2011, NERA received the PBR submissions of the Utilities; in October 2011, NERA answered information requests from both the Utilities and interveners (and received the Utilities' responses to their own information requests); and in December 2011, NERA received the PBR submission of the interveners. NERA's TFP study and those filings constitute the basis for this report.

II. Executive Summary

2. In the December 2010 TFP report, we emphasized the purpose of PBR in Canada and the United States: to permit regulated prices to change to reflect general price and industry productivity movements without the need for a base rate case, thus lengthening "regulatory lag" and better exposing regulated utilities to the type of incentives facing competitive firms. NERA's TFP study employed now-familiar methods and empirical sources that are grounded in scholarly work pre-dating the advent of PBR. As an element of a regulatory plan that should provide incentives for utilities to seek profitable innovations, we stressed the importance of transparency, stability and objectivity in the formula that governs price movements between future base rate cases. We stated that objective uniformity in a readily-available source of data

for the industry TFP component of a PBR plan in Alberta is of paramount importance, and that only the Federal Energy Regulatory Commission (FERC) "Form 1" data met such a standard.

3. The Utilities generally accepted our method and source of data as pertinent to PBR for Alberta gas and electric utilities. The differences in their TFP recommendations flow partly from using only the last 10-15 years of our study and partly from performing additional TFP computations using other sources. One intervener, the Consumers' Coalition of Alberta (CCA), recommended incremental improvements to our study, one of which we adopt as helpful that changes our result of average TFP growth from **0.87 percent** to **0.96 percent**.[1] Another intervener, the Office of the Utilities Consumer Advocate (UCA), recommended that our study should be disregarded as not relevant to Alberta utilities.

4. With respect to the Utilities' use of only a portion of NERA's time series, we respond by noting that there is no evidence of which we are aware, from disinterested or scholarly sources outside this proceeding, of an event or a circumstance that so changed the nature of the utility businesses tracked by the FERC Form 1 as to invalidate the relevance of the longest period represented by those data. PBR-based incentives for regulated firms are based on the value of long-term regulatory commitments, which in turn depend on the reasonableness and objectivity of the data and analysis used in their formation. The equilibrium prices in a competitive market (from which the incentives inherent in PBR plans are drawn) are themselves based on long-term trends. We know of no *ex ante* basis to be selective regarding the time period used to compute average TFP growth for the industry. In the absence of such external or scholarly reasons for truncating the time period, we continue to support the use of the largest time period available for empirical study as the most objective basis for the TFP component of a well-structured PBR plan.

[11] The tables and backup that accompanied our original report are attached to this update.

5. With respect to the claim by the UCA that the TFP growth study is not applicable to Alberta utilities, we disagree. It is evident from the UCA's evidence, and its information requests (IRs) to NERA, that what troubles the UCA most is the lack of detailed data on a range of characteristics for the population of firms in the study (e.g., geography and climate) that would allow those companies to serve as "proxies," in the UCA's words, for Alberta utilities. But a TFP growth study for a well-structured PBR plan is not about finding proxy firms for the regulated utilities in question. Rather, it is about measuring underlying industry productivity growth trends representing the kind of diverse individual company circumstances that one would expect to see in a competitive industry. That is to say, we did not in the TFP growth study seek a "model company" but an industry productivity growth trend. As such, we conclude that the UCA's general criticism of NERA's methods in performing a TFP study is not germane to our study.

6. With respect to the PBR plans proposed by the Utilities in general, and the alternatives and modifications proposed by the interveners, we draw a number of conclusions as requested by the AUC. The first concerned what can usefully be deemed "relevant jurisdictions." PBR started in the United Kingdom as an element of new regulatory institutions created for privatized utilities there. It appeared first in Canada and the United States in the regulation of telecommunications companies. We conclude, however, that neither utility regulatory jurisdiction outside North America nor the experience with telecommunications regulation is aptly relevant as a practical guide for the AUC in this proceeding. The regulation of utilities outside North America rests generally on a set of institutions that are newer and materially different than the longstanding regulatory institutions shaping rate regulation in Canada and the United States, and the *X-factor* plays a different role in those places. For telecommunication in

Canada and the United States, PBR was a bridge to genuine competition in the provision of such services and the demise of base rate cases generally, a circumstance not shared by energy distribution.

7. With respect to the elements of the Utilities' and interveners' PBR plans, most are familiar in PBR plans in Canada and the United States. For example, the inflation element, the *X-factor* for industry productivity (with or without a "stretch" factor), the *Z-factor* (for exogenous cost-raising events) and the earnings sharing/reopener aspects of the proposed plans are broadly similar to what the AUC encountered in its 2009 case regarding ENMAX (Proceeding ID. 12). The service quality proposals come in two familiar forms: set standards (like AUC Rule 002) or reward/penalty mechanisms focussed on a group of measurable service standards.

8. Some of the elements of the Utilities' plans, however, are uncommon. EPCOR proposes to limit the PBR plan formula to labour and overhead costs only. Two of the utilities (three if one counts ATCO's electric and gas submissions separately) include a *K-factor*, which serves to embrace the forecast capital expenditure needs over the multi-year period of the plan. All of the utility plans propose what is called a *Y-factor* for various lists of pass-through and deferral items to be added to rates outside the PBR formula. To a greater or lesser degree, these aspects of the proposed PBR plans are derogations from theory underlying PBR and do not appear in PBR formulas from other North American jurisdictions.

9. We conclude that the uncommon features of the Utilities' PBR proposals are so owing to both conceptual and practical problems that other jurisdictions seem in general to have desired to avoid. EPCOR's proposal to limit the PBR to non-capital costs effectively cuts its proposal off from the economic theory upon which most North American PBR plans rest. To be sure, the

theoretical underpinning of PBR, which seeks to mimic competitive pressures in lengthening regulatory lag, imposes pressures on utilities that are in fact not competitive for the distribution utility services they provide.

10. Nevertheless, even for utilities, capital and labour/overheads have some degree of substitutability for which a "total" factor productivity growth study is designed to allow. It is questionable in this respect whether a PBR regime based on "partial" factor productivity (PFP), which presumes that capital and other costs are not substitutable, is worth the considerable effort that it takes to implement an "inflation minus productivity" formula.

11. The *K-factor* proposals present more practical difficulties. Utility rate regulation in Canada and the United States generally rests on what is "known and measurable," which reflects the longstanding institutions of legislated accounting regulations and judicial precedent regarding the value of regulated property. Other regulators, like those in the United Kingdom and Australia, employ long-term forecasts (up to 8 years) of utility costs in rate making. But rate regulation in those countries is comparatively new and does not exhibit the accounting and constitutional foundations adopted decades ago in Canada and the United States. Given the general scepticism that North American regulators display with forecast costs for ratemaking, we do not think that the *K-factor* proposals are a practical part of a PBR plan, as such.

12. The *Y-factor* reflects pass through and deferral items that the Utilities would like to treat outside the "inflation minus productivity" part of the PBR formula. To be sure, the process of having rates change for various cost items without a base rate case is becoming more common to regulation generally through the use of "trackers," quite apart from PBR regulation. Trackers make good sense in those jurisdictions that have them, as we review those plans in this study. Such trackers allow for the efficient and timely recovery of particular costs requiring specialized

treatment without necessitating a base rate case. We would recommend that each recommended tracker receive the same kind of specialized treatment, and *ex post* accounting, evinced by other regulators generally. We do not recommend that the PBR formula, as such, be expanded beyond what is customary in North America to become a catch-all for a broad base of deferral and pass-through items. We agree with the caution of the City of Calgary that a PBR plan should not come to resemble "a 5-year test period under cost of service ratemaking."[2] Such would more resemble the practices of jurisdictions in the United Kingdom and Australia, which we think is inconsistent with the deeper and more meticulous institutional foundation for rate regulation generally in Canada and the United States.

13. "Efficiency carryover" mechanisms, which would make rates for subsequent periods somehow a function of performance in the prior period, are uncommon also. The sources of those suggestions is a desire to have the profit incentives of a PBR plan transcend to some degree the next base rate case, when rates would otherwise be squared with costs and profitable innovations capitalized for ratepayers. The discussions over whether to make PBR regulation more of a moving average with such efficiency carryover mechanisms are conceptual only. We have seen no evidence demonstrating that that particular innovation to PBR—a partial lengthening of regulatory lag—is worth the additional complications it would pose for the periodic future base rate cases.

III. NERA's TFP Study

14. NERA's TFP growth study prompted three types of reaction from the Utilities and interveners: (1) suggestions on improvements to NERA's data set; (2) truncations of the time period of the analysis of average TFP growth for the construction of an *X-factor*; and (3)

[2] City of Calgary, page 6 of 57.

suggestions that the population of companies used to perform the TFP growth study is not applicable or useful in the current circumstances in Alberta. We will deal with these three reactions in turn.

A. Suggestions for Improvements in the NERA Data Set

15. Pacific Economics Group Research LLC (PEG), on behalf of the CCA, recommends (at page 36) that we "recalculate the labor quantity by taking the difference between the growth in salaries and wages and the inflation in a appropriate salary and wage price index using relation [4]." Relation [4] is:

Growth Inputs = growth Cost – growth Input Prices.

16. This issue arises because, as we stated in our original report at page 9, "[b]eginning in 2002, the FERC Form 1 no longer contains employee data" and "we estimated the number of employees by using the previous years' electric distribution payroll growth rate for the years 2002 to 2009."

17. We accept PEG's recommendation and use the growth in the U.S. Bureau of Labor Statistics (BLS) Series of Wages and Salaries in the utilities sector to determine an inflation-adjusted electric distribution payroll growth for the years 2002 to 2009. We then use this inflation-adjusted electric distribution payroll growth for the years 2002 to 2009 to estimate the number of employees for those years. The U.S. BLS wage and salaries growth for utilities sector averaged approximately 3.1 percent during the period 2002 to 2009 (see table below).

Table 1. Wages and Salaries Growth in U.S. Utilities

Year	Qtr1	Qtr2	Qtr3	Qtr4	Annual
2001	3.7	3.8	3.2	3.5	3.6
2002	3.2	3.7	4.0	3.5	3.6
2003	3.6	2.4	2.4	2.5	2.7
2004	2.6	3.2	3.3	3.1	3.1
2005	3.1	2.7	2.5	2.7	2.8
2006	2.4	2.9	3.5	3.5	3.1
2007	3.5	3.3	3.0	3.2	3.3
2008	3.5	3.6	3.0	2.6	3.2
2009	2.8	2.5	2.7	3.4	2.9

Source: BLS, series CIU2024400000000A

18. The following table shows the labor index growth rate for the period 2002 – 2009 in the original NERA study and the NERA update. This change to our study increases measured TFP growth to 0.96 percent.

Table 2. Labor Index Growth Rate, 2002 – 2009, Original and Updated NERA Study

Year	Original NERA Study	NERA Update
2002	10.04%	4.48%
2003	8.24%	5.43%
2004	7.12%	3.98%
2005	7.90%	5.11%
2006	6.48%	3.40%
2007	11.18%	7.85%
2008	14.21%	10.93%
2009	-9.25%	-11.93%

19. PEG identifies another concern (at page 36) with the NERA study: that the FERC Form 1 data are sales volumes rather than delivery volumes. Their concern is that sales volumes "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." They cite the example of Massachusetts Electric, which under the FERC Form 1 sales data there is a decline in industrial sales from 4,044 MWh in 1998

to 445 MWh in 2009. PEG indicates that data on deliveries are available on Form EIA 861 for years after 1990 and this data source shows a much less precipitous decline than reported in FERC Form 1.

20. The observation by PEG is conceptually correct although we believe there are data issues that suggest caution in the use of a "patch" as recommended by PEG. First, implementing the "patch" would involve combining the EIA 861 and the FERC Form 1 data that although in theory should measure the same output, we found that there are differences between them. Second, we found some anomalies in the EIA 861 data. For example, according to the EIA 861 form Baltimore Gas and Electric Company reports 21,390 MWh of delivery and bundle sales in 2003 and only 2,756 MWh of such sales in 2009. In addition, out of our sample of 72 companies, we found that relatively few exhibited the growth pattern that PEG observed for Massachusetts Electric.

21. Nevertheless, we obtained Form EIA 861 data to examine the impact of PEG's criticism. We were able to distinguish between bundled and delivery only sales information for the different customer types (residential, commercial, industrial and public) for the period 2001 – 2009. For each customer type we created a new sales volume that consisted of bundled and delivery only.

22. Based upon this analysis we found that using EIA 861 bundled and delivery only sales as the output measure for the period 2001 – 2009 and maintaining the FERC Form 1 sales data for years prior to 2001 increases our measure of TFP by 0.12 percent. That is, if we were to use this patch, our TFP would increase to 1.08 percent from 0.96 percent. Given that there are issues with using the EIA 861 data and that the difference in results are not large, we do not conclude that

the use of FERC Form 1 sales volumes introduces a meaningful bias in our study—particularly given the long-term nature of our investigation.

B. Truncation of the Time Period for Analysis[3]

23. In their evidence, the Utilities subjected the data supporting Figure 10 from our report of December 2010 to various levels of *ex post* analysis, concluding that more recent periods in our TFP growth study were more representative of the conditions that would face Alberta utilities in the future. Dr. Carpenter, who recommends an *X-factor* of -2.0 percent, presents his analysis in this respect on pages 21-25 of his evidence for ATCO Gas and ATCO Electric.[4] Dr. Cicchetti, who recommends an *X-factor* of -1.0 percent, does so on pages 7-13 of his evidence for EPCOR.[5] Ms. Frayer, who also recommends an *X-factor* of -1.0 percent, does so on pages 55-58, and page 79 of her evidence for Fortis Alberta.[6] Dr. Schoech and Mr. Camfield recommend an *X-factor* of -1.3 percent on page 15 of their evidence for AltaGas. All four propose a negative *X-factor* based in part on the selective use of only the more recent time period covered by our December 2010 study.

24. We do not recommend such selectivity regarding the period of analysis. As we stated before, we view objectivity as an item of pre-eminent importance in performing a TFP growth

[3] Dr. Lowry (and others) for PEG, on behalf of the CCA, recommend a truncated period in our report for the years 1981-1995 (p. 38). That recommendation is not based on an *ex post* examination of time periods, but on particular criticisms that Dr. Lowry makes regarding the inputs to our TFP study.

[4] "As I have shown, the results in the early years of the NERA time frame are very different than the results in the later years, and are not likely to represent productivity growth that utilities can reasonably be expected to experience in the next few years." Carpenter, p. 27.

[5] "NERA estimated annual TFP growth from 1972 to 2009. This is simply far too long a period to use for estimating TFP growth for a regulatory application. I am not aware of any energy utility PBR plan where more than 18 years of data was used to estimate industry TFP growth." Cicchetti, p. 10.

[6] "Moreover, although not directly comparable, even the US experience in the last ten years for the electricity distribution sector, as documented in the NERA Study, is corroborative of such trends where the TFP growth rate among US local distribution utilities averaged -1.09% for the 2000-2009 period (ten years) and -0.28% for the 1995-2009 period (fifteen years)." Frayer, p. 79.

analysis for the purpose intended in this proceeding. Conclusions drawn from an after-the-fact examination of our original Figure 10, which documents the year-by-year TFP growth results from a methodology in wide acceptance, are not objective.

25. For PBR plans to work well, reliable methods for determining the elements of the key formulas for price changes must exist. The efficiency incentives for regulated firms inherent in PBR plans are based on the value of long-term regulatory commitments, which in turn depend on the reasonableness and objectivity of the data and analysis used in their formation. Only changes in long-run average cost affect, for example, the equilibrium prices in a competitive market (from which the incentives inherent in PBR plans are drawn). Short-run changes in productivity—even industry-wide changes in productivity—do not cause firms to enter or leave an industry.

26. Productivity growth rates for individual firms, on the other hand, vary greatly from year to year. The TFP growth results that we present demonstrate this high degree of short-term variability.[7] Given this high degree of variability and the fact that short-run fluctuations do not affect the long-term picture for competitive firms, a constant productivity target is preferable to a variable target given the underlying theory which draws productivity studies into PBR plans.

27. Unless there is reliable proof the to contrary, the best and most supportable economic assumption is that while productivity growth may fluctuate in an erratic short term, or longer-term cyclical fashion, from time to time, it will eventually revert back to its long-term, underlying trend. This basic view of long-term trends has been adopted by many academic

[7] Much of this variability simply reflects how utilities book their costs. An individual examination of the year-to-year TFP growth rates, in the NERA spreadsheets already provided to the parties, show many examples of countervailing positive and negative TFP growth numbers reflecting the particular decisions of when costs were booked to FERC accounts—a source of volatility that smoothes out over time.

researchers who have studied macroeconomic time series such as GNP, prices, wages, unemployment rates, money stock, interest rates, etc.

28. To be sure, there is no unanimity on this point regarding the stability of underlying trends developed with economic data. In an influential article, cited in thousands of subsequent scholarly papers, Charles Nelson and Charles Plosser (1982) postulate that macroeconomic variables are better characterized as "non-stationary" processes that have no tendency to return to a predetermined path, instead of being regarded as variables that fluctuate around a deterministic trend.[8] Pierre Perron (1989), on the other hand, in a similarly influential paper, makes one of the most compelling defenses of the "trend-stationary" model, arguing that the empirical evidence validates this model when one accounts for the existence of trend-breaks due to certain "structural shocks" that have lasting effects.[9] Perron finds that the only shocks with persistent effects are the 1929 Great Crash and the 1973 oil price shock.

29. Lawrence Christiano (1992) agrees that the trend-break hypothesis has a degree of *a priori* appeal, since a number of "big events" in the post-war period could have sparked a trend change.[10] Examples are the 1964 tax cut, the oil shock of the early 1970s and the financial deregulation of the 1980s. Nevertheless, Christiano refutes Perron's data testing approach on the grounds that the selection of the break point involved a pre-test data examination (including *visual inspection*), which lends itself to the possibility of "data-mining." He argues that the correct approach would be to let data, itself, select the appropriate break point (if any exists).

[8] Nelson, Charles R. and Charles I. Plosser, 1982, "Trends and Random Walks in Macroeconomic Time Series: Some Evidence and Implications," *Journal of Monetary Economics* 10, 139-162.

[9] Perron, Pierre, 1989, "The Great Crash, The Oil Price Shock, and the Unit Root Hypothesis," *Econometrica*, 57(6), 1361-1401.

[10] Christiano, Lawrence J., 1988, "Searching for a Break in GNP" (Federal Reserve Bank of Minneapolis and NBER).

After developing a suitable testing algorithm, Christiano finds that his objection is well supported by the macroeconomic data.

30. Zivot and Andrews (1992), Chu and White (1992), Ben-David and Papell (1994), and other researchers corroborate this view, devising improved methods for determining the date of a structural change.[11] They find that, in addition to the Great Crash and 1970s oil price shock, other significant break dates are the World Wars.

31. This academic literature suggests three basic issues that are relevant to our TFP growth analysis and the Utilities' desire to use a more recent period:

1. The conventional assumption that the industry productivity and input prices are characterized by a stable trend is valid. In fact, our purpose in using the longest data set available is to try to identify the magnitude of the trend in the best way possible.

2. If one suspects that any of the TFP growth series are not stable in the long-term or that they are subject to a structural break, as the Utilities imply, the appropriate response to such suspicion is to implement a statistical testing procedure along the lines of accepted research in the area of structural breaks.

3. The literature has shown that an *ad hoc* approach that relies on casual visual observation, or idiosyncratic trends, may yield misleading results.

32. We have not attempted a structural break test, as we have seen no evidence from outside this proceeding to lead us to believe that the nature of the utility distribution business has changed in a way that would require such a break to be imposed on the available Form 1 data. We see no necessary (or even reasonably plausible) reason to conclude that the credit crisis, for its part, changed the nature of the utility businesses that are subject to cost-based regulation even though it may have temporarily changed the relationship of inputs to outputs (where the latter is

[11] Zivot, Eric and Donald W. K. Andrews, 1992, "Further Evidence on the Great Crash, the Oil-Price Shock, and the Unit-Root Hypothesis," *Journal of Business & Economic Statistics*, 10(3), 251-299; Chu, Chia-Shang James and Halbert White, 1992, "A Direct Test for Changing Trend," *Journal of Business & Economic Statistics*, 10(3), 289-299; Ben-David, Dan and David H. Papell, 1994, "The Great Wars, the Great Crash, and the Unit Root Hypothesis: Some New Evidence About an Old Stylized Fact" (Centre for Economic Policy Research).

measured in kWh), if output has declined. As with other temporary or cyclical economic events that may affect utility sales, we would expect those effects to rebound and stabilize over time according to an underlying productivity trend.

C. Applicability of the TFP Growth Study for an Alberta PBR Plan

33. With respect to the form of the TFP study or its source of data, the Utilities more or less agree—excepting their desire to limit the number of years in the study. None of the Utilities question the use of U.S. data for a Canadian PBR plan. Dr. Lowry specifically recommends against using Canadian data for the computation of *X-factors*.[12] Dr. Carpenter points to the similarity of using U.S. data for Canadian regulatory purposes in case RH-003-2011 before the National Energy Board (NEB), on the basis of the similarity of the regulatory environments in the United States and Canada, citing a NERA work that comes to the same conclusion.[13]

34. Dr. Cronin, for the UCA, expresses a contrary opinion. He makes many references to our TFP growth study in his evidence. He devotes Section X of his evidence to our TFP growth study in a way that appears to embrace generally his other comment. We will limit our attention to his Section X.

35. In Q114—the last question and answer—of Dr. Cronin's evidence, he lists eight problems that lead to his ultimate conclusion that our study "is not applicable to Alberta gas and electric distribution utilities and is not relevant to this case, and should not be given any further consideration in the development for PBR for gas and electric distribution utilities in the

[12] "Data limitations discourage the use of Canadian data in the calibration of *X-factor*s for rate escalation mechanisms. Data collection is not standardized across Canada…" Lowry, et al, p. 25.

[13] See Evidence of Paul R. Carpenter before the NEB, case No. RH-003-2011, page 5, note 1 (citing a 2008 study for the Canadian Gas Association by Kenneth Gordon and Jeff Makholm). See "Gordon and Makholm," footnote 15.

Province of Alberta."[14] Some of these eight issues overlap, and we think it is fair to gather his eight objections to our study into four general areas:

1. Dissimilarity to conditions or regulation in Alberta (items 4, 6, and 8): Dr. Cronin thinks our TFP growth study is faulty because the population of companies we use exist in regulatory environments "dissimilar to Alberta" and operate in regions "not similar to Alberta" and that have "retail sales and number[s] of employees that are different from any Alberta gas and electric distribution utilities."

2. Empirical data problems (items 2 and 3). He says that our FERC Form 1 data "was not collected for the purpose of doing TFP … research," that it "does not contain key distribution data."

3. Methodological flaws/inconsistencies (items 1 and 5): Dr. Cronin thinks that our study has problems defining "costs and outputs" and that we use "selection criteria that are different" than those we employed in prior TFP growth studies.

4. Lack of experience (item 7): Dr. Cronin thinks that we lack experience in collecting and analyzing TFP data.

We think that it will be useful to deal with these criticisms in turn.

1. "Similarity to Alberta"

36. Three of the eight elements in Dr. Cronin's summary conclusions regarding what he holds to be deficiencies in our TFP growth study pertain to the uniqueness of Alberta utilities *vis-à-vis* those US utilities covered by the FERC Form 1. There are three reasons why we conclude that Dr. Cronin's criticisms in this respect are without merit. The first is that such a TFP study does not seek to explain productivity *levels* but instead productivity *growth rates*. The second is the theoretical purpose of the *X-factor* (to which the TFP growth study contributes) is not to find proxies for the companies to be regulated, but rather to find the sort of long-term, underlying industry productivity growth trend that a competitive firm would face in their own industries. As such, a focus on finding companies just like those in Alberta would not accomplish our objective. Third, there is a generally-perceived similarity of both the regulatory institutions

[14] Cronin, p. 244.

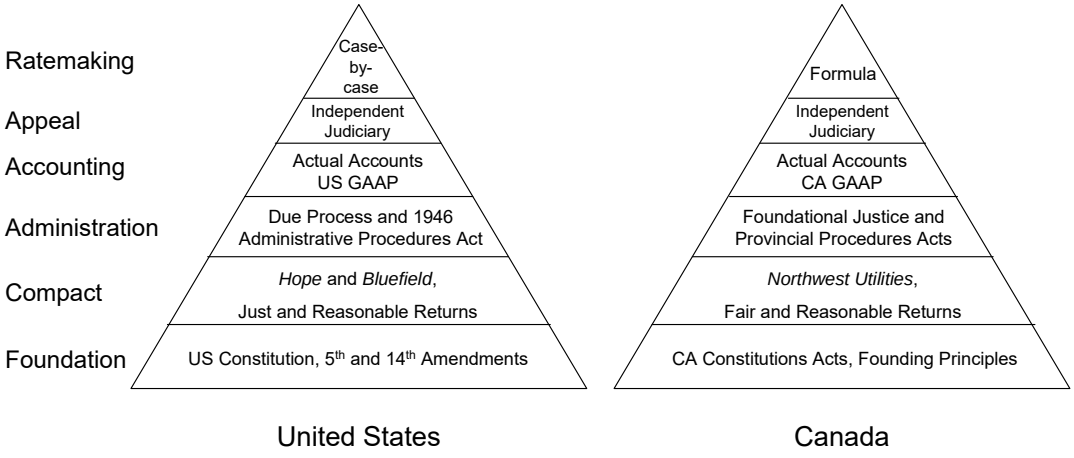
facing utilities in Canada and the United States, as well as the organization of the utility industries in the two countries. That perceived similarity causes both the Utilities and one intervener (the CCA) to have no particular problem using the larger and more consistent data set available from the United States.

37. As set out above regarding our comments on the time period, our principal pursuit in the TFP growth study is to characterize an underlying trend in industry productivity growth. We do not attempt—nor do other TFP growth studies attempt—to explain the productivity *level* of any utility. What we seek is to discover is an underlying trend in productivity *growth* that characterizes a broad population of utilities that is sufficiently objective, useful and stable to be part of PBR plan. Put another way, we do not examine whether one utility has a greater level of output for the same inputs levels than another. Rather, we study how the ratio of outputs to inputs changes over time. In this respect, the manifest differences in utilities situated in "high cost" versus "low cost" areas do not matter to the study—as we only examine the average of year to year *changes.* And as such, the unique cost features of any particular utility cancel out in the process.

38. As we stated on page 3 of our initial report of December 2010, the theory underlying the kind of PBR sought by the AUC seeks to inject the type of incentives experienced by company managements in competitive industries where benchmark prices move according to the productivity of the industry in question rather than to the particular costs of one company. In that respect, the TFP growth index that informs the *X-factor* is supposed to reflect industry growth trends, not the trends in Alberta alone or among a group of companies whose operations and cost levels look like those in Alberta.

39. With respect to differences in the regulatory climate faced by the utilities in Alberta versus those in the various U.S. states, we have written elsewhere that the "the differences that do exist are more procedural than fundamental." [15] As stated in that report, from the constitutional foundation through to administrative practices, accounting practices and judicial review, Canada and the United States have virtually indistinguishable regulatory environments—so much so that the US *Hope* and *Bluefield* decisions are even cited in Canadian rate cases. As we did before, we characterize the essential similarity of the foundations for the two jurisdictions below.

Figure 1. Institutional Elements of Common Regulation in the United States and Canada



40. Against what we measure in our TFP study (productivity *growth* and not *levels*), the theoretical foundation of the *X-factor* (to mimic industry productivity growth trends), and the essential close similarity between the institutions that define regulation in Canada and the United

[15] Kenneth Gordon and Jeff D. Makholm, NERA, "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis," Study Commissioned by the Canadian Gas Association, February 2008, pp. 32-34. ("Gordon and Makholm") Dr. Carpenter, in testimony dated October 31, 2011 for TransCanada Pipeline before the National Energy Board cited this paper as evidence that "the regulatory environments in Canada and the U.S. are comparable." (p. 5)

States, we conclude that Dr. Cronin's criticisms of the lack of similarity of the firms in our study to Alberta firms are incorrect.

2. "Data Problems"

41. In Section X of his testimony, Dr. Cronin offers a number of criticisms on the limitations of Form 1 data or specific adjustments that we make to compute TFP growths. He describes various adjustments we made to the data, or facts and circumstances pertaining to the particular companies among the 72 we used, or the data for those companies, as compromising our TFP study to the extent that it should be disregarded by the AUC.

42. A number of Dr. Cronin's observations on Form 1 data, such as that the number of employees requires estimating (rather than direct counting) after 2001, or that net distribution plant is not listed (but must be calculated) are correct. He is also correct to say, as he does in his summary, that the Form 1 data was "was not collected for the purpose of doing TFP and productivity research."[16]

43. Where we differ with Dr. Cronin is in his conclusion that such facts preclude the use of such data for an objective and stable TFP growth study that can contribute to a well-structured PBR plan. On the contrary, we conclude that the Form 1 data set is an acceptable source of long-term and reliable operating and financial data for U.S. electric utilities—an opinion that is shared generally. Form 1 data has been used for many scholarly studies that have had nothing to do with contested regulatory proceedings, including studies of electricity industry cost structures and productivity. Dr. Cronin says, "Despite holding up the FERC Form 1 data as a paragon of 'objective uniformity', NERA has testified previously that it had to make adjustments to the

[16] Cronin, p. 244.

FERC data."[17] We think that it is unreasonable for Dr. Cronin to suggest that adjusting data for the purpose at hand is a fault. In any event, it is fair to point out that Dr. Cronin offers no better source of long-term and consistent utility data for the purpose at hand.

3. "Methodological Flaws/Inconsistencies"

44. Dr. Cronin summarizes two criticisms of this nature: that we chose to use all 72 U.S. utilities in our population, which is different from our reports a decade ago in Maine and Alberta, and that we chose to use kWh as our single measure of electricity utility output over other possible measures of output. It is reasonable, of course, to question both of these choices for the electricity companies in our group.

45. As we explained in our December 10, 2010 report, and in the subsequent information responses,[18] we chose on an *ex ante* basis not to isolate the Western region for our TFP analysis. Since the last time we presented a TFP study in Alberta, the number of companies that remained in what we called the Western region declined, and we did not conclude that performing the analysis on the smaller number of companies would provide the kind of useful or stable results that a long-term and stable PBR regime requires. As a result of this decision, we did not perform separate calculations for different regions of the United States for the purpose of this assignment.

46. In our various TFP studies, we have consistently recognized the existence of a tradeoff between a large cross section of the whole United States and a smaller cross section of more similarly situated companies. Applying the results to a company with few other companies in its region would give a less robust measure of productivity growth. That is to say, a smaller region would not reflect the type of broad productivity index that the theory underlying PBR dictates.

[17] Cronin, p. 232.

[18] See AUC-NERA-5 (b).

47. With respect to the measure of output, there are two considerations. The first is whether one measure tops others in capturing the output for energy distributors that perform varied kinds of services with a multitude of capital facilities. The second question is whether it would be useful to include various sorts of outputs (kWh or numbers of customers) into a single output for measuring TFP. Our practice, both in this case and in previous TFP growth analyses, has been to use kWh as the measure of output. We conclude that if a single measure is chosen, it is the most representative of the nature of the utility, the size of its system, and its revenues. Of course, in a recession or in response to a price shock, kWh sales may decline with a distribution system that is otherwise unchanged—thereby seeming to show a decline in productivity growth for other reasons. On the other hand, a rising use per customer for a utility with a fully penetrated service territory (as in an urban area) may well show larger inputs over time for a static customer output—also seeming to show a decline in productivity growth for other reasons. It remains the case that for an energy delivery business where much of the cost is tied up in long-lived capital, there are trade-offs in using one imperfect measure of output or another. The theory underlying PBR does not help in the choice—only practicality. Our preference has always been to use kWh with the longest time series that Form 1 permits so as to dampen the effects of the kind of short-term or cyclical patterns that would most influence kWh sales as a measure of output.

48. Of course, it would be possible to specify two or more outputs and then somehow combine them into a single weighted average TFP figure for the purpose of deriving the *X-factor*. Or, one can perform an econometric analysis, like that offered by Dr. Lowry, to try to customize the TFP growth for the particular utility in question based on its own measurable characteristics.

We do not question the value of statistical methods like Dr. Lowry's for scholarly research.[19] But we question the effectiveness of such methods in the context of an adversarial proceeding among interested parties where every element of subjective or expert choice (and in a complex econometric analysis there are many) opens the door to esoteric debate among experts.

4. "Lack of Experience"

49. Regarding this last criticism, Exhibit 0077.00.NERA-566 contains the CVs of the Project Team which we invite Dr. Cronin to review.

50. That said, it appears as though Dr. Cronin's criticism pertains to his own experience in Ontario (which he discusses at page 86), where he "visited many of the Ontario LDCs during 1st Generation across the province … and held in-depth discussions with the municipal electric utilities (MEUs), particularly those that had [been] identified as the leaders in efficiency based on the data collected from these LDCs as part of the OEG's operational assessment."

51. Dr. Cronin's discussions with Ontario's utilities may indeed have had some useful purpose in that province's regulatory restructuring effort. But we would not endeavor to perform such on-site interviews as a substitute for consistent and reliable operating and financial data collected from utilities over many years as available in the FERC Form 1. Personal interviews and local company data collection are not components of a reliable and replicable TFP growth study that can serve as the basis for the kind of PBR plan that the AUC seeks in this case.

[19] Indeed, Dr. Makholm's 1986 Ph.D. dissertation included an econometric "decomposition" of a TFP index number study, using Form 1 data, into its explanatory components that is very much like the kind of econometric analysis that Dr. Lowry describes.

IV. The Proposed PBR Plans

52. In this section of our report, we summarize and compare the PBR plans offered by the Utilities and interveners against what is usual and/or common, versus those elements that are unusual and/or uncommon. In this respect, we have been asked to use our experience and understanding to form a basis for a critical evaluation of those plans.

53. The first item in our discussion concerns relevant jurisdictions. In this respect, we limit our analysis to North American regulatory practices for energy utilities. That is, we discuss and exclude consideration of those PBR practices abroad (in the United Kingdom and Australia in particular) where the basic institutional framework for regulation differs materially from that in Canada and the United States.

54. Limiting our analysis to North American energy utility regulation, we then turn to common and uncommon features in the utilities' and interveners' plans. First we identify what other regulators have done in the relevant jurisdictions given the types of proposals made by either Utilities or interveners. Second, we compare the key provisions of the plans offered by the Utilities and interveners to those practices. Third, we discuss the pros and cons of the key provisions of each utility or intervener proposal given the forgoing discussion.

A. Relevant Jurisdictions

55. As a method of regulating prices, what is known as PBR in North America arose subsequent to the privatizations in the United Kingdom (UK) in the 1980s. Privatization has been one of the more important economic developments of the last two decades as governments

try to improve utility services and end the drain on public funds.[20] As Professors Bias and Perotti state:

> Large privatization programs have occurred in the recent decades both in developed and developing countries. The main explanation has been that privatization leads to increased productivity and profitability, a consensus view which a vast empirical literature has confirmed.[21]

56. The trend toward privatization effectively began in the UK in 1979. The 1970s were an economically unstable time for the UK. The country was experiencing oil shocks along with the rest of the world, and expenditures were growing faster than revenues. Having committed not to curtail health and social security expenditures, the government was forced to cut public sector investment. Additionally, to counter the inflationary surge that resulted from the rise in oil prices, the government held down utility prices, causing utilities to experience cash flow problems and investment declines. For the government of Prime Minister Margaret Thatcher (newly elected in 1979) privatization emerged as an attractive solution to fiscal problems.

57. In addition to starting the worldwide trend in privatization generally, the UK also popularized a method of tariff regulation in water, electricity, gas and telecommunications called "RPI-*X*" or "price cap" regulation there.[22] According to Armstrong, *et al*:

> First applied to British Telecom (BT) in 1984, RPI-*X* regulation now exists for British Gas (BG), British Airports Authority (BSS), the regional water companies, and, in the electricity industry, the National Grid Company and the regional distribution and supply companies. [note omitted] Almost fifty firms in Britain

[20] Nobel Laureate, Economist Gary S. Becker notes that "[t]he privatization revolution sweeping the world surely ranks among the remarkable economic developments of the past few decades." Gary S. Becker, "Surprises in a World According to Adam Smith," *Business Week*, August 17, 1992, p. 16.

[21] Biais, B., and Perotti, E., "Machiavellian Privatization," *The American Economic Review*, Volume 92, No 1 (March 2002), page 240.

[22] The economic literature uses various synonymous terms for price cap regulation. Other terms include CPI-X regulation, RPI-X regulation, performance-based ratemaking (PBR).

> are subject to RPI – *X*, and the system has attracted considerable international interest.[23]

58. Following its popularity in the UK, price cap regulation was adopted in the United States for ATT in 1989 and for other gas and electricity companies in the United States and Canada subsequently.

59. The application of somewhat similar PBR pricing formulae, however, mask to a large extent the considerable underlying institutional differences upon which price regulation was based in the UK (and other jurisdictions that looked to the UK for regulatory guidance, such as Australia and Argentina). It is well known that neither the UK nor the other jurisdictions that began regulation with the UK-inspired privatization efforts have the constitutional, accounting and administrative institutions that define regulation in Canada and the United States.[24]

60. Probably the most useful way to signal that the institutions upon which basic regulation is based are quite different than in Canada and the United States than abroad concerns the source of the *X-factor*. In current practice in both the UK and Australia, the *X-factor* does not come from a TFP growth study but rather is a way to synchronize current prices (or revenues) with long-term economic forecasts (up to 8 years, depending on the formula period) of capital and operating costs.

61. Such forecasts of long-term costs are contrary to the "known and measurable" standard that lies at the base of utility regulation in North America.[25] Ofgem (the UK regulator), in a recent price review, backed-out the *X-factor* as the value that would permit current prices to

[23] Armstrong, M., Cowan, S., and Vickers, J., *Regulatory Reform: Economic Analysis and British Experience*, The MIT Press, Cambridge Massachusetts (1994), page 165.

[24] "Gordon and Makholm", pp. 32-34.

[25] "An agency is justifiably skeptical of budget cost estimates as a basis for ratemaking. It will rely on test period results to adjustment for known or reasonably expected changes." - Goodman, Leonard Saul. *The Process of Ratemaking.* Volume I, Public Utilities Reports, Inc. Vienna, VA. 1998, p. 281.

trend toward the forecast costs for electricity distributors ending 2015.[26] Australia defines its *X-factor* the same way, as the method of truing-up projected costs with projected revenues during the formula period.[27]

62. In neither case does the *X-factor* relate to a measure of industry productivity growth, as such, and in both cases the transition of regulated prices over the formula period follows forecasts of the type that we believe no regulator of energy utilities in the Canada or the United States has ever countenanced. Quite apart from the merits of the way those other regulators control utility prices, we are of the view that regulators in those other jurisdictions respond to substantially different regulatory institutions that argue against direct comparison to themselves in a PBR case.

63. In any event, there are sufficient North American examples of precedent and practices regarding the application of PBR for energy companies. As a result, we do not conclude that the search for patterns of common or uncommon practices among regulators would be helped by using example outside North America where regulators live in very different institutional environments.

[26] Ofgem (2009) on the electricity distribution price control for April 2010 to March 2015 (Distribution Price Control Review 5). Reference 149/09, 7 December, 2009. Starting on page 57 of that report, which is available online, are the tables for each electricity distribution business, showing how the *X-factor* in its regulatory formula is calculated. It shows a forecast of costs in prices of 07/08, and the *X-factor* that achieves the same revenue as costs with a smoothly rising trend ("profiled") from year to year. See: ttp://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=371&refer=Networks/ElecDist/PriceCntrls/DPCR5

[27] "[t]he *X-factor* must be designed to equalise (in terms of net present value) the revenue to be earned by the Distribution Network Service Provider from the provision of standard control services over the regulatory control period with the provider's total revenue requirement for the regulatory control period." See Australian national rules for electricity distribution (Chapter 6, National Electricity Rules), clause 6.5.9 of Chapter 6, entitled "The *X-factor*." The report can be found on the Australian regulator's website: www.aemc.gov.au.

B. PBR Regulatory Precedent in Canada and the United States

64. There is a reasonable history among regulators in the United States and Canada regarding the parameters that become part of PBR plans. Table 3, below, presents a summary of those plans.

Table 3. Cap-Based PBR Precedents for North-American Energy Utilities

Country	Province/ State	Company	Service covered [1]	Cap Type	Start Year	Term (Years)	Cost Scope [2]	X Factor	Includes Stretch Factor?	Inflation [3]	Flow through provisions / Y Factor?	Capex provisions / K Factor?	Z Factor?	Earnings Sharing Mechanism	Efficiency Carry-Over Mechanism?	Re-openers/ Off-ramps?	Service Quality Provisions	Source [4]
Canada	Alberta	ENMAX Power	Electricity T & D	Price	2007	7	Comprehensive	1.2%	Yes	Canadian EU CPI / Alberta Average Hourly Earnings, 50/50 weighting	Yes [1]	Yes [1]	Yes	50-50 for excess earnings	No	Yes	Penalties	1
	British Columbia	Terasen Gas Inc.	Gas D	Revenue	1998	3	Comprehensive	2.0%-3.0%	No	CPI-BC	Yes [2]	Yes [2]	Yes	50-50, no deadband	No	No	Annual review only	2
			Gas D	Revenue	2004	4	Comprehensive	50%-66% of Inflation	No	CPI-BC	Yes [3]	No	Yes	50-50, no deadband	Yes [1]	Yes	Various standards and incentives	3
		Fortis BC	Electricity G, T & D	Revenue	1996	4	Comprehensive	3.0-4.0% (O&M), 2.0% (Capex); 0% for all costs in last year	No	CPI-BC (O&M), CPI-Canada (Capex)	Yes [4]	Yes [3]	No	50-50, no deadband	No	Annual review	Assessment only	4
			Electricity G, T & D	Revenue	2000	3	Comprehensive	2.0%	No	CPI-BC	Yes [5]	Yes [4]	No	No	No	ND	ND	5
			Electricity G, T & D	Revenue	2007	2	Partial (O&M)	2.0%	No	CPI-BC	No	NA	Yes	50-50, no deadband	No	Annual review	Financial incentives	6
	Ontario	Enbridge Gas	Gas D	Revenue	2000	3	Partial (O&M)	1.1%	Yes	CPI-Ontario	No	NA	Yes	No	No	Yes [1]	Yes	7
			Gas D	Revenue	2008	5	Comprehensive	Implicit in inflation	NA	GDPPI-Canada+A; 0.45 ? A ? 0.60	Yes [6]	Yes [5]	Yes	50-50 sharing of excess earnings	No	Yes	No	8
		Union Gas	Gas D	Price	2001	3	Comprehensive	2.5%	No	GDPPI-Canada	Yes [7]	No	Yes	50-50 sharing around deadband	No	Yes	Penalties	9
			Gas D	Price	2008	5	Comprehensive	1.8%	No	GDPPI-Canada	Yes [8]	No	Yes	Variable/asymmetric sharing of excess earnings	No	No	No	10
		Ontario electricity distribution companies	Electricity D	Price	2000	3	Comprehensive	1.25%	Yes	IPI	No	No	Yes	50-50 sharing of excess earnings	No	No	No explicit financial incentives	11
			Electricity D	Price	2007	3	Comprehensive	1.0%	No	GDPPI-Canada	No	No	Yes	None	No	No	No	12
			Electricity D	Price	2010	3	Comprehensive	0.9-1.3%	Yes	GDPPI-Canada	No	Yes [6]	Yes	No	No	Yes	Reporting requirements only	13
U.S.	California	PacifiCorp	Electricity G, T & D	Price	1994	3	Comprehensive	1.4%	No	IPI	Yes [9]	No	Yes	No	No	No	Rewards & penalties	14
		San Diego Gas & Electric	Electricity and gas G, T & D	Revenue	1994	5	Partial (O&M)	0.9-1.1% [1]	No	IPI	No	Yes [7]	Yes	Variable/asymmetric sharing around deadband	No	Yes	Rewards & penalties	15
			Electricity and gas D	Price	1999	3	Comprehensive	1.1%-1.4%	Yes/No	IPI	Other*	No	Yes	Variable/asymmetric sharing around deadband	No	Yes	Penalties	16
		So. Cal. Edison	Electricity T & D	Price	1997	5	Comprehensive	1.2%-1.6%	No	CPI	No	No	Yes	Variable/asymmetric sharing around deadband	No	Yes	Penalties	17
		So. Cal. Gas	Gas T & D	Revenue	1997	5	Comprehensive	2.1%-2.5%	Yes	IPI	Other**	No	Yes	Variable/asymmetric sharing around deadband	No	Yes	Penalties	18
	Maine	Bangor Gas	Gas D	Price	2000	10	Comprehensive	0.5% [2]	No	GDP-PI	No	No	No	50-50 sharing of excess earnings	No	No	No	19
		Bangor Hydro Electric	Electricity D	Price	1998	3	Comprehensive	1.2%	No	GDP-PI	Yes [10]	No	Yes	50/50 sharing around deadband	No	No	No	20
		Central Maine Power	Electricity T & D	Price	1995	5	Comprehensive	0.5%-1.0%	Yes	GDP-PI	Yes [11]	No	Yes	50/50 sharing around deadband	No	No	Penalties	21
			Electricity D	Price	2001	7	Comprehensive	2.0%-2.9%	No	GDP-PI	No	No	Yes	50-50 sharing of below specified earnings level	No	No	Penalties	22
			Electricity D	Price	2009	7	Comprehensive	1.0%	No	GDP-PI	Yes [12]	Yes [8]	Yes	Yes, 50-50 sharing above 11% ROE	No	No	Penalties	23
U.S.	Massachusetts	Berkshire Gas	Gas D	Price	2002	10	Comprehensive	1.0%	Yes	GDP-PI	No	No	Yes	None	No	No	No	24
		Blackstone Gas	Gas D	Price	2005	5	Comprehensive	0.5%	No	GDP-PI	No	No	Yes	50-50 sharing around deadband	No	No	Penalties	25
		Boston Gas	Gas D	Price	1996	5	Comprehensive	1.5%	Yes	GDP-PI	No	No	Yes	75-25 shareholders-ratepayers sharing around deadband	No	No	Penalties	26
			Gas D	Price	2004	5	Comprehensive	0.4%	Yes	GDP-PI	No	No	Yes	75-25 shareholders-ratepayers sharing around deadband	No	No	Penalties & rewards	27
		Columbia Gas of Mass.	Gas D	Price	2006	10	Comprehensive	0.5%	Yes	GDP-PI	No	No	Yes	75-25 shareholders-ratepayer sharing around deadband	No	No	Penalties & rewards	28
		NSTAR Electric	Electricity D	Price	2007	7	Comprehensive	0.5%-0.75%	Yes	GDP-PI	No	No	Yes	Deadband with 50-50 sharing	No	Yes	Penalties & Rewards/Incentives	29
	Oregon	PacifiCorp	Electricity D	Revenue	1998	3	Comprehensive	0.3%	No	GDP-PI	Yes [13]	No	Yes	Deadband	No	No	Penalties & rewards	30

[1] "G" stands for "generation," "T" for "transmission," and "D" for "distribution."
[2] "Comprehensive" means the cap applies to all costs/rates; "partial" means the cap only applies to some costs/rates.
[3] "IPI" is any utility- or utility-industry-specific price index
[4] See "Sources" table

This sample does not include so-called "stair-step" plans or plans with only rate freezes.
This sample only includes plans with X factors.

Notes - X factor
[1] Stated X factor is implicit in SDG&E's "growth/productivity adjustment"
[2] Only applies to second half of plan.

Notes - efficiency carry-over mechanism:
[1] "Two-year phase out of the final year capital benefit"

Notes - re-openers/off-ramps:
[1] Off-ramp can be requested by company.

Notes - flow through provisions / Y Factor:
[1] For SAS rates in the distribution tariff, TAC Deferral Account, and AESO load settlement costs
[2] "Cost of Defined Required Incremental Activities" (not specified) plus a variety of deferral accounts
[3] Various deferral accounts
[4] Flow through of "variations in property tax, capital tax and AFUDC from the target costs"
[5] Recovery of "extraordinary" O&M expenses, flow through of variances from forecasted income tax rates, and deferrals of regulatory and other small misc. costs
[6] For adjustments for weather impacts on average use in addition to "[r]outine adjustments" including expenses for DSM, CIS, upstream gas, upstream transportation and storage, and tax changes, and various deferral accounts.
[7] For gas-related costs and changes related to ROE
[8] For adjustments for weather impacts on average use in addition to "[r]outine adjustments" including expenses for DSM, CIS, upstream gas, upstream transportation, and storage, and various deferral accounts
[9] For changes in accounting of DSM and taxes

Notes - capex provisions / K factor:
[1] For transmission rates, includes a "G" factor which accounts for prudent investments in transmission growth. Plan also includes a municipal rider for capital "requirements" for distribution operations, with an annual maximum of $15 million.
[2] "Capital Efficiency Mechanism" and allowal for Commission approval of certain capital additions.
[3] Can apply for recovery of "extraordinary" capex
[4] Recovery of "extraordinary" capex
[5] Flow through of incremental capex related to attachment of natural gas-fired power generation projects, classified as Y factor
[6] Incremental Capital Module Materiality Threshold--necessity of capital-related rate relief determined through formula.
[7] Separate cap for capital-related revenue
[8] Price cap adjusted for net capital gains/losses

Notes - flow through provisions / Y Factor:

1 For SAS rates in the distribution tariff, TAC Deferral Account, and AESO load settlement costs

2 "Cost of Defined Required Incremental Activities" (not specified) plus a variety of deferral accounts

3 Various deferral accounts

4 Flow through of "variations in property tax, capital tax and AFUDC from the target costs"

5 Recovery of "extraordinary" O&M expenses, flow through of variances from forecasted income tax rates, and deferrals of regulatory and other small misc. costs

6 For adjustments for weather impacts on average use in addition to "[r]outine adjustments" including expenses for DSM, CIS, upstream gas, upstream transportation and storage, and tax changes, and various deferral accounts.

7 For gas-related costs and changes related to ROE

8 For adjustments for weather impacts on average use in addition to "[r]outine adjustments" including expenses for DSM, CIS, upstream gas, upstream transportation, and storage, and various deferral accounts

9 For changes in accounting of DSM and taxes

10 True ups for misc. expenses related to power purchasing

11 For DSM, accounting changes, Electric Lifeline Program, and a few misc. items

12 For accounting, regulatory, or tax changes, plus a deferral account for tree trimming

13 For DSM

* Tree-trimming and some other misc. costs are excluded from SDG&E's rate indexing mechanism and appear to be recovered through balancing accounts.

** Some costs, such as "catastrophic event costs, environmental remediation costs, low-emission vehicle program costs, mandated social program costs, and regulatory transition costs" are recovered outside of the PBR mechanism.

Notes - capex provisions / K factor:

1 For transmission rates, includes a "G" factor which accounts for prudent investments in transmission growth. Plan also includes a municipal rider for capital "requirements" for distribution operations, with an annual maximum of $15 million.

2 "Capital Efficiency Mechanism" and allowal for Commission approval of certain capital additions.

3 Can apply for recovery of "extraordinary" capex

4 Recovery of "extraordinary" capex

5 Flow through of incremental capex related to attachment of natural gas-fired power generation projects, classified as Y factor

6 Incremental Capital Module Materiality Threshold--necessity of capital-related rate relief determined through formula.

7 Separate cap for capital-related revenue

8 Price cap adjusted for net capital gains/losses

65. For Canada, we list PBR plans for various firms in Alberta, British Columbia and Ontario. In the United States, we list plans employed in California, Maine, Massachusetts and Oregon. In Canada, the plans were rather evenly split between price and revenue caps (either of which is acceptable in our opinion, as long as the traditional and reasonable adjustments are made to the quantities over which average revenues are computed); price caps were the dominant type of PBR plan in the United States. Consumer prices index were the most common inflation factor in Canada, while GDP-PI was dominant in the United States. Almost all plans were comprehensive (i.e., applying to all costs), with only three examples of plans pertaining only to operating and maintenance costs. The *X-factors* were positive in all cases. Almost all plans had a *Z-factor* and some had various versions of pass-through provisions in *Y-factors* and *K-factors*. Almost all had some form of earnings sharing. Two had an efficiency carry-over mechanism and most had some sort of reward/penalty for service quality.

66. Table 4, below, presents the PBR proposals for the Utilities and interveners.

Table 4. Key Components of Applicants' PBR Proposals

Party	Service covered	Cap Type	Start Year	Term (years)	Cost Scope [1]	X Factor	Includes Stretch Factor?	Inflation	Y Factor?	K Factor or Capital Flow-through?	Z Factor?	Earnings Sharing Mechanism	Efficiency Carry-Over Mechanism?	Re-openers/ Off-ramps?	Service Quality Proposal
ATCO Electric	Electricity distribution	Price	2013	4	Comprehensive	-2.0%	No	.65*(AWE-Alberta) + .35*(EUCPI-Distribution)	Yes	Yes	Yes	50-50 sharing outside deadband	Yes	Yes	Rule 002
ATCO Gas	Gas distribution	Revenue	2013	5	Comprehensive	-2.0%	No	.57*(AWE-Alberta) + .43(CPI-Alberta)	Yes	Yes	Yes	50-50 sharing outside deadband	Yes	Yes	Rule 002
AltaGas Utilities	Gas distribution	Revenue	2013	5	Comprehensive	-1.3%	No	.57*(AWE-Alberta) + .43(CPI-Alberta)	Yes	Yes	Yes	Variable sharing outside deadband	No	Yes	Rule 002
EPCOR Distribution & Transmission	Electricity transmission & distribution	Revenue (trans.), Price (dist.)	2013	5	Comprehensive	-0.8% [1]	Yes	.2*(CPI-Alberta) + 0.8(AHE-Alberta) [1]	Yes	Yes	Yes	No	Yes	Yes	Penalties within plan [1]
FortisAlberta	Electricity distribution	Price	2013	5	Comprehensive	-1.0% [2]	No	.39*(EUCPI-Canada*.29) + 0.61*(AHE-Alberta)	Yes	Yes	Yes	50-50 sharing outside deadband	No	Yes	Rule 002
City of Calgary	Does not recommend PBR.														
Consumers Coalition of Alberta	Gas distribution	Revenue	2013	5	Comprehensive	1.32-1.69%	Yes	CPI-Alberta or GDPIPI (FDD) [2]	No	No	No	No	Yes	No	Yes
IPCAA [1]	Electricity distribution														
Consumer Advocate	Does not recommend PBR.														

[1] "Comprehensive" means the cap applies to all costs/rates.

Notes - Party

[1] The IPCAA PBR plan will only include general and administrative costs of non-power system assets and activities and they do not offer specific comments on PBR factors.

Notes - X Factor

[1] Only applied to O&M component of expenses/rates.

[2] FortisAlberta requests a X factor of -2.5% if disallowed flow-through of "externally driven" capital expenditures.

Notes - Inflation

[1] Only applied to O&M component of expenses/rates.

[2] CCA does not offer a specific inflation formula.

Notes - Service Quality Proposal

[1] The inclusion of penalties within the PBR plan would disallow penalties from Rule 002.

C. Common Features of PBR Plans for Canadian and US Energy Distributors

67. PBR plans typically adjust revenues or prices by the following items:

$$Inflation - X\text{-}factor \pm Z\text{-}factor \pm ESM \pm SQ$$

where *ESM* is an earnings sharing mechanism, and *SQ* is a service quality incentive. These make up the common features of PBR plans, and all are included in the applicants' proposals in AUC Proceeding ID 566.

1. Inflation

68. All companies propose to escalate rates by an inflation index reflecting inflation in labor and materials prices, respectively. The index used to reflect increases in the prices of labor is either the Average Weekly Earnings ("AWE") or Average Hourly Earnings ("AHE"), both for Alberta. The index used to reflect materials is either the Electric Utility Construction Price Index ("EU CPI") (with some variation) or the Consumer Price Index for Alberta.

69. While the most common inflation index used in PBR plans is the Gross Domestic Product Price Index (for either Canada or the United States depending on the location of the plan), using a weighted average of input prices is not uncommon. Five of the 30 plans surveyed have utility or utility-industry-specific input price indexes. Perhaps more importantly, the AUC has already approved a similar inflation index for ENMAX Power's PBR plan (one half EU CPI, one half AHE).

2. X-factor

70. The proposed *X-factors* on the part of the utilities range from -0.8 percent to -2.0 percent. Only one *X-factor* includes a stretch factor (0.2 percent, for EDTI). EPCOR's *X-factor* is also meant to reflect partial factor productivity because it only applies to the O&M portion of the

company's price cap formula. None of the cap-based PBR plans we surveyed contained negative *X-factor*s. Indeed, almost all of the *X-factor*s were positive. Plan *X-factor*s averaged around 1 percent, similar to the NERA TFP estimate.

3. Z-factor

71. Every company proposes a *Z-factor*. These typically account for *force majeure* events and have a materiality threshold, which specifies how much (in dollars) the event must impact the utility in order to be passed through to rate holders as a *Z-factor* addition. Ninety percent of the plans had Z factors. The *Z-factors* here were not identical—some allowed for the pass through of different events than others—but in general the plans permitted Utilities to recover the costs of unforeseeable events with material impacts.

4. Earnings Sharing/Re-openers

72. All proposals, except that of EPCOR, include an earnings sharing mechanism (ESM). Three of the four ESMs include symmetrical earnings sharing around a ROE "deadband." The ESM proposal of AltaGas is slightly more complicated and atypical: after the actual ROE reaches a certain level above or below the approved ROE, earnings are shared 60/40 among shareholders and ratepayers, respectively. One half of the PBR precedents had ESMs with 50-50 sharing. A little over one third had deadbands. Others had variable sharing (e.g., 60-40 or 25-75), sharing of all earnings above or below a ROE, or sharing of only excess earnings (i.e., earnings above a certain ROE).

5. Service Quality

73. All but one company proposes to continue regulating service quality under AUC Rule 002. The exception is EPCOR, which proposes to implement a new set of service-quality standards and potential penalties within its PBR plan. Rule 002 does not contain any explicit

penalties; it only states that utilities must justify any failure to meet performance standards and potentially correct for those failures. Of the PBR plans filed in this proceeding, the majority have built-in service-quality incentives. The remaining plans have only assessments/reporting requirements or no built-in measures at all. For those plans without built-in SQ provisions, we did not determine whether the utilities were already required to report SQ under a regulation akin to AUC Rule 002.

D. Uncommon Features of the Utilities' and Interveners' PBR Plans

74. Three key components of the applicants' proposals are *atypical*. These components—*K-factor*s, *Y-factor*s, and efficiency-carryover mechanisms ("ECMs") are not usually found in PBR plans. As above, we compare the provisions in the applicants' proposals to those found in the precedents surveyed in Table 3.

1. K-factor

75. All proposals include capital expenditure ("capex") provisions that, following the lead of some applicants, we label as "*K-factor*s."[28] The general purpose of *K-factor*s is to flow through capital expenditures into rates. *K-factor* provisions are generally *not* included in PBR plans because they can dampen efficiency incentives. The Ontario Energy Board (OEB) summarized the rationale for the non-inclusion of *K-factor*s in its rejection of a *K-factor* for the second generation PBR plan for Ontario electricity distributors:

> Typically, an incentive regulation mechanism is intended to encompass both capital and operating costs. This increases incentives for operating performance. In a capital intensive business such as electricity distribution, containing capital expenditures is a key to good cost management. The addition of a capital investment factor would mean that incentive [sic] under the price cap mechanism would be significantly reduced because the factor would address incremental

[28] Such capital expenditure provisions are also referred to as "Major Projects" factors or included for flow through in the "*Y-factor*" category.

> capital spending separately and outside of the price cap. Further, it would unduly complicate the application, reporting, and monitoring requirements for 2nd Generation IRM because it would require special consideration to be implemented effectively.[29]

76. Despite the common label, applicants' *K-factor* proposals vary in scope. Four of the five proposals are based on forecasts, while one (FortisAlberta's) is based on incurred costs. In addition, proposals specify to varying degree which capital expenditures are subject to flow through. On one end of the spectrum, we observe EDTI proposing to flow through all of its forecasted capital additions; on the other end, FortisAlberta only proposes to flow through a relatively narrow specification of "externally driven" capital expenditures.

Table 5. Applicants' Proposals for the Recovery of Future Capital Expenditures

Company	Proposal for recovery of capital expenditures
ATCO Electric	Flow-through of forecasted capital additions for "reliability," "end of life," and "clearance and safety" programs, in addition to "material capital investment that is unique in nature or not easily forecastable or not within ATCO Electric's Control", "buildings over $10 million," and the "impact of 2012 additions" (for inclusion in 2013)
ATCO Gas	Flow-through of forecasted capital additions - type/amount of additions not specified; also flow-through of "material capital investment that is unique in nature" such as "major buildings over $10 million" and CIS replacement
AltaGas Utilities	Flow-through of annually forecasted capital expenditures related to reliability and safety
EPCOR Distribution and Transmission	Flow-through of forecasted capital additions, with one initial forecast and mid-PBR-term forecast
FortisAlberta	Flow-through of "externally driven" capital expenditures including: distribution line moves, substation associated upgrades, AESO contributions, IPP interconnections

77. Few of the plans surveyed had provisions similar to the capital recovery mechanisms proposed by the applicants in the instant proceeding. We describe these provisions below and in doing so compare them to the applicants' proposals.

[29] OEB, December 20, 2006 Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, p. 37.

78. Only San Diego Gas & Electric's 1994 PBR plan flows through capital expenditures via a formula outside the (I-X) framework. But this formula is nowhere akin to the proposed *K-factor*s. For one, the formula only appears to allow for recovery of *average* capital expenditures, not *above* average or *extraordinary* capital expenditures. In addition, the formula is part of a *partial* PBR plan, in which the "I - X" component of the plan only applies to O&M expenditures—unlike all of the plans in the instant proceeding, save EDTI's.

79. ENMAX Power's PBR plan includes a "*G*" factor that flows through prudent capital expenditures on transmission plant. The *G-factor* is required for unique reasons, as stated in Decision 2009-035: "The *G-factor* is proposed to 'recover the necessary increase in revenue requirement related to infrastructure growth of the transmission system since, unlike the distribution revenue requirement, the Transmission revenue requirement does not increase automatically with load growth," because EPC only has one transmission customer, the Alberta Electric System Operator (AESO). The plan also includes a municipal rider that allows for a maximum annual addition of $15 million in funds for capex "requirements."

80. Two of the plans—both for FortisBC—allowed for approval of "extraordinary" capital additions. Note these plans were not pre-approvals, but only allowed for recovery of capital expenditures due to circumstances beyond the utility's control and subject to Commission approval. FortisBC's plan starting in 1996 allowed the company to apply for recovery of extraordinary capital expenditure, which the company did indeed do in 1999 for Y2K and CIS projects. FortisBC's plan starting in 2000 was more inclusive: it permitted the recovery of significant amounts of "extraordinary" capital expenditures—over half of the total forecasted capital expenditures for the PBR term. This latter plan is perhaps the most extensive of capital

provisions surveyed and also lends most precedence to the plans proposed in the instant proceeding.

2. Y-factor

81. All proposals include a *comprehensive* "*Y-factor.*" As described by the AUC in Decision 2009-035 approving ENMAX Power's PBR plan, *Y-factor*s "arise from cost elements that are - not unforeseen one time events. Flow-through items arise in the normal course of business, but are such that the company has no control over them" (p. 55) (our emphasis).

82. Like the proposed "*K-factor*s," the Y-factor proposals differ significantly from plan to plan, as shown in Table 6:

Table 6. Applicants' Proposals for Recovery of *Y-factor* Costs

Company	Y-Factor Flow-Through Items
ATCO Electric	AESO load settlement costs, system access service payments, distribution to transmission contributions, defined benefit pension plan, income tax items, VOO, rate hearing costs, reserve for injuries and damages, vegetation management costs, head office cost allocation percentage, "new" CIS replacement, REA purchases, changes in depreciation and financing rates, and impacts of regulatory decisions
ATCO Gas	Hearing costs, UCA assessments, reserve for injuries and damages, variable pay program, transmission costs, defined benefit pension plan, weather impacts, load balancing, income tax deductible capital costs, production abandonment costs, changes in the head-office cost-allocation percentage, "transmission driven" costs, costs from acquisitions of natural gas co-ops or other gas distribution systems, changes in depreciation and financing rates, and the impacts of regulatory decisions
AltaGas Utilities	Hearing costs, UCA and AUC assessments, implementation of a code compliant Natural Gas Settlement, DSM, income tax timing differences, changes in accounting standards, potential introduction of automated meter reading, management fees for 2011 generic cost of capital proceeding, and the acquisition of a new gas system with significant impacts on ROE
EPCOR Distribution and Transmission	AESO load settlements; AESO directed projects; property, business, and linear taxes; AUC tariff billing and load settlement initiatives, hearing cost reserves; generic cost of capital changes; "any generic proceeding that impacts operations or T&C's," and self insurance
FortisAlberta	AESO load settlement costs, AUC Rule 026 deferrals, hearing costs, self-insurance, impacts of reassessment by the Canada Revenue Agency, exchange-rate changes for ongoing metering project, commission rule changes, farm transmission costs, depreciation changes, interest-rate changes on long-term debt, income taxes payable, impacts of regulatory decisions, and "true up amounts between initial and final rates for any given year"

83. Comprehensive *Y-factor*s like the proposals above are indeed unusual. However, thirteen of the thirty plans we surveyed contained *some* "flow-through" items. Those *Y-factor* precedents are highly variable. Typical items include: (1) the continuation of some deferral accounts, (2) demand-side management (DSM) costs, (3) customer information system (CIS) costs, and (4) tree-trimming expenses. (Deferral accounts, however, have varied significantly from plan to plan; regulators appear to have approved them on a case-by-case basis. On average, the proposed deferral accounts may be more comprehensive and hence more prone to blunt efficiency incentives than deferral accounts included in previously approved PBR plans.) In addition,

several of the proposed "*Y-factor*" items—namely, accounting, legislative, regulatory, or tax changes—are often flowed through to rates as Z factors instead of "Y" factors.

84. A number of the Canadian PBR plans have some noteworthy *Y-factor* items. Most notably, that of ENMAX Power allows for flow through of SAS rates in the distribution tariff, the TAC deferral account, and AESO load settlement costs. FortisAlberta's 2000 PBR plan flows through some minor "extraordinary" O&M expenses, but they amount to significantly less than what the applicants propose in this proceeding. Enbridge's second generation plan includes flow-through of CIS and DSM, tax changes, and the continuation of numerous deferral accounts. PBR regimes for Terasen Gas and FortisBC also contain *Y-factor* provisions.

3. Efficiency Carryover

85. Three of the five submissions include an "efficiency carryover mechanism." Such mechanisms appear to be generally unprecedented in PBR. To our knowledge, only one plan had a provision similar to the "efficiency carryover mechanisms" proposed in the instant proceeding.

4. The Growth of "Trackers"

86. Both the *K-factor* and *Y-factor* elements in the Utilities' PBR plans have more or less similarity to automatic adjustments, or more colloquially "trackers," in the context of ratemaking. Because we think that there is merit in asking for certain kind of tracked cost recovery, even if not in the context of a PBR plan as such, we think it is useful to describe such plans as have developed recently among regulators in the United States.

87. Commissions have traditionally used automatic adjustment clauses to allow retail rates to change because of fuel/gas cost changes or taxes:

> Adjustment clauses typically are allowed for exceptional expenses, such as fuel or purchased gas by a LDC, and occasionally taxes other than income taxes, where the particular costs are a major element of the overall costs of the utility, fluctuate widely, and are outside the utility's control.[30]

88. More recently, regulatory commissions have adopted other adjustment clauses to allow for the recovery of specific investments outside a normal rate case, and capital trackers are such an example. Capital trackers allow a regulated firm to recover qualified investments quicker and more efficiently than a normal rate case. Trackers are used in various situations where the typical regulatory rate case provides an inadequate mechanism to adjust rates in response to increased investment in infrastructure. Capital trackers help ensure that the company in question has the financial standing necessary to invest in infrastructure needed to provide efficient, safe, adequate, and reliable service to its customers, in both good markets and bad, both now and in the long run. The objective of a cost recovery mechanism is to reverse the regulatory lag associated with infrastructure investment.

89. The basic idea of a capital tracker is to recover the costs of *qualified infrastructure investments* incurred between rate cases through an asset tracker. The definition of "qualified investments" varies; for example, the definition for People's Gas looks at qualified additions that have not been included in rate base associated with replacing aged facilities.[31] The definition of "qualified" infrastructure investments is specifically tailored to the specific needs of the company.

[30] Goodman, Leonard Saul. *The Process of Ratemaking.* Volume II, Public Utilities Reports, Inc. Vienna, VA. 1998. Page 1207.

[31] The program defines qualified investments as, "replacement mains and related appurtenances such as services, meters, regulators, measuring and regulating stations, city-gate check stations, and other ancillary infrastructure."

90. Capital trackers are used to recover the costs of a classified, pre-approved set of infrastructure investments. The tracker does not include all infrastructure investments, rather only infrastructure investments that meet the classifications set at the on-set of the tracker; all other infrastructure investments are recovered in the company's next rate case proceeding. A "qualified investment" is an investment that meets the pre-set conditions for inclusion in the asset tracker. Typically, the proposed accounts included in a capital tracker go beyond the scope of routine investments required to support existing infrastructure. Qualified investments are specific, non-routine investments recovered outside of the normal rate case proceeding. A list of examples of approved capital cost recovery trackers for both gas and electric distribution companies appears in the Appendix.

91. The typical review process for a capital tracker varies by jurisdiction and the type of infrastructure tracker in question. Some trackers are subject to prudence reviews in the case of cost overruns. In other cases, no adjustments are made if costs are higher than originally anticipated in the budget, and the company is forced to suffer from the cost overrun. In between these extremes are mechanisms in which the variation between the budgeted amount of the investment and the actual expenditure is shared between the company and its customers. Finally, specific investments may require specific review processes in order to ensure the effectiveness of the program, such as investment in smart grid. Trackers for smart grid investments, for example, often employ penalty/rewards that encourage effective investment and use of the smart grid system.

E. Pros and Cons of the Proposed PBR Plan Elements

92. In this section, we comment on the forms and parameters of the proposed PBR plans from the Utilities and interveners. In assessing each proposal, we are driven by the goals of objectivity, administrative efficiency, and usefulness of plan elements as innovations from traditional regulation supporting longer regulatory lag and enhanced incentives.

1. Inflation

93. An inflation index should be exogenous, reasonably reflecting the cost behavior facing the industry. It should also be based on publicly available information, frequently updated, transparent and easy to understand. In addition, we echo the Commission's statement in Decision 2009-035 (p. 30):

> Such an index should reflect changes in the costs experienced by as large a sample of distribution and transmission companies as possible. The Commission recognizes that the development of such an index can be made extremely complex by attempts to track discretely inflation rates for multiple cost elements and also recognizes that increased complexity does not necessarily lead to a superior index. The Commission recognizes that the Ontario Energy Board experimented with the development of such an inflation index and ultimately rejected it. (p. 30)

94. There is rarely any particular contention surrounding the inflation component of PBR plans, as objective and reliable price indexes are readily available both for input and output prices. None of the proposals from the Utilities or interveners appear problematic in this regard.

2. X-Factor

95. For PBR plans in North America, the *X-factor* draws the most attention—precisely because reasonable expectations about the future prospects for productivity growth in any industry are difficult to predict objectively. Such is the reason why regulators often-enough rely on index number studies to gauge productivity growth. Those productivity growth studies

require the meticulous gathering and processing of large data sets and are reasonably costly to perform. But they have a solid scholarly foundation that pre-dates their use for PBR plans, and they are capable of being readily updated in the future rate cases that such PBR plans call for. Most of all, such productivity growth studies are *objective*—a preeminent requirement given the money at stake over the multi-year runs of PBR plans and the role of the regulator as a quasi-judicial arbiter of the traditional clash of interests between utility investor-owners and the public served by those utilities. Objectivity is the most important criterion—ability to replicate in the future is second.

96. The utility *X-factor* proposals offered by the Utilities cannot be labeled objective, in one of two ways. The first is the truncation of our study without an objective basis for doing so, which we discuss at length above. The second is in the *ad hoc* selection of productivity index numbers not representative of the industry in question or also for time periods that are not drawn from objective or scholarly sources outside this case—much the same issue as the truncation of our study. We do not mean to be excessively critical of the various discussions offered by Dr. Carpenter for ATCO, Dr. Cicchetti for Epcor, Dr. Schoech and Mr. Canfield for AltaGas, or Ms. Freyer for Fortis Alberta. However, the *X-factors* that they offer are based on time periods or sources that cannot be freed from these analysts' subjective judgment. For a parameter that will affect ratepayer bills for multiple years, we conclude that any deviation from objectivity is a drawback.

97. The *X-factors* recommended by the Utilities are uniformly negative. The theory upon which PBR is based, which draws from the pressures facing competitive firms, makes no distinction or restriction for the sign of the *X-factor*. But there are two practical considerations concerning what the Utilities have recommended in this regard. First, as an empirical matter,

negative *X-factors* are outside the realm of experience for PBR plans in North America. Second, we do not think that it would be misplaced for the AUC to question the imposition of a PBR plan that would dictate a period of automatic real price (or revenue) increase in light of the utility industry's very longstanding experience with the opposite trend.

98. Dr. Lowry and his PEG colleagues, for the CCA, perform an index number study of the same type as ours, using a 14 year period for measuring gas distributions costs. We do not know whether that is the longest possible time period available for the data used for that study, as the case with the NERA study. While we support Dr. Lowry's method, and we appreciate his suggestions for improvements for our own, we also note that he uses input data that he considers proprietary. Without those proprietary data, his study is not replicable by others—either now or at the time of the next base rate case when the parameters of the PBR regime would be subject to re-set. In any event, the *X-factor* that Dr. Lowry recommends is in the range that one would consider acceptable given experience for other energy utilities in North America.

99. Dr. Lowry also includes an econometric analysis to predict TFP growth that he describes as "more customized to business conditions in Alberta." Because any econometric analysis of the factors that contribute to the size of the TFP growth numbers in a index study is unavoidably the result of many judgments that are difficult for non-specialists to understand, we would not recommend such econometric analyses for the purpose of setting the level of consumer prices in a PBR plan—as opposed to econometric studies for peer-reviewed scholarly research.

100. We have no opinion on the stretch factor recommended by Dr. Cicchetti. Ultimately, stretch factors are subjective judgments on the extent to which, given the history of the utilities in a jurisdiction, the change to PBR may spur innovation and cost reduction not shown

previously. We have not studied the Alberta utilities for such purposes, and hence we cannot offer an opinion.

3. Z-Factor

101. Regulators commonly use *Z-factors* to protect utilities against material events outside of their control—just as competitors in an industry would all adjust prices for exogenous cost changes that affect them all. All of the Utilities and interveners propose a *Z*-factor, and we support the practice.

4. Earnings sharing/Re-openers

102. An ESM reduces the risk of a PBR plan unintentionally tipping the regulatory balance in favor of customers or shareholders. As the AUC stated in Decision 2009-035, p. 57:

> [m]ost parties [in the ENMAX PBR application] suggested that earnings sharing should be adopted if the Commission considers that there is a significant risk of setting the productivity target either too high or too low. UCA in particular noted that PBR design errors, such as mistaken estimates of potential productivity, can result in sizeable increases in regulated monopolies' profits. … The earnings sharing mechanism was viewed by parties as an important safety measure to limit such increases.

103. We agree. While an ESM can reduce efficiency incentives, it may be prudent to include them to reduce regulatory risk. 50-50 sharing of earnings of excess earnings *and* earnings shortfalls is the most common sharing agreement and does not favor either customers or shareholders. Including a "deadband" within which utilities do not share deviations in earnings improves efficiency incentives, but increases financial risks for customers and shareholders alike.

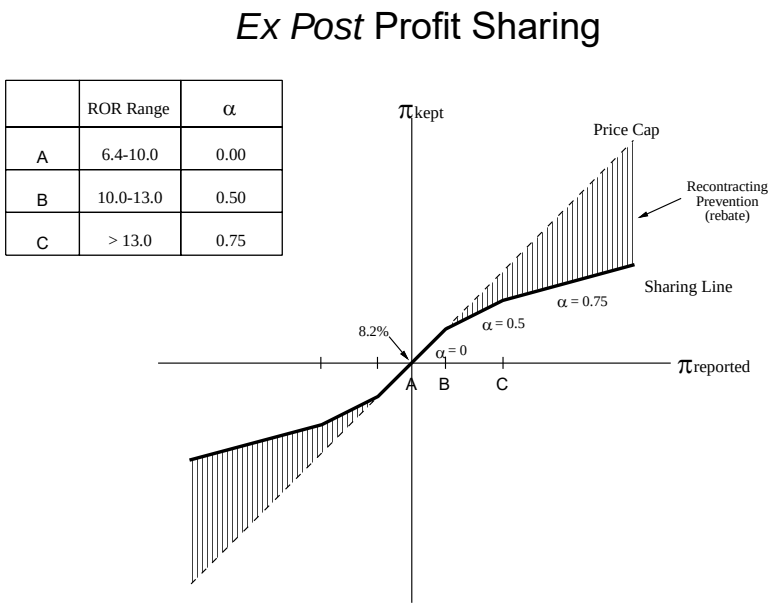
104. Under certain circumstances, the PBR plan may warrant amendments or termination before the end of the term of the plan. All of the applicants propose re-openers and off-ramps to amend or adjust the PBR plan if circumstances warrant such a change. Re-openers and off-ramps are common aspects of incentive plans, and we recommend such a mechanism in the current plan.

105. Earnings sharing reduces the incentives to the company, as when earnings are shared the company keeps less than the full profit it earns. Regulatory "recontracting," and the threat of it, also reduces the company's incentives. A balance between these two needs could include no sharing whatsoever. The early U.S. telecommunications plans featured earnings sharing mechanisms (along with relatively broad *Z-factors* and duration of less than 5 years). Since 1994, the duration until the first review for new plans has been five years or longer. Similarly, although earnings sharing was fairly common in early plans, *no* plan adopted after 1993 has included sharing.[32]

106. Earnings sharing can lend stability to a PBR regime, particularly one that is in its first generation. At the outset, no one can say with certainty that the parameters set will prove to be the right ones—parameters that result in the company having a reasonable opportunity to earn a fair return on its investments while still not rewarding the company unduly. The stabilizing effect of earnings sharing can be depicted as in Figure 2.

[32] Tardiff, T. and Taylor, W.E., "Revising Price Caps: The Next Generation of Incentive Regulation Plans," Topics in Regulatory Economics and Policy, Crew, Michael A. (Ed.), Vol. 24, Springer, 1997.

Figure 2. *Ex Post* Profit Sharing



107. In Figure 2, 8.2 percent is shown as the target cost of capital for illustrative purposes.[33] The dead band is 1.8 percent. If the company earns between 6.4 and 10 percent, there is no profit-sharing. If the company earns between 10 and 13 percent, it shares one half of the profits earned in that interval. If the company earns in excess of 13 percent, it shares one half of the profits from 10 to 13 percent plus 75 percent of the profits above 13 percent. In the Figure, losses are treated symmetrically.

108. The shaded area is the size of the rebate. The rebate dampens both the company's profits and losses. This dampening effect grows as the reported profits deviate by a greater degree from the allowed return. The rebate lessens the incentive to recontract. This protection from recontracting grows. It does so as achieved profits for the year deviate from what was expected when the profit sharing regime was set up.

[33] This is purely as an illustration. Actual capital costs for utilities in Canada are higher.

109. The cost of earnings sharing is that, to the extent sharing is in effect (i.e., outside the dead band), it dampens the incentives of a company to innovate to cut costs and expand sales. That is, some efficiency incentives are given up in return for a more stable regime. In Figure 2, the sharing line slopes upward, but at a decreasing rate as we move away from the origin (denoting that the sharing percentage increases). At expected profit levels, little or no sharing takes place and companies have full incentive to maximize profits. As profits increase, the level of sharing increases as well. The shape of this sharing line can help to provide a natural stability for PBR plans.

5. Service Quality

110. We agree with the perspectives of Dr. Cicchetti for Epcor and Dr. Lowry for the CCA on the question of service quality—that a plan to include a balance of rewards and penalties is a useful part of a PBR regime. To be sure, AUC Rule 002 is a reasonable benchmark for maintaining safe, adequate, and reliable service in the public interest. Nevertheless, PBR is driven by a belief in the power of profit incentives, and we are not in possession of any information that would lead us to conclude that balanced rewards and penalties—which dominate among North American PBR plans—are unwise to implement in Alberta.

6. K-Factor

111. Among the Utilities, the stated goal of *K-factors* is to ensure that the companies recover prudent capital expenditures. Of course, the regulatory compact generally specifies that utilities recover prudently-incurred costs in a in a reliable and timely manner. But PBR plans generally do *not* include *K-factor* provisions. The OEB, for its part, described the rationale for excluding such elements for the second generation PBR plan for Ontario electricity distributors:

> Typically, an incentive regulation mechanism is intended to encompass both capital and operating costs. This increases incentives for operating performance. In a capital intensive business such as electricity distribution, containing capital expenditures is a key to good cost management. The addition of a capital investment factor would mean that incentive under the price cap mechanism would be significantly reduced because the factor would address incremental capital spending separately and outside of the price cap. Further, it would unduly complicate the application, reporting, and monitoring requirements for 2nd Generation IRM because it would require special consideration to be implemented effectively.[34]

112. We would agree, as a general matter. Utilities must make capital expenditures to continue to operate in a safe and reliable manner; however these expenditures may be treated in a manner better targeted than an encompassing *K-factor*. Numerous regulatory bodies have adopted infrastructure trackers (see Section D.) for specific capital expenditures, and that is the approach we recommend here. The capital expenditures that are candidates for such trackers must be comparatively unusual and narrowly defined (such as cast iron pipe replacement for gas distributors or specific aged infrastructure replacement for electric distributors). The AUC did not approve a capital factor in its 2009 decision regarding Enmax.[35]

7. Y-Factor

113. *Y-factors* operate under the premise that management and/or ratepayers should not be held responsible for costs *beyond their control*. We agree. However, this classification of costs should be very limited. An overly broad *Y-factor* would reduce efficiency incentives under PBR.

114. The Utilities propose a variety of *Y-factor* items. Some have more precedence than others. We recommend that the Commission carefully examine each of the proposed *Y-factor* items to determine whether they satisfy the criteria for flow through that it set out in Decision

[34] OEB, December 20, 2006 Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, p. 37.

[35] AUC Decision 2009-035.

2009-035: "[F]low through rate adjustments arise from cost elements that are not unforeseen one time events. Flow-through items arise in the normal course of business, but are such that the company has no control over them."[36]

115. While the Commission did allow flow-through treatment for three specific items in the ENMAX Order, the Commission went on to state, "EPC proposed that the above items be included in the Commission approved FBR formulas as an "F" adjustment. The Commission does not consider it necessary to include these elements in the rate adjustment formulas because they are not rates adjusted by the formulas. They will continue to be treated as they are currently."[37]

8. Efficiency Carryover

116. As we have stated above, efficiency carryover mechanisms are uncommon in North America. We conclude that it is best to view the issue as a desire to lengthen regulatory lag by other means and could well be dealt with in that context. To be sure, the Utilities that support the measure offer only conceptual arguments for it. As such, we do not think that there is a reason for the AUC to depart from generally accepted practice and avoid the incremental complexity of an efficiency carryover mechanism.

[36] AUC Decision 2009-035, p. 55.

[37] AUC Decision 2009-035, p. 55.

V. Appendix

Table 7. Examples of Electric Recovery Mechanisms for Qualified Investments

State	Company	Tracker Name	Eligible Investments
Arkansas	SWEPCO	Generation Recovery Rider	Rider allows recovery of **costs associated with the Stall generating facility** that has received a certificate of environmental compatibility and public need issued by the Arkansas Public Service Commission
California	Southern California Edison	Advanced Metering Infrastructure Balancing Account	Expenditures up to the total authorized funding level of $1,633.5 million are deemed reasonable and the revenue requirement associated with those expenditures shall be recovered through the **SmartConnect (Advanced Metering Infrastructure)** without any after-the-fact reasonableness review.
Colorado	Public Service Company of Colorado	Transmission Cost Adjustment	**Rider to recover ongoing costs, other than operating and maintenance costs, associated with incremental transmission investments.**
Iowa	MidAmerican Energy	Cooper Tracking Mechanism	Additions Tracker provided a mechanism for recovery of the amount of **Cooper Nuclear Station capital expenditures** filed with the Iowa Utilities Board for recovery through the application of the tracker.
Louisiana	Cleco Power	Infrastructure and Incremental Costs Recovery	The Infrastructure and Incremental Costs Recovery Mechanism applies only to **Acadiana Load Pocket Transmission Project.**
Missouri	Atmos Energy	Infrastructure System Replacement Surcharge	The infrastructure system replacement surcharge (ISRS) covers only a part of the expenses that the Company must incur to **maintain and upgrade its system and to relocate facilities in connection with local, state and federal public improvement projects.**
New Jersey	Public Service Electric and Gas	Solar Loan II Program	Allows the Company to recover costs to **install 51 MW of solar on homes, businesses and municipal buildings.**
Ohio	Duke Energy Ohio	Infrastructure Modernization Rider	Infrastructure Modernization to recover increased costs for **maintaining and modernizing the distribution system, including SmartGrid investments** and a $9 million investment in an electronic bulletin board to enable Duke and alternative power suppliers to post market prices for consideration by consumers.
Oklahoma	Oklahoma Gas and Electric	Smart Grid Rider	Tariff Rider to recover up to $20 million of capital O&M costs related to company-proposed **SmartPower deployment of 42,000 smart meters** in Norman, OK.
Pennsylvania	PPL Electric Utilities	Renewable Energy Development Rider	Recover costs associated with **installing a device or devices not exceeding 10 KW which are, in the Company's sole judgment, a bonafide technology for use in generating electricity from qualifying renewable energy installations.**

Source: Company Tariffs

Table 8. Examples of Gas Recovery Mechanisms for Qualified Investments

State	Company	Tracker Name	Eligible Investments
Georgia	Atlanta Gas Light	Pipeline Replacement Program	The Atlanta Gas Light Pipeline Replacement Program is a 15-year project to replace more than 2,300 miles of **bare steel and cast iron natural gas pipeline** in Georgia. Each year in the fall, the Georgia PSC reviews the company's infrastructure replacement expenses from the previous year and then approves the new surcharge amount.
Illinois	Peoples Gas Light and Co	Rider Incremental Cost Recovery	Peoples Gas Light & Coke's tracking mechanism for investments related to gas main replacement programs was authorized in 2010 and implemented in 2011. The program covers **replacement mains and related appurtenances such as services, meters, regulators, measuring and regulating stations, city-gate check stations, and other ancillary infrastructure.**
Indiana	Vectren North	Distribution Reliability Adjustment	North received approval to implement a tracking mechanism that allows the utility to defer expenses associated with **investments in infrastructure replacement projects.** Vectren defers the recovery of depreciation expense and property taxes and continues to utilize the allowance for funds used during construction (AFUDC) for 4 years from the date that each replacement was put in service.
Mass.	Bay State Gas	Targeted Infrastructure Factor	Columbia Gas of Massachusetts received approval of its Targeted Infrastructure Reinvestment Factor (TIRF) as part of its last base rate case in October 2009. The TIRF allows for the recovery of the revenue requirement associated with **bare steel capital additions** for the previous calendar year, including: mains, services, service tie-ins, meters, meter installations, regulators, and industrial measuring and regulating equipment.
Mass.	National Grid	Targeted Infrastructure Factor	The Massachusetts DPU issued a decision in a rate case for National Grid Massachusetts companies Boston Gas, Essex Gas and Colonial Gas. The DPU adopted targeted infrastructure recovery factors for the companies. The TIRFs provide for the recovery of costs associated with the **accelerated replacement of gas mains** and the companies are allowed to surcharge customers up to 1% of total revenue.
Michigan	SEMCO	Cap. Infrastruc-ture Investment Auto. Adj. Mechanism	This mechanism will enable SEMCO Energy to recover the incremental capital-related costs associated with the accelerated **removal and replacement of cast iron and unprotected steel service lines and mains.**
Nebraska	All NG Utilities	NA	The ISRS allows the rates of a gas utility to be adjusted twice per year to provide for the recovery of costs of **eligible infrastructure system replacements.**
New Hamp.	National Grid	Cast Iron Bare Steel Replacement	New Hampshire – National Grid New Hampshire - Energy North Natural Gas Energy North Natural Gas has had a **Cast Iron Bare Steel (CIBS) Replacement Program** for several years.
Texas	Atmos Energy Corp.	Bare Steel Pipe Replacement	This rate is designed to recover costs related to the Company's **steel service line replacement program**. A risk-based approach will be adopted to allow replacement of the highest priority steel service lines within this time period.
Utah	Questar Gas	Infrastructure Replacement Adjustment	The Utah PSC authorized Questar Gas to implement a three-year pilot Infrastructure Replacement Adjustment (IRA) mechanism to track and recover between rate cases the costs associated with the **replacement of high-pressure natural gas feeder lines**. (1) Age and performance of existing pipeline (2) Reconditioned pipe (3) Operating and maintenance history. (4) Pipeline safety compliance.

Source: Company Tariffs